ATCO Electric Yukon
(AEY)

TOPIC: **Wholesale Sales Forecast**

REFERENCE:

	2017	2018	Source
Wholesale Sales (MWh)	309,000	309,519	Application, Table 2.1
Wholesale Purchases (MWh)	314,234		ATCO Electric Yukon Compliance Filing, Schedule 3.1, Approved Board Order 2017-03

PREAMBLE: AEY is interested in more information regarding YEC's Wholesale forecast.

QUESTION:

a) Please explain the difference between YEC's 2017 Wholesale Sales forecast and AEY's 2017 Purchase forecast. Please provide any calculations relevant to YEC's Wholesale Sales forecast.

ANSWER:

(a)

YEC's 2017 firm Wholesale Sales forecast of 309,000 MWh was finalized before receiving AEY's Compliance Filing 2017 firm Purchase Power forecast of 314,234 MWh.

At the time when YEC finalized its forecast of 309,000 MWh, YEC had noted AEY's prior forecast in its original Application of 300,325 MWh.

While YEC takes into account AEY's forecast on an annual basis, YEC prepares its own separate forecast based on professional judgement. In addition to considering information received from AEY, YEC used a multivariate linear regression model to validate the judgmental forecast.

Please also see responses to CW-YEC-1-11, and YUB-YEC-1-59.

Please also see response to YUB-YEC-1-3 regarding the difference between YEC's GRA and the AEY Compliance Filing as approved by Board Order 2017-03.

TOPIC: **LED Streetlight Retrofits**

REFERENCE: "In 2015, Yukon Energy decided to move forward with the retrofit of their streetlight assets with LEDs. A consultant was retained to develop a technical specification that was used in a competitive bidding process. Streetlights in downtown Dawson and Mayo were retrofit in 2016 with plans to retrofit the remaining streetlights in Faro, Mendenhall and Champagne in 2018.

The net cost of piloting LED streetlights to 2016 is $0.142 million and the cost for retrofitting the streetlights in Dawson and Mayo with LEDs in 2016 was $0.168 million. The cost of completing the retrofits will be $0.080 million in 2018."

- Application, Page 5-42

"293. With respect to LED streetlight installations that are not end-of-life conversions, the Board directs AEY to treat the costs related to new installations or requested conversions as capital costs that attract a full customer contribution in aid of construction."

- Board Order 2017-01

PREAMBLE: AEY is interested in more information regarding YEC's LED streetlight retrofitting program.

QUESTION:

a) Are the lights that YEC is retrofitting at their end-of-life? If so, please explain how YEC determines when lights are at end-of-life?

b) Did YEC receive customer contributions for the LED Streetlight Retrofits?

c) Please discuss YEC's views respecting LED retrofits in the context of: i) Board Order 2017-01; ii) the postage stamp rate environment in the Yukon; and iii) the shared investment policy with ATCO Electric Yukon.

ANSWER:

(a), (b) and **(c)**

Please see response to YUB-YEC-1-81.

TOPIC: **DCF**

REFERENCE: "Update to DCF Cap – Updated information on the adequacy of the existing DCF cap is reviewed, in order that the Board and interveners can assess options to the current +/-$8 million cap. No specific option to modify this cap is proposed in the Application."

- Application, Page 3.4-9

"Prospects today for continuation or a material increase in loads within the next several years helps to secure more efficient use of existing hydro generation capability, but also indicates ongoing need for a robust DCF to deal with water year variability of the hydro generation, i.e., the Minto mine is now expected to continue operations until at least 2020 (and perhaps until 2022), and there are also renewed near-term prospects for new connected Alexco Resources and Victoria Gold mine loads (see Tab 2 of this Application)."

- Application, Page 3.4-11

"Attachment 3.4.4 assesses the extent that a higher DCF cap of +/- $16 million (versus the current +/- $8 million cap) could reduce Rider E impact frequency and enable the DCF to be more robust in dealing with severe drought (with reduced rate instability for ratepayers)."

"Based on the DCF cap update assessments as reviewed above, the Board and intervenors can assess the indicated benefits of **increasing** the DCF cap at this time."
[**emphasis added**]

- Application, Page 3.4-12

PREAMBLE: AEY is interested in more information regarding YEC's DCF.

QUESTION:

a) What percentage of YEC's 2017 revenue requirement is related to the $8 million DCF cap? What percentage of YEC's 2017 revenue requirement would be related to a $16 million DCF? What would the DCF cap be based on 5% of revenue requirement?

b) Please discuss how YEC would financially support a negative DCF balance up to:
   a. $8 million;
   b. $16 million;
   c. 5% of revenue requirement;
   d. For example, would the corporation issue debt? How would carrying charges be addressed?

c) Please discuss the pros and cons of the DCF cap as a percentage of revenue requirement, as calculated in part a) of this response.

d) Has YEC considered decreasing the DCF cap?

e) Please discuss how appropriate price signals will be sent to customers to incent energy conservation, in the event of a drought and fossil fuel must be used for generation.

f) Please discuss YEC's views respecting time-of-use metering. Please comment on whether the DCF will continue to be relevant if time-of-use metering is implemented in the Yukon. Please comment on whether YEC believes time-of-use pricing will be implemented when fossil fuel is used for generation.

g) Please discuss intergenerational equity and how it relates to the DCF. Please comment on how the DCF may be impacted by a significant load addition if a drought is experienced around the time of connection.

ANSWER:

(a) and **(c)**

YEC's revenue requirement is not in any way related to, or affected by, the DCF cap, i.e., DCF determinations are not tied to YEC's revenue requirement as such, and the DCF cap does not affect DCF determinations relating to YEC's final generation costs in any given year.

YEC's revenue requirement in 2017 is $48.5 million.

- An $8 million DCF cap is 16% of $48.5 million.
- A $16 million DCF cap is 33% of $48.5 million.
- A DCF cap based on 5% of $48.5 million equals $2.4 million, i.e., an amount well below the +/-$8 million cap approved by the Board in Order 2015-01.

There is no apparent basis or benefit from setting the DCF cap as a percentage of revenue requirement as reviewed above. As reviewed by the Board in Order 2015-01, and as updated in Tab 3, Attachment 3.4.4, the principled basis for setting the DCF cap addresses minimizing the frequency of related rate riders and enhancing the robust ability of the DCF to deal with drought conditions affecting hydro availability.

(b)

YEC has a $10 million line of credit that would be used to finance a DCF shortfall up to the current cap of $8 million. If the Board directed that this cap would be increased to $16 million, YEC would propose to accrue cash sufficient to cover the increase in a trust bank account over a reasonable period of time. This approach would avoid finance charges on this excess balance.

As reviewed in Tab 3, Attachment 3.4.4, during a severe drought YEC would experience a need to borrow funds beyond the DCF caps examined in order to finance actual thermal generation costs incurred.

With respect to carrying charges on negative balances in the DCF, the DCF Term Sheet as approved by the Board provides as follows for interest relating to the Fund:

"The Fund is to attract interest based upon the short/intermediate term bond rates in which YEC may invest the Fund and any negative balances would only attract interest at the lowest short-term borrowing rate available to YEC through a line of credit."

(d)

Tab 3, Attachment 3.4.4, which reviewed the DCF cap, notes the reasons of the Board in Order 2015-01 for rejecting a lower DCF cap for 2013 and the fact that the current 2017/18 GRA forecast indicates a slightly higher forecast firm load and LTA generation in 2018 than was approved for 2013. YEC concluded as follows (page 3.4-11): "This alone suggests that there is no reasonable basis today to consider any lower cap than the +/-$8 million last approved by the Board."

(e), (f) and **(g)**

As reviewed at length in the last DCF proceeding, the DCF has been established to provide stability for rates, and to reflect the underlying long-term valuation of renewable hydro and wind generation (where economic feasibility typically is assessed based on long-term average energy supply). In this context, intergenerational equity is enhanced to the extent that the DCF is able to provide rate stability – and price signals (i.e., higher rates) during a drought to promote conservation are not seen as fair or reasonable.

The DCF requirements will remain with or without time of use metering and/or time of use pricing.

As reviewed in Tab 3, Attachment 3.4.4, DCF caps in the range from $8 to $16 million will still be expected to require special rate riders during historic drought water conditions.

- At a 420 GW.h load, increasing the DCF cap from $8 to $16 million reduces the peak drought year charge as estimated in this analysis from $13.6 million to $4.7 million, and reduces the average charge per year (for years with rate rider charges) from $4.2 million to $2.2 million.

- At a 450 GW.h load, increasing the DCF cap from $8 to $16 million reduces the peak drought year charge as estimated in this analysis from $14.0 million to $8.2 million, and reduces the average charge per year (for years with rate rider charges)

from $4.8 million to $3.5 million. A modest added increase in the DCF cap above $16 million is noted to likely be needed to reduce peak year charges to levels noted for the 420 GW.h load.

TOPIC: **DCF**

REFERENCE: "[12] Long-term average hydro generation under any set of assumed grid generation load and grid generation capacity and licence conditions is determined in the 2017/2018 GRA based on the then-current YECSIM power benefit model calculations based on 35 years of water record for the interconnected grid and updated reservoir and generation station water flow requirement changes as noted in Appendix 3.4 of the Application. As load grows a portion of the load growth is currently served (on average) by increased hydro output and the remainder by increased average thermal generation (diesel or LNG)."

- Application, Page 3.4-14

PREAMBLE: AEY is interested in more information regarding YEC's LTA water record.

QUESTION:

a) What explain and indicate how the "35 years of water record" is determined? Can operational changes at YEC influence the water record?

b) Is the "35 years of water record" publically available? If not, please provide the 35 years of water record along with descriptions of the data provided and how this information is used.

c) If operational changes at YEC impact the water record, per part a) of this response, has YEC considered a shorter period for the DCF water record? Please discuss the pros and cons of going to a shorter period for the DCF water record.

ANSWER:

(a), (b) and **(c)**

Tab 3, Attachment 3.4.2 outlines the data (including hydrological water records, used as input to the YECSIM model. Inflow water data is not generally influenced by operational

changes at YEC. The applicable water record data is provided in AEY-YEC-1-4 Attachment 1.

As regards considering a shorter period for the DCF water record, planning models for hydro generation systems seek to secure longer rather than shorter periods of reliable data for the water records used in the simulation models.

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1981	1	125.5	3.9	7.2
1981	2	106.0	-0.2	7.3
1981	3	115.4	3.2	7.5
1981	4	91.8	2.7	8.0
1981	5	86.1	1.9	5.2
1981	6	79.0	3.1	3.1
1981	7	90.8	1.7	3.3
1981	8	89.1	1.9	3.1
1981	9	73.6	2.5	3.2
1981	10	77.9	2.4	6.2
1981	11	64.1	2.4	6.5
1981	12	56.7	2.8	6.5
1981	13	50.2	2.9	6.6
1981	14	33.7	3.3	4.7
1981	15	34.5	3.0	3.3
1981	16	45.8	9.9	6.9
1981	17	41.7	9.1	7.6
1981	18	77.0	9.1	10.0
1981	19	148.6	9.1	55.9
1981	20	260.0	10.2	69.7
1981	21	432.7	15.2	55.4
1981	22	594.5	12.1	41.6
1981	23	535.2	16.2	43.5
1981	24	509.0	12.6	32.4
1981	25	666.2	11.7	31.0
1981	26	652.7	12.6	33.5
1981	27	566.7	20.8	51.1
1981	28	575.5	19.1	41.3
1981	29	727.5	13.8	28.9
1981	30	700.3	14.7	28.4
1981	31	658.5	10.3	26.7
1981	32	729.2	6.7	22.5
1981	33	607.7	9.9	20.1
1981	34	550.1	12.4	10.2
1981	35	594.1	7.7	2.6
1981	36	669.2	5.1	9.6
1981	37	739.9	5.3	20.4
1981	38	562.8	10.3	28.1
1981	39	432.1	10.8	21.7
1981	40	358.0	4.5	9.0
1981	41	343.2	5.6	10.1
1981	42	361.9	8.1	17.5
1981	43	327.2	10.7	9.3
1981	44	334.9	1.5	4.7

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1981	45	284.1	3.9	2.2
1981	46	219.9	4.1	6.1
1981	47	209.8	2.5	9.3
1981	48	168.1	3.5	10.7
1981	49	131.3	4.5	2.8
1981	50	145.5	3.0	9.0
1981	51	138.7	5.4	7.2
1981	52	106.8	3.3	9.5
1982	1	85.9	3.6	4.8
1982	2	119.9	6.7	4.8
1982	3	97.9	3.4	8.7
1982	4	105.4	1.8	11.6
1982	5	120.2	-1.5	9.6
1982	6	80.1	2.5	4.7
1982	7	75.7	2.2	4.2
1982	8	58.7	6.7	4.7
1982	9	71.3	1.2	4.1
1982	10	84.6	0.4	2.3
1982	11	69.0	0.4	1.1
1982	12	45.6	0.3	1.5
1982	13	29.3	0.4	0.2
1982	14	47.0	0.4	-4.5
1982	15	41.6	0.4	5.7
1982	16	57.0	3.7	6.0
1982	17	42.2	9.5	0.1
1982	18	44.0	4.5	-2.3
1982	19	48.4	17.0	18.1
1982	20	50.4	29.0	46.6
1982	21	105.5	29.9	72.1
1982	22	272.6	41.6	112.0
1982	23	461.1	45.6	131.9
1982	24	591.2	39.3	85.1
1982	25	584.7	29.0	49.9
1982	26	645.8	13.0	37.0
1982	27	629.6	19.1	30.0
1982	28	574.0	16.4	39.3
1982	29	526.0	16.9	64.3
1982	30	546.0	17.7	45.7
1982	31	580.0	14.8	73.5
1982	32	519.7	15.9	27.9
1982	33	489.7	15.8	33.7
1982	34	474.0	11.3	-7.7
1982	35	497.5	8.8	23.6
1982	36	443.7	8.6	28.7

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1982	37	395.8	5.0	36.1
1982	38	382.4	12.1	11.8
1982	39	372.1	8.5	15.7
1982	40	396.7	3.2	15.5
1982	41	370.7	2.0	9.9
1982	42	273.3	9.0	3.1
1982	43	245.2	3.1	9.0
1982	44	198.9	4.7	9.1
1982	45	159.9	1.0	6.3
1982	46	124.3	3.7	5.3
1982	47	121.9	1.5	7.2
1982	48	125.2	0.6	8.4
1982	49	111.8	4.9	8.5
1982	50	104.6	3.1	7.0
1982	51	91.0	4.0	7.7
1982	52	102.9	2.5	7.3
1983	1	105.6	5.5	5.1
1983	2	70.0	4.7	6.1
1983	3	86.8	2.6	5.1
1983	4	78.3	1.0	5.0
1983	5	85.5	-0.4	5.5
1983	6	49.8	0.8	4.8
1983	7	51.0	1.6	3.0
1983	8	61.2	3.3	0.9
1983	9	32.1	2.3	2.1
1983	10	39.6	2.0	3.6
1983	11	23.3	2.5	3.5
1983	12	42.9	1.3	2.8
1983	13	88.4	0.7	2.7
1983	14	67.2	1.5	3.5
1983	15	53.2	0.4	3.6
1983	16	54.2	2.2	4.7
1983	17	61.4	7.2	10.7
1983	18	105.4	15.1	29.9
1983	19	123.0	16.7	51.0
1983	20	119.0	16.9	68.9
1983	21	149.0	19.2	83.8
1983	22	312.2	24.7	90.7
1983	23	499.2	36.9	80.1
1983	24	450.2	29.5	63.1
1983	25	485.1	19.5	44.7
1983	26	621.6	19.6	36.5
1983	27	583.3	13.8	33.0
1983	28	454.5	16.7	31.6

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1983	29	426.8	15.5	30.9
1983	30	482.4	12.6	28.5
1983	31	517.3	9.7	27.9
1983	32	486.6	16.1	24.9
1983	33	439.2	22.2	24.0
1983	34	412.5	14.0	24.7
1983	35	446.6	18.1	24.5
1983	36	420.1	17.6	23.8
1983	37	348.3	9.9	27.5
1983	38	352.2	8.8	26.8
1983	39	289.5	8.1	23.8
1983	40	272.7	7.3	22.4
1983	41	238.1	4.6	21.0
1983	42	192.0	6.7	16.3
1983	43	174.1	1.5	11.5
1983	44	114.2	4.7	9.2
1983	45	106.0	3.1	8.7
1983	46	130.0	3.5	9.6
1983	47	124.0	4.2	8.3
1983	48	104.7	4.6	8.2
1983	49	104.0	2.8	7.7
1983	50	109.1	3.2	8.4
1983	51	83.1	1.2	8.8
1983	52	34.8	-0.4	8.2
1984	1	60.2	1.5	1.7
1984	2	77.6	1.4	0.1
1984	3	60.8	3.3	-2.5
1984	4	81.4	2.1	-2.3
1984	5	85.7	0.9	-1.6
1984	6	53.0	1.3	-0.7
1984	7	66.0	1.3	-0.5
1984	8	56.8	1.0	-7.6
1984	9	59.0	-0.6	-2.5
1984	10	45.9	0.8	1.9
1984	11	45.8	2.6	0.3
1984	12	41.1	1.9	2.4
1984	13	40.7	0.5	2.4
1984	14	43.7	1.0	2.0
1984	15	44.1	4.1	2.7
1984	16	65.4	5.8	4.7
1984	17	57.0	4.9	8.6
1984	18	55.0	3.7	26.2
1984	19	46.6	9.9	49.5
1984	20	83.3	12.0	65.8

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1984	21	174.2	14.4	81.8
1984	22	192.2	10.5	70.9
1984	23	257.0	19.8	75.4
1984	24	321.4	13.6	76.5
1984	25	435.5	13.4	42.0
1984	26	522.6	20.9	43.5
1984	27	402.6	27.8	47.7
1984	28	420.3	16.4	37.9
1984	29	338.9	14.6	40.0
1984	30	330.1	10.8	19.3
1984	31	394.4	12.4	13.5
1984	32	534.5	17.6	12.0
1984	33	495.2	10.6	11.3
1984	34	417.0	11.6	10.3
1984	35	401.2	15.0	12.8
1984	36	409.3	16.3	11.7
1984	37	383.6	11.5	14.0
1984	38	330.1	12.9	16.0
1984	39	285.0	5.4	12.5
1984	40	254.7	8.4	16.1
1984	41	231.2	10.5	17.0
1984	42	203.9	4.8	12.8
1984	43	161.1	3.9	3.9
1984	44	132.9	1.2	-1.5
1984	45	130.4	5.3	0.3
1984	46	113.9	3.5	4.0
1984	47	116.8	3.5	-0.5
1984	48	93.4	4.0	6.0
1984	49	97.4	7.0	17.5
1984	50	67.0	6.6	47.7
1984	51	76.9	5.8	64.8
1984	52	83.0	4.7	55.0
1985	1	91.9	1.8	-9.5
1985	2	92.2	8.1	5.0
1985	3	94.8	3.6	14.7
1985	4	77.2	5.4	11.1
1985	5	63.6	4.7	5.1
1985	6	47.8	8.4	3.3
1985	7	72.2	3.9	5.0
1985	8	78.7	-0.3	4.8
1985	9	57.6	-2.4	4.4
1985	10	51.2	-2.8	5.5
1985	11	35.6	1.7	5.1
1985	12	29.2	7.4	3.2

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1985	13	43.7	5.5	3.9
1985	14	33.9	5.0	4.9
1985	15	3.4	2.7	1.1
1985	16	-5.3	1.6	1.8
1985	17	13.8	4.4	4.2
1985	18	35.1	6.3	6.8
1985	19	52.2	7.7	21.1
1985	20	57.0	12.0	62.3
1985	21	151.5	20.6	105.5
1985	22	344.9	20.9	131.4
1985	23	381.4	22.1	143.6
1985	24	302.8	13.1	75.6
1985	25	308.0	18.1	57.0
1985	26	423.5	16.0	51.7
1985	27	654.1	15.7	40.6
1985	28	718.3	14.1	45.3
1985	29	671.2	15.4	50.7
1985	30	576.8	17.7	28.8
1985	31	502.6	11.4	28.3
1985	32	460.3	9.4	17.2
1985	33	469.4	17.8	17.0
1985	34	397.2	16.2	20.0
1985	35	343.8	16.1	19.5
1985	36	353.5	14.5	17.1
1985	37	363.6	15.4	20.8
1985	38	313.9	10.9	19.6
1985	39	272.4	14.4	16.4
1985	40	221.6	10.7	18.2
1985	41	187.0	10.5	16.5
1985	42	167.4	7.8	10.0
1985	43	147.1	3.1	9.5
1985	44	123.4	1.3	10.4
1985	45	122.0	3.6	5.3
1985	46	108.3	7.2	9.6
1985	47	88.1	6.8	7.1
1985	48	83.5	5.6	7.7
1985	49	89.3	5.0	4.8
1985	50	83.9	5.2	7.3
1985	51	102.8	5.5	9.1
1985	52	69.2	5.9	7.4
1986	1	68.3	0.7	6.9
1986	2	72.6	5.7	5.8
1986	3	71.8	5.4	5.3
1986	4	74.2	3.8	8.9

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1986	5	64.9	3.8	6.3
1986	6	47.4	3.8	5.6
1986	7	44.7	5.9	3.5
1986	8	56.7	-1.4	5.1
1986	9	69.2	1.3	4.8
1986	10	66.2	3.3	4.1
1986	11	56.0	10.9	3.6
1986	12	48.0	4.6	5.8
1986	13	30.3	0.9	4.0
1986	14	19.9	3.4	5.0
1986	15	14.6	2.2	5.2
1986	16	18.4	2.2	4.3
1986	17	27.3	5.8	3.3
1986	18	70.9	8.0	6.8
1986	19	91.0	12.0	39.4
1986	20	97.4	20.2	61.3
1986	21	89.8	32.5	85.2
1986	22	182.9	33.7	134.4
1986	23	230.9	30.5	143.3
1986	24	428.8	26.1	103.9
1986	25	631.8	39.0	79.7
1986	26	618.5	30.9	50.5
1986	27	828.0	28.0	29.4
1986	28	814.7	27.2	22.2
1986	29	774.9	23.9	19.3
1986	30	667.5	24.3	30.0
1986	31	577.6	20.0	23.8
1986	32	584.6	21.6	26.2
1986	33	527.6	22.8	50.9
1986	34	406.7	18.5	47.8
1986	35	493.5	19.0	40.3
1986	36	401.2	15.9	36.7
1986	37	343.7	12.6	24.7
1986	38	363.1	16.2	17.4
1986	39	326.0	13.1	7.9
1986	40	361.5	12.7	12.1
1986	41	244.0	8.4	5.6
1986	42	258.8	9.6	2.0
1986	43	283.2	6.3	-5.2
1986	44	252.1	4.5	-8.2
1986	45	210.0	2.5	0.0
1986	46	169.1	2.1	5.2
1986	47	157.5	5.9	3.5
1986	48	158.0	3.5	8.3

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1986	49	143.5	5.4	5.2
1986	50	138.7	4.5	4.7
1986	51	99.7	6.3	5.2
1986	52	128.6	4.7	4.7
1987	1	100.9	3.3	5.7
1987	2	84.3	4.4	5.7
1987	3	91.9	5.7	5.9
1987	4	75.7	3.8	7.4
1987	5	80.7	2.5	6.5
1987	6	78.0	3.8	3.9
1987	7	86.8	2.2	3.1
1987	8	55.5	4.9	1.0
1987	9	33.9	3.9	3.4
1987	10	67.3	3.2	3.5
1987	11	86.5	2.4	3.4
1987	12	67.0	3.1	2.5
1987	13	60.6	1.0	3.8
1987	14	24.4	0.1	2.3
1987	15	54.4	3.8	5.9
1987	16	28.6	2.0	3.6
1987	17	-8.9	3.1	4.2
1987	18	41.4	4.4	20.6
1987	19	94.0	10.0	40.1
1987	20	89.9	13.5	49.1
1987	21	135.3	16.8	92.3
1987	22	282.0	26.4	144.3
1987	23	331.8	18.8	85.0
1987	24	312.3	12.9	34.6
1987	25	371.0	9.8	34.5
1987	26	525.3	14.9	34.6
1987	27	723.8	14.3	27.7
1987	28	597.5	11.8	43.1
1987	29	503.6	13.6	27.1
1987	30	620.8	9.0	13.2
1987	31	614.5	7.1	10.4
1987	32	512.0	9.5	14.2
1987	33	454.6	19.2	20.1
1987	34	432.0	20.3	22.1
1987	35	452.5	14.3	15.8
1987	36	491.9	11.6	21.0
1987	37	478.6	18.2	31.8
1987	38	365.9	10.8	26.9
1987	39	381.3	10.6	28.3
1987	40	480.5	11.0	28.9

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1987	41	339.2	8.9	30.8
1987	42	283.4	1.9	29.0
1987	43	229.4	7.5	17.0
1987	44	216.0	4.8	8.9
1987	45	187.8	5.4	14.0
1987	46	157.6	4.2	10.3
1987	47	150.1	5.1	12.2
1987	48	140.0	3.9	9.7
1987	49	106.1	4.2	6.7
1987	50	118.6	5.5	7.0
1987	51	117.7	6.2	7.0
1987	52	78.3	3.3	6.6
1988	1	83.8	1.9	2.4
1988	2	78.3	2.9	2.5
1988	3	100.0	3.0	2.6
1988	4	66.7	5.9	2.9
1988	5	64.9	4.6	5.3
1988	6	75.4	4.1	-1.1
1988	7	83.0	4.0	0.2
1988	8	59.0	3.0	5.1
1988	9	54.4	1.3	2.8
1988	10	47.3	3.7	1.7
1988	11	42.8	5.6	6.5
1988	12	48.2	5.5	4.2
1988	13	39.0	4.9	3.8
1988	14	44.6	2.6	8.3
1988	15	40.4	2.3	1.6
1988	16	37.8	4.3	-1.4
1988	17	58.0	6.0	19.3
1988	18	52.3	12.1	50.4
1988	19	130.3	20.6	101.8
1988	20	234.1	24.2	142.6
1988	21	239.0	22.6	107.9
1988	22	294.9	20.1	98.3
1988	23	430.7	26.4	82.1
1988	24	769.2	25.2	66.4
1988	25	690.6	22.5	51.3
1988	26	503.7	25.2	48.7
1988	27	602.3	28.7	32.6
1988	28	663.0	54.1	36.8
1988	29	741.9	79.4	45.9
1988	30	612.2	65.3	63.4
1988	31	545.6	57.7	68.1
1988	32	540.5	40.4	55.3

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1988	33	486.5	38.8	41.5
1988	34	442.4	32.2	34.4
1988	35	466.9	22.3	16.1
1988	36	417.4	22.6	-5.3
1988	37	382.4	18.7	19.8
1988	38	361.2	13.5	19.1
1988	39	323.3	16.6	17.5
1988	40	333.7	10.2	17.2
1988	41	347.9	14.4	12.4
1988	42	300.7	5.9	5.8
1988	43	277.4	6.0	4.5
1988	44	211.0	7.9	4.9
1988	45	187.9	8.3	5.5
1988	46	159.0	4.3	6.3
1988	47	140.4	6.0	11.9
1988	48	187.9	8.5	11.3
1988	49	158.8	6.0	7.1
1988	50	142.8	6.8	5.3
1988	51	90.3	5.2	3.3
1988	52	116.9	4.6	6.8
1989	1	94.0	0.9	4.2
1989	2	101.9	4.5	4.5
1989	3	86.6	4.0	-0.3
1989	4	112.0	3.3	3.8
1989	5	64.7	2.2	4.6
1989	6	85.0	1.8	2.7
1989	7	74.4	-0.9	4.4
1989	8	60.4	4.0	1.6
1989	9	46.2	4.3	3.5
1989	10	58.9	3.0	1.6
1989	11	94.1	3.0	6.1
1989	12	46.8	3.7	5.1
1989	13	48.3	2.1	3.7
1989	14	49.9	2.2	3.1
1989	15	17.7	3.3	5.8
1989	16	39.3	5.5	2.2
1989	17	105.1	24.1	22.9
1989	18	177.4	33.0	82.7
1989	19	225.5	27.7	105.6
1989	20	272.5	23.8	77.7
1989	21	273.9	14.5	68.0
1989	22	455.7	11.7	56.0
1989	23	598.0	20.5	57.6
1989	24	564.6	21.0	41.3

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1989	25	497.2	16.5	27.1
1989	26	526.0	21.4	24.8
1989	27	638.4	17.6	29.4
1989	28	705.5	13.1	19.6
1989	29	670.9	18.2	13.3
1989	30	600.7	12.3	14.1
1989	31	621.5	11.2	15.0
1989	32	608.4	12.7	9.5
1989	33	636.8	7.7	7.8
1989	34	593.7	7.9	7.9
1989	35	539.3	3.9	5.1
1989	36	526.9	8.5	5.6
1989	37	497.0	7.1	6.6
1989	38	422.9	1.2	8.8
1989	39	426.8	6.4	10.1
1989	40	418.6	3.6	7.4
1989	41	391.3	5.6	3.6
1989	42	324.3	4.6	2.4
1989	43	261.0	4.2	2.0
1989	44	232.8	5.3	2.6
1989	45	152.9	1.8	2.1
1989	46	201.7	5.8	8.9
1989	47	161.7	4.8	8.2
1989	48	150.7	6.0	4.1
1989	49	136.9	4.9	4.7
1989	50	125.2	3.8	4.9
1989	51	127.3	5.2	5.2
1989	52	111.8	5.0	6.8
1990	1	117.0	5.0	5.5
1990	2	115.6	4.4	8.4
1990	3	97.4	7.0	5.0
1990	4	57.8	4.8	0.7
1990	5	52.8	2.6	-2.6
1990	6	69.1	2.7	-0.3
1990	7	67.1	4.1	2.5
1990	8	96.6	4.7	3.9
1990	9	85.8	4.8	1.1
1990	10	40.8	4.2	1.0
1990	11	44.7	4.5	-1.0
1990	12	44.7	3.5	-0.3
1990	13	63.9	3.6	2.4
1990	14	-3.2	4.0	0.2
1990	15	28.1	6.4	1.5
1990	16	49.6	9.2	2.2

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1990	17	69.1	14.0	7.6
1990	18	90.4	22.8	35.0
1990	19	127.2	20.3	50.6
1990	20	211.1	20.0	65.2
1990	21	269.3	24.2	79.7
1990	22	479.9	29.9	80.4
1990	23	726.2	36.7	37.7
1990	24	647.7	27.2	17.5
1990	25	517.0	27.7	19.6
1990	26	523.6	32.8	17.4
1990	27	655.8	24.4	11.0
1990	28	581.9	20.7	8.7
1990	29	519.7	17.9	6.9
1990	30	575.0	9.6	7.0
1990	31	571.1	9.6	12.4
1990	32	586.1	9.4	19.3
1990	33	676.7	6.4	15.2
1990	34	603.8	12.6	23.0
1990	35	534.2	9.2	23.4
1990	36	491.5	8.0	30.1
1990	37	466.2	8.0	41.4
1990	38	524.8	11.2	44.3
1990	39	611.7	9.6	50.9
1990	40	419.7	7.8	34.2
1990	41	342.4	6.7	25.0
1990	42	304.1	5.7	4.6
1990	43	306.6	5.3	11.9
1990	44	200.7	2.0	9.6
1990	45	144.9	4.5	6.5
1990	46	172.7	6.4	10.4
1990	47	137.8	5.6	9.0
1990	48	126.3	2.0	7.9
1990	49	143.4	2.2	11.6
1990	50	111.0	6.4	6.5
1990	51	102.3	6.8	9.2
1990	52	95.9	4.9	5.4
1991	1	82.2	3.9	13.3
1991	2	93.3	3.7	13.3
1991	3	92.0	-1.9	8.8
1991	4	63.0	5.1	7.1
1991	5	90.5	5.1	15.6
1991	6	81.5	6.4	12.4
1991	7	69.2	6.1	4.2
1991	8	72.2	6.0	1.8

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1991	9	76.0	7.1	1.3
1991	10	71.0	4.6	8.1
1991	11	63.6	4.4	6.6
1991	12	49.5	6.0	6.1
1991	13	47.9	4.7	9.3
1991	14	36.7	0.7	4.2
1991	15	46.0	1.9	-0.7
1991	16	52.3	4.5	8.3
1991	17	51.3	11.8	23.1
1991	18	59.7	25.5	78.0
1991	19	93.4	25.7	99.8
1991	20	154.8	20.3	78.4
1991	21	254.0	15.6	80.1
1991	22	293.8	16.5	71.3
1991	23	264.0	30.8	72.6
1991	24	315.6	28.3	63.4
1991	25	538.3	23.9	43.8
1991	26	756.0	24.7	26.5
1991	27	643.3	31.5	29.5
1991	28	517.2	38.6	29.7
1991	29	486.4	48.8	40.2
1991	30	502.3	48.8	34.0
1991	31	507.9	39.6	28.8
1991	32	477.3	31.4	31.7
1991	33	592.3	25.3	19.8
1991	34	571.2	28.5	14.2
1991	35	494.8	27.3	10.4
1991	36	516.7	41.3	18.3
1991	37	512.2	43.7	20.8
1991	38	503.6	30.7	26.2
1991	39	455.3	20.4	20.6
1991	40	405.2	34.6	19.5
1991	41	428.3	19.3	24.3
1991	42	367.4	11.3	12.5
1991	43	289.4	7.9	-5.5
1991	44	240.1	17.2	3.2
1991	45	222.3	12.3	3.8
1991	46	196.0	8.7	5.7
1991	47	184.1	10.2	7.8
1991	48	163.8	8.4	5.5
1991	49	158.9	11.2	7.5
1991	50	143.3	8.6	7.2
1991	51	153.0	10.5	8.0
1991	52	124.3	5.6	6.6

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1992	1	115.4	6.5	1.9
1992	2	116.7	6.1	5.7
1992	3	118.6	8.6	1.4
1992	4	102.4	4.7	7.3
1992	5	99.7	3.6	7.4
1992	6	80.1	1.4	0.9
1992	7	67.4	4.0	3.1
1992	8	100.7	9.3	3.8
1992	9	120.8	-0.8	7.7
1992	10	140.5	4.5	-2.7
1992	11	109.7	1.8	2.8
1992	12	85.5	1.3	5.1
1992	13	34.6	2.4	2.4
1992	14	58.5	5.3	-0.8
1992	15	49.0	4.7	1.5
1992	16	52.8	4.9	2.3
1992	17	77.5	7.8	5.1
1992	18	100.9	13.0	16.5
1992	19	133.5	17.8	26.5
1992	20	130.7	17.9	29.0
1992	21	199.4	37.2	92.4
1992	22	401.8	55.9	200.3
1992	23	504.5	42.3	178.3
1992	24	732.4	36.7	147.5
1992	25	756.2	39.3	119.3
1992	26	691.3	32.6	83.3
1992	27	982.7	32.2	46.1
1992	28	793.5	46.6	40.3
1992	29	641.0	57.7	45.7
1992	30	600.0	43.6	35.9
1992	31	577.8	35.3	6.4
1992	32	580.6	29.5	17.5
1992	33	543.1	29.8	19.5
1992	34	512.9	23.0	24.0
1992	35	431.9	29.1	24.0
1992	36	364.5	29.5	31.9
1992	37	304.4	21.6	27.1
1992	38	305.7	21.1	17.8
1992	39	322.2	16.1	21.9
1992	40	266.9	20.8	9.2
1992	41	179.8	13.6	9.6
1992	42	183.0	9.5	9.2
1992	43	181.5	8.8	9.2
1992	44	168.8	6.8	9.3

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1992	45	158.9	7.6	3.2
1992	46	115.9	8.4	7.9
1992	47	127.5	5.4	9.8
1992	48	115.2	5.9	3.9
1992	49	92.5	3.5	7.0
1992	50	93.2	3.5	5.5
1992	51	78.6	3.5	1.2
1992	52	105.4	1.1	2.5
1993	1	89.7	5.1	4.3
1993	2	67.3	11.0	1.2
1993	3	73.6	3.8	2.2
1993	4	65.3	9.9	-1.3
1993	5	125.2	4.2	3.1
1993	6	88.1	3.4	2.7
1993	7	74.8	4.5	2.2
1993	8	90.3	5.7	3.9
1993	9	72.5	3.8	4.3
1993	10	51.9	3.4	0.9
1993	11	38.8	2.6	-2.5
1993	12	59.8	2.7	1.8
1993	13	46.6	2.6	-0.2
1993	14	25.6	3.7	-0.3
1993	15	18.9	2.3	-0.4
1993	16	12.7	5.4	2.1
1993	17	63.5	11.4	8.3
1993	18	102.2	13.9	35.7
1993	19	123.7	11.8	65.0
1993	20	319.0	21.8	128.3
1993	21	547.6	23.5	121.0
1993	22	777.6	34.9	125.6
1993	23	831.5	22.9	96.1
1993	24	719.5	19.9	57.0
1993	25	661.8	17.3	41.6
1993	26	560.7	11.5	31.3
1993	27	522.3	14.9	31.7
1993	28	560.4	19.5	32.7
1993	29	660.9	15.7	18.7
1993	30	600.5	16.1	17.9
1993	31	597.3	20.5	11.0
1993	32	553.1	15.1	12.7
1993	33	509.5	12.6	10.6
1993	34	456.4	19.3	8.3
1993	35	461.6	11.4	19.0
1993	36	482.7	15.7	13.3

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1993	37	421.3	15.0	12.8
1993	38	387.0	8.1	9.3
1993	39	421.0	11.8	13.0
1993	40	464.2	13.5	8.9
1993	41	416.9	11.8	8.8
1993	42	355.0	8.8	7.7
1993	43	308.9	6.7	8.3
1993	44	257.4	8.2	-0.6
1993	45	256.1	6.7	6.2
1993	46	171.0	6.1	1.4
1993	47	178.6	4.2	8.9
1993	48	162.2	5.8	8.9
1993	49	142.1	4.8	11.2
1993	50	127.9	6.6	6.6
1993	51	121.0	5.4	7.5
1993	52	100.2	2.8	3.8
1994	1	78.1	3.1	1.8
1994	2	96.0	5.9	2.5
1994	3	106.6	4.0	2.2
1994	4	100.7	3.6	1.6
1994	5	72.6	2.9	4.4
1994	6	52.1	1.7	5.2
1994	7	90.7	1.5	2.7
1994	8	84.1	2.1	2.2
1994	9	101.9	2.0	1.3
1994	10	98.1	1.4	1.6
1994	11	41.8	2.9	2.8
1994	12	47.8	1.6	2.6
1994	13	51.3	1.6	3.1
1994	14	24.6	3.5	-0.9
1994	15	32.7	4.1	4.2
1994	16	30.7	7.5	3.1
1994	17	80.1	12.2	20.4
1994	18	114.7	12.4	44.4
1994	19	123.7	12.4	50.4
1994	20	181.3	9.2	70.7
1994	21	286.5	11.7	85.5
1994	22	307.5	9.5	61.3
1994	23	356.3	9.7	58.2
1994	24	550.4	9.6	49.1
1994	25	698.7	6.4	40.6
1994	26	623.0	10.6	45.5
1994	27	603.2	8.7	27.9
1994	28	569.3	7.1	19.1

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1994	29	574.0	1.3	15.4
1994	30	556.9	9.8	13.3
1994	31	634.4	3.9	12.9
1994	32	680.9	1.8	7.4
1994	33	642.7	1.5	5.9
1994	34	554.8	1.4	8.5
1994	35	477.7	1.6	7.7
1994	36	413.7	1.4	7.3
1994	37	430.4	1.8	8.1
1994	38	471.4	1.9	8.6
1994	39	451.3	1.8	12.4
1994	40	487.8	2.7	13.6
1994	41	468.3	3.2	15.1
1994	42	371.4	-0.3	12.4
1994	43	301.1	1.6	3.3
1994	44	244.1	-1.7	5.4
1994	45	192.7	0.3	6.0
1994	46	185.7	-0.1	4.4
1994	47	137.5	2.4	4.5
1994	48	120.6	3.2	7.1
1994	49	134.9	1.8	5.1
1994	50	121.1	1.0	7.3
1994	51	127.6	-1.5	-0.1
1994	52	63.9	2.5	7.6
1995	1	89.2	0.5	4.6
1995	2	89.4	0.6	4.8
1995	3	98.7	-0.9	4.2
1995	4	80.1	0.0	2.4
1995	5	83.0	-0.7	4.1
1995	6	58.7	2.1	4.1
1995	7	38.0	1.0	3.3
1995	8	72.9	1.5	4.8
1995	9	61.7	0.3	3.7
1995	10	41.4	0.6	4.3
1995	11	39.8	0.7	3.8
1995	12	30.1	1.8	-0.8
1995	13	86.3	2.7	2.8
1995	14	-14.5	0.8	1.9
1995	15	26.5	-0.9	-1.7
1995	16	44.9	3.7	3.1
1995	17	94.4	7.7	23.4
1995	18	117.5	11.2	51.6
1995	19	239.4	14.1	67.2
1995	20	404.4	14.7	64.4

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1995	21	319.8	5.2	34.0
1995	22	377.8	10.5	24.8
1995	23	308.4	10.1	25.3
1995	24	537.5	6.3	29.8
1995	25	479.5	4.9	28.7
1995	26	476.2	9.1	21.5
1995	27	499.5	13.7	20.3
1995	28	548.3	3.6	16.8
1995	29	501.9	10.5	16.8
1995	30	495.9	7.5	20.0
1995	31	427.2	6.4	27.9
1995	32	438.2	7.9	35.7
1995	33	430.5	8.7	25.1
1995	34	440.0	8.3	27.6
1995	35	446.4	9.0	26.8
1995	36	584.0	6.0	28.6
1995	37	467.4	11.1	30.2
1995	38	387.1	7.7	33.5
1995	39	398.6	1.1	17.6
1995	40	346.3	6.8	24.5
1995	41	262.8	3.0	18.7
1995	42	247.8	2.0	16.7
1995	43	194.9	0.7	13.8
1995	44	138.1	5.6	6.1
1995	45	147.9	-1.8	4.5
1995	46	158.6	3.7	9.9
1995	47	118.2	8.0	2.4
1995	48	82.0	-0.3	7.1
1995	49	97.2	3.4	1.3
1995	50	116.5	3.4	4.4
1995	51	102.1	2.3	5.5
1995	52	84.9	7.7	3.5
1996	1	81.9	3.0	3.4
1996	2	64.9	-3.8	4.8
1996	3	54.9	4.6	4.1
1996	4	41.9	2.4	1.2
1996	5	88.8	0.7	3.2
1996	6	78.2	-30.2	3.0
1996	7	57.0	40.5	3.0
1996	8	11.8	0.1	3.0
1996	9	37.5	-2.0	1.6
1996	10	65.1	3.2	1.7
1996	11	55.4	4.7	3.7
1996	12	47.4	2.3	0.2

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1996	13	7.4	3.7	-0.2
1996	14	76.6	3.5	4.0
1996	15	2.9	3.8	1.0
1996	16	35.8	4.2	2.8
1996	17	76.7	8.6	11.5
1996	18	75.5	13.1	17.9
1996	19	78.1	9.1	17.0
1996	20	53.4	47.2	21.7
1996	21	200.0	-28.7	61.0
1996	22	235.1	11.7	81.4
1996	23	376.8	3.3	67.8
1996	24	325.9	8.1	79.2
1996	25	437.7	-1.7	33.1
1996	26	622.0	20.0	19.1
1996	27	468.2	11.3	16.9
1996	28	437.8	21.1	30.8
1996	29	448.0	13.5	32.3
1996	30	454.6	13.5	17.5
1996	31	429.9	21.4	10.3
1996	32	392.3	11.5	14.4
1996	33	392.9	1.1	14.7
1996	34	438.1	21.0	20.9
1996	35	470.7	13.7	23.9
1996	36	378.9	1.8	22.8
1996	37	327.1	9.0	29.1
1996	38	274.3	0.2	31.5
1996	39	250.0	6.9	23.0
1996	40	252.4	8.0	15.1
1996	41	220.4	5.4	15.2
1996	42	159.1	2.9	7.5
1996	43	160.2	-6.9	8.0
1996	44	156.7	4.8	12.7
1996	45	103.6	3.7	5.4
1996	46	82.4	5.1	0.3
1996	47	100.2	8.3	6.1
1996	48	95.5	2.5	9.7
1996	49	84.9	22.7	6.0
1996	50	77.4	-12.6	8.1
1996	51	68.2	5.6	4.1
1996	52	44.6	-3.0	8.5
1997	1	39.8	7.0	4.3
1997	2	78.9	3.4	7.0
1997	3	49.4	5.5	5.4
1997	4	36.1	1.9	5.1

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1997	5	62.5	-2.8	4.7
1997	6	40.3	6.2	-0.7
1997	7	39.3	5.0	3.5
1997	8	43.3	0.8	8.5
1997	9	3.1	-5.1	0.9
1997	10	37.5	4.0	2.0
1997	11	54.2	3.3	2.3
1997	12	26.6	2.5	5.6
1997	13	44.1	2.2	5.0
1997	14	21.3	3.4	4.4
1997	15	13.8	2.2	4.4
1997	16	19.8	0.9	8.2
1997	17	81.1	5.8	14.3
1997	18	76.7	12.1	39.0
1997	19	90.5	12.8	60.3
1997	20	183.8	23.3	105.3
1997	21	291.6	23.4	99.0
1997	22	309.2	22.8	74.0
1997	23	503.5	20.7	91.6
1997	24	460.2	19.5	73.4
1997	25	489.5	24.8	53.0
1997	26	643.1	18.5	35.8
1997	27	627.3	9.7	28.4
1997	28	556.4	20.7	35.6
1997	29	489.5	6.9	47.3
1997	30	518.3	30.1	67.7
1997	31	501.8	20.4	54.6
1997	32	565.7	18.8	37.8
1997	33	592.6	29.5	34.0
1997	34	536.7	14.4	32.5
1997	35	512.4	14.2	24.1
1997	36	500.4	13.5	27.7
1997	37	436.4	7.5	26.3
1997	38	420.8	5.8	23.0
1997	39	453.7	17.6	19.6
1997	40	356.3	6.3	18.4
1997	41	269.4	2.1	18.6
1997	42	227.8	2.6	15.1
1997	43	191.9	6.0	11.7
1997	44	222.2	6.5	7.0
1997	45	150.1	4.6	7.7
1997	46	117.8	5.0	5.8
1997	47	117.7	3.0	5.2
1997	48	132.7	5.0	7.6

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1997	49	107.1	3.6	5.3
1997	50	107.0	8.7	7.1
1997	51	104.0	5.7	9.1
1997	52	60.7	8.3	7.1
1998	1	50.7	6.8	5.2
1998	2	80.0	7.2	8.3
1998	3	79.6	5.5	6.3
1998	4	65.8	4.8	5.8
1998	5	65.9	3.0	0.1
1998	6	53.9	-1.2	4.3
1998	7	63.0	1.2	6.6
1998	8	50.7	1.4	5.3
1998	9	19.6	2.5	4.7
1998	10	25.3	1.8	4.9
1998	11	53.7	0.0	6.9
1998	12	32.5	2.1	4.1
1998	13	37.4	1.8	1.5
1998	14	4.2	2.1	2.6
1998	15	29.6	1.4	4.8
1998	16	35.4	8.4	5.0
1998	17	54.7	6.2	11.9
1998	18	69.8	10.6	20.6
1998	19	61.8	8.4	26.0
1998	20	46.2	5.7	40.0
1998	21	202.3	16.2	64.8
1998	22	511.5	18.5	59.3
1998	23	744.7	13.5	40.6
1998	24	564.2	14.8	32.4
1998	25	409.8	13.1	28.6
1998	26	434.9	5.4	22.7
1998	27	513.9	1.0	14.5
1998	28	434.1	4.4	8.4
1998	29	423.1	-2.1	8.1
1998	30	425.9	8.7	5.6
1998	31	466.5	-5.1	4.9
1998	32	384.4	4.2	4.5
1998	33	409.0	3.5	7.3
1998	34	396.2	-3.3	8.3
1998	35	455.2	1.7	8.2
1998	36	400.0	0.5	7.5
1998	37	256.8	1.1	14.3
1998	38	302.4	1.2	12.4
1998	39	229.8	7.1	5.2
1998	40	197.7	2.4	4.9

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1998	41	190.7	-4.2	8.7
1998	42	239.5	0.0	11.7
1998	43	261.9	4.2	2.4
1998	44	250.6	-0.4	1.2
1998	45	158.3	-0.4	2.9
1998	46	127.4	-0.7	2.8
1998	47	120.1	0.2	7.2
1998	48	94.2	-1.3	4.1
1998	49	97.5	1.0	5.6
1998	50	98.6	1.4	2.7
1998	51	82.1	0.2	3.1
1998	52	56.1	2.2	2.7
1999	1	75.2	3.5	4.0
1999	2	87.8	1.5	8.2
1999	3	43.6	1.5	2.7
1999	4	58.4	4.2	5.6
1999	5	47.2	2.0	4.1
1999	6	56.0	-0.4	5.1
1999	7	66.4	-0.5	2.1
1999	8	51.5	0.8	1.3
1999	9	21.0	1.0	2.3
1999	10	46.3	-1.0	5.2
1999	11	44.4	-1.4	2.4
1999	12	23.5	1.6	2.1
1999	13	20.0	-0.6	3.9
1999	14	1.5	2.7	0.4
1999	15	22.1	-0.7	7.0
1999	16	36.5	1.3	8.8
1999	17	32.8	2.2	6.9
1999	18	56.3	8.4	23.8
1999	19	68.6	7.0	53.1
1999	20	79.2	12.0	57.1
1999	21	158.3	8.6	62.4
1999	22	177.3	19.4	76.2
1999	23	291.4	29.8	85.8
1999	24	587.2	25.4	65.2
1999	25	766.5	29.2	34.8
1999	26	528.8	35.6	23.5
1999	27	520.7	17.7	15.0
1999	28	470.4	19.2	14.5
1999	29	523.8	16.9	19.8
1999	30	446.6	16.4	34.7
1999	31	471.9	10.3	24.3
1999	32	532.4	10.6	18.0

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
1999	33	469.1	6.3	20.9
1999	34	386.4	12.6	24.2
1999	35	367.7	1.4	34.4
1999	36	350.9	16.0	37.2
1999	37	340.8	-0.3	33.2
1999	38	383.9	4.3	38.0
1999	39	276.2	6.3	32.3
1999	40	255.3	3.6	23.0
1999	41	218.6	3.2	18.3
1999	42	209.6	2.2	20.2
1999	43	204.7	5.1	19.9
1999	44	189.7	2.7	9.0
1999	45	152.6	2.6	6.6
1999	46	159.7	3.7	6.4
1999	47	109.8	4.1	3.4
1999	48	109.2	2.7	6.7
1999	49	115.8	4.8	5.4
1999	50	98.2	2.9	5.2
1999	51	112.0	1.6	8.0
1999	52	141.8	5.1	5.4
2000	1	138.1	2.2	4.1
2000	2	82.9	1.7	3.2
2000	3	98.8	0.8	2.4
2000	4	109.0	0.8	2.6
2000	5	87.7	3.2	3.7
2000	6	64.3	2.9	6.7
2000	7	72.1	1.4	6.9
2000	8	57.3	3.4	4.7
2000	9	46.9	2.3	3.3
2000	10	32.3	2.9	3.4
2000	11	51.2	1.3	3.4
2000	12	42.4	1.2	3.3
2000	13	32.5	3.3	3.3
2000	14	19.5	3.3	2.9
2000	15	29.0	2.6	0.7
2000	16	47.5	0.6	2.1
2000	17	50.5	4.9	4.1
2000	18	64.2	6.0	22.6
2000	19	65.6	13.1	49.1
2000	20	119.0	14.3	42.8
2000	21	138.3	19.1	65.8
2000	22	254.4	24.5	88.0
2000	23	412.6	30.0	109.3
2000	24	649.2	34.0	100.2

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2000	25	530.1	43.5	57.6
2000	26	695.4	39.2	44.7
2000	27	779.3	33.1	41.5
2000	28	693.1	55.4	37.2
2000	29	579.1	51.2	32.4
2000	30	565.8	45.9	40.3
2000	31	530.4	43.6	50.9
2000	32	544.1	35.6	39.8
2000	33	533.7	66.2	40.1
2000	34	480.8	79.6	46.2
2000	35	401.5	59.9	38.7
2000	36	412.5	60.7	29.8
2000	37	390.9	55.0	37.1
2000	38	430.2	49.5	43.8
2000	39	401.2	44.4	38.5
2000	40	403.5	28.1	31.9
2000	41	364.9	21.3	36.1
2000	42	286.2	18.3	27.5
2000	43	219.0	21.1	19.2
2000	44	207.1	13.4	17.7
2000	45	186.0	8.5	16.7
2000	46	156.6	7.1	15.2
2000	47	163.5	9.1	11.6
2000	48	127.5	8.3	6.4
2000	49	139.2	6.9	7.3
2000	50	96.9	6.2	6.5
2000	51	106.5	5.2	5.5
2000	52	123.4	4.5	5.3
2001	1	117.4	4.2	6.2
2001	2	78.9	0.8	4.9
2001	3	82.6	4.8	3.7
2001	4	88.3	7.8	4.1
2001	5	80.5	5.0	5.7
2001	6	64.6	4.5	4.9
2001	7	67.3	4.4	5.3
2001	8	70.2	0.9	4.1
2001	9	64.9	5.1	2.9
2001	10	72.7	0.3	4.7
2001	11	30.8	3.9	4.0
2001	12	41.6	0.9	3.1
2001	13	26.9	1.1	3.7
2001	14	17.1	1.5	3.3
2001	15	17.6	0.7	1.8
2001	16	13.0	2.1	2.0

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2001	17	35.8	3.7	4.0
2001	18	31.2	2.7	8.1
2001	19	31.2	6.0	17.9
2001	20	70.0	7.1	54.8
2001	21	78.4	15.2	74.9
2001	22	326.6	27.9	111.1
2001	23	424.6	26.4	164.2
2001	24	656.2	33.0	129.5
2001	25	740.0	31.1	74.5
2001	26	636.5	22.3	41.1
2001	27	634.3	19.6	45.1
2001	28	441.0	20.2	51.6
2001	29	567.1	16.6	42.9
2001	30	586.2	47.8	38.2
2001	31	493.2	49.3	39.2
2001	32	486.0	37.0	28.3
2001	33	483.3	28.5	27.8
2001	34	457.6	21.6	19.7
2001	35	433.8	19.8	30.7
2001	36	357.9	19.2	44.4
2001	37	420.9	12.5	43.5
2001	38	399.3	15.7	37.2
2001	39	339.6	15.7	31.9
2001	40	284.9	12.1	23.4
2001	41	214.1	13.2	22.3
2001	42	210.4	7.3	20.0
2001	43	180.7	7.8	14.4
2001	44	156.8	4.6	14.4
2001	45	134.4	5.3	18.9
2001	46	135.0	4.6	20.7
2001	47	106.7	6.9	6.0
2001	48	88.7	5.7	0.2
2001	49	118.6	6.1	3.6
2001	50	100.3	4.5	4.2
2001	51	108.0	1.6	3.9
2001	52	88.3	5.7	3.5
2002	1	101.7	2.3	4.8
2002	2	70.9	5.6	3.9
2002	3	71.5	6.1	7.3
2002	4	67.3	3.6	7.8
2002	5	83.2	3.9	6.3
2002	6	96.1	1.1	6.4
2002	7	61.7	6.0	6.2
2002	8	57.8	1.7	3.8

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2002	9	39.2	2.7	4.3
2002	10	44.9	2.8	3.3
2002	11	38.8	1.2	3.1
2002	12	65.3	1.6	2.9
2002	13	10.3	3.3	3.7
2002	14	14.1	1.9	2.7
2002	15	22.4	1.7	3.6
2002	16	10.5	5.1	3.1
2002	17	15.2	4.2	5.1
2002	18	34.4	8.1	12.2
2002	19	58.2	19.5	32.7
2002	20	108.9	33.5	63.1
2002	21	297.7	30.5	79.5
2002	22	438.8	23.2	56.3
2002	23	447.0	17.9	41.4
2002	24	476.2	16.3	36.1
2002	25	513.3	10.9	30.2
2002	26	432.1	11.0	23.1
2002	27	404.6	10.8	26.2
2002	28	390.7	13.6	35.8
2002	29	449.3	5.3	30.4
2002	30	495.4	23.8	31.2
2002	31	413.1	2.3	28.1
2002	32	470.1	11.2	30.7
2002	33	486.8	7.4	36.0
2002	34	482.4	14.9	64.5
2002	35	523.5	14.2	62.1
2002	36	446.2	3.8	39.8
2002	37	351.7	5.1	28.4
2002	38	338.4	8.4	21.8
2002	39	291.6	3.3	20.5
2002	40	263.0	6.2	19.5
2002	41	215.4	3.5	18.9
2002	42	257.0	4.8	22.8
2002	43	260.3	3.5	20.4
2002	44	186.1	3.4	13.9
2002	45	150.6	4.7	11.2
2002	46	162.7	1.2	11.0
2002	47	145.3	-2.6	10.0
2002	48	165.7	7.7	9.7
2002	49	140.6	0.9	9.2
2002	50	118.9	2.4	12.3
2002	51	106.0	0.9	9.5
2002	52	90.5	2.3	9.8

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2003	1	92.8	1.1	7.7
2003	2	81.8	0.5	7.4
2003	3	90.6	2.1	8.2
2003	4	87.6	3.0	5.4
2003	5	88.9	1.7	5.8
2003	6	60.7	3.2	7.9
2003	7	50.4	4.0	8.1
2003	8	63.8	1.6	6.0
2003	9	50.3	6.4	7.4
2003	10	30.3	1.6	6.1
2003	11	73.1	2.5	6.1
2003	12	43.4	2.5	7.4
2003	13	27.7	3.3	5.2
2003	14	46.8	2.2	2.5
2003	15	32.3	2.4	1.6
2003	16	24.8	3.3	2.9
2003	17	51.2	8.6	21.7
2003	18	69.4	7.0	36.5
2003	19	77.1	5.0	28.2
2003	20	67.3	5.6	38.3
2003	21	140.7	6.1	70.7
2003	22	194.2	7.3	79.2
2003	23	292.4	11.2	70.3
2003	24	458.4	7.4	52.1
2003	25	423.6	22.4	33.4
2003	26	361.7	21.9	30.2
2003	27	450.4	25.7	32.6
2003	28	537.5	14.3	20.6
2003	29	533.3	17.6	15.0
2003	30	478.3	11.2	9.7
2003	31	444.8	14.9	6.9
2003	32	433.4	2.4	8.4
2003	33	500.2	10.4	21.2
2003	34	403.4	6.5	23.6
2003	35	383.0	6.2	23.5
2003	36	400.8	9.0	33.6
2003	37	356.4	5.0	26.1
2003	38	329.1	0.1	16.3
2003	39	308.7	4.5	16.0
2003	40	317.3	6.6	16.8
2003	41	272.7	5.7	16.4
2003	42	216.8	2.1	11.5
2003	43	193.4	6.9	7.0
2003	44	188.3	-0.2	4.7

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2003	45	158.6	1.6	9.5
2003	46	120.5	2.8	9.6
2003	47	128.4	2.0	11.0
2003	48	131.3	4.3	13.1
2003	49	107.7	0.0	7.5
2003	50	106.1	3.2	7.3
2003	51	124.0	3.6	7.3
2003	52	70.6	4.2	8.4
2004	1	69.8	-1.8	7.1
2004	2	101.6	4.1	9.6
2004	3	86.3	0.3	11.7
2004	4	47.2	-1.9	9.4
2004	5	86.1	-1.9	7.8
2004	6	75.9	0.8	9.7
2004	7	67.0	0.9	8.3
2004	8	47.9	1.5	4.0
2004	9	38.1	1.4	3.2
2004	10	79.0	2.8	4.2
2004	11	12.5	1.6	3.7
2004	12	46.6	-0.5	4.2
2004	13	47.8	-0.7	5.8
2004	14	30.4	-0.1	5.6
2004	15	31.6	2.0	4.2
2004	16	30.6	6.2	5.5
2004	17	69.0	6.8	7.0
2004	18	91.9	21.1	15.4
2004	19	127.6	31.2	29.3
2004	20	291.5	28.7	92.5
2004	21	456.2	24.7	124.7
2004	22	455.8	26.1	127.4
2004	23	575.6	20.4	80.8
2004	24	595.5	21.7	54.9
2004	25	660.1	16.9	37.6
2004	26	711.1	13.1	21.0
2004	27	579.7	13.4	6.9
2004	28	565.5	8.6	7.1
2004	29	580.2	4.7	5.6
2004	30	540.0	13.4	7.6
2004	31	597.1	8.8	10.1
2004	32	601.6	7.6	7.7
2004	33	576.0	7.2	5.3
2004	34	537.5	4.3	3.9
2004	35	473.0	9.5	3.3
2004	36	373.7	3.9	4.5

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2004	37	311.1	11.7	4.8
2004	38	319.4	-2.2	10.7
2004	39	330.9	6.2	8.5
2004	40	358.0	8.8	8.7
2004	41	281.6	5.7	12.2
2004	42	232.4	3.6	7.2
2004	43	257.9	1.1	6.6
2004	44	174.3	5.6	11.2
2004	45	140.8	-2.6	9.7
2004	46	146.0	3.8	12.4
2004	47	137.7	4.4	10.6
2004	48	132.0	4.6	12.7
2004	49	97.2	2.6	9.6
2004	50	121.1	1.9	5.0
2004	51	108.5	2.9	7.6
2004	52	74.4	2.3	5.7
2005	1	101.5	1.9	4.0
2005	2	61.0	0.9	2.3
2005	3	111.8	-0.4	2.0
2005	4	89.6	2.3	3.1
2005	5	60.8	3.4	3.1
2005	6	89.2	-0.5	2.0
2005	7	66.1	0.5	2.6
2005	8	58.6	0.7	4.4
2005	9	65.2	2.1	4.1
2005	10	54.3	3.2	3.8
2005	11	20.9	2.1	4.6
2005	12	19.9	0.0	4.8
2005	13	39.7	4.3	5.4
2005	14	36.4	1.8	4.1
2005	15	58.8	3.7	3.2
2005	16	47.9	2.4	4.3
2005	17	67.0	13.7	13.7
2005	18	126.1	15.8	47.9
2005	19	258.2	13.2	117.3
2005	20	449.5	15.8	156.5
2005	21	470.7	8.2	117.0
2005	22	500.8	16.9	79.1
2005	23	539.4	14.7	59.0
2005	24	552.1	18.4	49.9
2005	25	638.2	23.1	32.4
2005	26	600.9	23.1	24.3
2005	27	580.0	23.7	21.6
2005	28	542.9	14.9	21.0

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2005	29	513.2	24.4	21.9
2005	30	512.0	16.1	27.8
2005	31	466.1	18.1	41.4
2005	32	495.9	15.2	37.1
2005	33	614.1	12.4	30.7
2005	34	535.1	12.0	34.0
2005	35	497.4	5.6	30.4
2005	36	458.6	13.8	29.0
2005	37	454.7	11.5	31.0
2005	38	414.1	10.5	32.6
2005	39	325.3	12.7	37.2
2005	40	281.9	9.3	33.8
2005	41	274.7	11.1	29.6
2005	42	210.1	1.2	22.9
2005	43	172.4	10.7	15.4
2005	44	113.5	5.8	12.0
2005	45	157.5	5.6	5.3
2005	46	181.5	-2.4	6.0
2005	47	235.3	9.1	8.1
2005	48	174.4	2.5	6.3
2005	49	160.4	3.6	6.1
2005	50	126.2	2.5	4.8
2005	51	118.2	5.1	8.1
2005	52	97.4	3.9	6.0
2006	1	95.4	1.4	4.8
2006	2	86.9	2.3	4.9
2006	3	92.8	0.5	5.9
2006	4	64.9	2.4	5.4
2006	5	85.3	2.0	4.5
2006	6	78.8	-0.3	3.8
2006	7	55.4	4.0	2.8
2006	8	57.3	1.5	3.7
2006	9	60.6	1.1	3.3
2006	10	28.8	5.4	2.8
2006	11	35.4	-3.2	2.3
2006	12	97.1	3.6	2.2
2006	13	52.4	-0.1	2.2
2006	14	44.7	1.5	3.3
2006	15	54.9	2.5	4.3
2006	16	33.5	-2.0	6.3
2006	17	-29.0	5.1	6.8
2006	18	48.6	1.4	8.7
2006	19	44.0	6.9	28.0
2006	20	106.7	15.1	66.4

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2006	21	228.5	26.7	87.8
2006	22	398.0	25.5	90.8
2006	23	537.0	20.7	73.2
2006	24	884.4	22.3	65.5
2006	25	751.7	13.7	58.1
2006	26	476.3	26.2	46.1
2006	27	579.5	19.6	36.6
2006	28	597.6	22.6	34.2
2006	29	523.5	12.7	24.7
2006	30	571.3	16.8	17.6
2006	31	495.7	12.0	11.4
2006	32	475.8	13.0	11.8
2006	33	467.4	4.1	15.6
2006	34	454.6	13.2	18.7
2006	35	442.4	9.0	29.2
2006	36	449.6	3.2	30.0
2006	37	327.4	6.0	26.8
2006	38	358.4	5.0	24.3
2006	39	398.3	4.7	28.2
2006	40	314.3	-2.1	29.2
2006	41	311.8	9.2	26.8
2006	42	300.5	-2.4	22.6
2006	43	219.0	6.1	22.5
2006	44	198.9	-1.1	16.8
2006	45	177.9	-0.5	17.5
2006	46	139.0	2.4	18.8
2006	47	135.2	2.0	14.1
2006	48	141.5	-0.4	18.2
2006	49	149.1	0.9	15.1
2006	50	108.7	3.7	10.7
2006	51	127.6	1.7	12.1
2006	52	123.9	-0.2	11.7
2007	1	92.4	5.8	11.3
2007	2	95.2	-1.8	8.8
2007	3	100.7	1.3	8.7
2007	4	79.6	2.1	5.2
2007	5	79.3	0.1	6.3
2007	6	64.7	-0.9	7.8
2007	7	69.2	2.0	6.4
2007	8	29.0	0.3	5.6
2007	9	46.3	0.5	2.4
2007	10	114.7	3.1	5.4
2007	11	84.6	2.3	5.6
2007	12	83.3	2.1	6.4

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2007	13	47.6	-0.4	3.4
2007	14	57.1	-2.9	4.1
2007	15	9.8	1.6	5.5
2007	16	-13.9	1.5	6.5
2007	17	46.3	9.3	17.8
2007	18	89.0	12.4	40.3
2007	19	111.6	14.1	47.8
2007	20	146.1	23.3	42.8
2007	21	292.9	23.1	85.9
2007	22	445.4	18.0	101.6
2007	23	791.4	20.6	96.3
2007	24	884.6	23.7	58.2
2007	25	959.2	24.3	41.7
2007	26	695.2	36.6	79.9
2007	27	633.6	30.2	91.7
2007	28	738.2	27.7	71.5
2007	29	928.2	24.3	51.3
2007	30	705.3	23.6	44.5
2007	31	666.6	20.5	39.2
2007	32	680.5	22.0	35.3
2007	33	641.6	16.0	33.7
2007	34	552.3	21.6	35.2
2007	35	526.9	12.9	32.0
2007	36	488.6	7.2	35.3
2007	37	492.4	19.4	63.1
2007	38	417.3	14.7	57.3
2007	39	378.2	10.7	36.1
2007	40	315.5	22.1	35.7
2007	41	294.8	4.2	39.4
2007	42	282.1	13.3	20.8
2007	43	308.1	3.7	25.7
2007	44	199.6	4.9	26.4
2007	45	176.4	4.1	24.7
2007	46	153.2	4.6	22.8
2007	47	138.0	0.5	11.6
2007	48	102.4	3.8	11.5
2007	49	117.2	1.9	15.6
2007	50	106.9	7.9	15.8
2007	51	98.2	1.8	7.5
2007	52	73.7	4.1	0.9
2008	1	99.2	2.9	2.5
2008	2	94.5	4.2	2.3
2008	3	87.0	0.5	3.9
2008	4	46.8	1.8	4.0

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2008	5	56.3	2.6	2.3
2008	6	64.4	-0.6	1.6
2008	7	110.7	-2.1	4.2
2008	8	56.4	4.8	-1.5
2008	9	41.8	-1.5	-3.5
2008	10	63.4	-0.6	1.1
2008	11	42.5	1.7	-0.5
2008	12	50.6	2.1	-0.9
2008	13	31.5	-0.9	-2.2
2008	14	32.1	-2.0	0.8
2008	15	24.2	3.4	1.2
2008	16	-10.0	1.0	2.2
2008	17	51.8	1.7	5.8
2008	18	102.9	15.7	37.9
2008	19	101.1	14.9	75.8
2008	20	69.0	18.6	69.7
2008	21	274.9	24.9	101.6
2008	22	433.2	14.4	57.6
2008	23	409.4	23.3	31.3
2008	24	332.6	25.5	49.7
2008	25	489.8	34.0	25.8
2008	26	447.0	31.9	30.6
2008	27	560.2	21.1	34.3
2008	28	496.8	29.3	35.2
2008	29	473.3	22.7	42.6
2008	30	343.0	17.5	52.0
2008	31	398.2	16.1	43.2
2008	32	484.0	12.8	55.9
2008	33	531.5	13.2	53.7
2008	34	499.8	22.6	64.4
2008	35	427.8	36.0	70.6
2008	36	359.3	20.4	60.8
2008	37	334.6	19.2	74.8
2008	38	362.3	17.9	87.8
2008	39	293.5	11.4	80.8
2008	40	387.5	15.1	102.8
2008	41	279.1	3.4	84.0
2008	42	233.1	1.5	70.3
2008	43	201.8	7.9	34.9
2008	44	186.7	5.1	34.5
2008	45	146.5	3.9	32.7
2008	46	124.0	8.7	28.5
2008	47	144.3	4.9	18.1
2008	48	85.3	8.0	16.2

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2008	49	122.5	4.5	17.5
2008	50	81.1	7.9	11.4
2008	51	81.7	3.0	11.3
2008	52	97.6	8.2	12.5
2009	1	64.8	2.9	10.8
2009	2	116.1	-0.5	10.8
2009	3	81.8	6.8	13.1
2009	4	66.6	1.2	9.1
2009	5	106.5	3.2	11.4
2009	6	57.4	3.7	6.9
2009	7	65.1	-0.1	6.2
2009	8	52.8	2.8	6.3
2009	9	53.6	3.7	6.1
2009	10	36.1	2.8	5.4
2009	11	76.4	5.0	4.1
2009	12	82.1	-1.4	5.0
2009	13	51.2	3.0	6.6
2009	14	26.8	-0.6	5.5
2009	15	3.4	3.8	3.2
2009	16	17.2	2.6	7.0
2009	17	70.5	6.7	5.9
2009	18	202.8	56.0	60.7
2009	19	153.4	47.7	80.8
2009	20	163.4	28.5	40.2
2009	21	276.1	24.3	123.8
2009	22	323.9	24.3	123.3
2009	23	648.4	23.8	81.1
2009	24	805.9	25.5	66.0
2009	25	483.9	17.6	57.0
2009	26	358.8	19.3	55.1
2009	27	461.0	11.7	39.1
2009	28	578.0	13.0	34.6
2009	29	511.1	-0.6	30.8
2009	30	469.5	10.0	27.9
2009	31	556.7	0.8	26.5
2009	32	484.8	6.4	28.1
2009	33	508.7	8.7	29.7
2009	34	592.6	2.5	35.0
2009	35	596.3	6.4	33.3
2009	36	482.2	1.9	31.2
2009	37	472.3	5.9	32.4
2009	38	442.9	1.4	41.7
2009	39	375.1	6.8	41.9
2009	40	314.4	6.1	39.0

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2009	41	261.3	3.0	24.2
2009	42	290.8	0.3	26.5
2009	43	219.8	11.2	18.8
2009	44	254.5	-1.9	13.7
2009	45	171.0	0.3	13.0
2009	46	159.8	4.8	12.7
2009	47	149.4	-2.2	14.3
2009	48	142.2	1.4	15.0
2009	49	106.3	0.6	10.4
2009	50	101.6	0.8	12.2
2009	51	74.5	4.2	7.9
2009	52	72.6	0.4	9.1
2010	1	83.2	1.0	7.9
2010	2	103.0	1.8	10.6
2010	3	90.9	4.4	13.6
2010	4	71.3	0.3	12.6
2010	5	78.9	-0.4	12.3
2010	6	68.0	1.6	8.1
2010	7	65.6	0.9	7.7
2010	8	46.1	2.1	6.3
2010	9	61.7	-3.3	8.0
2010	10	44.4	3.3	6.9
2010	11	30.8	2.3	6.3
2010	12	39.0	-0.7	7.1
2010	13	38.3	4.3	9.5
2010	14	44.6	2.4	10.5
2010	15	54.5	0.2	12.0
2010	16	52.7	6.5	9.4
2010	17	71.5	10.6	23.8
2010	18	85.6	14.1	32.2
2010	19	89.3	8.7	27.2
2010	20	135.2	12.2	53.1
2010	21	298.5	11.8	55.8
2010	22	603.7	12.5	37.8
2010	23	681.9	8.3	35.8
2010	24	516.7	13.9	31.4
2010	25	467.2	8.2	29.3
2010	26	554.7	14.8	29.6
2010	27	441.8	11.0	38.4
2010	28	516.7	21.0	21.6
2010	29	446.9	13.3	27.5
2010	30	426.3	13.6	21.6
2010	31	496.4	9.7	15.1
2010	32	497.7	11.0	16.1

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2010	33	540.3	18.0	16.5
2010	34	461.5	10.5	13.1
2010	35	418.3	16.0	12.1
2010	36	400.8	23.0	12.4
2010	37	383.3	23.1	9.7
2010	38	323.3	18.1	8.7
2010	39	340.4	7.9	10.1
2010	40	301.9	19.0	10.7
2010	41	266.5	17.0	8.0
2010	42	230.4	9.9	11.6
2010	43	208.3	3.4	4.2
2010	44	190.9	7.4	-1.2
2010	45	156.0	5.3	8.4
2010	46	115.6	5.9	5.2
2010	47	140.9	9.9	13.5
2010	48	106.6	7.2	13.7
2010	49	121.6	8.5	12.1
2010	50	85.9	6.5	10.1
2010	51	82.8	4.5	9.4
2010	52	80.8	1.9	5.5
2011	1	69.6	10.1	6.4
2011	2	34.2	-0.6	6.1
2011	3	96.5	6.3	5.6
2011	4	77.4	3.2	7.8
2011	5	75.6	2.3	8.3
2011	6	48.2	-0.4	8.6
2011	7	3.3	4.1	8.1
2011	8	44.1	3.8	7.7
2011	9	23.2	2.6	7.2
2011	10	39.7	1.0	8.3
2011	11	77.7	6.9	4.9
2011	12	83.6	0.6	8.8
2011	13	60.6	3.8	7.2
2011	14	41.4	2.8	6.4
2011	15	-7.0	5.5	1.9
2011	16	19.9	2.7	5.6
2011	17	51.3	5.8	5.3
2011	18	90.6	10.3	19.4
2011	19	90.2	22.1	40.1
2011	20	91.2	33.3	88.1
2011	21	287.4	47.4	157.4
2011	22	596.2	45.2	95.7
2011	23	687.7	56.0	46.8
2011	24	488.6	44.6	31.5

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2011	25	500.3	36.2	40.3
2011	26	599.3	39.9	45.3
2011	27	419.8	33.7	68.7
2011	28	454.6	32.9	60.8
2011	29	508.2	34.2	107.4
2011	30	484.3	35.1	73.9
2011	31	430.5	32.0	59.0
2011	32	438.1	46.3	54.1
2011	33	493.2	43.6	68.0
2011	34	507.0	46.2	73.2
2011	35	429.0	35.7	62.4
2011	36	460.8	39.0	58.3
2011	37	425.1	22.8	54.9
2011	38	390.0	23.8	59.7
2011	39	349.0	15.6	65.1
2011	40	348.4	14.9	42.6
2011	41	271.3	12.7	34.0
2011	42	202.9	13.1	22.9
2011	43	208.5	9.2	19.2
2011	44	154.3	3.7	12.5
2011	45	148.7	7.0	14.9
2011	46	117.9	7.3	9.5
2011	47	144.6	7.1	16.4
2011	48	152.8	4.3	16.5
2011	49	98.2	10.5	14.2
2011	50	104.2	5.3	12.2
2011	51	114.0	5.3	12.4
2011	52	66.6	9.1	22.2
2012	1	114.7	3.7	11.6
2012	2	55.0	6.5	11.6
2012	3	22.7	-0.7	10.7
2012	4	79.0	6.4	11.6
2012	5	103.0	2.9	11.9
2012	6	97.6	1.0	10.3
2012	7	70.1	4.6	9.6
2012	8	42.6	6.0	11.0
2012	9	57.0	3.8	7.9
2012	10	62.7	6.9	11.2
2012	11	59.0	4.4	9.3
2012	12	45.5	4.1	9.0
2012	13	51.5	4.1	5.0
2012	14	31.0	3.4	8.1
2012	15	19.4	3.8	9.8
2012	16	70.7	6.5	9.5

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2012	17	61.8	12.4	13.6
2012	18	83.6	13.2	37.9
2012	19	68.4	13.9	48.5
2012	20	105.3	21.4	45.4
2012	21	202.2	32.1	95.4
2012	22	319.5	27.3	110.9
2012	23	591.4	40.0	132.6
2012	24	676.5	44.5	93.9
2012	25	765.4	40.5	76.8
2012	26	897.0	44.4	65.5
2012	27	521.6	45.4	68.1
2012	28	524.7	42.0	86.8
2012	29	639.8	37.5	72.6
2012	30	654.8	36.0	42.4
2012	31	535.8	30.9	32.4
2012	32	548.3	36.7	31.3
2012	33	500.8	24.7	32.5
2012	34	482.6	34.7	19.5
2012	35	440.6	29.5	25.4
2012	36	377.9	43.0	20.7
2012	37	416.8	22.3	19.4
2012	38	362.4	27.6	17.7
2012	39	383.2	26.2	14.5
2012	40	365.1	22.3	12.8
2012	41	323.2	16.1	11.2
2012	42	256.6	16.3	9.4
2012	43	215.3	8.9	9.0
2012	44	192.5	10.9	11.5
2012	45	177.4	9.0	12.3
2012	46	117.8	10.4	10.0
2012	47	160.1	9.6	12.0
2012	48	117.2	8.5	13.0
2012	49	132.2	10.5	13.2
2012	50	118.9	11.0	11.3
2012	51	74.3	8.8	8.7
2012	52	96.1	3.0	6.8
2013	1	86.3	9.6	7.6
2013	2	92.5	7.0	11.7
2013	3	78.6	9.4	8.6
2013	4	47.5	7.0	9.8
2013	5	98.5	7.0	10.7
2013	6	87.0	5.2	9.0
2013	7	63.2	5.5	9.7
2013	8	48.2	6.3	7.1

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2013	9	38.5	4.6	6.0
2013	10	55.3	5.2	5.1
2013	11	5.6	5.0	5.0
2013	12	61.1	3.2	7.9
2013	13	84.3	5.1	7.5
2013	14	29.1	0.9	9.1
2013	15	22.7	7.9	5.6
2013	16	12.9	7.8	6.9
2013	17	38.2	6.3	13.2
2013	18	110.2	7.8	18.6
2013	19	165.9	27.3	26.0
2013	20	146.0	32.8	78.2
2013	21	287.4	30.5	105.0
2013	22	659.3	41.6	174.4
2013	23	581.7	41.8	66.0
2013	24	673.1	30.8	59.8
2013	25	806.3	22.8	46.3
2013	26	815.9	13.5	44.0
2013	27	589.8	15.2	40.3
2013	28	503.8	14.4	31.4
2013	29	586.0	36.1	33.6
2013	30	584.9	57.6	41.1
2013	31	634.9	41.8	23.3
2013	32	571.9	34.4	21.8
2013	33	604.0	20.7	27.8
2013	34	466.2	31.1	34.4
2013	35	512.7	11.5	21.8
2013	36	602.8	16.4	25.8
2013	37	538.5	20.8	38.5
2013	38	471.0	17.8	50.4
2013	39	379.7	18.6	54.2
2013	40	352.4	12.7	58.4
2013	41	294.5	13.7	56.5
2013	42	314.7	13.9	52.9
2013	43	314.6	7.3	49.8
2013	44	239.8	14.1	44.5
2013	45	174.1	6.0	7.5
2013	46	131.6	4.0	9.7
2013	47	157.3	3.8	9.1
2013	48	114.3	7.6	12.2
2013	49	152.4	7.7	9.1
2013	50	122.0	9.8	10.9
2013	51	117.5	7.4	8.9
2013	52	122.2	6.1	7.6

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2014	1	112.9	8.5	8.6
2014	2	114.3	3.7	8.1
2014	3	91.8	5.6	7.9
2014	4	90.1	9.0	7.0
2014	5	55.5	2.0	5.4
2014	6	60.4	4.0	6.2
2014	7	97.4	6.0	5.3
2014	8	48.1	3.5	5.1
2014	9	36.8	4.2	3.6
2014	10	89.9	2.0	4.3
2014	11	51.6	4.6	2.7
2014	12	18.0	4.0	3.6
2014	13	56.4	1.9	4.1
2014	14	54.2	4.1	4.3
2014	15	29.1	2.9	4.0
2014	16	69.0	2.1	5.3
2014	17	67.7	6.1	10.7
2014	18	96.9	14.1	50.9
2014	19	195.3	24.5	73.6
2014	20	376.9	30.7	68.3
2014	21	384.4	23.4	42.9
2014	22	358.9	19.3	39.3
2014	23	377.1	15.2	32.0
2014	24	393.2	8.0	54.7
2014	25	380.7	13.7	47.1
2014	26	435.2	16.0	36.7
2014	27	775.7	10.0	30.6
2014	28	693.6	13.5	23.4
2014	29	614.8	9.1	23.6
2014	30	513.3	13.2	21.7
2014	31	505.0	8.0	18.3
2014	32	498.9	4.4	45.8
2014	33	600.2	14.2	43.7
2014	34	546.1	5.1	50.5
2014	35	450.1	9.2	47.6
2014	36	526.2	15.2	35.9
2014	37	482.2	9.2	29.9
2014	38	481.0	19.7	36.0
2014	39	448.7	17.3	53.5
2014	40	448.0	8.1	66.7
2014	41	436.8	13.9	68.8
2014	42	396.7	12.2	62.1
2014	43	352.3	7.7	58.7
2014	44	298.7	9.1	52.9

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2014	45	253.7	4.8	50.2
2014	46	191.1	3.6	28.6
2014	47	182.6	7.0	21.4
2014	48	142.8	3.3	23.2
2014	49	162.5	5.9	24.4
2014	50	136.3	4.3	16.6
2014	51	123.7	4.6	11.0
2014	52	104.8	4.3	10.8
2015	1	100.9	3.0	18.8
2015	2	121.2	2.1	22.2
2015	3	96.2	7.6	16.5
2015	4	100.7	4.3	11.6
2015	5	67.5	1.7	14.0
2015	6	93.0	2.9	17.2
2015	7	104.8	3.7	16.0
2015	8	67.6	1.6	17.5
2015	9	63.4	2.2	15.8
2015	10	52.2	4.7	20.4
2015	11	67.5	4.3	21.3
2015	12	61.4	2.9	20.2
2015	13	60.5	6.1	19.9
2015	14	72.9	3.3	22.0
2015	15	73.9	3.4	20.7
2015	16	65.4	7.7	15.2
2015	17	57.5	5.9	18.6
2015	18	45.4	3.4	22.1
2015	19	94.2	11.7	82.7
2015	20	255.3	14.8	139.6
2015	21	566.7	15.1	106.3
2015	22	767.0	12.5	59.5
2015	23	566.5	18.6	35.6
2015	24	394.6	15.2	29.1
2015	25	547.0	8.0	23.2
2015	26	536.3	8.8	28.0
2015	27	519.3	15.4	31.2
2015	28	538.8	7.5	34.7
2015	29	505.0	14.6	33.7
2015	30	534.4	9.7	33.4
2015	31	538.8	9.3	41.7
2015	32	562.3	15.1	39.5
2015	33	542.8	9.9	44.2
2015	34	545.3	14.8	51.4
2015	35	501.9	17.6	71.6
2015	36	437.1	15.4	65.7

Year	Week	Inflows Available for Outflow (m^3/s)		
		Marsh	Aishihik	Mayo
2015	37	467.1	24.6	80.4
2015	38	369.4	27.8	72.0
2015	39	377.3	14.7	66.1
2015	40	362.5	21.2	51.2
2015	41	390.0	19.2	46.5
2015	42	353.5	18.5	43.2
2015	43	326.4	11.6	37.7
2015	44	266.5	7.3	23.9
2015	45	217.6	10.8	25.6
2015	46	167.4	4.1	23.1
2015	47	174.9	-0.1	20.6
2015	48	144.0	10.3	22.2
2015	49	136.8	7.4	18.5
2015	50	122.7	6.5	14.9
2015	51	119.5	6.4	17.2
2015	52	123.4	1.6	14.3

City of Whitehorse
(CW)

TOPIC: **Yukon Energy 2016 Resource Plan (Resource Plan)**

REFERENCE: Resource Plan, page 1, lines 7-11, YEC Application, page 8

PREAMBLE: In the Resource Plan, YEC states:

> A key component of the 2016 Resource Plan (the Plan) is a recommended Action Plan for meeting customer electricity demands. **The document does not seek approval for specific future projects**. While the Plan identifies resources of interest, the development of future resources will be managed through YEC's stagegate process for project development and approval, and will require engagement with First Nations and stakeholders, as well as regulatory reviews and permitting. (Emphasis added)

On page 8 of its Application, YEC states:

> Yukon Energy has provided as Volume 2 of its filed material the final 2016 Resource Plan. The 2016 Resource Plan addresses Yukon Energy's requirements for the next five years, as well as for the longer term planning horizon, and describes the extensive consultation undertaken during the preparation of this plan. Yukon Energy is not seeking specific approvals for the plan. The 2016 Resource Plan is provided for information of the Board and stakeholders and to provide context for capital expenditures and ongoing planning costs included in the test year forecasts.

CW requires information to understand the use of the Resource Plan.

QUESTION:

a) Please fully explain how the resource plan was used to create the GRA forecasts. Were projects in the resource plan specifically included in the GRA?

b) In the response to (b) above, please provide a cross reference between any projects in the GRA, and projects in the resource plan.

ANSWER:

(a) and **(b)**

The 2016 Resource Plan was used in YEC's GRA Application to provide context for the GRA capital expenditures and ongoing planning costs included in the test year forecasts.

Sales and generation forecasts in the GRA were prepared separately from the 2016 Resource Plan, based on the information and analysis as reviewed in Tab 2 of the Application and the required focus on 2017 and 2018 versus the 20-year planning period relevant to the Resource Plan. The relevant 2016 Resource Plan forecasts for sales, generation, winter peak capacity, and single contingency dependable capacity shortfalls are referenced in the Application.

Capital and deferred cost projects referenced in the 2016 Resource Plan for possible future development are noted where relevant throughout Tab 5 of YEC's Application. Examples for major projects (over $1 million spending) include: LNG Third Engine, Battery Project, Thermal Plant Project, Stewart Keno City Transmission Project, DSM, Marsh Lake (Southern Lakes) Storage Enhancement Project, Mayo Lake Storage Enhancement Project. Many of these projects remain in WIP at the end of 2018 and therefore do not affect test year revenue requirements or rates.

TOPIC: **Yukon Energy 2016 Resource Plan (Resource Plan)**

REFERENCE: Resource Plan, page 1, lines 2-6

PREAMBLE: On page 1 of the Resource Plan, YEC states:

> Yukon Energy Corporation (YEC) prepares an update to its 20-Year Resource Plan every five years. The following document is an update of the 2006 and 2011 Plans. The purpose of this plan is to provide recommendations as to how to cost-effectively meet the electricity needs of the Yukon Energy's customers over the next 20 years. Consistent with the values of these customers, environmental protection and low cost were key drivers in shaping the recommendations of this plan.

CW requires information to assess the accuracy of Resource Plans in forecasting needs.

QUESTION:

a) Please provide copies of 2006 and 2011 plans.

b) Please provide tables of annual sales forecasts for the 20 year period for each of the plans.

c) Please provide actual annual sales for each year from 2006-2016.

d) Please provide a table of peak load forecasts for the 20 year period for each of the plans.

e) Please provide the actual peak load for each year from 2006-2016.

f) Please provide a comparison of the proposed projects in each of the plans to the actual projects completed in the 2006-2016 time period. In the response, please explain variances between proposed and actual projects.

g) Please confirm that YEC facility planning is based on this resource plan. If not confirm please fully explain.

ANSWER:

(a)

Yukon Energy's 2006 Resource Plan is available from the YUB website for the proceeding re: Yukon Energy Corporation 20-Year Resource Plan at the link below.

http://yukonutilitiesboard.yk.ca/pdf/YEC%2020-Year%20Resource%20Plan/152_resource20yearplan.pdf

Yukon Energy's 2011 Resource Plan Overview dated July 2012 was filed as Attachment 1 to YECL-YEC-1-18(a), and is available on the YUB website at the link below.

http://yukonutilitiesboard.yk.ca/proceedings/yec-2012-general-rate-application/

A subsequent update to this forecast that was filed with the Board in November 2012 as Exhibit B-20 is provided as CW-YEC-1-2(a) Attachment 1.

(b) and **(d)**

Please see Table 1 below for a summary of the earlier Resource Plan Base Case generation and peak load forecasts.

The 2011 Resource Plan forecasts are from the July and November 2012 forecasts as filed with the Board during the 2012/13 GRA. The November version reflected non-industrial GRA load forecasts for 2012 and 2013 and DSM based on the ICF Marbek January 2012 report; it also included Minto, Alexco and Whitehorse Copper tailings loads.

The 2006 Resource Plan addressed the WAF and MD grids separately as these were not yet connected, and focused on the WAF grid. The Base Case assumed WAF non-industrial load growth at 1.85% per year over 2004 loads with no industrial load. Table 1 below provides an approximation of the energy forecast for the combined grids based on this assumed annual load growth, and the peak load for the WAF grid based on the 1.85% annual growth rate assumption.

Table 1: Summary of 2006 and 2011 Resource Plan Forecasts

Forecast Years	Base Case with DSM - Total Load (GW.h)			Base Case with DSM - Total Peak Load (MW)		
	2006 RP - 1.85%yr Case	2011 RP - July 2012 Version	2011 RP - Nov 2012 Version	2006 RP - 1.85%yr Case - WAF only	2011 RP - July 2012 Version	2011 RP - Nov 2012 Version
2006	302.0			57.4		
2007	307.6			58.5		
2008	313.3			59.5		
2009	319.1			60.6		
2010	325.0			61.8		
2011	331.0			62.9		
2012	337.1	416	406	64.1	80	78
2013	343.3	430	412	65.3	81	79
2014	349.7	443	437	66.5	83	82
2015	356.2	449	449	67.7	84	84
2016	362.8	455	461	68.9	85	88
2017	369.5	454	469	70.2	85	89
2018	376.3	460	474	71.5	86	90
2019	383.3	462	471	72.8	88	91
2020	390.4	441	469	74.2	89	92
2021	397.6	409	456	75.6	81	88
2022	404.9	416	464	77.0	83	90
2023	412.4	422	434	78.4	84	86
2024	420.1	429	443	79.8	85	88
2025	427.8	437	453	81.3	87	90
2026		444	463		88	92
2027		452	475		90	94
2028		459	486		91	97
2029		467	498		93	99
2030		475	510		94	101

(c)

Actual annual sales (including secondary sales) from 2006-2016 are as follows:

Year	Sales (GWh)
2006	302.0
2007	307.7
2008	315.7
2009	345.6
2010	351.5
2011	368.7
2012	392.1
2013	388.5
2014	373.9
2015	380.7
2016	386.0

(e)

Actual peak load for each year from 2006-2016 is as follows:

Year	Hourly Avg. Peak Generation [MW]
2006	65.0
2007	63.1
2008	67.5
2009	69.0
2010	72.6
2011	76.3
2012	82.2
2013	82.7
2014	76.5
2015	82.1
2016	88.1

(f)

Near term proposed projects (i.e., within the first five years of each plan) in the earlier Resource Plans are reviewed below:

1. **2006 Resource Plan:**

    a. **Proposed** - The initial plan proposed four projects (Aishihik 3rd Turbine, Carmacks-Stewart Transmission Project (CSTP), Mirrlees Life Extension (at Whitehorse), and Marsh Lake Fall-Winter Storage); the plan was subsequently revised to remove the Marsh Lake Fall-Winter Storage and to add Mirrlees life extension at Faro.[1]

    b. **Actual** – The Aishihik 3rd Turbine was developed, along with the CSTP in two stages; two Mirrlees units received life extension work; the Marsh Lake storage project continues to be examined (now referenced as Southern Lakes Storage Enhancement).

2. **2011 Resource Plan:**

    a. **Proposed** – The plan proposed the following (in addition to proposing cost-effective DSM) in the "recommended plans" section of the Overview:
        i. LNG transition option to establish LNG generating capability in Whitehorse prior to 2015, as a transition option able to meet current forecast loads with the least cost option available for near-term implementation.
        ii. Near term hydro enhancements related to planning for the Marsh Lake Storage hydro enhancement project, and to reach a final determination on the Gladstone Diversion project.
        iii. Other activities related to completing Ferry Hill wind monitoring, continuing planning studies for priority longer-term greenfield hydro

[1] The Yukon Utility Board's Report and Recommendations regarding the 2006 Resource Plan, Section 6.6, noted as follows regarding the Marsh Lake storage project "The Board is of the view that this project is not likely to be completed in the near term, given the argument by YEC regarding local opposition to the project. However, the Board sees some viability to this project in terms of either displacing diesel generation or delaying future capacity additions. Therefore, the Board recommends that this project be retained in the Plan but be removed as a near-term project. YEC should update the status of this project when it files its next resource plan. The timing for YEC's next resource plan is discussed in Section 13.

development opportunities, and studies for other potential future options (including geothermal, grid extensions, wood biomass, solar, and pipeline/natural gas).

b. **Actual** – The LNG Project was developed, planning continued on the Marsh Lake Storage project, and a final determination was reached on not pursuing the Gladstone Diversion project. Planning studies continued to review in the latest Resource Plan updates on a range of other potential longer-term resource options.

(g)

YEC generation and transmission planning utilizes the available resource plans to assess priorities and options, with updates on these plans carried out every five years. As noted in each resource plan, YEC's final decisions on any specific resource project involve additional stages of assessment and planning by management and YEC's Board of Directors.

B20

YUKON ENERGY

YUKON UTILITIES BOARD
EXHIBIT B-20
DAY | ENTERED BY YEC | DATE NOV 14/12

YUKON ENERGY CORPORATION

OVERVIEW OF 20-YEAR RESOURCE PLAN: 2011-2030

UPDATED APPENDIX A

November 2012

APPENDIX A: UPDATED NEAR-TERM GRID LOAD SCENARIOS

The 2011 Resource Plan grid load scenarios are updated on an ongoing basis. As at November 2012, four load scenarios are currently applicable for Yukon Energy grid generation and capacity planning (see Table A-1):

1. Load scenarios without connection of major new mines:

   a. **Base Case:**[1]

      i. GRA non-industrial forecast loads for 2012 and 2013[2];

      ii. Non-industrial growth at 2.26%/year[3] for 2014 and 2015, at 2.45%/year[4] for 2016-2020 inclusive, at 2.82%/year for 2021-2025 inclusive, at 3.13%/year for 2026 and thereafter;

      iii. DSM/SSE assumed at 32% of annual load growth based on Yukon Electricity Conservation and Demand Management Potential Review (CPR) report prepared by ICF Marbek (January 2012);

      iv. Minto generation load (includes grid losses) at 32.3 GW.h/2012, 28.3 GW.h/2013, 38.0 GW.h/2014 and at 39.1 GW.h/year for 2015-2022 (no load thereafter)[5];

      v. Alexco generation load (includes grid losses) for 2012 and 2013 are at the same level as in 2012/13 GRA (14.2 GW.h/2012 and 15.8 GW.h/2013)[6], at 20.9 GW.h/2014 and step-by-step increasing to approximately 33 GW.h in 2016, and decreasing to approximately 22 GW.h/year level by 2020 (no load thereafter); and

      vi. Whitehorse Copper Tailings (WHCT) generation load (includes grid losses) at 9.3 GW.h/yr 2014-2018 (as compared to 5.2 GW.h/yr in 2013, as per 2012/13 GRA) and 4.1 GW.h in 2019 (no load thereafter).

[1] The Base Case loads have been updated from the June 2012 Update for years after 2013 to reflect current information on industrial loads and non-industrial load growth rates and DSM/SSE projections based on the ICF Marbeck January 2012 CPR report. GRA forecasts for 2012 and 2013 are retained for this update, except for adjustments to reflect the major reductions in forecast Minto mine loads.

[2] YEC's current 2012 BP forecasts indicate loads in 2012 (9 month actual) and 2013 that exceed GRA forecasts (including losses, the 2012 BP is 7.0 GWh higher than GRA forecast and the 2013 BP is 8.0 GW.h higher than GRA forecast [includes impact from delay in Fish Lake hydro plant in-service]). Non-industrial Resource Plan forecasts have not been adjusted at this time to reflect the current 2012 BP adjustments.

[3] 2011 Resource Plan forecast annual growth rate for non-industrial load.

[4] The annual growth rates for 2016-2020, 2021-2025 and 2026-2030 are from Marbek's final CPR report.

[5] Minto generation load reflects major reductions as provided by Minto in fall 2012 that materially changed forecasts previously provided in fall 2011.

[6] Alexco generation load after 2013 reflects updated forecasts as recently provided by Alexco. (The 2012 and 2013 GRA forecasts are retained - Alexco's recent updates suggest a small generation load reduction in 2012 (0.6 GWh) and a small generation load increase in 2013 (1.3 GW.h).

b. **Base Case with Brewery Creek:** Base Case with the added connection, starting July 2014, of Brewery Creek mine with generation load (including grid losses) assumed of 9.6 GW.h/yr in 2014, 19.0 GW.h/yr for years 2015-2017, and 29.0 GW.h/yr thereafter until the end of 2023[7].

2. Load scenarios with connection of major new mines:

   a. **Scenario A:** Base Case with Brewery Creek and Victoria Gold mine, starting April 2015 with generation load (including grid losses) of 124.7 GW.h/yr for 2015-2018 (2015 at 103.4 GW.h, assuming April start of operations), 143.3 GW.h/yr for 2019-2020, 145.1 GW.h/yr for 2021 and 152.3 GW.h/yr for 2022-2024 (no load thereafter)[8].

   b. **Scenario B:** Base Case with Brewery Creek, Victoria Gold and Carmacks Copper mine, starting January 1, 2016 with generation load (including grid losses) of 54.4 GW.h/yr that continues until the end of 2022 and 27.2 GW.h/yr for 2023 (no load thereafter)[9].

[7] Negotiation of a PPA with Brewery Creek has not yet commenced.

[8] PPA negotiations are ongoing with Victoria Gold (an earlier LOI set out principles for connection to the grid). It is assumed that Victoria Gold will pay all costs required for grid connection, plus upgrade of the Mayo-Keno line. The timing for connection of this mine remains uncertain (but will not be earlier than the Q2 2015 assumed in Scenario A).

[9] Carmacks Copper has recently re-started its regulatory review processes, with an announced filing of a revised application planned this year with YESAB, followed shortly thereafter with revised filing with the YWB. PPA discussions occurred in the past – Carmacks Copper will be required to pay all costs required for grid connection plus a contribution to CSTP capital costs. The timing for connection of this mine remains uncertain, but could potentially occur by Q1 2016.

Table A-1: Updated Grid Load Scenarios

Forecast Years	Base Case (w DSM/SSE)			Base Case w Brewery Creek (w DSM/SSE)			Base Case with Brewery Creek and Victoria Gold (w DSM/SSE)			Base Case with Brewery Creek, Victoria Gold and Carmacks Copper (w DSM/SSE)		
	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)
2012	359.0	46.5	405.5	359.0	46.5	405.5	359.0	46.5	405.5	359.0	46.5	405.5
2013	362.6	49.3	411.9	362.6	49.3	411.9	362.6	49.3	411.9	362.6	49.3	411.9
2014	368.3	68.3	436.6	368.3	77.9	446.2	368.3	77.9	446.2	368.3	77.9	446.2
2015	374.1	74.5	448.6	374.1	93.5	467.7	374.1	196.9	571.0	374.1	196.9	571.0
2016	380.6	80.4	461.0	380.6	99.4	480.0	380.6	224.2	604.7	380.6	278.5	659.1
2017	387.2	81.5	468.8	387.2	100.6	487.8	387.2	225.3	612.5	387.2	279.6	666.9
2018	394.0	79.5	473.6	394.0	108.6	502.6	394.0	233.3	627.3	394.0	287.6	681.7
2019	401.0	70.2	471.1	401.0	99.2	500.2	401.0	242.6	643.6	401.0	297.0	697.9
2020	408.1	60.9	469.0	408.1	89.9	498.0	408.1	233.3	641.4	408.1	287.7	695.8
2021	416.5	39.1	455.6	416.5	68.2	484.7	416.5	213.3	629.8	416.5	267.6	684.1
2022	425.2	39.1	464.3	425.2	68.2	493.3	425.2	220.5	645.6	425.2	274.8	700.0
2023	434.1		434.1	434.1	29.0	463.1	434.1	181.3	615.4	434.1	208.5	642.6
2024	443.2		443.2	443.2		443.2	443.2	152.3	595.5	443.2	152.3	595.5
2025	452.6		452.6	452.6		452.6	452.6		452.6	452.6		452.6
2026	463.4		463.4	463.4		463.4	463.4		463.4	463.4		463.4
2027	474.5		474.5	474.5		474.5	474.5		474.5	474.5		474.5
2028	485.9		485.9	485.9		485.9	485.9		485.9	485.9		485.9
2029	497.7		497.7	497.7		497.7	497.7		497.7	497.7		497.7
2030	509.8		509.8	509.8		509.8	509.8		509.8	509.8		509.8

Note: The 2012/2013 forecasts for this update retain the 2012/2013 GRA forecasts, except for the updated reduction to the Minto mine load. YEC 2012 BP updates indicate higher non-industrial generation loads (including grid losses) in 2012 (+7.0 GW.h) and in 2013 (+8.0 GW.h) compared to the 2012/2013 GRA forecasts.

September 22, 2017
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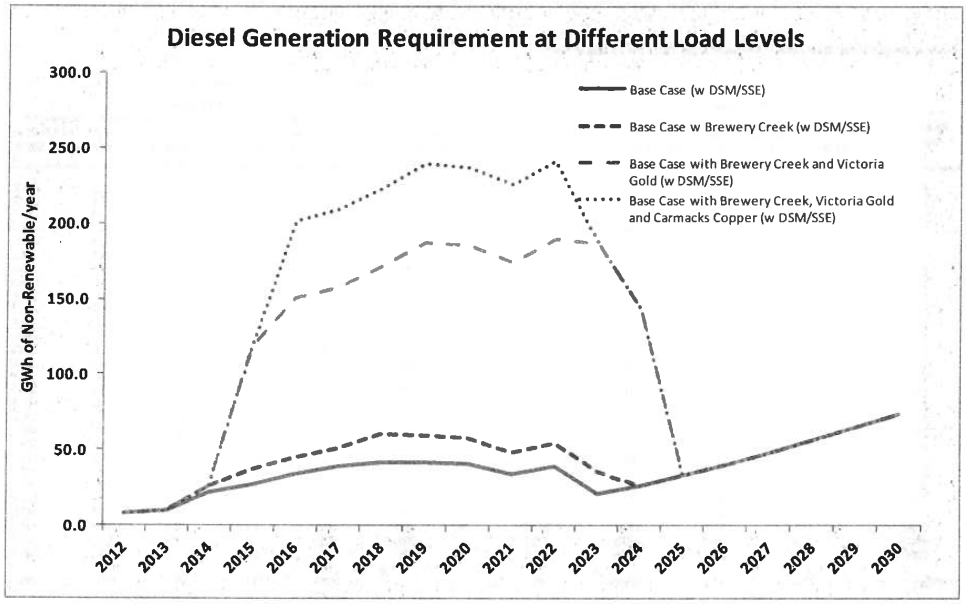
2017 – 2018 General Rate Application
CW-YEC-1-2 Attachment 1

Figure A-1: Diesel Generation Requirements at Different Forecast Loads: 2012-2030



Diesel Energy Requirement (GWh)	2012	2015	2020	2025	2030
Base Case	8.1	26.6	40.8	32.8	74.0
Base Case with Brewery Creek	8.1	37.3	57.8	32.8	74.0
Base Case with Brewery Creek and Victoria Gold	8.1	117.6	184.8	32.8	74.0
Base Case with Brewery Creek, Victoria Gold and Carmacks Copper	8.1	117.6	236.9	32.8	74.0

Figure A-1 and table provide the forecast diesel generation requirement during the 20-year planning period for each of the load scenarios.

1. The numbers are based on updated load for 2012-2030.
2. Diesel requirement numbers are long-term average diesel.
3. Model run with Aishihik 10-year rolling average rule, Mayo Lake assumed in-service by 2015.

Diesel generation forecasts for each load scenario reflect long-term average hydro generation, i.e., the average hydro generation over 28 recorded water year conditions at the assumed load, as estimated by the power benefits model used by YEC for grid generation planning. Table A-2 and the Figure A-2 below it provide a detailed review of potential diesel generation variability for the year 2015 under each load scenario for each of the 28 water years (the figure shows the annual load duration curve for diesel for each load scenario).

Table A-2: Forecast Diesel Generation Variability (GW.h) Depending on Water Year Conditions - Load Scenarios for 2016 and 28 Water Years of Record

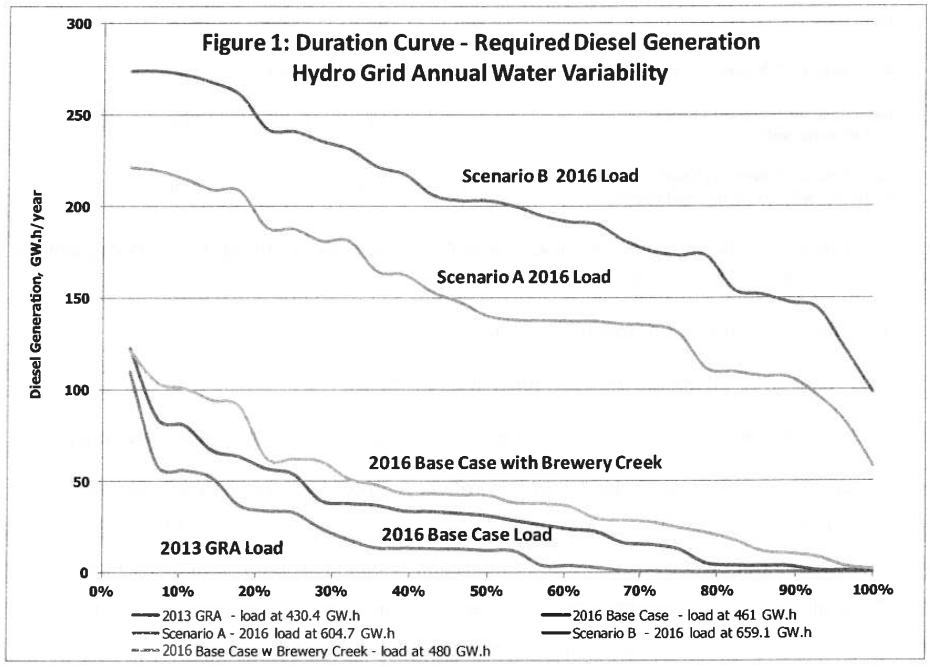
Average Annual Diesel Generation (Averaged Load Years for 28 Water Years)

Water Year	2016 Base Case - load at 461 GW.h	2016 Base Case w Brewery Creek load at 480 GW.h	Average diesel generation required (GW.h) Scenario A - 2016 load at 604.7 GW.h	Scenario B - 2016 load at 659.1 GW.h
1981	3.9	10.3	137.8	203.1
1982	26.2	48.0	147.7	194.7
1983	28.5	38.2	135.0	191.5
1984	37.9	62.1	188.5	242.1
1985	33.5	43.3	162.7	217.4
1986	37.0	43.2	135.7	181.3
1987	12.9	24.6	137.5	199.9
1988	15.3	27.6	111.7	147.6
1989	3.6	8.4	109.7	175.5
1990	5.2	17.8	138.1	190.1
1991	3.4	11.7	107.4	144.2
1992	1.0	1.9	58.2	98.5
1993	1.2	3.6	96.6	154.4
1994	0.9	21.8	209.1	267.4
1995	56.9	94.1	219.5	273.8
1996	80.5	103.6	221.3	271.7
1997	84.3	100.5	181.1	231.2
1998	63.4	90.8	214.9	273.8
1999	122.5	121.1	208.4	260.7
2000	66.9	62.6	137.3	173.1
2001	33.8	28.6	82.3	121.8
2002	39.6	36.1	140.2	203.2
2003	31.1	51.3	187.6	240.9
2004	53.8	60.7	181.2	235.5
2005	23.9	42.2	153.4	206.3
2006	22.4	37.7	164.7	221.7
2007	32.4	42.5	130.8	173.3
2008	16.3	29.5	106.6	151.9
Average	33.5	45.1	150.2	201.7

Distribution of Annual Water Year Loads (Figure 1)

	% of Years not less than	2013 GRA - load at 430.4 GW.h	2016 Base Case - load at 461 GW.h	2016 Base Case w Brewery Creek - load at 480 GW.h	Scenario A - 2016 load at 604.7 GW.h	Scenario B - 2016 load at 659.1 GW.h
1	4%	109.9	122.5	121.1	221.3	273.8
2	7%	58.5	84.3	103.6	219.5	273.8
3	11%	55.9	80.5	100.5	214.9	271.7
4	14%	51.8	66.9	94.1	209.1	267.4
5	18%	36.8	63.4	90.8	208.4	260.7
6	21%	33.6	56.9	62.6	188.5	242.1
7	25%	32.8	53.8	62.1	187.6	240.9
8	29%	24.3	39.6	60.7	181.2	235.5
9	32%	18.0	37.9	51.3	181.1	231.2
10	36%	13.5	37.0	48.0	164.7	221.7
11	39%	13.3	33.8	43.3	162.7	217.4
12	43%	12.9	33.5	43.2	153.4	206.3
13	46%	12.8	32.4	42.5	147.7	203.2
14	50%	12.0	31.1	42.2	140.2	203.1
15	54%	11.6	28.5	38.2	138.1	199.9
16	57%	3.8	26.2	37.7	137.8	194.7
17	61%	3.7	23.9	36.1	137.5	191.5
18	64%	2.6	22.4	29.5	137.3	190.1
19	68%	0.9	16.3	28.6	135.7	181.3
20	71%	0.6	15.3	27.6	135.0	175.5
21	75%	0.3	12.9	24.6	130.8	173.3
22	79%	0.1	5.2	21.8	111.7	173.1
23	82%	0.1	3.9	17.8	109.7	154.4
24	86%	0.0	3.6	11.7	107.4	151.9
25	89%	0.0	3.4	10.3	106.6	147.6
26	93%	0.0	1.2	8.4	96.6	144.2
27	96%	0.0	1.0	3.6	82.3	121.8
28	100%	0.0	0.9	1.9	58.2	98.5
		18.2	33.5	45.1	150.2	201.7

Figure A-2: Duration Curve – Required Diesel Generation Hydro Grid Annual Water Variability



Projected annual grid capacity MW surplus (shortfall) under each load scenario is provided in Table A-3, assuming existing plant and planned diesel unit retirements and applying YEC's approved N-1 and LOLE capacity planning criteria. These shortfalls assume that L172 is re-enforced (with by twinning or by provision for the 35 kV system to be able to by-pass this line between Takhini and McIntyre substations).

The following are noted regarding assumed diesel unit retirements, using projected shortfalls under the Base Case to demonstrate the impact of assumed retirements:

- 2015 Base Case shortfall of 3.8 MW: reflects following 8 MW of diesel unit retirements:
    - Mirrlees WD#1 and WD#2 retired in 2014/2015 (2011 Resource Plan rating of 3.50 and 4.5 MW=8 MW total).
    - Replacing one of these units with at least the same capacity would totally resolve the 2015 shortfall.
- 2020 Base Case shortfall of 16.9 MW: reflects following 13.11 MW of diesel unit retirements:
    - The above Mirrlees retirements (8 MW) plus.
    - Dawson retirement of 3 units (total 2.56 MW retired in 2017, 2018 and 2020).
    - Mayo retirement of 2 units (total 1.7 MW in 2019).
    - Faro retirement of 1 unit (0.85 MW in 2019).
- 2025 Base Case shortfall of 41.2 MW: reflects following 28.61 MW of diesel unit retirements:
    - The above 13.11 MW retired by 2020 plus.
    - Whitehorse retirement of 4 units (total 11.5 MW - last Mirrlees (4.5 MW) and 3 EMDs).
    - Faro Mirrlees unit (4.0 MW in 2021).
- 2030 Base Case shortfall of 58.4 MW: reflects following 34.41 MW of diesel unit retirements:
    - The above 28.61 MW retired by 2025 plus.
    - Whitehorse CAT (3.0 MW in 2026).
    - Faro CAT (2.8 MW in 2027).

Table A-3: Grid Capacity Planning - Forecast MW Surplus (Shortfall) by Load Scenario: 2012-2030

Forecast Years	Base Case (w DSM/SSE)			Base Case w Brewery Creek (w DSM/SSE)			Base Case with Brewery Creek and Victoria Gold (w DSM/SSE)			Base Case with Brewery Creek, Victoria Gold and Carmacks Copper (w DSM/SSE)		
	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)
2012	77.8	7.2	7.2	77.8	7.2	7.2	77.8	7.2	7.2	77.8	7.2	7.2
2013	78.6	6.5	6.5	78.6	6.5	6.5	78.6	6.5	6.5	78.6	6.5	6.5
2014	81.9	1.8	1.8	84.4	1.8	1.8	84.4	1.8	1.8	84.4	1.8	1.8
2015	84.2	-3.8	-3.8	86.7	-3.8	-3.8	95.1	-3.8	-11.6	95.1	-3.8	-11.6
2016	87.9	-5.1	-5.1	90.4	-5.1	-6.9	98.8	-5.1	-15.3	106.1	-5.1	-22.6
2017	89.2	-7.3	-7.3	91.7	-7.3	-9.1	100.1	-7.3	-17.5	107.4	-7.3	-24.8
2018	90.0	-9.4	-9.4	92.5	-9.4	-10.6	100.9	-9.4	-19.0	108.2	-9.4	-26.3
2019	90.6	-13.4	-13.4	93.1	-13.4	-13.8	101.5	-13.4	-22.2	108.7	-13.4	-29.5
2020	92.0	-16.9	-16.9	94.5	-16.9	-17.3	102.9	-16.9	-25.7	110.2	-16.9	-33.0
2021	88.4	-27.0	-27.0	90.9	-27.0	-27.0	99.3	-27.0	-30.6	106.5	-27.0	-37.8
2022	90.1	-28.8	-28.8	92.6	-28.8	-28.8	101.0	-28.8	-32.3	108.3	-28.8	-39.6
2023	86.2	-30.5	-30.5	88.7	-30.5	-30.5	97.1	-30.5	-30.5	104.4	-30.5	-35.7
2024	88.0	-32.3	-32.3	88.0	-32.3	-32.3	96.4	-32.3	-32.3	96.4	-32.3	-32.3
2025	89.9	-41.2	-41.2	89.9	-41.2	-41.2	89.9	-41.2	-41.2	89.9	-41.2	-41.2
2026	92.0	-46.3	-46.3	92.0	-46.3	-46.3	92.0	-46.3	-46.3	92.0	-46.3	-46.3
2027	94.2	-51.3	-51.3	94.2	-51.3	-51.3	94.2	-51.3	-51.3	94.2	-51.3	-51.3
2028	96.5	-53.6	-53.6	96.5	-53.6	-53.6	96.5	-53.6	-53.6	96.5	-53.6	-53.6
2029	98.8	-56.0	-56.0	98.8	-56.0	-56.0	98.8	-56.0	-56.0	98.8	-56.0	-56.0
2030	101.3	-58.4	-58.4	101.3	-58.4	-58.4	101.3	-58.4	-58.4	101.3	-58.4	-58.4

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TOPIC: **Yukon Energy 2016 Resource Plan (Resource Plan)**

REFERENCE: Resource Plan, page 7-3 lines 42-43 and 7-4, lines 1-5

PREAMBLE: On pages 7-3 and 7-4 of the Resource Plan, YEC states:

- Technological uncertainties, either due to policy changes (such as the introducing more stringent local building codes), or as-yet unanticipated developments in technology such as what has already occurred with LED lighting. The resulting risk is increased rates caused by reduced load and, consequently, reduced sales; and

- Uncertainties over distributed electrical generation technologies such as solar panels, which could lead to the risk of lower electricity demand to be serviced by YEC, or a significant change in the annual pattern of demand. The resulting risk is increased rates caused by reduced load and, consequently, reduced sales.

CW requires information to assess the risks of Resource Plans in forecasting needs.

QUESTION:

a) Given that this is a 20 year plan, please fully discuss how the cost of any stranded assets that may arise will be treated if there is a disruptive technology change. Will customers be expected to bear the cost of stranded assets? Will the shareholders bear these costs, which ultimately makes taxpayers responsible for them? Please fully explain.

ANSWER:

(a)

The issue of stranded electricity utility asset risks related to major disruptive technology change is an emerging issue in many jurisdictions.

Focusing on Yukon, reducing risk was recognized to be an essential goal in the development of the 2016 Resource Plan. YEC believes that it has successfully struck the appropriate balance in the resulting Action Plan, in terms of meeting future customer demands, while mitigating future risks – the risk of stranded assets identified as being critical.

The 2016 Resource Plan incorporates the need for flexibility to deal with risks such as major and sudden changes in loads, and the possible inability to develop a preferred resource proposed in the Action Plan. The Action Plan is resilient and robust under various potential load scenarios and regulatory, financial and development outcomes. A portfolio of relatively small, scalable and modular assets, as proposed in the Action Plan presents a lower risk than a single large asset, in terms of regulatory approvals, financing, fuel diversity and resourcing. To further reduce risks, the resource plan is revisited and adjusted every five years to reflect changes, including that of possible disruptive technology changes.

Risks are inherent in developing resources to meet future customer needs. These risks include stranded assets, but also include the risk of unserved future customer demands, in the event of load growth outstripping forecasts, or an inability to develop resources as planned. The consequence of unsatisfied customer demand includes significant safety issues, particularly during the winter, constrained economic activity due to lessened electricity reliability, and the potential necessity to incur ultimately even higher costs, due to the need to expedite new electricity supplies.

With respect to who would bear the costs of possible stranded costs, utility industry history indicates that, typically, ratepayers would bear these, as this group is the most direct beneficiary of a reliable source of electricity. Nevertheless, the allocation of the costs is based on social values expressed through social policies and/or the regulatory framework at the time of decision making. As a consequence, the utility, ratepayers, or taxpayers, or any combination of those three could potentially bear the costs.

TOPIC: **Yukon Energy 2016 Resource Plan (Resource Plan) – Electricity and Peak Demand Forecast**

REFERENCE: Resource Plan page ix (PDF page 11), lines 2-4

PREAMBLE: At lines 2-4, YEC states

> Energy and peak demand forecasts are a critical input into YECs planning processes. The energy and peak demand forecast developed for this Resource Plan presents YEC's predicted electricity needs over the 20 year (2016 to 2035) planning period.

YEC then refers to a two stage approach, the first stage being an economic forecast for the Yukon, and the second stage, being a statistically adjusted end-use (SAE) model. As energy and peak demand forecasts are "critical inputs", the CW requires information to assess the forecasts.

QUESTION:

a) Please provide a copy of the detailed economic and demographic model described at lines 12-13 of page ix. In the response please include all assumptions, the basis for the assumptions, and all tables in Excel format. In the response, please also include an explanation of how each formula was developed, and how it is relevant or appropriate.

b) Please provide a copy of the SAE model referred to at line 15 of page ix. In the response, please include explicit reference to the inputs from the economic model provided in response to (a) above. Also, in the response, please include all assumptions, the basis for the assumptions, and all tables in Excel format. In the response, please also include an explanation of how each formula was developed, and how it is relevant or appropriate

c) Please provide any and all analysis that demonstrates that the results of the models provided in response to (a) and (b) above are statistically valid. In the

response please discuss and explain any and all statistical tests done on the models.

d) Please fully explain how the sales and demand forecasts developed for the Resource Plan are used in the actual GRA. In the response please provide a reconciliation between the sales and demand forecasts in the Resource Plan to the sales and demand forecasts in the GRA.

ANSWER:

(a)

The Yukon Macroeconomic Model (MEM) used to complete the econometric scenarios was developed and is maintained by the Centre for Spatial Economics (C4SE). Given the proprietary nature of the model, the details of the MEM cannot be publically released.

A detailed description of the model and the analyzed economic scenarios as part of the 2016 Resource Plan are presented in Appendix 4.2 of the 2016 Resource Plan. Links to the 2016 Resource Plan Appendices are provided in YUB-YEC-1-83(e). This document is also publicly available at the link below.

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.2_-_Yukon_Macroeconomic_Model.pdf

(b)

Itron Inc. developed the Statistically Adjusted End-use (SAE) model for the Yukon using their proprietary statistical modeling application MetrixND, Given the proprietary nature of the forecasting methodology and modeling application, the details of the SAE model cannot be publically released.

A detailed account of the econometric model results used in the SAE model, assumptions, forecasting methodology, model validation and results is included Appendix 4.3 of the 2016 Resource Plan. Links to the 2016 Resource Plan Appendices are provided in YUB-YEC-1-83(e). This document is also publicly available at the link below.

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.3_Long_Term_Load_and_Demand_Forecast_2016-2035.pdf

(c)

Please refer to Appendix 4.2 of the 2016 Resource Plan for a description of the Yukon MEM and Appendix 4.3 of the 2016 Resource Plan for a description of the SAE model. Links to the 2016 Resource Plan Appendices are provided in YUB-YEC-1-83(e). These documents are also publicly available at the links below. Historic data related to load and customers were used to calibrate and verify the SAE model, while a number of historical economic and demographic variables are used as inputs to the MEM to ensure its validity.

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.2_-_Yukon_Macroeconomic_Model.pdf

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.3_Long_Term_Load_and_Demand_Forecast_2016-2035.pdf

(d)

The sales and demand forecasts from the Resource Plan inform the GRA forecasts but not directly. Fundamentally, the two documents have a very different time resolution; as a long term planning method, the Resource Plan forecasts rely on high level long term trends in global factors (e.g. GDP, territorial population, end user behaviour, etc). In contrast, the GRA forecasts are much shorter term and therefore, there is more granularity of data to support the forecast; that is, for a 12-24 month forecast, YEC is able to access customer and community specific information on growth and incorporate that into the forecast. This level of information is not generally available for a 20 year forecast, thus the Resource Plan uses the higher level trend information.

While it is not feasible to conduct a specific variance analysis of the differences in the forecast, it is worth noting that the trends for loads are similar:

	2016	2017	2018
GRA	412,812	420,398	382,966
Resource Plan	414,300	417,800	377,000

Note that 2018 loads are for non-industrial customer classes only; the Resource Plan assumed no industrial customers on the system in 2018; the GRA was prepared at a later date after Capstone mining confirmed their Minto operation would continue to require service in 2018.

TOPIC: **Yukon Energy 2016 Resource Plan (Resource Plan) – Electricity and Peak Demand Forecast**

REFERENCE: Resource Plan page ix (PDF page 11), lines 21-27 and Chapter 4 (page 4-6, PDF 104) of the Resource Plan

PREAMBLE: At lines 21-27, YEC discusses a number of scenarios it considered, and discusses "sensitivity scenarios layered on government spending and economic activity".

CW requires information to assess the scenarios.

QUESTION:

a) Please provide a detailed summary of each of the 10 sensitivities discussed, including key assumptions, key variables, and the impact on the sales demand forecast.

b) Please provide a probability assessment of the likelihood of each of the 14 scenarios and 10 sensitivities of actually occurring. In the response, please provide the basis for each probability.

ANSWER:

(a)

The Yukon Macroeconomic Model (MEM) used to complete the econometric scenarios was developed and maintained by the Centre for Spatial Economics (C4SE). Given the proprietary nature of the model, the details of the MEM cannot be publicly released.

A detailed description of the model and the various economic scenarios assessed as part of the 2016 Resource Plan is presented in Appendix 4.2. This document is publicly available at the link below. Links to the 2016 Resource Plan Appendices are provided in YUB-YEC-1-83(e).

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.2_-_Yukon_Macroeconomic_Model.pdf

(b)

Itron Inc. developed the Statistically Adjusted End-use (SAE) model for the Yukon using their proprietary statistical modeling application MetrixND. Given the proprietary nature of the forecasting methodology and modeling application, the details of the SAE model cannot be publicly released.

A detailed account of the econometric model results used in the SAE model, assumptions, forecasting methodology, model validation and results is included Appendix 4.3 of the 2016 Resource Plan. This document is publicly available at the link below. Links to the 2016 Resource Plan Appendices are provided in YUB-YEC-1-83(e). Additional information is not available on the probabilities of the scenarios. Please also see the response to CW-YEC-1-7.

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.3_Long_Term_Load_and_Demand_Forecast_2016-2035.pdf

TOPIC: **Yukon Energy 2016 Resource Plan (Resource Plan) – Electricity and Peak Demand Forecast**

REFERENCE: Resource Plan page 4-8 (PDF page 106), lines 11-15.

PREAMBLE: At lines 11-15, YEC discusses calibration of the SAE model.

QUESTION:

a) Please provide the results of the calibration and verification process.

ANSWER:

(a)

Descriptive statistics showing the model performance for commercial (average energy use per customer, and customer models), residential (average energy use per customer, and customer models) and peak models are included in Appendix 4.3 of the 2016 Resource Plan. This document is publicly available at the link below. Links to the 2016 Resource Plan Appendices are provided in YUB-YEC-1-83(e).

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.3_Long_Term_Load_and_Demand_Forecast_2016-2035.pdf

TOPIC: **Yukon Energy 2016 Resource Plan (Resource Plan) – Electricity and Peak Demand Forecast**

REFERENCE: Resource Plan page ix (PDF page 11), lines 28-35

PREAMBLE: At lines 28-35, YEC states "five main industrial activity scenarios were brought forward as the base scenarios throughout the rest of the Plan."

CW requires information to assess the impact of these scenarios.

QUESTION:

a) Please provide a probability assessment of the likelihood of each of the five main industrial activity scenarios actually occurring. In the response, please provide the basis for each probability.

ANSWER:

(a)

Given the complexity and the quantity of internal and external variables affecting the territorial economy, YEC does not believe a quantitative probability assessment would bring further insight on the conclusions of the 2016 Resource Plan.

In completing the 2016 Resource Plan, YEC performed a portfolio analysis and obtained a solution for the five main industrial activity scenarios, as reported in the short term and long term action plans (2016 Resource Plan, Chapter 9, PDF pages 380-386). The results indicated that ten resource options were common to all main industrial activity scenarios. Deviations between portfolios were only observed in 2022 going forward. The update of the load forecast, planned for 2018, will inform YEC on which load scenario is unfolding while affording sufficient time to develop new resource options to meet the future loads and peak demand.

YEC adopted a prudent scenario based approach to define the five main industrial activity scenarios used for the econometric and subsequently the load and peak demand forecast using the Statistically Adjusted End-use model. These scenarios are intended to cover a

wide range of potential economic outcomes, allowing YEC to quantify the impacts on loads and peak demand. To define the scenarios, YEC received advice from multiple business and institutional leaders, members of its technical advisory committee and from the Yukon Minerals Advisory Board.

A detailed description of the methodology used and of the scenarios is provided in the Economic Scenarios section of Appendix 4.2 (pages 3-4) at link below. Links to the 2016 Resource Plan Appendices are provided in YUB-YEC-1-83(e).

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.2_-_Yukon_Macroeconomic_Model.pdf

TOPIC: **Yukon Energy 2016 Resource Plan (Resource Plan) – Portfolio Analysis**

REFERENCE: Resource Plan page xviii (PDF page 20), lines 21-32

PREAMBLE: YEC has used a portfolio analysis to assess options to assess scenarios.

QUESTION:

a) Please confirm that YEC uses the least cost alternative over the lifecycle of each asset. If not confirmed, please fully explain.

b) Please fully explain why a discount rate of 3.38% is appropriate. In the response, please fully discuss the impact of a higher discount rate on the results of the model.

c) Please fully discuss YEC's understanding of the appropriate discount rate from a customer perspective, i.e. what is the appropriate cost of capital for customers. In the response, please fully explain all research that YEC has done to understand what an appropriate customer discount rate would be.

ANSWER:

(a)

Please refer to Portfolio Analysis Methodology (Section 8.1) of the Portfolio Analysis chapter (Chapter 8) of the 2016 Resource Plan for details on the methodology used to recommend the assets presented in Short Term Action Plan (Sections 9.2) and Long Term Action Plan (Section 9.3) of the Action Plan chapter (Chapter 9) of the 2016 Resource Plan.

(b)

The discount rate equates to YEC's weighted average cost of capital as approved by the YUB at the last GRA applied at the 60:40 capital structure approved by the YUB and adjusted for inflation to achieve the real rate (i.e., last approved WACC = 5.45%; adjusted for 2% inflation, this equates to 3.38%). This approach ensures that a utility project will

meet or exceed the utility's requirement to pay debtors and earn a return sufficient to ensure the financial integrity of the utility including providing for sufficient resources for reinvestment. In general terms, the higher the discount rate, the lower the project present value calculated.

(c)

YEC deemed that inclusion of the customer discount rate (cost of capital) into the 2016 Resource Plan would not bring any value to the overall analysis, since the cost of capital is related to asset development. At this point in time, customers are not involved in developing assets that are a part of the YEC integrated grid. YEC could not predict the penetration of future technologies that would introduce customers as significant developers of grid integrated assets. YEC will monitor development of related technologies and, if warranted, introduce the customer discount rate into the next resource plan(s).

TOPIC: **Yukon Energy 2016 Resource Plan (Resource Plan) – Transmission Considerations**

REFERENCE: Resource Plan page 2-7 (PDF page 56), Section 2.6 and Section 5.2.12.

PREAMBLE: YEC discusses how it is an "Islanded grid". CW requires information to assess transmission options.

QUESTION:

a) Please fully explain all analysis that YEC has undertaken to connect the Yukon to the British Columbia Grid. In the response, please fully explain the length of transmission line needed, and the costs of the transmission line.

b) Please compare the costs of constructing a transmission line to the costs of the proposed projects. In the response, please consider the potential of incremental revenue from the sales of surplus power.

ANSWER:

(a)

Yukon Energy has referenced the following three recent Yukon-specific studies that will be provided on request:

1. Yukon - BC Interconnection Costing. Submitted by BBA Engineering Ltd. Document No.: 5954010_001RPT, Rev 0 Date: April 8, 2011.
2. Next Generation Hydro: Yukon Next Generation Hydro and Transmission Viability Study: Jurisdictional Transmission Line Technical Logistics Analysis. Submitted by: Midgard Consulting Incorporated. Date: July 6, 2015.
3. Next Generation Hydro: Yukon – Transmission Market Benefits Assessment. Submitted By: Midgard Consulting Incorporated. Date: July 24, 2015.

The interconnections to neighbouring jurisdictions studied involved hundreds of kilometers of transmission lines in very remote and challenging terrain. The costs would reach up to

$1.7bn. The details on the length, cost and technical attributes of the transmission lines are presented in the response to CW-YEC-09 (b) and the referenced documents.

(b)

In developing the 2016 Resource Plan, Yukon Energy's efforts were focused on recommending a plan and actions for serving its customers with reliable, cost-effective electricity generated in an environmentally and socially responsible manner. A critical outcome of this work was that YEC's primary current and future need is additional dependable capacity, driven by customer demands on cold winter days. The Action Plan arising from the 2016 Resource Plan was not driven by export potential. The interconnections to neighbouring jurisdictions studied each involved hundreds of kilometers of transmission lines in very remote and challenging terrain. Apart from the resulting physical reliability issues, depending on neighbouring jurisdictions for critical power supply would introduce new legal, regulatory and political risks.

With respect to the costs and potential benefits of building and operating transmission assets to neighbouring jurisdictions (Alaska and British Columbia), the following is a summary of the conclusions of these studies.

Connecting to British Columbia would involve a 287kV transmission line from Whitehorse (Takhini substation) to Iskut in British Columbia. The line would be 763 km in length, with an estimated capital cost of $1.71 billion. The line would have a potential export capacity range of 64-127 MW. This range is due to the (variable) state of both generation output and domestic demands on the BC Hydro grid, particularly in the vicinity of the BC Hydro Northwest Transmission Line. The export constraints on this line would be greatest during the spring freshet, due to the high level of generation output of regional BC-based (run of river) hydroelectric generation. Unfortunately, this period coincides with peak generation output in the Yukon.

The following statement summarizes the economic evaluation of the export potential:

> "Midgard does not see a plausible scenario, given the assumptions employed in the analysis, where exporting electricity from the Yukon to either British Columbia or Fairbanks, Alaska makes economic sense."

To provide a fulsome response, the following quotation from the Midgard report economic assessment is also included regarding the import potential of a Yukon-BC transmission line:

> "Importing electricity into the Yukon is similarly unattractive… Midgard cannot see a plausible scenario, given the assumptions, where Yukon profitably imports electricity. Moreover, the import scenario requires that the Yukon be willing to accept that it will be dependent on an external jurisdiction for critical winter energy supply which raises reliability issues."

TOPIC: **Yukon Energy 2016 Resource Plan (Resource Plan) – Capacity Deficits**

REFERENCE: Resource Plan page 4-54 (PDF page 152)

PREAMBLE: YEC provides a table that shows dependable capacity deficits in every year.

QUESTION:

a) Please confirm that industrial activity is the major driver in changes in requirements, and for the construction of assets proposed in the resource plan. If not confirmed, please fully explain.

b) Please fully explain how the costs of new assets will be allocated between wholesale customers, YEC retail customers, and industrial customers. In particular, please confirm that any surplus capacity generated by new assets will be only allocated to industrial load, and not to wholesale load.

ANSWER:

(a)

Industrial activity is one of the drivers of the territorial economy but it isn't the only driver affecting the construction of new assets. Industrial activity is specifically not a driver for construction of assets to address the dependable capacity deficits referenced in the preamble to this question.

Several resource options defined in the short term action plan are capacity based and intended to bridge the current dependable capacity shortfall under the Single Contingency (N-1) criterion. This criterion excludes industrial loads and construction of new assets for this purpose cannot be attributed to industrial activity.

Econometric model results have shown that a new industrial load, whether connected to the Yukon Integrated System or not, will affect other industries of the Yukon economy and ultimately, contribute to the increase in sales and peak demand. Results for other scenarios have indicated that a growth in the Tourism sector could also have a material

effect on loads and peak demand (See 2016 Resource Plan, Section 4.1.5.5.2 Commercial Energy Forecast Risks and Uncertainties, PDF page 124).

Industrial loads connected to the grid are the main driver affecting material changes in forecast energy requirements and related opportunities to potentially develop new renewable energy resources.

(b)

Costs of new resources will be allocated to customer classes in a Cost of Service Study (COSS) using normal utility COSS principles and in accordance with OIC directions to the YUB, and would require a specific YUB proceeding with consolidated YEC-AEY revenue requirement for the Yukon. The preparation of a COSS is not part of the scope of this GRA, therefore it cannot be confirmed today that surplus capacity provided by new assets will be only allocated to industrial load, and not to wholesale or other loads. Under the current forecasts, the capacity shortfall to be addressed by new assets is attributed entirely to non-industrial winter peak load requirements on the grid.

Prior to YUB review of a COSS and related YUB changes to rates, changes to rates are assumed to continue to require across-the-board rate rider adjustments with the same percentage rate changes for each customer class.

TOPIC: **System Sales – Wholesale sales**

REFERENCE: YEC Application, Section 2.2.1

PREAMBLE: In section 2.2.1 of its application, YEC discusses its wholesale forecast

QUESTION:

a) Please provide the latest approved GRA forecast from AEY.

b) At lines 6-7, on page 2-4 of its Application, YEC indicates that each year, AEY provides YEC with a forecast power purchase estimate. Please provide the latest forecast for 2017, and if available, 2018.

c) Please fully explain the discussions and communications between YEC and AEY regarding forecast sales and potential changes in sales levels.

d) On page 2-5 of its Application, at line 7, YEC discusses a multi-variable regression of wholesale sales. Please provide the regression analysis in excel format with formulae and links intact.

e) On lines 1-6 of page 2-5, YEC describes the increases in wholesale sales in 2015 and 2016 as slight increases over the prior year. Please provide an explanation as to why the 2015 and 2016 wholesale sales “increase slightly” over the prior year.

f) On lines 3-7 of page 2-6, YEC discusses the AEY forecast grid firm load and AEY forecast Fish Lake hydro generation. Please provide copies of both forecasts for 2017 and 2018.

g) Please provide the monthly wholesale sales for each of 2013, 2014, 2015, and 2016, as well as for 2017 year to date.

h) Please provide the actual and normal heating degree days by month for Whitehorse each of 2013, 2014, 2015, and 2016. In the response please indicate the determination of normal heating degree days.

i) Please provide the forecast heating degree days by month for Whitehorse for 2017 and 2018.

ANSWER:

(a)

As per Schedule 3.1 of AEY's compliance filing, AEY's 2017 firm power purchases forecast is 314.2 GWh.[1]

Please also see response to YUB-YEC-1-3 regarding the difference between YEC's GRA and the AEY Compliance Filing as approved by Board Order 2017-03.

(b)

Prior to the Board's final decision on the AEY GRA, AEY provided YEC with a forecast of 300.3 GWh for 2017 and 303.0 GWh for 2018 for firm power purchases. YEC has not received any updates from AEY after its Compliance Filing.

(c)

Senior management of AEY and YEC participated in both conference calls and email communications. Prior to filing of YEC's Application, no discussions occurred on this matter after the AEY Compliance Filing.

(d)

Please note the model description included in the Application (Page 2-5, Lines 7-14) was developed to further understand the basis of the AEY forecast of 300.3 GWh for 2017 and 303 GWh for 2018 as indicated in response to (b) above. The table included in CW-YEC-1-11 Attachment 1 presents the input variables and the multi-variate regression coefficients used to support the wholesales forecast of 309 GWh and 309.5 GWh for the 2017 and 2018 test years, as included in Table 2.1 of the Application. The regression uses the past six years of monthly sales data with the impact of Fish Lake hydro generation.

[1] Schedule 3.1 of AEY's May 26, 2017 Compliance Filing.
http://yukonutilitiesboard.yk.ca/pdf/YECL_GRA_2016-2017/2017-05-26_AEY_2016-2017_GRA_Compliance_Filing.pdf

The model calibration yields a coefficient of determination (R^2) of 96.3%, indicating a very strong correlation between the input variables and the monthly sales data.

(e)

See response to YUB-YEC-1-59.

(f)

AEY provided YEC with the following forecasts prior to the Board's decision on its GRA (the 2017 forecasts were consistent with AEY's GRA as filed[2]):

- Forecast AEY grid load of 318.3 GWh for 2017 and 322.9 GWh for 2018, including secondary sales and sales supplied by AEY's Fish Lake Hydro.
- Forecast AEY Fish Lake Hydro generation of 8.5 GWh for 2017 and 8.4 GWh for 2018.
- Forecast AEY standby diesel generation of 0.04 GW.h in 2017 and 2018.
- Forecast secondary power purchases of 9.4 GW.h in 2017 and 11.5 GW.h in 2018.
- Forecast firm power purchases of 300.3 GW.h in 2017 and 303.0 GW.h in 2018.

(g)

Monthly firm wholesale sales for each of 2013-2016 and 2017 to July are provided in Table 1 below.

[2] Please see Schedule 3.1 of AEY's 2016-17 GRA original filing.
http://yukonutilitiesboard.yk.ca/pdf/YECL_GRA_2016-2017/2016-05-09_AEY_2016-2017_GRA_-_Phase_I.pdf

Table 1: Monthly Wholesale sales, GW.h

Month	2013	2014	2015	2016	2017
JAN	32.6	29.7	31.2	29.4	36.9
FEB	26.5	30.0	29.9	29.3	30.5
MAR	26.6	28.5	28.0	26.5	33.5
APR	27.8	23.0	22.8	21.6	22.8
MAY	22.6	20.0	19.4	21.8	23.7
JUN	18.5	20.0	20.4	19.6	20.4
JUL	21.8	19.8	19.3	19.6	20.4
AUG	19.6	18.2	19.9	19.7	
SEP	22.0	22.5	21.3	21.8	
OCT	24.7	24.7	24.0	27.5	
NOV	28.6	25.2	29.2	29.1	
DEC	36.6	33.7	32.7	35.4	

(h)

Monthly Heating Degree-Days (below 13 ^{o}C) for the 2012-2016 period are provided in Table 2 below.

Table 2: Monthly Heating Degree Days

Month	Year					Normal (5-yr Avg.)
	2012	2013	2014	2015	2016	
JAN	958.1	797.0	576.3	760.5	655.5	749.5
FEB	547.2	525.4	841.3	698.6	525.4	627.6
MAR	592.6	696.1	681.5	498.2	441.2	581.9
APR	299.3	489.9	344.6	298.7	233.7	333.2
MAY	197.6	156.7	114.3	78.4	105.4	130.5
JUN	63.7	28.2	63.9	28.4	23.4	41.5
JUL	29.0	7.1	8.3	8.8	3.9	11.4
AUG	29.4	22.0	29.8	60.7	20.7	32.5
SEP	142.7	121.0	164.3	188.4	151.3	153.5
OCT	484.5	309.6	360.7	315.9	451.2	384.4
NOV	819.6	706.5	610.2	602.3	541.3	656.0
DEC	1041.8	965.3	677.3	773.5	895.4	870.7

(i)

Forecast heating days in 2017 and 2018 equal the Normal as shown in (h).

TOPIC: **System Sales – Major Industrial sales**

REFERENCE: YEC Application, Section 2.2.2

PREAMBLE: In section 2.2.2 of its application, YEC discusses its Industrial Sales forecast

QUESTION:

a) Please fully provide a copy of all communication between the Minto Mine and YEC related to forecast 2017 and 2018 load.

b) In Table 2.1 the 2016 Industrial load was 41,169 MWh compared to 2015 actual of 37,186 MWh. Please fully explain the reason for the increase.

c) In Table 2.1, 2017 forecast Industrial load decreases from 41,169 MWh in 2016 to 38,219 MWh in 2017. Please fully explain the decrease of 2,950 MWh (7.2%)

d) On page 2-8 of its Application, YEC discusses two potential sources of load, Eagle Gold and Alexco Mine. Please provide an update as to the status of these projects.

ANSWER:

(a)

For the purpose of establishing the 2017/18 GRA forecast, YEC received a forecast range of possible sales from the on-site analyst. YEC senior management contacted the Minto General Manager and determined that the mine expected to achieve similar power purchases as recent years. The parties agreed that a three year average was an appropriate proxy for test year sales.

(b)

There was an equipment failure at the mine site that affected revenue metering between October 2015 and March 2016. The correction was posted to 2016, which resulted in 2,776.68 MWh of 2015 sales being recorded in 2016. See table below for adjustment for

this correction. The residual variance is not material (<4%) and therefore no specific reason is noted for the variance

(in MWh)

Year	Recorded	Adjustment	Actual
2015	37,186	2,777	39,963
2016	41,169	- 2,777	38,392
		Actual Difference	**- 1,570**

(c)

Adjusting for the metering issue noted in (b) results in the following:

(in MWh)

Year	Recorded	Adjustment	Actual
2016	41,169	- 2,777	38,392
2017	38,219		38,219
		Actual Difference	**- 173**

The corrected variance is less than 0.5%; no specific explanation is available for this difference.

(d)

With respect to Eagle Gold, please see response to John Maissan-YEC-1-5. Alexco Resource has publicly stated a desire to resume industrial mining activities by late 2018; however, to date, YEC has received no official notification.

TOPIC: **System Sales – Yukon Energy Firm Retail Sales**

REFERENCE: YEC Application, Section 2.2.3 and Table 2.1

PREAMBLE: In section 2.2.3 of its application, YEC discusses its firm retail sales forecast.

QUESTION:

a) For Residential and General Service, please provide the working papers in support of the calculation of customer forecasts. Please provide the response in Excel format with formulae and links intact.

b) For Residential, there is an increase in customers of 27 in 2015 and 22 in 2016. Please fully explain why there is only a forecast of 14 and 12 new customers in 2017 and 2018 respectively.

c) For General Service, there is an increase in customers of 5 in 2014, 6 in 2015 and 8 in 2016. Please fully explain why there is only a forecast of 1 and 0 new customers in 2017 and 2018 respectively

d) For Residential and General Service, please provide the working papers in support of the calculation of use per customer forecasts. Please provide the response in Excel format with formulae and links intact.

ANSWER:

(a)

Please see CW-YEC-1-13 Attachment 1.

(b)

The general approach is to use the average of historical actual customers, not growth in customers. Each community is looked at individually based on information available at the time of the preparation of the forecast. In certain situations, the general approach is then

adjusted based on the information available that may cause a difference in the forecast (for example, a significant housing or commercial development).

(c)

The general approach is to use the average of historical actual customers, not growth in customers. Each community is looked at individually based on information available at the time of the preparation of the forecast. In certain situations, the general approach is then adjusted based on the information available that may cause a difference in the forecast.

(d)

Please see CW-YEC-1-13 Attachment 1.

TOPIC: **System Sales – Yukon Energy Secondary Sales**

REFERENCE: YEC Application, Section 2.2.4 and Table 2.1

PREAMBLE: In section 2.2.4 of its application, YEC discusses its secondary sales forecast.

QUESTION:

a) Please provide the calculation of the four year average for the Canada Games Centre. In the response, please provide monthly data.

b) Please provide the calculation of the three year average for the Yukon Hospital. In the response, please provide monthly data.

c) Please fully explain why 2011, 2012, 2013, and 2014 data was not used for the Yukon Hospital. Please provide monthly load data for the Yukon Hospital for each of 2011, 2012, 2013, and 2014.

d) Please provide actual to date, as of the end of August, 2017, sales for each of the Canada Games Centre, the Yukon Hospital, and the Yukon College.

e) In Table 2-1, the cents per KWh for secondary sales declines from 7.7 cents in 2016 to 5.6 cents in 2017 and 2018. Please fully explain why the rate declines. In the response please provide the actual price to the end of August, 2017, and an explanation of why the 7.7 cent amount is not appropriate for 2017 and 2018 forecasts.

ANSWER:

(a)

Details (kW.h) for Canada Games Centre are shown in Table 1 below. YEC uses an average, as well as professional judgement in determining forecasts for these customers.

Table 1: Canada Games Centre Sales: 2013-2016 (kWh)

Month	2013	2014	2015	2016	Average
January	398,400	448,200	472,200	382,200	425,250
February	366,000	372,600	359,400	400,200	374,550
March	408,000	360,600	364,200	456,600	397,350
April	391,200	418,200	438,000	386,400	408,450
May	355,800	405,000	329,400	264,600	338,700
June	250,800	261,600	204,600	265,800	245,700
July	154,800	228,000	196,800	208,800	197,100
August	141,600	159,600	171,000	186,600	164,700
September	78,600	184,200	143,400		135,400
October	271,800	298,200	148,200		239,400
November	301,800	337,200	306,000		315,000
December	441,600	394,200	390,600		408,800
Total	**3,560,400**	**3,867,600**	**3,523,800**	**2,551,200**	**3,650,400**

(b)

Details (kW.h) for Yukon Hospital are below - please note that while Section 2.2.4 of the Application notes that the forecast was based on an average of 2009, 2010 and 2015, the four years of data noted in Table 2 below were actually used. YEC uses an average as well as professional judgement in determining forecasts for these customers.

Table 2: Yukon Hospital Sales: 2008-2010, 2015 (kWh)

	2008	2009	2010	2015	Average
January	435,000	366,000	303,000	21,000	281,250
February	201,000	252,000	417,000	297,000	291,750
March	672,000	114,000	522,000	540,000	462,000
April	822,000	237,000	456,000	399,000	478,500
May	495,000	342,000	537,000	336,000	427,500
June	474,000	360,000	501,000	339,000	418,500
July	411,000	228,000	453,000	318,000	352,500
August	525,000	81,000	393,000	363,000	340,500
September	579,000	315,000	93,000	60,000	261,750
October	480,000	606,000		126,000	404,000
November	-	591,000		384,000	487,500
December	-	360,000			360,000
Total	**5,094,000**	**3,852,000**	**3,675,000**	**3,183,000**	**3,951,000**

(c)

Yukon Hospital did not purchase power under the secondary sales rate schedule during those years.

(d)

August data is not available as of the date of preparation. Actual 2017 secondary sales for each of the three customers to July 31, 2017 is below:

	KWh
Canada Games Centre	1,636,800
Yukon Hospital	1,365,000
Yukon College	1,800,000

(e)

Pursuant to Rate Schedule 32 Secondary Energy (as approved in Board Order 2005-12), the Secondary Energy rate is adjusted on a quarterly basis. Each quarter it is adjusted based on published Yukon Territorial Government – Bureau of Statistics biweekly prices for Furnace Oil in Whitehorse. At the time of filing the GRA, 5.6 cents was the calculated rate in effect. The 2017 Q4 rate has just been finalized and it remains at 5.6 cents.

TOPIC: **System Sales – Losses**

REFERENCE: YEC Application, Table 2.2

PREAMBLE: In Table 2.2 of its application, YEC calculates losses.

QUESTION:

a) Please confirm that the entire YEC system is fully integrated. If not confirmed, please provide a loss calculation for each portion or segment of the system.

ANSWER:

(a)

Confirmed.

TOPIC: **Fuel and Purchased Power**

REFERENCE: YEC Application, Section 3.2 and Table 3.2

PREAMBLE: In section 3.2 of its Application, YEC discusses Fuel and Purchased Power

QUESTION:

a) For each year in Table 3.2, please provide the working papers that convert thermal generation to Fuel costs for each type of thermal generation. In the response, include the heat rate, losses and prices of fuel that are used to convert generation to amounts of fuel and then to costs.

b) Please fully explain why 2014 actual fuel costs decrease from 2013 actual costs. In the response include a price and quantity variance analysis that demonstrates the impact of changing prices, and changing thermal requirements.

c) Please fully explain why 2015 actual fuel costs increase from 2014. In the response include a price and quantity variance analysis that demonstrates the impact of changing prices, and changing thermal requirements.

d) Please fully explain why 2016 actual fuel costs decrease from 2015. In the response include a price and quantity variance analysis that demonstrates the impact of changing prices, and changing thermal requirements.

e) Please fully explain the difference between “Existing” and “Proposed” for 2017 and 2018. In the response, please fully explain why YEC cannot apply the “Existing” forecast for proposed rates.

ANSWER:

(a)

The rate applicable to fuel expense in a non-test year is that rate as approved by the YUB at the most recent GRA. The rate for diesel applicable to the years 2013-2016 is $0.2872

(see Tab 3 of the 2012/13 GRA for the determination of this rate). The calculation of fuel expense based on volumes is shown in CW-YEC-1-16 Attachment 1.

(b) through **(d)**

As shown in CW-YEC-1-16 Attachment 1, fuel costs are primarily determined by the DCF Transfer Cost, which is calculated from LTA Expected Thermal Generation based on Actual grid load. The variances in DCF Transfer Costs (and actual fuel costs) from 2013 to 2016 are a direct result of variances in grid load.

(e)

For the explanation of the difference between "Existing" and "Proposed", see YUB-YEC-1-1(b).

The "Existing" for Table 3.2 uses fuel prices and YECSIM assessments as approved in the last GRA.

The "Proposed" in Table 3.2 uses proposed updates to the data used in the calculation, including the following:

- Expected Fish Lake load;
- Expected wind generation;
- LTA thermal as per updated DCF Term Sheet;
- Inclusion of LNG as a thermal source;
- LTA Diesel/LNG allocation as proposes;
- Diesel prices updated for this GRA;
- LNG prices updated for this GRA.

TOPIC: **Non Fuel Operating and Maintenance Expenses**

REFERENCE: YEC Application, Section 3.3 and Tables 3.3 - 3.4

PREAMBLE: In Table 3.3, YEC provides total Labour, and in Table 3.4, YEC provides staffing. The following table, taken from YEC data provides the cost per employee.

	2013 GRA compliance	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast Proposed 2017	Forecast Proposed 2018
Labour - From Table 3.3	$ 9,348	$ 10,604	$ 11,172	$ 11,068	$ 11,739	11,770	11,823
Staff - From Table 3.4	92.00	92.95	92.90	93.19	93.31	93.70	93.70
Cost per Employee	$ 101,605.47	$ 114,084.65	$ 120,264.03	$ 118,761.42	$ 125,810.33	$ 125,609.61	$ 126,176.66

QUESTION:

a) Please fully explain why the cost per employee declines in 2015 compared to 2014.

b) Please fully explain why this decline does not continue into 2016, and the test period forecasts.

ANSWER:

(a) and **(b)**

The calculation is not an accurate presentation of cost per employee because it ignores the labour cost charged to balance sheet accounts (e.g. capital projects, RFID, etc). Table 3.3 only captures labour costs charged to the income statement (O&M and Administration expense). Section 3.3 explains the factors impacting labour. Please also see YUB-YEC-1-7 for further explanation of the impact of the capital/maintenance allocation and its impacts.

TOPIC: **Non Fuel Operating and Maintenance Expenses**

REFERENCE: YEC Application, Section 3.3 page 3-6

PREAMBLE: At lines 12-14, YEC discusses Labour Rates including such things as base pay, benefit costs annual increments (performance increments, cost of living adjustments), etc.

QUESTION:

(a) Please provide a detailed analysis that separates base pay from incentive pay for each year in Table 3.3. Please ensure that the total equals total Labour.

(b) Please provide the YEC incentive pay policy, and a complete analysis of the targets, thresholds and metrics used to determine incentive pay.

(c) Please provide a detailed analysis of YEC benefits for each year in Table 3.3, with a complete explanation of all changes in benefits, with the cost of each change clearly identified. In the analysis, please explain where employee benefits are reported.

(d) Please provide the annual cost of living increases awarded for each year in Table 3.3, on an actual basis, and forecast for the test period. Please provide the percentages for each bargaining unit, as well as out of scope staff.

(e) Please provide the actual 2017 wage increase for each bargaining unit as well as out of scope staff.

(f) Please provide all analysis and research YEC has conducted to demonstrate that its wages and salaries are prudent, including, but not limited to salary surveys, Statistics Canada benchmarks of average weekly earnings and inflation, or any other research YEC has conducted.

ANSWER:

(a)

Incentive pay is only available to the President through the employment contract. Labour in table 3.3 includes $36,000 estimate of this pay item in each of 2017 and 2018.

(b)

YEC does not have an incentive pay policy. The Presidents employment contract has provision for incentive pay based on goals established by the Board of Directors.

(c)

Employee benefits are reported in Labour costs. As employee benefits apply to YEC as a whole (including capital labour), analysis is not specific to only non-fuel operating and maintenance expense labour.

Below is a table summarizing the total cost of benefits:

Table 1: Cost of Benefits

Cost of Benefits

	2013	2014	2015	2016	2017 Forecast	2018 Forecast
Northern	$1,028,306	$1,017,448	$1,037,274	$1,053,587	$1,061,226	$1,074,109
Benefits	$890,769	$838,602	$721,293	$863,237	$922,407	$926,392
VTA	$237,983	$226,502	$250,431	$255,750	$262,150	$259,600
Pension/RRSP	$967,746	$1,408,649	$1,280,374	$1,330,008	$1,493,515	$1,280,734
Leave	$1,224,330	$1,285,501	$1,239,757	$1,332,104	$1,370,350	$1,386,152
Stat	$413,148	$430,265	$446,818	$450,374	$454,565	$466,555
Totals	$4,762,282	$5,206,966	$4,975,947	$5,285,060	$5,564,212	$5,393,543

	2013	2014	2015	2016	2017 Forecast	2018 Forecast
Wage Increase	2.25%	2.00%	2.00%	1.75%		

	2013	2014	2015	2016	2017 Forecast	2018 Forecast
FTE Count	93.16	93.11	93.4	94.1	93.91	93.91

	2013	2014	2015	2016	2017 Forecast	2018 Forecast
Vacancy Rate	4.4	0.57	1.85	1.6	2	2

YEC has a general provision for forecast negotiated wages. The specific rate included cannot be provided at this time as this would compromise YEC's negotiations with the unions as part of the collective bargaining process. However, YEC can confirm that rates used in lieu of the actual wages increase were developed consistent with awards granted in arbitration in the last two collective agreement settlements.

The main factors driving the cost of benefits are wage increases, FTE counts and vacancy rates.

- **Northern Allowances:** This is impacted by yearly wage increases, increase/decreases to FTE Count, and the vacancy rate.

- **Benefits (Location Allowance, Vac. Pay for Casual, EI, CPP, AD&D Ins., Life Ins., Dental and Health):** This is impacted by yearly wage increases, increases/decreases to the FTE Count, and vacancy rate. A decrease in premiums for life insurance, dental and health was negotiated with YEC's insurance provider for 2015. In 2016/2017 (forecast) those benefits were re-negotiated which resulted in an increase in costs.

- **Vacation Travel Allowances**: This is impacted by Increase/decreases to FTE Count, the vacancy rate and the number of dependants a new or former employee claims/or has claimed in the past will impact the cost this benefit. As well, new employees are not able to claim the benefit for the first year of their employment.

- **Pension/RRSP:** This is impacted by yearly wage increases, increase/decreases to FTE count, and vacancy rate. The define benefit pension plan is a large cost driver; factors such as changes in market values (2013/2014), changes in accounting standards (move IFRS in 2015), as well as employees retirements from the pension plan have affected the pension costs over the years.

- **Leave**: Yearly wage increases, increases/decreases to FTE count and the vacancy rate impact leave costs. Employees get increases to vacation entitlements the longer they are with the company and the average employee tenure has increased in recent years. Offsetting this, YEC has a number employees that have/are forecasted retire and are being replaced by new employees that are only allocated the minimum amount of vacation time each year.

- **Stat:** This is impacted by yearly wage increases, increases/decreases to FTE count and the vacancy rate. There will be an increase to costs due to the addition of Aboriginal Day in 2018.

(d)

Out of scope staff received the same percentages as each bargaining unit.

(e)

No wage increase has been granted to staff for cost of living as collective bargaining arrangements have not been concluded to date for 2017.

(f)

As part of collective bargaining, YEC conducts local market surveys of wage increases of like organizations. In each of the last two union agreements, staff were awarded cost of living increments at or near that awarded Yukon Government in its most recent settlement.

TOPIC: **Non Fuel Operating and Maintenance Expenses**

REFERENCE: YEC Application, Section 3.3 page 3-6

PREAMBLE: At lines 15-23, YEC discusses Capital/Maintenance Allocation.

QUESTION:

a) Please provide the detailed working papers in support of the Capital/Maintenance allocation for each year in Table 3.3.

b) Please fully explain why the forecast ratio of 18:82 is appropriate, given the history, and forecast capital program.

c) Please provide the YEC Capitalization policy that is currently in place, and the one that was in place immediately prior to the current one, with any changes clearly marked and explained.

ANSWER:

(a)

The Capital/Maintenance allocation calculation is provided in the Table 1 below:

Table 1: Capital/Maintenance Allocation

	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Forecast	2018 Forecast
Non-Capital	$10,604,235	$11,172,035	11,067,742	$11,738,919	$11,770,210	$11,823,345
Capital	$2,246,695	$2,344,331	$2,776,884	$2,248,19	$2,544,854	2,581,609
	$12,850,930	$13,516,366	$13,844,626	$13,987,115	$14,315,064	$14,404,953
Capital	17%	17%	20%	16%	18%	18%
Non-Capital	83%	83%	80%	84%	82%	82%

(b)

Please see response to YUB-YEC-1-7.

(c)

Please see CW-YEC-1-19 Attachment 1 for the current capitalization practice with tracked changes to show the previous version.

YUKON ENERGY	Finance Accounting Practice FX-Appendix	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Finance	~~Fixed Asset~~Property, Plant and Equipment Definitions
		ISSUED:	REVIEW DATE:	APPROVED BY:
		January 1, 2014~~05~~	January 1, 2017~~08~~	Chief Financial Offici~~e~~r

1.0 Purpose

To provide detailed definitions for various ~~fixed asset~~Property, Plant and Equipment (PP&E) terminologies.

2.0 Definitions

1~~8~~. ***Property, plant and equipment*** are identifiable tangible assets that meet all of the following criteria:

a) are held for use in the production or supply of electrical services, for administrative purposes, or for the development, construction, maintenance or repair of other property, plant and equipment;
b) have been acquired, constructed or developed with the intention of being used on a continuing basis for longer than one year;
c) are not intended for sale in the ordinary course of business (i.e. goods purchased for resale),
d) have a cost greater than $1,000.

~~***1.*** ***Fixed Assets*** are assets of a permanent or lasting nature whose useful service life is expected to extend over several years. Examples include land, buildings, equipment and furniture.~~

2. ***Acquisition Costs***

a) The cost of an item of property, plant and equipment includes the purchase price and other acquisition costs such as options costs when an option is exercised, brokers' commissions, installation costs, site preparation costs, freight, brokerage and duty charges, transportation insurance costs, ~~training costs~~, acceptance and commissioning costs.

~~***b)*** The cost of an item of property, plant and equipment includes direct construction or development costs (such as material and labour), and Engineering, Services & General (ES&G) attributable to the construction or development activity.~~

~~***c)***~~***b)*** The cost of an item of property, plant and equipment that is acquired, constructed, or developed over time includes carrying costs directly attributable to the acquisition, construction, or development activity such as interest costs. For a~~n item of~~ rate-regulated ~~property plant and equipment~~ asset, the cost includes the directly attributable AFUDC allowed by the Yukon Utilities Board (YUB) (see 10.)

3. ***Units of Property*** represent the main units of equipment or property contained within each ~~Fixed Asset~~PP&E category. A unit of property is defined as that which is independently operational, readily separable ~~from the Fixed Asset~~ and useful in its own right. Examples include dam, turbine, wood pole structures, conductors, transformers, regulators, circuit breakers, diesel engines and hydro generators.
(refer to GP Users Manual for Property, Plant and Equipment for additional information)

4. ***Components of Units*** represent the associated parts or items making up units of property. Components must be in service to be considered for capitalization. Examples include transformer bushings, voltage regulator bushings, fuel pumps, cross arms, guys or insulators.

5. ***Betterment*** is an upgrade and/or enhancement that extends the life of a capital asset or increases its functionality or service potential without replacement of a complete unit. Betterment relates to such additions to the asset that increase its useful life, results in reliability and/or quality improvements, increase in previously assessed physical output or service capacity, reduces operating costs by a substantial and quantifiable amount over a period of at least three years or reduces financial liability, environmental or safety risks. Overhaul and maintenance of machinery and equipment are not betterment expenditures.

6. ***Maintenance costs*** incurred to maintain the service potential of an item of property, plant or equipment are repairs and must be expensed.

   Note: If a cost has the attributes of both a repair and betterment, the portion considered ~~being~~ a betterment should be capitalized.

7. ***Overhauls*** are routinely conducted on diesel, wind and hydro production units. Major overhauls extend the useful life of the unit and minor overhauls maintain the efficient and effective operations of the unit. Costs associated with major overhauls are capitalized and depreciated, while costs associated with minor overhauls are expensed in the period in which they are incurred. (refer to FX-002 Overhauls for additional information)

~~8. ***Property, plant and equipment*** are identifiable tangible assets that meet all of the following criteria:~~

   e) ~~are held for use in the production or supply of electrical services, for administrative purposes, or for the development, construction, maintenance or repair of other property, plant and equipment;~~
   f) ~~have been acquired, constructed or developed with the intention of being used on a continuing basis for longer than one year;~~

g) ~~are not intended for sale in the ordinary course of business (i.e. goods purchased for resale),~~
h) ~~have a cost greater than $1,000.~~

~~9. ***Engineering Services and General (ES&G)*** is overhead that is applied to capital and feasibility projects. It is intended to recover costs that are not charged directly to capital projects such as supervision, preliminary engineering and support, as well as administration and financial services. (Refer to Finance and Administration Policy FX-003 for complete details on application of ES&G).~~

10. ***Allowance for Funds Used During Construction (AFUDC)*** is imputed interest that is applied to capital projects during construction. It is intended to cover the cost of financing a capital project during the period of construction ~~that carry over a fiscal year-end, which result in additions to Property, Plant and Equipment~~. AFUDC ceases when an item of property, plant and equipment is substantially complete and ready for productive use. Determining when an asset, or a portion thereof, is substantially complete and ready for productive use requires consideration of the circumstances and operating functions.
(refer to FX-004 AFUDC for additional information)

11. ***Asset retirements*** – when assets reach the end of their useful life they are retired from service.

12. ***Salvage*** - is any recovery associated with the retirement of an asset from service including any proceeds received from the sale of the retired asset.

13. ***Net Salvage*** – is proceeds received from salvage less any costs incurred to remove or dismantle assets retired from service.

14. ***Disposals*** – assets are said to be disposed of when they are sold, destroyed, lost, abandoned, or expropriated. Disposals require the approval of the Chief Financial Officer.

TOPIC: **Non Fuel Operating and Maintenance Expenses**

REFERENCE: YEC Application, Section 3.3 page 3-6

PREAMBLE: On page 3-6, YEC discusses the drivers for Labour. CW requires information about non-labour cost drivers.

QUESTION:

a) Please provide all assumptions used in the derivation of non-labour forecasts. In the response please include forecasts of Whitehorse inflation, CPI, GDP, and any other assumptions that influence costs in Whitehorse.

ANSWER:

(a)

Please see the response to YUB-YEC-1-29.

There was no general overall escalation. Some of the specific assumptions are as follows:

- Whitehorse property taxes were based on the City of Whitehorse forecast increases of 1.7% and 2.3% in 2018;
- Phone costs were based on contracted amounts;
- Donations were based on YEC's donation policy;
- All risk insurance was based on 2016 premiums;
- Software fees were based on increases of between 0% and 2%;
- Auto insurance was based on a rate increase of 2%, adjusted for changes in the forecast of vehicles; and
- Liability insurance was based on 2016 premiums.

TOPIC: **Non Fuel Operating and Maintenance Expenses**

REFERENCE: YEC Application, Section 3.3 page 3-9 and 3-10

PREAMBLE: On pages page 3-9 and 3-10 YEC discusses transmission costs.

QUESTION:

a) Transmission Brushing decreases from $1.161 million in 2014 to $1.069 million 2015 and to $1.034 million in 2016, then increases to $1.182 million in 2017. Please fully explain why total Transmission brushing decreases between 2014 and 2016.

b) In the response to (a) above, please fully explain why the decreases experienced between 2014 and 2016 cannot be maintained into 2017 and 2018. In the response please fully explain what causes the increases in detail and do not just refer to implementation of the YEC vegetation management policy.

ANSWER:

(a) and **(b)**

Fluctuations in transmission brushing costs result from the different site specific characteristics (i.e., size of area, terrain difficulties, access issues, density and composition of brush, etc.) and variations in contractor unit rates resulting from annual competitive processes (e.g., volume of participants, level of activity in other jurisdictions). YEC continues to apply the recommendations of the YUB-mandated brushing study with respect to designation of areas requiring attention.

TOPIC: **Non Fuel Operating and Maintenance Expenses**

REFERENCE: YEC Application, Section 3.3 page 3-11

PREAMBLE: On pages page 3-11 YEC discusses distribution costs.

QUESTION:

a) Please fully explain why YEC only spent $39,000 on distribution brushing in 2016.

b) Distribution Brushing decreases from $0.262 million in 2014 to $0.160 million in 2015 and to $0.039 million in 2016, then increases to $0.304 million in 2017. Please fully explain why total Distribution brushing decreases between 2014 and 2016.

c) In the response to (b) above, please fully explain why the decreases experienced between 2014 and 2016 cannot be maintained into 2017 and 2018. In the response please fully explain what causes the increases in detail and do not just refer to implementation of the YEC vegetation management policy.

ANSWER:

(a), (b) and **(c)**

Fluctuations in distribution brushing costs result from the different site specific characteristics (i.e. size of area, terrain difficulties, access issues, density and composition of brush, etc.) and variations in contractor unit rates resulting from annual competitive processes (e.g. volume of participants, level of activity in other jurisdictions).

Distribution brushing is more cyclical than transmission brushing due to the smaller scale. There were no significant lines required to be brushed in 2016. Distribution brushing costs are expected to be higher in 2017 and 2018 due to the cyclical nature of the distribution brushing requirements.

TOPIC: **Non Fuel Operating and Maintenance Expenses**

REFERENCE: YEC Application, Section 3.3 page 3-11 and 3-12

PREAMBLE: On pages 3-11 and 3-12 YEC discusses general operating and maintenance costs.

QUESTION:

a) Please fully explain why Transportation, Maintenance of Company Owned Property, and SCADA Communication decrease between 2015 and 2016.

b) Please fully explain why the costs for Transportation, Maintenance of Company Owned Property, and SCADA Communication are forecast to increase in 2017, and why the decreases experienced in 2016 do not continue into 2017.

ANSWER:

(a)

Explanations of differences are discussed below.

($000's)	Actual 2015	Actual 2016	Change	Reasons for differences
Transportation	$ 505	$ 459	$ (46)	Decrease in fuel costs resulting from lower mileage
Maintenance of Company Owned Properties	$ 673	$ 501	$ (172)	2015 was abnormally high due to extensive company-wide crane repairs/maintenance
SCADA Communication	203	197	$ (6)	External consulting budget was not required

(b)

See YUB-YEC-1-10 for an explanation regarding differences in Transportation and Maintenance of Company Owned Properties costs. See below for SCADA communication costs.

($000's)	**Actual 2016**	**Forecast 2017 and 2018**	**Change**	**Reasons for differences**
SCADA Communication	$197	$202	$5	Expect to use external consulting budget

TOPIC: **Non Fuel Operating and Maintenance Expenses**

REFERENCE: YEC Application, Section 3.3 page 3-12 through 3-14

PREAMBLE: On pages page 3-12 through 3-14 YEC discusses Administration costs. In total, administration increases by $600,000 (7.1%) yet the explanations focus on where the increases are, not why the costs increase.

QUESTION:

a) Please provide a detailed explanation of why each of the cost items included in Administration change from year to year, between the 2013 and 2016 actual costs.

b) Please provide a detailed explanation of why each of the cost items is forecast to change in 2017 from the 2016 actual results.

c) Please provide a detailed explanation of why each of the cost items is forecast to change in 2018 from the 2017 forecast.

ANSWER:

(a)

Administration costs have increased by $0.430 million (5%) from 2013 to 2016 primarily due to Labour which increased $0.482 million over this period. Labour and other increases between 2013 and 2016 are discussed below:

- Labour ($0.482 million)
  - Annual wage increments as per the collective bargaining agreement
  - Changes in benefits (see CW-YEC-1-18)
  - Changes to the capital/maintenance allocation (see CW-YEC-1-19)
- General ($0.023 million)
  - Engineering services external consulting for vibration monitoring
- Information Systems ($0.095 million)
  - Costs have increased in external consulting, license fees and data circuits all resulting from increased importance of technology

- Safety ($0.008 million)
  - Nothing significant
- Recruitment ($0.107)
  - 2013 was an abnormally low year
  - Vacancy rate was abnormally high (see YUB-YEC-1-2)
- Board of Directors ($0.010)
  - Nothing significant
- Contracting ($0.001)
  - Nothing significant

(b)

Changes in costs from 2016 actual to 2017 forecast are below.

	Actual 2016	Proposed 2017	Change	Reasons for differences
Labour	$ 5,783	$ 5,961	$ 178	See YUB-YEC-1-11
Resource Planning	14	48	$ 34	Additional maintenance for water flow monitoring
Communications	129	130	$ 1	Nothing significant
Customer Accounting	208	224	$ 16	See YUB-YEC-1-11
Environmental Mgmt	166	278	$ 112	See YUB-YEC-1-11
General	613	705	$ 92	See YUB-YEC-1-11
Information Systems	576	631	$ 55	See YUB-YEC-1-11
Fish Hatchery	157	168	$ 11	Expected increase in professional fees
Safety	172	171	$ (1)	Nothing significant
Training	143	175	$ 32	See YUB-YEC-1-11
Recruitment	231	244	$ 13	See YUB-YEC-1-11
Board of Directors	160	182	$ 22	See YUB-YEC-1-11
Union	0	95	$ 95	See YUB-YEC-1-11
Regulatory Affairs	99	33	$ (66)	See YUB-YEC-1-11
Material Management	41	38	$ (4)	Nothing significant
Contracting	14	12	$ (2)	Nothing significant
Professional Development	3	15	$ 12	See YUB-YEC-1-11
Total Administration	$ 8,509	$ 9,110		

(c)

Changes in costs from 2017 to 2018 forecast are below.

	Proposed 2017	Proposed 2018	Change	Reasons for differences
Labour	$ 5,961	$ 5,911	$ (50)	See YUB-YEC-1-11
Resource Planning	48	48	$ -	Nothing significant
Communications	130	130	$ -	Nothing significant
Customer Accounting	224	225	$ 1	Nothing significant
Environmental Mgmt	278	238	$ (40)	See YUB-YEC-1-11
General	705	662	$ (43)	See YUB-YEC-1-11
Information Systems	631	645	$ 14	See YUB-YEC-1-11
Fish Hatchery	168	168	$ -	Nothing significant
Safety	171	182	$ 12	Nothing significant
Training	175	175	$ -	Nothing significant
Recruitment	244	229	$ (15)	See YUB-YEC-1-11
Board of Directors	182	182	$ -	Nothing significant
Union	95	20	$ (75)	See YUB-YEC-1-11
Regulatory Affairs	33	33	$ -	Nothing significant
Material Management	38	37	$ (0)	Nothing significant
Contracting	12	12	$ -	Nothing significant
Professional Development	15	15	$ -	Nothing significant
Total Administration	$ 9,110	$ 8,912		

TOPIC: **Non Fuel Operating and Maintenance Expenses**

REFERENCE: YEC Application, Section 3.3 page 3-14 and 3-15

PREAMBLE: On pages 3-14 and 3-15 YEC discusses its insurance and RFID

QUESTION:

a) Please fully explain all changes in the YEC insurance coverages, including changes in limits, deductibles, or any other changes in the coverage.

b) In Table 3.11, YEC provides a 10 year history of RFID annual charges. Please provide a detailed analysis of the items included in each year. Please update the table to include 2016 actual data.

ANSWER:

(a)

With respect to annual property insurance, premiums are based on the replacement cost of insured assets. As YEC expands and updates its property portfolio, there is upward pressure on the overall premium (annual premium rate stated in premium dollars/$1000 of insured assets is not subject to material changes year over year). During the 2017 property & equipment renewal, YEC reduced the deductible on mechanical breakdown from $250,000 to $100,000 without an increase in premium rate. There was no change in the liability program as YEC is in the second year of a 3-year agreement.

(b)

Please see table below.

($000's)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Takhini Substation Break-In	15	-	-	-	-	-	-	-	-	-	-
Kulan Break In	32	-	-	-	-	-	-	-	-	-	-
L171 Lightning Arrestor Failure	11	-	-	-	-	-	-	-	-	-	-
L171 Insulator Failure	35	-	-	-	-	-	-	-	-	-	-
Whitehorse Hydrant Leak	36	-	-	-	-	-	-	-	-	-	-
Unit 63 Vehicle Theft	2	-	-	-	-	-	-	-	-	-	-
WH1 Hub and Blade Overhaul	302	-	-	-	-	-	-	-	-	-	-
Aishihik Cable Repair	200	-	-	-	-	-	-	-	-	-	-
L174 Broken Pole	-	39	-	-	-	-	-	-	-	-	-
Water Damage at MLCS	-	17	-	-	-	-	-	-	-	-	-
Kulan Warehouse Water Damage	-	7	-	-	-	-	-	-	-	-	-
L172 Insulator Failure	-	-	40	-	-	-	-	-	-	-	-
Rock Creek Crossing	-	-	11	-	-	-	-	-	-	-	-
Polaris Ranger & Trailer Rplcm	-	-	9	-	-	-	-	-	-	-	-
Outage Damages- Oct.2008	-	-	41	-	-	-	-	-	-	-	-
Whitehorse Hydrant Leak	-	-	-	16	-	-	-	-	-	-	-
Outage Damages- Oct.2008	-	-	-	2	-	-	-	-	-	-	-
Aishihik Sub Cable Failure	-	-	-	24	-	-	-	-	-	-	-
Premature VFD Failure	-	-	-	27	-	-	-	-	-	-	-
Lost Tool Kit	-	-	-	2	-	-	-	-	-	-	-
Aishihik Service Building Crane Cable Replacement	-	-	-	60	-	-	-	-	-	-	-
Aishihik Pole Fire	-	-	-	24	-	-	-	-	-	-	-
Vehicle Rollover Deductible	-	-	-	5	-	-	-	-	-	-	-
WH4 Rotor Crack Repair	-	-	-	-	315	-	-	-	-	-	-
MH1 Slip Ring Repair	-	-	-	-	74	-	-	-	-	-	-
Aishihik Station Transformer	-	-	-	-	27	-	-	-	-	-	-
Mayo Customer Damage	-	-	-	-	-	6	-	-	-	-	-
Trail Blazer	-	-	-	-	-	3	-	-	-	-	-
S150 Cable & PT Repairs	-	-	-	-	-	10	-	-	-	-	-
Repair WD6 Premature Failure	-	-	-	-	-	271	-	-	-	-	-
WH4 Rotor Crack Repair	-	-	-	-	-	12	-	-	-	-	-
Lewes Cont.Structure-Gate Fire	-	-	-	-	-	-	150	-	-	-	-
Frazil Ice Blockage-P125 Intake	-	-	-	-	-	-	53	-	-	-	-
Aishihik Forest Fire 2013	-	-	-	-	-	-	-	25	-	-	-
L170 Carmacks Forest Fire 2013	-	-	-	-	-	-	-	343	-	-	-
L171 Lighting Response 2013	-	-	-	-	-	-	-	35	-	-	-
Whitehorse Ice Blockage 2014	-	-	-	-	-	-	-	-	196	-	-
L177 Dempster Corner Fire 2015	-	-	-	-	-	-	-	-	-	116	-
L170 L173 and Faro Fire Outage	-	-	-	-	-	-	-	-	-	20	-
Mayo River Crossing Emergency	-	-	-	-	-	-	-	-	-	57	-
Whitehorse Spillway Gearbox	-	-	-	-	-	-	-	-	-	-	352
L177 Structure Damaged	-	-	-	-	-	-	-	-	-	-	90
WH4 Rotor Crack Repair	-	-	-	-	-	-	-	-	-	-	253
LNG Tank Leak Tests and repair	-	-	-	-	-	-	-	-	-	-	192
Aishihik Transformer Failure	-	-	-	-	-	-	-	-	-	-	49
L178 Snow Shed Emergency Repair	-	-	-	-	-	-	-	-	-	-	82
Total	**633**	**63**	**101**	**159**	**415**	**302**	**204**	**404**	**196**	**193**	**1,018**

TOPIC: **Rate Base, Depreciation and Amortization**

REFERENCE: YEC Application, Section 3.4

PREAMBLE: YEC Application, Section 3.4

QUESTION:

a) Please confirm that YEC is using the exact same depreciation and amortization rates as approved in 2013. If not confirmed, please fully explain and provide a detailed analysis of each change in depreciation or amortization rates, along with an explanation of the reason for the change.

b) If (a) above is not confirmed, please provide a depreciation study in support of any changed depreciation or amortization rate.

c) Please provide a detailed working paper, in excel format, that applies the depreciation rates used by YEC to plant and contribution balances to arrive at total depreciation and amortization.

ANSWER:

(a) and **(b)**

Please see response to YUB-YEC-1-18.

(c)

Please see response to YUB-YEC-1-17

TOPIC: **Return on Rate Base**

REFERENCE: YEC Application Section 3.5

PREAMBLE: In section 3.5.1, YEC discusses cost of debt.

QUESTION:

a) Please fully explain if the debt secured through the Yukon Development Corporation is funded by the Yukon Development Corporation (or the Yukon Government) or borrowed in the market by the Yukon Development Corporation and then provided to YEC.

b) If, in response to (a) above, the financing is borrowed in the market, please fully explain whether the debt secured through the Yukon Development Corporation includes any mark up or premium that is retained by the Yukon Development Corporation, or if the cost of debt is mirrored down to YEC at cost. If there is a premium retained by the Yukon Development Corporation, please provide a detailed analysis of the amount and rate of the premium.

ANSWER:

(a) and **(b)**

The interest rate assigned to debt from the parent is market-based. At the time of debt commitment, YEC requests a market rate for long term debt from a Canadian Chartered Bank (TD Commercial). This is the rate that is used. YEC is not privy to YDC`s decision making on how it sources it`s capital and that process is not relevant to this proceeding.

TOPIC: **Return on Rate Base**

REFERENCE: YEC Application Section 3.5 and Section 8

PREAMBLE: In section 3.5.2, YEC discusses Return on Common Equity. In Section 8, YEC provides more detail about its requested ROE.

QUESTION:

a) On page 8-1, lines 12-14, YEC states it faced "considerably higher risk levels than ATCO Electric Yukon (AEY)". Please provide a detailed analysis of the risks faced by each of AEY and YEC. In the response, please provide copies of any and all outside research or expert reports that YEC relied on to reach its conclusion.

b) In Table 8.1 and 8.2, YEC includes three comparators, Fortis BC Inc, PNG West and PNG NE.
   a. Please fully explain why YEC only considered three comparators.
   b. Please explain why YEC did not include AltaGas Utilities Inc. (AUI) as a comparator. Please provide similar data as in Tables 8.1 and 8.2 for AUI.
   c. Please provide a complete list of other Canadian utilities that have revenues of less than $100 million.

ANSWER:

(a)

It has been long accepted by the Board (in its orders), Yukon Energy, and AEY (and experts retained by AEY) that Yukon Energy faces higher risk levels than AEY. Specifically, this was noted by AEY's expert Kathy McShane in the 2008/2009 GRA[1] (whose evidence on fair return was also relied on by AEY in the 2013-15 GRA), and accepted by the Board in Order 2009-2 as follows[2]:

[1] YECL 2008/09 GRA. Transcript Volume 2, page 206 lines 4-7 Ms. McShane acknowledges that relative to YECL, YEC has more risk. This was cited by intervenors in argument at the time and also by cited in Order 2009-2.
[2] Order 2009-2, page 29.

Should a risk premium be applied?

In Appendix A to Board Order 2005-12, the Board accepted YEC's recommendation of a risk premium of 52 basis points and noted that it was greater than the risk premium for FortisBC and less than the risk premium for Pacific Northern Gas. YEC argued that it was more risky than FortisBC since FortisBC had inter-tie connections with other utilities allowing more purchase power options and affording greater flexibility to its generation. The evidence in the Foster Report, although related to capital structure, also suggested a risk premium for YECL. The Board accepts that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.

What risk premium should be applied to YECL?

In its reply argument, YECL suggested a risk premium of 52 basis points, the same as YEC. However, the Board notes that YECL acknowledges that relative to YECL, YEC has more risk[3]. The Board considered Appendix A of Board Order 2005-12 in finding that without the same inter-tie connections as FortisBC, YECL is more risky than FortisBC. As a result, the Board finds it reasonable to place the risk premium for YECL at the midpoint of the risk premiums between YEC and FortisBC — at 46 basis points. Therefore YECL is directed to use an ROE for 2008 of 9.08%. For 2009, YECL will use a risk premium of 46 basis points above the BCUC 2009 benchmark ROE.

The following is specifically noted in this regard:

- AEY is predominantly a distribution utility (with its own generation sources supplying only 9% of its requirements); in contrast Yukon Energy has generation, transmission and distribution functions and its own generation sources supply 100% of its requirement).

- AEY has a retail customer base of about 17,600 retail customers across Yukon (and has no industrial customers); Yukon Energy's load is dominated by one wholesale customer (AEY) and an industrial customer (Minto mine) with other potential industrial connections in the near future (Alexco and Victoria Gold).

[3] Transcript Volume 2, October 8, 2008. Page 206 lines 4-7 inclusive.

(b)

Please see the response provided in YUB-YEC-1-53 regarding the rationale for using Fortis BC Electric and PNG-West as comparable utilities for determining the Yukon Energy risk premium above the low risk utility ROE.

As noted in that response, the Board has repeatedly noted that the BCUC model for determining ROE is most appropriate for Yukon; FortisBC Electric and PNG West are each BC-based utilities that have a BCUC approved risk premium over and above the BCUC-approved benchmark ROE of 8.75%.

Based on the above, other utilities outside of BC, and utilities that do not have a BCUC approved risk premium, are not useful comparators for the purpose of YEC's Application.

TOPIC: **Vegetation Management Policy**

REFERENCE: YEC Application, Appendix 3.1

PREAMBLE: In Appendix 3.1, YEC provides its vegetation management policy, dated May 2017.

QUESTION:

a) Please provide the date of any prior vegetation management policy. If a prior policy exists, please provide a copy of the policy with all changes clearly identified.

b) Please fully explain the process for developing this version of the vegetation management policy. In the response, please provide copies of all other such policies from other utilities that YEC examined or considered in the preparation of this policy.

ANSWER:

(a)

No prior policy exists.

(b)

The policy was drafted by internal YEC staff with collaboration and input from the operations, environment, health & safety, and engineering departments. In addition, the policy reflects a review of brushing practices which was reviewed in the 2012/13 application. While YEC did some cursory reviews of other utility brushing approaches, these reviews were not used in any substantive way in the YEC policy development.

TOPIC: **Reserve for Injuries and Damages (RFID) Policy**

REFERENCE: YEC Application, Appendix 3.2

PREAMBLE: In Appendix 3.2, YEC provides its RFID, dated March 2012.

QUESTION:

a) Please confirm that this is the latest policy. If not confirmed, please provide the latest policy, with any changes from this policy clearly marked.

b) The review date is February 2015. Please fully explain what review took place in February 2015, and the results of the review.

ANSWER:

(a)

Confirmed

(b)

The February 2015 review date represents the standard 3-year review cycle for YEC policies. Please see YUB-YEC-1-20 for a description of updates to the policy.

TOPIC: **Rates**

REFERENCE: YEC Application, Tab 4

PREAMBLE: In Tab 4, YEC discusses rates.

QUESTION:

a) Please confirm that YEC has not included any Phase II rate adjustments in this application, and that this is solely a Phase I application. If not confirmed, please provide a detailed Cost of Service study in support of new rates.

b) Please confirm that YEC is not proposing any changes to its Terms and Conditions of service. If not confirmed, please provide a revised copy of its Terms and Conditions of Service, with all changes clearly marked.

c) Please advise when YEC expects to file its next Phase II application and/or Cost of Service Study and explain its understanding of any government directions or government-imposed constraints that impact YEC's answer.

ANSWER:

(a)

Confirmed.

(b)

Confirmed.

(c)

Please see response to UCG-YEC-1-2. Current OIC direction effectively provides that material rate design changes that would result in rebalancing of rates between different customer classes cannot be undertaken until mid-2019 at the earliest.

TOPIC: **Capital Projects**

REFERENCE: YEC Application, Section 5.2.1.1

PREAMBLE: In Section 5.2.1.1, YEC discusses a legal dispute with a contractor.

QUESTION:

a) At lines 23, 24 and 25 of page 5-6, YEC mentions costs of $2.715 million, $2.574 million, and $2.117 million. At line 9 of page 5-7, YEC identifies the amount in dispute as $1.623 million and legal fee of $0.962 million. Please provide a detailed analysis of the cost in question. In the response, please itemize the total costs in dispute and the related legal fees separately.

b) Please fully explain how the costs and legal fees have been treated in YEC's accounts, and for rate making purposes.

c) At lines 27-28 YEC mentions a final settlement and an appeal. Please provide the Court docket number of any proceedings leading to any decision that is under appeal, the citation to the decision and the court action number of any appeal from that decision.

ANSWER:

(a) and **(b)**

Please see the response provided to YUB-YEC-1-61.

(c)

The court action number of the proceedings that led to the decision that is under appeal was Yukon Supreme Court No. 11-A0114. The citation to the decision that is under appeal is North America Construction (1993) Ltd. v. Yukon Energy Corporation, 2016 YKSC 33. The court action number of the appeal is Yukon Court of Appeal No. 16-YU787.

TOPIC: **Capital Projects**

REFERENCE: YEC Application page 6-6

PREAMBLE: At page 6-6, YEC responds to a board direction to include business cases for all projects greater than $1 million. In the response, YEC indicates that Business Cases are provided in Tab 5. In a review of Tab 5, sections 5.2.1 and 5.3.1, there is a description of each major project.

QUESTION:

a) Please confirm that the documentation in sections 5.2.1 and 5.3.1 are what YEC asserts are its business cases. If not confirmed, please provide references to where YEC has provided business cases.

b) Please fully explain what internal documentation YEC provides to management for approval and sign off of capital projects.

ANSWER:

(a)

Confirmed.

(b)

Capital project initiation begins with a Project Identification Document (PID). Any staff member can initiate a PID based on their observation of an issue. After pre-screening by the Director Engineering Services, including review of a priority ranking, the project goes to a cross-functional review committee for a funding decision. Once funding is granted, a project manager (PM) is assigned who creates an Authorization for Expenditure (AFE). A completed AFE is required before the PM is assigned a project code in the financial system (i.e., an AFE must be complete before any spending can occur). The AFE is signed by the Director Engineering Services, CFO and, for large dollar projects, the President. Once the project is started, any significant changes to scope, schedule or budget require completion of a Project Change Request to explain the change. Project Change Request approvals are similar to the AFE.

TOPIC: **Capital Projects**

REFERENCE: YEC Application, page 5.4-2, PDF page 257, Schedule 5.2

PREAMBLE: Under "Development of Asset Management Program", YEC states:

> Currently there is no asset management methodology or plan for managing critical hydro and transmission assets at YEC. This results in ad hoc repairs and replacement projects that are costly and unplanned. An asset management program will consist of documented plans to systematically assess major asset groups (Hydro, Substations, T&D) and manage the planning of investments to meet overall corporate goals. This project will develop the asset management program and involves defining program goals and scope, a gap analysis of current state and desired future state, development of strategies for assessing and managing the different asset groups, and the creation of an implementation plan for the program.

On lines 2-8 of page 55 (PDF page 176), YEC indicates that it has focussed on projects required to address sustaining capital requirements.

In Appendices 5.3 and 5.4, YEC provides a summary or each project between $100,000 and $1 million.

CW requires information to assess YEC's current approach to asset replacement.

QUESTION:

a) Please fully explain the current YEC method to decide which assets should be replaced. In the response, please provide a detailed explanation of how, under YEC's current approach, customers can be assured that costs are prudent, and YEC has undertaken the least cost alternative.

b) Please fully discuss and explain YEC's asset monitoring processes and procedures. In the response, please provide the results of any inspections, testing or other processes that have driven the YEC capital plan for this GRA.

c) Other than for the major projects on schedule 5.2, please provide an analysis that demonstrates that the forecast project and costs are required to sustain capital and assets. In the response, please fully explain the impact of delaying the costs outside the test period. In effect, please explain why the costs are required now.

d) For L170 Line Access (PDF page 249), YEC indicates that it lacks the necessary permitting and the asset may not have been constructed to an acceptable standard.
   i. Please fully explain when the L170 line was built and who built it.
   ii. Please fully explain why customers should pay for costs to correct an asset that was not constructed to an acceptable standard, and lacks the proper permitting.
   iii. Please provide a list of all YEC assets that are not constructed to an acceptable standard, or lack proper permitting.

e) On PDF page 283, YEC discusses Mayo Transient Trailer unit.
   i. Please provide an analysis of the number of nights that the proposed unit will be used.
   ii. Please provide the actual nights that local accommodation were used for each of 2013-2016.
   iii. Please provide the cost of local accommodation for each of 2013-2016.
   iv. Please provide the forecast annual operating costs for the Trailer unit.

ANSWER:

(a) and **(b)**

Please see YUB-YEC-1-86 for an explanation of current method of asset evaluation. With respect to the request for "any inspections, testing or other processes", the request is overly broad. YEC constantly monitors, measures and inspects asset condition and performance. This could be internal or external reporting that may result in a formal assessment report or could be internal communication only. YEC has provided examples of assessment reports in the following interrogatory responses:

- CW-YEC-1-40 – Insulator and cross arms.
- John Maissan-YEC-1-37 – Building condition assessments.
- UCG-YEC-1-16 – Communication needs assessment.
- YUB-YEC-1-63 – Aishihik Hydro Assessment (RE: electrical & control upgrades).

(c)

Appendix 5.3 provides the rationale for the projects referenced.

(d)

(i), (ii) and **(iii)**

The requirement for this project is unrelated to the original construction of the transmission line. Past practice whereby the regulator allowed for ad hoc access to the power line right of way has been deemed unacceptable now and thus YEC is being directed to change its approach.

(e)

(i)

Based on the average of prior years and the future work planned for the Mayo area, the trailer is expected to be used 250 room-nights per year

(ii) and **(iii)**

Please see Table 1 below.

Table 1: Local Accommodation (2013-2016)

Year	Nights	Cost
2013	267	$ 30,324
2014	265	$ 30,251
2015	214	$ 24,118
2016	130	$ 14,280

(iv)

Please see response to YUB-YEC-1-87(f).

TOPIC: **Capital Projects**

REFERENCE: YEC Application, Section 5.2.1.2

PREAMBLE: In Section 5.2.1.2, YEC discusses the Aishihik Elevator Shaft Structural Steel Rehabilitation project.

QUESTION:

a) Please provide the detailed initial estimate or budget for the project.

b) Please explain any variances between the initial estimate and the actuals/latest forecast.

c) Please provide the status of the project.

ANSWER:

(a), (b) and **(c)**

Please see YUB-YEC-1-62

TOPIC: **Capital Projects**

REFERENCE: YEC Application, Section 5.2.1.3

PREAMBLE: In Section 5.2.1.3, YEC discusses the Aishihik Electrical and Control Upgrades project.

QUESTION:

a) In line 15 of page 5-8, YEC mentions end of life. Please provide all analysis conducted by YEC that demonstrates end of life. In the response, please confirm and discuss whether YEC determines end of life based on condition or age.

ANSWER:

(a)

Please see the response to YUB-YEC-1-63.

YEC typically determines end of life based on asset condition. Depending on specific operating conditions and environment, an asset may have a longer or shorter life than suggested by the manufacturer.

TOPIC: **Capital Projects**

REFERENCE: YEC Application, Section 5.2.1.4

PREAMBLE: In Section 5.2.1.4, YEC discusses Communications Upgrades projects.

QUESTION:

a) On lines 3-8 of page 5-12, YEC discusses the benefits of the projects. Please fully explain each benefit, and any cost savings that result.

b) Please fully explain all research done by YEC that demonstrate that the purported benefits are wanted or needed by customers.

ANSWER:

(a)

Increase performance: The current communications links to certain sites are barely large enough to carry essential information. The increase in performance will enable YEC to transfer more information allowing better analysis and decision making. Being able to see grid statistics in real time as opposed to when someone is on site reading meters allows significantly more proactive behaviors thereby extending the life of the assets. A major benefit of this increased performance is the ability of remote troubleshooting, saving staff substantial travel time.

Improved reliability: Having multiple paths to get data from site to site creates redundancy that will result in fewer outages and less travel to remote sites for troubleshooting. Having two links provides the ability to work on one link remotely with no downtime, something that would have previously taken two people (one on each end) combined with travel to the remote site. This currently occurs multiple times a year per site. This project will also allow for a full backup location for system control, so that a loss of the Whitehorse office does not result in a full loss of SCADA control of the grid.

(b)

YEC has not performed any specific research to determine the wants or needs of customers regarding internal operational communication infrastructure, however the Resource Plan Values Survey reported that 71% of respondents indicated they would support a rate increase due to efforts to reduce power outages in their area.

TOPIC: **Capital Projects**

REFERENCE: YEC Application, Section 5.2.1.5

PREAMBLE: In Section 5.2.1.5, YEC discusses the Hydro Unit #WH4 Overhaul project.

QUESTION:

a) In lines 3-6 of page 5-15 YEC discusses a 10 year Major Overhaul. Please fully explain the basis for a 10 year major overhaul, including discussion of practises by other utilities, and industry standards.

b) Please fully explain whether all assets are subject to a 10 year major overhaul. If all assets are not subject to a 10 year major overhaul, please fully explain why not, and which assets are subject to a 10 year major overhaul.

ANSWER:

(a)

Given the nature of the isolated Yukon grid, the reliability of generation assets is critical to dependable service to customers. As a result, YEC aims to perform a major overhaul on hydro units every 10 years. A major overhaul also provides YEC with an opportunity to inspect certain components that are otherwise inaccessible, offering key insights into asset health and the ability to remedy minor problems before they result in an in-service failure. Other utilities will have differing maintenance timeframes based on the nature of their assets and operating conditions which may allow for major overhauls to occur on a much less frequent basis.

(b)

YEC Hydro units are the only assets subject to 10 year major overhauls, although the 10 year timeframe could be modified depending on the actual usage of a specific unit. Diesel generators are maintained on an hour-based schedule and other assets are typically maintained based on manufacturer recommendations.

TOPIC: **Capital Projects**

REFERENCE: YEC Application, Section 5.2.1.7

PREAMBLE: In Section 5.2.1.7, YEC discusses the T&D – Breaker Replacements project.

QUESTION:

a) In line 18 of page 5-18, YEC mentions end of life. Please provide all analysis conducted by YEC that demonstrates end of life. In the response, please confirm and discuss whether YEC determines end of life based on condition or age.

ANSWER:

(a)

YEC Condition Assessment: Based on the OEM assessment these assets are in medium to poor condition and are demonstrating material reliability and performance declines from their historical condition. There is a low level of confidence that the equipment will perform well under normal operating conditions. Restricted operation and/or non-routine maintenance is necessary. YEC typically determines end of life based on condition. ABB no longer supplies parts for the operating mechanisms coupled to the breakers and for the poles there are limited spares available at this time.

YEC Consequence Assessment: Reliability – Prudent system design has allowed for minor reliability impact (brief localized loss of service) due to the failure of a single breaker, however, the failure of multiple units simultaneously would result in rolling blackouts or local outage for longer than 48 hours. There are no longer ASEA parts available for these breakers and so damaged components could result in lengthy downtime.

Based on the above condition and consequence assessment the risk to YEC is deemed unacceptable.

TOPIC: **Capital Projects**

REFERENCE: YEC Application, Section 5.2.1.8

PREAMBLE: In Section 5.2.1.8, YEC discusses the T&D - Line Replacement project.

QUESTION:

a) On lines 16 and 17 of page 5-19, YEC discusses two events that it purports drive the need for an external assessment of the line (Line 18). Please provide the external assessment.

b) Please provide all documents provided to the entity conducting the assessment, and all instructions given to the entity.

ANSWER:

(a)

Please see CW-YEC-1-40 Attachment 1.

(b)

The entity was given drawings of the transmission line structures, a sample is attached. See CW-YEC-1-40 Attachment 2. They were instructed to determine the cause of the failed component and determine the condition of test components removed from service before failure.

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POWERTECH LABS INC.

FAILURE ANALYSIS AND CONDITION ASSESSMENT TESTS ON SUSPENSION INSULATORS FROM YUKON ENERGY 138 KV TRANSMISSION LINE

PROJECT NO. PL-01281

ABSTRACT: Yukon Energy sent seventy-eight insulators that had been removed from a failed wood pole 138 kV transmission structure (it burned) to Powertech for determination of the root cause of the fire and to assess the condition of all insulators removed from the same structure. A series of test were carried out on the insulators. Twenty percent of the individual insulators had a failure load below the rated value on a combined mechanical and electrical test.

The root cause of fire was most likely due to excessive leakage current which triggered a pole top file. If the condition of these insulators is typical of the insulators in this transmission line it is recommended that all insulators that are marked with “Made in England 1968” or “Buller’s England 1968” be replaced. Any live line work done on these transmission lines should take into account there is a significant risk that there are punctured insulators and there may be insulators with low mechanical strength in the insulator strings being work on.

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The results relate only to the items tested
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1 SUMMARY

Yukon Energy sent nine strings of insulators to Powertech (three suspension and three dead-end horizontal strings with three jumper strings - 78 insulators). They had been removed from a failed wood pole 138 kV transmission structure (it burned). Powertech was requested to determine the root cause the fire incident and to assess the condition of all insulators removed from the same structure. A series of test were carried out on the insulators.

The megger tests found one failed insulator. Visual inspection found that the insulator strings had some electrical and environmental damage. Pollution level tests (ESDD) found the pollution level on the insulators was very low. Five percent of the insulators failed an RIV (radio-influence voltage) test. Two of the insulators punctured on the AC flashover test and one of the insulators was cracked. Corrosion assessment of the insulators found them to be in good shape from a corrosion perspective. Twenty percent of the individual insulators had a combined mechanical and electrical failure load below the rated value.

The root cause of fire was most likely due to excessive leakage current which triggered a pole top file. No parts of the wood structure were available for examination therefore it is not possible to definitively conclude that the fire was due to high leakage current, however, based on the poor condition of the insulators and the absence of lightening or switching activity in the this is the most likely cause of the failure.

These insulators were all removed from on structure so it is not possible to determine if the insulator condition is typical of the insulators on this transmission line. However, if this is typical it is recommended that all insulators marked “Made in England 1968” or “Buller’s England 1968” be replaced. They are all at high risk of failing either electrically and mechanically. Given that there were three similar failures in 2015 there is a high probability of further failures. It is recommended that a replacement program be implemented as soon as possible. If live line work is to be done on these transmission lines the work procedures should take into consideration that there may be punctured (shorted) insulators and/or insulators with lower than rated mechanical strength on the structure being worked on.

2 REQUEST

Yukon Energy requested Powertech to determine the root cause of an pole fire incident on its 138 kV transmission line and to assess the condition of all insulators removed from the same structure.

The following information was provided on the incident:

- Failure occurred on Oct. 8 2015 around 19:00
- Failed structure was str.1248 on L-178
- The insulators are brown porcelain made in England in 1968
- It was raining when the string failed
- There is sign of flashover on the glass
- There had been a trip on L-178 two weeks earlier but it was caused by a tree on C phase
- We replaced all the glass on str. 1248 and one other string also should signs of tracking
- There have been three similar failures this year all of them have been on three pole double dead ends. I believe it may be cause by the lack of bonding and the close proximity of the dead end to the uninsulated guy.

The results relate only to the items tested
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- There is no known history of maintenance on this structure.

Appendix II shows pictures taken at the failure site.

Nine strings of insulators (three suspension and three dead-end horizontal strings with three jumper strings) were removed from the failed wood pole structure and sent to Powertech. The insulators received were only identified by the phase they came from. The individual insulators were not identified as to which insulator string they came from or by their position in the insulator string.

3 TEST STANDARD

The tests were performed in accordance with CAN/CSA-C411.1, "AC Suspension Insulators" and IEEE Std. 4, "IEEE Standard Techniques for High-Voltage Testing".

4 TESTS PERFORMED

The following tests were performed on the insulators:

- Megger all insulators at 1 kV
- Visual examination on all insulators
- An ESDD (pollution level) measurement on six insulators from three strings of insulators
- Radio influence voltage (RIV) test on all insulators
- Dry AC flashover test on all insulators
- Assessment of any corrosion on the insulators
- Combined mechanical and electrical test on all insulators

5 INSULATOR IDENTIFICATION

The insulator strings were identified as follows:

Identification on Glaze: Type 1: Made in England 1968
Type 2: Buller's England 1968

The insulator strings were removed from structure 1248, L-178 (based on the marking on the insulator crates):

Insulator type: ANSI Class 52-3 (based on the insulator dimensions and rating on the insulators)

The insulators from each string were identified as follows:

1. Structure 1248, L-178 (Road phase).

PT Identification	Name on the Glaze	PT Identification	Name on the Glaze
1273-1A	England	1273-14A	England

1273-2A	England	1273-15A	England
1273-3A	England	1273-16A	England
1273-4A	England	1273-17A	England
1273-5A	England	1273-18A	England
1273-6A	England	1273-19A	England
1273-7A	England	1273-20A	England
1273-8A	England	1273-21A	England
1273-9A	England	1273-22A	England
1273-10A	England	1273-23A	England
1273-11A	England	1273-24A	England
1273-12A	England	1273-25A	England
1273-13A	England	1273-26A	England

2. Structure 1248, L-178 (Centre phase).

PT Identification	Name on the Glaze	PT Identification	Name on the Glaze
1273-1B	England	1273-14B	England
1273-2B	England	1273-15B	England
1273-3B	England	1273-16B	England
1273-4B	England	1273-17B	England
1273-5B	England	1273-18B	England
1273-6B	England	1273-19B	England
1273-7B	Buller’s	1273-20B	England
1273-8B	Buller’s	1273-21B	England
1273-9B	Buller’s	1273-22B	England
1273-10B	Buller’s	1273-23B	England
1273-11B	Buller’s	1273-24B	England
1273-12B	Buller’s	1273-25B	England
1273-13B	England	1273-26B	England

3. Structure 1248, L-178 (Bush phase)

PT Identification	Name on the Glaze	PT Identification	Name on the Glaze
1273-1C	England	1273-14C	England
1273-2C	England	1273-15C	England
1273-3C	England	1273-16C	England
1273-4C	England	1273-17C	England
1273-5C	England	1273-18C	England
1273-6C	Buller’s	1273-19C	England
1273-7C	England	1273-20C	England
1273-8C	England	1273-21C	England
1273-9C	England	1273-22C	England
1273-10C	England	1273-23C	England
1273-11C	Buller’s	1273-24C	England
1273-12C	Buller’s	1273-25C	Buller’s
1273-13C	England	1273-26C	Buller’s

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6 TEST DATE

The tests were performed during the period of 13 April 2016 to 31 May 2016.

7 TEST RESULTS

7.1 *Megger Test*

7.1.1 Acceptance Criterion

This test was done to determine if any of the insulators "as received" were punctured. The insulators pass the test, if the insulator is not shorted or it does not have a low resistance value at 1000 VDC.

7.1.2 Test Procedure

A voltage of 1000 VDC was applied between each insulators cap and pin and the insulator resistance value was recorded.

7.1.3 Test Results

Structure 1248, L-178 (Road phase)

Insulator No.	Megger Reading	Insulator No.	Megger Reading
1273-1A	>20 GΩ	1273-14A	>20 GΩ
1273-2A	>20 GΩ	1273-15A	>20 GΩ
1273-3A	>20 GΩ	1273-16A	>20 GΩ
1273-4A	>20 GΩ	1273-17A	>20 GΩ
1273-5A	>20 GΩ	1273-18A	>20 GΩ
1273-6A	>20 GΩ	1273-19A	>20 GΩ
1273-7A	>20 GΩ	1273-20A	>20 GΩ
1273-8A	>20 GΩ	1273-21A	>20 GΩ
1273-9A	>20 GΩ	1273-22A	>20 GΩ
1273-10A	>20 GΩ	1273-23A	>20 GΩ
1273-11A	>20 GΩ	1273-24A	>20 GΩ
1273-12A	>20 GΩ	1273-25A	>20 GΩ
1273-13A	>20 GΩ	1273-26A	>20 GΩ

Note: None of the Road phase insulators failed the megger test.

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Structure 1248, L-178 (Centre phase)

Insulator No.	Megger Reading	Insulator No.	Megger Reading
1273-1B	>20 GΩ	1273-14B	>20 GΩ
1273-2B	>20 GΩ	1273-15B	>20 GΩ
1273-3B	>20 GΩ	1273-16B	>20 GΩ
1273-4B	>20 GΩ	1273-17B	>20 GΩ
1273-5B	>20 GΩ	1273-18B	>20 GΩ
1273-6B	>20 GΩ	1273-19B	>20 GΩ
1273-7B	>20 GΩ	1273-20B	>20 GΩ
1273-8B	>20 GΩ	1273-21B	>20 GΩ
1273-9B	>20 GΩ	1273-22B	>20 GΩ
1273-10B	>20 GΩ	1273-23B	>20 GΩ
1273-11B	>20 GΩ	1273-24B	>20 GΩ
1273-12B	>20 GΩ	1273-25B	>20 GΩ
1273-13B	>20 GΩ	1273-26B	>20 GΩ

Note: None of the Centre phase insulators failed the megger test.

Structure 1248, L-178 (Bush phase)

Insulator No.	Megger Reading	Insulator No.	Megger Reading
1273-1C	>20 GΩ	1273-14C	>20 GΩ
1273-2C	>20 GΩ	1273-15C	>20 GΩ
1273-3C	>20 GΩ	1273-16C	0.2 MΩ
1273-4C	>20 GΩ	1273-17C	>20 GΩ
1273-5C	>20 GΩ	1273-18C	>20 GΩ
1273-6C	>20 GΩ	1273-19C	>20 GΩ
1273-7C	>20 GΩ	1273-20C	>20 GΩ
1273-8C	>20 GΩ	1273-21C	>20 GΩ
1273-9C	>20 GΩ	1273-22C	>20 GΩ
1273-10C	>20 GΩ	1273-23C	>20 GΩ
1273-11C	>20 GΩ	1273-24C	>20 GΩ
1273-12C	>20 GΩ	1273-25C	>20 GΩ
1273-13C	>20 GΩ	1273-26C	>20 GΩ

Note: Insulator 1273-16C of the Bush phase failed the megger test.

7.2 *Visual Examination*

7.2.1 Examination Results

The visual examination looks for any abnormalities or damage in all parts of the insulators i.e. the cap, the porcelain shell the pin and the cement. This examination is used to make an overall visual assessment of the insulator condition.

Structure 1248, L-178 (Road phase)

Insulator No.	Visual Examination Results
1273-1A	15000 lb, No rust on cap, the mould was a little rougher than other insulators. There is a round mould bump on top. The code "HF 8326" was moulded onto the cap. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. The portion of the cap under the lip is not as recessed as other brands. There is a brass coloured sheen in this area; there is a light line of material run off from the cap on the porcelain surface under the lip. There is also a fine line running from the point on the cap to the edge. The porcelain retains its lustre. Some points where the glaze is missing, the surface of the glaze is covered with extremely tiny pits. Light dust covers the surface, common to all. The sheds underneath have a light dust layer. The 3rd skirt in has a portion missing, probably done in disassembly of the strings or shipping. There are some manufacturer defects, such as runny glaze that appears darker and raised. Some tiny points of missed glaze. There is no rust on the pin. The grout looks O.K.
1273-2A	15000 lb, No rust on cap, the mould was a little rougher than other insulators. There is a round mould bump on top. The code "HF 8326" was moulded onto the cap. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. There is brass colour sheen in this area. There is a deposit on the porcelain in this area about 3" long under the cap. The deposit fans out towards the edge. There are 2 flashover marks etched into the porcelain beside this deposit, they converge on a point at the edge. The rest of the porcelain looks good with very tiny pits on the surface. Underneath the point where the tracking occurs there is a similar etching going from shed to shed then along the surface to the pin. There is no damage on the pin. The rest of the porcelain retains its lustre. There are bits of grit glazed into the surface and a lot of pits without glaze. The grout has a single crack otherwise O.K.
1273-3A	15000 lb, No rust on cap, there is a slight brass colour on one side. There is a long triangular stain coming up from the cap bottom; it has a white powder along its perimeter. This area has a concrete deposit on the porcelain for about 5 cm. The top porcelain looks O.K. it still holds its lustre with the same roughened tiny pits on the surface. The porcelain underneath has a hardened dust deposited on its surface on one side about 20%. The three inner sheds have a layer of light brown dirt in the troughs. There are some manufacturer defects like flattened shed, raised surface, tiny points of missed glaze. The pin is O.K. but off centre. Grout looks good.
1273-4A	15000 lb, No rust on cap. The code "HF 8326" was moulded onto the cap. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base, the mould line is raised, the mould plug is raised and rough. There are tiny deposits beneath the cap on the porcelain around most of the circumference. There is a fine layer of dust on the surface, there is tiny pitting on the surface, and there are tiny points where there is no glaze. Underneath the surface has hardened dust that can be removed by wiping with force. The sheds on one side have about 20% of hardened dust in the troughs. The inner shed beside the grout it is baked on. The pin is O.K. with some slag on the surface from manufacture. The grout looks O.K.

The results relate only to the items tested
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Insulator No.	Visual Examination Results
1273-5A	15000 lb, this insulator looks rougher than others, the cap looks rough and the galvanizing is not smooth. There is a rust ring on top outside of the socket possibly from wear as there is some shine on the surface on the other side of the socket. There is little bit of deposit under the cap. The top part of the porcelain still has its lustre but is roughened. The outside edge has had some abrasion as it looks scuffed and lustreless, this could have occurred during shipping. The porcelain underneath has a hardened dust deposited on its surface on one side about 20% There are some manufacturer defects like irregular surfaces on shed and missed glaze. The pin stem looks O.K. but the ball is blackened, there is tinge of rust possibly from arcing. The grout looks O.K.
1273-6A	15000 lb, the cap looks O.K. the socket is blackened, there are some wear patterns on the pin surface. There is one dot of rust on the surface of the cap. The top porcelain looks O.K. but with some tiny pits. Underneath the porcelain there is a light layer of dirt, except around the pin where there is some hardened dust and possibly concrete from the grout. The glaze has some grit in it, the pin looks O.K., and the grout surface is slightly eroded.
1273-7A	15000 lb, No rust on cap, the cap looks O.K. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. There is a fine deposit under cap from dust, the cap itself and cement. There is some light dust on the top porcelain. Underneath the porcelain there is some dense dust. There are some manufacturer defects, some tiny points of missed glaze, same with the top porcelain. The pin is O.K. The grout looks O.K.
1273-8A	15000 lb, No rust on cap. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. There is a 1cm deposit underneath the porcelain; quite thick and cement coloured, it extends and fades as it approaches the porcelain edge in a streaky pattern. There is some electrical etching on this portion. There are tiny points on whole porcelain surface. There is a light layer of dust underneath the porcelain. There are some manufacturer defects, such as runny glaze that appears darker and raised. Some tiny points of missed glaze The pin is O.K. The grout has a 3mm weathered hole against pin.
1273-9A	15000 lb, No rust on cap, the cap looks O.K. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. There is a 2cm concrete colour deposit under this portion and it is fairly thick near the cap then fades towards the edge. There is highly dense dust on the top porcelain. Underneath the porcelain there is some light dust slightly heavier on one side, otherwise it looks good. There are some manufacturer defects, such as some tiny points of missed glaze. The pin is O.K. The grout has one crack and a tiny hole against the porcelain.
1273-10A	15000 lb, No rust on cap. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base, there is a slight brass discolour at this area, the other side of the porcelain has two points that might be slight arc damage, there is a faint line from the cap t the edge that coincides with the two points. There is a slight layer of dust on the top porcelain. The cap has a point of stain with deposit underneath that extends and fades to the edge. Slightly roughened surface, there is a light dust layer

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Insulator No.	Visual Examination Results
	underneath. There are some bits in glaze and pin point glaze flaws. There is a round deposit on porcelain near grout. The pin is O.K. The grout looks O.K.
1273-11A	15000 lb, No rust on cap. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base, at the bottom edge of this area it is darker and rougher, the stain comes to point in within this darker area but light at the point. There is a 4cm deposit on the porcelain underneath the cap that extends the full width but fades around the porcelain edge. There is a thin line etched into this deposit edge. There is light dust on the top porcelain covered with tiny points of glaze. Underneath there is some light dust layered, with some particles in glaze and pin point missed glaze. The pin is O.K. The grout looks O.K.
1273-12A	15000 lb, No rust on cap. There is some cement on the cap. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. There is a large bloom in galvanizing near the socket opening. There is a stain on the cap under the pattern on the porcelain, it extends and fades towards the edge. There is some light dust on the surface underneath. There are some points of exposed glaze, with a couple of bits glazed into the surface. There is a bump beside the inner ring that has some electrical erosion. The pin is O.K. The grout has some cracks
1273-13A	15000 lb, there is a tiny area of rust neat the cotter pin. There is uneven moulding coming off of the cap base to the middle of the cap, at the top of this there is a wear mark, it is hard to tell if it is electrical or mechanical. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. There is a point on the cap with fingers spreading out to the top and cotter pin hole. There is a bright tinge at this area. There is some deposit on the porcelain surface in this area. There is a very faint deposit extending towards the porcelain edge. The top porcelain has lustre and covered with tiny pits. There is some grit glazed into the porcelain. Some accumulation of dirt in one area of skirts underneath heaviest in inner skirt, the rest is fairly clean and retains lustre, some missing points of glaze and glazed over bumps. The pin is O.K. There are a couple of superficial cracks on the grout surface.
1273-14A	15000 lb, No rust on cap. The original moulding is not smooth. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. There is a light deposit on the porcelain under the point about 3cm wide extending and fading towards the porcelain edge. The top porcelain has lustre with tiny pits on the surface, also there are some points with missed glaze, and Some accumulation of dirt in one area of skirts underneath heaviest in inner skirt, the rest is fairly clean and retains lustre. There is a number of glazed bumps on the surface of skirts and one point of missed glaze.
1273-15A	15000 lb, No rust on cap There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. There is a deposit about 5cm under the cap that won't scrape off, it is dark at the cap and lightens as it reaches the cap edge. There are tiny pits on the porcelain surface with some missed glaze parts. Underneath there are a number of points of missing glaze. Irregularities on skirt edges from the moulding.

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Insulator No.	Visual Examination Results
	Lustre O.K. The pin is O.K. The grout looks O.K.
1273-16A	15000 lb, No rust on cap. There are some bits of concrete on it. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base, it has a slight brass colour. There are deposits on porcelain underneath. There is a streak pattern with electrical lines etched in it that extend almost all the way to the porcelain edge. The porcelain has lustre, a point of no glaze and tiny pits. There is high dust accumulation underneath the porcelain, some bits in glaze.
1273-17A	15000 lb, No rust on cap. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base, slight brass colour, There are deposits on porcelain underneath, it extends across porcelain surface to the edge fanning out and fading. The porcelain retains its lustre. Some points where the glaze is missing, the surface of the glaze is covered with extremely tiny pits, there is slight arc damage on the edge. There is a tiny bit of dust underneath. There is arc damage corresponding to the bit on the edge, it extends right to the pin.
1273-18A	15000 lb, No rust on cap There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base, and the base of the cap is much darker. There is a deposit on porcelain underneath about 4cm, the deposit extends and fades to the edge, to the left of this deposit there is a thin arc damage line that extends to the edge then underneath to the pin. The porcelain retains its lustre. Some points where the glaze is missing, the surface of the glaze is covered with extremely tiny pits.
1273-19A	15000 lb, No rust on cap, but rough mould on seams. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. There are some circular marks below socket opening that look like arc damage. There is a light deposit on porcelain under extending and fading towards the porcelain edge. There is a faint layer of dust on the surface. The porcelain retains its lustre. Some points where the glaze is missing, the surface of the glaze is covered with extremely tiny pits. The porcelain underneath looks O.K. There are bits of grout in the glaze, some missing glaze points. The pin is O.K. with a tinge of rust on the bell. The grout looks O.K.
1273-20A	15000 lb, No rust on cap. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. Outside the cap opening there is a large circle of shiny galvanizing with possible electrical lines going through it, the pattern comes to a point on the cap bottom. There is a deposit underneath on the porcelain about 3cm that extends to the porcelain edge fading as it approaches. There appears to be electrical lines etched into this part of the surface. The porcelain retains its lustre. Some points where the glaze is missing, the surface of the glaze is covered with extremely tiny pits. There is light dust on the top and bottom of the shell. There are a number of points missing glaze underneath. There is some grit on the porcelain. The pin is O.K. The grout looks O.K.
1273-21A	15000 lb, No rust on cap. There is no noticeable pattern on the cap as the previous insulators did, but there is a large circle underneath the cap opening. There is no real deposit under the cap on the porcelain. There are very faint fingers that extend from the edge of the cap to the edge of the porcelain. There is not much lustre

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Insulator No.	Visual Examination Results
	underneath; there is a light deposit underneath that is easily scrapped off. There is dirt about 15% on one area of the inner sheds. There are some particles in the glaze. The pin is O.K. The grout looks O.K.
1273-22A	15000 lb, there is a slight tinge of rust on the very top of the cap otherwise the cap is O.K. Porcelain has lustre overall. There are tiny pits on the surface. Underneath the lustre is somewhat lost. There is baked on deposit that can be scrapped off. There is some dirt on the inner rings, one portion about 20%. There is some grout in the glaze with a tiny bit of rust on the pin top.
1273-23A	15000 lb, No rust on cap, there is some discoloration on the bottom edge; the galvanizing has a bloom shape near the opening at the bottom. The top porcelain looks O.K. There is a circular mark on the surface that can't be scratched off. There are a lot of tiny pits on the surface. Underneath the surface has little lustre as there is a film attached to the surface that is wiped off with some force. The two inner skirts on one side have dirt in the recess. There is a mould imperfection, bumps on the skirts and the inner ring. There is some grout in the glaze. The pin is O.K. The grout looks O.K.
1273-24A	15000 lb, There is a tinge of rust at the top and bottom edge. There is a small rust spot just outside the cap opening. There are some rough spots from the galvanizing, also a small chunk of concrete stuck on the surface beside the cap opening. There is also a galvanized bloom beneath the opening, the top porcelain has its lustre but with a lot of tiny pits. There is a circular mark on the surface that can't be scratched off. Underneath there is a thin film on the surface that can be rubbed off with some force. The two inner skirts on one side have dirt in the recess. There are some manufacturer defects, such as moulding flaws, grit in glaze and some tiny points of missed glaze. The pin is O.K. The grout looks O.K.
1273-25A	15000 lb, the cap has very light rust on the opening at the top. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. The porcelain surface underneath this point has a deposit running about 4cm under the cap; the deposit extends to the porcelain edge; narrowing and fading. There are electrical streamers from the cap etched into the surface. The surface is pitted, but it retains its lustre. The underneath retains its lustre. There is dirt between sheds on one side. There are a number of pin points of missing glaze. The pin is O.K. There are some cracks on the grout.
1273-26A	15000 lb, the cap has slight rust on the top edge of the opening. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. Under this point there is a deposit about 3cm wide. It narrows and fades as it reaches the edge of the porcelain. There is some tracking in the deposit, beside this deposit there are 2 spots on the shell possibly from electrical erosions, it appears in one of the spots as if the glaze has lifted off. There are a lot of pits on the surface, and a few spots where the glaze was missed and one large spot without glaze. There are a number of depressions on the surface in this area. Underneath is fairly clean, the lustre is retained. There are some pin points of missing glaze. The pin is O.K. The grout has a couple of cracks.

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Structure 1248, L-178 (Centre phase)

Insulator No.	Visual Examination Results
1273-1B	15000 lb, Cap rust free. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. There is a deposit on the porcelain under the point about 3cm long, it extends halfway to the edge and then fades out. There is some electrical environmental activity on the deposit bot it is not etched in the surface. The surface is pitted but it retains its lustre. Underneath, the porcelain is covered in light dust. There is some grit in the glaze and exposed points of glaze. There are a few moulding flaws. There are some spots of rust at the bottom of the pin ball, otherwise O.K. There is a single crack in the grout.
1273-2B	15000 lb, Cap rust free. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. There is a slight brass colour on this pattern. There is a deposit on the porcelain under the point about 1cm long, it extends halfway to the edge and then fades out. There is some electrical environmental activity on the deposit and around it. There are some fine lines etched into the surface to the edge. The surface is pitted but it retains its lustre. Underneath, the porcelain is covered in light dust. There are a number of fine bits in the glaze. The pin looks O.K. The grout looks O.K.
1273-3B	15000 lb, Cap rust free. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. There is a deposit on the porcelain under the point about 1cm long, it extends halfway to the edge and then fades out. The surface is pitted but it retains its lustre. Underneath, the porcelain is covered in light dust, but it retains its lustre. There are some bits in glaze and some missed glaze points. The pin looks O.K. The grout looks O.K.
1273-4B	15000 lb, Cap rust free. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. There is a bloom circle of galvanizing under the cap opening. There is a deposit on the porcelain under the point about 3cm long, it extends halfway to the edge and then fades out. There is some electrical environmental activity on the deposit bot it is not etched in the surface. The surface is pitted but it retains its lustre. Underneath the porcelain retains good lustre. There are bits of grit in the porcelain. The pin looks O.K. The grout looks O.K.
1273-5B	15000 lb, there is a tiny bit of rust on the top of the cap. Uneven area during original manufactured concrete on surface. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. There is a bloom circle of galvanizing under the cap opening. There is a deposit on the porcelain under the point about 4cm long, it extends halfway to the edge and then fades out. There is some electrical environmental activity on the deposit bot it is not etched in the surface. Some missed glaze points, but still has its lustre. Underneath the porcelain retains its lustre. There are some missed glaze points and some grit in the glaze. The pin looks O.K. The grout looks O.K.
1273-6B	15000 lb, Cap rust free. There is a light stain caused by electrical activity coming

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Insulator No.	Visual Examination Results
	from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. There is a brass hue to this portion. There is a deposit on the porcelain under the point about 1cm long, it extends halfway to the edge and then fades out, there are some electrical streamers in it, a few are etched in and extend to the edge of the porcelain. The deposit fades 1/3 away from the cap. There are some points of missing glaze. There are a couple of circular blemishes permanently on the surface. Underneath the lustre is O.K. There are bits in the glaze and points of missing glaze. The pin looks O.K. The grout has a couple of cracks.
1273-7B	10000 lb, there are light rust marks on some areas of the cap. There is a light stain caused by electrical activity coming from the socket to the cap base, it appears as lines at the top and converges to a point on the cap base. This brand of insulator has a smoother edge on the cap. There is a deposit on the porcelain under the point about 1cm long, it extends halfway to the edge and then fades out. There are some points of missed glaze. The porcelain underneath is in good shape, and it retains its lustre. The pin is O.K. The grout is O.K. but is deep down inside the insulator.
1273-8B	10000 lb, the cap is O.K. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit on the porcelain under the point about, it extends halfway to the edge and then fades out. There is some grit in the glaze, underneath there is good lustre, and a number of points of missed glaze. There is a halo around some areas on sheds where they are bunched points. The glaze around the pin hole has some manufacturer flaws, grit, concrete and thinner glaze. The pin is O.K. but there is erosion on the grout at the glaze interface.
1273-9B	10000 lb, the cap is O.K. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit on the porcelain under the point about 2cm long, it extends halfway to the edge and then fades out. There is electrical activity marks etched into the deposit, the porcelain retains its lustre, and there are some tiny points of missed glaze. The porcelain underneath retains its lustre, but there are a lot of missed glaze points especially in the area nearest to the pin. There are a couple of halos on the shed edges. There are some manufacturer defects in the porcelain around the pin.
1273-10B	10000 lb, the cap is O.K. There is white material in the socket. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit on the porcelain under the point about 1cm long, it extends 1/3 to the edge and then fades out. The porcelain lustre is good; there is a dense dirt layer above and below. There is a good lustre underneath; there is grit in the glaze as well as points of missed glaze or thin glaze. The pin and grout look O.K. There are a couple of halos on the shed edges; they can't be rubbed off, possible flashover marks.
1273-11B	10000 lb, the cap is O.K. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit on the porcelain under the point about 1cm long, it extends halfway to the edge and then fades out. There is electrical activity marks etched into the deposit. The porcelain underneath retains its lustre, but there are a lot of missed glaze points. Underneath the edge where the deposit sits on the top of the shell, there are a couple of metallic looking halos on the shed edges, possibly flashover marks. The pin and grout are O.K.
1273-12B	10000 lb, the cap is O.K. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit on the porcelain, it extends halfway to the edge and then fades out. There is electrical activity marks etched into

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Insulator No.	Visual Examination Results
	the deposit. The porcelain underneath retains its lustre, but there are a lot of missed glaze points. Underneath lustre is good, there are some points of glaze missing, and some manufacturer defects. There is a chunk of porcelain missing from one of the sheds, possibly cracked off during disassembly. The outside shed has a halo spot over from activity on the top shell. The pin and grout are O.K.
1273-13B	15000 lb, the cap has some rust on one side near the opening at the base of the opening and a pin cotter pattern in the opening. There is no patter on the cap like the other insulators did. The top porcelain is O.K. There is pitting on the surface. Underneath there is some dirt on one side between 2 skirts. There is some deposit reducing the porcelain's lustre it can be wiped off with force. There are some bits in the glaze and some points of missed glaze. The pin and grout are O.K.
1273-14B	15000 lb, there is no rust on the cap. There is a circular galvanized bloom below the opening. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit on the porcelain, it extends halfway to the edge and then fades out. The porcelain still has its lustre, there are some concrete deposits under the cap on the porcelain, and there is a lot of pitting. Underneath there is some dirt in between 2 sheds. There is some deposit reducing the porcelain's lustre it can be wiped off with force. There are some bits in the glaze, and some points of missing glaze. The pin and grout are O.K.
1273-15B	15000 lb, there is a tinge of rust on the top. There is one spot of rust at the bottom on mould seam. There is a galvanized bloom under the opening and below at the cap base. The porcelain has some pitting but it retains its lustre. Underneath there is some dirt on one side on the inner 2 skirts. There is some deposit on the surface mostly on the inner area and it reduces the lustre. There are pin points of missed glaze, some bits in the glaze. The pin is O.K. The grout is O.K. Except one area at the pin base where there is a space between the grout and the pin, possibly during manufacture.
1273-16B	15000 lb, there is no rust on the cap. There is a galvanized bloom under the opening and below at the cap base. There is a light stain caused by electrical activity coming from the socket to the cap base. The top porcelain is O.K. There is some pitting and grit in the glaze. There are circular halos on the surface that can't be scrapped off. Underneath there is some dirt on the inner 2 skirts. There is deposit on most of the surface, as well as some mould flaws. The pin and grout look O.K.
1273-17B	15000 lb, there is slight rust on the cap. There is a galvanized bloom under the opening and below at the cap base. There is a light stain caused by electrical activity coming from the socket to the cap base. The top porcelain is O.K. There is some pitting and grit in the glaze. There are circular halos on the surface that can't be scrapped off. Underneath there is some dirt on the inner 2 skirts. There is deposit on most of the surface, as well as some mould flaws. The pin O.K. but not centred, grout looks O.K.
1273-18B	15000 lb, there is a tinge of rust on the cap. There is no pattern on the cap like the previous insulators. The porcelain retains its lustre. There are tiny pits on the porcelain and some bits of missed glaze. There are a few bumps on the surface. There is a deposit underneath on most of the surface. There is some dirt on the 2 inner sheds on one side. The surface on the inner ring is irregular. There are some electric lines at this spot. There is some dirt in the glaze and some missed points of glaze. The pin is O.K. and the grout has uneven surface.

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Insulator No.	Visual Examination Results
1273-19B	15000 lb, the cap is O.K. There is a light stain caused by electrical activity coming from the socket to the cap base which is different from the others; the lines are finer and numerous and converge on a round spot in the middle of the cap. There is a circular bloom on the other side of the cap. The porcelain lustre is O.K. at the top and bottom. There is very little dirt underneath. There are some manufacturer flaws. The pin is O.K. but not centred, the grout has no cracks but there is a hole.
1273-20B	15000 lb, the cap is O.K. There is a large stain caused by electrical activity coming from the socket to the cap base which is different from the others. Below the point there is a very light deposit about 3cm that extends and fades to the porcelain edge. There is electrical activity etched in the surface. There is some lustre on the top porcelain, with small points of missing glaze, there are some grits in the glaze and manufacturer flaws near the centre porcelain near the pin. The pin and grout look O.K.
1273-21B	15000 lb, the cap is rust free. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit on the porcelain under the point about 4cm wide, it extends halfway to the edge and then fades out, there is some electrical activity etched on the surface of the deposit, but it can be wiped off with the deposit. There are some pits in the porcelain. Underneath the porcelain retains its lustre, there are some bits in the glaze and a few points of missing glaze. The pin and the grout look O.K
1273-22B	15000 lb, there is a tinge of rust on the cap opening. There is a light stain caused by electrical activity coming from the socket to the cap base. Underneath the point there is a 3cm deposit, extending and fading towards the edge of the porcelain. There is some electrical activity that etched into the deposit. There are several pits on the porcelain surface. Underneath is fairly clean, there are some missing points of glaze and tiny debris in the glaze. The inner small shed near the pin and grout is deformed in shape and has a concentrated amount of small pits. The pin looks O.K. The grout looks O.K.
1273-23B	15000 lb, the cap is rust free. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a fine deposit on the porcelain under the cap that fades across the porcelain. Underneath there is good lustre, the porcelain has some pits, there are some points of missed glaze and grit in the glaze. The pin looks O.K. The grout has a single crack.
1273-24B	15000 lb, the cap is rust free. There is some concrete on the top of the cap. There is a light stain caused by electrical activity coming from the socket to the cap base, the imprint is quite defined. Underneath the cap there is a deposit about 2cm wide that extends and fades towards the porcelain edge, electrical activity etched into the surface. The top porcelain surface is pitted. Underneath lustre is good, but there is some light dirt. There is some missed glazed and there is grit in the glaze. The pin looks O.K. The grout looks O.K.
1273-25B	15000 lb, there is a tinge of rust on the cap socket. There is not a pattern on the cap like other insulators. There is a weld spot on the centre of the cap on the cotter pit side. In front of it, on the porcelain there is a shiny metallic deposit with flashover marks etched into it. There is a small point of missed glaze on top of the porcelain. Underneath lustre is lost due to deposits, they can be wiped off with force. There are some flaws during manufacturing and point of missed glaze. The pin is O.K. The grout is O.K.

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Insulator No.	Visual Examination Results
1273-26B	15000 lb, The cap is rust free. There is not a pattern on the cap like other insulators. The top porcelain has a darkened chip on the surface. Lustre is O.K. but with some pits on the surface and points of missed glaze. Underneath the inner sheds have baked dirt and a deposit on most of the bottom porcelain. The pattern of dirt around the porcelain suggests heavy electrical activity. There are some pitting and flaws on the surface. There is a bit of rust on the pin top and at pin base/grout interface, also on the pin stem. The grout has a rust colour and one crack.

Structure 1248, L-178 (Bush phase)

Insulator No.	Visual Examination Results
1273-1C	15000 lb, There is a slight tinge of rust at the top of the cap. There is a light stain caused by electrical activity coming from the socket to the cap base. There is no deposit below this point but there is more pitting and a rougher surface on the side. Underneath there is a layer of dirt on one side, and a fine dust cover the rest. Underneath this layer there is a deposit that can be scraped off, it is most noticeable in the centre porcelain near the pin. The deposit has a heavy electrical pattern on its surface. There is some grit in the glaze and a few points of missing glaze. There is a tiny bit of rust on the pin head and the stem/grout interface. The grout is O.K but it has a rust tinge.
1273-2C	15000 lb, There is a slight tinge of rust at the top of the cap. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a small deposit under the cap about 3cm wide that extends 1cm towards the edge of the porcelain. There is a small bloom on the porcelain to the side of the deposit that can't be rubbed off. Underneath the porcelain retains its lustre. There are a number of manufacturer flaws. There are also tiny points of missed glaze. The pin is O.K. The grout is O.K.
1273-3C	15000 lb, the cap is rust free. There is a slight discoloration at the top of the cap. There is some concrete from manufacturing on the cap. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit below the stain underneath the cap about 3cm that extends and narrow to the edge of the porcelain edge. There is a metallic sheen on the deposit next to the cap. There is some electrical activity on the surface of the deposit. The top porcelain has pitting and missed glaze points. Underneath lustre is good, there are some manufacturer flaws. Outside the shed there is a thin line about 1.5cm of missing glaze. The pin is O.K. The grout has a single crack.
1273-4C	15000 lb, there is some rust on the top of the cap and a dark rust pattern alongside near the opening. The galvanizing is rough near the cotter pin and opening. There is a light stain caused by electrical activity coming from the socket to the cap base. The metal is a brass colour. There is some concrete from manufacturing at the bottom of the cap. There is a deposit about 2cm on the porcelain underneath the cap, it extends and fades towards the porcelain edge. Lustre on top porcelain is O.K. There is some pitting. Underneath the lustre is good. There is a small chip on the second shed from the pin. There are some bits in the glaze. The pin is O.K. The grout is O.K.
1273-5C	10000 lb, There is a small amount of rust at the top of the cap. Lustre is good .

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Insulator No.	Visual Examination Results
	There are some points of missing glaze. Underneath there is dirt in between two rings on one side. There is a light deposit on the rest of the bottom porcelain. There are a number of tiny points of missed glaze. There is a "W" stamp in the middle near the pin. There is some electrical activity etched into this area. The pin is set deep in the insulator, and the grout is about 1.5cm down.
1273-6C	10000 lb, there is a small amount of rust at the top of the cap. Lustre is good . There are some points of missing glaze. Underneath there is dirt in between two rings on one side. There is a light deposit on the rest of the bottom porcelain. There are a number of tiny points of missed glaze. There is a "W" stamp in the middle near the pin. There is some electrical activity etched into this area. The pin is O.K. The grout is O.K.
1273-7C	15000 lb, there is no rust on the cap. There is a light stain caused by electrical activity coming from the socket to the cap base. There is some discoloration where the stain pattern is. Underneath the cap there is a deposit on the porcelain about 3cm wide that extends and fades towards the edge. There is some electrical activity on the surface of the deposit; one line is faintly etched in the surface. The top porcelain has tiny pits, there are a couple of points of missed glaze. Underneath lustre is good, there are some manufacturer flaws on the inner ring closest to the pin, it also has a number of concentrated pits.
1273-8C	15000 lb, there is no rust on the cap. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit underneath the cap on the porcelain about 4cm wide that extends and fades towards the edge. There is some electrical activity on the deposit with a couple of lines slightly etched in the porcelain surface. There are tiny pits on the surface of the porcelain. Underneath there is good lustre, there are some pin points of missing glaze and a bit of grit in the glaze. The pin is O.K. The grout has a single crack.
1273-9C	15000 lb, there is no rust on the cap. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit underneath the cap below the stain patter about 4cm wide that narrows and fades towards the porcelain edge. There is some electrical activity etched in the deposit. The porcelain has some points of missed glaze. There are some manufacture flaws like bumps and flat spots on the sheds. The pin is O.K. The grout is O.K.
1273-10C	15000 lb, there is a slight tinge of rust on the top of the cap. There are bits of concrete on the surface. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit on the porcelain at this point below the cap about 3cm wide that extends and fades towards the porcelain edge. There is some electrical activity etched into the deposit. The top porcelain has some grit in the glaze. The surface is pitted. There are a couple of points of missed glaze. Underneath the porcelain still has good lustre. There are several pin points of missed glaze, uneven surfaces. The centre ring around the pin has little lustre. The pin is O.K. The grout is O.K.
1273-11C	10000 lb, There is some rust on the side at the seam. There is no stain on the cap as the other insulators did. The porcelain has good lustre with some points of missed glaze. Most of the porcelain has some dirt on it. There is some grit in the glaze. The pin is O.K. The grout is O.K.
1273-12C	10000lb, there is no rust on the cap. There is no stain on the cap as other insulators did. The top porcelain has good lustre. There are several pin points of missed glaze,

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Insulator No.	Visual Examination Results
	and there is some grit in the glaze. Underneath there is some dirt on the two inner rings. There are deposits on most of the bottom porcelain reducing its lustre. There are a number of points missing glaze. The pin is O.K. The grout is roughened but O.K.
1273-13C	15000 lb, there is a tinge of rust on the cap. There is a light stain caused by electrical activity coming from the socket to the cap base. The cap is discoloured at the stain. There is a 3cm wide deposit on the porcelain underneath the cap that extends and fades towards the porcelain edge. There is electrical activity etched in the deposit, with a metallic sheen to it. There are some pits on the surface. Underneath the lustre is good, but there are tiny bits of concrete on the surface, tiny bits of missing glaze, and a few missed glaze points. The pin is O.K. The grout is O.K.
1273-14C	15000 lb, There are a couple of tiny rust spots on top of the cap. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit about 3cm that extends and fades towards the porcelain edge. The top porcelain is pitted and there are tiny points of missed glaze. There is a single piece of grout in the glaze. Underneath the glaze is good, but there are bits of missed glaze. There are some manufacture flaws, flattened surface on the sheds, runny glaze. The pin is O.K. The grout has a single crack.
1273-15C	15000 lb, There is no rust on the cap. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit about 2cm that extends and fades towards the porcelain edge. There is some electrical activity etched into the deposit. The top porcelain is pitted and there are tiny points of missed glaze. Underneath the lustre is good. There are bits of missed glaze. The pin is O.K. The grout has a crack with a hole in it.
1273-16C	15000 lb, There is no rust on the cap. This sample is marked “punctured 0.2MΩ”. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit about 1cm that extends and fades towards the porcelain edge. There is some electrical activity etched into the deposit. The top porcelain is pitted and there are tiny points of missed glaze. There is a single bloom on the porcelain. Underneath the lustre is good, but there are some bits in the glaze. There are some manufacture flaws like flattened porcelain on the sheds. The pin is O.K. The grout is O.K.
1273-17C	15000 lb, There is a tiny bit of rust on the top. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit about 3cm that extends and fades towards the porcelain edge. There is some electrical activity etched into the deposit. There is a circular bloom near the edge. There are bits of missed glaze. Underneath the lustre is good There are bits of missed glaze. The centre porcelain around pin has glaze erosion. The pin is O.K. The grout is O.K.
1273-18C	15000 lb, there is a tinge of rust on the cap. There is a galvanizing bloom near the opening. There is no stain pattern like other insulators did. The porcelain is pitted. Underneath the lustre is hidden by deposit on most of the surface it can be rubbed off with force. There is some dirt on one side of the inner rings. There is some grit in the glaze and a few pin points of missed glaze. The pin is O.K. The grout is O.K.
1273-19C	15000 lb, there is no rust on the cap. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit about 3cm that extends and fades towards the porcelain edge. The porcelain is pitted. There are

Insulator No.	Visual Examination Results
	bits of missed glaze. There is a bloom on the surface. Underneath the lustre is good. There are bits of missed glaze. The pin is O.K. The grout is O.K.
1273-20C	15000 lb, there is no rust on the cap, but does have 4 arc damage points. One below the cotter pin and three in line under the side of opening. There are a couple of light arc marks in line on the porcelain. The surface under the cap is rough and has a tiny bit of porcelain damage. There is a faint pattern on the cotter pin side that includes the one arc point on the cap. There is a small deposit that extends and fades towards the porcelain edge. The top porcelain is pitted and there are tiny points of missed glaze. There is no arc damage underneath. There are some manufacture flaws. The pin is O.K. The grout is O.K.
1273-21C	15000 lb, there is no rust on the cap. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit about 3cm that extends and fades towards the porcelain edge. There is some electrical activity etched into the deposit. The top porcelain is pitted and there are tiny points of missed glaze. The lustre is less than others. Underneath the lustre is good. There is some arc damage on the edge of the outer shed. There are some manufacture flaws. The pin is O.K. The grout is O.K.
1273-22C	15000 lb, there is a tinge of rust on the cap. There is some concrete on the surface. There is a light stain caused by electrical activity coming from the socket to the cap base. There is a deposit about 2cm that extends and fades towards the porcelain edge. There is some electrical activity etched into the deposit. The lustre is good but there are pits and points of missed glaze. Underneath there is arc damage in a small area on the 3 outer sheds. The 2nd shed is discoloured, showing high temperature damage. The rest of the area looks good with lustre. There are bits of missed glaze. The pin is O.K. The grout is uneven with a hole at the base of the pin.
1273-23C	15000 lb, there is no rust on the cap, but some discoloration on one side. There is a light stain caused by electrical activity coming from the socket to the cap base. There are a couple of arc marks around the cotter pin area and one near opening. There is a deposit about 3cm that extends and fades towards the porcelain edge. There is some electrical activity etched into the deposit. The top porcelain is pitted and there are tiny points of missed glaze. Underneath the lustre is good There are bits of missed glaze. The pin is O.K. The grout is O.K.
1273-24C	15000 lb, there is no rust on the cap. There is a light stain caused by electrical activity coming from the socket to the cap base. The cap is discoloured at the stain patter. There is a deposit about 3cm that extends and fades towards the porcelain edge. There is some electrical activity etched into the deposit. The top porcelain is pitted and there are tiny points of missed glaze. There are some manufacture flaws underneath, runny glaze, irregular bumps on sheds, bits in glaze. The pin is O.K. The grout is O.K.
1273-25C	10000 lb, there is a tinge of rust on the cap. There is no stain pattern like other insulators did. The top porcelain has good lustre. There are bits of missed glaze. There is a metallic stain on the surface, not sure if it is from a tool or arc damage, it can't be scrapped off. Underneath is quite dirty; there is an electrical pattern in the dirt. There is some missed glaze on the inner shed by the pin. There are pin points of missing glaze. The pin is O.K. but off centre. The grout is O.K.

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Insulator No.	Visual Examination Results
1273-26C	10000 lb, there is no rust on the cap. There is no stain pattern like other insulators did. The lustre is good but there is some grit in the glaze and there are bits of missed glaze. Underneath is quite dirty. There is some missed glaze. The lustre is hidden by the dirt and surface deposits can be wiped with force. The pin and grout are O.K.

7.2.2 Main findings in the visual inspections:

Visual inspection shows these insulator strings had some electrical and environmental damage. The inspections found evidence on all of the insulator strings of some electrical activities such as: flashover and electrical discharge. This electrical activity indicates that all of these insulators have been subjected to higher than normal leakage current. Many of the insulators in all the strings have cracks in the grout; however, there was no significant loss of grout observed. The cracks are typical of old insulators and are not an immediate concern unless accompanied by loss of grout.

Figures 1 to 3 shows examples of electrical damage:

Figure 1 – Stain from the cap that extends and fades towards the porcelain edge.

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Figure 2 - Electrical activity etched in the stain,

Figure 3 – Arcing damage

7.3 *ESDD Measurement*

7.3.1 Test Description:

The ESDD test (Equivalent Salt Deposit Density-IEEE Std. 4) is a measure of the pollution level on the insulators. The pollutant on the upper and the lower surfaces of the insulators was washed off separately and the ESDD was determined for each surface.

Two insulators from each of the three different insulator sets were tested.

7.3.2 Test Results:

Insulator Sample No.	ESDD (mg/cm^2)
1273-20A Top	0.014925
1273-20A Bot	0.007788
1273-6A Top	0.014433
1273-6A Bot	0.017628
1273-11B Top	0.019195
1273-11B Bot	0.009725
1273-17B Top	0.014343
1273-17B Bot	0.013867
1273-25C Top	0.015205
1273-25C Bot	0.01653
1273-8C Top	0.014817
1273-8C Bot	0.007517

According to the information from IEC Standard 815, the ESDD level on an insulator below 0.03 mg/cm^2 is generally considered to be very light pollution level. The results from the ESDD measurement on these insulators show that the pollution level was lower than a "very light pollution level" on all the insulators tested.

7.4 *Radio Interference Test*

7.4.1 Acceptance Criterion

According to the CSA standard each of five tested insulators shall meet the requirements for maximum radio interference voltage (RIV). If one insulator fails an additional five insulators are to be tested. In this investigation all 78 insulators were tested in order to give an overall picture of the condition of the insulators on the 138 kV transmission line.

Rating: < 50 µV @ 1 MHz, using an applied test voltage of 10 kV rms.

A high RIV reading indicates that there is partial discharge activity on the insulators which means that there is some damage to the insulator. This test is normally done as type test but no insulator in service should exhibit high RIV (partial discharge) levels. The high RIV level

can be caused by external problems with the insulators (such as glaze damage) or to internal problems (such as cracks).

7.4.2 Atmospheric Test Conditions

Test date:	May 2, 2016	May 3, 2016
Barometric pressure:	752.2 mmHg	758.1 mmHg
Temperature, dry-bulb:	21.2 °C	22.2 °C
Relative humidity:	34.0 %	44.0 %

Background RIV = <1.0 µV @ 1 MHz at an applied test voltage of 10 kV rms

7.4.3 Test Results

Note: In the following tables all insulators that had an RIV above 50 µV electrical or mechanical failure below the rating of 15 kip are highlighted in red.

Structure 1248, L-178 (Road phase)

Insulator No.	Name on the Glaze	Radio-influence voltage (µV)	Insulator No.	Name on the Glaze	Radio-influence voltage (µV)
1273-1A	England	0.75	1273-14A	England	94.5
1273-2A	England	0.56	1273-15A	England	0.67
1273-3A	England	3.67	1273-16A	England	2.62
1273-4A	England	2.25	1273-17A	England	0.67
1273-5A	England	0.75	1273-18A	England	0.56
1273-6A	England	2.62	1273-19A	England	0.41
1273-7A	England	2.43	1273-20A	England	0.71
1273-8A	England	0.56	1273-21A	England	0.75
1273-9A	England	0.56	1273-22A	England	94.1
1273-10A	England	0.93	1273-23A	England	0.63
1273-11A	England	0.45	1273-24A	England	1.12
1273-12A	England	1.12	1273-25A	England	0.75
1273-13A	England	0.56	1273-26A	England	0.75

Structure 1248, L-178 (Centre phase)

Insulator No.	Name on the Glaze	Radio-influence voltage (µV)	Insulator No.	Name on the Glaze	Radio-influence voltage (µV)
1273-1B	England	1.50	1273-14B	England	1.50
1273-2B	England	1.68	1273-15B	England	52.5
1273-3B	England	0.93	1273-16B	England	0.56
1273-4B	England	1.12	1273-17B	England	2.62
1273-5B	England	2.43	1273-18B	England	1.50
1273-6B	England	2.25	1273-19B	England	9.37

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1273-7B	Buller's	0.67	1273-20B	England	2.06
1273-8B	Buller's	0.93	1273-21B	England	1.31
1273-9B	Buller's	9.37	1273-22B	England	2.06
1273-10B	Buller's	2.06	1273-23B	England	0.75
1273-11B	Buller's	52.5	1273-24B	England	1.12
1273-12B	Buller's	0.56	1273-25B	England	2.06
1273-13B	England	45.0	1273-26B	England	0.56

Structure 1248, L-178 (Bush phase)

Insulator No.	Name on the Glaze	Radio-influence voltage (µV)	Insulator No.	Name on the Glaze	Radio-influence voltage (µV)
1273-1C	England	0.75	1273-14C	England	0.48
1273-2C	England	0.75	1273-15C	England	1.87
1273-3C	England	0.56	1273-16C	England	Punctured-not tested
1273-4C	England	0.75	1273-17C	England	2.25
1273-5C	England	0.56	1273-18C	England	0.56
1273-6C	Buller's	1.12	1273-19C	England	0.75
1273-7C	England	0.56	1273-20C	England	1.12
1273-8C	England	0.56	1273-21C	England	56.2
1273-9C	England	1.50	1273-22C	England	2.25
1273-10C	England	0.75	1273-23C	England	1.68
1273-11C	Buller's	6.00	1273-24C	England	1.68
1273-12C	Buller's	9.37	1273-25C	Buller's	2.25
1273-13C	England	1.50	1273-26C	Buller's	0.93

7.4.4 Summary of RIV test results:

The radio-interference voltage of all the insulators was measured.

The overall failure rate of the insulators was 6% (5 out of 78). These insulators failed the radio-interference voltage test.

7.5 *Dry Power-Frequency Voltage Flashover Test*

7.5.1 Acceptance Criterion

The insulators pass the test, if the average dry flashover voltage of three tested insulators is equal to or exceeds 95% of the rated dry flashover value of 80 kV (corrected to standard atmospheric conditions) and no insulators are punctured. For evaluation purpose all the insulators were tested and they were evaluated on the basis of the complete string.

7.5.2 Test Procedure

The applied voltage to the insulator was initially increased to approximately 75% of its flashover value. Then it was increased gradually with a rate of rise of about 2% of the estimated flashover voltage (80 kV) per second until the flashover voltage was reached. Five flashover values were obtained per insulator.

7.5.3 Atmospheric Test Conditions

Date of test:	2 May 2016	3 May 2016
Barometric pressure:	757.2 mmHg	758.1 mmHg
Temperature dry-bulb:	21.2 °C	22.2 °C
Relative humidity:	39.2 %	44.0 %

Note: Test results are corrected to standard atmospheric conditions, as specified by the test standards, so that the evaluation of the results is based on the same atmospheric conditions.

7.5.4 Test Results

Note: In the following tables all insulators that had an RIV above 50 µV electrical or mechanical failure below the rating of 15 kip are highlighted in red.

Structure 1248, L-178 (Road phase)

Insulator No.	Flashover Voltage (kV)	Flashover Voltage (kV)	Flashover Voltage (kV)	Flashover Voltage (kV)	Flashover Voltage (kV)	Average Flashover Voltage (kV)	
1273-1A	80.48	77.84	77.68	76.64	76.78	76.41	
1273-2A	76.24	76.00	76.32	74.24	78.24	76.20	
1273-3A	76.44	76.16	76.48	76.00	76.96	76.41	
1273-4A	74.64	77.84	75.20	77.20	76.88	76.35	
1273-5A	74.64	75.12	74.16	76.00	77.44	75.47	
1273-6A	79.20	77.76	74.12	77.60	77.04	77.14	
1273-7A	76.80	76.80	76.80	75.20	75.20	76.16	
1273-8A	76.00	76.00	76.00	75.20	73.60	75.36	
1273-9A	76.00	76.80	76.80	76.00	77.60	76.64	
1273-10A	73.60	73.60	74.40	76.00	76.80	74.88	
1273-11A	75.76	74.72	73.20	74.16	73.60	74.28	
1273-12A	80.40	78.16	77.60	76.64	76.56	77.87	
1273-13A	75.84	76.64	79.76	78.16	77.88	77.65	
1273-14A	78.40	77.40	78.40	79.28	79.12	75.52	
1273-15A	77.40	76.60	75.60	76.08	77.12	76.56	
1273-16A	77.60	78.20	78.00	75.40	78.16	77.47	
1273-17A	75.80	79.80	77.00	75.60	77.50	77.14	
1273-18A	75.20	75.20	77.60	76.80	76.00	76.16	
1273-19A	77.28	80.48	79.68	77.04	77.92	78.48	
1273-20A	75.04	76.72	77.44	78.00	80.32	77.50	
1273-21A	77.76	75.68	74.16	75.70	76.16	75.89	
1273-22A	22.32	20.80	20.80	22.96	20.00	21.37	
1273-23A	77.70	75.40	74.64	76.60	74.30	75.74	

Not Corrected 74.2

Corrected to standard atmospheric conditions 75.0

Insulator No.	Flashover Voltage (kV)	Flashover Voltage (kV)	Flashover Voltage (kV)	Flashover Voltage (kV)	Flashover Voltage (kV)	Average Flashover Voltage (kV)	
1273-24A	75.50	75.40	75.10	74.90	75.04	75.18	
1273-25A	74.40	75.20	74.40	73.60	76.00	74.72	
1273-26A	77.60	76.80	79.20	74.40	76.80	76.96	

Structure 1248, L-178 (Centre phase)

Insulator No.	Flashover Voltage (kV)	Flashover Voltage (kV)	Flashover Voltage (kV)	Flashover Voltage (kV)	Flashover Voltage (kV)	Average Flashover Voltage (kV)	
1273-1B	73.92	75.52	76.16	76.96	78.08	76.12	Not Corrected 74.8 Corrected to standard atmospheric conditions 75.6
1273-2B	74.56	78.00	76.16	76.64	77.76	76.62	
1273-3B	77.60	75.36	77.68	75.28	77.60	76.70	
1273-4B	77.28	77.12	81.84	78.80	77.84	78.57	
1273-5B	75.68	76.80	77.36	79.36	75.44	76.92	
1273-6B	75.12	77.92	76.80	75.28	77.60	76.40	
1273-7B	70.16	72.40	71.76	73.92	72.72	72.19	
1273-8B	71.20	71.68	72.00	73.60	71.84	72.06	
1273-9B	72.24	71.76	71.76	72.96	71.44	72.03	
1273-10B	72.80	72.64	72.32	74.16	72.96	72.97	
1273-11B	73.52	73.44	72.08	73.60	72.96	73.12	
1273-12B	73.36	73.36	71.12	74.08	73.84	73.15	
1273-13B	76.56	76.08	74.88	75.84	74.48	75.56	
1273-14B	76.80	76.64	76.16	77.16	76.24	76.60	
1273-15B	78.24	76.56	76.48	76.00	77.60	76.96	
1273-16B	75.92	76.08	76.08	76.24	77.44	76.35	
1273-17B	72.32	74.96	74.64	73.44	74.64	74.00	
1273-18B	76.96	76.40	75.84	76.48	76.48	76.38	
1273-19B	75.76	73.10	73.68	74.08	74.00	74.12	
1273-20B	77.60	76.64	76.24	75.28	78.00	76.75	
1273-21B	77.68	76.48	75.84	73.60	76.80	76.08	
1273-22B	75.36	74.16	75.36	73.68	74.96	74.70	
1273-23B	75.68	75.92	74.56	76.00	74.40	75.31	
1273-24B	77.28	78.88	76.08	75.92	78.16	77.26	
1273-25B	75.60	76.64	76.24	77.20	80.3	77.20	
1273-26B	75.44	73.44	75.60	77.20	punctured	60.33	

Structure 1248, L-178 (Bush phase)

Insulator No.	Flashover Voltage (kV)	Flashover Voltage (kV)	Flashover Voltage (kV)	Flashover Voltage (kV)	Flashover Voltage (kV)	Average FLO Voltage (kV)	
1273-1C	78.32	79.36	77.28	77.92	76.48	77.87	Not Corrected 71.7 Corrected to standard atmospheric
1273-2C	74.32	73.52	76.08	72.56	74.56	74.20	
1273-3C	76.80	74.80	74.40	74.96	75.44	75.28	
1273-4C	71.52	73.12	73.52	74.96	73.84	73.39	
1273-5C	70.72	78.12	69.76	69.28	67.76	69.12	
1273-6C	73.36	72.08	72.56	72.56	71.04	72.32	
1273-7C	77.28	75.92	76.48	76.48	74.40	76.11	
1273-8C	74.16	75.08	76.00	74.80	75.36	75.08	

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1273-9C	77.84	75.76	78.80	77.12	78.40	77.58	conditions
1273-10C	72.40	76.08	76.0	76.96	73.12	74.91	72.4
1273-11C	69.68	67.28	72.88	68.48	70.48	69.76	
1273-12C	71.36	68.88	71.36	71.68	74.32	71.52	
1273-13C	76.80	80.24	79.68	75.84	76.88	77.88	
1273-14C	73.68	74.80	72.16	74.80	74.80	74.04	
1273-15C	73.28	73.12	78.48	76.80	78.16	75.96	
1273-16C	punctured						
1273-17C	75.20	77.84	78.16	80.16	75.84	77.40	
1273-18C	76.08	77.20	75.84	74.28	77.12	76.10	
1273-19C	77.68	78.80	78.24	74.96	77.12	77.36	
1273-20C	75.60	75.76	75.36	75.52	76.56	75.75	
1273-21C	74.40	74.72	74.40	72.00	75.60	74.22	
1273-22C	75.60	78.80	73.36	76.48	73.92	75.63	
1273-23C	79.52	75.20	75.76	74.72	75.84	76.20	
1273-24C	75.60	72.00	74.24	72.96	75.52	74.06	
1273-25C	70.64	69.94	71.28	72.32	73.52	71.54	
1273-26C	71.92	69.84	71.76	71.28	69.52	70.86	

Overall the insulators fail the requirements of CAN/CSA-C411.1-M89, Clause 5.3: "Dry power frequency voltage tests". The corrected average flashover voltage was <76 kV (95% x 80 kV). There were two insulator punctures and one cracked insulator (very low flashover voltage of 21 kV).

7.6 *Assessment of Corrosion*

7.6.1 Condition Assessment of Insulators

The condition of the galvanized fittings and grouted interfaces were assessed with respect to corrosion attack. The samples were subjected to the following examinations:

- Visual Examination of Galvanized Fittings and Grouted Interfaces
- Energy Dispersive X-ray Spectroscopy
- Coating Thickness Measurements

7.6.2 Visual Examination

All sample sets showed varying degrees of similar features, with the following observations noted:

- The galvanized cap and pin of the insulators are in excellent condition. The majority of samples do not exhibit any corrosion product on the surface. Several samples were noted having a white crystalline corrosion product present on the cap; typical of minor corrosion attack of a galvanized coating. However, the amount of corrosion product was minor and the presence of the zinc corrosion products is actually beneficial, as they are adherent and fairly insoluble; acting as a passive layer to slow the effective corrosion rate as time progresses and the corrosion product builds. The typical surface condition of the galvanized caps is seen in Figures 4 and 5.

- Several samples sets showed dust like debris primarily on the bottom side of the sheds, seen in Figure 6

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- The grout condition on the underside of the insulators is also in good condition, with no cracking, shrinkage or porosity noted in the grout. Similarly no features of cement growth phenomena which can lead to cracking in the shells was noted. Examples of the grout condition is seen in Figure 4

Figure 4: Overall Condition of In-Service Insulators. No apparent corrosion attack of the galvanized coating is noted in the majority of samples.

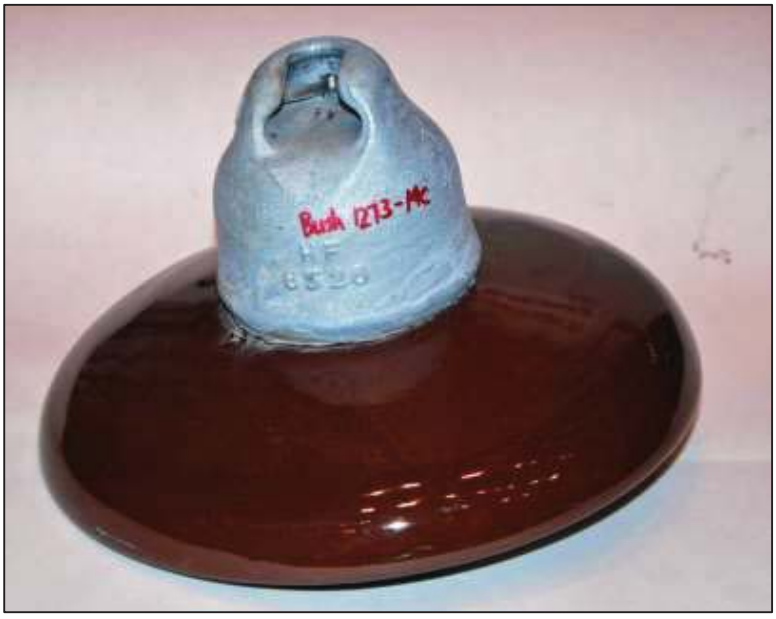


Figure 5: Example of insulator containing a small amount white crystalline deposit on cap of

insulator.

Figure 6: Debris present on underside of insulator sheds. Also note good condition of grout

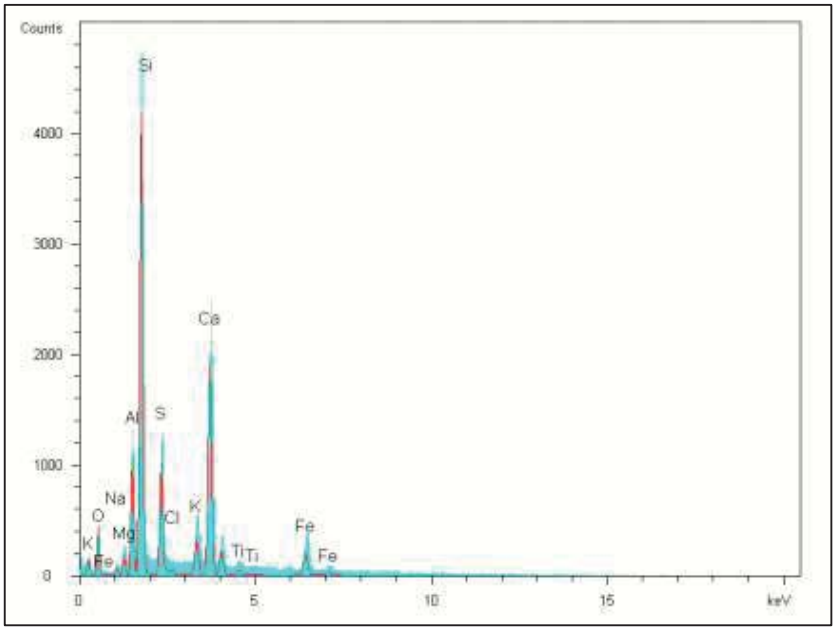
Figure 7: Typical condition of underside of insulator, with no dust like debris on underside

7.6.3 Energy Dispersive X-ray Spectroscopy

The general dust like debris on the underside of several sheds noted in the assessment was sampled from the insulators. The collected material was then placed in a Hitachi SU1510 Scanning Electron Microscope and analyzed by Energy Dispersive X-ray Spectroscopy (EDS) to determine the elemental composition.

A representative EDS spectrums obtained from the analyses is seen in Figure 5.

The dust debris on the underside of the sheds consisted primarily of silicon (Si), calcium (Ca), aluminum (Al), and sulphur (S), as expected for general dust contamination (Figure 7). Minor concentrations of potassium (K), iron (Fe), magnesium (Mg) and sodium (Na) were also noted in the spectrum, elements that are also commonly attributed to general dust contamination. While sulphur can act as a corrosion accelerant, this typically occurs in environments where there is continuous wet / dry cycling. The presence of sulphur in the debris on the sheds of the insulators is clearly not causing corrosion, as the galvanized components are in excellent condition.



7.6.4 Coating Thickness Measurements

The coating thickness of the cap and pin of selected insulators was measured using a PosiTector 6000 coating thickness gage. At each test location, the surface of the area tested was cleaned of any surface debris. Three reading were performed in each area, and the average value reported. The results of the coating thickness measurements are seen summarized in Table 1.
There was minor variation in the coating thickness between samples, however all samples tested show a significant remaining coating thickness, with the current values consistent with a newly hot dip galvanized product

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Table 1: Coating Thickness Measurements

Sample ID	Coating Thickness Readings Cap (mils)			Avg. Coating Thickness Cap (mils)	Coating Thickness Readings Pin (mils)			Avg. Coating Thickness Pin (mils)
1273-3A	5.4	6.3	6.7	**6.1**	4.6	5.0	5.4	**5.0**
1273-20A	6.0	5.9	6.4	**6.1**	6.0	5.2	5.8	**5.7**
1273-13B	5.8	5.2	6.0	**5.7**	6.4	6.4	6.0	**6.3**
1273-25B	7.2	6.4	6.6	**6.7**	6.3	5.9	6.1	**6.1**
1273-9C	5.6	5.8	5.4	**5.6**	5.6	6.5	6.1	**6.1**
1273-14C	6.1	5.4	6.4	**6.0**	4.9	5.4	5.3	**5.2**

7.7 *Electro-mechanical Failing Load Test*

7.7.1 Test Procedure

Each insulator was tested individually. The insulator was subjected to a mechanical load with the load initially increased rapidly and smoothly from zero to approximately 11.3 kip (75 % of the specified electromechanical failing load). It was then increased at a rate between 35% to 100% of the rating per minute until the failing load was reached. Simultaneously, a 60 Hz voltage of 60 kV was applied to the tested insulator - an internal electrical discharge would indicate that a mechanical failure of the insulating part (porcelain shell) has occurred prior to the mechanical failure. An electrical failure causes the circuit breaker on the high voltage to trip. The load at which this occurs is recorded while the mechanical load increase is continued at the same rate till the mechanical failing load is reached. The electrical (E) and mechanical (M) failure loads were both recorded.

7.7.2 Acceptance Criteria

The insulators pass the test if the tested units (normally ten insulators. in this case the complete set of 26 insulators was evaluated) comply with the electro-mechanical failing load test requirements of CAN/CSA-C411.1-M89, Clause 6.6 as follows:

(a) $X \geq R + 3S$

where X = mean value of the lowest (electrical or mechanical) individual failing load test
R = specified failing load (rating) of 15 kN
S = standard deviation of sample test units provided by the formula

$$S = \sqrt{\frac{(X_1 - \overline{X})^2 + (X_2 - \overline{X})^2 + \cdots (X_N - \overline{X})^2}{N - 1}}$$

where

N = number of units tested

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(b) each value measured should be equal to or greater than the rating of 15 kip ($X_i \geq R$)

where

X_i = each individual failing load value measured
i = 1, 2, 3, … N

7.7.3 Test Results

Note: In the following tables all insulators that had an electrical or mechanical failure below the rating of 15 kip are highlighted in red.

Structure 1248, L-178 (Road phase)

Insulator Sample No.	Failure load (kip) (Electrical)	Failure load (kip) (Mechanical)	Mechanical Failure mode	Initial Failure Mode (M or E)	Acceptance parameters		
					X (kip)	S (kip)	X + 3 x S (kip)
1273-1A	14	19	Pin stretch and pullout	E	Electrical 16.2 Mechanical 20.2	Electrical 5.2 Mechanical 1.4	Electrical 15 + 3x5.2 = 30.7 16.2<30.7 Mechanical 19.3 20.2>19.3
1273-2A	21	21	Pin pullout	E			
1273-3A	18	18	Pin pullout	M			
1273-4A	20	21	Pin pullout	Both			
1273-5A	18	19	Pin stretch and pullout	E			
1273-6A	21	21	Pin pullout	Both			
1273-7A	21	21	Cap pullout, pin loose	Both			
1273-8A	17	22	Pin pullout	E			
1273-9A	13	19	Pin pullout	E			
1273-10A	21	21	Pin pullout	E			
1273-11A	20	20	Pin pullout	M			
1273-12A	17	17	Pin pullout	M			
1273-13A	14	19	Cap pullout, pin loose	E			
1273-14A	14	19	Pin pullout	E			
1273-15A	13	19	Pin stretch and pullout	E			
1273-16A	23	23	Cap pull out	Both			
1273-17A	17	19	Pin pullout	E			
1273-18A	20	20	Pin pullout	M			
1273-19A	15	20	Cap pullout, pin loose	E			
1273-20A	5	23	Pin pullout	E			
1273-21A	17	20	Pin stretch and pullout	E			
1273-22A	0	21	Porcelain already cracked	E			
1273-23A	20	20	Pin pullout	E			
1273-24A	19	20	Pin stretch and pullout	E			

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Insulator Sample No.	Failure load (kip) (Electrical)	Failure load (kip) (Mechanical)	Mechanical Failure mode	Initial Failure Mode (M or E)	Acceptance parameters		
					X (kip)	S (kip)	X + 3 x S (kip)
1273-25A	12	22	Pin stretch and pullout	E			
1273-26A	11	20	Pin pullout	E			

Road phase individual insulators summary:

Insulators Tested	Electrical Failures (<15 kip)	Mechanical Failures (<15 kip)	Total Failures (<15 kip)
26	8 (30 %)	0 (0 %)	8 (30 %)

Structure 1248, L-178 (Centre phase)

Insulator Sample No.	Failure load (kip) (Electrical)	Failure load (kip) (Mechanical)	Mechanical Failure mode	Initial Failure Mode (M or E)	Acceptance parameters		
					X (kip)	S (kip)	X + 3 x S (kip)
1273-1B	18	22	Pin stretch and pullout	E	Electrical 18.0 Mechanical 19.3	Electrical 3.1 Mechanical 2.5	Electrical 15 + 3x3.1 = 24.3 18.0<24.3 Mechanical 15 + 3x2.5 = 22.5 19.3<22.5
1273-2B	15	18	Pin pullout	E			
1273-3B	14	16	Pin stretch and pullout	E			
1273-4B	16	16	Pin stretch and pullout	M			
1273-5B	20	20	Pin stretch and pullout	M			
1273-6B	18	21	Cap pullout	E			
1273-7B (10 kip)	17	17	Cap pullout, pin loose	E			
1273-8B (10 kip)	11	16	Cap pullout	E			
1273-9B (10 kip)	20	20	Cap pullout	Both			
1273-10B (10 kip)	23	23	Cap pullout, pin loose	Both			
1273-11B (10 kip)	14	15	Cap pullout	E			
1273-12B (10 kip)	14	18	Cap pullout	E			
1273-13B	19	23	Cap pullout, pin loose	E			
1273-14B	19	19	Cap pullout Pin pullout	Both			
1273-15B	23	23	Pin stretch and pullout	M			
1273-16B	20	20	Pin stretch and pullout	M			

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Insulator Sample No.	Failure load (kip) (Electrical)	Failure load (kip) (Mechanical)	Mechanical Failure mode	Initial Failure Mode (M or E)	Acceptance parameters		
					X (kip)	S (kip)	X + 3 x S (kip)
1273-17B	21	22	Pin stretch and pullout	E			
1273-18B	20	20	Pin stretch and pullout	M			
1273-19B	19	19	Pin stretch and pullout	M			
1273-20B	15	21	Pin stretch and pullout	E			
1273-21B	20	20	Pin stretch and pullout	M			
1273-22B	21	15	Pin stretch and pullout	E			
1273-23B	17	17	Pin stretch and pullout	M			
1273-24B	14	21	Cap pullout Pin stretch and pullout	E			
1273-25B	21	21	Cap pullout	Both			
1273-26B	20	20	Cap pullout	M			

Center phase individual insulators summary:

Insulators Tested	Electrical Failures (<15 kip)	Mechanical Failures (<15 kip)	Total Failures (<15 kip)
26	5 (19 %)	0 (0 %)	5 (30 %)

Structure 1248, L-178 (Bush phase)

Insulator Sample No.	Failure load (kip) (Electrical)	Failure load (kip) (Mechanical)	Mechanical Failure mode	Initial Failure Mode (M or E)	Acceptance parameters		
					X (kip)	S (kip)	X + 3 x S (kip)
1273-1C	19	19	Pin stretch and pullout	M	Electrical 18.6	Electrical 2.7	Electrical 15 + 3x2.7 = 23.1
1273-2C	15	20	Pin stretch and pullout	E			
1273-3C	19	19	Pin stretch and pullout	M			18.6<23.1
1273-4C	12	22	Pin stretch and pullout	E	Mechanical 19.3	Mechanical 2.0	Mechanical 15 + 3x2.0 = 21.0
1273-5C (10 kip)	21	21	Cap pullout Porcelain cracked	Both			18.6<21.0
1273-6C (10 kip)	22	22	Porcelain fell off	M			
1273-7C	20	20	Pin stretch and pullout	M			

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Insulator Sample No.	Failure load (kip) (Electrical)	Failure load (kip) (Mechanical)	Mechanical Failure mode	Initial Failure Mode (M or E)	Acceptance parameters		
					X (kip)	S (kip)	X + 3 x S (kip)
1273-8C	20	20	Pin stretch and pullout	M			
1273-9C	20	20	Pin stretch and pullout	M			
1273-10C (10 kip)	19	19	Pin stretch and pullout	M			
1273-11C	14	17	Cap pullout	E			
1273-12C (10 kip)	23	23	Porcelain fell off	M			
1273-13C (10 kip)	21	15	Cap pullout	E			
1273-14C	20	20	Pin stretch and pullout	E			
1273-15C	19	20	Pin stretch and pullout	E			
1273-16C	21	21	Cap pullout	M			
1273-17C	20	18	Cap pullout	E			
1273-18C	19	18	Pin stretch and pullout	E			
1273-19C	21	21	Pin stretch and pullout Cap pullout	E			
1273-20C	15	19	Pin stretch and pullout	E			
1273-21C	14	20	Pin stretch and pullout	E			
1273-22C	16	16	Pin pullout	M			
1273-23C	19	16	Pin stretch and pullout	E			
1273-24C	18	19	Pin stretch and pullout	E			
1273-25C (10 kip)	17	17	Cap pullout	Both			
1273-26C (10 kip)	20	20	Cap pullout	Both			

Bush phase individual insulators summary:

Insulators Tested	Electrical Failures (<15 kip)	Mechanical Failures (<15 kip)	Total Failures (<15 kip)
26	3 (12 %)	0 (0 %)	3 (12 %)

The tested insulators did not comply with the acceptance criterion, which requires that $X_i \geq R$ and X + 3S and that the average electrical or mechanical failure exceed the rating of 15 kip. A large percentage (21%) of the individual insulators had an electrical failure load below the rated value. The mechanical failure load in all cases were at or above the rated load, however, the centre and bush phases did not meet the requirement that $X \geq R + 3S$.

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7.7.4 M&E Test Result Summary

The three sets of insulators failed to meet the requirements of CAN/CSA-C411.1Clause 6.6.1: "Electro-mechanical failing load test" based on the rating of 15 kip (.

The Electro-mechanical failing load test results show serious concern for the electrical and mechanical strength of these insulators.

8 DISCUSSION AND CONCLUSIONS

The megger test found one failed insulator on the Structure 1248, L-178 (Road phase). The visual inspection found that the insulator strings had some electrical and environmental damage. The inspections found evidence on all of the insulator sets of electrical activities such as flashovers and electrical discharge. The ESDD evaluation of the insulators found the pollution level on the insulators was very low. Five of the 78 (6%) insulators failed the RIV test. Two of the insulators were found to be punctured on the AC flashover test and one of the insulators was cracked. Each of the three sets of insulators had a punctured or cracked insulator. The corrosion assessment of the insulators found them to be in good shape from a corrosion perspective. All three sets of insulators failed the combined mechanical and electrical test. They did not comply with the acceptance criterion, which requires that $Xi \geq R$ and $X + 3S$ and that the average electrical or mechanical failure exceed the rating of 15 kip. A large percentage (21%) of the individual insulators had an electrical failure load that was below the rated value. The mechanical failure load in all cases was at or above the rated load, however, the center phase and bush phase insulators did not meet the requirement that $X \geq R + 3S$. The failure rate was evenly distributed between the two insulator types.

These insulators were manufactured in 1968. The condition of the glaze has deteriorated over time due electrical activity and the porcelain on some of the insulators has punctured. The porcelain does slowly degrade over time due to the electric field. The rate of this degradation slow but the higher the electric field and the temperature the faster the degradation will be. Insulators can also puncture due to steep front transient voltages that the transmission line is expose to from lightning. Insulators manufactured today are required to pass a steep front impulse test. Insulators manufactured in 1968 did not have to pass this test and based on testing experience it very unlikely these insulators would have passed a steep front when they were manufactured.

Fires on wood structures can be caused be insulator string flashovers or by excessive leakage current into the structure. Flashovers can be due to transient conditions (such as lightning strikes or switching transients) or due to loss of insulation strength. Excessive leakage current flowing into the wood can also occur due to moist/fog weather conditions combined with polluted insulation combined, poor insulator quality or a combination of these conditions. In this case there is no evidence of polluted insulation. The insulators are, however, in poor electrical condition. The pole top fire occurred on bush phase. This phase of the line had one punctured insulator which would have resulted in an increase in leakage current due to the higher electrical stress on the remaining intact insulators. This structure did not have any bonding. There was no reported lightning or switching activity at the time of the failure. It was raining at the time of the failure.

None of the wood structure was available for examination. Based on the condition of the insulators, the lack of pollution on the insulators and information provided that there were no lighting and switching activity at the time of the failure the most probable cause of the pole top fire is excessive leakage current which initiated the fire. In dry weather the wood structure dries out and then under

the wet humid conditions the leakage current increases. The current flows through from the insulators into the wood. If the wood is dry enough and the current is high enough the wood will be ignited and a fire will start. It is not possible to definitively conclude that the fire was due to high leakage current, however, based on the available information about the event the poor electrical condition of the insulators as determined in the test program this is the most likely cause of the failure.

In general to reduce the risk of pole top fires on wood structures excessive current must be prevented from entering the wood structure or the current density where it enters the pole must be decreased. There are a number of methods that can be used to achieve these objectives.

1. Increase the number of insulators in the string to reduce the leakage current.
2. Increase the surface area of the metal at the area that the current enters the pole. This will reduce the current density. This has been found to be effective in some line designs were the washers used were too small.
3. Bond all metal parts on the pole together and connect them to a local ground so the current does not flow into the pole. This is the most reliable solution. However this method will reduce the lightning and switching transient insulation withstand level for the structure as it will no longer have the added insulation of the wood components.
4. In this particular transmission line replacing faulty insulators with new insulators that meet the specification will also reduce the risk of a pole top fire.

It is recommended that all 1968 vintage insulators from these manufacturers be replaced. They are all at high risk of failing either electrically and mechanically. Given that there were three similar failures reported in 2015 there is a high probability of further failures. It is recommended that a replacement program be implemented with the priority being given to structures that have more than one insulator string per phase. The greater the number of insulator strings on the same structure the higher the leakage current would be.

The information we have is that this transmission line has not had a long term history of having problems with pole top fires, this is a recent issue. This is consistent with the problem being due to deterioration of the insulators. Replacing the insulators will restore the structures to their original electrical condition. At present the horizontal suspension strings have nine insulators and the vertical suspension strings have eight insulators. Increasing all strings to nine insulators would provide an increase safety margin.

The insulators evaluated in this project were all removed from on structure. The recommendation to replace all 1968 vintage insulators is based on the assumption that the results are typical of all the insulators of this type on this transmission line. This could be confirmed by removing and evaluating additional insulators from this transmission line. For such a program we would recommend that insulators from 0.5 % (based on recommendation for quality conformance testing of ANSI C29.2B, “Wet Process Porcelain and Toughened Glass-Transmission Suspension Type”) of the structures be evaluated.

Any live line work done on these transmission lines should take into account there is a significant risk that there are punctured insulators and there may be insulators with low mechanical strength in the insulator strings being worked on.

The results relate only to the items tested
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APPENDIX I - TEST EQUIPMENT SPECIFICATIONS

1. Resonant Test Set (used for AC flashover and RIV tests)	Manufacturer:	American High Voltage Test Systems
	Rating:	800 kV_{rms}
2. Voltage Divider (used for AC flashover and RIV tests)	Manufacturer:	Haefely
	Type:	capacitive
	Rating:	800 kV_{rms}, 1000 pF
	Ratio:	8000:1
	Accuracy:	± 1%
3. Tensile Testing Machine (used for M&E tests)	Manufacturer:	Tinius Olsen
	Model:	400 Super L
	Capacity:	400,000 lbs
	Ser. No.:	162665
4. Test Transformer (used for M&E tests)	Manufacturer:	CGE
	Serial No:	742245
	Rating:	138 kV_{rms}, 60 Hz, 8 kVA
5. Voltage Divider (used for M&E tests)	Manufacturer:	Plastic Capacitor/BC Hydro
	Type:	capacitive (150 pF)
	Rating:	100 kV_{rms}, 60 Hz
	Ratio:	1000:1
	Accuracy:	± 1%
4. Megohm Meter (used for megger tests)	Manufacturer:	Norma
	PTL No:	10433

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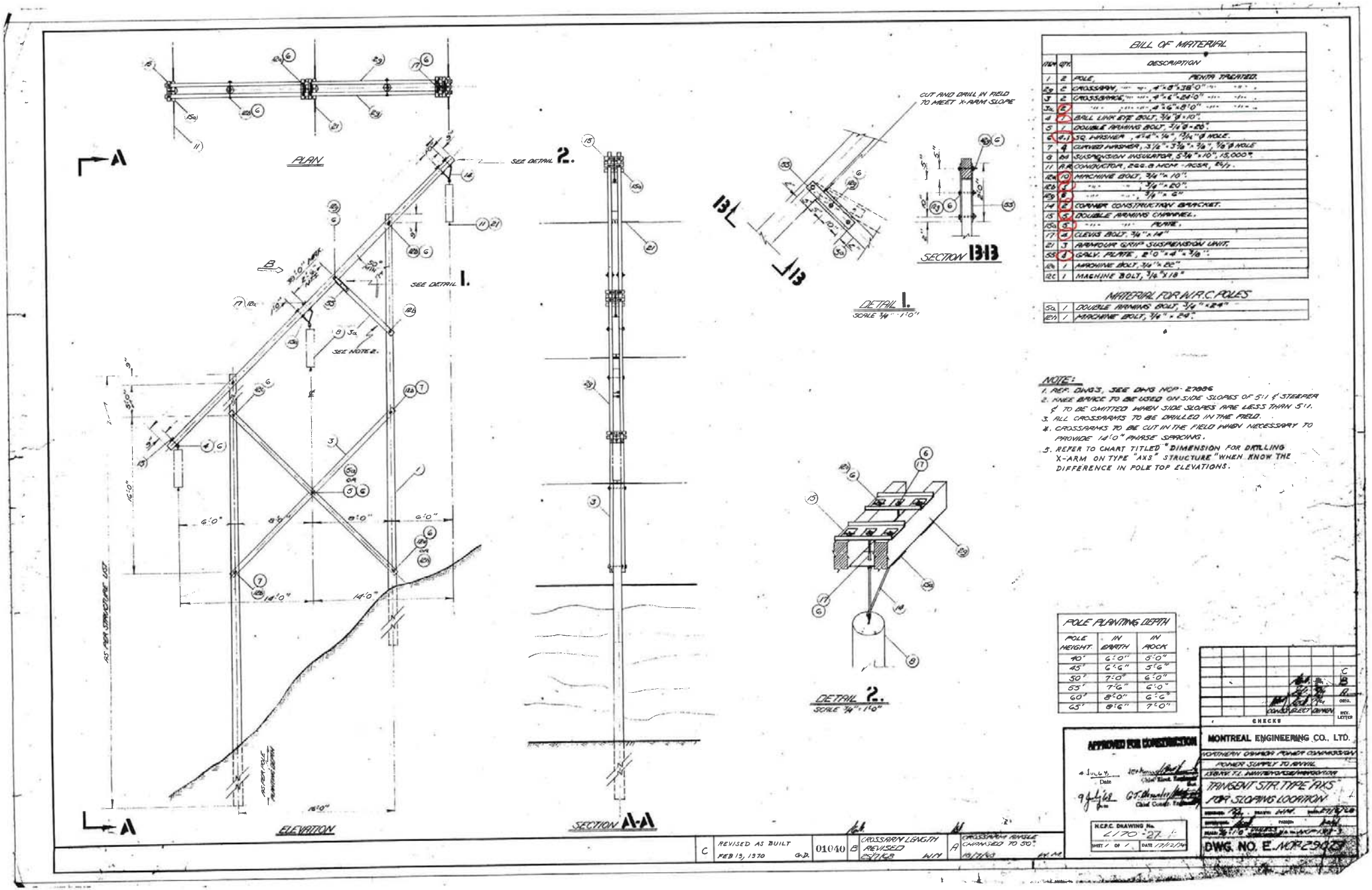
APPENDIX II - SITE PICTURES

Figure A1

Figure A2

Figure A3



BILL OF MATERIAL

ITEM	QTY.	DESCRIPTION
1	2	POLE, PENTA TREATED.
2a	2	CROSSARM, " " 4"×8"×38'0" " "
3	2	CROSSBRACE, " " 4"×6"×24'0" " "
3a	2	" " " " 4"×6"×8'0" " "
4	1	BALL LINK EYE BOLT, 3/4"ø×10".
5	1	DOUBLE ARMING BOLT, 3/4"ø×20".
6	4	SQ. WASHER, 4"×4"×3/16"ø HOLE.
6a	1	" " 4"×4"×1/4"×3/16"ø HOLE.
7	4	CURVED WASHER, 3 1/2"×3 3/8"×3/8", 13/16"ø HOLE
8	84	SUSPENSION INSULATOR, 5 3/4"×10", 15,000#
11	A.R.	CONDUCTOR, 266.8 MCM - ACSR, 84/3.
12a	10	MACHINE BOLT, 3/4"×10".
12b	1	" " 3/4"×20".
12c	6	" " 3/4"×2".
14	2	CORNER CONSTRUCTION BRACKET.
15	3	DOUBLE ARMING CHANNEL.
15a	3	" " PLATE.
17	12	CLEVIS BOLT, 3/4"×14"
21	3	ARMOUR GRIP SUSPENSION UNIT.
33	1	GALV. PLATE, 2'0"×4"×3/8".
42a	1	MACHINE BOLT, 3/4"×22"
12c	1	MACHINE BOLT, 3/4"×18"

MATERIAL FOR N.R.C. POLES

5a	1	DOUBLE ARMING BOLT, 3/4"×24"
12a	1	MACHINE BOLT, 3/4"×24".

NOTE:
1. REF. DWG 3, SEE DWG NOR-27886
2. KNEE BRACE TO BE USED ON SIDE SLOPES OF 5:1 & STEEPER & TO BE OMITTED WHEN SIDE SLOPES ARE LESS THAN 5:1.
3. ALL CROSSARMS TO BE DRILLED IN THE FIELD.
4. CROSSARMS TO BE CUT IN THE FIELD WHEN NECESSARY TO PROVIDE 14'0" PHASE SPACING.
5. REFER TO CHART TITLED "DIMENSION FOR DRILLING X-ARM ON TYPE "AXS" STRUCTURE" WHEN KNOW THE DIFFERENCE IN POLE TOP ELEVATIONS.

POLE PLANTING DEPTH

POLE HEIGHT	IN EARTH	IN ROCK
40'	6'0"	5'0"
45'	6'6"	5'6"
50'	7'0"	6'0"
55'	7'6"	6'0"
60'	8'0"	6'6"
65'	8'6"	7'0"

REV. LETTER	CHECKED	CONST. SHEET OWNER	ORIG.
C			
B			
A			

MONTREAL ENGINEERING CO. LTD.
SOUTHERN ONTARIO POWER COMMISSION
POWER SUPPLY TO ARVIDA
ESSAIM Y.I. MANITOU-CHAMOUCHOUAN
TRANSIENT STR. TYPE AXS FOR SLOPING LOCATION
DWG. NO. E. NOR 29078

APPROVED FOR CONSTRUCTION
4 July 68 Date — Chief Electrical Engineer
9 July 68 Date — G.T. Chandler, Chief Consulting Engineer

N.C.P.C. DRAWING No. 2170-27
SHEET 1 OF 1 | DATE 11/12/68

C	REVISED AS BUILT FEB 13, 1970 G.D.	01040	B	CROSSARM LENGTH REVISED OFFICE WIN	A	CROSSARM ANGLE CHANGED TO 30° 10/11/68	

TOPIC: **Capital Projects**

REFERENCE: YEC Application, Section 5.2.1.12

PREAMBLE: In Section 5.2.1.12, YEC discusses the LNG Third Engine project.

QUESTION:

a) YEC indicates that the project is driven by the 2016 Resource Plan. Please fully explain all alternatives examined to defer the project to 2019, or avoid the project entirely.

ANSWER:

(a)

The 2016 Resource Plan identified a dependable capacity shortfall for the Yukon Integrated System under the single contingency (N-1) capacity reliability criterion that approximates 6 MW in 2017, increasing to about 13 MW by 2020 and 23 to 24 MW by 2021.[1] Yukon Energy is required to provide sufficient dependable winter capacity to meet the single contingency capacity reliability criterion. There is no acceptable "do nothing" option given the need to maintain reliable service, and permanent solutions are needed to address an ongoing and growing dependable capacity shortfall. There is no basis to defer introduction of a cost effective resource to address the dependable capacity shortfall.

The LNG Third Engine project as outlined at Section 5.2.1.12 of YEC's Application is the first new resource identified for in-service in early 2019 to address a portion (4.4 MW) of the dependable capacity gap. Regulatory reviews have already been concluded for this project. Section 5.2.1.12 notes additional option review conducted in late 2016. In summary, this project is a cost effective addition to dependable capacity, and is also able to be in-service sooner than other options identified.

Please refer to Portfolio Analysis (Chapter 8) and Action Plan (Chapter 9) of the 2016 Resource Plan for details on the methodology and alternatives examined that led to the

[1] The 2017/18 GRA Application Tab 2 includes a forecast dependable capacity shortfall on this same basis at 5.6 MW in 2017 and 6.9 MW in 2018. The 2021 shortfall assumes retirement of two Mirrlees units (8.5 MW) located in Whitehorse and Faro in the summer of 2021.

recommendation of the LNG Third Engine as a part of the Short Term Action Plan (Section 9.2) of the Action Plan chapter (Chapter 9) of the 2016 Resource Plan.

TOPIC: **Capital Projects**

REFERENCE: YEC Application Section 5.3

PREAMBLE: On page 5-31, YEC discusses a number of projects that are under way, with costs in WIP, including Sustaining Capital ($2.899 million), Capacity Planning Requirements ($13.067 million) and potential future Generation and Transmission requirements ($9.845 million), which in total amount to $25.811 million.

QUESTION:

a) Please fully explain what approvals, if any, YEC is seeking in this GRA, regarding deferred costs.

b) Regarding the Capacity Planning Requirements projects, YEC indicates that the projects are driven by the 2016 Resource Plan. Please fully explain all alternatives examined to defer each project to 2019, or avoid each project entirely

c) Please provide the status of each Capacity Planning Requirement Project.

d) Regarding the Thermal Plant (Section 5.3.1.4), please fully discuss and explain all renewable energy options considered in the evaluation of this project.

ANSWER:

(a)

YEC is seeking approval to transfer to rate base deferred costs of about $14.130 million in 2017 as illustrated in Table 5.7 and about $3.122 million in 2018[1] as illustrated in Table 5.8.

In Order 2013-01, [paragraph 398] following the review of YEC's 2012/13 GRA, the Yukon Utilities Board directed YEC that for project expenditures incurred in the 2012 and 2013

[1] 2018 excluding forecast 2017/18 GRA cost at $0.817 million which will be part of the hearing reserve account.

test years and beyond, that expenditures be held in WIP until such time the costs are brought before the Board. The amount for 2017 at $14.130 million includes $13.017 million deferred costs held in WIP by end 2016 and $1.113 million additional expenditures forecast to occur in 2017 for new and existing projects held in WIP.

The 2018 proposed transfer to rate base includes new projects started in the 2017 and 2018 test years [except for two projects: Mt Sumanik Wind Feasibility Study and Moon Lake Hydro Project started in 2014 and 2015 years respectively].

The transfer to rate base also includes large projects which are discussed in Section 5.3 of YEC's Application.

By end of 2017 test year, the deferred costs remaining in WIP are forecast to be $15.349 million [excluding 2017/18 GRA cost] and by end of 2018 $29.858 million. Major projects that remain in WIP are as follows:

- Stewart Keno Transmission Project that has incurred approximately $2.807 million of rate base costs which are fully offset by contributions;
- Marsh Lake Storage with about $8.156 million incurred cost by end of 2018,;
- Battery project with about $8.856 million incurred cost by end of 2018;
- Thermal plant project with about $4.211 million incurred cost by end of 2018;
- Mayo Lake Hydro Enhancement Project with about $3.356 million incurred cost by end of 2018;
- Aishihik Relicensing project with about $2.899 million incurred cost by end of 2018.

(b)

The 2016 Resource Plan identified a dependable capacity shortfall for the Yukon Integrated System under its single contingency (N-1) capacity reliability criterion that approximates 6 MW in 2017, increasing to about 13 MW by 2020 and 23 to 24 MW by 2021.[2] Yukon Energy is required to provide sufficient dependable winter capacity to meet the single contingency capacity reliability criterion. There is no acceptable "do nothing" option given the need to maintain reliable service, and permanent solutions are needed to

[2] The 2017/18 GRA Application Tab 2 includes a forecast dependable capacity shortfall on this same basis at 5.6 MW in 2017 and 6.9 MW in 2018. The 2021 shortfall assumes retirement of two Mirrlees units (8.5 MW) located in Whitehorse and Faro in the summer of 2021.

address an ongoing and growing dependable capacity shortfall. Temporary options such as mobile thermal plants are not considered due to the lead time that is deemed too long to provide reliable power in winter months. Consequently, there is no basis to defer introduction of a cost effective resource to address the dependable capacity shortfall.

The LNG Third Engine project as outlined at Section 5.2.1.12 of YEC's Application is the first new resource identified for in-service in early 2019 to address a portion (4.4 MW) of the dependable capacity gap. The two Capacity Planning Requirement projects identified in Section 5.3 (i.e., Battery Project and the Thermal Plant Project) are the other projects identified in the Application specifically to address the dependable capacity gap.

As reviewed in Sections 5.3.1.3 and 5.3.1.4 of YEC's GRA Application, earliest completion of these two Capacity Planning Requirement projects is the end of 2019 (Battery Project) and the end of 2020 (Thermal Plant Project). Each project's costs are forecast to be incurred in WIP by the end of 2018, and not yet included in rate base in this GRA. Sections 5.3.1.3 and 5.3.1.4 review ongoing work requirements for each project before construction can commence, including steps to define options (alternatives relating to each project are noted in the Application), Stagegate 3 project reviews in late 2017/ early 2018, and project proposal submissions to YESAB. There is no apparent basis to defer the project, or avoid it all together.

Please also refer to Portfolio Analysis (Chapter 8) and Action Plan (Chapter 9) of the 2016 Resource Plan for details on the methodology and alternatives examined that led to the recommendations presented in the Short Term Action Plan (Section 9.2) and Long Term Action Plan (Section 9.3) of the Action Plan chapter (Chapter 9) of the 2016 Resource Plan.

Please see also response to CW-YEC-1-8(a) and CW-YEC-1-41(a).

(c)

Please see Table 1 provided below (includes reference to recently completed projects and major capital projects reviewed in Section 5.2.1 of YEC's Application, as well as major deferred cost projects reviewed in Section 5.3.1 of YEC's Application).

Table 1: Capacity Planning Requirement Projects

Project	Status
Whistle Bend Supply / Takhini Upgrade	Complete
LNG Plant	Complete
LNG Third Engine	Completion of RFQ for supply, installation, and commissioning of engine; Class 3 cost estimate for entire project
Battery	Initial planning
Thermal	Initial planning

(d)

The 2016 Resource Plan reviewed a wide range of renewable energy options, including various small hydro and pumped storage hydro options, various scales and sites for wind options, solar PV options, and biomass options. Based on the range of load forecast scenarios considered, fossil fuel thermal expansion options (with the potential inclusion of the Battery Project) were found to be the least costly options able to address the existing and growing dependable capacity planning shortfall as soon as practical. In the event that sufficient additional mine loads are connected to the grid, the 2016 Resource Plan also identified a small hydro option that could potentially provide 8 MW of dependable capacity by 2023 and defer the need for further thermal generation capacity development (i.e., another 10 MW of thermal plant capacity development, beyond the Thermal Plant Project identified in YEC's Application).

Please see the Portfolio Analysis (Chapter 8) and Action Plan (Chapter 9) of the 2016 Resource Plan for details on the methodology and alternatives examined that led to the recommendations presented in the Short Term Action Plan (Section 9.2) and Long Term Action Plan (Section 9.3) of the Action Plan chapter (Chapter 9) of the 2016 Resource Plan.

John Maissan

TOPIC: **Introduction to Application**

REFERENCE: Page 5 Re: Non-Fuel Operating and Maintenance Costs**.**

QUESTION:

a) What portion of the requested increase in non-fuel O&M costs is due to the amortization of the balance in the RFID and the vegetation management deferral accounts?

b) What portion of the rate increase requested is this?

ANSWER:

(a)

11% as calculated by:

Amortization of RFID balance	$	212
Amortization of Brushing balance	$	222
Total amortization of RFID and Brushing balances	$	433
Increase in non-fuel O&M Costs	$	3,905
Amortization of Balance Portion		11%

(b)

0.6% as calculated by:

2018 Non-Fuel O&M Costs	$ 22,016
2013 Compliance Filing Non-Fuel O&M Costs	$ 18,111
Increase in Non-Fuel O&M Costs	$ 3,905
Revenue at Existing Rates - 2018	$ 49,864
Revenue at Existing Rates - 2013	$ 43,279
Required Increase in Rate Revenue	$ 6,585
Increase in Non-Fuel O&M Costs	$ 3,905
Required Increase in Rate Revenue	$ 6,585
Non-Fuel O&M Portion of Rate Increase	59%
Consolidated Revenue Rate Increase	9.08%
Non-Fuel O&M Rate Impact	5.4%

Non-Fuel O&M Rate Impact	5.4%
Amortization of Balance Portion	11%
Impact of Amortization of Balance on Rates	0.6%

TOPIC: **Section 1 Introduction**

REFERENCE: Page 1-3 Re. Mayo Flexible Debt Financing last sentence "Lower Loads in 2014 resulted in negative interest payments from YDC to YEC of $0.112 million, further reducing the impact to ratepayers in that year."

QUESTION:

a) Please explain how reduced or negative interest payments to YDC were a direct benefit to ratepayers as opposed to improving YEC's ROE?

ANSWER:

(a)

Lower interest payments for YEC in 2014 helped reduce pressure for YEC to seek a new GRA with rate increases; however, no other direct benefit was provided in 2014 to ratepayers by such a YEC cost reduction.

TOPIC: **Section 1 Introduction**

REFERENCE: Page 1-9 Re: Continued planning to meet other future supply requirements.

QUESTION:

a) Please detail the demand side initiatives YEC is planning to undertake with respect to addressing the growth in peak demand. In particular please detail the initiatives aimed at reducing the peak demand from electric space heating.

b) Which of these initiatives will commence in 2017 and which in 2018?

ANSWER:

(a)

YEC is planning to conduct the capacity DSM feasibility study in 2018 to help design a suite of new peak load reduction aimed DSM programs to complement the existing inCharge program. In addition, as a part of developing peak load reduction DSM programs, YEC is involved in the electric thermal storage (ETS) pilot project with the Energy Solutions Centre of the Energy, Mines and Resources department of the Yukon Government.

(b)

YEC's involvement in the ETS pilot project with the Energy Solutions Centre of the Energy, Mines and Resources department of the Yukon Government started in 2017, while the capacity DSM feasibility study will be initiated in 2018.

TOPIC: **Section 2 Sales and Revenue**

REFERENCE: Page 2-1 "Starting in 2014, firm load supplied by Yukon Energy to non-industrial customers on the Integrated System has fallen below the actual and approved forecast load for 2013 …"

QUESTION:

a) Please explain why the 2012-2013 GRA sales forecasting failed to identify the significant downturn in sales that started in 2014.

b) Please provide a copy of the sales forecast that was part of the 2013 LNG Application and please provide any updated provided in the 2014 LNG proceeding.

c) Did the LNG proceeding forecast recognize the downturn that appeared to begin with Alexco's shutdown in 2013?

d) Given the significant downturn in sales in 2014 from forecasted levels, please explain why YEC did not come forward with a 2014- 2015 GRA to address this matter rather than wait until 2017.

ANSWER:

(a)

The 2012-13 GRA addressed changes in mine load forecasts as these were then known. The overall 2013 actual firm sales at 384.4 GW.h were slightly higher than the approved forecast at 383.1 GW.h.

The 2012/13 GRA was not forecasting sales beyond 2013. The subsequent sales downturns reflected mainly the loss of Alexco load and the impact of warmer than normal temperatures, plus (to a much lesser extent) the economic decline. Sales forecasts do not address forecasts for variances from normal temperatures.

(b)

Table 2.1 of the current Application provides the approved sales forecast for 2013 GRA.

The forecast in the 2013 Part 3 LNG Application (Appendix C to that filing) focused on a Base Case load scenario with no Alexco mine load after the fall of 2013. This Base Case load forecast was described as follows in that application (it was not updated in the 2014 proceeding):

a. **Base Case no Alexco after fall 2013:**

i. Updated non-industrial forecast load for 2013 and 2014[1], reflecting the following:

- Non-industrial growth at 2.26%/year for 2015, at 2.45%/year for 2016-2020 inclusive, at 2.82%/year for 2021-2025 inclusive, at 3.13%/year for 2026 and thereafter; and
- DSM/SSE assumed at 32% of annual load growth based on Yukon Electricity Conservation and Demand Management Potential Review (CPR) report prepared by ICF Marbek (January 2012); to reflect proposed DSM plans (YECL 2013-15 GRA goal of 8.5 GW.h/year sustained electricity savings by 2018), impact reduced for the first year (2015) taking ¼ of the assumed 32%, 2/3 for 2016, and at full 32% starting from 2017.

ii. Minto generation load (includes grid losses) at 34.6 GW.h/2013, 38.0 GW.h/2014, 40.2 GW.h/2015 and at 43.5 GW.h/year for 2016-2022 (no load thereafter)[2]; and

[1] Non-industrial load forecast for 2013 is based on January-October preliminary actuals and November-December updated forecasts. The 2013 updated YEC non-industrial load forecast (340 GW.h excluding grid losses) is about 2 GW.h lower than 2013 GRA approved forecast due to lower wholesales; however, the GRA approved wholesales forecast included 5.1 GW.h related to WHCT (which did not connect in 2013), i.e., overall updated non-industrial load for 2013 is forecast about 3 GW.h higher than the approved GRA forecast with January-October actuals as reported reflecting warmer than normal temperature conditions. The 2014 forecast is based on YEC's latest update which uses 2.26% growth rate over weather normalized 2013 full-year-forecast wholesales (308.5 GW.h) reduced by 4.36 GW.h to reflect Fish Lake Unit #1 being in operation in 2014. The non-industrial growth rates remain unchanged from the March 2013 update: 2011 Resource Plan forecast annual growth rate for non-industrial load for 2014 and 2015; annual growth rates for 2016-2020, 2021-2025 and 2026-2030 are from Marbek's final CPR report.

[2] Minto generation load forecast reflects updates reviewed with Minto in fall 2013.

iii. Alexco generation load (includes grid losses) at 9 GW.h for 2013 and no load thereafter[3].

Table 1: 2013 Part 3 LNG Application Base Case Load Forecast (Appendix C of the December 9, 2013 filing)

Forecast Years	Base Case no Alexco			
	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Diesel (GW.h)
2013	369.9	43.5	413.4	11.2
2014	377.9	38.0	416.0	12.3
2015	386.1	40.2	426.3	17.0
2016	393.9	43.5	437.3	22.9
2017	400.9	43.5	444.3	26.9
2018	408.0	43.5	451.5	31.4
2019	415.4	43.5	458.9	36.1
2020	422.9	43.5	466.4	41.1
2021	431.8	43.5	475.3	47.4
2022	441.0	43.5	484.4	54.7
2023	450.4		450.4	33.1
2024	460.0		460.0	39.8
2025	470.0		470.0	46.8
2026	481.3		481.3	55.0
2027	493.0		493.0	63.6
2028	505.1		505.1	72.7
2029	517.6		517.6	82.3
2030	530.4		530.4	92.5

[3] In July 2013 Alexco Resource Corp. announced that it will close Bellekeno mine for winter and will reopen in spring of 2014 assuming the silver market has improved. Although the project could reopen in 2014, there is no current basis for addressing a 2014 forecast update - and the time of reopening of the mine is very uncertain. To address this uncertainty, two separate cases were prepared for the Base Case with and without Alexco. The case with Alexco assumes mine re-opening in 2015.

(c)

The response to (b) above indicates that the forecast for the Part 3 LNG Application did not forecast the impact of warmer than normal weather or other factors accounting for the reduced sales after 2013.

(d)

Please see section 1 of the current GRA Application, and in particular section 1.1 and Table 1.1 for a review of the factors affecting YEC revenues and costs after 2013, and in particular the impact starting in 2015 of the YDC debt refinancing.

TOPIC: **Section 2 Sales and Revenue**

REFERENCE: Page 2-6 to 2-9 Re firm wholesale sales and public information from the media that Victoria Gold Corp. (discussed on page 2-8) has now started development work.

QUESTION:

a) Please explain how Victoria Gold will likely change wholesale sales in 2018 and how YEC will adjust their application to reflect this change.

b) Please explain how YEC's firm retail sales will change as a result of this development work and how the application will be adjusted to reflect this change.

c) For Victoria Gold please provide a table by month and year the energy loads that YEC understands the mine will require (by year of operation if applicable).

d) In a similar table please provide the monthly peak demands that YEC understands that Victoria Gold will require of the grid (again by year if applicable).

e) Media coverage around the time of Victoria Gold's announcing the start of development included interviews with YEC officials. It was understood that YEC said that there was an adequate supply of power available on the grid for Victoria Gold. Please provide YEC's official position on grid power – energy and capacity – available for Victoria Gold.

f) Please provide a table of the additional (to the forecasts provided in the Application) monthly hydro, diesel, and LNG generation that would be required to meet Victoria Gold's requirements in its first year of operation.

g) How will service to Victoria Gold affect residential and General Service customer rates?

ANSWER:

(a) and **(b)**

YEC has no estimates or assessments as to the potential impacts of Victoria Gold development work on AEY retail sales (and therefore on YEC wholesales) or on YEC firm retail sales in the GRA test years. According to the latest mine development plan, the mine is not expected to be operational until after the test years and therefore no impact on firm sales is expected. No adjustments are proposed in the YEC GRA Application to reflect changes of this nature that occurred after the test year forecasts were prepared.

(c) through **(g)**

The Application at page 2-8 summarized the status (when the Application was prepared) of Victoria Gold's Eagle Gold mine, and noted that a Power Purchase Agreement (PPA) would be required between YEC and Victoria Gold Corp. (with approval of the YUB), and plans confirmed to replace the existing 69 kV line between Mayo and Keno.

YEC is currently in discussions with Victoria Gold Corp. regarding the required PPA. When the PPA is concluded, it will be filed with the Board for its review and approval along with necessary supporting assessments regarding potential impacts on YEC's operations, revenues and costs. Prior to completion of the PPA and the related filing with the Board, YEC is not able to provide more than the following updates:

- The Application noted that the earliest potential operation of this mine would be in late 2018 (if development was to commence by summer 2017). YEC's current understanding is that the earliest potential operation of this mine would be in Q2 2019, assuming construction commenced by Q2 of 2018.

- The Application noted initial industrial power purchases at about 62 GW.h/yr, increasing to about 69 GW.h/yr in years 2 and 3 and to about 92 GW.h/yr by year 6 of operation. YEC's current understanding is that industrial power purchases are likely to be lower than previously stated, e.g., at about 52 GW.h/yr in the initial year, increasing to about 64 GW.h/yr in year 2 and about 74 GW.h/yr by year 6 of operation.

- The mine's load will be sharply reduced (i.e., one half or less of monthly load in other months) during a 90-day stockpile period starting in early December of each operating year.

- Peak load is expected to be about 10 MW in year 1 (5.1 MW during 90-day stockpile period), increasing to about 12.8 MW in year 6 (5.8 MW during 90-day stockpile period).

TOPIC: **Section 2 Sales and Revenue**

REFERENCE: Page 2-7 and 2-8 Major Industrial

QUESTION:

a) Please provide an estimate of the long term average (LTA) hydro energy that would be spilled by month in each of 2017 and 2018 if all sales are as projected in the application.

b) Please provide a breakdown of the forecasted secondary sales in each of 2017 and 2018 by month.

c) Is the LTA energy available to supply future industrial customers (potentially Victoria Gold in 2018) the sum of the above "spilled" hydro energy plus the forecasted secondary sales figures or more than the sum? Please explain and provide a monthly table if more than the sum.

ANSWER:

(a)

Please see Table 1 provided below.

Table 1: Hydro Energy Long Term Average

Month	2017 Spilled Hydro [GWh]	2018 Spilled Hydro [GWh]
January	0.0	0.0
February	0.0	0.0
March	0.0	0.0
April	0.0	0.0
May	1.5	1.5
June	7.3	7.3
July	13.6	13.5
August	13.2	13.1
September	11.2	11.1
October	5.6	5.6
November	0.1	0.1
December	0.0	0.0
Total	52.6	52.1

(b)

Secondary sales by month for 2017 and 2018 are shown in Table 2:

Table 2: Forecast Secondary Sales by Month (2017, 2018)

(KWh)

Month	Hospital	CGC	Yukon College	Total
January	374,551	425,000	450,000	1,249,551
February	257,888	375,000	400,000	1,032,888
March	116,664	400,000	425,000	941,664
April	242,537	405,000	415,000	1,062,537
May	349,991	340,000	350,000	1,039,991
June	368,411	250,000	250,000	868,411
July	233,327	200,000	217,000	650,327
August	82,893	165,000	175,000	422,893
September	322,360	150,000	175,000	647,360
October	620,159	240,000	250,000	1,110,159
November	604,808	315,000	320,000	1,239,808
December	368,411	405,000	425,000	1,198,411
Total	**3,942,000**	**3,670,000**	**3,852,000**	**11,464,000**

(c)

LTA hydro energy from existing facilities is forecast based on 35 years of water record, using the YECSIM simulation model as reviewed in Appendix 3.4 of the Application. LTA hydro energy available to supply future loads is not assessed based on the sum of recent year spilled hydro energy plus forecasted secondary sales, as suggested in this question.

Appendix 3.4, Attachment 3.4.2 reviews how LTA hydro and LTA thermal generation vary as grid load varies from 380 GW.h/yr to 450 GW.h/yr. Table 3.4-1 in the DCF Term Sheet provides a more detailed indication as to LTA hydro and thermal changes as grid load (net of LTA wind and Fish Lake hydro) varies between 370 GW.h/yr. and 485 GW.h/yr.

As reviewed in response to John Maissan-YEC-1-5, updated information on Victoria Gold indicates that the earliest potential date for start of operation for the Eagle Gold mine is now in 2019.

TOPIC: **Section 2 Sales and Revenue**

REFERENCE: Page 2-8 Alexco Mine

QUESTION:

a) Please provide a table of the metered energy and metered demand for the last 12 months of the Alexco Mine's full operation (prior to shut down in 2013).

ANSWER:

(a)

Please see Table 1 provided below.

Table 1: Alexco Mine Metered Energy

		Primary Sales KWh	Measured Demand Kva
2012	SEP	1,057,400	1,811
2012	OCT	1,060,400	2,428
2012	NOV	1,066,000	1,923
2012	DEC	1,151,900	1,930
2013	JAN	1,114,400	2,036
2013	FEB	985,500	2,239
2013	MAR	964,500	2,312
2013	APR	1,201,100	2,404
2013	MAY	993,600	2,218
2013	JUN	914,100	2,404
2013	JUL	1,090,900	2,221
2013	AUG	1,001,100	2,195

TOPIC: **Section 2 Sales and Revenue**

REFERENCE: Page 2-10 lines 24 and 25 and footnote 18

QUESTION:

a) Has the Mayo hydro plant not been said by YEC to supply more than 9 MW (11 MW?) of firm generation in past documentation? If so please explain why this has now been reduced to 9 MW.

b) Please explain the down-river icing and flooding issues on the Mayo River.

c) What constraints have these placed on Mayo B and how has the winter energy and dependable capacity available from the Mayo hydro system been affected by this constraint?

ANSWER:

(a)

The 9 MW dependable capacity at the Mayo Hydro facility is capacity that can be reliably provided to meet the demand over two consecutive weeks out of the four "winter" months (November to February) as defined in the 2016 Resource Plan. This value also takes into account the recently implemented ice management protocol developed by Yukon Energy (YEC), the Yukon Government and the Village of Mayo in response to recent icing and flooding issues that occurred near Mayo, starting in late 2010, about a year before Mayo B was put in service.

(b)

The down-river icing and flooding issues that were first observed in 2010 are complex issues that have been the topic of several studies over the past decade. Based on the work of Morrison Hershfield (2015), completed on behalf of the Yukon Government, the *"cause of the flooding is complex, subject to many variables and a wide variety of ever changing of environmental conditions; overall it is highly complex issue and not well understood."*

Their analysis suggested that *"the accumulation of frazil ice in the lower reach of the Mayo River (between Silver Trail Bridge and the Stewart River) is the most likely direct mechanism causing the freeze-up related flooding. Specifically, increased frazil-ice production in the upper reach of the river during freeze-up (between Wareham Dam and the Sliver Trail Bridge) is conveyed to the lower reach of the river. This lower reach no longer has the hydraulic capacity to convey the increased winter flows and its associated frazil-ice, to the Stewart River, causing the frazil-ice to accumulate in the lower reach."*

(c)

Over the past two winter seasons, there hasn't been any incidents of flooding in the Village of Mayo. This coincides with the implementation of the ice management protocol developed in collaboration with the Village of Mayo and the Yukon Government. As per the protocol, YEC sets the ice on the Mayo River by maintaining a low and constant river flow of 15 m^3/s. Once the ice cover is set, YEC can then ramp up flow in defined increments up to 24 m^3/s.

During the 2016-2017 winter season, YEC was able to progressively increase the flows and to achieve high flow, or 24 m^3/s corresponding to about 11 MW, in late January.

In addition to the protocol, Yukon Government has completed in-stream work in 2016 and 2017. The work appears to have assisted with flow management and ice formation but additional monitoring is needed to fully assess and quantify the benefit of the in-stream work.

TOPIC: **Section 2 Sales and Revenue**

REFERENCE: Page 2-10 Re Mayo Hydro

QUESTION:

a) What constraints in energy and capacity does the silted outlet of Mayo Lake impose on the Mayo hydro facilities?

b) When does YEC plan to dredge the outlet of Mayo Lake to remove these constraints?

c) Are there any other constraints on the Mayo hydro plant? If so please explain them and their impact.

ANSWER:

(a)

The silted outlet of Mayo Lake imposes constraints on flows out of Mayo Lake to the Mayo hydro facility during periods when Mayo Lake levels approach current license low supply levels. Enhanced storage at Mayo Lake cannot be effective with these constraints.

Additional modeling completed for the test years using a rating curve at the outlet of Mayo Lake similar to the one assumed during the 2012 GRA indicates that the silted outlet increases thermal requirements under LTA conditions by 0.835 GWh for both 2017 and 2018.

Please see response to YUB-YEC-1-48 for a review of the impacts on YECSIM LTA assessments due to the combined effects of upstream and downstream constraints at Mayo hydro.

(b)

There are 3 key factors affecting the timing of potential dredging of the Mayo Lake outlet to address the historic and on-going aggradation of sediment.

1. The first factor is ensuring sufficient knowledge is gathered to understand the mechanisms and processes that are causing the aggradation to occur and to develop a suitable engineering design to remove the sediment and minimize the frequency of future re-dredging. Cost estimation would also be part of this planning process. This work is proposed to be completed in 2018.

2. The second factor relates to the costs and benefits of proceeding with dredging and also of the 'do-nothing' option. There must be a demonstrated business case to advance a dredging project and until Item 1 above is complete such an analysis and decision to proceed cannot be prudently made. Information necessary to make such a decision could be available by the latter part of 2018, depending on the timing of Item 1, above.

3. The third key factor affecting the timing of dredging relates to the schedule and outcomes of the requisite assessment and permitting processes, which are anticipated to take anywhere from 12-18 months. Should such processes be started in 2019 it may be feasible to commence dredging as early as the open water period of 2020, but more likely in 2021.

YEC will apply the Stagegate Project Development Framework approach for a project of this nature. At the end of 2018, once the business case information has been developed, YEC Board of Directors will review the information as part of a Stagegate and provide a go/no go decision.

Please see response to YUB-YEC-1-78 for additional details on the Stagegate Project Development Framework.

(c)

There is an operational constraint associated with the common water intake used for both Mayo A and Mayo B plants. The decision for the penstock for Mayo A and Mayo B to share a common intake was taken due to cost implications of constructing a separate Mayo B intake. This limits the total flow through the water conveyance at 25 m^3/s, which represents about 11.5 MW.

TOPIC: **Section 2 Sales and Revenue**

REFERENCE: Page 2-11 lines 24 and 25 Spinning reserve

QUESTION:

a) Please describe YEC's policy or policies with regard to spinning reserve, including how that may vary by season if applicable.

b) Around early August there were a series of 3 or 4 quite extensive grid outages. For each of these outages please provide:
   i. The grid load (MW) at the time of the outage;
   ii. A list of the plants operating at the time of the outage and the load supplied by each plant;
   iii. The plant or other facility that tripped to cause the outage;
   iv. The spinning reserve running at the time of the outage and which plant or plants were providing that spinning reserve;
   v. The shortfall in generation as a result of the trip (load less operating generation including spinning reserve);
   vi. The spinning reserve that would have been required to prevent an outage; and
   vii. A list of the diesel generators that were brought on line to assist in restoration from the outage.

c) What forms of spinning reserve (hydro, diesel, LNG, etc.) would have been required at the time of these trips to prevent outages?

ANSWER:

(a)

YEC does not have a formal policy with regard to spinning reserve other than as described in the Application at page 2-11 lines 21-22 as follows:

"When thermal is generating on the system, Aishihik also provides the spinning reserve which is to provide coverage for the largest thermal unit on line."

(b)

Please see outage reports provided as John Maissan-YEC-1-10 Attachment 1.

With regard to (iv) through (vi), spinning reserve is not intentionally maintained when thermal generation is not on the system.

(c)

Although other forms of generation could provide spinning reserve, YEC typically relies on hydro for this function from an economic perspective. YEC chooses to operate thermal units at full capacity whenever possible for efficiency and asset health reasons.

Yukon Energy Corporation

System Disturbance Report

Date: Aug 3, 2017

System Operator: Myles O'Brien

Weather: 16C clear and sunny

Estimated Load Loss 13.2 MW

Percentage of Grid: 31%

Pre-Disturbance Generation Setup

WH4	18.1
WH3	8.0
WH2	5.3
WH1	2.8
MBH1	2.9
MH1	2.0
AH3	3.5

Total Generation 42.6 Mw

Disturbance:

Time	Event
07:40:13	WH4 Trip – Speed Signal Fail
07:40:14	S150 52-22 Trip U/F 56.1Hz
07:40:15	S6838 Trip U/F 56.1Hz
07:40:15	S6837 Trip U/F 56.1Hz
07:40:15	S250 52-2 Trip U/F 56.1Hz
07:40:18	P158 52-F2 Trip U/F 56.1Hz

Restoration

07:45:16	WD7 Online
07:48:51	P158 52-F2 Closed by SCC
07:49:38	S250 52-2 Closed by SCC
08:05:16	S6838 Close by SCC under ATCO direction
08:05:49	S6837 Close by SCC under ATCO direction
08:32:21	S150-52-22 Close by SCC under ATCO direction

Time Variance

Feeder	Opened / Tripped	Closed	Variance
P158 52-F2	07:40:18	07:48:51	00:08:25
S250 52-2	07:40:15	07:49:38	00:09:15
S6838	07:40:15	08:05:16	00:24:37
S6837	07:40:15	08:05:50	00:25:11

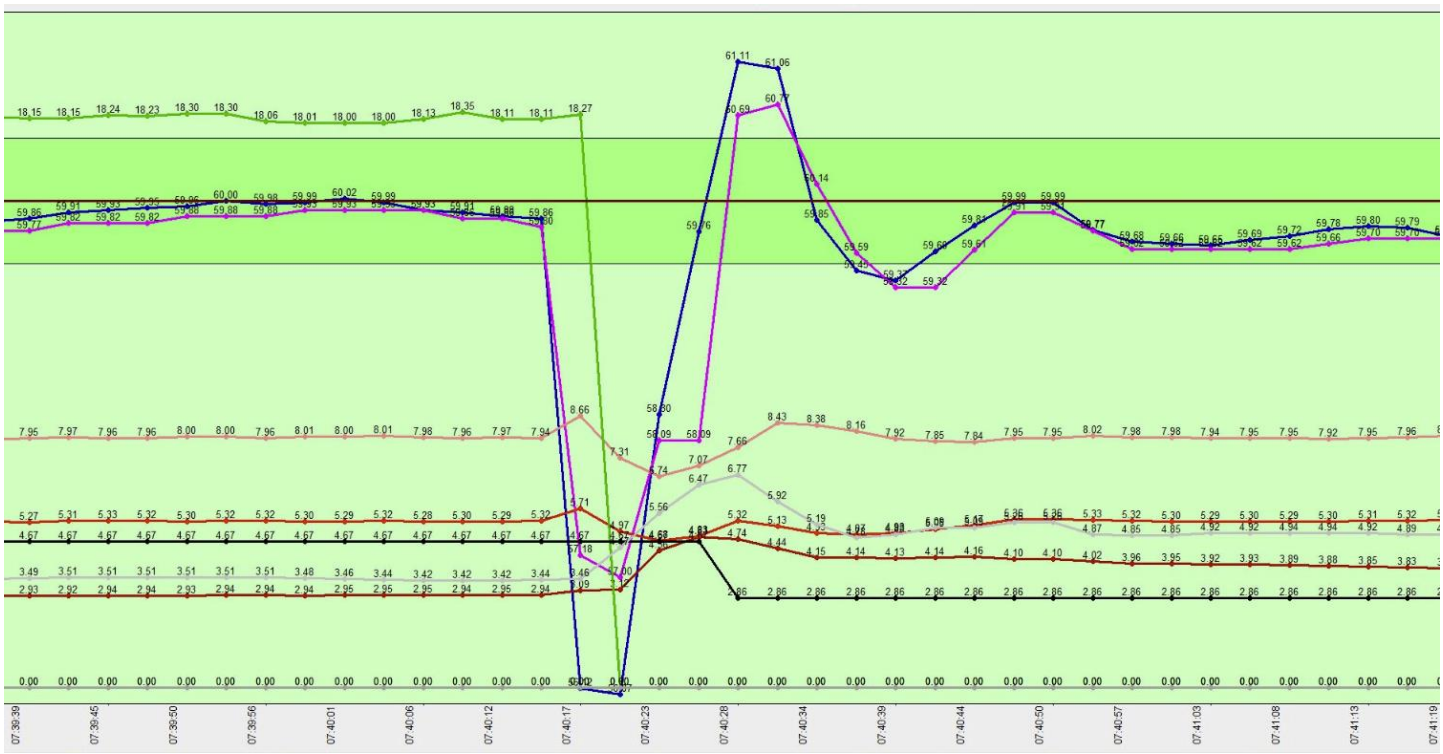
S150-52-22	07:40:14	08:32:21	00:51:18

Target /Flags.

WH4 Secondary Speed Device Failed
WH4 Speed Signal Failed
WH4 86 Lock-out trip

Comments .

WH4 tripped offline at 18.1 MW causing breakers to shed load on U/F.
ATCO personnel start work at 0800 and were still inbound to their compound when the outage occurred.
This caused delays in sectionalizing.



Yukon Energy Corporation
System Disturbance Report

Date: Aug_08_2017

System Operator: Stephen Blysak

Weather: sunny 12 c

Estimated Load Loss Percentage of Grid: 29%

Pre-Disturbance Generation Setup

MBH1	4.4 mw
MBH2	3 mw
MH1	2 mw
MD1	0.8 mw
MD2	0.8 mw
MD3	0.8 mw
DD5	1.1 mw
DD4	1 mw
DD3	0.6 mw
DD2	0.6 mw
DD1	0.3 mw
WH1	4 mw
WH2	5 mw
WH3	7.9 mw
WD7	2.4 mw
WD6	2 mw
WD5	2 mw
WD4	2 mw

Total Generation: 40.7 Mw

Disturbance:

Time	Event
07:24:58	S251 T1 overcurrent Trip
07:24:58	S251 52-5 Trip
07:24:58	S251 52-8 Trip
07:24:58	S251 52-1 Trip

07:25:01	S256 52-1 Trip
07:25:01	S256 52-2 Trip
07:25:01	S250 52-5 Trip
07:24:57	S150 52-22 Trip
07:24:57	S170 S6837 Trip
07:25:00	S170 S6838 Trip
07:25:00	DD1 Trip reverse power
07:25:10	MD1 Trip " "
07:25:10	MD2 Trip " "
07:25:10	MD3 Trip " "

Restoration:

07:32:41	S256 52-1 Closed
07:33:17	S256 52-2 Closed
07:41:36	S250 52-5 Synced Closed
07:43:43	S251 52-5 Closed
07:44:03	S251 52-8 Closed
07:47:36	S251 52-1 Synced Closed
08:02:47	S170 S6838 Closed
08:10:29	S150 52-22 Closed
08:10	WG2 On
08:17	WG1 On
08:39:49	S170 S6837 Closed
08:42	WG2 OFF (glycol spill)
08:35	WG1 OFF " "
09:04	MD1 On
09:05	MD2 On
09:06	MD3 On

Time Variance

Feeder	Opened / Tripped	Closed	Variance hr/min/sec
S256 52-1	07:25:01	07:32:41	0:07:40
S256 52-2	07:25:01	07:33:17	0:08:16
S250 52-5	07:25:01	07:41:36	0:16:35
S251 52-5	07:24:58	07:43:43	0:18:45
S251 52-8	07:24:58	07:44:03	0:19:05
S251 52-1	07:24:58	07:47:36	0:22:38
S150 52-22	07:24:57	08:10:29	0:45:32
S170 S6838	07:24:57	08:02:47	0:37:50
S170 S6837	07:24:57	08:39:49	1:14:52

Targets/Flags

S251 T1 tripped on an overcurrent this caused the system to split and u/f trips on 9L S6837 and S6838

Comments:

S251T1 protection settings at 14MVA, due to lack of gen available on the southern grid we were generating heavy from the north this caused the protection setting on S251 T1 to trip on over current

The cause of the second August 8th outage occurred during the system restoration from the loss of WH4. Northern thermal and hydro generation used to replace the lost generation from WH4 exceeded the protection settings of a transformer located at Stewart Crossing. The transformer protection settings are lower than the transformer capacity. The protection settings will be review and changed.

Yukon Energy Corporation
System Disturbance Report

Date: 08-08-2017

System Operator: Stephen Blysak

Weather: 29°c

Estimated Load Loss Percentage of Grid: 1.282 MW (2.8%)

Pre-Disturbance Generation Setup

WH4	16.5 MW
WH1	4.8 MW
WH2	4.8 MW
WH3	7.9 MW
MH0	2.2 MW
MBH1	3.8 MW
MBH2	4.8 MW

Total Generation: 44.8 MW

Disturbance:

Time	Event
16:30:21	P158 52-F2 U/F Trip (732kW)
16:30:17	S250 52-2 U/F Trip (550kW)

Restoration:

16:33:30	WD7 Online - Group Start
16:34:52	WD4 Online - Group Start
16:34:59	WD5 Online - Group Start
16:35:15	WD6 Online - Group Start
16:39:20	DD4 Online
16:45:11	DD2 Online
16:46:39	P158 52-F2 Closed by SCC
16:47:18	DD1 Online
16:50:13	WH4 Offline - Controlled reduction of load by SCC
17:00:53	DD5 Online
17:05:44	S250 52-2 Closed by SCC

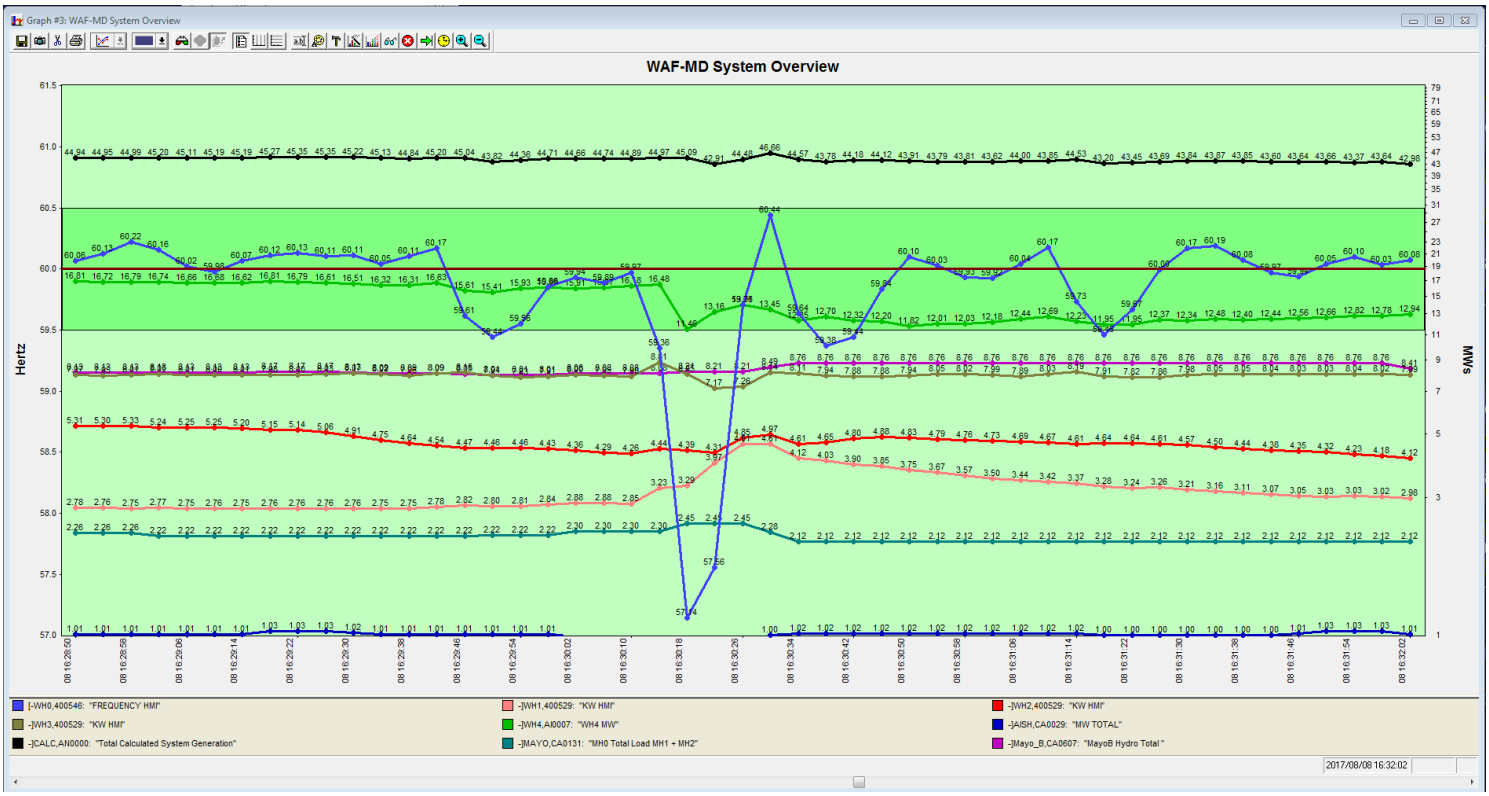
Time Variance

Feeder	Opened / Tripped	Closed	Variance hr/min/sec
P158 52-F2	16:30:21	16:46:39	0:16:18
S250 52-2	16:30:17	17:05:44	0:35:27

Targets/Flags

Dawson feeders tripped on U/F

Comments: WH4 shed around 4MW of load as unit was being brought off line due to speed sensing issues. This caused P158 52-F2 and S250 52-2 to trip on U/F. WH4 was taken offline in a controlled manner by SCC.



Yukon Energy Corporation
System Disturbance Report

Date: Aug 8, 2017

System Operator: Cameron Hoyt

Weather: Clear

Estimated Load Loss (Mw): 3.28MW

Percentage of Grid: 10%

Pre-Disturbance Generation Setup

WH1	1.73MW
WH2	2.94MW
WH3	5.79MW
WH4	11.9MW
MH1	2.14MW
MBH1	2.86MW
MBH2	.88MW
AH3	.82MW
WD5	1.3MW
WD6	1.5MW
WD7	1.1MW

Total Generation: 32.96 Mw

Disturbance:

Time	Event
05:50:20	WH4 P127-52-WH4 Open (11.9MW
05:50:22	S250-52-2 Open (Tripped under frequency 280kW)
05:50:22	S6838 Open (Tripped under frequency 3MW)

Restoration:

05:57:09	S250-52-2 Closed by SCC
06:20:30	S6838 Closed by SCC

Time Variance

Feeder	Opened / Tripped	Closed	Variance hr/min/sec
S250-52-2	05:50:22	05:57:09	00:06:47
S6838	05:50:22	06:20:30	00:30:08

Targets/Flags

Comments:

WH4 HPU pumps could not keep HPU oil pressure at appropriate levels. Diesel units were brought on and load was starting to be shifted to take unit down in a controlled manner, when WH4 tripped offline. WH4 issues are still being investigate at this time.

Yukon Energy Corporation
System Disturbance Report

Date: Aug 9, 2017

System Operator: Cameron Hoyt

Weather:Clear

Estimated Load Loss (Mw): 8.03 MW

Percentage of Grid: 25.91%

Pre-Disturbance Generation Setup

WH1	2.02 MW
WH3	8.02 MW
AH2	14.2 MW
AH3	2.40 MW
MH1	2.3 MW
MBH1	3.3 MW

Total Generation: 32.24 Mw

Disturbance:

Time	Event
04:16:38	P130-52-AH2 Tripped 14.2 MW
04:16:38	S250-52-2 Tripped .29 MW (Hunker Feeder)
04:16:38	S150-52-22 Tripped 2.4 MW (9L Carcross)
04:16:38	S6837 Tripped 2.4 MW (Mnt. View)
04:16:41	P158-52-F2 Tripped .338 MW (Dawson Feeder 2)
04:16:41	S6838 Tripped 2.6 MW (Laberge/Porter Creek)

Restoration:

04:30:42	P158-52-F2 Closed by SCC
04:30:53	S250-52-2 Closed by SCC
05:20:07	S150-52-22 Closed by SCC
05:41:28	S6837 Closed by SCC
05:42:25	S6838 Closed by SCC

Time Variance

Feeder	Opened / Tripped	Closed	Variance hr/min/sec
P158-52-F2 (Feeder 2)	04:16:41	04:30:42	00:14:01
S250-52-2 (Hunker)	04:16:38	04:30:53	00:14:15
S150-52-22 (9L)	04:16:38	05:20:07	01:03:29
S6837 (Mnt. View)	04:16:38	05:41:28	01:24:50
S6838 (Porter Creek)	04:16:41	05:42:25	01:25:44

Targets/Flags

AH2 Upper Guide Bearing Temp Trip (80c)
AH2 86 Lockout Trip

Comments:

At 04:16:38 AH2 tripped offline. The Upper guide bearing temp trip (80c) alarm came in and the unit locked out. All Main breakers were closed at 05:42:25 and load pickups were completed shortly after 07:00. Restoration was done with Whitehorse Diesels and AH2, after it was inspected.

The cause of the August 9th outage was a high temperature bearing trip on Aishihik unit 2 (AH2). AH2 was placed on line on Aug 8th to eliminate the thermal being used to replace WH4 generation. The unit had been inspected after being on line for an hour with no issues found. The bearing over heated due to a clogged cooling water supply to the bearing.

TOPIC: **Section 2 Sales and Revenue**

REFERENCE: Page 2-12 Drought-Flood Year Constraints

QUESTION:

a) What would be the reductions in LTA annual hydro-generation from a 1 in 100 year drought and from the driest year on record?

ANSWER:

(a)

Drought conditions in each watershed where YEC's hydro generating assets are located are not coincident. For instance, the Mayo Lake watershed could experience a "dry" year but the Aishihik Lake and Southern Lakes watersheds could experience a "wet" year making the water year from a system standpoint an "average" year. When determining the thermal requirement for each water year, YECSIM takes this regional variability into account. The table below presents the hydro generation for the driest system water year and under the long term average water condition for the 2017 and 2018 test years. Yukon Energy does not calculate 1 in 100 year drought for planning or operational purposes.

Test Year	**Total Generation**	**LTA Hydro Generation**	**Driest Water Year**
	[GWh]	[GWh]	[GWh]
2017	420.4	405.7	312.6
2018	421.2	406.1	312.9

TOPIC: **Section 2 Sales and Revenue**

REFERENCE: **Page 2-12 Diesel and LNG Thermal Generation**

QUESTION:

a) For the years 2012 to 2016 inclusive please present a table of actual diesel and LNG generation by month.

b) Please discuss the cold load pick-up capability (i.e. after an outage) of diesel vs. LNG generators.

c) For each year from 2012 to 2016 please list the number of outages on the Yukon integrated system that required the use of the Whitehorse Rapids diesel plant for restoration.

d) What diesel capacity is required for restoring the grid as quickly as reasonably possible, from a grid outage affecting 50% or more of the electrical load?

ANSWER:

(a)

As per below, LNG generation did not commence until June 2015 (which was still commissioning of the plant until July).

		Diesel KWh	LNG KWh
2012	JAN	1,049,135	
	FEB	30,817	
	MAR	52,508	
	APR	31,075	
	MAY	8,688	
	JUN	68,590	
	JUL	53,705	
	AUG	23,343	
	SEP	95,631	
	OCT	125,276	

		Diesel KWh	LNG KWh
	NOV	336,502	
	DEC	1,179,865	
2013	JAN	217,448	
	FEB	35,176	
	MAR	182,266	
	APR	38,977	
	MAY	22,704	
	JUN	101,487	
	JUL	747,132	
	AUG	37,176	
	SEP	37,313	
	OCT	57,754	
	NOV	61,283	
	DEC	370,800	
2014	JAN	49,387	
	FEB	140,038	
	MAR	59,173	
	APR	84,667	
	MAY	27,270	
	JUN	50,287	
	JUL	158,370	
	AUG	114,885	
	SEP	54,202	
	OCT	173,127	
	NOV	540,003	
	DEC	114,189	
2015	JAN	564,599	
	FEB	512,333	
	MAR	57,249	
	APR	23,773	
	MAY	385,530	
	JUN	332,714	310,000
	JUL	94,708	-
	AUG	280,563	12,000
	SEP	476,948	123,000
	OCT	402,476	194,200
	NOV	165,729	235,600
	DEC	276,967	420,100

		Diesel KWh	LNG KWh
2016	JAN	65,483	135,300
	FEB	23,749	68,200
	MAR	28,747	47,900
	APR	27,316	36,000
	MAY	133,108	10,900
	JUN	94,492	9,650
	JUL	507,074	23,950
	AUG	125,687	6,800
	SEP	637,993	1,234,000
	OCT	50,968	198,400
	NOV	71,203	-
	DEC	1,113,601	1,480,100

(b)

Compared to LNG engines, YEC diesel generators are more effective for cold load pickup due to a faster responding governor which is able to recover frequency quicker.

(c)

Year	Outages Requiring Whitehorse Diesel
2012	2
2013	1
2014	3
2015	6
2016	1

(d)

This question cannot be answered without further detail (e.g., specific grid load, definition of “quickly as reasonably possible”).

TOPIC: **Section 2 Sales and Revenue**

REFERENCE: Page 2-18 Table 2.2

QUESTION:

a) Table 2.2 (line below line 17) shows that the total forecasted thermal generation in 2017 and 2018 will be 2,172 and 2,010 MWh respectively. These figures are less than one-half of the actual thermal generation required in 2015, and approximately one-third of the actual thermal generation required in 2016. Please explain this, particularly in light of the increase in peak demand forecast.

b) Line 17 indicates that the actual forecasted LNG generation is approximately 53.9% and 53.5% in 2017 and 2018 respectively. In light of these figures, please explain how YEC calculated a mix of 90% LNG and 10% diesel (Application page 4 and elsewhere) on a go forward basis.

c) If these 2017 and 2018 forecasts include diesel generation required for restoration from outages and diesel maintenance (regular run-ups), please provide separately diesel and LNG consumptions by year for:
    i. Maintenance and outage restoration; and
    ii. The LTA requirements based on hydro energy and/or capacity limitations.

d) If the forecasts for 2017 and 2018 incorporate above LTA water availability please answer (c) above as though LTA water availability applies to 2017 and 2018.

ANSWER:

(a) through **(d)**

The forecasted thermal generation in 2017 and 2018 as shown in Table 2.2 includes the following:

1. Forecast “actual” generation (lines 16 and 17): As noted in footnote 4, this forecast includes generation required for maintenance, capital and peaking (based on short term hydro generation forecasts). Specific amounts included in the forecasts of

total "actual" thermal generation of 2,172 MW.h in 2017 and 2,010 MW.h in 2018 are as follows:

a. Maintenance (as summarized at page 3-4 of the Application):
    i. Diesel at 312.5 MW.h in 2017 and 229.2 MW.h in 2018
    ii. LNG at 133.3 MW.h in 2017 and 100.0 MW.h in 2018

b. Capital at 596.4 MW.h each test year (as noted in footnote 4 to Table 2.2, assumed to be diesel)

c. Peaking at 1,130 MW.h in 2017 and 1,084.4 MW.h in 2018, assumed at 90% LNG and 10% diesel.

2. LTA thermal generation – based on firm generation load (line 6) less LTA wind generation and LTA hydro generation, the LTA thermal generation is 14,146 MW.h for 2017 and 14,480 MW.h for 2018.

3. The following are noted regarding the relationships between the LTA thermal and the forecast actual thermal generation in Table 2.2 (and the related impacts on forecast GRA fuel costs in Table 3.2):

    a. LTA thermal is assumed to include "peaking" as forecast under "actual" generation, i.e., in Table 3.2 the LTA thermal is included at the assumed 90/10 LNG/diesel split, and peaking is not added to this assessment. Accordingly, the peaking thermal generation forecast as such does not affect Table 3.2 forecast GRA fuel costs.

    b. LTA thermal is assumed not to include maintenance thermal generation or capital thermal generation:
        i. Table 3.2 forecast GRA fuel costs includes forecast maintenance LNG and diesel generation (in addition to LTA thermal generation).
        ii. Table 3.2 forecast GRA fuel costs does not include capital-related thermal generation (these fuel costs are assumed in the relevant capital project costs). Accordingly, the capital thermal generation forecast as such does not affect Table 3.2 forecast GRA fuel costs.

The 2017 and 2018 “actual” thermal generation forecasts in Table 2.2 are lower than actual thermal generation in 2015 and 2016 due to lower capital/RFID thermal generation (which was 2,047 MW.h in 2015 and 1,043 MW.h in 2016) and the extent that “peaking” generation (which is affected by a wide range of factors) was higher in these earlier years than in the GRA forecast for the test years. These variances have no impact on the GRA forecast fuel costs in Table 3.2 for the test years.

The proposed 90/10 LNG/diesel split for LTA thermal generation in the test years has no bearing to actual LNG/diesel splits as shown in Table 2.2. Please see response to YUB-YEC-1-25 for a more detailed review.

Outage restoration thermal generation is not forecast for GRA test year thermal generation as shown in Table 2.2 or in forecast fuel costs as shown in Table 3.2.

TOPIC: **Section 3 Revenue Requirement**

REFERENCE: Page 3-10 Brushing costs and Appendix 3.1

QUESTION:

a) YEC's 2012-2013 GRA said on page 3-9 lines 8 and 9: "In 2012 Yukon Energy is field testing the recommendations (e.g., herbicide treatments) prior to developing a formal policy." Please provide the results of these field testing trials of these species specific herbicides.

b) Appendix 3.1 suggests (Section 9) that YEC is still "studying" the use of these herbicides, please explain in detail. Does "studying" include field trials as were being done in 2012?

ANSWER:

(a)

Please see study attached as John Maissan-YEC-1-14 Attachment 1.

(b)

YEC is still monitoring the established trial plots to provide ongoing validation of study findings.

VEGETATION MANAGEMENT OF POWER LINE RIGHTS-OF-WAY IN NORTHERN CANADA

Vegetation Control Strategies, Including Herbicide-Use, on Power Line Rights-of-Way in the Yukon Territory

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EXECUTIVE SUMMARY

This technical report summarizes work completed from May 2014-May 2017 in fulfillment of the NSERC ARD grant entitled “Vegetation management of power line rights-of-ways in northern Canada”. Partners on the grant included Yukon Energy Corporation, Environmental Dynamics Inc. and Yukon College with collaboration from the University of Saskatchewan. The summarized findings constitute the requirements from two Master of Science degrees at the University of Saskatchewan (Isbister 2016; Jimmo 2017). A preliminary ecological risk assessment is presented based on the data gathered by Isbister and Jimmo. Finally, the need for effective vegetation mapping and consideration of community and cultural values for responsible vegetation control on Yukon power line rights-of way are discussed.

Utility companies are required to provide safe, reliable service that can be compromised by trees near or underneath the transmission lines. Today, right-of-way (ROW) managers have more complex treatment options to evaluate and implement. Integrated Vegetation Management (IVM) is a decision matrix used to support the development of a vegetation management plan. IVM is an adaptive management approach that implies no one treatment will be effective for all sites and situations and many factors need to be considered. The first step in developing an IVM plan is to establish a thorough understanding of local plant community dynamics and how they are affected by or respond to different management methods. Eight vegetation management methods were evaluated on ROW plant communities one year after treatment in field trials at four Yukon ROW sites. Findings from the field trial include:

- Chemical management with the herbicides triclopyr (Garlon XRT) and imazapyr (Arsenal Powerline) was more effective (75 to 95% reduction of target) at controlling target woody species than mechanical cutting (<50% reduction) one year post treatment;
- Imazapyr caused more damage to non-target plants than triclopyr, and non-target plants damaged by triclopyr recovered one year after treatment;
- Significant non-target plant community changes were not detected; however, selective impacts of treatments on life forms/species are promising as the differences indicate treatments can be designed to meet management objectives; and,
- Further monitoring over the duration of a management cycle (8-10 years) is required to determine the longer-term efficacy of treatments and the nature of the newly developed plant communities.

Aside from treatment efficacy, environmental and socio-economic impacts of chemical treatments must be considered. Chemical persistence in the environment and sensitivity of non-target plants and other ecological receptors to imazapyr and triclopyr were determined to quantify the observed effects in the field. Chemical dissipation rates and characteristics were estimated in field-treated soil and vegetation (*Salix glauca*). Direct chemical sensitivity of non-target plants and soil invertebrates to herbicides were determined using standard Environment Canada or Organization for Economic Cooperation and Development toxicity testing procedures in greenhouse and laboratory trials. Indirect determination of

chemical risk to herbivorous animals (e.g., moose) was estimated through a preliminary ecological risk assessment. Findings include:

- Imazapyr's high phytotoxicity to many non-target species and persistence in soil and vegetation indicates that it is not a suitable product for northern ROWs;
- Soil invertebrates were relatively insensitive to either herbicide;
- The likelihood of risk to herbivorous animals from acute or chronic exposure to either herbicide was low or deemed acceptable; therefore,
- Triclopyr is the better herbicide option for inclusion in an IVM plan when all lines of evidence are considered.

Ecological effects of herbicide use are only one aspect for consideration when designing an IVM plan. Some considerations to improve the public consultation process are presented. These include:

- Integration of GIS and community input to determine buffer zones to water ways, First Nation communities and properties, and other private and public properties that might be impacted;
- Encourage local contractors to direct efforts into training for data acquisition and vegetation monitoring; and,
- Maintain consistent communication between stakeholders to build trust and collaboration, helping to ensure continued stakeholder support.

The summarized studies in this report provided a number of insights to various vegetation management techniques including method efficacy, persistence of herbicidal chemicals, and potential sensitivity of non-target organisms to chemical treatments. However, it is by no means comprehensive. The following issues need to be address in order better formulate IVM strategies:

- Long-term monitoring of the treated plots is necessary to determine the trajectory of developing plant communities;
- Additional data and samples were collected but not analyzed because time limitations;
- Efficacy of alternate/lower herbicide application rates in the field need testing; and,
- Impact of treatments on aquatic organisms and water quality and habit alteration for birds and animals were not considered.

The work completed to date determined that different management techniques can alter northern boreal plant communities, chemical management methods are effective at short-term (up to one-year post treatment) woody species control, and triclopyr is the better chemical control when all lines of evidence are considered. While developmental trajectories of boreal plant communities after treatment require long-term monitoring, results from this study indicate that IVM principles can be applied to northern power line ROWs. Socio-economic and environmental considerations will vary between sites, requiring the integration of Geographic Information System (GIS) with information from public consultation. An IVM strategy can then be formulated to reflect local environmental and socio-economic conditions.

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1.0 INTRODUCTION

Electrical utility rights-of-way (ROWs) present unique and demanding challenges for vegetation management. Utility companies are required to provide safe, reliable service that can be compromised by trees near or underneath the transmission lines. Adjacent forests provide locally adapted seeds and suckers to rapidly recolonize ROWs, which results in a cyclical management regime of tree/tall shrub removal (Berkowitz et al. 1995). Prior to the 1940s, mechanical methods of brushing, mowing, or hand cutting were the only tools utilized. After the Second World War, herbicide use became more common and is now widely used in North America (Sulak and Kielbaso 2000).

Promoting interspecific competition through seeding or enhancing shrubby or grass species is a relatively new technique that may also be used to supplement either mechanical or chemical treatments (Meilleur et al. 1997). With this increased toolbox, ROW managers have much more complex treatment options to evaluate and implement. The term “Integrated Vegetation Management” (IVM) is applied to this decision matrix and implies that no one treatment is going to be effective for all sites and situations and many factors must be taken into consideration. The first step in developing an IVM plan is to establish a thorough understanding of local plant community dynamics and how they are affected by different management methods (Nowak and Ballard 2005).

1.1. Background

There are more than 1000 km of power line ROW in Yukon, Canada. Vegetation management along the 30 m wide corridors has historically been by mechanical methods using heavy equipment to mow or brush the vegetation. In the summer of 2013 Yukon Energy Corporation (YEC) began exploring the potential to use herbicides (glyphosate, imazapyr and triclopyr) as a component of IVM on power line ROWs in Yukon, Canada. Although, initial trials indicated that short-term vegetation control could be achieved with the use of herbicides (EDI 2013) many questions and concerns remain regarding the application, fate and toxicity of herbicides in a northern environment.

Herbicide effectiveness and attenuation have been extensively studied in more temperate climates; however, few studies have examined the impact of herbicides in cold regions (Tilsworth et al. 1991; Nash 1998; Barnes and Seefeldt 2009; Seefeldt et al., 2013). To determine the effectiveness and risk assessment implications associated with herbicide application in northern ROWs further studies are required.

No single method is the most effective method under all site conditions, likely due to the response of different vegetation growth forms and differences in environmental and soil conditions (Tilsworth et al., 1991; Nash 1998). Therefore, vegetation management based upon an understanding of how vegetation and soil communities respond to physical and chemical disturbance in northern boreal ecosystems can provide a means to improve management success, while reducing cost and environmental risk.

1.2. Regulatory Guidance Relevant to Herbicide Usage on Power Line Rights-of-Way

Herbicides were one of several potential tools evaluated for incorporation into IVM strategies to control vegetation in Yukon power line ROWs. A detailed review of the legislations and standards applicable to the use of herbicides for vegetation control on ROWs is provided by EDI, 2013 (**Appendix A**). The work involving the use of herbicides reported herein was completed in accordance with applicable guidance from various regulatory jurisdictions where available. Primary guidance from the following documents was applied:

- Yukon Environment Act (2002) – Pesticide Regulations (1994) (Yukon Government, 2002);
- Pest Control Products Act (2002);
- Transportation of Dangerous Goods Act (1992);
- Fisheries Act (1985);
- Migratory Birds Convention Act (1994);
- Species at Risk Act (2002); and,
- Transmission Vegetation Management (NERC, 2006); and,

1.3. Objectives and Overview of this Technical Report

Based on the recommendations from EDI (2013), a research project investigating potential IVM strategies for Yukon ROWs began in 2014 to examine potential management impacts on target and non-target vascular plants one year after treatment. Specifically, this involved documenting how mechanical, chemical and biological management techniques influenced ROW plant communities, the short-term efficacy of treatments on target species control, and the response of non-target species in terms of cover change and herbicide induced damage in a field trial. This research was conducted in collaboration between YEC, EDI, Yukon College, and the University of Saskatchewan. This research resulted in two dissertations completed in fulfillment of the Master of Science requirements at the University of Saskatchewan. The report in-hand is a technical summary (**Section 4.0**) of the following dissertations:

- Isbister, K.M. 2016. Early Responses of Northern Boreal Vegetation to Power Line Right-of-Way Management Techniques including the Acute Toxicity of Imazapyr and Triclopyr to Non-Target Plants. M.Sc. Thesis, University of Saskatchewan, pp.147 (refer to **Appendix B** of this report). Parts of this thesis were assembled into a manuscript, peer reviewed and accepted for publication. The citation for the published manuscript is “Herbicide toxicity testing with non-target boreal plants: the sensitivity of *Achillea millefolium* L. and *Chamerion angustifolium* L. to triclopyr and imazapyr” (Isbister et al. 2017). It is also included in **Appendix B.**
- Jimmo, A. 2017. Linking Herbicide Dissipation to Soil Ecological Risk along Rights-of-Way in the Yukon Territory. M.Sc. Thesis, University of Saskatchewan, DRAFT (refer to **Appendix C** of this report).

Consult these two appendices for full details of the materials presented in this technical summary.

Herbicide usage for vegetation control on ROWs is not common in Yukon because its usage is often met with negative public and government reactions. To date rejection of herbicide use is linked to insufficient assessment of herbicide toxicity to non-target organisms (vegetation, animals, human) and

inadequate community engagement. To address the former, a preliminary environmental risk assessment (**Section 5.0**) is provided in this technical report based on the field-based herbicide dissipation results and greenhouse and laboratory-based toxicity testing completed by Isbister (2016, 2017) and Jimmo (2017).

Community engagement is a complex process where scientific results are used to facilitate the conversation between the proponent, the public, and government. A brief framework for incorporating IVM and Geographical Information System (GIS) as an adaptive strategy to meet the community socio-economic values is presented in **Section 6.0**. This framework is a work-in-progress that will require input and revision from all stakeholders.

2.0 LITERATURE REVIEW

The objective of this literature review is to examine the fundamental vegetation management principles behind integrated vegetation management (IVM) and the current management options for power line ROWs. How these principles can be applied and adapted for vegetation management on Yukon ROWs is investigated. Understanding how plant species are impacted by herbicide applications is a critical component of IVM. As a tool for determining individual plant species sensitivities to herbicides, the application and limitations of dose-response relationships and phytotoxicity testing are discussed. In addition to direct impacts of herbicide applications on plants and plant communities, persistence of herbicide active ingredients in plant tissue can provide a vector into other ecosystem compartments. The potential for herbicide persistence in vegetation and soils under northern conditions is briefly discussed. The impact of herbicides on soil ecosystems is further considered through assessing the toxicity of herbicides to soil invertebrates commonly found on northern ROWs. The reviewed information is excerpted from Isbister (2016, 2017) and Jimmo (2017).

2.1. Designing Disturbance to Meet Vegetation Management Objectives

2.1.1. Response of vascular plant species to disturbance

The process of manipulating disturbance type, size and intensity to promote the establishment of desired plant species or communities was first described as “designing” disturbance by Rosenberg and Freedman (1984). To design disturbance and thus promote plant communities to meet management objectives, the first task is to understand the local ecosystem and how plant species respond to disturbance (Pickett et al. 2009).

There are many factors involved in plant community development, but disturbance history consistently has a major influence (Attiwill 1994; Rydgren et al. 2004; Schmitz et al. 2006). In the northern boreal forest, this has been demonstrated by differences in communities after varying fire regimes or harvesting practices (Johnstone 2006; Macdonald and Fenniak 2007). Each plant species will react to disturbance differently. By altering the type, frequency and intensity of disturbance, plant communities can effectively be designed to meet management objectives (Attiwill 1994; Pickett et al. 2009). Integrated Vegetation Management (IVM) was founded on these principles.

2.1.2. The IVM toolbox: vegetation management methods for power line ROWs

One of the fundamental principles of IVM is that methods need to be appropriate for site, environmental and socio-economic conditions and one method is likely not suitable for all sites (Nowak and Ballard 2005). A range of options, therefore, must be available to managers. Prior to the 1940s, mechanical methods of brushing, mowing or hand cutting were the only tools readily available to vegetation managers, but today many strategies can be utilized.

Mechanical control of target species by brushing, mowing or hand cutting physically removes the aboveground vegetation with varying amounts of soil disturbance. Mechanical methods are still widely used across North America (Sulak and Kielbaso 2000), despite significant evidence that mowing or

brushing can often increase target species reproduction and growth on ROWs (Luken et al. 1991; Yahner and Hutnik 2004).

After the Second World War, chemical use became more common and is now widely used by many companies for power line ROW vegetation management (Sulak and Kielbaso 2000). There are many formulations and application methods for herbicide use on ROWs. Unlike mechanical mowing, herbicide applications are intended to kill both the above and belowground portions of target species (Egler 1954). The chemicals themselves can be broad-spectrum or selective: impacting only certain plant groups such as dicots (Stephenson and Solomon 2007). Application methods vary from non-selective (broadcast foliar spray or soil dispersal) to selective (cut stump, basal, stem-foliar and foliar) (Stephenson and Solomon 2007).

Seeding or transplanting competitive shrub and forb species – also known as ecological/biological control or manipulation – is a relatively new method with the potential to use interspecific plant competition to the manager's advantage. Transplanting or encouraging natural reproduction of woody shrubs is one of two ecological manipulation strategies for ROWs. This includes layering – the process of anchoring the tips young stems to the ground to promote rooting and expansion of woody shrubs – which was found to be successful in increasing *Cornus stolonifera* cover on a ROW in Quebec (Meilleur et al. 1997). Coppicing – cutting main stems to encourage suckering in woody shrubs – is another enhancement method that was reported to increase stem density but not crown cover of *Viburnum lentago* and *Cornus racemosa* on New York ROWs (Ballard 2006). Seeding cover crops of competitive agronomic or native grasses is another biological manipulation strategy for disturbed sites. The seeding of *Dactylis glomerata*, a highly competitive grass from Eurasia, successfully established and reduced regrowth of tree transplants near Tobermory, Ontario. Though not widely documented on power line ROWs, success with establishing native grass has been reported for abandoned gravel pits and roadsides (Maslen 1989; Tyser et al. 1998; Petersen et al. 2004). These grass communities resisted invasion of other species and persisted for multiple years.

Identifying desirable cover types for Yukon ROWs and management methods that may promote the development of these communities are discussed in the next section.

2.2. Examining Vegetation Management Strategies to Promote Desired Successional Pathways for Yukon ROWs

2.2.1. Identifying desired cover types

Selecting an appropriate cover type for local ecological and environmental conditions is critical for limiting the growth of target species (de Blois et al. 2004) and needs to be completed before potential management methods can be determined. In southern jurisdictions, maintaining or enhancing shrub cover has been identified as the most effective and logistically practical method of inhibiting target species establishment under transmission lines (Niering and Goodwin 1974; Dreyer and Niering 1986; Meilleur et al. 1994). Shrub cover or stem density has been proven to reduce target species invasion on ROWs.

Desirable shrub species on ROWs have been documented in eastern North America (e.g. Ballard et al. 2011), but there are few shared species between eastern deciduous and northern boreal forests. Nevertheless, many northern shrubs share characteristics such as clonal growth and preference for sun exposure that have been linked to the formation of dense cover (Meilleur et al. 1994). Prickly rose (*Rosa acicularis*) and bog bilberry (*Vaccinium uliginosum*) are common shrubs on Yukon ROWs and capable of forming dense, low-growing thickets.

In addition to shrub cover types, aggressive perennial grasses may provide a solution as they are well documented competitors of tree seedlings in the northern forestry industry (Ballandier et al. 2006). The roots and litter of bluejoint reedgrass (*Calamagrostis canadensis*), for example, can directly suppress aspen seedling and sucker development by maintaining cooler soil temperatures and physically preventing sucker penetration through the soil (Landhäusser and Lieffers 1998; Landhäusser et al. 2007).

Two potential cover types, therefore, may be appropriate for Yukon ROWs: a low growing shrub community or a dense mat of competitive native grass species. Which management methods may promote development of these plant communities remains uncertain as community development after disturbance is a site-specific and complex process.

2.2.2. Control methods selection

On Yukon ROWs, *Populus tremuloides*, *Populus balsamifera* and *Salix* spp. are the most common target species though *Betula neoalaskana* is locally dominant at wetter sites. Target species were identified as species that grow quickly after disturbance and to a height that can interfere with transmission lines. *P. tremuloides* and *P. balsamifera* are well known for aggressive suckering after aboveground disturbance (Frey et al. 2003; Ilisson and Chen 2009). Willows such as *Salix bebbiana* are clonal and common in disturbed areas (Amiro and Courtin 1981; Carleton and MacLellan 1994). *Betula* spp. are also colonizers after disturbance (Peinado et al. 1998). Mechanical control by brushing and/or mowing has traditionally been used on Yukon power line ROWs. The abundance of these target species on Yukon ROWs and their life histories strongly indicate that mechanical treatments do not promote the development of plant communities resistant to these species. Herbicide use is a potential tool for Yukon ROWs as many products are registered for the most common target species requiring management.

Many utility companies use herbicides for vegetation management on ROWs (Sulak and Kielbaso 2000). A recent review of forestry-use herbicides was completed by a consulting company, Environmental Dynamics Inc. (EDI), and aminopyralid, glyphosate, imazapyr and triclopyr were identified as candidates for use on Yukon ROWs based on their effectiveness on target species, environmental risk and use by other comparable jurisdictions (EDI 2013). A small-scale field trial by EDI indicated triclopyr and imazapyr as the most effective on northern target species. There is very little information available on herbicide behaviour under northern conditions (Newton et al. 2008) and environmental risks are difficult to estimate. To further investigate herbicide use for vegetation management on Yukon ROWs, Garlon XRT (triclopyr) and Arsenal Powerline (imazapyr) were chosen as candidates for testing.

Triclopyr (commercial formulation Garlon XRT, 755 g L-1 triclopyr butoxyethyl ester; Dow AgroSciences Canada Inc, Calgary, AB) is a pyridine-based herbicide in the carboxylic acid family. It is formulated as a

butoxyethyl ether or triethylamine salt, both of which readily dissociate into triclopyr acid in water. It was first registered in Canada in 1989 as a Group 4 selective herbicide for use on broadleaf and woody vegetation in non-crop areas. Similar to the phenoxyacetic acids (e.g. 2,4-D) and benzoic acids (e.g. dicamba), triclopyr acts as an auxin mimic, effectively giving the plant a hormone overdose. As a foliar spray, triclopyr is rapidly absorbed from the leaf and translocated through the plant in as little as 12 hours (Lewer and Owen 1990). It has low leachability and the majority deposited on the forest floor remains in the organic layer (Lee et al. 1986; Thompson et al. 2000). Triclopyr typically degrades rapidly in both soil and water by microbial breakdown or photolysis (Johnson et al. 1995).

Imazapyr (commercial formulation Arsenal Powerline, 240 g L-1 imazapyr acid; BASF Canada Inc., Mississauga, ON) is a broad spectrum herbicide in the imidazolinone family. It is available both as imazapyr acid or isopropylamine salt. First registered in Canada in 1994, imazapyr is a Group 2 herbicide typically used to control grasses, broad-leaf weeds and select perennial shrubs. Like the sulfonylurea family (e.g. metsulfuron), imidazolinone herbicides inhibit the production of three amino acids by binding to the acetolactate synthase (ALS) enzyme and are most effective on young, actively growing plants (Schoenhals et al. 1990). It degrades by both photolysis on the soil surface and by microbial breakdown (Wang et al. 2005; Ramezani et al. 2008). Imazapyr can be applied pre- or post-emergence and may remain active and mobile in soils for an extended period of time (Loux and Reese 1993; Bovey and Senseman 1998; Gianelli et al. 2014).

The literature strongly recommends selective herbicide treatments for preserving non-target species, especially shrubs, as the primary method of creating tree-resistant communities (Dreyer and Niering 1986; Niering et al. 1986; Bramble et al. 1991; Mercier et al. 2001; Yahner and Hutnik 2004). The efficacy of selective herbicide on target species is also a critical component, as even intact shrub communities are susceptible to invasion by suckers from established trees (Dreyer and Niering 1986). The most common selective treatments are basal bark application, cut stump/wet-blading, and targeted low-high volume foliar spray (Nowak and Ballard 2005a). Point injection has also been gaining popularity, especially for woody invasive species control (Lewis and McCarthy 2008). Non-selective herbicide treatments also change plant community structures, but generally favour annual species that do not persist long enough to inhibit target species growth (Bramble et al. 1991; Luken et al. 1994). In Alaska however, shrub control with broadcast spray applications of triclopyr resulted in higher graminoid cover as triclopyr's mode of action does not affect monocots (Seefeldt et al. 2013). It is unknown whether this grass cover persisted for more than two years or inhibited reestablishment of woody species. The complexity of vegetation dynamics after disturbance makes predictions very difficult, but by trying both selective and non-selective herbicides applied by selective and non-selective methods new community development trajectories may be induced.

Establishing graminoid cover may also be improved by direct seeding. Species selection for native grass seeding depends on species characteristics as well as site conditions and seed availability (Karim and Mallik 2008). Two prominent competitors of tree species in the boreal forestry industry, bluejoint reedgrass (*Calamagrostis canadensis*) and tufted hairgrass (*Deschampsia caespitosa*), are native to Yukon and have the potential to reduce target species regrowth under power lines (Ballandier et al. 2006). *C. canadensis* is a grass that aggressively develops a thick mat of roots and rhizomes and can out

compete both woody and herbaceous species for soil nitrogen (Hangs et al. 2003; Landhäusser and Lieffers 1998). In Yukon, *C. canadensis* can aggressively colonize disturbed areas where mineral soil is exposed, and stagnate ecosystem development (Simpson 2012). *D. caespitosa* is a slower growing grass, but once established it can successfully compete with woody species for moisture (Collet et al. 1996). Rapid colonization after disturbance is also an important characteristic for herbaceous cover crop species (Brown 1995) and slender wheatgrass (*Elymus trachycaulus*) is a rapidly establishing native grass often used for revegetation purposes (Buss et al. 1997; Petersen et al. 2004). Glaucus bluegrass (*Poa glauca*), violet wheatgrass (*Elymus violaceus*; previously *E. alaskanus*) and rocky mountain fescue (*Festuca saximontana*) are recommended for grass cover on dry sites in Yukon and are already found on Yukon ROWs (Matheus and Omzigt 2011). By applying a mix of species, graminoid covers can be designed to establish quickly, provide adequate ground cover and potentially out compete undesirable tree and tall shrub species.

2.3. Special Management Considerations: Phytotoxicity of Herbicides to Non-Target Organisms and Persistence of Active Ingredients in Plant Tissue and Soil

In northern Canada, herbicide use for woody species control is not widespread nor are its effects on northern native plant species in local soils well understood. In Alaska, applications of triclopyr and 2,4-D for shrub control had species-specific impacts on non-target vascular plants (Seefeldt et al. 2013). Forb cover overall did not decline two years after treatments; however, certain species such as *Chamerion angustifolium* significantly declined in triclopyr broadcast spray plots and *Erigeron acris* was highly sensitive to 2,4-D broadcast spray. It is likely that Yukon ROW non-target plant species will also have a large range of sensitivities to herbicides. Terrestrial plant acute toxicity tests provide a standardized method to assess potential impacts on important non-target species from chemical vegetation management strategies.

2.3.1. Assessing phytotoxicity of herbicides to non-target terrestrial plants

Ecotoxicity testing to assess environmental risks of pest control products is a key component of pesticide regulation. Toxicity is the degree to which a substance causes negative effects on an organism and phytotoxicity refers to the toxicity of a substance specifically to plants. Test organisms are subjected to a series of increasing doses and a predetermined endpoint such as surviving individuals, size or biomass is measured at the end of the test. The tests typically use non-linear regression techniques to model dose-response relationships and generate percent growth inhibition (Inhibition Concentration: ICx) or percent mortality of individuals (Effective Concentration: ECx) (EC 2013). The estimates provide standardized values to compare toxicities of chemicals or sensitivities of organisms (Seefeldt et al. 1995). There are two tests used to characterize acute toxicity of herbicides to terrestrial plants: the vegetative vigour test and the seedling emergence and seedling growth test (OECD 2006, USEPA 2012). The vegetative vigour test evaluates sensitivity of young plants to foliar spray, while the seedling emergence and seedling growth test assesses the effect of herbicide concentrations in soil on the germination of seeds and early seedling growth. For regulatory purposes, testing is typically completed on 6-10 annual field/row crop species from multiple families with the intention of encompassing the range of any non-target plant sensitivity.

There is considerable debate whether non-target species sensitivities are adequately represented by regulatory testing (McKelvey et al. 2002; Boutin et al. 2004; Clark et al. 2004; White and Boutin 2007). Greater sensitivities of wild species than crop species to multiple herbicides have been reported (Boutin et al. 2004), though similar sensitivities between wild and crop plants have been demonstrated as well (Carpenter and Boutin 2010; White and Boutin 2007). Within a single plant species, differences in sensitivity between cultivars and ecotypes have also been detected (White and Boutin 2007; Boutin et al. 2010). The range of sensitivities to herbicides can also vary more between wild species than agricultural ones (Olszyk et al. 2008). In addition, plant response to herbicide is also dependent on environmental conditions and even slight variations can impact sensitivity in phytotoxicity testing (Boutin et al. 2010).

The production of homogenous "crops" of wild plants for toxicity testing is a significant challenge. Seed for wild species is less readily available than for field/row crops (White et al., 2009) and quality is less consistent (Pallett et al. 2007). Many wild species' seeds also have dormancy requirements that must be met to maximize germination percentages (White et al., 2009). Wild plants are often slower to reach the required growth stage for testing (Boutin et al. 2004) and there is higher intrinsic variability in individual plant growth rates and biomass (Pallett et al. 2007). Nevertheless, there are successful examples of wild plant species meeting regulatory criteria for valid toxicity testing (Boutin et al. 2004; Olszyk et al. 2008; Boutin et al. 2010; Princz et al. 2012).

2.3.2. Assessing herbicide toxicity to soil invertebrates

Soil ecotoxicology has lagged behind that of aquatic ecotoxicology due to the heterogeneous nature of soil and the difficultly associated with laboratory and field testing (EC 2014). With the expansion of soil ecotoxicological studies, standardized single species toxicity test protocols have been developed to aid in the development of site-specific soil quality guidelines (van Gestel 2012). These standardized tests have aided in the understanding of the life histories, as well as, expanded knowledge of the impact of contaminants on test species (Princz et al. 2012; van Gestel 2012). To gain adequate representations of the risk to different soil ecosystems standardized tests including species with a range of sensitivities have been developed (Princz et al. 2012). In addition, standardized tests also need to be ecologically relevant by incorporating species found at or near the sites being tested (Römbke et al. 2006).

Toxicity assays can aid in the development of site-specific guidelines for herbicide usage, which can help drive application rates. Standardized soil toxicity tests were lacking in Canada until the Canadian Council of Ministers for the Environment (CCME) published a framework for ecological risk assessment. Since publication, the framework has become a fundamental component of ecological risk assessment for terrestrial sites in Canada (Römbke et al. 2006; EC 2014). Recent research has focused on the role of soil dwelling organisms to determine applicability of specific invertebrate species for laboratory toxicity testing of contaminants in Canadian boreal and tundra soils (Römbke et al. 2006; Princz et al. 2012). Conducting tests within a laboratory setting is important as it reduces variability within the results increasing confidence in those results (Stark et al. 1995; Moran 1999; Princz et al. 2012). However, there is still some uncertainty when trying to apply laboratory test results to field conditions (Moran 1999; Princz et al. 2012).

Bioassays using soil invertebrates are important to gauge the toxicity of the bioavailable fraction of the chemicals (Loureiro et al. 2005). However, there is a lack of single species toxicity data for many chemicals (Loureiro et al. 2009). The data that is available tends to focus on earthworms. A range of species with different sensitivities should be included in risk assessments (Frampton et al. 2006; Loureiro et al. 2009). Soil invertebrate species selected for laboratory toxicity assays are generally of ecological relevance and are easy to handle and maintain (Römbke et al. 2006; Princz et al. 2012). Collembola and enchytraeid species are ideal because they are abundant and provide an important ecological service in the decomposition of organic matter and in the structure of soil (Jansch et al. 2006; Princz et al. 2010, 2012). Princz et al., (2010) determined that, due to their prevalence in boreal soil systems, Oribatid mites should be added to ecotoxicity testing in Canada. To assess the effects of herbicides on terrestrial ecosystems along ROWs within the Yukon Territory, three invertebrate groups – enchytraeid (*Enchytreaus crypticus*), collembola (*Folsomia candida*), and mites (*Oppia nitens*) – are evaluated.

2.3.3. Benefits of toxicity testing with ecologically relevant species and substrates

Estimating boreal plant species sensitivities to herbicides is difficult as there is limited background information on herbicide behaviour in northern Canada. It is uncertain whether native boreal species are similarly sensitive to herbicides as crop species. Princz et al. (2012), for example, found boreal plants to be more sensitive to hydrocarbon contaminated soil than crop species but similarly sensitive to soil salinity. Shrub control research in Alaska indicates herbicide sensitivities of boreal plants vary between species and sometimes site specific (Seefeldt et al. 2013). The sensitivities of the two most frequent and abundant native herbaceous species at the Yukon ROW research sites, *Achillea millefolium* and *Chamerion angustifolium*, are of particular concern. *A. millefolium* and *C. angustifolium* are widespread rhizomatous perennials that are ecologically and culturally important. Snowshoe hare (*Lepus americanus*), a keystone boreal species, feeds on both plant species during the late summer (Seccombe-Hett and Turkington 2008). *C. angustifolium* is also particularly attractive to bees and other pollinators (Kevan et al. 1993) and is an important component of moose summer diet (Johanson et al. 1994). Both species are culturally important as edible and/or medicinal plants (Gray 2012). Covering more than 5% of Yukon ROW research sites, the disappearance *A. millefolium* and *C. angustifolium* may have negative effects on ROW plant communities and ecosystems. The use of these two species for phytotoxicity testing provides species-specific toxicity information to increase knowledge of herbicide impacts on non-target plants on Yukon ROWs.

In addition to species variability, bioavailability of herbicide can differ depending on soil characteristics (Loux and Reese 1993; Eliason et al. 2004; Allison et al. 2013). The sorption of herbicide to soil particles can lower the amount of herbicide readily absorbed by plant roots and thus, toxicity to seeds and seedlings may be soil specific. Triclopyr and imazapyr are weak acids and exist mostly in their anionic state in all but the most acidic soils (Johnson et al. 1995; Gianelli et al. 2014). With a negative charge, these chemicals do not sorb strongly to soil particles and are relatively mobile. When deposited on the forest floor, the majority of triclopyr residues remain in the organic soil horizon (Thompson et al. 2000) suggesting triclopyr sorption will increase with organic carbon content. Imazapyr does not readily sorb to organic matter unless soil pH is very low (<5) and bioavailability is not typically affected by soil organic carbon (Pusino et al. 1997). Imazapyr sorption is positively associated with clay, iron and aluminum

content and imazapyr is likely less available to plants in clay, iron and /or aluminum rich soils (Gianelli et al. 2014). Both herbicides are degraded in soil primarily through microbial breakdown (Johnson et al. 1995; Gianelli et al. 2014) and the use of native soils with intact microbial communities better represents field conditions than sterilized soil. The use of field collected soils for seedling emergence and seedling growth tests provides a better representation of northern ROW conditions than generic potting soil and incorporates the effects of soil type on herbicide bioavailability into the test.

2.3.4. Persistence of herbicide active ingredient in plant tissue

In addition to acute phytotoxicity of herbicides to plants, the dissipation rates of these chemicals in plant tissue is also of concern. Degradation, persistence and dissipation are all terms related to the residence time of herbicides in soil and vegetation. Degradation is the breakdown of the herbicide molecule from the parent compound to metabolites by a chemical process (Mueller and Senseman 2015). Persistence involves the length of time herbicide residues are present in soil and is considered the inverse of dissipation (Mueller and Senseman 2015). Dissipation is the sum of all possible outcomes of the parent compound (Mueller and Senseman 2015). As the primary producers in intricately connected ecosystems, grasses, forbs and shrubs provide pathways for herbicide residue into the wider environment including transfer to wildlife (Tatum 2004). Foliage can also act as a source for soil contamination when fallen leaves decompose on the forest floor (Thompson et al. 1994). It is widely accepted that the rate of dissipation of herbicides from vegetation is significantly dependent on environmental conditions (Newton et al. 2008); how northern climates will impact dissipation rates is not well understood.

If the herbicide persists on the leaf surface, it can dissipate through volatilization, photolysis or microbial breakdown (Bentson and Norris 1991; Newton et al. 2008). The net effect of northern environmental conditions on these processes is unknown. Long photoperiods in the summer associated with higher latitudes may increase the rate of photolysis on the leaf before it can be absorbed, however, microbial breakdown may be slower due to cooler temperatures. Once absorbed, degradation requires the herbicide be metabolized or deposited in foliage (Newton et al. 1990). The ability to metabolize herbicides is species specific as demonstrated by Sidhu and Feng (1993). Plant metabolic activity is limited in the North partially due to cool soil temperatures (Bonan and Shugart 1989) and this may increase the residency of herbicide in plant tissue in the North. Temperature was identified as a major factor influencing dissipation rate from foliage by Newton et al. (1990). Triclopyr rapidly dissipated from foliage within the first 80 days after application, but concentrations within vegetation changed very little over the winter. In Alaska, however, Newton et al. (2008) found dissipation rates of triclopyr and imazapyr from vegetation similar to those reported at more southern latitudes. The strong influence of environmental conditions on the dissipation of herbicide from plant tissue suggests more research is needed to confirm whether rates are similar to southern regions.

2.3.5. Persistence of herbicide active ingredients in soil

Various soil processes, properties and climatic conditions contribute to the dissipation of herbicide residues in the soil. Soil processes contributing to the degradation of herbicides include adsorption, microbial degradation and photodegradation (Goetz et al. 1990; Baker and Mickelson 1994; Johnson et al. 1995; Gevao et al. 2000; Wang et al., 2006; Remucal 2014). Soil properties such as soil organic

matter, clay content and pH influence dissipation rates (MacRae and Alexander 1965; Goetz et al. 1990; Johnson et al. 1995; Jourdan et al. 1998; Gevao et al. 2000; Wang et al., 2005; Douglass et al. 2016). Climatic conditions including temperature and moisture can also influence degradation pathways and thus attenuation rates.

3.0 EXPERIMENTAL DESIGN

The reported research work is categorized as field- or greenhouse/laboratory-based trials. The field-based trial was conducted on study sites located on Yukon power line ROWs. There were two components to the field-based trial. The first was to investigate how plant communities on ROWs responded to treatment with eight vegetation management techniques. This involved describing and quantifying the vegetation community and other ecologically relevant parameters on-site before and one year after treatment.

The second component of the field trial was to quantify the dissipation rates of the two tested herbicides in treated vegetation and soil. This was completed to quantify how persistent the tested herbicides are in the environment. This involved collecting vegetation and soil samples over a period of time and determining the concentration of herbicides in these samples. Because herbicide residue in treated vegetation and soil might impact non-target organisms through translocation and/or consumption, herbicide dissipation information is used for evaluation of the potential risk from the tested herbicides on non-target ecological receptors.

The greenhouse/laboratory-based trial involved testing the two herbicides on a battery of plant and soil invertebrate species to determine the sensitivity of non-target organisms to the tested herbicides in a controlled/standardized environment (i.e., greenhouse). These toxicity tests followed standardized Environment Canada (EC) and Organization for Economic Cooperation and Development (OECD) testing protocols. Seedling emergence and growth and vegetative vigor after herbicide treatment were the life-stages measured for three boreal plant species. Adult survival/mortality and reproduction (number of progenies) were measured for the ecologically relevant soil invertebrates.

3.1. Field-Based Trial: Early (One-Year Post Treatment) Response of Plant Communities on Power Line Rights-of-Way to Eight Vegetation Management Techniques

3.1.1. Study areas

Four study sites were established on power line ROWs in Yukon, Canada, in 2014 (**Figure** 1). Sites were distributed across the territory within the Boreal Cordillera Ecozone and were representative of the ecotypes where Yukon ROWs are found (**Table 1**). A fifth site (LS) was established in 2015. Sites were selected for the study by aerial survey to ensure homogeneity of vegetation type and similar development since the last mowing cycle, which occurred between one and six years previously. The more southern sites were bordered by mid-successional boreal forests dominated by white spruce (*Picea glauca*) and trembling aspen (*Populus tremuloides*) and the more northern site (DAW) bisected a mature coniferous stand (*Picea* spp.). Dominant vascular plant covers on the ROWs prior to application of treatment are summarized in **Table 3.2** of **Appendix B**

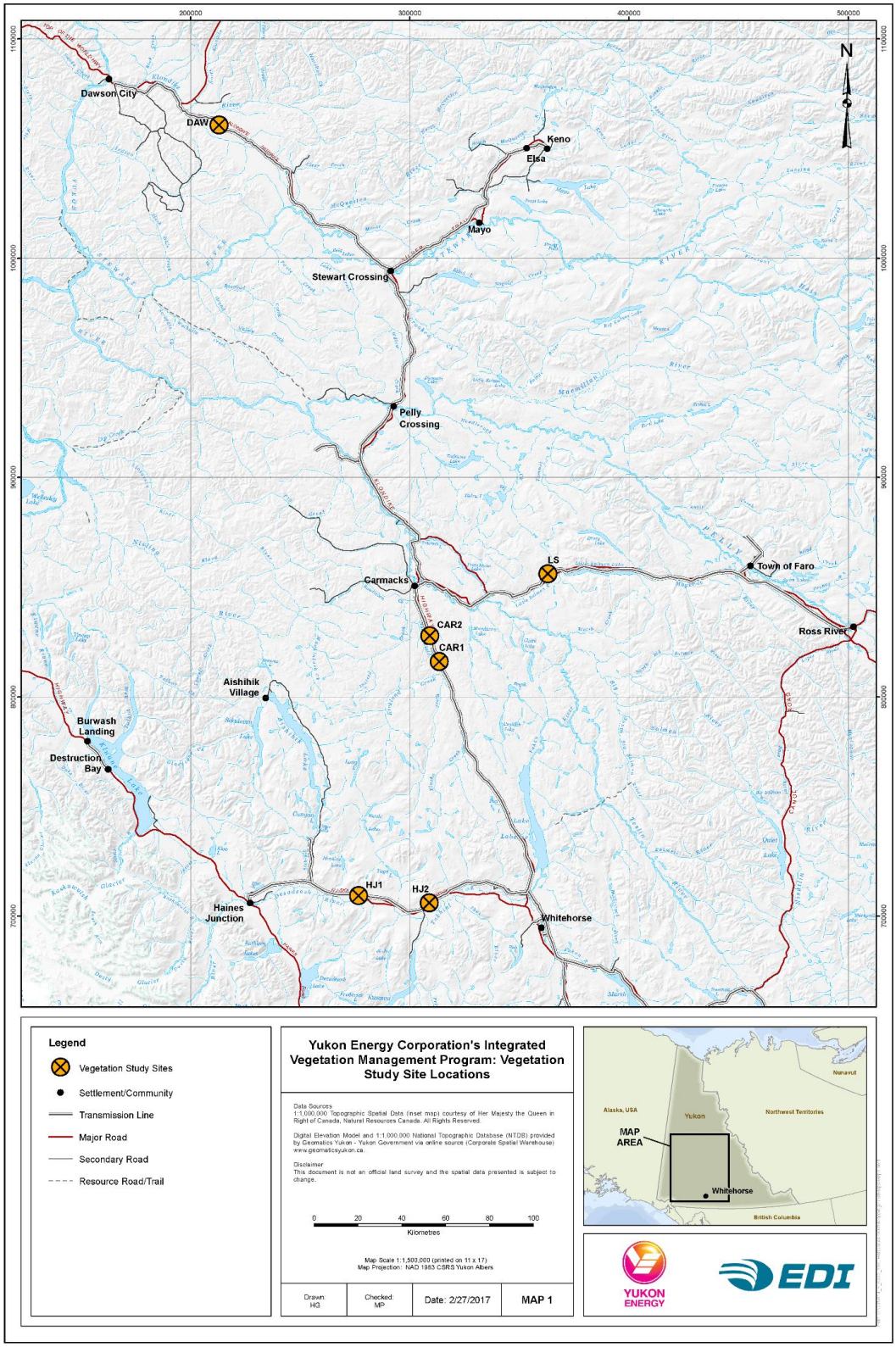

Figure 1 Map of field study locations on power line rights-of-way in Yukon Territory, Canad

Table 1 Summary of site information including GPS co-ordinates, ecoregion, soil type, last mowing cycle, mean annual precipitation, mean January and July temperatures, and treatment application date. Modified from Appendix B and C.

Site (Abbreviation)	Coordinates	Ecoregion†	Soil Type‡	Last Mowing Cycle	Mean Annual Precipitation §	Mean January Temp§	Mean July Temp§	Treatment Application
					(mm)	(°C)	(°C)	(dd-mm-yy)
Carmacks¶ (CAR)	61.8° N, 136.0° W; 61.9° N, 136.1° W	Yukon Plateau - Central	1	2010	323.4	-17.2	14.9	15-07-14
Dawson (DAW)	63.9° N, 138.4° W	Yukon Plateau - North/ Klondike Plateau	1	2008	324.3	-26.0	15.7	03-08-14
Haines Junction 1 (HJ1)	60.8° N, 136.6° W	Yukon Southern Lakes	2	2013	297.3	-16.1	13.0	19-07-14
Haines Junction 2 (HJ2)	60.8° N, 136.0° W	Yukon Southern Lakes	2	2011	297.3	-16.1	13.0	25-07-14
Little Salmon (LS)	62.1° N, 135.1° W	Yukon Plateau - Central	3	2014	319.7	-21.1	14.0	28-07-15

† As per 'Ecoregions of the Yukon Territory: Biophysical properties of Yukon landscapes' (Smith et al. 2004).
‡ Soil Type: 1) Eutric Brunisol on Sand;2) Eutric Brunisol on Clay Loam; and, 3) Eutric Brunisol on Silt Loam.
§ Weather data from Environment Canada 1981-2010 Climate Normals: Mayo Road (CAR), Dawson Airport (DAW), Otter Falls (HJ1 & HJ2) and Drury Creek (LS).
¶ Carmacks site was divided into two sections due to the variability of vegetation types and to avoid surface water drainage on the right-of-way. Blocks 1 & 2 were installed on 15-07-14 while Block 3 was installed 10km north of Blocks 1 & 2 on 21-07-14.

3.1.2. Treatment and sampling design

Each of the four sites was laid out in a randomized complete block design (RCBD). At each site three blocks with eight randomly assigned treatment plots per block were installed (**Figure 2**). The 6 m x 6 m treatment plots were spaced at a minimum of 50 m apart to avoid interference between treatments (i.e., herbicide drift). Four 1-m^2 permanent vegetation cover plots were established within each treatment plot and percent cover data recorded 5-14 days before treatments were applied in July of 2014. Total percent cover of each species was recorded to the nearest percent and all unknown species were collected from outside the plot for later identification (**Table 3.2** of **Appendix B**). Vegetation cover was recorded again in 2015 within ten days of the original observation dates.

Eight treatments were designed to represent mechanical, chemical and biological strategies for ROW vegetation management (**Table 2**). The control was mechanical mowing, the current standard vegetation management treatment. Two common products used for woody species control were selected: Garlon XRT (755 g L^{-1} triclopyr butoxyethyl ester; Dow AgroSciences Canada Inc, Calgary, AB) and Arsenal Powerline (240 g L^{-1} imazapyr acid; BASF Canada Inc., Mississauga, ON). These two herbicides were applied through three methods: broadcast spray, cut stump and point injection at the maximum rates specified on the labels (broadcast spray: 4530 g active ingredient (a.i.) ha^{-1}, 720 g a.i. ha^{-1}; cut stump and point injection: 143.5 g a.i. L^{-1} canola oil, 22.6 g a.i. L^{-1} deionized water). A backpack sprayer was used for the broadcast spray treatment. Cut stump applications were completed by hand cutting all vegetation at 20-30 cm and applying products to all cut stems with a paint brush. Point injections were applied via a syringe inserted into a small drilled hole or incision in the stem of a target species. In selective cutting/ecological manipulation plots, only target species were hand cut and removed. Point injection and selective cutting/ecological manipulation plots were also seeded with native grasses at 50 kg ha^{-1} as high seeding rates have been shown to reduce species invasion of disturbed areas in Yukon (EDI 2009). Litter was raked out of the plot to prepare the seedbed and a native grass seed mix from DLF Pickseed Canada (Lindsay, ON) was broadcast by hand (see **Table 2** seed mix composition). After seeding the plot was lightly raked to enhance seed-soil contact. Treatments were applied between mid-July and early August 2014.

Target species were defined based on two criteria: 1) rapid regrowth after disturbance; and, 2) the ability to grow tall enough to interfere with transmission lines. The main target species identified were trembling aspen (*Populus balsamifera*), balsam poplar (*Populus balsamifera*) and willow (*Salix* spp.) which were present at every site, and Alaska paper birch (*Betula neoalaskana*) was included at the DAW site. Although conifers in the Yukon Territory can grow to a height where they may interfere with lines, they are not considered a management concern by the utility company because of their slow growth rate and were thus not included as target species.

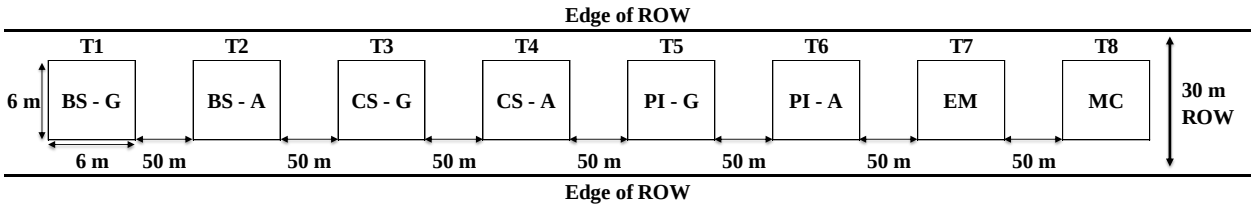

Figure 2 Study design for determining the effect of eight treatment strategies (including two herbicides) for vegetation control and for determination of herbicide dissipation in soils on Yukon power line rights-of-way (ROWs). This is an example of a block within the randomized complete block design with eight treatments: backpack spraying (BS), cut stump (CS), and point injection (PI) with two herbicides (triclopyr = Garlon XRT (G) and imazapyr = Arsenal Powerline (A)), ecological manipulation (EM), and a mowing only control (MC). Three blocks were established at each site for a total of 120 treatment plots (5 sites x 8 treatments x 3 replicates). Figure adapted from **Appendix C**.

Table 2 Description of eight rights-of-way vegetation management treatments applied in field research sites within Yukon in 2014. Table adapted from **Appendix B**.

Treatment	Abbreviation	Strategy	Description
Mowing (Control)	MC	Mechanical	Cut and removed all vegetation at 10-20 cm above soil surface
Broadcast Spray – Triclopyr/Garlon	BS-T/G	Chemical	Applied herbicide with a backpack sprayer to all vegetation; any stems above 1.5 m were cut prior to spraying
Broadcast Spray – Imazapyr/Arsenal	BS-I/A	Chemical	
Cut Stump – Triclopyr/Garlon	CS-T/G	Chemical	Cut all vegetation at 20-30 cm above soil surface and applied herbicide with a paintbrush
Cut Stump – Imazapyr/Arsenal	CS-I/A	Chemical	
Point Injection – Triclopyr/Garlon	PI-T/G	Chemical/Biological	Incised small stems/drilled large stems of targets only and applied herbicide with a syringe; seeded native grasses†
Point Injection – Imazapyr/Arsenal	PI-I/A	Chemical/Biological	
Ecological Manipulation/Selective Cutting	EM/SC	Mechanical/Biological	Hand cut and removed targets; seeded native grasses†

† Litter was raked out of the plot to prepare the seed bed and a native grass seed mix of 42% (b/wt) violet wheatgrass (*Elymus violaceus*), 26% slender wheatgrass (*Elymus trachycaulus*), 8% rocky mountain fescue (*Festuca saximontana*), 6% glaucous bluegrass (*Poa glauca*), 5% bluejoint reedgrass (*Calamagrostis canadensis*) and 2% tufted hairgrass (*Deschampsia caespitosa*) from DLF Pickseed Canada (Lindsay, ON) was broadcast by hand.

Visual herbicide damage assessments were completed one and two year(s) after application in all chemically treated plots for CAR, DAW, HJ1, and HJ2 sites. First year (2015) data for these four sites was analyzed (**Appendix B**). Second year (2016) data has not yet been analyzed but is available. For the LS site, there is only data for one year after treatment (2016) because the site was established in 2015. This data set is available, but it has not yet been analyzed.

Targets were evaluated by species and damage to treated stems and new suckers/seedlings were separated to identify duration of effect. Non-targets were assessed by life form: erect shrubs (<1.5 m in height), prostrate shrubs, forbs and graminoids. A scale of 0-100 was used with 0 being unaffected and 100 being completely dead. Only herbicide-related damage was recorded and untreated areas surrounding the plot were used as a reference to differentiate between natural and herbicide damage.

Species richness and evenness were determined for each treatment plot using the average cover and total number of species from the four vegetation cover subplots. Species richness was defined as the total number of species per plot and evenness was calculated with the EVar index based on the average percent cover of each species per plot (Smith and Wilson 1996).

Refer to **Appendix B** for the detailed description of the statistical analysis of this data.

3.2. Field-Based Trial: Dissipation of Triclopyr and Imazapyr from Treated Soil and *Salix glauca* (White Willow) Foliage

3.2.1. Study areas

Soil sampling for determination of herbicide dissipation rates was conducted at the five sites described in **Section** Error! Reference source not found.. Vegetation was also sampled at the same time; however, herbicide concentration was determined for soil only.

An additional 500 m section along the ROW near HJ2 (60.778°N, 136.071°W) was used to conduct a 30-day field-based triclopyr and imazapyr dissipation experiment in the foliage of *Salix glauca* (white willow). *S. glauca* was chosen because it is commonly found along the power line ROW, and its foliage is consumed by foraging ungulates such as moose. Individual *S. glauca* plants spaced a minimum of 2 m apart and at least 5 m from the edge of the ROW we selected. Vascular plant species within a 1.5 m radius of the selected plant were removed by hand to reduce effects of competition between June 1, 2015 and the end of the experiment. Soil was not sampled in this experiment.

3.2.2. Treatment and sampling design

Soil was collected from each herbicide-treated plot at CAR, DAW, HJ1, and HJ2 on 1, 30 and 365 days after treatment (DAT). At LS, soil samples were collected as soon as herbicides had dried (~ 2 hours after application) and at 1, 3, 7, 14, 21, 30 and 60 DAT. Increased sampling intervals were used at LS to model and determine the dissipation rate of each herbicide. A trowel with a depth gauge was used to sample areas approximately 8 cm in diameter to a depth of 3 cm (upper soil layer) regardless of the depth of the organic layer.

For the herbicide dissipation experiment with *S. glauca* at HJ2, a backpack sprayer was used to apply herbicides at the same rates as other sites (**Section 3.1.2**) to a 1.5 x 1.5 m area around each individual plant. Sampling was done within one hour of the spray drying (~ 2 h post application) and at 1, 3, 7, 14, and 30 days after spraying. Thirty (30) plants for each herbicide were treated. Foliage from five *S. glauca* plants were harvested at each interval, i.e., each individual shrub was only sampled once.

Samples were analyzed by the University of Guelph Laboratory Services following certified method 069 Phenoxy Acid – Soil/Veg. A subsample was also used to determine percent moisture of each sample.

Refer to **Appendix B** and **C** for further details on the sampling method, sample processing method, analytical chemistry method for determining herbicide concentration, and modelling and statistical analysis of the triclopyr and imazapyr dissipation from soil and vegetation chemistry data. The certificates of chemical analyses are also in these two appendices.

3.3. Greenhouse/Laboratory-Based Trial: Herbicide Toxicity Testing with Non-Target Boreal Plants and Soil Invertebrates

The purpose of this study was to assess the toxicity of triclopyr and imazapyr to non-target plants and soil dwelling invertebrates that are of ecological, socio-economic, and cultural relevance in the boreal region of Canada. Specifically, the objective was to determine the sensitivity of the common boreal plants *Achillea millefolium* and *Chamerion angustifolium* and soil invertebrates *Enchytreaus crypticus* (enchytraeid), *Folsomia candida* (collembola/springtail) and *Oppia nitens* (mite) to triclopyr and imazapyr by challenging them over a range of herbicide concentrations through broadcast spraying (plant vegetative vigor test) or applied directly to soils (plant seedling emergence and seedling growth test and all soil invertebrate tests) collected from five field sites representative of ROWs in the Yukon.

With the exception of the *O. nitens* adult survival and reproduction test, all herbicide toxicity tests followed the standard test methods detailed by the Organization for Economic Cooperation and Development (OECD) or Environment Canada (EC). The referenced method for *O. nitens* is currently under review for adoption as the standard method by Environment Canada. Please refer to the following references for further details on the specified test method:

- Plant vegetative vigor test - Test No. 227 (OECD 2006);
- Plant seeding emergence and seedling growth test (EC 2013);
- *E. crypticus* adult survival and reproduction test (OECD 2004);
- *F. candida* adult survival and reproduction test (EC 2014); and,
- *O. nitens* adult survival and reproduction test (Princz et al. 2010).

3.3.1. Soils used in herbicide toxicity testing

Approximately 20 kg of untreated soil from the top 3-cm was collected and processed from each site listed in **Table 1**. The soils collected from each site were used in the seedling emergence and seedling growth tests for plants and in the adult survival and reproduction tests for soil invertebrate. These tests were repeated in a standard “artificial soil”. Testing in artificial soil is necessary to facilitate comparisons between studies with soils of varying properties and assessment of test organism performance within a

study (EC, 2014). For the plant vegetative tests, plants were grown in commercial potting soil (Sunshine Mix #4, Sun Gro Horticulture, Agawam, MA).

3.3.2. Herbicide toxicity testing with non-target boreal plants

Achillea millefolium and *Chamerion angustifolium* are common colonizers after anthropogenic disturbance in Yukon (Lister 2009), the dominant herbs on Yukon ROWs (**Appendix B**), and are of ecological and cultural importance in the region. Snowshoe hare *(Lepus americanus*), a keystone boreal species, feeds on both plant species during the late summer (Seccombe-Hett and Turkington 2008). *C. angustifolium* is also particularly attractive to bees and other pollinators (Kevan et al. 1993) and a key component of moose summer diet (Johanson et al. 1994). Both species are also harvested as edible and/or medicinal plants (Gray 2012). If *A. millefolium* and *C. angustifolium* perform well as test organisms, their inclusion in standard toxicity tests for industrial chemicals would better represent plant communities of disturbed boreal sites than the crop species often used for other areas of Canada (Princz et al. 2012).

Seeds for the vegetative vigour test were donated by the Alaska Plant Materials Center (Palmer, AK). *A. millefolium* seed was collected from cultivated plants at the Alaska Plant Materials Center Farm and *C. angustifolium* seed was gathered from a wild stand in western Alaska. The same *A. millefolium* seed was used for the seedling emergence and seedling growth test, but a second lot of wild *C. angustifolium* seed from central Yukon (62.9°N, 139.1°W) was used because of insufficient germination of the first lot. *Calamagrostis canadensis* was included in the seedling emergence and seedling growth test because *C. canadensis* was the only non-target boreal species listed by Environment Canada (2013) that occurred on the ROW research sites. *C. canadensis* seed was donated by Brett Young (Winnipeg, MB).

3.3.2.1. Vegetative vigor test

Refer to **Appendix B** for a detailed description of the procedures, conditions, and statistical analyses used in both the range finding (used to determine the approximate lowest lethal dose for each herbicide-species combination) and definitive tests. A brief description of the definitive test follows. The test was conducted at the University of Saskatchewan Agriculture Greenhouse between January and April, 2015, following OECD Test No. 227 protocol (OECD 2006).

The dose range used to challenge *A. millefolium* and *C. angustifolium* plants grown in the greenhouse followed a logarithmic scale with the lowest lethal dose identified in the range finding test being the highest concentration in the range. An error in calculation for triclopyr doses resulted in testing between 0.25 and 1 times the application rate only. Solutions of imazapyr and triclopyr for both tests were prepared from commercial formulations.

For each species, 10-cm x 10-cm pots were filled with commercial potting soil and five seeds planted in each pot. This was replicated five times for each dose tested. *A. millefolium* was sprayed 22 days after planting at the 2-4 true leaf stage. Because *C. angustifolium* emerged and grew slower, it was sprayed 25 days after planting at the 6-10 true leaves stage. A custom built track sprayer was used for herbicide application (Agassiz Scientific Ltd., Saskatoon). Treatments were applied in sequence starting with the lowest dose, and the equipment was cleaned between herbicide. A visual damage assessment was

conducted 28 days after treatment using a 0-100 scale, with 0 being no damage and 100 being dead. Each plant was clipped at the soil surface at 28 days after treatment for dry weight determination.

3.3.2.2. Seedling emergence and seedling growth test

Refer to **Appendix B** for the detailed description of the procedures, conditions, and statistical analyses used in both the range finding and definitive tests. A brief description of the definitive test follows. The test was conducted at the Yukon Research Centre Greenhouse in Whitehorse, Yukon, following the test methods described by Environment Canada (EC 2013).

Because herbicide is usually applied on a per area basis, an equation was used to convert g a.i. ha^{-1} doses to approximate µg a.i. g^{-1} soil for this test. It was assumed that imazapyr and triclopyr remained within the top 3-cm of the upper horizon when applied in the field. Three cm reflects the approximate depth of soil collected from the five field sites (**Table 1**) for the toxicity tests, and it represents the potential "worst case scenario" where herbicide residues concentrate in the upper organic layer.

Doses for each soil were calculated along a logarithmic scale with the highest lethal dose determined from the range finding test and prepared using the commercial formulation of each herbicide. Dosed soils for each site were prepared and placed into 355 mL Styrofoam cups to the predetermined wet weight. Five seeds were planted per cup. After 28 days, emergence (plant shoots ≥3 mm) and damage were recorded. To maintain functional microbial communities, soils were not sterilized and any volunteer plants that emerged from the natural seedbank were also recorded. Cups were either harvested immediately or frozen until processing. The longest plant shoot and root from each cup was measured and recorded. All plants from the pot were collected for dry weight determination. Total biomass was divided by emergence to determine mean biomass per plant.

3.3.3. Herbicide toxicity testing with soil invertebrates

Applied herbicides are known to reach and accumulate at soil surface and can potentially impact the soil invertebrate community. Soil invertebrates serve important ecological functions (e.g., decomposition) and are the key components of the food web. As part of the ERA, the environmental fate and toxicity of a herbicide must be evaluated in natural soils, with similar soil types and climatic condition observed in the proposed use areas (PMRA, 2000). With respect to the toxicological study, no specific species are outlined. Rather, it is up to the risk assessors to specify which species are important based on biodiversity and ecosystem health and sustainability (PMRA, 2000, 2005). A common soil dwelling invertebrate used for pesticide toxicity assessments are earthworms. However, earthworms are not typically found in northern Canada, and, in many cases, are considered an invasive species in the Boreal forest (Addison, 2009; Saltmarsh et al., 2016). As a consequence, the toxicological profile of herbicides in northern ecosystems is largely incomplete (Princz et al. 2012). To improve our understanding of the ecological risk of herbicide use in northern ecosystems, sensitivity of representative soil invertebrates to these chemicals must be determined (Römbke et al. 2006; Princz et al. 2012). In this case, ecologically relevant soil invertebrates *Enchytreaus crypticus* (enchytraeid), *Folsomia candida* (collembola/springtail) and *Oppia nitens* (mite) were challenged over a range of triclopyr and imazapyr concentrations to determine their sensitivity to these two herbicides.

Refer to **Appendix C** (and the reference test methods from OECD (2004), EC (2014), and Princz et al. (2010)) for the detailed description of the procedures, conditions, and statistical analyses used in both the range finding and definitive tests. A brief description of the definitive test follows.

The tests were conducted in the Soil Toxicology Laboratory at the University of Saskatchewan. Soils from the five sites (**Table 1**) were dosed with a series of eight increasing concentrations of each herbicide (as mg a.i. kg^{-1} soil by dry weight) plus a negative control (where no herbicide is added). For testing with imazapyr, a surfactant control was included as well because Hasten™ Spray Adjuvant was need for suspension of the commercial product (Arsenal Powerline) in water. Five replicates were included at each treatment.

All invertebrates were cultured and synchronized to ensure all tested organisms were at the proper life-stage. Each test consisted of adding defined number of individuals to a glass vessel containing a volume of approximately 30-mL of dosed soil. The mass of soil added to the vial was different for each site and depended upon soil density and particle size distributions (EC 2014). Test vessels were maintained in the dark at 20 ± 2°C. Adult survival and reproduction (number of progenies) were assessed for each organism 28 days post treatment.

3.3.4. Chemical analysis

Soil samples were analyzed at the University of Guelph's Food and Agriculture Laboratory using High Performance Liquid Chromatography coupled with tandem Mass Spectrophotometry (HPLC-MS/MS). Soil samples were analyzed to determine the actual concentrations at each nominal dose level in order to accurately establish the toxicity of the herbicides to the test organisms. Refer to **Appendix B** and **C** for further details and the certificates of chemical analysis.

4.0 SUMMARY OF RESULTS AND DISCCUSSION FOR THE FIELD AND GREENHOUSE/LABORATORY TRIALS

4.1. Early (One Year Post Treatment) Response of Plant Communities on Power Line Rights-of-Way to Eight Vegetation Management Techniques

All treatments altered the ROW plant communities one year after treatment. However, control of target species (trembling aspen, balsam poplar, willow, and Alaska paper birch) was significantly greater in chemically treated plots (ranged between 66-94% control) than in mechanically treated plots with or without grass seeding (less than 55% control; **Figure 3**). Mowing was the least effective treatment with approximately 40% control of the target species. Recovery of target species in chemical treatment plots to mowing control levels is unlikely to occur rapidly because damage assessments of treated stems indicated nearly lethal damage. This demonstrates that the efficacy of triclopyr (Garlon XRT) and imazapyr (Arsenal Powerline) for short-term woody species control on northern ROWs are comparable to results reported for more southern/temperate jurisdictions (Bramble et al. 1991; Luken et al. 1991; Mercier et al. 2001; Yahner and Hutnik 2004).

All treatments caused a neutral to minor reduction in percent cover (up to16% for triclopyr broadcast spray) of the four monitored non-target plant life-form groups of erect shrub, prostrate shrub, forb and graminoid cover (**Figure 3.2** of **Appendix B**). Decreases in non-target shrub and herbaceous cover are commonly reported one year after both mechanical and chemical site preparation techniques in boreal clear cuts (Sullivan et al. 1996; Man et al. 2010). Furthermore, as treatments were applied by hand, the observed reduction in percent cover of non-target plants might partly be attributable to trampling.

Imazapyr broadcast spray, though most effective at controlling target species (94% reduction, **Figure 3**), also caused greater visual damage and, in some cases, cover reduction to non-target vegetation than other treatments (**Figure 4**). Prostrate shrubs were the exception and the most common species, kinnikinnick (*Arctostaphylos uvaursi*), appeared to tolerate imazapyr well. Leaf chlorosis, stunted growth and tissue deformity of many species occurred after broadcast spraying. Chlorosis, deformity and stunting of forbs were common in cut stump and point injection plots, but severity was highly species specific. The variability in sensitivity confirms that plant species exhibit a large range of tolerances to imazapyr (Bovey and Senseman 1998; Douglass et al. 2016). Observed damage to non-target species in the imazapyr cut stump and point injection plots indicate that imazapyr persists in the environment at concentration not high enough to prevent non-target species germination, but had sufficient potency to cause visible injury. Alternatively, imazapyr may translocate from target species to non-target species by mechanisms such as mycorrhizal association (Barto et al. 2011).

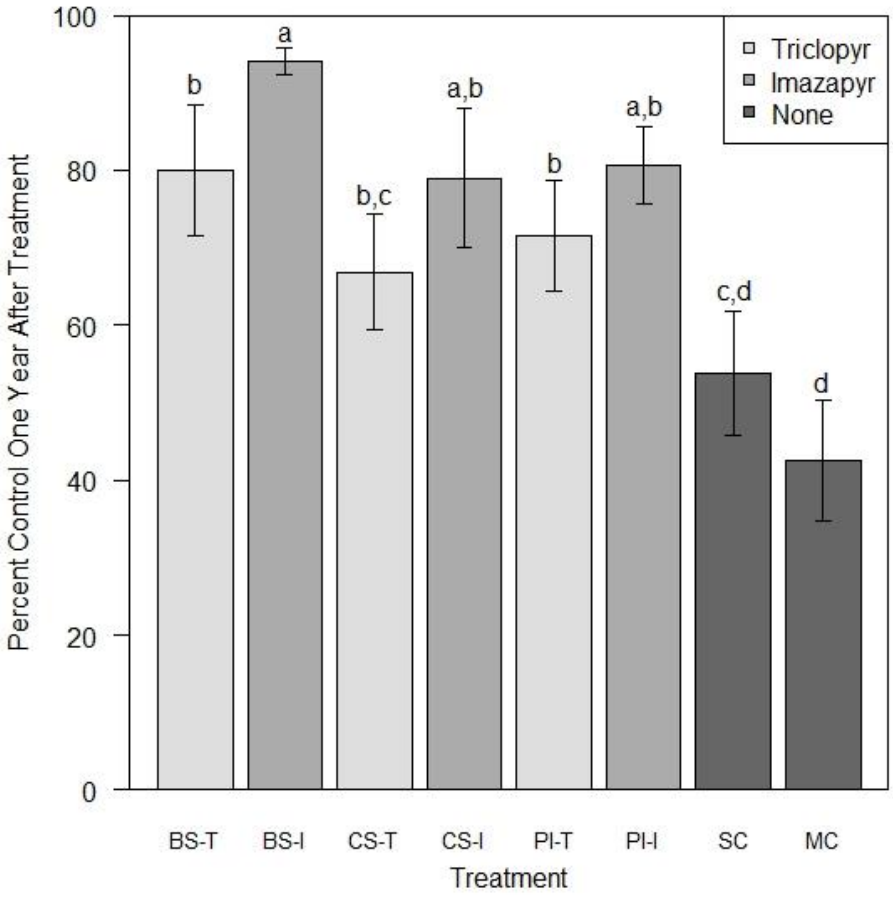

Figure 3 Control of target species (trembling aspen, balsam poplar, willow, and Alaska paper birch) on Yukon power line rights-of-way one year after eight vegetation management treatments. Percent control is defined as the difference in cover between 2014 and 2015, divided by 2014 cover x 100. Shading indicates type of herbicide and treatment codes are described in Table 1. Error bars represent standard error with n= 17, 21, 19, 16, 22, 26, 16, 15 for each treatment; n differs between treatments as all four target species were not present in each plot. Different letters indicate statistically significant differences between least square means ($p < 0.05$). Figure was originally presented in **Appendix B**.

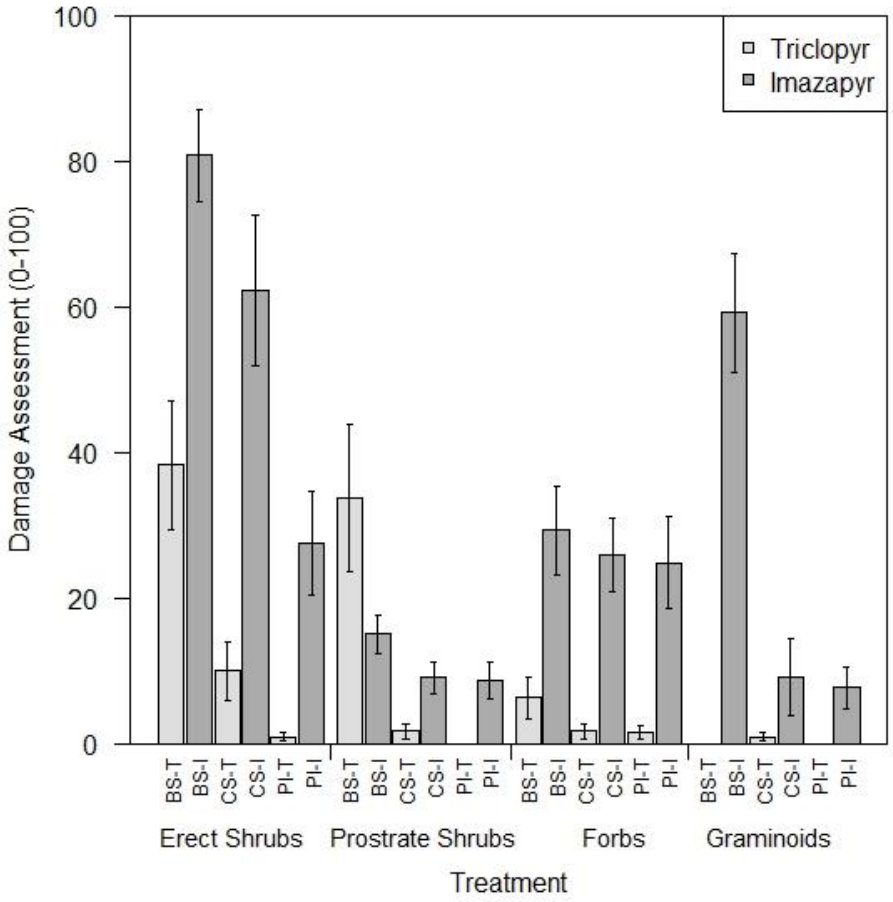

Figure 4 Herbicide damage to non-target vegetation one year after right-of-way vegetation management treatments were applied in Yukon. Mean damage assessment values (0-100) are grouped by life form and shading indicates the different herbicides used. Treatment codes are described in Table 1. Error bars represent standard error and for erect shrubs: n=11,7,9,6,8,10; prostrate shrubs: n=11,12,11,9,10,10; forbs: n=12,12,11,11,11,11; and graminoids: n=12,12,11,11,11,11 Figure was originally presented in **Appendix B**.

In contrast to imazapyr, broadcast spray of triclopyr substantially reduced prostrate shrub cover (up to 16%), but had less effect on percent cover on other non-target plant life-forms. Furthermore, there was limited visual damage from triclopyr using other application methods. The recovery of forbs and substantial increase in grass cover two years after triclopyr broadcast spray and cut stump applications has been demonstrated in both boreal forests and rangelands (Bell and Newmaster 2002; Seefeldt et al. 2013). It is likely that herbaceous species abundance on Yukon ROWs will increase by the second year after triclopyr treatments. Recovery time for shrubs after triclopyr applications is less consistent ranging from 2-5 years (Bell and Newmaster 2002; Seefeldt et al. 2013).

Treatment effects on non-target species, overall, were life form or species specific which is encouraging. Treatments were designed to impact life forms differently based on species' height and physiology (monocot vs. dicot) to induce different recovery trajectories. Evidence of early community changes indicates the initial plant community compositions of treatment plots were altered; hence, the development of new and distinct plant communities can be expected over time (Niering 1987; Strong and Sidhu 2005).

Whether the composition of these new plant communities will be consistent with ROW management goals is unknown at this time. The most important changes in species composition and abundance in boreal forests usually occur in the initial years following disturbance (de Grandepre and Bergeron 1997). This hypothesis likely applies to Yukon ROWs. Data from two years after treatment is available; however, it is unlikely that trends would significantly differ from those observed one year after treatment. The ability to characterize future plant communities and their capacity to resist the regrowth or invasion by target species is limited by the length of the current study. Monitoring vegetation following treatment disturbance for at least one cycle equivalent to the current ROW mowing practice (8 to 10 years) is needed for full evaluation of community development at the field sites.

4.2. Dissipation of Triclopyr and Imazapyr from Treated Plot Soil and *Salix glauca* (White Willow) Foliage

4.2.1. Soil Dissipation

The dissipation rate of triclopyr (**Figure 5**) for broadcast sprayed ROW soil at the LS site was faster than imazapyr (**Figure 6**). Whereas the DT_{50} (time required for herbicide concentration to decrease to 50% of initial) was 1 DAT (day(s) after treatment), it was 16 DAT for imazapyr. This corroborates with the understanding that imazapyr does persist longer in soil than triclopyr (Senseman 2007; Douglass et al. 2016). Rapid dissipation of triclopyr indicates that it is readily lost from soil through volatilization and photodegradation mechanisms (Hill and Schaalje 1985). In contrast, slower imazapyr dissipation indicates its persistence in the environment is likely controlled by soil adsorption and microbial degradation processes (Wang et al. 2005; Gianelli et al. 2014).

The calculated rates for both herbicides in LS soils likely represent best-case scenarios because they are much faster than those reported in other studies. In northern Ontario, triclopyr residues had longer residual periods in soil with a DT_{50} of 14 days (Stephenson et al., 1990). In addition, triclopyr was shown to have half-lives ranging from 5 – 16 days in varying soils from Colorado (Douglass et al. 2016).

Similarly, published imazapyr DT_{50} values ranged from 37 to 144 DAT (Börjesson et al. 2004; Wang et al, 2005; Newton et al. 2008; Gianelli et al. 2014). In addition, we observed higher concentrations of residues for both herbicides applied via backpack spraying at other site soils included in this study (**Table 3**).

Even though dissipation rate as defined by DT_{50} was rapid in this study, persistent concentrations of both triclopyr and imazapyr was detectable at least one year post treatment at all field sites (**Table 3**). These residuals are likely related to observable damages to target and non-target new-growth (**Section 4.1**; **Appendix B**). In Alaska, the majority of residues dissipated during the summer months with residues falling below quantification limits within 100 days of herbicide treatment (Newton et al. 2008). In contrast, triclopyr residues in forest soils in Sweden were observed up to two years after application (Torstenssen and Stark 1982). Imazapyr is known to persist even at 454 and 730 DAT in Alaska and Sweden, respectively (Torstenssen and Stark 1982; Newton et al, 2008).

However, herbicide persistence in soil can be mitigated by application method (**Table 3**). For the cut stump treatment, the concentration of triclopyr was minimal or below detection limits in most soil 365 DAT. This coincides with the hypothesis that the transfer of triclopyr to the soil through root exudation is minimal (Braverman 1995; Wahlers et al. 1997). For point injection the majority of the residues dissipated between 30 and 365 DAT. However, imazapyr residues were above detectable limits for both cut stump and point injection treatments at both time intervals. Residual concentrations for the imazapyr point injection treatment were actually similar to those observed for the spray application technique and are present at concentrations high enough to effectively control target species and also have a pronounced effect on non-target species (**Table 3**). Based on these results point injection may be a viable alternative to broadcast application (Nowak and Ballard 2005a). Furthermore, there is higher risk associated with the use of imazapyr compared to triclopyr from the perspective of soil persistence and effects to non-target species.

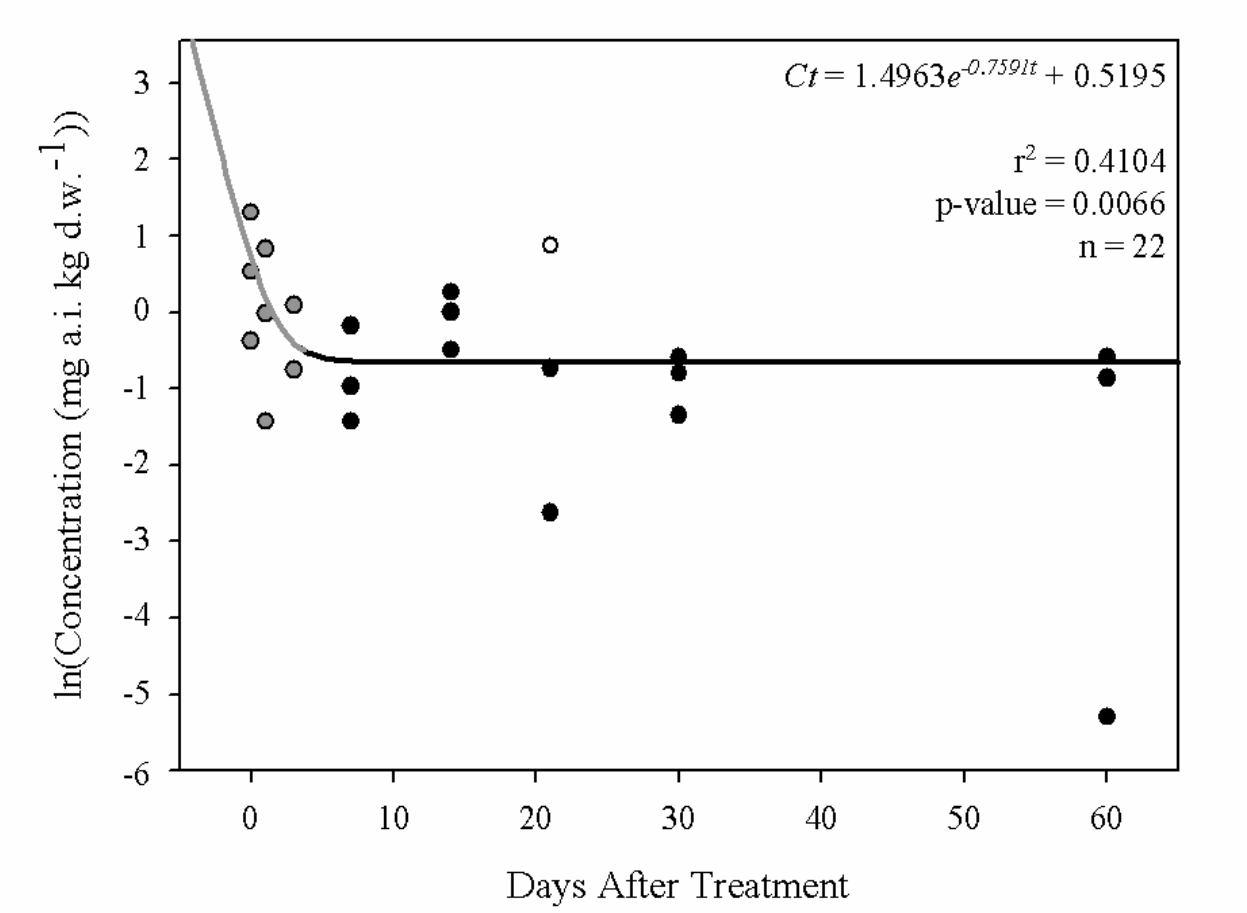

Figure 5 Dissipation model for triclopyr residues in the upper soil horizon at the LS site. A three parameter biphasic dissipation model was the best fit for the data (r^2 = 0.4104). Calculated DT_{50} and DT_{90} values based on this model are 1 DAT and 3 DAT, respectively. The concentration in the persistent phase is 0.52 mg a.i. kg^{-1} soil. Grey line and circles represent the first phase modeled with first order kinetics while the black dots and line represent the persistent phase. The open circle indicates data point that was removed to obtain optimal model fit, but it was not statistically identified as an outlier. Figure adapted from **Appendix C.**

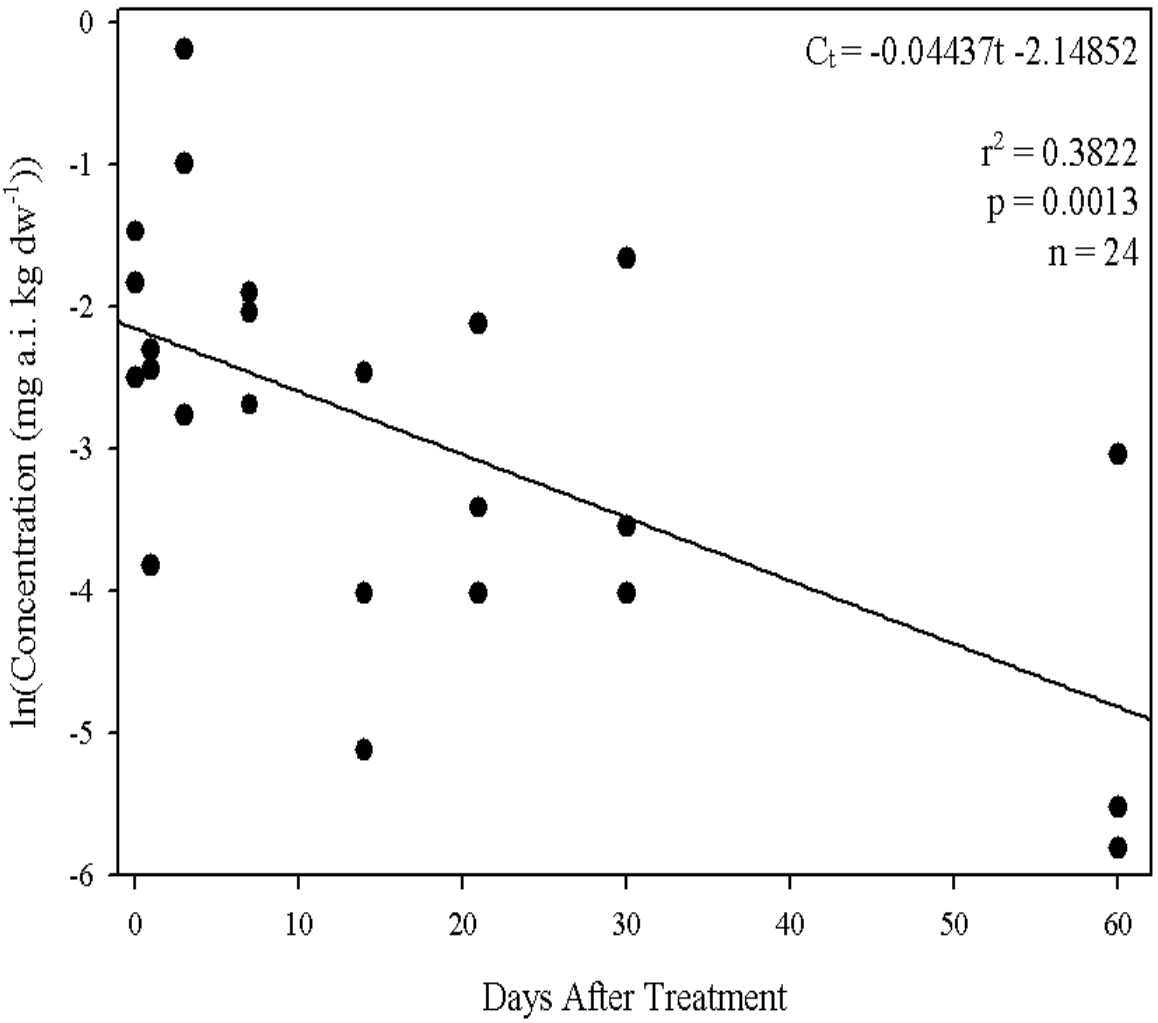

Figure 6 Dissipation model for imazapyr residues in the upper soil horizon at the LS site. First order model best described the dissipation of imazapyr from LS soil (r^2=0.3822) from soils collected from the upper soil horizon (0-3 cm). The DT_{50} and DT_{90} were calculated as 16 and 52 DAT, respectively.

Table 3 Triclopyr and Imazapyr concentrations (mg active ingredient per kg dry weight) for the backpack spray (n=3), cut stump (n=1) and point injection (n=1) treatments at 30 and 365 days after treatment at four sites (CAR, DAW, HJ1, HJ2), as well as, the Mean ± SE for treatment and time interval across all sites. <0.005 indicates concentrations were below detection level for triclopyr. Cut stump and point injection treatments were not analyzed for the LS site. As a result, LS was not included in this table. NA = Not Analyzed.

Herbicide	Site	Days After Treatment					
		Backpack Spray		Cut Stump		Point Injection	
		30	365*	30	365	30	365
Triclopyr	CAR	3.1	NA	0.13	<0.005	0.34	0.05
	DAW	8.0	NA	3.8	<0.005	32	0.09
	HJ1	2.4	NA	<0.005	0.04	0.04	<0.005
	HJ2	0.42	NA	1.1	<0.005	0.25	0.83
	Mean±SE	3.46 ± 1.61	NA	1.26±0.88	0.01±0.01	8.16±7.95	0.24±0.20
Imazapyr	CAR	0.16	0.01	0.02	0.01	1.6	0.08
	DAW	0.12	0.01	0.002	0.01	0.57	0.02
	HJ1	0.07	0.02	0.16	0.01	0.001	0.004
	HJ2	0.12	0.005	0.03	0.003	0.002	0.01
	Mean±SE	0.12 ± 0.02	0.012 ± 0.003	0.05 ± 0.04	0.01 ± 0.002	0.54 ± 0.38	0.03 ± 0.02

* 365 Days After Treatment samples were not analyzed for triclopyr.

4.2.2. Dissipation from *Salix glauca* (White Willow) Foliage

The rate of triclopyr dissipation from *S. glauca* foliage was slower than anticipated. A first order model best described the dissipation of triclopyr from *S. glauca* foliage (**Figure 7**; r^2=0.7647). The initial mean concentration was approximately 1200 ug/g and the final mean concentration on Day 30 was 197 ug/g. The estimated DT_{50} of 11.5 days is slower than the expected 1.5 to 2 days (Whisenant and McArthur 1989; Thompson et al. 1994). This is also slower than what was observed for triclopyr dissipation from soil (**Section 4.2.1**). Cooler temperatures during the study period may have slowed triclopyr metabolism and dissipation from *S.glauca* (Bentson and Norris 1991). Note that an error in the conversion between ppm (part per million) fresh weight and ug g^{-1} dry weight with the data for the dissipation of triclopyr from *S. glauca* foliage occurred during the preparation of the thesis presented in **Appendix B**. The corrected data are presented in **Figure 7**.

Triclopyr in *S. glauca* foliage did not dissipate to low or undetectable levels by the end of the 30 day experiment. Research in Alaska demonstrated near complete dissipation of triclopyr from vegetation within 30-45 days (Newton et al. 2008) which is similar to dissipation published for southern studies (Whisenant and McArthur 1989, Thompson et al. 1994). The results from this study do not support that northern herbicide dissipation rates are similar to rates in warmer climates. Newton et al. (1990) also reported relatively high levels of triclopyr persisting in vegetation; however, their study included conifers with substantially different leaf morphology making comparisons difficult. *S. glauca* leaves were dried and shriveled at 30 DAT suggesting metabolic degradation of triclopyr residues had ceased. The deposition of leaves as litter may provide a secondary input of triclopyr residues into the soil (Tatum 2004; Thompson et al. 1994).

In contrast to triclopyr, imazapyr dissipation from *S. glauca* foliage was initially very rapid (DT_{50} = 1.5 days) followed by a persistent phase from Day 14 onwards. The initial mean concentration was 259 ug/g and the mean concentration by Day 30 was approximately 35 ug/g. The bi-phasic nature of imazapyr dissipation from vegetation is reflected in the rapid herbicidal effect of imazapyr on the treated *S. glauca* where most plants were wilted within seven days after treatment, and no further metabolism of imazapyr was possible from that time forward.

The persistence of both herbicides in soil and vegetation may potentially impact non-target organisms. Even though both triclopyr and imazapyr have relatively rapid initial dissipation rates in soil and *S. glauca* foliage in the field, both herbicides did persist at detectable concentrations in both environmental compartments. Furthermore, visual damage to non-target plant species was observed at one year after treatment (**Section 4.1**). The residual phytotoxic effects is actually desirable from a ROW-management perspective as it provides extended control of target plant species, which might help drive the development desirable floral communities even if some non-target plant species might be affected. However, it also represents potentially longer exposure period to these chemicals for other ecological relevant but non-target organisms. The potential risk from exposure to the residual concentrations of these two herbicides to ecological receptors is evaluated in **Section 5.0.**

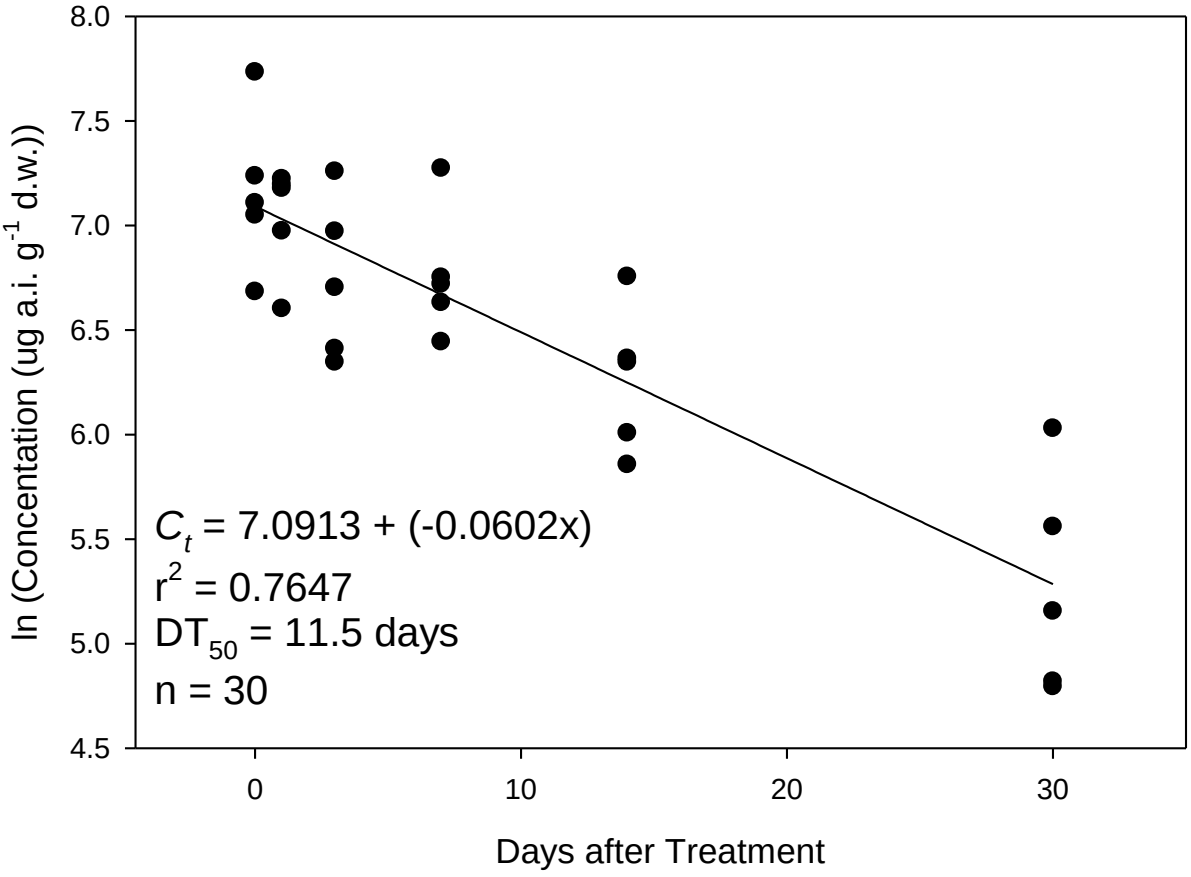

Figure 7 Dissipation of triclopyr residues in *Salix glauca* foliage on a Yukon power line right-of-way over a 30 day period between June 2nd and July 2nd, 2015. A first order model best described the dissipation of triclopyr from *S. glauca* foliage (r^2=0.7647). This indicated triclopyr concentration declined at a constant rate in plant tissue during the monitored 30-day period. The initial mean concentration was approximately 1200 ug/g and linearly declined to 197 ug/g by Day 30. The estimated DT_{50} = 11.5 days. Adapted from **Appendix B.**

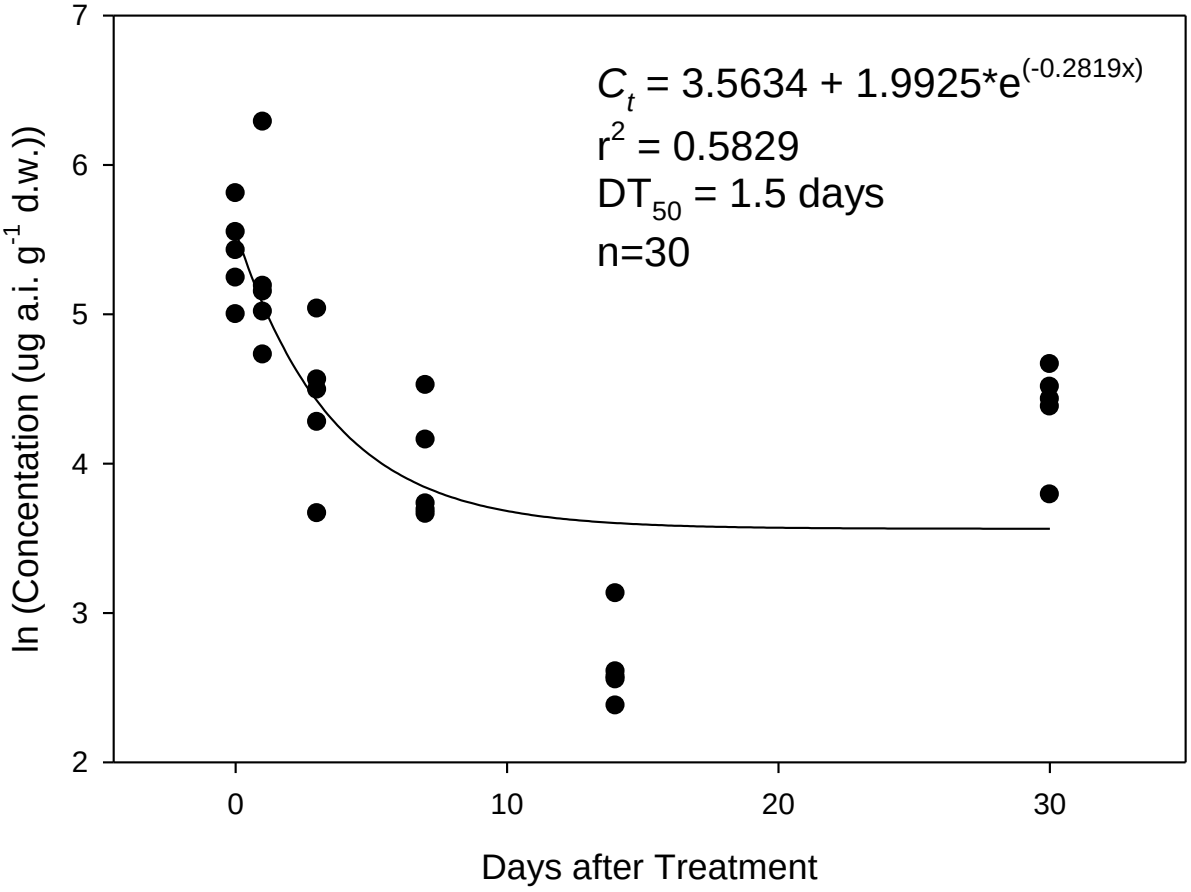

Figure 8 Dissipation of imazapyr residues in *Salix glauca* foliage on a Yukon power line right-of-way over a 30 day period between June 2nd and July 2nd, 2015. A biphasic (two-stage) model best described the dissipation of imazapyr from *S. glauca* foliage (r^2=0.5829). This indicated that imazapyr rapidly dissipated (DT_{50} = 1.5 days) from *S. glauca* tissue within the first seven days of monitoring followed by a persistent phase from Day 14 onwards. The initial mean concentration was approximately 259 ug/g and the mean concentration by Day 30 was approximately 35 ug/g.

4.3. Herbicide Toxicity Testing with Non-Target Boreal Plants and Soil Invertebrates

4.3.1. Plants

The vegetative forms of both tested non-target boreal plant species were very sensitive to either herbicides (**Figure 9**). Imazapyr and triclopyr caused significant damage to *C. angustifolium* with an IC_{50} (inhibitory concentration where 50% of the population is affected) estimate of 1.2% of maximum field application rate for imazapyr. No IC_{50} estimate for triclopyr and *C. angustifolium* was possible because all tested doses were lethal; however, this was a function of a calculation error that resulted in a tested dose range of only 25 to 100%. *Achillea millefolium* was equally sensitive to imazapyr (IC_{50} = 0.7% of maximum field application rate), but showed signs of recovery (new leafs) after damage by triclopyr (IC_{50} = 31.3% of maximum field application rate). The potential for recovery is linked to the field observation where percent cover of *A. millefolium* did not decrease significantly in triclopyr broadcast spray plots one year following treatment (**Section 4.1; Appendix B**) and the more rapid dissipation rates observed from soil and vegetation for triclopyr (**Section 4.2**). The high phytotoxicity of both herbicides on non-target plant species is not unexpected as the herbicides are designed for vegetative control of both herbaceous and woody species. Many desirable species on northern ROWs are categorized as weeds in other settings (e.g. *C. angustifolium* competes with conifer seedlings in the boreal forestry industry (Hangs et al. 2003)).

In the emergence and seedling growth test, germination percentages of all species were reduced when exposed to >10 µg triclopyr g^{-1} soil; however, *C. angustifolium* seeds were the most sensitive (EC_{50} = 1.56 µg g^{-1}). Higher concentrations relative to the application rate of imazapyr (5-12 µg g^{-1} ≈ 1x the maximum application rate) were required to inhibit germination of *A. millefolium* (EC_{50}=63.60 µg g^{-1}). *C. angustifolium* seeds were again more sensitive than *A. millefolium* while *C. canadensis* (EC_{50} = >100 µg g^{-1}) germination was relatively insensitive to imazapyr. In soils, imazapyr was more phytotoxic to seedlings than triclopyr. Where information was available, IC_{50} estimates of the boreal species were typically within the range of standard test species; however, most endpoints of this test were at the more sensitive end of the spectrum. This might indicate greater bioavailability of the herbicides in the ROW soils relative to other studies.

From a vegetation management perspective, broadcast spray application of imazapyr or triclopyr at rates appropriate for woody species control will likely cause significant damage to *C. angustifolium* and *A. millefolium*. The very high sensitivity to imazapyr also indicates both species may be substantially damaged by drift from spray applications. In soil, triclopyr inhibited germination at lower concentrations than imazapyr, but imazapyr was significantly more phytotoxic to seedlings. Even if triclopyr degrades rapidly, residues could potentially limit *C. angustifolium* germination for a short period of time after application. If imazapyr persists in soil, which is common in soils with low pH and high organic matter, the herbicide could cause significant damage to *C. angustifolium* and *A. millefolium* seedlings. If preservation of herbaceous non-target species is a management objective, use of imazapyr for woody species control on northern ROWs is not recommended.

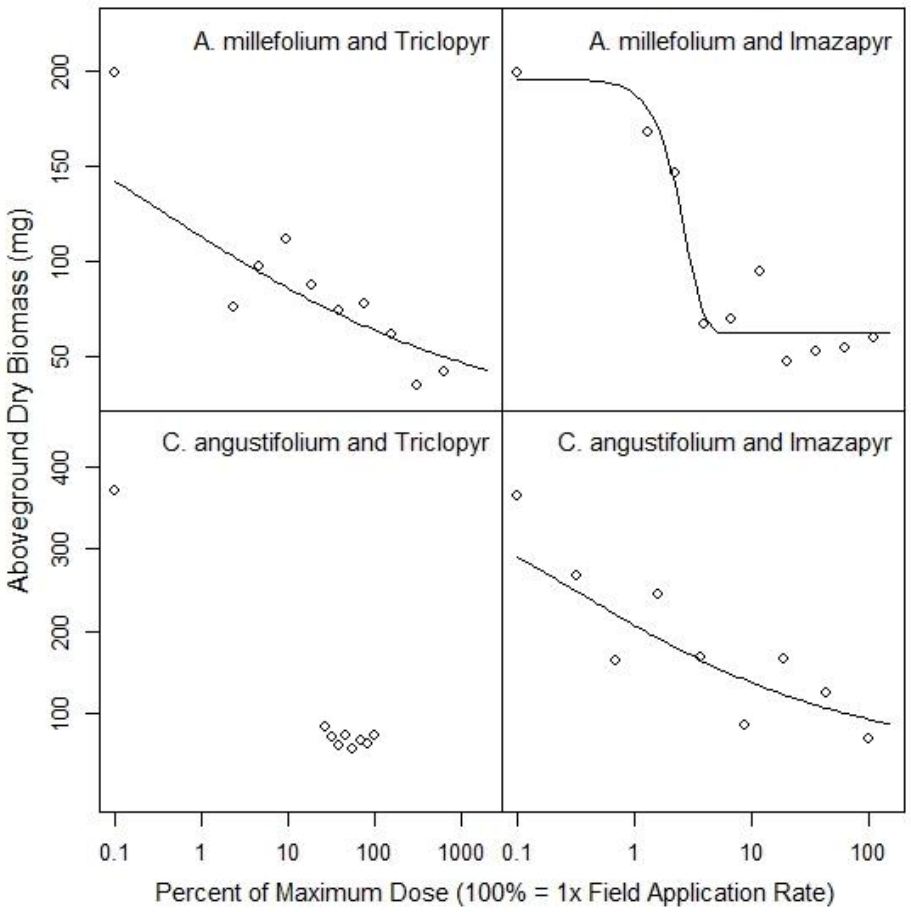

Figure 9 *Achillea millefolium* and *C. angustifolium* dose response curves for the 28 day vegetative vigour test: imazapyr or triclopyr applied as a foliar spray. 100% of maximum dose is equivalent to the maximum field application rate for woody species control (720 g imazapyr ha^{-1}, 4530 g triclopyr ha^{-1}). The IC_{50} estimate for *C. angustifolium* and imazapyr was 1.2% of the maximum field application rate (±0.9SE, n=30). A dose response curve could not be generated for *C. angustifolium* response to triclopyr as all doses were lethal. IC_{50} estimates were 0.7% (±0.3SE, n=49) for *A. millefolium* and imazapyr and 31.3% (±22.4SE, n=55) for *A. millefolium* and triclopyr. Lack-of-fit test comparing dose response curves to a one-way ANOVA indicated adequate fit in all three fitted models ($p>0.05$). Adapted from **Appendix B**.

4.3.2. Soil Invertebrates

In contrast to the herbicide phytotoxicity tests with the non-target plant species, the three soil invertebrate species tested were insensitive to triclopyr and imazapyr in all five field soils (**Figure 10**). This was reflected by the use of LC_5 (lethal concentration where 5% of the population was affected) or EC_5 to estimate the concentrations for the two herbicides that is needed to elicit a detectable/observable effect on the soil invertebrates. In ecological toxicology, LC_5 and EC_5 estimates are normally reserved for protection of individual organisms or species at risk and endangered species where the loss of a few sensitive individuals from a population will impair that population and the ecological function they serve with high probability. Although these populations serve important ecological functions, there are no known endangered or at-risk soil invertebrate species that require this level of protection.

Soil invertebrates are unlikely to be exposed to levels of triclopyr or imazapyr even at the LC_5 or EC_5 level in the field. For example, the triclopyr EC_5 for reproduction in CAR and DAW soils were estimated at 66.2 and 55.9 mg a.i. kg^{-1} soil dry weight, respectively. However, from the **Appendix C** and **Section 4.2.1**, even when applied as foliar spray, mean soil concentration of triclopyr at CAR and DAW did not exceed 6 mg a.i. kg^{-1} soil dry weight when measured 1 DAT. Field concentration declined rapidly with time. Therefore, any adverse effects observed in these tests are unlikely to occur in the field. For comparative purposes, all LC_{25} and EC_{25} values are available in **Appendix C.**

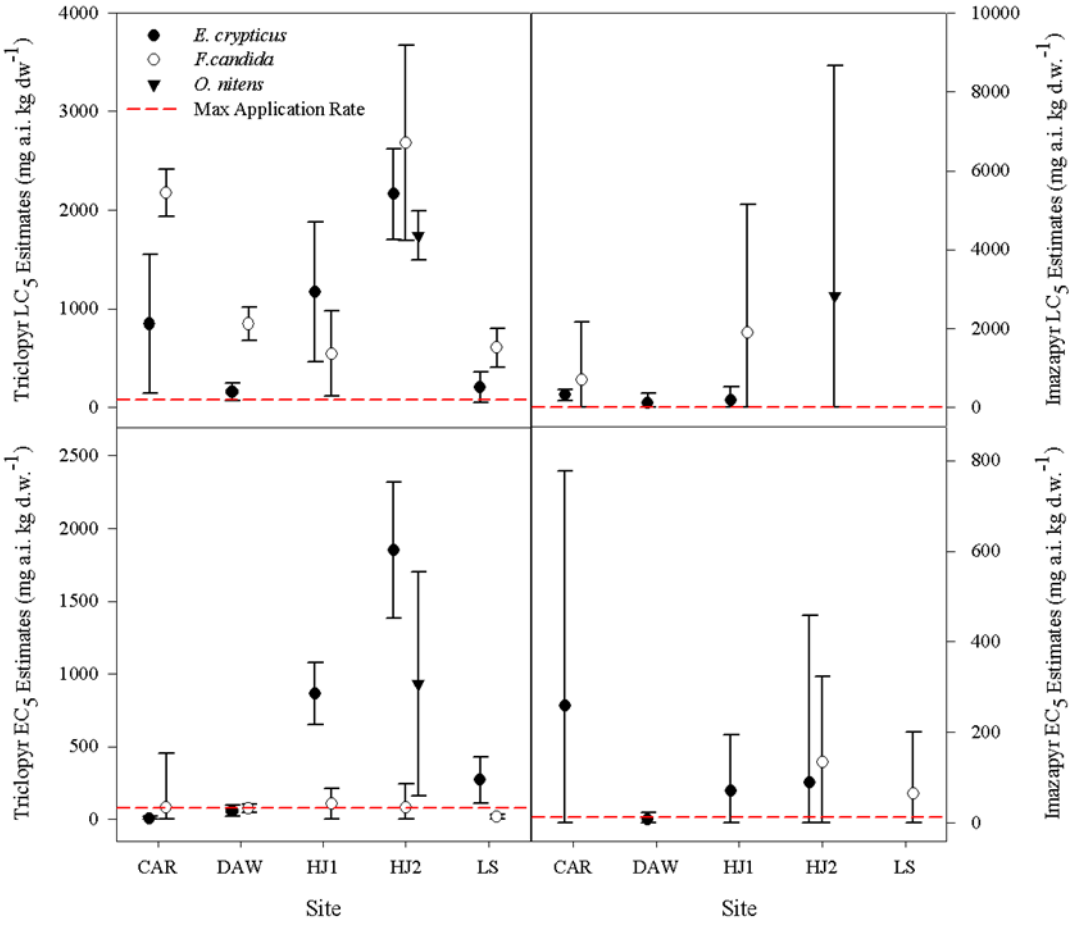

Figure 10 Summary of LC_5 and EC_5 values for *E. crypticus*, *F. candida* and *O. nitens* response to triclopyr and imazapyr from organic soils collected at five ROW sites in the Yukon Territory, Canada. Triclopyr results are on the left and imazapyr are on the right. LC_5 values are in the top panels with EC_5 values in the bottom panels. Symbols represent the species with bars representing the 95% confidence intervals. Negative lower confidence intervals were corrected to 0. The red dashed line represents the maximum field-equivalent application rates of 75.5 mg triclopyr kg dw^{-1} and 12.0 mg imazapyr kg dw^{-1}. Adapted from **Appendix C**.

5.0 PRELIMINARY ASSESSMENT OF RISK FOR IMAZAPYR AND TRICLOPYR RESIDUES TO NON-TARGET ECOLOGICAL RECEPTORS (TERRESTRIAL MAMMALS AND BIRDS)

The dissipation characteristics of both herbicides in soil and vegetation (*S. glauca* in particular) demonstrated in **Section 4.2** indicated that their persistence in both environmental compartments could pose potential risk to the health of ecological receptors if affected soil and vegetation are consumed. This section attempts to quantify these potential risks from imazapyr (Arsenal Powerline) and triclopyr (Garlon XRT) exposure to terrestrial mammals and birds.

Conceptually, for the purposes of this preliminary assessment, only the direct ingestion of herbicide residue in *S. glauca* by herbivorous terrestrial mammals and birds is considered. Alternative exposure pathways (e.g., inhalation, direct dermal contact), exposure media (e.g., affected surface and groundwater, soil invertebrates, insects, etc.), transport and bioaccumulation mechanisms, and ecological receptors (e.g., aquatic organisms, carnivorous organisms) are not considered because: a) herbicides are unlikely to reach groundwater; b) herbicides are not known to bioaccumulate; c) herbicides will not be used within buffer zones to surface water bodies; and, d) insufficient information is available for quantification. In addition, human health risk from consumption of herbicide residue in affected vegetation is not considered.

This preliminary ecological risk assessment (ERA) was prepared in accordance with applicable guidance from various regulatory jurisdictions. Primary guidance was from the following documents:

- Health Canada (2012) – Federal Contaminated Sites Action Plan (FCSAP): Ecological Risk Assessment Guidance;
- Ontario Ministry of the Environment and Climate Change (OMOECC, 2011) – Rationale for the Development of Soil and Groundwater Standards for use at Contaminated Sites in Ontario; and,
- British Columbia Ministry of the Environment, Lands and Parks (1998) – Recommended Guidance and Checklist for Tier 1 Ecological Risk Assessment of Contaminated Sites in British Columbia.

Aside from problem formulation (i.e., quantify potential risk to ecological receptors from consumption of herbicide affected vegetation), the general risk assessment framework is composed of three other elements: 1) toxicity assessment; 2) exposure assessment; and, 3) risk characterization.

Toxicity assessment is concerned with the nature of the chemical of potential concern (herbicides in this case). It involves understanding the toxicological profile of each herbicide and the determination of the dose-response characteristics as quantified by the toxicological reference value (TRV). The acute and chronic TRVs for both herbicides are listed in **Table 4**. Note that based on the acute TRVs, both imazapyr and triclopyr are deemed non-toxic to mammals and birds by the USEPA and Health Canada at this time. Furthermore, the acute and chronic TRVs are calculated with the inclusion of 10-fold and 100-fold safety factors, respectively, to account for trans-species and intra-species variability/uncertainty.

Table 4 Acute and Chronic toxicological reference values of imazapyr and triclopyr

Herbicide	Toxicological Reference Values (mg herbicide kg^{-1} body weight day^{-1})		Reference
	Acute	Chronic	
Imazapyr	500[a]	2.53[b]	USEPA (2006)[a], Health Canada (2016)[b]
Triclopyr	630	5	USEPA (1998)

Exposure assessment is quantifying the amount of herbicide a receptor may absorb into its body over a lifetime. It includes receptor characterization, determination of exposure point concentration, bioavailability assessment, exposure amortization, and exposure analysis. It is numerically summarized by the average daily intake (ADI). The chosen herbivorous receptors, their characteristics, and their ADI are presented in **Table 5**. The ADI for each receptor is calculated by: ADI = food ingestion rate x herbicide concentration in food.

The worst-case scenario is usually first considered when conducting a risk assessment. If the likelihood/probability of risk to ecological receptors is acceptable for the worst-case scenario, other scenarios need not be considered. The worst-case scenario considered here is that the herbivorous ecological receptors will only consume *S. glauca* on the ROW that contains the maximum average observed concentration of imazapyr or triclopyr over the span of their entire lifetime. From **Section 4.2.2**, the maximum average observed concentrations of imazapyr and triclopyr are 0.26 and 1.2 mg herbicide g^{-1} *S. glauca* dry weight, respectively.

The herbivorous receptors chosen for assessment are moose (*Alces alces*), meadow vole/field mouse (*Microtus pennsylvanicus*), and red-winged blackbird (*Agelarius brevicauda*). The food ingestion rate for moose is from McArt et al. (2009) while the rates for the meadow vole and the red-winged blackbird are from OMOECC (2011). It is recognized that the meadow vole and the red-winged blackbird might not be present/relevant in the Yukon; however, they are well characterized receptors that are commonly used as surrogates for uncharacterized herbivorous small mammals and birds that are likely present on the ROW.

Table 5 Ecological receptors, their characteristics and calculated averaged daily intake of herbicides based on worst-case scenario where maximum observed herbicide concentrations persisted in vegetation

Herbicide (max observed concentration)	Average Daily Intake for each Ecological Receptor (mg herbicide kg^{-1} body weight day^{-1})		
	Moose (*Alces alces*)	Meadow Vole (*Microtus pennsylvanicus)*	Red-Winged Blackbird (*Agelarius brevicauda*)
Imazapyr (0.26 mg g^{-1} *S. glauca)*	10.0	0.6	7.4
Triclopyr (1.2 mg g^{-1} *S. glauca*)	46.1	2.8	34.1
Food Ingestion Rate (g *S. glauca* dry weight/day)	38.4	2.3[a]	28.4[a]

[a] Reported values from OMECC (2011) are based on wet weight. Values are expressed based on dry weight by assuming 98% water content in leafs of *S. glauca.*

Finally, risk characterization is the numerical estimation of potential health risks to the receptor from exposure to an herbicide. This is achieved by comparing the estimated site-specific risk levels of a compound (i.e., ADI) to the respective target risk level (i.e., TRV) through the calculation of the hazard quotient (HQ = ADI/TRV). The HQ values for the worst-case scenario are presented in **Table 6**.

Table 6 Likelihood of acute and chronic risk to ecological receptors from consumption of herbicide-affected *S. glauca* based on worst-case scenario where maximum observed herbicide concentrations persists in vegetation.

Herbicide	Receptor	Hazard Quotient = ADI/TRV	
		Acute	Chronic
Imazapyr	**Moose**	0.02	**4.0**
	Meadow Vole	0.001	0.2
	Red-Winged Blackbird	0.01	**2.9**
Triclopyr	**Moose**	0.07	**9.2**
	Meadow Vole	0.004	0.6
	Red-Winged Blackbird	0.01	**6.9**
BOLD	Bold and gray-filled values indicate unacceptable probability of risk		

If HQ < 1, the likelihood of risk is acceptable – no further assessment needed. If HC ≥ 1, the likelihood of risk is not acceptable; therefore, further assessment or integration of study information into the risk scenario is necessary. For example, dissipation rate /persistence of herbicide, proportion of diet/home range of receptors, applicability of/alternative TRV, etc., might be used in revising the calculation of the HQ values.

Acute toxicity to herbivorous animals was unlikely in the worst-case scenario because all calculated acute HQ values are well below the threshold level of 1. This agrees with the current determination by the USEPA and Health Canada that both imazapyr and triclopyr are not acutely toxic to mammals and birds. No further assessment of acute risk is needed for these receptors.

In contrast, the likelihood of risk is not acceptable for moose and red-winged blackbird in the worst-case chronic exposure scenario where the calculated HQ values from chronic exposure to imazapyr or triclopyr are above 1. However, the HQ values calculated for the worst-case scenario is highly conservative. For example, both the moose and the red-winged blackbird are unlike to be exposed to the worst-case scenario for either herbicides throughout their entire lifetime because: 1) both imazapyr and triclopyr dissipates to much lower levels 30 days post treatment (**Figure 7** and **Figure** 8); 2) both animals are unlikely to feed on wilting or wilted herbicide-treated vegetation; and, 3) both animals are unlikely to reside on ROWs exclusively because of relative openness of the area. Furthermore, the 10- and 100-fold safety factors included in the TRV values (**Table 4**) are highly conservative.

By modifying the HQ calculation with the observed mean concentration of imazapyr at 30 days post treatment (0.035 mg g^{-1}), the HQ values for the moose and red-winged black bird becomes 0.5 and 0.4, respectively. The likelihood of risk from chronic imazapyr exposure to these two receptors is considered acceptable in this more realistic scenario. Likelihood of risk from chronic exposure to triclopyr is acceptable with similar alterations to the worst-case scenario.

This preliminary ecological risk assessment is by no means definitive, but based on the available information, exposure to imazapyr and triclopyr at the measured concentrations in *S. glauca* for the representative ecological receptors appear to have minimal risk. The general understanding at this time is that neither imazapyr nor triclopyr is known to have observable acute or chronic effects on terrestrial animals or birds at environmentally relevant concentrations (USEPA and Health Canada). Until further information is available, the results of this risk assessment are in agreement with this consensus.

6.0 COMBINING IVM, GEOGRAPHICAL INFORMATION SYSTEM (GIS), AND COMMUNITY AND CULTURAL VALUES FOR RESPONSIBLE VEGETATION CONTROL ON YUKON POWER LINE RIGHTS-OF WAY

There is clearly no single solution that will be applicable to all situations when managing vegetation over the vast territory represented by the power line ROWs. Each tested method was better than the traditional management method of mowing for controlling target vegetation at least within the one year monitoring period (**Section 4.1**); however, each has issues related to efficacy, persistence (for herbicides), side-effects on non-target plants/animals, and/or public perception. Therefore, it is best to consider each of these tested management methods as tools within the IVM toolbox that is adaptable to stakeholder needs.

6.1. Geographic Information System and IVM

Public consultation and geographical information system (GIS) are too important elements linked to the adaptability of IVM. For example, though herbicides appear to a very promising tool for controlling target plant species on ROWs, even with regulatory approval and license, ROW proximity to or on private properties might preclude its use depending on land-owner consent. Because of such considerations, it is necessary to integrate GIS capacity to help manage and visualize community input to determine buffer zones to water ways, First Nation communities and properties, and other private and public properties.

The following is an example of how GIS can be used for adaptive IVM. **Figure 11** illustrates various sources for potential concern from the public and the government if herbicides were used along this section of the ROW for vegetation control. Potential concerns include the traversing of two water ways by the ROW, proximity to four First Nations properties including an identified trap line, and other private agricultural and industrial sites adjacent to the ROW. Protection of aquatic life and potable or navigable waters is always a primary concern. With the GIS system, aside from identifying obvious buffer zones, additional buffers can be delineated based on topography and the watershed. With changing land claims and other property lines, rapid updates can be managed through GIS. Other important considerations such as potential animal migration routes, First Nation sacred areas, or public recreational areas may be identified through public consultation and be easily located through the GIS process.

Aside from the obvious benefit of quickly and accurately translating consultation information into maps that aids in operational decision-making for IVM, GIS can be used to monitor long-term efficacy of treatment methods, changes in public input over time, and provide quick visual updates for stakeholders. This will demonstrate to the public a commitment to work transparently, cooperatively, and responsibility to adapt and implement the best practices to satisfy vegetation management goals and gain community trust and approval.

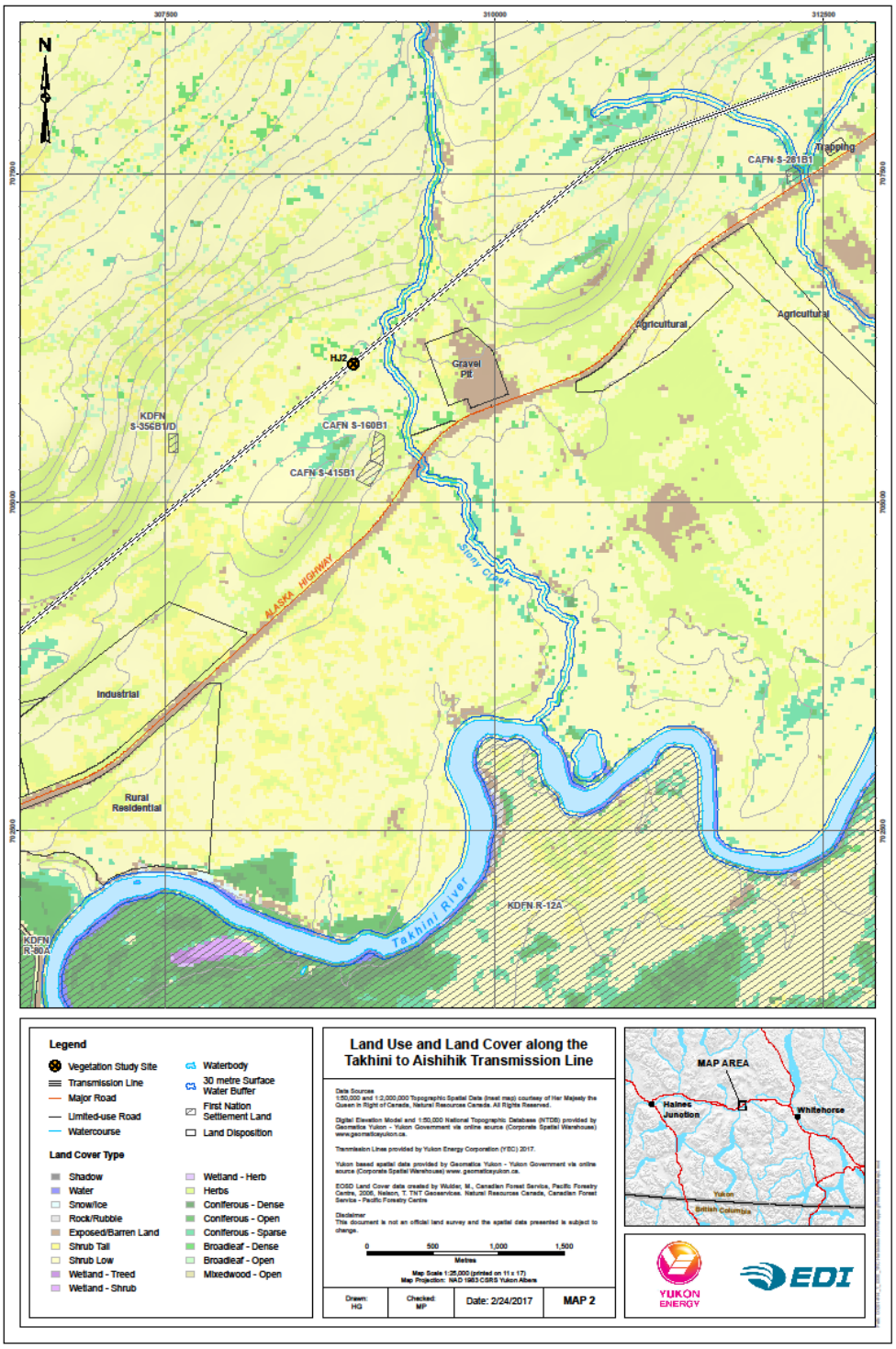

Figure 11 Map of area surrounding the field site at Haines Junction 2 (HJ2). Potential public concerns regarding the use of herbicide for vegetation control may stem from the power line right-of-way traversing two water ways, proximity to four First Nations properties including an identified trap line, and other private agricultural and industrial sites adjacent to this section of the ROW.

6.2. Communication and IVM

Integrated vegetation management can include a combination of chemical, biological, cultural, mechanical, and manual treatments (USEPA 2016). The way in which these methods are combined can dramatically change the communication strategy for use with stakeholders. Communication, within a consultation framework, is defined as an intentional transfer of information designed to respond to public concerns or public needs (Höppner et al. 2010). Effective communication is key to providing land managers in the surrounding areas with all of the necessary information to understand the proposed management strategies. Land managers are people employed with the intention of ensuring there is low risk of serious irreversible harm to the land. In many cases, these are community members themselves who use the land near the ROW and are directly affected by the management strategy.

Vegetation management strategies serve different purposes and should fulfill the various needs of the stakeholders. It is crucial that the target audience for communication be identified and that the means of communication are directed at this audience in order to improve the efficacy of the consultation process (Lahr and Kooistra 2009).

A vegetation management plan can be considered effective if the risk management program addresses liabilities created by trees and other plant life that pose the largest threat to electrical transmission and distribution systems (Cieslewicz and Novembri 2004). However, it is also necessary that regulatory compliance, public and employee safety, and public concerns are understood, engaged, and mitigated. IVM plans need to incorporate communication to be considered a valuable approach.

To carry out an IVM program, information regarding vegetation management operations, treatment efficacy, as well as, on-going monitoring of vegetation community development on the ROW is needed. Furthermore this information can then be used to deploy personnel, forwarded to regulators, and shared with the public (Cieslewicz and Novembri 2004). Another aim of communication is to improve awareness and knowledge of any associated risks of the plan to the community. This is especially crucial when there are contentious aspects to a management plan. To accomplish acceptance and usability of herbicides as part of an integrated vegetation management strategy, involvement from stakeholders is essential.

Co-management is one approach to vegetation management that involves a multidisciplinary group of people working together to develop a strategy. The rationale for this approach has come from the experience of managers struggling to integrate a strategy within the socio-economic fabric of the surrounding region (Lane 2001). An example of this could include developing a technical aspect of IVM, such as selective herbicide application, while considering socio-economic benefits to the local community by providing employment opportunities. Furthermore, a co-management approach could consist of technical representatives from a utility collaborating with First Nations to develop and design baseline vegetation studies on ROWs near their Traditional Territory. Developing cooperative relationships with local stakeholders and sharing the burden of management responsibilities has emerged as a new paradigm (Lane 2001). Stakeholder involvement and public participation are essential for informed decision-making, leading to better awareness and greater acceptance and trust in the end

management strategy. This involves developing a framework for interpretation and informed decision-making regarding results.

For example, the Canadian Pacific Railway (CPR 2015) IVM Plan discusses the management of vegetation on properties owned by Canadian Pacific Railway including, but not exclusive to, ROWs. This plan described CPR's planning process and how these approaches ensure vegetation management while considering and incorporating environmental and human health values (CPR 2015). The objectives of the IVM program are to prevent or manage unwanted vegetation, including the control of noxious weeds and invasive plants. Prior to implementing vegetation management, general site conditions and environmental sensitivities are assessed and documented by qualified persons, such as the proximity to water bodies and water sources. A justification of herbicide use for each area is provided, as well as, the different application methods to be used and their rationale. This information is made available to the public through shared documents. A description of the reporting, notifications completed and approaches that will be taken to complete public consultation is also included in the plan. The consultation plan clearly describes its objectives and how and when it will be publicly advertised. A summary of public consultations, as well as, the nature of concerns and/or recommendations is provided. CPR describes in their First Nations Consultation plan wanting to ensure that First Nations have an opportunity to identify concerns and for CPR to address those concerns before the IVM plan is finalized and a Pesticide Use Notice is submitted for confirmation (CPR 2015).

In contrast, the BC Hydro Facilities IVM Plan (BC Hydro 2016) discusses in detail the requirements for responsible treatment options and method selection criteria for suppressing vegetation populations. However, it is limited in its description of communicating this to the relevant public. Before work starts with the use of herbicides, BC Hydro mentions that input from parties who may be significantly impacted will be pursued. However, the management plan does not explain the qualifications for the parties to be deemed significantly impacted, nor does it describe the process by which the input will be collected (BC Hydro 2016). Similar to the Canadian Pacific Railway IVM plan, BC Hydro lists in its IVM plan the descriptions of all approved herbicides and describes the different application methods and their rationale. As well, the report clearly defines the management areas within sites that have different action thresholds for vegetation control and those areas which should remain herbicide-free at all times, such as watersheds, riparian areas, and water sources (BC Hydro 2016). However, while discussing measures to protect community watersheds, it does not mention processes where the communities in question will be engaged on this subject or provided relevant documentation. In order for there to be an engaged public, there must be a clear consultation plan in place within the IVM plan. This includes clearly defined objectives and how and when these objectives will be publicly advertised. To have valuable consultation, the public must then have an opportunity to share their response. This can be completed through many avenues, one of which being public meetings, where the public can share their concerns and/or recommendations with the utility. In **Appendix D** example materials that could be used for communications with the public regarding IVM and herbicide-use are provided.

Despite a wide diversity in circumstances, communication and community engagement should ideally pursue a set of common objectives: 1) to equalize power differences within the research/consultation

process; 2) to build trust and ensure transparency; and, 3) to provide opportunities to identify concerns and have time and an appropriate channel to address those concerns.

In on-going work regarding IVM, herbicide-use and community concerns regarding vegetation management strategies in boreal Saskatchewan, research is being conducted to improve informed environmental decision-making among Indigenous communities and a Crown corporation (Brock 2017). This research is a collaboration between SaskPower, Lac La Ronge Indian Band (LLRIB) and the University of Saskatchewan. Through a multi-stage process of literature review, interviews and workshops, primary outcomes from this work will include:

- A foundation for LLRIB, SaskPower and the Ministry of Environment to work together in the future on vegetation management along rights-of-way in traditional territory;
- A modified framework for good-practice engagement that supports on-going, collaborative and respectful relationships, and that contributes to informed decision-making for application in other settings; and
- A good-practices engagement handbook for Industry that provides guidance on establishing respectful partnership between Indigenous peoples and Industry

7.0 CONCLUSIONS

Integrated Vegetation Management incorporates both environmental and socio-economic values into a sophisticated system of power line ROW vegetation management. The first step in developing an IVM program is gathering information on the disturbance dynamics of local ROW plant communities. The research presented was designed to provide northern-specific information for power line vegetation mangers in Yukon considering adopting an IVM model.

Impacts of eight vegetation management methods were evaluated on ROW plant communities one year after treatment at four Yukon ROW sites (**Section 4.1**). The sites were located in three biogeoclimatic zones, and although plant communities differed at each site, treatment effects were consistent among sites. Findings from this field trial include:

- Chemical management with the herbicides triclopyr (Garlon XRT) and imazapyr (Arsenal Powerline) was more effective (75 to 95% reduction of target) at controlling target woody species than mechanical cutting (<50% reduction) one year post treatment;
- Non-target species cover was reduced after all treatments; however, broadcast spray with imazapyr caused the most damage to non-target species;
- Non-target recovery from triclopyr damage was observed;
- Impacts of herbicides on non-target plant species can be mitigated by application where cut-stump and basal-bark application had less impact on non-target plant species than broadcast spraying;
- Although significant vegetation community changes were not detected, numerous life form (e.g., erect shrub, forb, graminoid) or species-specific changes were detected. Selective impacts of treatments on life forms/species are promising as the differences indicate treatments can be designed to meet management objectives;
- Further monitoring over the duration of a management cycle (8-10 years) is required to determine whether the treated vegetation on Yukon ROWs will develop into alternate, distinct plant communities and what cover types best resist target species invasion.

The efficacy of target woody species control by imazapyr and triclopyr applications indicates herbicide use may be a management option for Yukon ROW. However, environmental and socio-economic impacts must also be considered. To further inform on the environmental impacts of herbicide use on Yukon ROWs, chemical persistence in the environment (**Section 4.2**) and sensitivity of non-target plants (**Section 4.3**) to imazapyr and triclopyr were determined to quantify the observed effects in the field.

For imazapyr:

- Dissipation rate of broadcast applied imazapyr from soil was gradual and relatively slow (DT_{50} = 16 days). Slow dissipation of imazapyr might indicate it does not easily volatilize or photo-degrade in the soil environment;

- The dissipation from broadcast treated vegetation (white willow (*S. glauca*)) in the field followed a more rapid decline pattern with a calculated DT_{50} of 1.5 days followed by a persistence concentration in the treated vegetation;
- In the greenhouse trials, sensitivity of non-target plants to imazapyr was high with estimated IC_{50} values ranged from 0.7% to 1.2% of manufacturer's recommended field application rate;
- Its long persistence in the soil and high sensitivity of plants to it indicates imazapyr has long-term potential to impact non-target plant species even at trace amounts. This was reflected in the relatively high level of damage to non-target plants observed in the field one year post treatment; and,
- Its persistence in treated vegetation might be a secondary release mechanism that can impact non-target plants beyond the initial treatment.

For triclopyr:

- The rate of dissipation from soil when applied through broadcast spray in the field was initially rapid (DT_{50} = 1 day) followed by a persistence phase at very low concentration. The rapid dissipation phase of triclopyr might indicate it is readily volatilized or photo-degraded within the soil environment;
- The dissipation from broadcast treated vegetation (white willow (*S. glauca*)) in the field followed a more gradual decline pattern with a calculated DT_{50} of 11.5 days;
- In the greenhouse trials, sensitivity of non-target plants to triclopyr was relatively low in comparison to imazapyr with the estimated IC_{50} value at 31% of manufacturer's recommended field application rate;
- Its relatively rapid dissipation from soil and lower phytotoxicity(than imazapyr) indicate triclopyr has limited impact on non-target vegetation beyond the initial treatment. This was reflected in *A. millefolium* recovery at 21-28 days after application in the greenhouse and non-target vegetation recovery in the field one year after treatment; and,
- Although, triclopyr does persist in treated vegetation, it is not at concentrations that will impact non-target vegetation if released during decomposition.

Imazapyr's high phytotoxicity to many non-target species, ability to transfer between treated and untreated vegetation, and persistence in soil indicates that it is not a suitable product for northern ROWs, if maintaining or directing non-target vegetation development is a management priority. Triclopyr is the better herbicide option.

Neither herbicide appears to have measurable negative impacts on other ecological receptors. Sensitivity of soil invertebrates to both herbicides was determined directly through standardized toxicity testing (**Section 4.3.2**). Potential risk from indirect herbicide exposure for herbivorous animals (where herbicide residues in soil and plants may be consumed) was determined through a preliminary ecological risk assessment (**Section 5.0**). The findings include:

- Soil invertebrates were relatively insensitive to either herbicide. The estimated IC_5 and EC_5 values for the three tested soil invertebrate species were at or above the manufacturers' recommended field application rates;
- Acute (short-term) toxicity to herbivorous animals was unlikely even at the highest residual herbicide concentrations measured in the field for treated soil and vegetation (worst case scenario); and,
- Potential risk to herbivorous animals (e.g., moose) was detected in the worst case chronic (long-term) exposure scenario. However, when input parameters such as dissipation/persistence of herbicides, proportion of diet/home range of the animal, and/or applicability of/alternative reference dose were considered, the likelihood of risk to these animals from chronic exposure to either herbicide was low or deemed acceptable.

Triclopyr is the better herbicide option for inclusion in an IVM plan when all lines of evidence are considered. However, the biological and ecological effects of herbicide use are only one aspect for consideration when designing an IVM plan.

The socio-economic concerns of stakeholders towards herbicide use need to be addressed. This involves an extensive consultation process with the public, First Nations, and the government. Obviously, this is beyond the scope of this technical report. However, some thoughts are presented for consideration in order to improve the public consultation process and likelihood of a positive outcome (**Section 6.0**). These include:

- Integration of GIS and community input to determine buffer zones to water ways, First Nation communities and properties, and other private and public properties that might be impacted. GIS is an relatively simple tool to visualize large quantity of evolving information from stakeholders;
- Transition local contractors (if applicable) away from manual (mowing) ROW maintenance. Mowing will continue to be one tool in the IVM toolbox; however, it is not the only one;
- Local contractors can be trained in safe handling and use of herbicide or alternative strategies for ROW maintenance. They will be needed for long-term field data acquisition to fill identified data gaps (**Section 8.0**). Furthermore, they should be involved with the long-term monitoring of ROW plant community development to gauge the effectiveness a IVM strategies in altering the plant community composition or how well the newly developed plant community might resist invasion by target species over time; and,
- Develop a communication strategy as an integral element of an IVM plan and maintain consistent communication between stakeholders to build trust and reliance. IVM is an iterative approach where strategies might be altered over time as new tools and conditions develop or knowledge of old tools is revised. Communication and collaboration is the only way to ensure continual buy-in from all stakeholders in an ever-changing world.

Integrated Vegetation Management requires an understanding of the disturbance dynamics on power line ROWs to effectively design treatments to meet management objectives. The work completed to

date determined that different management techniques can alter northern boreal plant communities, chemical management methods are effective at short-term (up to one-year post treatment) woody species control, and triclopyr is the better chemical control when all lines of evidence is considered. These results support that IVM principles can be applied to northern power line ROWs. The developmental trajectories of boreal plant communities after treatments were not yet clear. Continued monitoring of treatment plots or monitoring of larger-scale treated areas is required to determine if desirable plant communities establish. Once a suitable level of knowledge is achieved, management objectives beyond target woody species control will need to be defined. Socio-economic and environmental considerations will vary between sites. This will require the integration of GIS with information from public consultation. Once consultation is complete, treatments can then be selected to reflect local environmental and socio-economic conditions.

8.0 DATA GAPS AND RECOMMENTDATIONS

The summarized studies in this report provided a number of insights to various vegetation management techniques that might be included in IVM strategies for use on power line ROWs. This included information on the efficacy of various techniques, the persistence of herbicidal chemicals in a northern climate, and potential sensitivity of non-target organisms to chemical treatments. However, there are outstanding questions that the current studies could not address because of their limited scope. The following issues need to be address in order better formulate IVM strategies that will meet the ecological/environmental and socio-economic values of all stakeholders:

1) Long-term monitoring of the treated plots is necessary. It is expected that plant community changes will need several years to be established and detected. One site has already been lost as it underwent scheduled routine vegetation management (mowing). It is recommended at least one out of the five sites be designated for long-term monitoring;

2) Collected non-target vegetation from the field sites could be analyzed for residual herbicide concentration to improve our understanding of herbicide translocation and persistence in non-target vegetation in northern ROWs. This will also improve our estimation of potential risk to ecological receptors that come into contact with or consume these plants. Not all vegetation can be analyzed because of cost; however, in consultation with local communities, candidate species could be identified for analysis based on potential ecological, socio-economical, and cultural significance;

3) From the greenhouse trial, it was demonstrated that non-target boreal plants are sensitive to imazapyr and triclopyr at concentrations well below the manufacturer suggested rate. The efficacy of alternate/lower herbicide application rates in the field should be explored;

4) Impact of treatments on aquatic organisms and water quality was not considered. Both surface run-off and groundwater percolation may lead to herbicides reaching receiving surface water bodies. Alternatively, changes in plant community composition may alter surface and groundwater movement and impact surface water quality in general; and,

5) Habit alteration for birds and animals was not addressed. Potential treatment effects and plant community changes over time might impact the quality and quantity of habitat for birds and animals on the ROW. In combination with long-term vegetation monitoring, habitat monitoring is needed.

9.0 CLOSURE

This report was prepared for the exclusive use of Yukon Energy Corporation and its agents. The summarized work was completed in fulfillment of the Master of Science degree for the University Saskatchewan. As such, the published data and the primary authors' interpretation were peer- reviewed and are available to in the public.

The preliminary risk estimates likely represent upper bound of the estimate of risk based on the level of contaminants detected at the Site and exposure scenarios herein described. Risk estimates might be higher than those provided should future investigations identify areas of soil, groundwater, and vegetation impacts with contaminants greater than those stated or should the exposure scenarios change.

No other warranty, expressed or implied, is made. Any use which a third party makes of this report, or any reliance on or decisions to be made based upon it, are the responsibility of such third parties. The University of Saskatchewan accepts no responsibility for damages, if any, suffered by any third party as a result of the decisions made or actions based on this report.

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Appendix A

EDI 2013

(refer to attached electronic files)

Appendix B

Isbister 2016; Isbister et al. 2017

(refer to attached electronic files)

Appendix C

Jimmo 2017 (DRAFT)

(refer to attached electronic files)

Appendix D

Public engagement materials

(refer to attached electronic files)

TOPIC: **Section 3 Revenue Requirement**

REFERENCE: Page 3-11 Table 3.8

QUESTION:

a) Please explain what SCADA Communication entails.

b) Please explain why SCADA Communication costs more than doubled in 2014 over previous years and has continued at this higher level.

ANSWER:

(a)

SCADA (supervisory control and data acquisition) Communication is YEC's control system architecture for high-level process supervisory management and interfaces with plant and equipment. It includes YEC's System Control Centre operations as well.

(b)

The change in 2014 resulted from the reclassification of data circuit costs. It was determined that these costs were more appropriately classified under SCADA Communication. Previously, these costs were included under Operation Supervision of Production Costs (Table 3.5).

TOPIC: **Section 3 Revenue Requirement**

REFERENCE: Page 3-19 Hearing Cost Reserve Account

QUESTION:

a) YEC requests a decrease in the hearing reserve account appropriation to $250,000 per year from $550,000. Does this mean that YEC is proposing to have a GRA once every 4 years instead of every 2 years?

b) Does YEC not consider a Phase 2 hearing within the next 2 to 4 years a possibility? Would not more stable rates in the long term result from maintaining a modest credit balance by simply reducing the annual appropriations to something under $550,000 but more than $250,000?

ANSWER:

(a)

No. YEC has not established a fixed cycle for GRA's.

(b)

Please see the response provided to UCG-YEC-1-2 regarding considerations governing the timing for any future Phase 2 proceeding.

Maintaining a modest credit balance is a reasonable target. More stable rates would occur in the long-term if YEC was able to accurately predict the timing and costs for future hearings; however, this is difficult given the nature and uncertainties regarding regulatory processes.

TOPIC: **Section 3 Revenue Requirement**

REFERENCE: **Page 3-21 and 3-22 Cost of Debt**

QUESTION:

a) Did YEC initiate discussions with YDC to reduce its debt, or did the YDC/Yukon Government initiate these discussions?

b) In January 2011 YEC's debt with YDC was reduced from 4.65% - 7.00% on various debts to 4.25%, and in Board Order 2013-01 the YUB reduced the interest rate to 3.97% for 2012 and to 3.58% for 2013. These were based on long-term (30-year) Canada bond rates plus 120 basis points. Since these interest rates were based on 30-year bond rates, why were these debts refinanced less than 5 years later?

c) In lines 17-20 on page 3-22, the interest rate is forecast at 2.15% "… based on the most recent market rate for such borrowings as at May 2017." Please explain in detail what "market" is being referred to and what is meant by "such borrowings". Does this assume that YEC is a stand-alone utility?

ANSWER:

(a)

YEC initiated discussions on debt with the parent YDC.

(b)

The refinancing was done to take advantage of lower market rates available at the time. This benefit flows directly to ratepayers through lower utility revenue requirements.

(c)

"Market" refers to the commercial long term debt market in this case represented by TD Commercial Banking. "Such borrowings" refers to long-term (25 year) debt. The assessment assumes that YEC income is sufficient to finance debt obligations, and that this debt is guaranteed by YDC and the Yukon government.

TOPIC: **Section 3 Revenue Requirement**

REFERENCE: Appendix 3.3 reportable outages

QUESTION:

a) Please explain the protection systems that minimize the extent of outages when a generating plant trips off-line.

b) It appears that often certain areas or subdivisions in and around Whitehorse are tripped off whereas others are not. Please explain how these areas are determined and how they fit into the response for (a) above.

c) Are industrial customers treated as a separate group or category for being tripped-off to minimize the impact to residential and general service customers? If not why not?

d) Would the answer to (c) above be different if the Victoria Gold and Alexco mines were grid customers? If not why not?

ANSWER:

(a)

A load shedding scheme is employed to minimize the extent of outages when a generating plant trips off-line. The purpose of Under Frequency Load Shedding (UFLS) is to balance generation and load when an event causes a significant drop in frequency on the system. The activation of UFLS is the last automated reliability measure associated with a decline in frequency in order to rebalance the system. UFLS protection schemes are based on frequency thresholds and on frequency rate of change. Various stages of UFLS are employed on the Yukon power system. YEC utilizes UFLS on the Dawson town feeders. ATCO has UFLS on numerous feeders with staging that can be altered between the feeders. ATCO controls the protection settings on these feeders.

(b)

The specific load shedding scheme in place at any given time in and around Whitehorse is determined by AEY.

(c)

No. The Minto Mine is the only industrial customer on the Integrated System and the infrastructure serving the mine is not configured for load shedding. In addition, tripping a large industrial load can create other issues for grid power supply (i.e. stability of supply).

(d)

Protection settings are established based on individual customer loads and grid characteristics. As both of these factors can change over time, the corresponding settings must similarly be reviewed periodically. At this time, YEC is reviewing the specific load profiles of these customers and assessing different protection schemes. It is possible that both Victoria Gold and Minto will be configured for UFLS in the future.

TOPIC: **Section 3 Revenue Requirement**

REFERENCE: Appendix 3.4 Page 3.4-6 "Actual LNG unit operation has been constrained by unit size at 4.4 MW, i.e., smaller existing diesel units are relied upon for thermal loads less than 2.6 MW …"

QUESTION:

a) 2.6 MW from a 4.4 MW LNG unit represents 59% of its capacity. Please explain why the LNG units cannot run at a loading less than 59%.

b) IF LNG units are really constrained to 2.6 MW why would YEC not run them at 2.6 MW and conserve water at Aishihik (or elsewhere) when thermal loads are less than 2.6 MW?

c) Are diesel units not also operated this way, i.e. when a diesel unit is required it is operated constantly at or near peak efficiency by reducing the hydro output, thereby saving the water for future use and at the same time increasing the hydro spinning reserve?

ANSWER:

(a)

The 2.6 MW constraint is a direction from the OEM.

(b)

While the LNG units can be run at 2.6 MW, there is a negative impact to fuel efficiency by running at this lower load and running at less than optimal loading has a negative effect on maintenance requirements. YEC would run a smaller diesel at higher loading to achieve greater efficiencies as the main decision criteria. In addition, as noted in the application, the units are also subject to minimum run times which are factored into the decision for next-on generation.

(c)

As described in John Maissan-YEC-1-10, thermal units are run at optimal load while hydro provides load following (spinning reserve).

TOPIC: **Section 3 Revenue Requirement**

REFERENCE: Appendix 3.4 Page 3.4-9 "2016 average delivered LNG fuel cost of 18.17 cents per kW.h was actual costs [sic] of LNG used from inventory …"

QUESTION:

a) Please explain how the boil-off gas was used and accounted for, and how the vented LNG is accounted for in these calculations.

b) If the boil-off and the vented LNG in 2016 is not included in the referenced cost, please explain where the costs for this LNG are accounted for.

ANSWER:

(a) and **(b)**

For the configuration at the Whitehorse generation station, boil off gas is either burned in the GE generators or is consumed in the boiler for space heat in the existing diesel plant (P126). Generation fuel is included in Fuel expense (Tab 7, Schedule 10, line 12); fuel consumed for heat in P126 is included in Production expense. Unreconciled amounts (whether from venting or other reasons) are also accounted for in Fuel expense.

Table 1 below illustrates the gas consumption for 2016:

Table 1: Gas Consumption (2016)

	A=B+C	B	C	D	E=B+D
Date	**WG1 and WG2 LNG Volume**	**HP Vapour**	**HP Sendout**	**P126 Boiler Boil-Off Gas Volume**	**Total Boil-off**
	[m^3 LNG]	**[m^3 LNG]**	**[m^3 LNG]**	**[m^3 LNG]**	**[m^3 LNG]**
Jan-16	50.6	12.9	37.6	15.0	27.9
Feb-16	27.1	22.5	4.5	5.9	28.5
Mar-16	18.6	6.0	12.6	9.3	15.3
Apr-16	14.5	13.4	1.1	41.2	54.5
May-16	4.4	3.4	0.9	25.4	28.8
Jun-16	3.9	1.5	2.3	16.8	18.4
Jul-16	9.2	0.3	8.9	35.9	36.3
Aug-16	2.4	1.2	1.2	45.8	47.0
Sep-16	462.7	8.7	453.9	5.3	14.0
Oct-16	79.4	2.3	77.1	0.9	3.1
Nov-16	0.0	0.0	0.0	39.6	39.6
Dec-16	566.2	5.6	560.6	0.0	5.6
	1,238.8	78.0	1,160.8	241.0	319.0

Column A is total gas consumed in the generators and is the sum of columns B and C. Column C represents “normal” run mode for the generators where the LNG is vaporized and fed into the generators; column B – HP vapor is boil off gas that is sent to the generators at the end of the generation run specifically to reduce the pressure in the tank (by design, tank pressure must be brought up to a higher pressure to feed the generators; for storage purposes, the tank pressure is drawn down for optimal storage (i.e., lowest boil off rate)). Column D is “normal” boil off gas that is fed to boilers for heating purposes.

TOPIC: **Section 3 Revenue Requirement**

REFERENCE: Appendix 3.4 Page 3.4-12 Re. summary highlights impacts with a $16 million DCF cap option.

QUESTION:

a) Please explain how these impacts would change with the addition of the Victoria Gold mine at 62 GWh per year (year 1) to the grid.

ANSWER:

(a)

The 450 GW.h load option examined in this section is a good proxy for the impact of the Victoria Gold mine absent the Minto mine.

Assessment of the 450 GW.h load relative to the 420 GW.h load forecast for 2018 with a $16 million DCF cap option indicates the following changes in impacts (see page 3.4-33):

- Helps to reduce the frequency of rate riders; and

- Increases slightly the peak year charges, i.e., a modest further increase in the DCF cap would likely be needed to remove this change.

TOPIC: **Section 3 Revenue Requirement**

REFERENCE: Appendix 3.4 Page 3.4-13 "The Diesel Contingency Fund ("DCF") operates to smooth customer rate changes … caused by fluctuation of hydro generation due to water conditions or changes in wind conditions."

QUESTION:

a) The water conditions are readily available to the public based on data from Water Survey of Canada gauging stations, however changes in wind conditions (on Haeckel Hill?) are less readily apparent. Please provide the data source that YEC is or will be relying on to determine wind conditions (short term and long term), and indicate whether this is available to the public.

b) How will wind production losses related to operational and maintenance decisions, as opposed to wind "conditions", be determined?

c) The Vestas wind turbine appeared to be shut down for a large portion of August (to the present), what factors are / were involved in it not operating?

ANSWER:

(a) and **(b)**

Wind data used for DCF purposes is based on recent operational (2015-2016) performance of the Vestas unit (WW2). A review of historical performance of WW2 indicates the period selected for DCF purposes yields an average generation higher than the average for all complete years since the unit was put in-service. Wind conditions were not part of this review; the forecast is based on recent actual performance.

(c)

The turbine had been shutting down on over current trips. The OEM was contracted to perform the annual maintenance and investigate the cause of the shutdowns. The test results clearly indicates a failure of the generator rotor.

The OEM recommendation is to replace the generator with a new or refurbished unit.

YEC is reviewing the recommendation from the OEM and will conduct a complete asset assessment before an action plan is determined.

TOPIC: **Section 4 Rates**

REFERENCE: Page 4-9 lines3 to 6 and Appendix 4.2

QUESTION:

a) Please provide a table detailing the revenue requirement reductions in each of 2017 and 2018 resulting from each of the following:
   i. The renegotiation of YEC's long term debt effective 2015;
   ii. The capital contribution of $22.4 million from YDC;
   iii. The Mayo B flexible debt financing compared to conventional debt at the same unreduced interest rate; and
   iv. The $128.5 million in contributions (from page 5-4) towards the cost of various projects.

b) Is it not true that Yukon's power rates are where they are compared to NWT and Nunavut as a result of significant YDC, Yukon government and federal government capital contributions for various infrastructure projects effectively subsidizing the rates through reduced revenue requirements?

ANSWER:

(a)

Please see Table 1 below.

Table 1: Estimated Impact of Government Contributions

Refinancing and Contributions	Impact to 2017 and 2018 Revenue Requirement	Note
Refinancing YDC long term debt in 2015	Reduces interest payments in 2017 and 2018 by $1.5 million and $1.4 million respectively.	2017-18 GRA, Tab 3, page 3-21
Capital contribution of $22.4 million from YDC in 2015	The impact of $18.3 million contributions to the LNG plant is about $1.3 million reduction in revenue requirement for each 2017 and 2018 test years. This reduction will be longer term compared to deferred cost impacts. The impact of remaining $4.2 million contributions is about $0.7 million reduction in revenue requirement for each 2017 and 2018 test years.	$18.3 million used to offset the capital costs of the Whitehorse Diesel Natural-Gas Conversion Project (LNG Project) and the balance of the contribution ($4.2 million) was used to offset amounts for deferred projects in rates [2017-18 GRA, Tab 1, page 1-3]
Mayo B flexible debt	Reduces interest payments in 2017 and 2018 by approximately $0.7 million and $0.6 million respectively.	Calculated based on the maximum face interest of 5.46% and the interest expense based on load forecast for 2017 and 2018.
Total of $128.5 million contributions towards Carmacks-Stewart Transmission Project Stage 2, Mayo B and Aishihik Third Turbine Projects	The estimated impact is about $7.6 million/year reduction in revenue requirement [depreciation and return on rate base].	$41.9 million for Carmacks-Stewart Transmission Project Stage 2; $81.6 million for Mayo B; and $5 million for Aishihik Third Turbine Project [2012/13 GRA, YUB-YEC-1-32 c)]

(b)

Generally, the statement is not correct. It focuses on recent projects and funding and fails to reflect the long established lower costs for Yukon hydro grid generation compared to the generation sources required to supply power in NWT and Nunavut.

Since 2006, Yukon Energy has engaged intensively in planning and development activities required to identify the next generation of lower cost sources of supply for Yukon. The additional major bulk power (generation and transmission) projects have been added to the Yukon system which have enhanced system performance and reduced Yukon diesel generation requirements. It is true that significant contributions from YDC, Yukon Government and funding through federal programs for these various infrastructure projects in Yukon have reduced the revenue requirement today and lowered rates for ratepayers compared with what would be required without such assistance. However, absent such government funding assistance, the full CSTP and Mayo B project developments would not have proceeded when they did and Yukon generation requirements would still have been met mainly with long established hydro generation.

It is also important to note the role of the utility in negotiating and securing funding, as well as initiating the measures taken to help manage ongoing cost pressures. The planning and development activities to refinance the existing high cost debt would be examples of those activities.

Hydro generation remains the predominant source of generation in Yukon with over 95% supplied by hydroelectric generation, and the remaining 5% supplied by natural gas and diesel thermal generations, mostly for the isolated diesel communities. In contrast, the Northwest Territories Power Corporation's 2016-18 GRA shows approximately 75% of its total generation is from hydroelectric generation and 25% is from thermal generation sources. Qulluq Energy Corporation generation in Nunavut is 100% based on isolated diesel generation.

TOPIC: **Section 5 Capital Projects**

REFERENCE: Page 5-7 Section 5.2.1.2 Aishihik elevator shaft

QUESTION:

a) Can YEC confirm that the Aishihik elevator shaft structural steel was installed in approximately 1975?

b) If correct, the useful life of the original structure was far less than 72 years, so how can YEC justify an expectation of 72 years of life from the replacement structural steel?

ANSWER:

(a)

Confirmed.

(b)

Based on the nature of the asset, this project was classified as “Hydro Structures and Improvements” which has an approved depreciation rate of 72 years.

TOPIC: **Section 5 Capital Projects**

REFERENCE: Page 5-12 Communications upgrades

QUESTION:

a) Will the installation of the proposed upgrades result in the retirement of the power line carrier communications system? If not, please explain.

ANSWER:

(a)

The power line carrier communications system will not be retired as it is still used for protection communication purposes and control redundancy.

TOPIC: **Section 5 Capital Projects**

REFERENCE: Page 5-15 Whitehorse Hydro unit No. 4 overhaul

QUESTION:

a) Has the unit 4 overhaul been completed?

b) Have the spider replacement and the excitation system replacements been completed?

c) If the answers to (a) and / or (b) above are yes, please provide the actual costs of the completed works.

d) Was a capacity increase of WH 4 by the installation of a new turbine ("wheel" or "runner") design a consideration? Please explain.

ANSWER:

(a)

Yes.

(b)

Yes.

(c)

Please see response to YUB-YEC-1-68.

(d)

YEC did not consider installing a new turbine as part of the WH4 overhaul. A study was commissioned to provide a technical and economic review and analysis of the potential options for the uprating of the Whitehorse hydro generating units, however, it was not completed in time to be included in this project. Due to the engineering and planning time

required for an uprate of WH4, as well as the emergency nature of the repair, a new turbine design was not feasible for this project.

TOPIC: **Section 5 Capital Projects**

REFERENCE: Pages 5-22 to 5-26 (and page 5-6) LNG plant

QUESTION:

a) Please provide the capital cost estimate for the LNG plant provided in the 2014 LNG Part 3 Application.

b) Please provide the capital cost estimate for the alternative diesel project provided in that Application.

c) Please provide the capital cost estimate for the addition of the third LNG unit in that Application.

d) Please provide the updates to the costs in (a) to (c) provided during the hearing.

e) Please provide the long term oil and gas cost forecasts provided in the LNG proceeding on which the economic analyses and economic justification was based.

f) Please provide the delivered diesel fuel costs and the delivered LNG costs (per litre of diesel equivalent) that result from (e) above.

g) Please provide the forecasted cost per kWh from a new diesel plant and the then proposed LNG plant.

h) Please provide the present (July 31, 2017) actual figures for (e) to (g) above.

i) YEC's LNG Application on page 10 in Figure 3-1, and in the table below it, provides a graphical figure and a table of ratepayer costs for capital and fuel costs with new diesel and with LNG. Please reproduce the graph and the table with costs using actual energy loads and actual fuel prices for the same years, and also both with and without YDC's $18.3 million contribution towards the capital cost.

j) Please confirm that the capital cost estimate for the "diesel" alternative (page 5-26 line 21) was for two 6.7 MW dual fuel engine generators and included infrastructure to distribute gas to the engines within the diesel plant.

k) Please confirm that the capital cost estimate for the "diesel" alternative included electrical switchgear replacements and other building upgrades designed to service three 6.7 MW dual fuel generators.

ANSWER:

(a), (b), (c) and **(d)**

The LNG Part 3 Application filed in December 2013 provided the following capital costs (2013$) estimates (updates provided during the proceeding are also noted):

1. LNG Plant (8.8 MW for 2 units)
    a. Application: $34.4 million (Table 4-3, Ex. A-4)
    b. Update: $36.5 million (Table 1, Ex. B-13)

2. Alternative Diesel Plant (13.4 MW for 2 units)
    a. Application: $33.5 million (Table 4-3, Ex. A-4)
    b. Update: $32.7 million (Table 1, Ex. B-13)

3. LNG third unit (4.375 MW)
    a. Application: $4.4 million (Table 4-3, Ex. A-4)
    b. Update: $5.5 million (Table 1, Ex. B-13)

(e), (f), (g) and (h)

The oil and gas cost forecasts in the LNG Part 3 Application proceeding update (Exhibit B-13) on which the economic analyses and economic justification was based are summarized below along with present (July 31, 2017 where feasible) actual figures:

1. Long term oil and gas cost forecasts
    a. Application: The April 2013 U.S. Energy Information Administration forecast outlook indicated that crude oil price is expected to be 4 times that

of North American natural gas price with the expectation that this would continue for a period extending beyond 2030 (Figure 4-2, Ex. A-4).

b. Current: The National Energy Board of Canada's latest energy market assessment (Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040 – An Energy Market Assessment – October 2016.[1]
    i. Overall, this latest NEB update shows a continued major gap per GJ for oil prices compared to natural gas prices with a wide range to reflect uncertainty.
    ii. For the NEB Reference Price Forecasts (2015$):[2]
        - 2016 Brent crude oil price at US$7.35/GJ is US$5.0/GJ higher (3.2 times) than the 2015 Henry Hub natural gas price at US$2.32/GJ.
        - By 2040, the forecast crude oil price at US$14.71/GJ is US$10.6GJ higher (3.6 times) than the natural gas price at US$4.08/GJ.

2. Delivered (at YEC) fuel prices assumed in the LNG Project update economic assessments (Exhibit B-13) and delivered fuel prices for the current GRA:

    a. LNG Part 3 proceeding update (Table 1, Ex. B-13):
        i. Delivered diesel price at Whitehorse of $1.1265 per litre based on last six months actual prices;
            - 26.3 c/kW.h for new diesel plant (4.28 KW.h/litre assumed) and 30.8 c/kW.h for existing diesel units (3.66 kW.h/litre).
        ii. Delivered natural gas cost at $15.6/GJ (assumed supply from Fortis at Tilbury, B.C. with natural gas commodity cost of $4.55/GJ, Fortis LNG liquefaction costs at $4.79/GJ, and haul cost with A-Train at $6.25/GJ):
            - 14.0 c/kW.h with new natural gas units (assumed 40% HHV energy conversion efficiency in the new units, or 9 GJ per MW.h).

[1] The U.S. Energy information Administration's Annual Energy Outlook 2017 (page 64) similarly forecasts a reference price for crude oil through to 2040 more than three times higher than the natural gas price reference price on an energy equivalent basis.
[2] Assumes 6.12 GJ per barrel for crude oil and 0.948 MMBtu per GJ.

b. Current GRA for 2017 and 2018:
    i. Delivered diesel price at Whitehorse of $0.9163 per litre
        - 21.4 c/kW.h if retain assumption that new diesel unit efficiency at 4.28 kW.h/litre; GRA assumes 3.60 kW.h/litre average efficiency for existing Whitehorse diesel units (equals 25.45 c/kW,h at forecast diesel price).
    ii. Delivered natural gas cost at $15.9/GJ ($0.3767 per litre with 0.02369 GJ/litre).
        - 14.67 c/kW.h at actual average efficiency of 2.57 kW.h/litre (39% HHV)

c. Current pricing as at July 31, 2017
    i. Delivered diesel price at Whitehorse of $0.8583/litre (contract fuel price adjusted as of August 1, 2017);
        - 20.1 c/KW.h @ 4.28 KW.h/litre;
        - 23.8 c/KW.h @ 3.60 KW.h/litre.
    ii. Delivered natural gas cost at $18.96/GJ ($0.4491 per litre with 0.02369 GJ/litre).
        - 17.47 c/kW.h at actual average efficiency of 2.57 kW.h/litre (39% HHV)

(i)

Figure 3-1 and related table in the 2013 LNG Application were derived from the analysis in Table 4.3 of the Application. This information was updated in the 2014 hearing in Ex. B-13.

Figure 3-1 and related table are reproduced using the following information:

1. **Capital costs**: assumed 40-year depreciation for costs other than decommissioning; return on mid-year rate base at 5.45% prior to 2017, and at 5.00% for 2017 and 2018[3]. The following capital costs and timing has been assumed for the LNG Project and the New Diesel Alternative:

[3] The 5.45% return was based on prior GRA and the 2013 Part 3 LNG Application, assuming the 8.25% return on equity approved in the last GRA (40% of capital structure) and 3.6% cost of new debt as then forecast (60% of capital structure). The 5.00% return for 2017 and 2018 reflects the

a. LNG Project
    i. Initial 2 units, in-service July 1, 2015:
        1. Total before YDC contribution: $41.933 million
        2. Net after YDC contribution: $23.633 million
    ii. Third LNG Engine (assumed in-service Q1 2019): NA in Figure 3-1 time period (2015 to 2018).[4]
b. New Diesel Alternative (costs of $32.7 million and timing in 2014 and 2015 retained as per Part 3 Application Update)

2. **Delivered fuel costs**: actual diesel and LNG fuel costs for 2015 and 2016, and 2017-18 GRA forecast diesel and LNG fuel costs for 2017 and 2018:
    a. 2015:
        i. diesel at 20.3 c/kW.h for new diesel and 23.7 c/kW.h for existing diesel.
        ii. LNG at 18.83 c/kW.h per DCF filing.
    b. 2016:
        i. diesel at 18.63 c/kW.h for new diesel and 21.8 c/kW.h for existing diesel at Whitehorse.
        ii. LNG at 18.17 c/kW.h per DCF filing.
    c. 2017 and 2018: per GRA
        i. diesel at 22.0 c/kW.h for new diesel and 25.45 c/kW.h for existing diesel at Whitehorse (new engine efficiency assumed at 39%).
        ii. LNG at 14.67 c/kW.h per DCF filing (new engine efficiency assumed at 39%).

3. **LTA Thermal Generation**: actual and forecast as per Table 2.2 of GRA (10.0 GW.h for 2015, 10.5 GW.h for 2016, 14.1 GW,.h for 2017 and 14.5 GW.h for 2018).

4. **Percent of LTA Thermal**: based on GRA and noted constraints on use of larger units for small and short duration loads, assume 90% LTA thermal supplied by LNG (15% for 2015 due to in-service only after mid-year); for new diesel alternative, assume 50% of LTA thermal supplied by these units (based on similar

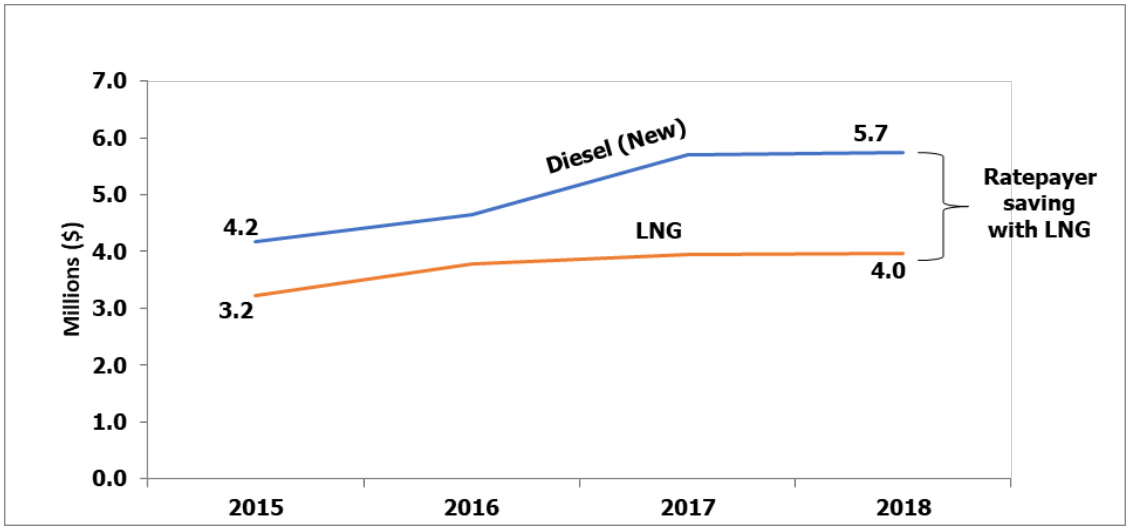
current GRA proposed 8.75% return on equity (40% of capital structure) and an assumed 2.5% cost for new debt (Schedule 11 at page 7-15 shows interest on new debt below this level since 2014).

[4] GRA cost estimate (page 5-26) of $6.2 million; this has been adjusted to $8.9 million; see YUB-YEC-1-71

constraints on use of larger units for small and short duration loads plus assumed low incentive to use for enhanced hydro storage during drought).

Figures 1 and 2 below provided the updated Figure 3-1 with and without YDC's $18.3 million contribution towards the LNG plant capital costs. John Maissan-YEC-1-27 Attachment 1 provides the supporting updated Table 4-3.

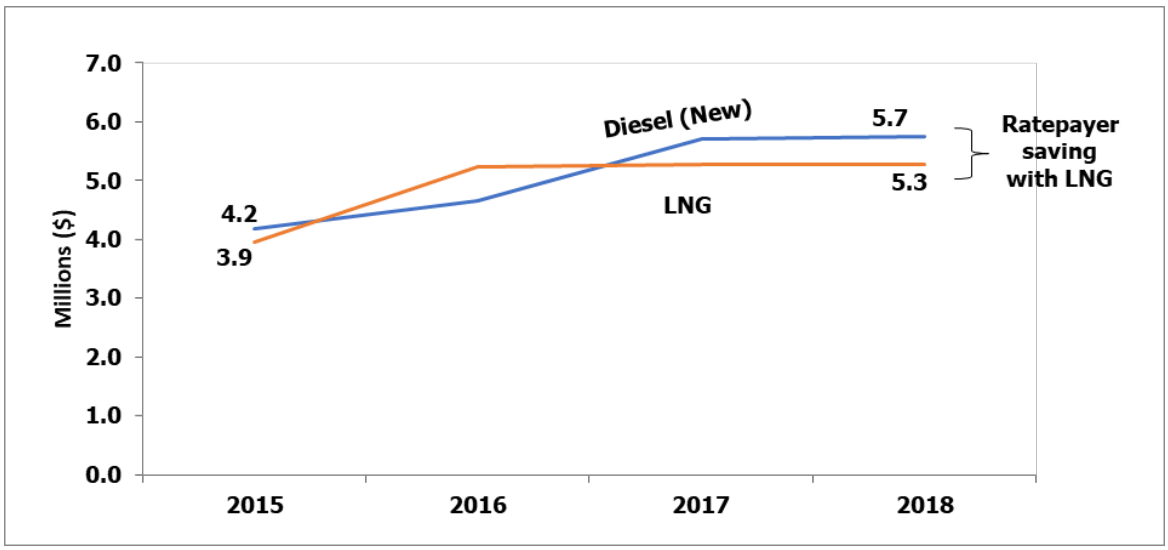
Figure 1: Updated: Annual Ratepayer Costs - LNG vs New Diesel: 2015-2018 (LNG Capital Cost at $23.63 million)



Annual Ratepayer Cost for Capital & Fuel ($million per year)

	2015	2016	2017	2018
Diesel (New)	4.2	4.6	5.7	5.7
Gas/LNG	3.2	3.8	3.9	4.0
Saving (Diesel-LNG)	**1.0**	**0.9**	**1.8**	**1.8**

Figure 2: Updated: Annual Ratepayer Costs - LNG vs New Diesel: 2015-2018 (LNG Capital Cost at $41.93 million)



Annual Ratepayer Cost for Capital & Fuel ($million per year)

	2015	2016	2017	2018
Diesel (New)	4.2	4.6	5.7	5.7
Gas/LNG	3.9	5.2	5.3	5.3
Saving (Diesel-LNG)	**0.2**	**-0.6**	**0.4**	**0.5**

(j) and **(k)**

Confirm that this cost was for two 6.7 MW dual fuel engine generators. Estimates used for the diesel fuel option included building upgrades to service the two new generators. These costs did not assume natural gas use within the diesel plant.

Table 1: Updated Table 4-3 – Capital Costs $23.63 after YDC Capital Contribution

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	21.60	11.10			
	LNG		23.63			
Net	Diesel (new)	21.60	32.2	31.4	30.6	29.8
	LNG	0.00	23.3	22.7	22.2	21.6
Difference (LNG-Diesel)						
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.516	0.794	0.794	0.794
	LNG		0.295	0.591	0.591	0.591
Return	Diesel (new)		1.466	1.732	1.550	1.510
	LNG		0.636	1.256	1.123	1.093
Total	Diesel (new)		1.982	2.526	2.343	2.304
	LNG		0.931	1.847	1.713	1.684
Difference (LNG-Diesel)			**-1.050**	**-0.680**	**-0.630**	**-0.620**
Annual Fuel Cost ($million)						
Forecast LTA Diesel (GWh)			10.0	10.5	14.1	14.5
% New	Diesel (new)		50%	50%	50%	50%
	LNG		15.0%	90%	90%	90%
Fuel Cost	Diesel (new)		2.200	2.121	3.356	3.435
	LNG		2.297	1.946	2.228	2.280
Difference (LNG-Diesel)			**0.097**	**-0.175**	**-1.128**	**-1.155**
Net Ratepayer Impact ($million)						
	Diesel (new)		4.182	4.647	5.700	5.739
	LNG		3.228	3.793	3.941	3.964
Difference (LNG-Diesel)			**-0.954**	**-0.855**	**-1.758**	**-1.775**

Notes:

1. Updated capital costs as of 2017-18 GRA ($0.553 million with LNG for decommissioining Mirrlees units is now assumed after 2018). All capital costs (excluding decommissioning) depreciated over 40 years; return on mid-year rate base at 5.45%/year prior to 2017, and 5.00% thereafter.
2. Diesel fuel costs vary by year: for 2015 average Oct-Dec at 20.3 c/kWh new diesel (WH), 23.7 c/kWh existing diesel (grid average), $0.867 per litre; for 2016 average at Whitehorse Jan-Dec at 18.6 c/kWh new diesel (WH), 21.8 c/kWh other diesel, $0.798 per litre; for 2017 and 2018, as per GRA, Whitehorse diesel price at $0.9163 per litre and 22.0 c/kW.h for new diesel and 25.45 c/kW.h for existing diesel at Whitehorse. In 2015 and 2016, assume 4.28 kW.h/l for new diesel and 3.66 kW.h/l average for existing diesel; in 2017 and 2018, GRA assumption of 3.60 kW.h for existing Whitehorse diesel and 4.17 kW.h/litre for new diesel (39% efficiency).
3. LNG delivered fuel costs vary by year: for 2015, at 18.83 c/kWh (DCF Filing) based on May-Dec actual delivered fuel cost of $20.92/GJ and assumed (per DCF filing) 40.0% unit efficiency at 2.683 kWh/litre of LNG and 24.15 GJ/m^3 of LNG; for 2016, at 18.17c/kW.h actual average cost from inventory based on DCF Annual Report filing; for 2017 and 2018, 14.67 c/kW.h per the GRA forecast (cost of $0.3767 per litre, Sept. to Dec. average for deliveries from Ferus with assumed energy content of 0.02369 GJ per litre, efficiency of 2.57 kW.h litre (39%)).
4. Updated LTA Default Diesel (GW.h) as per Table 2.2 of 2017-18 GRA: actual for 2015 and 2016 LTA as reported in DCF filing; 2017 and 2018 LTA as per GRA.
5. Percent of LTA thermal supplied by LNG as per DCF filing for 2015 (partial year impact) and 90% thereafter (per 2017-18 GRA assessments). Percent of LTA thermal supplied by new diesel at 50% based on capacity limits and assumed insufficient incentive to use for enhanced hydro storage during drought.

Table 2: Updated Table 4-3 – Capital Costs $41.93 without YDC Capital Contribution

		2014	2015	2016	2017	2018
Capital cost ($million) at yr end						
Total	Diesel (new)	21.60	11.10			
	LNG		41.93			
Net	Diesel (new)	21.60	32.2	31.4	30.6	29.8
	LNG	0.00	41.4	40.4	39.3	38.3
Difference (LNG-Diesel)						
Annual Capital Cost ($million)						
Deprec	Diesel (new)		0.516	0.794	0.794	0.794
	LNG		0.524	1.048	1.048	1.048
Return	Diesel (new)		1.466	1.732	1.550	1.510
	LNG		1.128	2.228	1.992	1.939
Total	Diesel (new)		1.982	2.526	2.343	2.304
	LNG		1.653	3.277	3.040	2.988
Difference (LNG-Diesel)			**-0.329**	**0.750**	**0.697**	**0.684**
Annual Fuel Cost ($million)						
Forecast LTA Diesel (GWh)			10.0	10.5	14.1	14.5
% New	Diesel (new)		50%	50%	50%	50%
	LNG		15.0%	90%	90%	90%
Fuel Cost	Diesel (new)		2.200	2.121	3.356	3.435
	LNG		2.297	1.946	2.228	2.280
Difference (LNG-Diesel)			**0.097**	**-0.175**	**-1.128**	**-1.155**
Net Ratepayer Impact ($million)						
	Diesel (new)		4.182	4.647	5.700	5.739
	LNG		3.950	5.223	5.268	5.268
Difference (LNG-Diesel)			**-0.232**	**0.575**	**-0.432**	**-0.471**

Notes:

1. Updated capital costs as of 2017-18 GRA ($0.553 million with LNG for decommissioining Mirrlees units is now assumed after 2018). All capital costs (excluding decommissioning) depreciated over 40 years; return on mid-year rate base at 5.45%/year prior to 2017, and 5.00% thereafter.
2. Diesel fuel costs vary by year: for 2015 average Oct-Dec at 20.3 c/kWh new diesel (WH), 23.7 c/kWh existing diesel (grid average), $0.867 per litre; for 2016 average at Whitehorse Jan-Dec at 18.6 c/kWh new diesel (WH), 21.8 c/kWh other diesel, $0.798 per litre; for 2017 and 2018, as per GRA, Whitehorse diesel price at $0.9163 per litre and 22.0 c/kW.h for new diesel and 25.45 c/kW.h for existing diesel at Whitehorse. In 2015 and 2016, assume 4.28 kW.h/l for new diesel and 3.66 kW.h/l average for existing diesel; in 2017 and 2018, GRA assumption of 3.60 kW.h for existing Whitehorse diesel and 4.17 kW.h/litre for new diesel (39% efficiency).
3. LNG delivered fuel costs vary by year: for 2015, at 18.83 c/kWh (DCF Filing) based on May-Dec actual delivered fuel cost of $20.92/GJ and assumed (per DCF filing) 40.0% unit efficiency at 2.683 kWh/litre of LNG and 24.15 GJ/m^3 of LNG; for 2016, at 18.17c/kW.h actual average cost from inventory based on DCF Annual Report filing; for 2017 and 2018, 14.67 c/kW.h per the GRA forecast (cost of $0.3767 per litre, Sept. to Dec. average for deliveries from Ferus with assumed energy content of 0.02369 GJ per litre, efficiency of 2.57 kW.h litre (39%)).
4. Updated LTA Default Diesel (GW.h) as per Table 2.2 of 2017-18 GRA: actual for 2015 and 2016 LTA as reported in DCF filing; 2017 and 2018 LTA as per GRA.
5. Percent of LTA thermal supplied by LNG as per DCF filing for 2015 (partial year impact) and 90% thereafter (per 2017-18 GRA assessments). Percent of LTA thermal supplied by new diesel at 50% based on capacity limits and assumed insufficient incentive to use for enhanced hydro storage during drought.

TOPIC: **Section 5 Capital Projects**

REFERENCE: Page 5-26 LNG third generator

QUESTION:

a) Since the LNG plant was designed for three 4.4 MW generators, please explain why each of the proposed option review, preliminary engineering, development of equipment specifications, grid impact, and detailed engineering studies are required?

b) Why is it not just a matter of specifying and ordering equipment identical to the equipment specified, purchased, and brought into service just over 2 years ago?

c) Once the third generator is installed, what will be the dependable annual energy capability of the LNG plant?

ANSWER:

(a)

From Phase 1 (when 2 engines were installed) there were some key lessons learned and to translate these lessons into technical requirements, YEC performed preliminary engineering and specification development. In addition, the utility is required to complete grid impact and detailed engineering each time a new project is initiated to ensure successful implementation and integration of new equipment into the YEC grid.

(b)

There are two reasons to revisit the specification and design: first, the original selection process was executed over 2012/13, about five years ago. It is prudent for YEC to re-visit the market to ensure the selection is still in the best interests of the utility; this includes market pricing as well as potential technology changes. Secondly, it is logical to review the selection criteria for knowledge gained during construction and operation of Phase I of this project.

(c)

Assuming a capacity factor of 95%, firm annual energy capability for 13.2 MW of LNG generation is approximately 110 GWh.

TOPIC: **Section 5 Capital Projects**

REFERENCE: Page 5-29 lines 6-8

QUESTION:

a) If the subject work extends the life of the WAF lines, is there a corresponding reduced depreciation cost? If not why not?

ANSWER:

(a)

Replacement of components of the transmission system contribute to life extension, however, this does not translate necessarily into lower depreciation expense. One important countervailing effect is the vintage of the investment; that is, when a component is replaced today, rate base is inflated at today's dollars, replacing dollars that were spent up to 40-50 years ago. This effect alone will have significant upward pressure on depreciation.

TOPIC: **Section 5 Capital Projects**

REFERENCE: Page 5-32 to 5-33 Stewart Crossing - Keno City Transmission Line

QUESTION:

a) Detailed line design and substation design work was expected to be complete in Q1 2017, now that we are in Q3 is this work complete? Please provide an update.

b) The last paragraph on this topic on page 5-33 suggests that the project could be staged with the first stage being the removal and replacement of end of life infrastructure. Is this not in effect what has been happening over the past 20 or more years?

c) Could Victoria Gold's requirements be met with the present 69 kV line for at least a period of time? Or for an indeterminate time?

ANSWER:

(a)

Detailed line design was completed in Q1 2017. The design for a new substation required by Victoria Gold will be completed in Q3 2017.

(b)

Over the past 20 years, line structures have typically been repaired when needed but not replaced. In addition, maintenance has been deferred whenever feasible in anticipation of replacing the line. A key element of this project is the replacement of the conductor, which cannot be completed as a maintenance activity.

(c)

Based on the current forecasted mine load, the existing line could meet full loads in year 1. As noted YCS-YEC-1-76 and YCS-YEC-1-17, the 69 kV line from Mayo to the Keno region was constructed in the 1950's, is end-of-life, and needs to be replaced as soon as feasible.

TOPIC: **Section 5 Capital Projects**

REFERENCE: Pages 5-34 to 36 Battery project

QUESTION:

a) Around early August there were a series of quite extensive outages.
   i. What was the cost to YEC to restore the grid from these outages (labour, diesel fuel, lost sales etc.)?
   ii. What was the estimated cost to AEY?
   iii. What is the cost of each outage to each of Yukon businesses, industry, and governments?

b) Did the analysis of potential benefits of a BESS include the reduction of cost impacts to customers from fewer outages as a result of a more resilient grid from the provision of additional spinning reserve from the battery?

c) If the hydro grid currently provides the spinning reserve would the grid's hydro resources be better utilized (e.g. more energy available in winter) if a BESS could / would provide at least some portion of the necessary spinning reserve? If so please estimate the potential benefits.

d) Is the difference in cost between the two options listed ($5.7 million) a matter of the difference in the cost of capacity only, or is there a difference in energy storage capability or other features between the two battery options as well?

e) What is the incremental cost of capacity for each of the two battery types?

ANSWER:

(a)

(i)

YEC is unable to respond to this request at this time because final cost impacts are not yet known.

(ii)

YEC does not have access to the information necessary to respond to this request.

(iii)

YEC does not have access to the information necessary to respond to this request.

(b) and **(c)**

The TransGrid Solutions Inc. study focused on thermal displacement as primary use for the energy storage system (ESS). The planned system studies for 2017 and 2018 will look at ancillary benefits such as frequency control, blackstart and spinning reserve.

(d)

The cost included in the Application refer to the 4MW/40MWh Lead-acid ESS ($21.7 million) and the 8MW/40MWh Lithium-ion ESS ($27.4 million). Details regarding the basis of the estimates can be found in the Appendix 5.19 of the 2016 Resource Plan at the link below.

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.19_Evaluation_of_Energy_Storage_Technologies_(Transgrid_Solutions_2016).pdf

(e)

Please see Table 5-107 (2016 Resource Plan, Section 5.2.10, PDF page 273) for a comparison of levelized cost of capacity for all energy storage options.

TOPIC: **Section 5 Capital Projects**

REFERENCE: Pages 5-36 to 5-39 New thermal plant

QUESTION:

a) Is YEC considering an option of installing two new diesel generators in the existing Whitehorse diesel plant effectively replacing the retired Mirrlees generators? If not why not?

b) On what grounds does YEC think that a third party can supply gas to an LNG plant more cheaply than they can supply it themselves?

c) Would the new thermal plant be designed so that it could "firm-up" new intermittent renewable energy supplies (such as the potential Mt. Sumanik wind farm) whether developed by YEC or IPPs?

ANSWER:

(a)

As part of the planned 2017-2018 activities for the New Thermal Plant project, YEC will further study the option of removing the three Mirrlees engines in its existing Whitehorse thermal plant, two of which are already out of service and one of which is approaching end of life, and replacing them with new, efficient dual-fuel engines. The new dual fuel units would allow YEC to decrease its operating costs as it would benefit from the low cost LNG fuel to generate power. Since the original BBA study (2013) excluded certain aspects of the plant retrofit, the new study aims at updating and building upon the work completed in 2013 to reduce remaining uncertainties.

Please see also response to YUB-YEC-79(b).

(b)

Please see response to YUB-YEC-79(b) regarding the potential option of a third party providing an LNG depot in Whitehorse.

(c)

The portfolio analysis completed as part of the 2016 Resource Plan showed thermal assets would be relied upon to primarily meet capacity under the single (N-1) contingency criterion. To a lesser extent, they would be used to support system energy requirements until such time as new renewable resource options could be brought online that would offer least cost solutions (2016 Resource Plan, Chapter 8, Section 8.2.7, PDF page 369).

TOPIC: **Section 5 Capital Projects**

REFERENCE: Page 5-41 DSM

QUESTION:

a) The development of capacity focused DSM programming is expected to take 2 years, why so long especially since peak load growth has been apparent for some time and some capacity programming was considered in the previous CPR study?

ANSWER:

(a)

The DSM program planning process is outlined in the response to YUB-YEC-1-80(g).

TOPIC: **Section 5 Capital Projects**

REFERENCE: Page 5-50 Time of Use Rate Structure and Smart Grid study

QUESTION:

a) Please discuss this item in light of the YUB's decision to not to approve AEY's proposed contribution of $100,000. How does this affect YEC's cost?

b) Along the same lines as secondary sales, is YEC considering other rate or rate structure measures that would encourage summer season use of energy when hydro is often in surplus supply while conserving winter supplies (e.g. seasonal rates, or summer farm or irrigation rates that would support other Yukon government initiatives in food self-sufficiency)? Please explain.

ANSWER:

(a)

YEC believes this is a legitimate utility project. The key conclusion from the Resource Plan Update is the challenge the utility faces with growing peaks and lack of generation capacity to meet these peaks. The primary goal of time-of-use rates is to shift peaks, either daily or seasonally, to mitigate this challenge. In addition, smart meters are critical infrastructure to properly implement time-of-use rate programs. We intend to continue our dialogue with AEY regarding possible partnership in this study, and we will be looking at potential government funding support; we do not know today if these options will or will not materialize or how this could affect the scope of YEC's plans.

(b)

No other rate or rate structures are being considered at this time.

TOPIC: **Section 5 Capital Projects**

REFERENCE: Page 5-50 Detailed Line Inspection

QUESTION:

a) Is this work a repeat of similar work carried out about 15 years ago? Please explain.

ANSWER:

(a)

Yes, similar work was carried out in the past and is required to be regularly updated in order to assess the constantly changing condition of transmission assets.

TOPIC: **Section 5 Capital Projects**

REFERENCE: Page 5.3-4 Whitehorse Wind 1 Decommission

QUESTION:

a) Has YEC tried to sell this asset “as is where is” to minimize ratepayer costs?

b) Should the cost not come from a net salvage value account? If not why not?

ANSWER:

(a)

YEC is currently exploring the option of selling the asset to a third-party.

(b)

Any cost to decommission the asset will be charged to the Reserve for Site Restoration fund.

TOPIC: **Page 5.3-9 Building Condition Report**

REFERENCE:

QUESTION:

a) Please provide a copy of this report.

b) Is it YEC's intention to bring all of its buildings into full compliance with all of the most recent building codes? Please explain.

c) Can this work and cost be spread out over a longer period of time?

ANSWER:

(a)

Please see the report provided as John Maissan-YEC-1-37 Attachment 1.

(b) and **(c)**

YEC will bring buildings into compliance with building codes where there is a health and safety or environmental risk, an impact on operations, or a positive cost benefit in doing so. Portions of the work are being deferred to future years and scheduled based on report recommendations combined with internal YEC priority assessment.

John Maissan-YEC-1-37 Attachment 1

(Large attachment – please see 2017/2018 General Rate Application Round 1 Interrogatory Responses Appendix A)

TOPIC: **Section 5 Capital Projects**

REFERENCE: Page 5.3-10 Mayo B exterior overhead crane

QUESTION:

a) How was this deficiency in the recently built Mayo B plant overlooked? Why shouldn't the contractor be responsible for correcting this deficiency?

b) How often is this crane inspected and serviced?

c) What is the cost of renting the boom hoist?

d) Can this project be deferred?

ANSWER:

(a)

YEC did not anticipate the complications or costs involved in accessing the crane equipment for inspections. As the access door was not specified in the plant design, it is not considered a project deficiency.

(b)

The crane is inspected annually and serviced as determined by the inspections.

(c)

The cost of renting a boom hoist to service or inspect the crane is approximately $600 per day plus transportation to Mayo at $175 per hour.

(d)

Deferral of this project may result in ongoing additional costs as well as the potential for a significant period of time without access to the crane if it were to suffer a mechanical failure in the middle of the span.

TOPIC: **Section 5 Capital Projects**

REFERENCE: Page 5.3-10 Stewart-Minto Local SCADA

QUESTION:

a) How did such an important design features get overlooked in these recently built facilities?

b) Was it to minimize capital costs in their original construction?

c) Can this project be deferred?

ANSWER:

(a) and **(b)**

At the time of construction of Carmacks-Stewart Transmission Project Stage 2, it was not normal practice for YEC to retrieve fault data from substations for detailed analysis. In recent years, in an effort to improve grid reliability, this type of analysis has become common practice. As a result, YEC did not anticipate the frequency of required site visits and consequent cost and the significant benefits of remote diagnostic capability and SCADA control. Although there were some cost savings realized in the original installation, this was not the primary driver of the decision.

(c)

With any significant load growth in the Mayo region, the frequency of issues and events could be expected to increase; enhanced remote SCADA access to these sites will become increasingly beneficial and allow YEC to accomplish more work without increasing staff levels.

TOPIC: **Section 5 Capital Projects**

REFERENCE: Page 5.4-2 Aishihik and Mayo Hydro Climate Change Study

QUESTION:

a) Please provide the scope of work and any other documentation YEC possesses on these studies.

b) What portion of the overall study cost is YEC covering?

c) At over $441,000 these studies are very costly to YEC and ratepayers. Since predictions of future water flows can only be general in nature at best, please justify this cost to ratepayers at a time of significant rate increases.

ANSWER:

(a)

The objective of the Aishihik and Mayo Climate Change Study is to develop and implement a distributed hydrological modeling system on Aishihik and Mayo watersheds YEC uses for power generation. This modelling system will be used for short (up to 2 weeks) and long (seasonal, annual) term inflow forecasting into Mayo and Aishihik lakes.

The short-term model will enable YEC to more efficiently plan short term energy generation, while the long-term model will enable YEC to forecast impacts of climate change on long-term inflow availability, inflow timing and extreme events, and, consequently, power generation. As such, the model outputs will be used as inputs to both operations planning and integrated resource planning.

The study scope is presented in terms of milestones and description of activities in Table 1.

Table1: Scope of the Aishihik and Mayo Hydro Climate Change Study

Milestone (WP - Work Package)	Descriptioin of activities
WP1 - Forecasting System - First Version	Database design, model calibration
	implementation of the forecasting procedure,
	development and implementation of the GUI
WP2 - Permafrost & Snow	Integration of an analytical model, permafrost surveying
Permafrost Module	and validation of the model
Technical group meetings	Twice-a-year in-person technical meetings
Technology transfer meetings	Once-a-year in-person technology transfer meetings
WP2 - Permafrost & Snow	Development of the model, Validation of the model and
Multilayer Snow Module	Snow surveying
WP5 - Hydroclimatic assessment	Simulations, Frequency analysis, and Change signal analysis
WP5 - Hydroclimatic assessment	Selection of CMIP5 simulations
WP5 -Ocean-Atmosphere	Selection of CMIP5 simulations, Data preprocessing,
circulation & hydrology	Design of observed data databases, Development of
	computational procedure, Identification of large-scale
	circulations, and Large-scale circulations & hydrology
WP1 - Forecasting System - Final Version	Updating w/r to WP2 and WP3, & integration of the
	data assimilation techniques, training

(b)

YEC is covering 50% of the study costs.

(c)

Please see response to part (a). Any measurable improvement in YEC operation of its facilities on these key watersheds will yield long-term savings in thermal generation costs.

TOPIC: **Section 5 Capital Projects**

REFERENCE: Page 5.4-3 Mt. Sumanik Wind Study

QUESTION:

a) At the end of 2018 will there be a completed wind farm feasibility for Mt. Sumanik?

b) Will this study be made public?

ANSWER:

(a)

YEC had initiated collection of wind data at Mt Sumanik. The Mt. Sumanik project goal is the wind data collection and interpretation. Part of the project scope includes removal of monitoring equipment from the site once the data collection is completed. The completion of the study will depend on the quality of data collected. If warranted, the study might be extended beyond 2018.

(b)

At this time, YEC cannot commit to make public a study that is in progress. Typically, YEC strives to make its studies public, subject to normal restrictions on privacy, proprietary rights and commercial value.

TOPIC: **Section 5 Capital Projects**

REFERENCE: Page 5.4-3 Northern Diesel Plant Relocation Study

QUESTION:

a) Would it be YEC's intention to sell the land on which these plants are currently located if it is decided to move them?

ANSWER:

(a)

YEC has not yet studied options or taken a position with respect to land disposition.

TOPIC: **Other issues**

REFERENCE: **Very high levels of studies and capital projects**

QUESTION:

a) YEC's rate base seems to be growing rapidly because of high numbers of studies and a high number of smaller capital projects. They give the impression of everyone's wish list being included. Given the requested rate increases it would seem that this must be an unsustainable level of activity from a ratepayer point of view, even if no other. Please discuss what YEC anticipates in the five years following the test years – will the level of activity and costs forecasted in smaller projects for the test years continue? Please explain.

b) Does YEC have a plan or target for reducing these costs to reduce future rate increases? Will projects be selected more carefully in future, and will costs be pared down to bare essentials in future? Please explain why or why not.

ANSWER:

(a) and **(b)**

YEC takes exception to the suggestion that capital planning is done based on a "wish list" approach or that projects are not selected carefully.

The utility has been clear during this and previous proceedings that the approach to allocation of capital spending involves a thorough vetting of options with the impact to ratepayers who depend upon reliable service at front of mind at all times. This approach is explained in CW-YEC-1-34. Many of YEC assets are approaching end-of-life. While options to extend life are always reviewed, at some point this is not a viable strategy and replacement is required. Even with a like-for-like replacement, rate base and therefore rates will be increased as assets originally capitalized in the 50's, 60's and 70's are being replaced with current dollars.

YEC further disagrees with the assertion that this level of spending is "unsustainable"; YEC has a duty to provide reliable service to customers as a condition of its franchise under the *Public Utilities Act*.

YEC continually updates future capital plans; it is unreasonable at this time to speculate on levels of activity in future years outside of the test years. That being said, based on the age of the existing asset portfolio, as well as increasing demands on energy and capacity generation, it appears unlikely that investment levels will decline over time.

Utilities Consumers' Group
(UCG)

TOPIC:

REFERENCE: June 22, 2017 Application

PREAMBLE:

QUESTION:

a) Please provide details of all customer and stakeholder consultations conducted by Yukon Energy Corporation during development of this application prior to submitting it to the YUB.

b) Please provide specific details on how YEC's customers were informed of proposals being considered for inclusion in the application and how input from customers was used to develop details of the application.

c) Please provide all documentation related to issues discussed during these consultations and a list of all parties involved in the consultations.

d) Please confirm how and when the leadership / owners of YEC approved the General Rate Application as provided to the YUB. Please identify the dates on which these approvals were provided.

ANSWER:

(a), (b) and **(c)**

YEC did not conduct stakeholder consultations on the context of the GRA prior to the filing.

(d)

Yukon Energy's Board of Directors was briefed regarding the filing of a GRA in February 2017. The GRA documentation was completed following this discussion.

TOPIC:

REFERENCE: June 22, 2017 Application page 1

YEC states "Pursuant to the Order in Council (OIC) 2014/23 direction, the Board must ensure until the end of 2018 that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers. Consequently, for both 2017 and 2018, all proposed rate adjustments for retail customers and industrial customers apply equally, as percentages".

Board Order 2010-13, Appendix A – Reasons for Decision

"29. Therefore, the Board directs the Companies to file a joint COS study within six months of the expiry of OIC 2008/149. The Board further directs the Companies to incorporate all findings and directions of this Decision into the next COS study."

PREAMBLE:

QUESTION:

a) Please provide details on the progress made to date and the expected schedule for completing and filing the joint COS study as directed by the YUB.

ANSWER:

(a)

OIC 2014/23 is a specific direction of the Yukon Government and prevents rate rebalancing between rate classes until after December 31, 2018.

In Order 2013-01 the Board provided a series of directives related to the Cost of Service Study as filed by the Companies noting that it "[did] not accept the COS study as filed by the Companies", "an updated COS study approved by the Board is essential to establishing a future rate restructuring process" and directed the Companies to "file a joint COS study within six months of the expiry of OIC 2008/149" that "incorporate[s] all findings

and directions of the decision." Since Order 2013-01, further directions have been provided by the government that restrict rate rebalancing [OIC 2012/68 and OIC 2014/23].

Current OIC direction effectively provides that material rate design changes that would result in rebalancing of rates between different customer classes cannot be undertaken until mid-2019 at the earliest.

TOPIC:

REFERENCE: June 22, 2017 Application page 2
YEC states "*Yukon Energy's last requested rate increase was for the 2012 and 2013 test years – this was the first requested increase in Yukon Energy firm retail rates for non-industrial customers since the 1998/1999 rate review (which focused on issues arising from the closure of the Faro mine).*"

ATCO Electric Yukon 2016-2017 General Rate Application

- AEY Response to UCG-AEY-16
- ATCO Electric Yukon 2016-2017 GRA Compliance Filing (May 26, 2017)
- Board Order 2017-03

PREAMBLE:

QUESTION:

a) Please confirm that the bills of Yukon ratepayers have continued to change since the 1998/1999 rate review due to the reliance by YEC and YECL/AEY on across-the-board percentage rate riders (e.g., Riders F, J and R) to recover approved rate revenue requirements and changes to fuel costs beyond what was provided by base rates.

b) Please provide detailed calculations of the total bill (including all riders, rate relief, and taxes) for a YEC residential customer using 800 kWh, 1000 kWh, 1200 kWh and 1400 kWh per month in January 2012, January 2013, January 2014, January 2015, January 2016, January 2017 and January 2018 assuming that the 2017 and 2018 rate adjustments proposed by YEC are approved. Please provide details of the bill calculions and indicate overall percentage changes in the total bill for each year.

c) Please provide detailed calculations of the total bill (including all riders, rate relief, and taxes) for an ATCO Electric Yukon (AEY) residential customer in Whitehorse using 800 kWh, 1000 kWh, 1200 kWh and 1400 kWh per month in January 2015, January 2016, January 2017 and January 2018 with the approved AEY riders and

assuming that the 2017 and 2018 rate adjustments proposed by YEC are approved. Please provide details of the bill calculations and indicate overall percentage changes in the total bill for each year.

d) Please provide detailed calculations of the total bill (including all riders, rate relief, and taxes) for an ATCO Electric Yukon (AEY) residential customer in Whitehorse using 800 kWh, 1000 kWh, 1200 kWh and 1400 kWh per month in January 2015, January 2016, January 2017 and January 2018 with the approved AEY riders and assuming that only 50% of the 2017 and 2018 rate adjustments proposed by YEC are approved. Please provide details of the bill calculations and indicate overall percentage changes in the total bill for each year.

ANSWER:

(a)

Confirmed. Adjustments to rates were implemented on a revenue neutral basis, by utility and by class.

(b) and **(c)**

Please see Tables 1-1 through 1-4 below (at the end of this response) and UCG-YEC-1-3 Attachment 1 for the requested information. For the Hydro Zone YEC and AEY customers pay the same rate. Therefore, the bill change table is provided for Whitehorse for the range of consumption requested in the question.

(d)

Please see Tables 2-1 through 2-4 below (at the end of this response) and UCG-YEC-1-3 Attachment 2 for the requested information. Please note that the table uses YEC Rider J assumption of 16.57% for January 1, 2018 column. This is based on the 50% of the proposed Rider J increase effective January 1, 2018 [22.12% proposed compared to 11.01% existing or increase of 11.11%; 50% of the increase of 11.11% is 5.56% which would be 16.57% with the existing Rider J of 11.01%].

Table 1-1 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 800 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	800 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	800	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12
3=KWh*Base rate	Second Block Energy (kWh)	-	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$2.82	$0.001910	$1.53	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$3.90	-$0.005600	-$4.48	-$0.000110	-$0.09	-$0.000110	-$0.09
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	$7.15	11.01%	$12.31	11.01%	$12.31	11.01%	$12.31	11.01%	$12.31	16.51%	$18.45	22.12%	$24.72
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$4.19	3.62%	$4.05		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$5.44	-$0.006800	-$5.44	-$0.006800	-$5.44	-$0.006800	-$5.44
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$7.27	7.20%	$8.05	7.20%	$8.05	11.62%	$12.99	8.30%	$9.28	8.30%	$9.28
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$114.59		$124.64		$135.39		$132.12		$122.79		$127.14		$133.97		$140.24
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$0.84	-0.75%	-$0.84	-0.60%	-$0.67	-0.55%	-$0.61	-0.52%	-$0.58	-0.52%	-$0.58	-0.52%	-$0.58	-0.52%	-$0.58
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29
12=Sum(9:11)	Total After Rebates, before GST			$92.46		$102.52		$113.43		$110.22		$100.92		$105.27		$112.10		$118.37
13=12*1.05	Total After GST			$97.08		$107.64		$119.10		$115.73		$105.96		$110.54		$117.71		$124.29
	Change from last rate					*$10.56*		*$11.46*		*-$3.37*		*-$9.77*		*$4.57*		*$7.17*		*$6.58*
						10.9%		*10.6%*		*-2.8%*		*-8.4%*		*4.3%*		*6.5%*		*5.6%*

Note:
1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Table 1-2 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,000 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,000 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
3=KWh*Base rate	Second Block Energy (kWh)	-	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$3.52	$0.001910	$1.91	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$4.87	-$0.005600	-$5.60	-$0.000110	-$0.11	-$0.000110	-$0.11
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	$8.71	11.01%	$14.98	11.01%	$14.98	11.01%	$14.98	11.01%	$14.98	16.51%	$22.46	22.12%	$30.09
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$5.10	3.62%	$4.93		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$6.80	-$0.006800	-$6.80	-$0.006800	-$6.80	-$0.006800	-$6.80
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$8.84	7.20%	$9.80	7.20%	$9.80	11.62%	$15.81	8.30%	$11.29	8.30%	$11.29
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$139.57		$151.77		$164.80		$160.82		$149.15		$154.44		$162.89		$170.53
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$1.02	-0.75%	-$1.02	-0.60%	-$0.82	-0.55%	-$0.75	-0.52%	-$0.71	-0.52%	-$0.71	-0.52%	-$0.71	-0.52%	-$0.71
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61
12=Sum(9:11)	Total After Rebates, before GST			$111.94		$124.14		$137.37		$133.47		$121.84		$127.12		$135.58		$143.21
13=12*1.05	Total After GST			$117.54		$130.35		$144.24		$140.14		$127.93		$133.48		$142.36		$150.37
	Change from last rate					*$12.81*		*$13.89*		*-$4.10*		*-$12.21*		*$5.55*		*$8.88*		*$8.01*
						10.9%		*10.7%*		*-2.8%*		*-8.7%*		*4.3%*		*6.7%*		*5.6%*

Note:
1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Table 1-3 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,200 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,200 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68
3=KWh*Base rate	Second Block Energy (kWh)	200	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$4.22	$0.001910	$2.29	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$5.84	-$0.005600	-$6.72	-$0.000110	-$0.13	-$0.000110	-$0.13
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	$11.90	11.01%	$20.48	11.01%	$20.48	11.01%	$20.48	11.01%	$20.48	16.51%	$30.70	22.12%	$41.14
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$6.97	3.62%	$6.73		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$8.16	-$0.006800	-$8.16	-$0.006800	-$8.16	-$0.006800	-$8.16
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$12.09	7.20%	$13.39	7.20%	$13.39	11.62%	$21.61	8.30%	$15.44	8.30%	$15.44
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$190.19		$207.14		$225.27		$219.84		$205.83		$213.18		$223.82		$234.25
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$1.39	-0.75%	-$1.39	-0.60%	-$1.12	-0.55%	-$1.02	-0.52%	-$0.97	-0.52%	-$0.97	-0.52%	-$0.97	-0.52%	-$0.97
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61
12=Sum(9:11)	Total After Rebates, before GST			$162.19		$179.13		$197.54		$192.20		$178.25		$185.60		$196.24		$206.67
13=12*1.05	Total After GST			$170.30		$188.09		$207.42		$201.81		$187.17		$194.88		$206.05		$217.01
	Change from last rate					*$17.79*		*$19.33*		*-$5.60*		*-$14.65*		*$7.71*		*$11.17*		*$10.96*
						10.4%		*10.3%*		*-2.7%*		*-7.3%*		*4.1%*		*5.7%*		*5.3%*

Note:
1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Table 1-4 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,400 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,400 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96
3=KWh*Base rate	Second Block Energy (kWh)	400	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$4.93	$0.001910	$2.67	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$6.82	-$0.005600	-$7.84	-$0.000110	-$0.15	-$0.000110	-$0.15
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	$15.10	11.01%	$25.97	11.01%	$25.97	11.01%	$25.97	11.01%	$25.97	16.51%	$38.95	22.12%	$52.18
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$8.85	3.62%	$8.54		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$9.52	-$0.006800	-$9.52	-$0.006800	-$9.52	-$0.006800	-$9.52
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$15.33	7.20%	$16.98	7.20%	$16.98	11.62%	$27.41	8.30%	$19.58	8.30%	$19.58
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$240.82		$262.51		$285.73		$278.85		$262.51		$271.91		$284.74		$297.97
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$1.77	-0.75%	-$1.77	-0.60%	-$1.42	-0.55%	-$1.30	-0.52%	-$1.23	-0.52%	-$1.23	-0.52%	-$1.23	-0.52%	-$1.23
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61
12=Sum(9:11)	Total After Rebates, before GST			$212.44		$234.13		$257.71		$250.94		$234.67		$244.08		$256.90		$270.14
13=12*1.05	Total After GST			$223.06		$245.83		$270.59		$263.49		$246.40		$256.28		$269.75		$283.65
	Change from last rate					*$22.77*		*$24.76*		*-$7.11*		*-$17.08*		*$9.87*		*$13.47*		*$13.90*
						10.2%		*10.1%*		*-2.6%*		*-6.5%*		*4.0%*		*5.3%*		*5.2%*

Note:
1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Table 2-1 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 800 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	800 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		50% of Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	800	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12
3=KWh*Base rate	Second Block Energy (kWh)	-	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$2.82	$0.001910	$1.53	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$3.90	-$0.005600	-$4.48	-$0.000110	-$0.09	-$0.000110	-$0.09
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	$7.15	11.01%	$12.31	11.01%	$12.31	11.01%	$12.31	11.01%	$12.31	16.51%	$18.45	16.57%	$18.51
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$4.19	3.62%	$4.05		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$5.44	-$0.006800	-$5.44	-$0.006800	-$5.44	-$0.006800	-$5.44
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$7.27	7.20%	$8.05	7.20%	$8.05	11.62%	$12.99	8.30%	$9.28	8.30%	$9.28
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$114.59		$124.64		$135.39		$132.12		$122.79		$127.14		$133.97		$134.03
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$0.84	-0.75%	-$0.84	-0.60%	-$0.67	-0.55%	-$0.61	-0.52%	-$0.58	-0.52%	-$0.58	-0.52%	-$0.58	-0.52%	-$0.58
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29
12=Sum(9:11)	Total After Rebates, before GST			$92.46		$102.52		$113.43		$110.22		$100.92		$105.27		$112.10		$112.16
13=12*1.05	Total After GST			$97.08		$107.64		$119.10		$115.73		$105.96		$110.54		$117.71		$117.77
	Change from last rate					*$10.56*		*$11.46*		*-$3.37*		*-$9.77*		*$4.57*		*$7.17*		*$0.06*
						10.9%		*10.6%*		*-2.8%*		*-8.4%*		*4.3%*		*6.5%*		*0.1%*

Notes:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.
2. January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to toal of 16.57%].

Table 2-2 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,000 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,000 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		50% of Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
3=KWh*Base rate	Second Block Energy (kWh)	-	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$3.52	$0.001910	$1.91	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$4.87	-$0.005600	-$5.60	-$0.000110	-$0.11	-$0.000110	-$0.11
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	$8.71	11.01%	$14.98	11.01%	$14.98	11.01%	$14.98	11.01%	$14.98	16.51%	$22.46	16.57%	$22.54
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$5.10	3.62%	$4.93		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$6.80	-$0.006800	-$6.80	-$0.006800	-$6.80	-$0.006800	-$6.80
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$8.84	7.20%	$9.80	7.20%	$9.80	11.62%	$15.81	8.30%	$11.29	8.30%	$11.29
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$139.57		$151.77		$164.80		$160.82		$149.15		$154.44		$162.89		$162.97
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$1.02	-0.75%	-$1.02	-0.60%	-$0.82	-0.55%	-$0.75	-0.52%	-$0.71	-0.52%	-$0.71	-0.52%	-$0.71	-0.52%	-$0.71
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61
12=Sum(9:11)	Total After Rebates, before GST			$111.94		$124.14		$137.37		$133.47		$121.84		$127.12		$135.58		$135.65
13=12*1.05	Total After GST			$117.54		$130.35		$144.24		$140.14		$127.93		$133.48		$142.36		$142.43
	Change from last rate					*$12.81*		*$13.89*		*-$4.10*		*-$12.21*		*$5.55*		*$8.88*		*$0.08*
						10.9%		*10.7%*		*-2.8%*		*-8.7%*		*4.3%*		*6.7%*		*0.1%*

Notes:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.
2. January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to toal of 16.57%].

Table 2-3 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,200 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,200 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		50% of Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68
3=KWh*Base rate	Second Block Energy (kWh)	200	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$4.22	$0.001910	$2.29	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$5.84	-$0.005600	-$6.72	-$0.000110	-$0.13	-$0.000110	-$0.13
5=(1+2+3)*Rider J rate	YEC Rider J (%)			6.40%	$11.90	11.01%	$20.48	11.01%	$20.48	11.01%	$20.48	11.01%	$20.48	16.51%	$30.70	16.57%	$30.81	
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$6.97	3.62%	$6.73		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$8.16	-$0.006800	-$8.16	-$0.006800	-$8.16	-$0.006800	-$8.16
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$12.09	7.20%	$13.39	7.20%	$13.39	11.62%	$21.61	8.30%	$15.44	8.30%	$15.44
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$190.19		$207.14		$225.27		$219.84		$205.83		$213.18		$223.82		$223.92
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$1.39	-0.75%	-$1.39	-0.60%	-$1.12	-0.55%	-$1.02	-0.52%	-$0.97	-0.52%	-$0.97	-0.52%	-$0.97	-0.52%	-$0.97
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61
12=Sum(9:11)	Total After Rebates, before GST			$162.19		$179.13		$197.54		$192.20		$178.25		$185.60		$196.24		$196.34
13=12*1.05	Total After GST			$170.30		$188.09		$207.42		$201.81		$187.17		$194.88		$206.05		$206.16
	Change from last rate					*$17.79*		*$19.33*		*-$5.60*		*-$14.65*		*$7.71*		*$11.17*		*$0.11*
						10.4%		*10.3%*		*-2.7%*		*-7.3%*		*4.1%*		*5.7%*		*0.1%*

Notes:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.
2. January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to toal of 16.57%].

Table 2-4 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,400 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,400 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		50% of Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96
3=KWh*Base rate	Second Block Energy (kWh)	400	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$4.93	$0.001910	$2.67	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$6.82	-$0.005600	-$7.84	-$0.000110	-$0.15	-$0.000110	-$0.15
5=(1+2+3)*Rider J rate	YEC Rider J (%)			6.40%	$15.10	11.01%	$25.97	11.01%	$25.97	11.01%	$25.97	11.01%	$25.97	16.51%	$38.95	16.57%	$39.08	
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$8.85	3.62%	$8.54		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$9.52	-$0.006800	-$9.52	-$0.006800	-$9.52	-$0.006800	-$9.52
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$15.33	7.20%	$16.98	7.20%	$16.98	11.62%	$27.41	8.30%	$19.58	8.30%	$19.58
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$240.82		$262.51		$285.73		$278.85		$262.51		$271.91		$284.74		$284.87
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$1.77	-0.75%	-$1.77	-0.60%	-$1.42	-0.55%	-$1.30	-0.52%	-$1.23	-0.52%	-$1.23	-0.52%	-$1.23	-0.52%	-$1.23
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61
12=Sum(9:11)	Total After Rebates, before GST			$212.44		$234.13		$257.71		$250.94		$234.67		$244.08		$256.90		$257.03
13=12*1.05	Total After GST			$223.06		$245.83		$270.59		$263.49		$246.40		$256.28		$269.75		$269.89
	Change from last rate					*$22.77*		*$24.76*		*-$7.11*		*-$17.08*		*$9.87*		*$13.47*		*$0.14*
						10.2%		*10.1%*		*-2.6%*		*-6.5%*		*4.0%*		*5.3%*		*0.1%*

Notes:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.
2. January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to toal of 16.57%].

Table 1-1: Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 800 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	800 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	800	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12
3=KWh*Base rate	Second Block Energy (kWh)	-	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$2.82	$0.001910	$1.53	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$3.90	-$0.005600	-$4.48	-$0.000110	-$0.09	-$0.000110	-$0.09
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	$7.15	11.01%	$12.31	11.01%	$12.31	11.01%	$12.31	11.01%	$12.31	16.51%	$18.45	22.12%	$24.72
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$4.19	3.62%	$4.05		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$5.44	-$0.006800	-$5.44	-$0.006800	-$5.44	-$0.006800	-$5.44
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$7.27	7.20%	$8.05	7.20%	$8.05	11.62%	$12.99	8.30%	$9.28	8.30%	$9.28
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$114.59		$124.64		$135.39		$132.12		$122.79		$127.14		$133.97		$140.24
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$0.84	-0.75%	-$0.84	-0.60%	-$0.67	-0.55%	-$0.61	-0.52%	-$0.58	-0.52%	-$0.58	-0.52%	-$0.58	-0.52%	-$0.58
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29
12=Sum(9:11)	Total After Rebates, before GST			$92.46		$102.52		$113.43		$110.22		$100.92		$105.27		$112.10		$118.37
13=12*1.05	Total After GST			$97.08		$107.64		$119.10		$115.73		$105.96		$110.54		$117.71		$124.29
	Change from last rate					*$10.56*		*$11.46*		*-$3.37*		*-$9.77*		*$4.57*		*$7.17*		*$6.58*
						10.9%		*10.6%*		*-2.8%*		*-8.4%*		*4.3%*		*6.5%*		*5.6%*

Note:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Table 1-2 : Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,000 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,000 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
3=KWh*Base rate	Second Block Energy (kWh)	-	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$3.52	$0.001910	$1.91	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$4.87	-$0.005600	-$5.60	-$0.000110	-$0.11	-$0.000110	-$0.11
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	$8.71	11.01%	$14.98	11.01%	$14.98	11.01%	$14.98	11.01%	$14.98	16.51%	$22.46	22.12%	$30.09
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$5.10	3.62%	$4.93		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$6.80	-$0.006800	-$6.80	-$0.006800	-$6.80	-$0.006800	-$6.80
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$8.84	7.20%	$9.80	7.20%	$9.80	11.62%	$15.81	8.30%	$11.29	8.30%	$11.29
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$139.57		$151.77		$164.80		$160.82		$149.15		$154.44		$162.89		$170.53
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$1.02	-0.75%	-$1.02	-0.60%	-$0.82	-0.55%	-$0.75	-0.52%	-$0.71	-0.52%	-$0.71	-0.52%	-$0.71	-0.52%	-$0.71
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61
12=Sum(9:11)	Total After Rebates, before GST			$111.94		$124.14		$137.37		$133.47		$121.84		$127.12		$135.58		$143.21
13=12*1.05	Total After GST			$117.54		$130.35		$144.24		$140.14		$127.93		$133.48		$142.36		$150.37
	Change from last rate					*$12.81*		*$13.89*		*-$4.10*		*-$12.21*		*$5.55*		*$8.88*		*$8.01*
						10.9%		*10.7%*		*-2.8%*		*-8.7%*		*4.3%*		*6.7%*		*5.6%*

Note:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Table 1-3: Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,200 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,200 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68
3=KWh*Base rate	Second Block Energy (kWh)	200	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$4.22	$0.001910	$2.29	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$5.84	-$0.005600	-$6.72	-$0.000110	-$0.13	-$0.000110	-$0.13
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	$11.90	11.01%	$20.48	11.01%	$20.48	11.01%	$20.48	11.01%	$20.48	16.51%	$30.70	22.12%	$41.14
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$6.97	3.62%	$6.73		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$8.16	-$0.006800	-$8.16	-$0.006800	-$8.16	-$0.006800	-$8.16
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$12.09	7.20%	$13.39	7.20%	$13.39	11.62%	$21.61	8.30%	$15.44	8.30%	$15.44
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$190.19		$207.14		$225.27		$219.84		$205.83		$213.18		$223.82		$234.25
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$1.39	-0.75%	-$1.39	-0.60%	-$1.12	-0.55%	-$1.02	-0.52%	-$0.97	-0.52%	-$0.97	-0.52%	-$0.97	-0.52%	-$0.97
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61
12=Sum(9:11)	Total After Rebates, before GST			$162.19		$179.13		$197.54		$192.20		$178.25		$185.60		$196.24		$206.67
13=12*1.05	Total After GST			$170.30		$188.09		$207.42		$201.81		$187.17		$194.88		$206.05		$217.01
	Change from last rate					*$17.79*		*$19.33*		*-$5.60*		*-$14.65*		*$7.71*		*$11.17*		*$10.96*
						10.4%		*10.3%*		*-2.7%*		*-7.3%*		*4.1%*		*5.7%*		*5.3%*

Note:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Table 1-4: Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,400 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,400 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96
3=KWh*Base rate	Second Block Energy (kWh)	400	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$4.93	$0.001910	$2.67	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$6.82	-$0.005600	-$7.84	-$0.000110	-$0.15	-$0.000110	-$0.15
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	$15.10	11.01%	$25.97	11.01%	$25.97	11.01%	$25.97	11.01%	$25.97	16.51%	$38.95	22.12%	$52.18
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$8.85	3.62%	$8.54		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$9.52	-$0.006800	-$9.52	-$0.006800	-$9.52	-$0.006800	-$9.52
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$15.33	7.20%	$16.98	7.20%	$16.98	11.62%	$27.41	8.30%	$19.58	8.30%	$19.58
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$240.82		$262.51		$285.73		$278.85		$262.51		$271.91		$284.74		$297.97
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$1.77	-0.75%	-$1.77	-0.60%	-$1.42	-0.55%	-$1.30	-0.52%	-$1.23	-0.52%	-$1.23	-0.52%	-$1.23	-0.52%	-$1.23
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61
12=Sum(9:11)	Total After Rebates, before GST			$212.44		$234.13		$257.71		$250.94		$234.67		$244.08		$256.90		$270.14
13=12*1.05	Total After GST			$223.06		$245.83		$270.59		$263.49		$246.40		$256.28		$269.75		$283.65
	Change from last rate					*$22.77*		*$24.76*		*-$7.11*		*-$17.08*		*$9.87*		*$13.47*		*$13.90*
						10.2%		*10.1%*		*-2.6%*		*-6.5%*		*4.0%*		*5.3%*		*5.2%*

Note:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Table 2-1 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 800 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	800 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		50% of Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	800	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12
3=KWh*Base rate	Second Block Energy (kWh)	-	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$2.82	$0.001910	$1.53	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$3.90	-$0.005600	-$4.48	-$0.000110	-$0.09	-$0.000110	-$0.09
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	$7.15	11.01%	$12.31	11.01%	$12.31	11.01%	$12.31	11.01%	$12.31	16.51%	$18.45	16.57%	$18.51
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$4.19	3.62%	$4.05		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$5.44	-$0.006800	-$5.44	-$0.006800	-$5.44	-$0.006800	-$5.44
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$7.27	7.20%	$8.05	7.20%	$8.05	11.62%	$12.99	8.30%	$9.28	8.30%	$9.28
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$114.59		$124.64		$135.39		$132.12		$122.79		$127.14		$133.97		$134.03
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$0.84	-0.75%	-$0.84	-0.60%	-$0.67	-0.55%	-$0.61	-0.52%	-$0.58	-0.52%	-$0.58	-0.52%	-$0.58	-0.52%	-$0.58
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29	-$0.02661	-$21.29
12=Sum(9:11)	Total After Rebates, before GST			$92.46		$102.52		$113.43		$110.22		$100.92		$105.27		$112.10		$112.16
13=12*1.05	Total After GST			$97.08		$107.64		$119.10		$115.73		$105.96		$110.54		$117.71		$117.77
	Change from last rate					*$10.56*		*$11.46*		*-$3.37*		*-$9.77*		*$4.57*		*$7.17*		*$0.06*
						10.9%		*10.6%*		*-2.8%*		*-8.4%*		*4.3%*		*6.5%*		*0.1%*

Notes:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

2. January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to toal of 16.57%].

Table 2-2 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,000 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,000 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		50% of Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
3=KWh*Base rate	Second Block Energy (kWh)	-	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$3.52	$0.001910	$1.91	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$4.87	-$0.005600	-$5.60	-$0.000110	-$0.11	-$0.000110	-$0.11
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	$8.71	11.01%	$14.98	11.01%	$14.98	11.01%	$14.98	11.01%	$14.98	16.51%	$22.46	16.57%	$22.54
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$5.10	3.62%	$4.93		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$6.80	-$0.006800	-$6.80	-$0.006800	-$6.80	-$0.006800	-$6.80
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$8.84	7.20%	$9.80	7.20%	$9.80	11.62%	$15.81	8.30%	$11.29	8.30%	$11.29
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$139.57		$151.77		$164.80		$160.82		$149.15		$154.44		$162.89		$162.97
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$1.02	-0.75%	-$1.02	-0.60%	-$0.82	-0.55%	-$0.75	-0.52%	-$0.71	-0.52%	-$0.71	-0.52%	-$0.71	-0.52%	-$0.71
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61
12=Sum(9:11)	Total After Rebates, before GST			$111.94		$124.14		$137.37		$133.47		$121.84		$127.12		$135.58		$135.65
13=12*1.05	Total After GST			$117.54		$130.35		$144.24		$140.14		$127.93		$133.48		$142.36		$142.43
	Change from last rate					*$12.81*		*$13.89*		*-$4.10*		*-$12.21*		*$5.55*		*$8.88*		*$0.08*
						10.9%		*10.7%*		*-2.8%*		*-8.7%*		*4.3%*		*6.7%*		*0.1%*

Notes:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

2. January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to toal of 16.57%].

Table 2-3 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,200 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,200 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		50% of Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68	$0.1214	$145.68
3=KWh*Base rate	Second Block Energy (kWh)	200	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$4.22	$0.001910	$2.29	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$5.84	-$0.005600	-$6.72	-$0.000110	-$0.13	-$0.000110	-$0.13
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	$11.90	11.01%	$20.48	11.01%	$20.48	11.01%	$20.48	11.01%	$20.48	16.51%	$30.70	16.57%	$30.81
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$6.97	3.62%	$6.73		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$8.16	-$0.006800	-$8.16	-$0.006800	-$8.16	-$0.006800	-$8.16
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$12.09	7.20%	$13.39	7.20%	$13.39	11.62%	$21.61	8.30%	$15.44	8.30%	$15.44
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$190.19		$207.14		$225.27		$219.84		$205.83		$213.18		$223.82		$223.92
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$1.39	-0.75%	-$1.39	-0.60%	-$1.12	-0.55%	-$1.02	-0.52%	-$0.97	-0.52%	-$0.97	-0.52%	-$0.97	-0.52%	-$0.97
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61
12=Sum(9:11)	Total After Rebates, before GST			$162.19		$179.13		$197.54		$192.20		$178.25		$185.60		$196.24		$196.34
13=12*1.05	Total After GST			$170.30		$188.09		$207.42		$201.81		$187.17		$194.88		$206.05		$206.16
	Change from last rate					*$17.79*		*$19.33*		*-$5.60*		*-$14.65*		*$7.71*		*$11.17*		*$0.11*
						10.4%		*10.3%*		*-2.7%*		*-7.3%*		*4.1%*		*5.7%*		*0.1%*

Notes:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.
2. January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to toal of 16.57%].

Table 2-4 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,400 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,400 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		50% of Proposed Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																	
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96	$0.1214	$169.96
3=KWh*Base rate	Second Block Energy (kW	400	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.003520	$4.93	$0.001910	$2.67	$0.000000	$0.00	$0.000000	$0.00	-$0.004870	-$6.82	-$0.005600	-$7.84	-$0.000110	-$0.15	-$0.000110	-$0.15
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	$15.10	11.01%	$25.97	11.01%	$25.97	11.01%	$25.97	11.01%	$25.97	16.51%	$38.95	16.57%	$39.08
6=(1+2+3)*Rider R rate	YEC Rider R (%)			$0.00	3.75%	$8.85	3.62%	$8.54		$0.00		$0.00		$0.00		$0.00		$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-$0.006800	-$9.52	-$0.006800	-$9.52	-$0.006800	-$9.52	-$0.006800	-$9.52
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	$15.33	7.20%	$16.98	7.20%	$16.98	11.62%	$27.41	8.30%	$19.58	8.30%	$19.58
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			$240.82		$262.51		$285.73		$278.85		$262.51		$271.91		$284.74		$284.87
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-$1.77	-0.75%	-$1.77	-0.60%	-$1.42	-0.55%	-$1.30	-0.52%	-$1.23	-0.52%	-$1.23	-0.52%	-$1.23	-0.52%	-$1.23
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61	-$0.02661	-$26.61
12=Sum(9:11)	Total After Rebates, before GST			$212.44		$234.13		$257.71		$250.94		$234.67		$244.08		$256.90		$257.03
13=12*1.05	Total After GST			$223.06		$245.83		$270.59		$263.49		$246.40		$256.28		$269.75		$269.89
	Change from last rate					*$22.77*		*$24.76*		*-$7.11*		*-$17.08*		*$9.87*		*$13.47*		*$0.14*
						10.2%		*10.1%*		*-2.6%*		*-6.5%*		*4.0%*		*5.3%*		*0.1%*

Notes:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.
2. January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to toal of 16.57%].

TOPIC:

REFERENCE: June 22, 2017 Application, page 2

YEC states: "Measures since the 2012/13 GRA that have helped to manage Yukon Energy's ongoing pressures and defer the requirement for the Application include debt re-negotiation with Yukon Development Corporation (YDC), the Mayo B Promissory Note's flexible debt financing provisions, YDC contributions that reduced project costs to be recovered from ratepayers, secondary sales revenues, and adjusted thermal fuel costs related to Diesel Contingency Fund operation and also to the implementation of the Whitehorse Diesel-Natural Gas Conversion Project (LNG Project or LNG Plant project)."

June 22, 2017 Application, pages 1-3 and 1-4

YEC states that Debt Re-Negotiation with YDC lowered YEC's interest costs by about $1.5 million in 2017 and $1.4 million in 2018 and that revenues from secondary sales are forecast at $0.642 million per year in 2017 and 2018, all of which is used to lower the required level of retail rates for firm power.

PREAMBLE:

QUESTION:

a) Please provide specific details regarding the actual impact that the Mayo B Promissory Note's flexible debt financing provisions, YDC contributions that reduced project costs to be recovered from ratepayers, adjusted thermal fuel costs related to Diesel Contingency Fund operation, and the implementation of the Whitehorse Diesel-Natural Gas Conversion Project has had on YEC's revenue requirements for 2017 and 2018.

b) Please provide specific details of how YEC has reduced ongoing costs to offset other cost pressures.

c) Please provide details of YEC's efforts to date to consider a performance-based regulation mechanism including earnings sharing.

ANSWER:

(a)

Please see responses to John Maissan-YEC-1-23 (a), YUB-YEC-5(a) and UCG-YEC-1-23(a-e)**.**

(b)

Please see Tab 1, Section, 1.2 pages 1-2 to 1-4 of the Application which reviews the measures since 2013 to defer the need for a rate increase.

(c)

In UCG-YEC-1-19(c) from the 2008/09 GRA, Yukon Energy addressed this UCG concept as follows:

> As noted in response UCG-YEC-1-32 provided during the 2005 Required Revenues and Related Matters proceeding, a multi-year performance based regulatory framework is not currently in place in Yukon. Implementing this form of regulation would likely require significant changes to the regulatory framework in the Yukon that have not yet been assessed. Yukon Energy has not assessed measures that the Yukon Government might adopt to bring in legislation or policy related to performance-based regulation.

TOPIC:

REFERENCE: June 22, 2017 Application, page 4
YEC states that it is requesting approval of a forecast revenue requirement of $48.544 million for 2017 and $49.864 million for 2018.

PREAMBLE:

QUESTION:

a) Please confirm that the YUB-approved revenue requirements for 2012 and 2013 were $38.850 million and $42.263 million respectively.

b) Please provide a table similar to Table 3.1 showing YUB-approved revenue requirement components and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column and include footnotes identifying the YUB orders that approved the revenue requirements.

c) Please provide a table similar to Table 3.2 showing YUB-approved fuel and purchased power costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

d) Please provide a table similar to Table 3.3 showing YUB-approved non-fuel O&M expenses and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

e) Please provide a table similar to Table 3.4 showing YUB-approved employee complement and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

f) Please provide a table similar to Table 3.5 showing YUB-approved production costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

g) Please provide a table similar to Table 3.6 showing YUB-approved transmission costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

h) Please provide a table similar to Table 3.6.1 showing YUB-approved brushing costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

i) Please provide a table similar to Table 3.7 showing YUB-approved distribution costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

j) Please provide a table similar to Table 3.8 showing YUB-approved general O&M costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

k) Please provide a table similar to Table 3.9 showing YUB-approved administration costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

l) Please provide a table similar to Table 3.10 showing YUB-approved insurance and reserve for injuries and damages costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

m) Please provide a table similar to Table 3.12 showing YUB-approved property taxes costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

n) Please provide a table similar to Table 3.13 showing YUB-approved rate base components and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

o) Please provide a table similar to Table 3.14 showing YUB-approved depreciation and amortization costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify percentage changes from column to column.

p) Please provide a table similar to Table 3.15 showing YUB-approved cost of capital and actuals for 2012, 2013, 2014, 2015 and 2016.

ANSWER:

(a)

Confirmed.

(b) through **(p)**

Please see below copies of the tables as requested from Tab 3 of the Application for the years 2012 to 2016.

Table 3.1
Yukon Energy Revenue Requirement
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Fuel and Purchased Power	$ 2,316	$ 3,743	62%	$ 3,200	$ 3,878	21%	$ 1,569	-60%	$ 2,756	76%	$ 2,159	-22%
Non-Fuel Operating and Maintenance	17,210	17,769	3%	18,111	19,381	7%	19,957	3%	19,580	-2%	20,470	5%
Depreciation and Amortization	7,927	8,225	4%	8,604	9,500	10%	7,783	-18%	8,690	12%	7,816	-10%
Return on Rate Base	11,396	7,346	-36%	12,348	11,139	-10%	11,938	7%	10,829	-9%	12,242	13%
Revenue Requirement/Revenue	$ 38,850	$ 37,083	-5%	$ 42,263	$ 43,897	4%	$ 41,247	-6%	$ 41,855	1%	$ 42,686	2%

Table 3.2
Fuel and Purchased Power
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Fuel	$ 2,276	$ 3,715	63%	$ 3,160	$ 3,848	22%	$ 1,528	-60%	$ 2,720	78%	$ 2,114	-22%
Purchased Power	40	28	-30%	40	30	-26%	41	38%	36	-12%	45	26%
Total Fuel and Purchased Power	$ 2,316	$ 3,743	62%	$ 3,200	$ 3,878	21%	$ 1,569	-60%	$ 2,756	76%	$ 2,159	-22%

Note:
1. Fuel costs reflect long-term average thermal generation fuel costs at forecast firm loads, maintenance and run-up requirements, and forecast fuel prices.

Table 3.3
Non-Fuel Operating and Maintenance Expenses
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	$ 9,155	$ 9,635	5%	$ 9,348	$ 10,604	13%	$ 11,172	5%	$ 11,068	-1%	$ 11,739	6%
Production	1,449	1,552	7%	1,437	1,639	14%	1,795	10%	1,595	-11%	1,906	19%
Transmission	760	785	3%	853	1,266	49%	594	-53%	680	15%	709	4%
Distribution	201	786	292%	226	322	43%	553	72%	541	-2%	284	-47%
General O&M	1,094	901	-18%	1,154	1,224	6%	1,321	8%	1,382	5%	1,156	-16%
Administration	3,179	2,691	-15%	3,646	2,778	-24%	2,947	6%	2,585	-12%	2,726	5%
Insurance and Reserve for Injuries/Damages	1,061	1,097	3%	1,121	1,216	8%	1,243	2%	1,256	1%	1,263	1%
Property Taxes	312	322	3%	326	331	1%	331	0%	473	43%	686	45%
Total OM&A (Tab 7, Schedule 10)	$ 17,210	$ 17,769	3%	$ 18,111	$ 19,381	7%	$ 19,957	3%	$ 19,580	-2%	$ 20,470	5%

Table 3.4
Employee Complement History

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
President	4.50	4.50	0%	4.50	5.00	11%	5.00	0%	5.46	9%	5.09	-7%
Communications	1.00	1.00	0%	1.00	1.00	0%	1.00	0%	1.00	0%	1.00	0%
Human Resources & Info. Mgmt.	6.25	6.18	-1%	6.25	6.16	-1%	6.12	-1%	6.13	0%	5.20	-15%
Resource Planning and Environment	7.00	7.00	0%	7.00	7.00	0%	6.00	-14%	6.00	0%	6.00	0%
Finance, Cust. Acctg. & Purchasing	17.00	17.06	0%	17.00	16.96	0%	17.63	4%	16.81	-5%	16.87	0%
Operations	41.25	42.10	2%	41.25	42.83	4%	42.15	-2%	42.79	2%	44.15	3%
Engineering Services	13.00	12.00	-8%	13.00	12.00	-8%	13.00	8%	13.00	0%	13.00	0%
Health, Safety & Environment	2.00	2.00	0%	2.00	2.00	0%	2.00	0%	2.00	0%	2.00	0%
Total	92.00	91.84	0%	92.00	92.95	1%	92.90	0%	93.19	0%	93.31	0%

Note:
1. The employee complement numbers are net of allocation to YDC.

Table 3.5
Production Costs
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	$ 3,003	$ 3,262	9%	$ 3,057	$ 3,671	20%	$ 3,792	3%	$ 3,876	2%	$ 4,133	7%
Diesel	425	446	5%	439	444	1%	569	28%	430	-24%	548	27%
LNG									61		224	269%
Hydro	938	872	-7%	909	1,024	13%	1,107	8%	1,024	-8%	1,058	3%
Wind	27	34	25%	18	17	-2%	43	146%	3	-93%	14	388%
Operation Supervision	59	199	235%	72	154	115%	77	-50%	78	2%	62	-21%
Total Production	$ 4,452	$ 4,813	8%	$ 4,494	$ 5,310	18%	$ 5,588	5%	$ 5,472	-2%	$ 6,039	10%

Table 3.6
Transmission Costs
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	$ 431	$ 508	18%	$ 440	$ 577	31%	$ 507	-12%	$ 562	11%	$ 621	10%
Brushing Cost	505	561	11%	639	948	48%	1,161	22%	1,069	-8%	1,034	-3%
Deferred Brushing							(748)	na	(632)	-15%	(550)	-13%
Net Brushing Cost	505	561	11%	639	948	48%	413	-56%	437	6%	484	11%
Other Non-Labour	255	224	-12%	214	318	49%	180	-43%	243	35%	225	-7%
Total Transmission	$ 1,190	$ 1,293	9%	$ 1,293	$ 1,843	43%	$ 1,100	-40%	$ 1,242	13%	$ 1,330	7%

Note:
1. YUB order 2013-01 [paragraph 108] directed that for the period beyond 2013 test year, distribution and transmission vegetation management ("brushing") related costs greater than 2011 actual brushing costs are to be held in the newly created vegetation management deferral account. The total transmission and distribution brushing cost in 2011 was $0.502 million.

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Table 3.6.1
Brushing Costs
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Transmission Brushing	505	561	11%	639	948	48%	1,161	22%	1,069	-8%	1,034	-3%
Distribution Brushing	93	157	69%	113	113	0%	262	131%	160	-39%	39	-76%
Total Brushing	598	718	20%	752	1,062	41%	1,424	34%	1,229	-14%	1,073	-13%
Transmission Deferred	na	na	na	na	na	na	748	na	632	-15%	550	-13%
Distribution Deferred	na	na	na	na	na	na	169	na	95	-44%	21	-78%
Brushing Deferred	na	na	na	na	na	na	917	na	727	-21%	571	-21%
Net Transmission Brushing	505	561	11%	639	948	48%	413	-56%	437	6%	484	11%
Net Distribution Brushing	93	157	69%	113	113	0%	93	-18%	65	-30%	18	-72%
Net Brushing Expense	$ 598	$ 718	20%	$ 752	$ 1,062	41%	$ 507	-52%	$ 502	-1%	$ 502	0%

1. YUB order 2013-01 [paragraph 108] directed that for the period beyond 2013 test year distribution and transmission vegetation management ("brushing") related costs greater than 2011 actual brushing costs are to be held in the newly created vegetation management deferral account. The total transmission and distribution brushing cost in 2011 was $0.502 million.

Table 3.7
Distribution Costs
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	$ 579	$ 758	31%	$ 592	$ 794	34%	$ 912	15%	$ 746	-18%	$ 837	12%
Brushing Cost	93	157	69%	113	113	0%	262	131%	160	-39%	39	-76%
Deferred Brushing							(169)	na	(95)	-44%	(21)	-78%
Net Brushing Cost	93	157	69%	113	113	0%	93	-18%	65	-30%	18	-72%
Other Non-Labour	108	630	483%	113	209	84%	460	120%	476	3%	266	-44%
Total Distribution	$ 780	$ 1,544	98%	$ 819	$ 1,117	36%	$ 1,465	31%	$ 1,288	-12%	$ 1,121	-13%

Note:
1. YUB order 2013-01 [paragraph 108] directed that for the period beyond 2013 test year distribution and transmission vegetation management ("brushing") related costs greater than 2011 actual brushing costs are to be held in the newly created vegetation management deferral account. The total transmission and distribution brushing cost in 2011 was $0.502 million.

Table 3.8
General Operating and Maintenance
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	$ 245	$ 217	-11%	$ 250	$ 261	4%	$ 414	59%	$ 368	-11%	$ 366	-1%
Transportation	427	184	-57%	451	569	26%	550	-3%	505	-8%	459	-9%
Maintenance of Company Owned Properties	581	665	14%	611	565	-8%	552	-2%	673	22%	501	-26%
SCADA Communication	86	53	-39%	93	90	-3%	219	144%	203	-7%	197	-3%
Total General O&M	$ 1,339	$ 1,117	-17%	$ 1,405	$ 1,485	6%	$ 1,735	17%	$ 1,749	1%	$ 1,522	-13%

Table 3.9
Administration
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	$ 4,897	$ 4,891	0%	$ 5,008	$ 5,301	6%	$ 5,547	5%	$ 5,516	-1%	$ 5,783	5%
Resource Planning	26	89	242%	26	18	-31%	9	-50%	6	-33%	14	138%
Communications	105	102	-3%	105	155	47%	100	-36%	144	44%	129	-10%
Customer Accounting	190	197	3%	191	232	21%	224	-3%	214	-4%	208	-3%
Environmental Mgmt	338	330	-2%	569	230	-60%	350	52%	273	-22%	166	-39%
General	910	438	-52%	1,099	590	-46%	741	26%	438	-41%	613	40%
Information Systems	569	536	-6%	607	481	-21%	488	1%	557	14%	576	3%
Fish Hatchery	182	154	-16%	187	169	-9%	124	-27%	162	30%	157	-3%
Safety	177	121	-32%	189	164	-13%	150	-8%	165	10%	172	4%
Training	260	146	-44%	260	161	-38%	154	-5%	169	10%	143	-15%
Recruitment	120	260	116%	120	124	3%	280	125%	296	6%	231	-22%
Board of Directors	180	112	-38%	168	150	-10%	255	70%	99	-61%	160	62%
Union	23	49	113%	23	117	407%	0	-100%	0	#DIV/0!	0	#DIV/0!
Regulatory Affairs	34	2	-95%	34	113	232%	0	-100%	39	#DIV/0!	99	152%
Material Management	33	147	344%	35	58	66%	55	-5%	17	-69%	41	138%
Contracting	15	10	-34%	16	12	-25%	8	-35%	5	-44%	14	202%
Professional Development	17	0	-100%	17	4	-77%	9	137%	1	-89%	3	155%
Total Administration	$ 8,076	$ 7,583	-6%	$ 8,654	$ 8,080	-7%	$ 8,495	5%	$ 8,101	-5%	$ 8,509	5%

Table 3.10
Insurance and Reserve for Injuries & Damages
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Insurance	$ 835	$ 871	4%	$ 895	$ 990	11%	$ 1,017	3%	$ 1,030	1%	$ 1,037	1%
Reserve Appropriation (RFID)	226	226	0%	226	226	0%	226	0%	226	0%	226	0%
Total	$ 1,061	$ 1,097	3%	$ 1,121	$ 1,216	8%	$ 1,243	2%	$ 1,256	1%	$ 1,263	1%

Note:

1. The RFID amount for 2012-2016 years reflect annual appropriation of $0.190 million plus amortization of the balance over five year period [$0.036 million/year] to total $0.226 million per YUB Order 2013-01.

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Table 3.12
Property Taxes
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Property Taxes	$ 312	$ 322	3%	$ 326	$ 331	1%	$ 331	0%	$ 473	43%	$ 686	45%

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Table 3.13
Mid-Year Net Rate Base
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Year-End:												
Net plant in service[1]	$ 219,444	$ 216,964	-1%	$ 222,393	$ 217,202	-2%	$ 216,836	0%	$ 250,737	16%	$ 251,405	0%
Mid-Year:												
Net plant in service												
Before contributions	$ 377,608	$ 376,408	0%	$ 386,941	$ 382,576	-1%	$ 379,478	-1%	$ 402,204	6%	$ 425,340	6%
Less contributions	167,254	167,172	0%	166,023	165,732	0%	162,459	-2%	168,417	4%	174,269	3%
Net plant in service	210,354	209,236	-1%	220,918	216,844	-2%	217,019	0%	233,787	8%	251,071	7%
Mid-year regulatory deferral[2]	2,005	2,559	28%	1,486	1,693	14%	1,367	-19%	2,007	47%	2,061	3%
Working capital	4,108	4,021	-2%	4,280	4,521	6%	4,495	-1%	4,791	7%	4,928	3%
Net Rate Base	$ 216,467	$ 215,816	0%	$ 226,684	$ 223,058	-2%	$ 222,881	0%	$ 240,585	8%	$ 258,060	7%

Notes:
[1] Net plant in service at year end is gross property, plant and equipment plus deferred study and relicensing costs, less work in progress, depreciation, amortization, customer contributions, reserve for future removal and site restoration, deferred fire gain, and disallowed assets.
[2] This reflects the regulatory deferred costs (see Tab 5, Tables 5.3 to 5.8), excluding DSM and the balance of the hearing reserve account (see Table 3.14.1).

Table 3.14
Depreciation and Amortization
($000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Fixed Asset Depreciation	$ 8,406	$ 8,503	1%	$ 8,989	$ 8,894	-1%	$ 8,906	0%	$ 9,828	10%	$ 10,615	8%
Less: Customer contribution	(3,536)	(3,584)	1%	(3,569)	(3,677)	3%	(3,691)	0%	(3,624)	-2%	(4,102)	13%
Less: Amortization of fire insurance recoveries	(262)	(270)	3%	(262)	(262)	0%	(262)	0%	(262)	0%	(262)	0%
Less: Disallowed Depreciation	(4)	(4)	0%	(16)	(16)	0%	(16)	0%	(16)	0%	(16)	0%
Plus: Amortization of deferred charges	3,324	3,580	8%	3,462	4,561	32%	2,846	-38%	2,764	-3%	1,581	-43%
Total Depreciation & Amortization	$ 7,927	$ 8,225	4%	$ 8,604	$ 9,500	10%	$ 7,783	-18%	$ 8,690	12%	$ 7,816	-10%

Notes:

1. Disallowed depreciation reflects fixed asset depreciation amounts for disallowed assets per YUB Orders: $0.004 million (YUB 1992-1) and $0.012 million (YUB 2013-01).

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Table 3.15
Cost of Capital

	2012 GRA compliance	Actual 2012	Change	2013 GRA compliance	Actual 2013	Change	Actual 2014	Change	Actual 2015	Change	Actual 2016	Change
Average Cost of Debt	3.27%	3.47%	0.20%	3.58%	3.38%	-0.20%	3.22%	-0.16%	2.00%	-1.21%	2.10%	0.10%
Return on Equity	8.25%	3.30%	-4.95%	8.25%	7.42%	-0.83%	8.44%	1.01%	8.10%	-0.34%	8.69%	0.59%
Average Cost of Capital	5.26%	4.78%	-0.48%	5.45%	4.99%	-0.46%	5.36%	0.36%	4.50%	-0.86%	4.74%	0.24%

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TOPIC:

REFERENCE: June 22, 2017 Application, page 9
YEC states "The 2016 Resource Plan addresses Yukon Energy's requirements for the next five years, as well as for the longer term planning horizon, and describes the extensive consultation undertaken during the preparation of this plan. Yukon Energy is not seeking specific approvals for the plan. The 2016 Resource Plan is provided for information of the Board and stakeholders and to provide context for capital expenditures and ongoing planning costs included in the test year forecasts."

PREAMBLE:

QUESTION:

a) Please explain how the YUB and other stakeholders are to put any faith into YEC's 2016 Resource Plan's claim that there is a current and growing need for new capacity to meet requirements under the single contingency (N-1) criterion if YEC is not seeking any type of approval of this plan which can only result in a thorough, stand-alone regulatory review of the Resource Plan.

b) Please provide the studies that substantiate the 2016 Resource Plan's forecast that the single contingency (N-1) dependable capacity shortfall is 6 MW for 2017 and 8 MW for 2018.

c) Please provide details by year of all costs incurred to develop the updated 2016 Resource Plan and how it will impact rates.

ANSWER:

(a), (b) and **(c)**

YEC has provided ongoing assessments of capacity requirements (including shortfalls when these occur) under the single contingency (N-1) criterion since the 2006 Resource Plan review by the YUB, including reviews at each GRA and each Part 3 review of specific new resource generation projects (Mayo B and the LNG Plant projects). The most recent

studies in the 2016 Resource Plan are documented in that plan and its appendices, which have been provided for public review throughout the development of the 2016 Resource Plan. Specific updates to capacity shortfalls for the 2017 and 2018 test years are provided in YEC's GRA Application. Costs by year for the 2016 Resource Plan are detailed in Tab 5 of YEC's Application under section 5.3.1.6 and related Tables 5.6-5.8.

TOPIC:

REFERENCE: June 22, 2017 Application, page 1-7
YEC states "Forecasts for the Minto mine load in 2017 and 2018 have changed significantly since the start of 2017. Through early January 2017, it was understood that the mine would cease operations in late 2017. The forecast in this Application now assumes continued Minto mine operation through 2018, based on updated information provided in April 2017."

PREAMBLE:

QUESTION:

a) Please provide a copy of the referenced updated information and details regarding its source.

b) Please provide all other information gathered by YEC to confirm its industrial load forecasts for 2017 and 2018.

c) Please provide a table showing sales to each industrial customer in 2013, 2014, 2015, 2016, 2017 and 2018 and associated revenues.

d) Please provide a description and details of the actual costs associated with providing service to each of the industrial customers (Minto and Alexco, including negotiations numbers with Eagle) and how these costs are determined.

e) Please provide an update on anticipated industrial customer load requirements beyond 2018.

f) Please provide details on any planning that YEC is conducting to implement on-site generation for the transient industrial loads of mines and other large customers.

ANSWER:

(a), (b) and **(e)**

YEC's GRA Application in section 2.2.2 provides the requested information summarizing what was communicated to YEC by Minto mine management, and by the management of Alexco and Victoria Gold. Please see the response to John Maissan-YEC-1-5 for updates with regard to Victoria Gold. YEC relies on the information it receives in this regard from each mine.

(c)

Please see Table 1 below for the requested information.

Table 1: YEC Industrial Sales and Revenues

	Actual				Forecast	
	2013	**2014**	**2015**	**2016**	**2017**	**2018**
Sales in MW.h						
Minto	32,248	36,302	37,186	41,169	38,219	38,219
Alexco	8,265					
Total	**40,513**	**36,302**	**37,186**	**41,169**	**38,219**	**38,219**
Revenues in $000						
Minto	$3,546	$3,958	$4,159	$4,478	$4,198	$4,198
Alexco	$1,049					
Total	**$4,595**	**$3,958**	**$4,159**	**$4,478**	**$4,198**	**$4,198**
Rider J	**$229**	**$291**	**$306**	**$330**	**$309**	**$309**
Total incl. Rider J	**$4,825**	**$4,249**	**$4,465**	**$4,808**	**$4,507**	**$4,507**

(d)

YEC has not developed any cost of service analysis for the current GRA – the last such analysis, as developed for the 2009 GRA test year, indicated that major industrial customers are paying rates in excess of allocated costs of service determined in accordance with OIC 1995/090 and normal regulatory principles applicable to similar regulated electricity utilities in Canada.

Incremental capital costs associated with specific transmission, substation and other related facilities required to connect the Minto and Alexco mines were recovered directly from each mine in accordance with Power Purchase Agreements (PPA's) reviewed and approved by the YUB for each mine after a public hearing review. The Alexco mine and mill also paid YEC's costs to negotiate that mine's PPA and a Fixed Charge each year that it was in operation, pursuant to the approved PPA. Similar to the Alexco PPA, YEC will negotiate a PPA with Victoria Gold for the Eagle Gold mine, and this PPA will be subject to review and approval by the YUB.

(f)

YEC is not conducting any planning to implement on-site power generation at mine sites.

TOPIC:

REFERENCE: June 22, 2017 Application, page 1-7
YEC states "Overall, forecast mid-year net rate base (i.e., after contributions) in 2018 is $64 million higher than the mid-year net rate base as approved for 2013 in the last GRA."

PREAMBLE:

QUESTION:

a) Please confirm that YEC's capital expenditures are not rolled into rate base (i.e., treated as work in progress) for rate setting purposes until the project is completed and deemed to be used and useful and then approved for inclusion in rate base by the YUB.

ANSWER:

(a)

Please see response to UCG-YEC-1-13(a).

TOPIC:

REFERENCE: June 22, 2017 Application, page 1-8

YEC states "The 2012/13 GRA identified the continuing need to meet capacity planning requirements, and Yukon Energy's 2016 Resource Plan has highlighted a current and growing need for new capacity to meet requirements under the single contingency (N-1) criterion. This Application (Tab 2, Section 2.4) forecasts the dependable capacity shortfall at 7.6 MW for 2017 and 8.7 MW for 2018, based on forecast non-industrial load growth without any new diesel unit retirements."

August 15, 2017, Whitehorse Star, Power for Mines is Plentiful

YEC's president Andrew Hall is quoted in this article saying that providing grid power to both the Eagle Gold Project and Alexco Resource Corp.'s silver operation in Keno City won't be an issue.

PREAMBLE:

QUESTION:

a) Please provide details of how power will be provided to these projects.

b) Is YEC currently negotiating a power purchase agreement with Eagle Gold. When is this mine proposed to take industrial power from the grid? Will this affect any of the proposed revenue requirements and rates in 2017 and 2018?

c) Please confirm that when YEC proposed the Whitehorse Diesel-Natural Conversion Project, it was based on no load related to Alexco's mining operations.

d) Has YEC ever negotiated a power purchase agreement with Alexco? Please provide details of this agreement and whether it was followed.

e) Please provide details of how power will be provided to these projects (Alexco and Eagle) and how costs will be managed and paid for.

f) Since Alexco discontinued their prior industrial power load within a few years after hooking up to industrial grid power, after considerable expense to the utility and

thus other ratepayers, how does YEC propose to protect ratepayers from future risk from this company which has not proven to be stable?

ANSWER:

(a), (b) and **(e)**

As noted, each of these projects will be supplied with power from the Yukon grid. Further details please see responses provided to CW-YEC-1-12(d), John Maissan-YEC-1-5, and John Maissan-YEC-1-6(c).

(c) and **(f)**

The load scenarios reviewed in the Part 3 Application for the Whitehorse Diesel-Natural Gas Conversion Project did not assume Alexco. Ratepayers were protected from added capital costs related to serving Alexco by the PPA with Alexco (which required Alexco to pay for these costs at the outset).

(d)

The PPA with Alexco was reviewed and approved by the Board in 2011. Materials filed during this process including the Application and the Power Purchase Agreement are on the Board's website at the link below. The PPA has been followed by the Parties to the agreement.

http://yukonutilitiesboard.yk.ca/proceedings/yec-alexco-power-purchase-agreement/.

TOPIC:

REFERENCE: June 22, 2017 Application, page 1-10

With respect to its Demand Side Management (DSM) Accounting Policy, YEC states "In Order 2013-01 following the 2012/13 GRA, the Board deferred its findings and directions regarding YEC's DSM accounting policy until YEC and ATCO Electric Yukon (AEY) had jointly filed a DSM plan as directed in a prior section. The utilities' joint DSM Plan was filed as part of AEY's 2013-15 General Rate Application and was subject to review by the Board and intervenors. The Board's comments on the DSM Plan were provided in Order 2014-06".

PREAMBLE:

QUESTION:

a) Please identify where in Board Order 2014-06 YEC was given specific directions with respect to its DSM program.

b) Please provide details on how the impacts of DSM efforts are reflected in the actual sales and load forecasts of YEC's customer classes including secondary sales customers for the period 2013-2018.

c) Please confirm that all DSM-related costs will be subject to a prudence review by the Yukon Utilities Board prior to being recovered in rates.

d) Please provide details of YEC's DSM-related expenditures in 2013, 2014, 2015, 2016, 2017 and 2018 and their corresponding percentage of total revenue requirement for those years.

e) Please identify how and where YEC's application reflects benefits to Yukon ratepayers of DSM-related expenditures.

ANSWER:

(a)

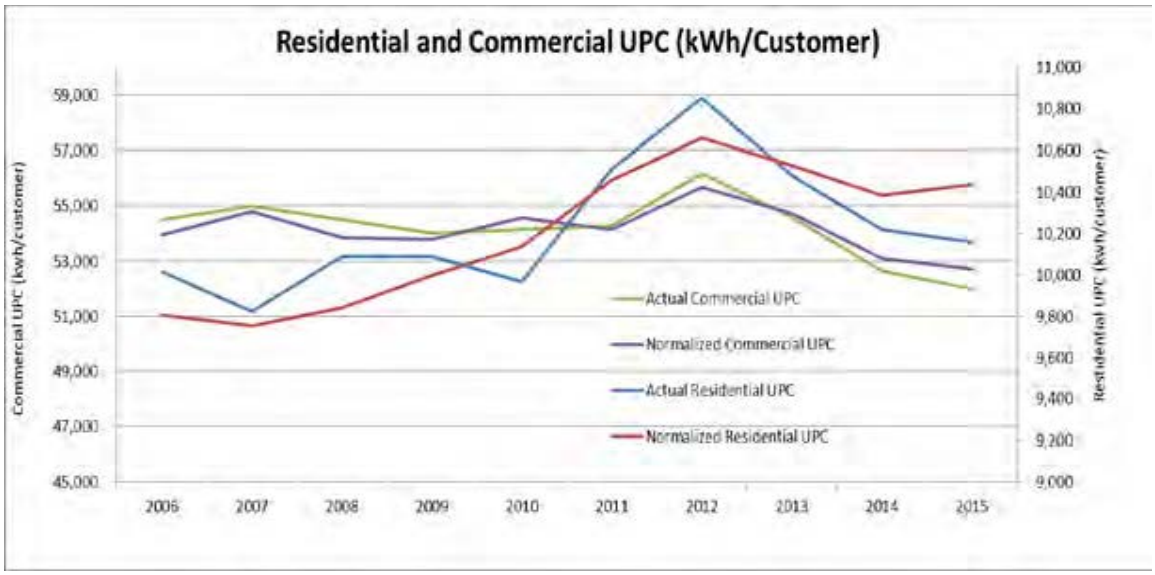
Please see YEC GRA Application, Tab 6, pages 6-2 and 6-3 which reviews relevant elements of Order 2014-06.

(b)

YEC uses historical sales data to forecast future sales so the savings from delivery of DSM programs is reflected in these recent year actual sales and therefore factored into future year forecasts.

Please see also response to YECL-YUB-6(c) from the AEY 2016/17 GRA, which notes as follows:

> AEY does not specifically track and measure the actual impact of DSM initiatives for actual sales. The estimated deemed energy savings associated with this program can be found in Table 2 of the inCharge - Interim Evaluation dated July 31, 2015 and provided in YUB-YECL-6(c) Attachment 1.
>
> As shown on Table 2 of this report, the deemed energy savings in year 1 and year 2 of the program resulted in a reduction of 6,454 MWh and 9,015 MWh, respectively. As shown in the graph below, AEY has experienced a reduction in residential and commercial use per customer since 2012. While AEY cannot attribute the reduction in use per customer solely to the DSM initiatives, it does consider the reduction in use per customer attributable to a variety of reasons including Micro Generation, Commercial Energy Initiative Programs and DSM programs.
>
> AEY has not explicitly adjusted its 2016 and 2017 forecast to reflect future savings as a result of DSM initiatives, but rather, the underlying data and methodology used to derive the forecast incorporates impacts of the DSM initiatives incorporated in the 2014 and 2015 actual consumption.



(c)

Confirmed.

(d)

Please see Table 1 for the requested information.

Table 1: YEC Total Revenues/Revenue Requirements and Net DSM Costs

	Actual				Forecast	
in $000	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Total Revenues/ Revenue Requirement [Table 3.1]	$43,897	$41,247	$41,855	$42,686	$48,544	$49,864
Net DSM Expenditures [Tables 5.3 through 5.8]	$571	$383	$298	$403	$210	$625
DSM Expenditures as % of total Revenues/ Revenue Requirement	1.3%	0.9%	0.7%	0.9%	0.4%	1.3%

(e)

Please see Tab 5, section 5.3.1.5, which reviews the DSM program elements, costs and benefits of implementation. Please see also responses to YUB-YEC-1-80, YCS-YEC-1-14 and John Maissan-YEC-1-3 for further information regarding the DSM program.

TOPIC:

REFERENCE: June 22, 2017 Application, page 2-10
With respect to Power Generation, YEC states that there is a small amount of wind generation available on the system

PREAMBLE:

QUESTION:

a) Please provide an update on negotiations with Northern Energy Capital on a purchase power agreement related to the proposed wind turbines to be built on Haeckel Hill.

b) Please provide details of correspondence which indicates YEC's support for the proposed project.

c) Please provide details of any impact this proposed project will have on YEC's revenue requirements in 2017 and 2018.

d) Please provide details of how this proposed project impacts YEC's current Resource Plan.

ANSWER:

(a)

Negotiations on a power purchase agreement with NEC have not commenced, in part because the implementation guidelines for the Standing Offer Program (SOP) of the IPP policy have yet to be developed.

(b)

YEC has been actively engaged and responsive to NEC in planning activities including site access for wind monitoring activities. YEC has not issued explicit letters of support in this matter.

(c)

Based on current information, YEC believes the earliest in-service date for this project is the summer of 2019, assuming that the proponent moves forward with procurement of the turbines by the summer of 2018. On this basis, there is no impact to YEC 2017/18 revenue requirement from this project.

(d)

The generation of the wind asset that is currently in service was taken into account in the 2016 Resource Plan as available existing generation. In addition, the Plan includes assumed generation from IPPs of 10 GWh per year.

TOPIC:

REFERENCE: June 22, 2017 Application, page 4-4
YEC states that, despite not including any secondary energy sales in its last GRA forecast, "surplus hydro generation (reflecting favourable water conditions as well as reductions in firm grid loads) resulted in actual secondary sales between 3.9 to 7.0 GW.h per year from 2013 to 2016".

PREAMBLE:

QUESTION:

a) Please provide a table showing actual and projected secondary energy sales and revenues for 2012, 2013, 2014, 2015, 2016, 2017 and 2018.

b) Please explain how Yukon ratepayers have benefited from secondary energy sales in the 2013-2016 time period when no such sales were included in the last GRA forecast.

c) Please provide references to when secondary sales and revenues were last reviewed by the YUB.

d) Please explain why YEC believes that secondary sales should not be reviewed as part of this application.

ANSWER:

(a)

Please see Table 1 below.

Table 1: Actual and Forecast Secondary Energy Sales and Revenues

Unit	2012	2013	2014	2015	2016	2017F	2018F
Sales (MWh)	1,993	3,959	5,415	7,030	4,835	11,464	11,464
Revenues ($000)	$165	$275	$410	$544	$371	$642	$642

(b)

Secondary sales revenues over the period from 2013 through 2016 helped to mitigate the impacts of loss of load and to defer the requirement for another GRA until 2017.

Please see Tab 1, Section 1.2 which notes as follows at pages 1-3 and 1-4 [excerpted below]:

> **Secondary Sales Revenues to mitigate impacts of loss of load:** No secondary sales were forecast in each test year for the 2012/13 GRA. Due to the fact that diesel was on the margin, secondary sales had been shut off for increasing periods of time, and YEC had proposed in the 2012/13 GRA that any future secondary sales revenues be paid to the account of the reactivated Diesel Contingency Fund rather than to YEC's revenues. The Board did not approve YEC's proposal to reassign secondary sales revenues in the last GRA. Since the 2012/13 test years, industrial load (except for 2016) and firm wholesale load have both declined during a period of higher than average hydro flows, resulting in further opportunities for secondary sales over the period from 2013 to 2015. Since the last GRA, Yukon Energy has actively pursued secondary sales opportunities, including three new SCADA connections, and annual secondary sales from 2013 to 2016 have ranged between 3.9 GW.h and 7.0 GW.h with revenues as follows: $0.275 million in 2013; $0.410 million in 2014; $0.544 million in 2015; $0.371 million in 2016. Secondary sales are forecast at 11.464 GW.h/year in 2017 and 2018, with revenues forecast (at lower rates now applicable) at $0.642 million per year. All forecast revenues from secondary power in the test years go to lower the required level of retail rates for firm power. As defined by the rate schedule, the impact of quarterly rate adjustments to market are charged against the Rider F – Diesel Fuel Price Variance Account.

(c)

Forecast secondary sales revenues for the 2012 and 2013 test years [included in Yukon Energy's Compliance Filing] were approved by the Board following the 2012/13 GRA in Orders 2013-03 and 2013-04.

The secondary sales rate schedule was approved in Order 2005-12 and no changes were sought in the 2009 Phase II rate proceeding. The rate schedule includes an automatic adjustment mechanism that adjusts the rate on a quarterly basis based on the lowest of the three most recent Yukon Bureau of Statistics bi-weekly furnace oil prices for Whitehorse. The last adjustment to the rate was effective January 1, 2017. The most recent quarterly update provided on August 29, 2017 did not change the rate.

(d)

Secondary sales revenue forecasts are included for review in this application. Yukon Energy is not seeking any changes to the rate schedule at this time, and is not aware of any specific basis today for seeking any change (given that the rate is automatically adjusted each quarter to reflect current heating oil prices).

TOPIC:

REFERENCE: June 22, 2017 Application, pages 5-6 and 5-7

YEC states "The Aishihik hydro facility 7 MW third turbine (AH3) came into service in December 2011. Yukon Energy has incurred $2.715 million of costs after 2012 for wrap up activities related to this project, including $2.574 million of costs from a dispute with a contractor on this project.

…

A decision on the dispute was provided in August 2016 by the Yukon Supreme Court, awarding the contractor a net amount of $1,623,565 plus interest and costs. The amount awarded by the Court included $1,308,462 that consisted of holdbacks and extra works done where the price had been agreed upon, but not yet paid due to YEC's claims for set-off rights. The final cost of the claim dispute includes YEC legal fees of $0.962 million. Based on the advice of legal counsel, YEC has filed the necessary documentation to appeal the court decision."

YEC 2012-2013 GRA, Response to CW-YEC-1-28(c)

YEC states that in August 2010, a feasibility review was undertaken that determined that at a revised project cost of $12.813 million, the Aishihik Third Turbine project was still economically feasible and would have a Net Present Value of $9.77 million and a payback period of 7.9 years.

PREAMBLE:

QUESTION:

a) Please confirm that YEC's capital expenditures are not rolled into rate base (i.e., treated as work in progress) for rate setting purposes until the project is completed and deemed to be used and useful and then approved for inclusion in rate base by the YUB.

b) Please provide the original costs of this project as of August 2010 by component and the actual costs incurred to date in the same detail with explanations for variances greater than ±5% between August 2010 totals and actual.

c) Please provide a copy of any feasibility reviews that have been undertaken related to the costs of the Aishihik Third Turbine project since August 2010.

d) Please provide a copy of the August 2016 decision by the Yukon Supreme Court.

e) Please provide supporting documentation for the $962,000 in legal costs incurred by YEC for the appeal process including timing of when these costs have been incurred.

f) Please explain what benefit ratepayers receive as a result of the legal costs being incurred by YEC through this ongoing appeal process.

ANSWER:

(a)

Not confirmed; as has been accepted practice in Yukon, capital expenditures are put into service and thereby rate base at the point when the asset is deemed used and useful. YUB approval is required to place the asset into rates, but the addition to rate base is independent of this process.

(b)

The question is not relevant; YEC applied for this asset to be included in rates as part of the 2012/13 application. The YUB approved this addition at $13.8 million in Order 2013-01, P.298.

(c)

No such studies have been completed.

(d)

Please see UCG-YEC-1-13 Attachment 1.

(e)

The referenced amount is fees paid to legal counsel to assist with settlement negotiations and preparation and defense of the legal claim at trial. The spending by year is as follows:

2012	$0.129
2013	$0.031
2014	$0.079
2015	$0.256
2016	$0.467
	$0.962

(f)

The assessment of legal counsel and management is that the expected settlement exceeds the costs to defend the case. This assessment cannot be determined until the legal proceeding has been completed, therefore, YEC is not applying for any of these costs to be recovered at this time.

SUPREME COURT OF YUKON

Citation: *North America Construction (1993) Ltd v Yukon Energy Corporation*, 2016 YKSC 33

Date:20160801
S.C. No.:11-A0114
Registry: Whitehorse

Between:

North America Construction (1993) Ltd.

Plaintiff

SUPREME COURT OF YUKON
COUR SUPRÊME DU YUKON
AUG 01 2016
FILED / DÉPOSÉ

And

Yukon Energy Corporation

Defendant

Before Mr. Justice G. Hawco

Appearances:

Mr. H. David Edinger / Harpreet Tosanjh — Counsel for the Plaintiff

Morgan Burris / Todd Shikaze — Counsel for the Defendant

REASONS FOR JUDGMENT

[1] North America Construction (1993) Ltd. ("NAC") is a construction company with a fair amount of experience with respect to the construction of dams and generation plants. It had not worked in the Yukon before bidding for this particular job, but it was well aware of the location and the nature of the project.

[2] The man in charge of the project at the time was Mr. Pat Maloney, his first assignment as a project manager, Mr. Scott McPherson, the president of NAC, who had spent some 23 years with the company, knew him well and had no doubt as to his ability to carry out this job.

[3] Yukon Energy Corporation ("YEC") is a Crown corporation, owned by Yukon Development Corporation. YEC owns and operates the Aishihik generating station which is located 120 kms northwest of Whitehorse. The Aishihik facility has been in operation since 1975. It is a unique facility, located approximately 120 meters underground. It was originally built with two turbine-generator units and was designed for the future addition of a third turbine. In April of 2009 YEC's Board of Directors retained AECOM, an engineering firm, to work on preliminary budgeting and design. AECOM was to perform the engineering and detail design, as well as to perform construction management services.

[4] In January of 2010 YEC put the matter out for tender. NAC and two other construction companies attended at the site with YEC representatives and each submitted a tender. YEC cancelled the tender on the basis that all of the bids received exceeded the project budget. Instead of re-tendering, YEC negotiated directly with NAC and the other two contractors.

[5] On or about August 6, 2010, YEC accepted NAC's proposal of $7,136,885.00 subject to finalization of a number of matters, including what is described as a fan wall design, the size of the camp, the penstock design, which were the pipes to transport the water into the turbine, as well as a schedule.

[6] The contract price was originally based on a substantial completion date of June 11, 2011. The notice to proceed was issued by YEC to NAC in August of 2010, prior to the contract actually being completed. The contract was not executed until December of

2010. By the time it was executed, it was agreed that NAC was to obtain substantial completion by November 30, 2011.

[7] Because the contract price earlier agreed upon was based upon a completion date of June 19, 2011, it was agreed in Schedule D of the contract that:

> *The Price will be adjusted to reflect the contractor's actual cost caused by the new completion date of November 30, 2011 under Section 3.3. The price at Section 8.1 is based upon the original completion date of June 19, 2011 with a 6 week shutdown commencing May 1, 2011.*

[8] The contract also made provisions for changes to the work under Sections 4.5 and 4.6. Section 4.5(d) stated:

> *If a Change to the Work .... increases or decreases the cost to the Contractor by more than $1,000.00, the Parties will agree, in writing, upon a fair adjustment to the Price, on a time and material basis as per Schedule B....*

[9] The project was somewhat different and difficult because it appeared to have been a work in progress. As I indicated, when the parties entered into their agreement in early August, 2010, the design was not yet complete and the time frame for completion was yet to be determined.

[10] Notwithstanding the date of the execution of the contract, NAC had mobilized to the site and began its work in late August or early September, 2010.

[11] Because of the ongoing design changes, the parties entered into an agreement which was known as Schedule D. The clause dealing with adjustment to the cost are referred to above.

[12] NAC substantially completed the contract in early December, 2011. The facility has been generating power since December 6 or 7, 2011.

[13] There were ongoing discussions and disputes during the construction of the facility. Much work was done which was claimed by NAC to be extra, without a decision having been made on the cost. Many of the changes made were agreed upon. Some were not, in the sense that NAC has claimed that it was required to carry out certain work which it said was, or should have been, an extra, while YEC takes a position that such work fell under the existing terms and conditions of the contract. YEC claims that the contract provided that such work fell within the existing terms and conditions and therefore it ought not to pay any extra funds for such work.

[14] In addition to these disputes, YEC carried out what it determined to be remedial work which should have, in the normal course of events, been carried out by NAC. Once the project was substantially complete, YEC refused to let NAC back on the site after they had demobilized because they were of the view that NAC was so incompetent that they could not be relied upon to carry out the remedial work properly.

[15] The disputes will be looked at separately, as the Parties have done. I will deal with NAC claims for monies owning for what it says were extra to the contract. I will then look at YEC's claim for remedial work carried out as well as for work which has not yet been carried out. As will be seen, for the most part, NAC has been successful with respect to its claims for extra work required to be carried out.

[16] YEC is also entitled to set off a certain amount for deficient work carried out by NAC.

[17] It is not unusual that friction develops when a project is, in both a literal and figurative meaning, highly charged and under time pressures. That was the case here and, unfortunately, the spirit of cooperation which marked this project in the beginning descended into an atmosphere of confrontation. In such a situation, each party inevitably suffers to some degree.

NAC CLAIMS

[18] YEC has agreed that under the terms of the contract, it owes NAC $1,308,462.00 which consists of holdbacks and extra work done where the price has been agreed upon, but not yet paid, as well as certain labour and materials. This amount has not been paid by YEC because it has claimed the right to set-off approximately that same amount for work that it says it had to carry out to properly complete the contract, or will have to pay.

[19] There are other monies which NAC claims to be due and owed for various change orders (CRX's). These will be looked at individually. I propose to deal with each of the outstanding CRX's. I will then look to YEC's claims of set-off.

CRX 20

[20] This is one of the most contentious of NAC's claims. It arises because of "Shut Downs" which were agreed upon but with respect to which there was no agreement as to the impact upon the project and the additional cost.

[21] The parties did agree, pursuant to s. 3.3 that:

> *Prior to the Completion Date, YEC will facilitate two shut-downs of the entire facility (the "Shut Down Windows") in*

> *order to permit the tie of the penstock and substation retrofit work:*
>
> > a. *The first Shut Down Window will commence on June 20, 2011 and be completed on June 30, 2011.....*
> >
> > b. *Subject to the status of Mayo outage, the Second Shut Down Window is tentative scheduled to start on October 1, 2011 and be completed by October 31, 2011....*
>
> *The price is based upon a completion date of June 19, 2011 with a six week shut down window commencing May 1, 2011. The price is subject to adjustment under Schedule D.*

[22] Schedule D of the contract provided that:

> *The [Contract] Price will be adjusted to reflect the contractor's actual costs caused by the new Completion Date of November 30, 2011, under Section 3.3.*

[23] NAC's position is relatively simple. Schedule D is a price adjustment clause. As stated in NAC's brief:

> *(b) It was intended to entitle NAC for additional payments for its costs resulting from the extension of the construction schedule and time that NAC had to spend on site to complete this work under the contract as a result of the scheduling changes which YEC determined to impose on NAC, with knowledge of NAC's expected additional costs.*

[24] The extra time that NAC spent on the project was 102 days. The cost of those extra 102 days was $633,510.48. That figure was based upon NAC's original estimate and was consistent with Mr. Landry's projected costs for a six week overrun on September 21, 2010. Mr. Landry had determined that figure by simply multiplying 102 days by the sum of $6,501.89, which was NAC's actual cost per day over the whole project.

[25] YEC's response was that NAC really did not incur any costs as a result of the schedule changes. Rather, the costs claimed were costs incurred because it took NAC longer than it expected to complete the project.

[26] There was a fair amount of evidence from a number of the YEC people on site. Mr. Bob Toms was the first project manager on YEC's behalf. He had no concerns in the beginning of the project with NAC, but did eventually have concerns with respect to what he considered to be their lackadaisical approach to general safety matters on site. He observed delays occurring because of a required design change to what was known as the "Thrust Box" and a delay which he attributed to NAC using an incorrect mix in the concrete used to level the floor in the tunnel. The completion of the floor of that tunnel was along the critical path of the project.

[27] In general, Mr. Toms was concerned about the competency of many of the NAC work crews, as was Mr. Bob Simonson and Mr. Ed Peake. Mr. Toms considered NAC's work to be somewhat sloppy and was generally of the view that NAC had been responsible for any delays to the project.

[28] What I found to be not only unusual, but somewhat incongruous, was that under cross examination, Mr. Toms agreed that NAC had expedited the delivery of the Penstock pipe which was critical to the project on time; that the switch gear building and the installation of equipment with respect to that building was critical and was delivered on time; that the Thrust Box was indeed delivered on time. Mr. Toms went on to admit that YEC continued to have difficulty getting drawings from AECOM throughout the project but that, generally, NAC was keeping up with its schedule.

[29] I also found that Mr. Simonson, a contract administrator with CAP management, an agent of the Defendant, was quite critical of the Plaintiff and was of the view the Plaintiff, because of its inexperience and the laziness of its crew, could have finished the project 4 to 5 weeks earlier than they did.

[30] There is difficulty with some of Mr. Simonson's evidence with respect to the perceived delays which he observed. That is, that no witness for the Plaintiff, neither the project manager nor Mr. Laith Hamad, who was the electrical coordinator and very much on top of things overall with this project, was cross examined in any manner on any of this evidence.

[31] I spoke with counsel during the trial about my concerns about these and other matters that arose in the Defendant's case and had not been touched upon during the Defendant's cross examination of the Plaintiff's witnesses. I explained my concerns within the parameters of *Browne v Dunn* (1893), 6 R.67 (H.L.). I allowed the evidence to go in, but I advised counsel there would or could be a problem as to the amount of weight attached to such evidence.

[32] Having said this, I must say that little of Mr. Simonson's evidence in particular had any adverse impact upon the Plaintiff's claim under CRX 20. The fact is, and was, that the Plaintiff finished this project on time. The items to which Mr. Simonson referred, even if totally accepted, would be, in my mind, rather small. This is, of course, not something which should be simply rejected, but I do so because overall I was not greatly impressed with his evidence. Many of the matters which he considered to be

major appeared to me to be rather minor and with respect to which, hindsight is almost so much better.

[33] In the early stages, there was a lot of interaction between the Plaintiff and the Defendant, even commencing before the contract was executed. Both parties were acting in good faith. Everyone knew that there would be delays, indeed two shutdowns were planned. Discussions were occurring with respect to design changes. Drawings were not complete. The pipe had not yet even been ordered.

[34] It was, in short, organized confusion with much weight being placed upon good faith. Thus, Schedule D.

[35] Relatively early in the project, to be specific, September 27, 2010, Mr. Landry advised Mr. Joudry that they expected NAC costs would be some $278,000.00 for the additional six weeks spent on the project. The length of delay increased significantly.

[36] Certainly, the Plaintiff's work was often sloppy, to put it crudely. Their work habits often left YEC's management frustrated. They were not as efficient as they might have been. YEC's management may well have been better organized and more efficient. The bottom line, however, is they got the work done within the time agreed upon.

[37] YEC does have legitimate concerns with respect to a number of matters which either were done improperly, or simply poorly. These will be dealt with in this judgment in due course.

[38] I accept NAC's claim for $633,510.48. I am satisfied that the Plaintiff was required to spend 102 days more on this project than either they or the Defendant had anticipated when the contract was signed.

CRX - Lug Changes

[39] NAC claimed that YEC requested it to increase the number of lugs on various couplings. The original design was varied somewhat by YEC and its engineer, AECOM. Mr. Toms seemed to agree with the fact that it requested a change. He disputed the cost. The CRX is approved. The amount is $13,381.00.

CRX 39 - Flanges

[40] The issue between the parties here was whether this constituted a change by YEC. Mr. Maloney said that he had submitted the drawings from the pipe manufacturer to YEC, which indicated that the flanges were to be 150 pounds and that YEC had approved them. YEC later said it wanted 300 pound flanges, so the Plaintiff had to change them.

[41] The specifications referred to the court, in Volume 1, Tab 686, does not appear to support this position. I accept YEC's submissions that there was a mistake by NAC or its supplier. The flanges supplied were not in accordance with the contract specifications. That claim is not allowed.

CRX 43 - High Voltage Switch Support

[42] This was a claim for approximately $18,000.00 with respect to an item which Mr. Maloney appeared to concede may have been missed by NAC's estimator. That claim is not allowed.

CRX 52 - Lifting Equipment

[43] The Plaintiff has claimed approximately $21,000.00 because it had not allowed for its equipment to lift as much weight as was required. It may be that the original specifications indicated that the Plaintiff would only be required to lift X pounds, but the Defendant had told the Plaintiff before they prepared their tender that the equipment would have to lift Y pounds.

[44] This claim is not allowed.

CRX 71 - Fan Wall Installation

[45] The issue here was whether the Plaintiff should be paid to assemble an Air Handling Unit (AHU) which arrived unassembled. Document 167 would indicate that this was how it was originally supposed to arrive.

[46] That claim is not allowed.

CRX 92 - October Compressed Shutdowns

[47] In their claim, the Plaintiff says that it was required to do a certain amount of work in less time than it had planned. Mr. Hamad said he had 10 men doing 2 extra hours a day for 28 days.

[48] However, it was clear from the evidence that NAC never did, at least during this particular period of time, have 10 men on the job. They only had 5 electricians on the job. In addition, the compressed work was done within 18 days. My math would consist of 5 men working 2 extra hours a day for 18 days at $58.25 for a total $10,485.00. The Plaintiff's claim on this CRX is allowed to that extent.

CRX 97 – Generator-Turbine Changes

[49] The Plaintiff claims that the original contract specifications were far less detailed than the actual plans and specifications which arrived. The original details were some 15 to 20 pages (excluding the drawings). On February 28, 2011, the provider supplied the manual and the installation plan, consisting of some 127 pages. The work itself was far more extensive than could have been anticipated in the estimate. NAC's original estimates had been 500 to 600 hours for the work, based upon the contract instructions. The actual man-hours expended were 1200. Mr. Maloney stated that the additional hours were due to the increased instructions.

[50] Indeed, Mr. Maloney had estimated that it could cost the Plaintiff $155,000.00 more than could reasonably have been anticipated. The Plaintiff was only seeking to recover less than half of that amount, or $65,868.00.

[51] I accept Mr. Maloney's reasoning and calculations and allow the claim in that amount.

CRX 100 – Cable Changes

[52] NAC claims for a change to the work for its additional labour costs incurred to comply with YEC's requirement that NAC perform extra work to install electrical cables which were not shown on YEC's drawings. The revised amount is $119,004.00.

[53] This was another contentious issue which arose because of the continuing problem which the Plaintiff faced, of building a generator and turbine some 400 feet underground while the designer/engineer was still working on producing all the

necessary drawings and information. Thousands of feet of cable were required, ranging from centimeters in diameter to inches in diameter.

[54] When NAC bid on the project, the design drawings and the information required to determine just how much cable and how many connections, receptors and receptacles would be required was not known, and, according to the Plaintiff, was not capable of being known. This led to NAC having to "guestimate" a cost for the materials.

[55] In late December of 2010 and early January of 2011, Mr. Hamad was very concerned that the information which he had received thus far from YEC and AECOM was not sufficient for him to even begin to order all of the cable required, as well as the electrical panels and the hundreds of connections.

[56] Mr. Hamad sent a number of requests for information (RFI's) to attempt to have a better understanding of what was needed. That RFI (RFI 44) was followed up by yet another RFI, RFI 44-1.

[57] It soon became obvious to Mr. Hamad that only about one half of the cable required was covered by the drawings and specifications NAC had received initially.

[58] Negotiations began about the cost of these additional materials, which resulted in CRX 24 being agreed upon. This CRX gave NAC an additional $46,000.00 to acquire the extra cable.

[59] Mr. Hamad was quite confident that CRX-24 only covered the cost of acquiring much of the "new" cable. It did not include any of the costs of connecting any of the cables as no one yet knew exactly where the connections would be located.

[60] Indeed, at the time CRX 24 was agreed upon, AECOM still had not provided the Plaintiff with any of the designs within the various panels or the input/output schematics.

[61] Further drawings and information continued to flow, resulting in yet further changes and the resultant costs. These new drawings and changes continued up to October 3, 2011.

[62] The situation was one described by Mr. Hamad as working and making changes "on the fly" without being assured they would be compensated adequately, but doing the necessary work because they were on the critical path and this work had to get done for the project to become completed on time.

[63] I found Mr. Hamad to be an honest and forthright witness. He was very familiar with the project and familiar with the various emails and other documentation that went back and forth between the parties.

[64] YEC's response to CRX 100 is primarily that NAC had already been compensated for the additional cable (CRX 24) and had been compensated for most of the other work in CRX 79, CRX 80, CRX 85 and CRX 86.

[65] In addition, YEC argued that Mr. Tillebrook and Mr. Peake had seriously undermined the basis of Mr. Hamad's projection of the cost increase after May 2011, as shown in Tab 347.

[66] I did find both Mr. Tillebrook and Mr. Peake to be very good and credible witnesses. However, what was particularly telling in Mr. Peake's evidence was his admission that there were indeed glitches in the design and that the equipment

sometimes arrived in a different conformation than expected and that AECOM's drawings were often unclear.

[67] It was Mr. Peake who was quite critical of the estimate of 4,000 meters of additional cable which NAC had estimated was required. In his opinion, the appropriate figure would have been closer to 400 meters.

[68] As well, the estimate of the crane time, which NAC had estimated was far more than he would have thought necessary.

[69] Unfortunately, we once again come back to the cross examination of Mr. Hamad and Mr. Maloney, or the lack of cross examination of either of these individuals on these very specific points.

[70] I have referred to my concerns about the failure of the Defendant to adhere to the principles annunciated in *Browne v Dunn* and it is particularly telling here.

[71] The Defendant would have known, during the examination-in-chief and cross examination of the Plaintiff's witnesses, that it was going to be proffering a witness (Mr. Peake) who had estimated that the amount of cable and the amount of crane time would be significantly less than either Mr. Hamad or Mr. Maloney had taken into consideration when preparing the estimates with respect to these particular items. It is, quite frankly, simply an issue, as I remarked to counsel, of fair play. If one knows one is about to put forth evidence that calls into question, for example, cost estimates of time and materials, the witnesses putting forth that evidence should be cross examined on the discrepancy that is intended to put forth by the Defendant. That was not done. In my

view, not very much weight may be placed upon the evidence from Mr. Peake with respect to just how much cable was required and the resultant crane time. I do not, as I have said, question Mr. Peake's credibility, what I question is how there can be a legitimate gap in the quantity of cable when nothing was asked of Mr. Hamad with respect to these rather important items. There were questions put to Mr. Hamad about CRX 100, but none that involved the quantity of cable or the crane time.

[72] In the end, I am quite satisfied that as a result of the lack of drawings and detailed connections, due to the evolving design and changes to the previous plans, the Plaintiff was put to a lot of extra time and materials.

[73] I am satisfied that CRX's which were agreed upon, being CRXs 24, 79, 80, 85, and 86 did not included any amount for cable which had yet to be shown to be required.

[74] Both parties were somewhat lax in adhering to a proper extra work charge protocol. It was, as said by Mr. Hamad, a moving target and a reaction to that which had not been envisaged or planned by either party. While both Mr. Hamad and Mr. Peake were good witnesses, and credible witnesses, both cannot be totally right.

[75] I am not able to come up with any firm costs. I will therefore award one half of CRX 100, which would, by my calculations, be $59,500.00.

[76] My calculation of the amount owing to NAC is, therefore, that which was agreed upon, being $1,308,462.00 plus those amounts which I have found due and owing pursuant to the various claims, being $633,510 for CRX 20, $13,381.00 with respect to the Lug Changes, $10,485.00 with respect to the October Compressed Shutdown,

$65,868.00 with respect to the Generator-Turbine Changes and $59,500.00 with respect to CRX 100 – Cable Changes, for a total of $2,032,301.00.

YEC's Claims

[77] I now turn to YEC's claim for its costs to what it characterizes as poor workmanship of NAC and additional work it claims had to be carried out because of the actions, or inactions, of NAC.

CRX 104

[78] The first of these would be CRX 104, relating to Bentley-Nevada. This dispute concerned whether Bentley-Nevada was even on site on the dates for which a claim was made covering the 18th, 19th, and 20th of October. There were further claims with respect to two additional days spent after completion of the project, which I have not taken into consideration, because of the date and lack of sufficient evidence.

[79] With respect to the three days, Mr. Hamad was quite clear. He had requested that Bentley-Nevada attend on October 18, 2011. His recollection was that they did not show up on the 18th because YEC had told them to work on another YEC site. He recalls that they did return on October 21st when the Plaintiff was demobilizing and that he therefore had no opportunity of supervising them. As a result, one of YEC's representatives attended with them.

[80] It was Mr. Hamad's recollection that Bentley-Nevada did the work which was required and that NAC paid them directly.

[81] Mr. John Bruineman, a Bentley-Nevada representative, sent Mr. Hamad an e-mail on October 21, 2011 which seems to indicate that Bentley-Nevada was indeed on site on the 18th and 19th, and perhaps 20th. There were other e-mails (see Tab 546) which indicate that Bentley-Nevada was only on the site two days.

[82] While I have already assessed Mr. Hamad's credibility as being quite high, the e-mails back and forth would indicate that Mr. Hamad was mistaken with respect to this issue. One of the other e-mails which I referred to immediately above does indicate that the time spent by Bentley-Nevada was two days, not three. I have simply reduced the claim by YEC by 1/3. They are allowed the claim of $15,166.00 with respect to the Bentley-Nevada matter.

CRX 106 – Fuel Leak

[83] NAC admits having caused a fuel spill while on site. It only disputes the amount of money required to adequately remedy the situation.

[84] The Defendant's witness was Ms. Shannon Mallory, who was the YEC environmentalist coordinator.

[85] The Plaintiff received a plan prepared by EBA on June 15, 2011. The anticipated costs at that time were $15,245.00, plus GST (see Tab 575).

[86] YEC did not approve this report and so NAC requested EBA to prepare another estimate. This next estimate, dated March 15, 2012, came in at $42,070.00. This was also presented to Ms. Mallory who was not satisfied with that report either and proceeded to draw up her own estimate, which was based, primarily, upon the EBA estimate.

[87] Ms. Mallory produced a document showing a budget of $116,517.00 to totally clean up the site. She arrived at that figure by unilaterally doubling the EBA estimate, and adding another 20%, after having increased the EBA estimate by 20% before doubling it.

[88] Quite frankly, I considered Ms. Mallory to be not particularly helpful at all in this regard. She had no idea of how much soil had been excavated and hauled away and she had no real reason for rejecting the second EBA report.

[89] This claim is allowed, but in the amount of $42,070.00, being EBA's second estimate.

CRX 111 – Cabinets

[90] YEC's claim with respect to this item is that NAC failed to supply the control and protection panels with open backs.

[91] NAC's response was that it had ordered cabinets with removable backs, but their supplier did not provide these cabinets with either open or removable backs.

[92] YEC approved NAC's drawings without having noted that the drawings required cabinets with open backs.

[93] In any event, the cabinets which were supplied had welded backs. Modifications had to be made to them by making holes in the sides and in the backs so that they could be used. They are still being used, but are not what was requested or required by YEC.

[94] YEC is seeking to replace the cabinets totally at a cost of some $206,000.00. Mr. Maloney estimated that it would cost $20,000.00 to $30,000.00 to cut the panels out. Mr. Peake thought they could be "fixed" for $100,000.00.

[95] I am satisfied that the cabinets should have been delivered with either removable backs or open backs.

[96] They should be repaired. I accept Mr. Peake's evidence and allow this claim in the amount of $100,000.00.

Deficiency Claims

[97] This is perhaps the most contentious claim. YEC says that NAC was sloppy, unprofessional and unsafe with respect to so much of its work that it had totally lost confidence in NAC's ability to repair or remedy any of the multitude transgressions which it alleges have occurred.

[98] NAC maintains that the list of deficiencies prepared by YEC is quite exaggerated, as is the cost of remedying them.

[99] NAC has always indicated its willingness to attend and rectify any deficiencies. Indeed, numerous discussions were held and at least one walkthrough.

[100] NAC also argues that YEC has a duty to mitigate its damages and that by not allowing NAC back on site, or doing some of the work itself, it has failed to mitigate and that this claim should be dismissed.

[101] As I said earlier in this decision, the spirit of cooperation which permeated this project initially slowly faded. In its place, a sourness began to creep into the relationship.

[102] Minor items such as lack of orderliness and a failure to be careful, or a perceived failure to live up to what YEC considered a minimum standard of quality became more than irritants. Work was viewed as sloppy or careless. Standards began to be imposed without anyone having been given notice that much more was now being expected.

[103] The installation of the cables in the elevator shaft is a good example of how the dynamics changed:

(i) Notwithstanding that it was YEC itself who determined what "Code" was to be followed, what had been acceptable before was now considered to be not acceptable.

(ii) How cable was to be fastened to the duct should not be done the way it had been done just years before.

(iii) The cable trays no longer were sufficient.

(iv) The clearance was no longer sufficient.

(v) The electrical code was being followed or not being followed, depending on who was interpreting it at any given time.

(vi) The cables were now not "tidy".

(vii) "Sloppy" work became "deficient work".

(viii) A very slight indentation in a cable coverage became "damage".

[104] It seems to be, and did seem to me during the trial, that the Defendant had formed the view toward the end of the project that the Plaintiff was simply incompetent. It began viewing the work done through coloured glasses, "rose coloured" not being one of the lenses.

[105] Complaints of deficiencies were being directed at the Plaintiff without specifics being given.

[106] It was clear that the Defendant had had enough of the Plaintiff and it was not going to be fixing anything for the Defendant in the future, or doing any more work once they demobilized.

[107] The Plaintiff urges the Court to reject all of the Defendant's deficiencies list because the project was substantially completed and the deficiencies were not serious ones. That being the case, the Plaintiff argues, there was no fundamental breach of the terms of the contract. That, in turn, required the Defendant to mitigate its damages. The best way to mitigate its damages was to allow the Plaintiff to carry out the necessary remedial work.

[108] I agree with the Plaintiff that that the deficiencies were not so serious as to amount to a fundamental breach of the contract having been committed by the Plaintiff.

[109] I also agree with the Plaintiff that an owner is required to mitigate its damages. However, with the greatest respect to the learned trial judge in *Beta Construction Inc. v Chiu*, 2015 ONSC 5288, at para 86, I do not agree that the owner must allow the contractor an opportunity to repair the deficiencies.

[110] In my respectful view, to compel an owner to allow a contractor with whom it has no confidence simply makes no sense.

[111] But, if such an owner - in this case - YEC, does not want NAC to perform the deficiency work, it cannot simply get the most expensive estimate it can find and ask the Court to award damages in that amount.

[112] I do wish to comment on some of the deficiencies within the elevator shaft before turning to the estimate to which I referred to above.

[113] It struck me time and again during the trial that while some of NAC's work was indeed sloppy, YEC's expectations were perhaps higher than they should have been.

[114] I am aware of the term in the contract that provides that: "The Contractor will perform the Work diligently in a workman like manner and in accordance with the highest industry practice used in Canada."

[115] I am also aware that the majority of this contract was carried out some 140 km north of Whitehorse, much of it in the middle of winter, and at a depth of some 400 feet underground.

[116] Mr. Tillbrook, an electrical engineer on site, considered much of NAC's electrical work to be sloppy. He thought that NAC was "not structured enough". He did not like NAC's overall plan, but admitted that the commissioning of the project did go forward and that the project was up and running within a few days of the substantial completion date. He was of the opinion that the tie wrapping was contrary to the electrical code,

depending on how one might interpret it. But I saw no evidence which satisfied me that the wrapping was improper.

[117] In this connection, it should be noted that the cables which were wrapped, lowered and supported during this project were done much in the same way that the previous cables had been suspended, wrapped and generally looked after.

[118] Mr. Tillbrook was critical of the protection given by NAC to the grips and wrapping, but admitted that nothing was contrary to any approved procedure.

[119] He criticized or commented on "damage" to the covering of one of the cables. The photograph of this particular piece of cable showed a very slight indentation in the wrapping.

[120] Mr. Bob Simonson's criticisms had more to do with safety issues and lack of organizational skill than to deficiencies in the work carried out. Mr. Peake was also quite critical of NAC's work within the cable trays. It was primarily sloppy and did not appear to be neat, in his mind. He thought the cable trays themselves were not secure enough and that they had been structurally weakened.

[121] It seemed to me that Mr. Peake's key concern and complaint was that NAC's people were not very qualified and that the work they were performing met the "bare minimum" quality level but did not meet what he considered would be the industry standard.

[122] Some of Mr. Peake's other criticisms were that the wiring was not tidy; that the trays were overstuffed; and that the clearance was not sufficient.

[123] A fair amount of Mr. Peake's evidence concerned the cable trays. Some of his evidence arose as a result of an incident which occurred in October of 2013 when the elevator wires and the cable trays came into contact, resulting in a visit from the Yukon Workers' Compensation Health and Safety Board. In their report, the Board noted that minimum clearance distances between the conveyance and cables and cable trays were not being met. It also referred to the fact that there were deficiencies that were noted in an inspection report dated May 5, 2011 that had not been rectified.

[124] The end result of that incident was that a new design was prepared and the cable trays were ultimately fixed. However, my difficulty is that at the time of the installation, YEC was the electrical code authority and it was admitted that NAC was not advised of the clearance requirements prior to installing the trays or "overstuffing them".

[125] I very much hesitate to consider the cable trays and much of the remedial work done within the elevator shaft as a deficiency as a result of a report made by the Occupational and Safety Board some two years later. Admittedly, the way the wires were "stuffed" into the trays was not particularly tidy or pretty. However, I am not satisfied it constituted a deficiency.

[126] Much of the "Deficiency Claim", indeed, some $264,000.00, related to the elevator cables (See Exhibit 41). My concerns with respect to the legitimacy of recovering these costs have been voiced.

[127] It was Mr. Peake who quite honestly said that while conducting the walkthrough with Mr. Hamad and others from NAC toward the end of the project, that he and the other YEC people who were attending with him had already determined that they were

not going to have NAC come back to do any of the deficiencies. They did not like NEC's work and refused to allow them to carry any further work out.

[128] YEC was entitled to come to that conclusion and was entitled to make such a decision.

[129] The question then becomes should NAC have to pay anything since the deficiencies did not amount to a fundamental breach of the contract. In my view, they do, because they did not complete the job as they were required to do under the contract.

[130] As I have already said, YEC is entitled to come to that conclusion and make the decision to have someone else perform the work. They are not, however, entitled to have the work carried out in the manner suggested by the Orbus report, prepared by Mr. Amin Kassam. Mr. Kassam had estimated the cost of remedying the deficiencies would be $970,961.25.

[131] I found Mr. Kassam to be a very interesting witness. He declared himself to be an independent expert and not biased in any manner. However, his bias came through quite clearly.

[132] On a number of occasions, he appeared to suffer from a loss of memory with respect to information which he had received from Mr. Mortimer, a fellow colleague who had prepared an earlier estimate, and was argumentative when, in my view, there was no need to be.

[133] Mr. Mortimer, Mr. Kassam's former colleague, had prepared an estimate as to the cost of remedying the deficiencies. His estimate was $686,500.00. Mr. Kassam professed to be more aware of the "conditions" and "factors" that should be taken into consideration notwithstanding that Mr. Mortimer was a senior field technology expert and that Mr. Mortimer had spent some 35 years with the company, presumably mostly in the North.

[134] Notwithstanding Mr. Mortimer's apparent expertise in the field, Mr. Kassam determined that Mr. Mortimer had not taken into consideration that:

1) the plant would be operating, not shut down;

2) the plant was located in a Northern site, and

3) the people carrying out the work would not be as skilled as Mr. Mortimer was.

[135] Mr. Craig Miller, an employee of NAC, is an operations analysist and an electrical estimator. He has prepared dozens of estimates on jobs throughout Canada. He was retained to prepare a report and did so. That was introduced as Exhibit 35 in these proceedings.

[136] Mr. Millar had been given a copy of Mr. Kassam's estimate. In fact, he was given both the Orbus reports of 2012 and 2016. He prepared a very detailed estimate of the work that would need to be carried out. He examined the deficiency list prepared by YEC and specifically the list and report of Mr. Kassam. He was very familiar with the site, visited it at least twice. He did not question whether any of the deficiencies were in fact deficiencies. He simply assumed that they were.

[137] Mr. Miller's estimate of the cost to repair was $251,521.52.

[138] Mr. Kassam was of the view that all of Mr. Miller's estimates of time required were far too low. Where Mr. Miller had estimated some 65 hours to complete "the labelling", Mr. Kassam estimated 482 hours. Where Mr. Miller estimated some 40 hours to prepare as built to drawings, Mr. Kassam estimated some 653 hours. Where Mr. Miller estimated some 4 hours to complete what were described as "code items", Mr. Kassam estimated that this should take some 1,116 hours.

[139] These are rather stunning contrasts, none of which were put to Mr. Miller. Mr. Miller did, however, have access to and read the reports, so would have been aware of them. No cross examination was put to him, however, in that regard.

[140] Mr. Kassam did say that he was aware of a number of matters which he had estimated had been removed from the list as a result of the evidence, primarily, of Mr. Peake. That, in his view, would have reduced his costs by some 10 to 15%. The total hours on site which he had anticipated would be 5,268 hours, would have been reduced by some 37% if the items removed were considered.

[141] Had YEC mitigated their damages, they would have been able to revenue the deficiencies at a cost of, depending on the estimates used, some $252,000.00 to $433,000.00 (using Mr. Mortimer's estimate less the 37% with respect to items which had been removed and as conceded by Mr. Kassam).

[142] I was not particularly impressed by Mr. Kassam's evidence. Mr. Mortimer was not called and therefore not questioned with respect to his estimate. Mr. Miller's report was,

in my view, fair and reasonable. I award YEC the sum of $251,500.00 with respect to the deficiencies as prepared by YEC.

[143] In the end result, from the total of $2,032.031.00 is payable to NAC pursuant to the terms of the contract, YEC is entitled to deduct the sum of $408,736.00 for a total judgment owing to NAC of $1,623,565.00.

[144] The Plaintiff is, of course, entitled to interests and costs. Costs may be spoken to by counsel by means of a conference call.

HAWCO J.

TOPIC:

REFERENCE: YUB Order 2009-8, Appendix A, page 37

"Further, in future GRA applications, the Board directs YEC to include business cases for major capital items, including electronic models. Business cases will include:

- descriptions of the project
- economic analysis including preliminary engineering estimates
- discussion of alternatives and how the chosen option was determined
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs."

Reference: YUB Order 2013-01: Reasons for Decision, Appendix A, page 65

"However, in future, the Board directs YEC to provide business cases for all projects, including reliability projects, greater than $1 million. These business cases are to include alternatives to the recommended projects as well as the economic impact to ratepayers of the recommended projects."

Reference: June 22, 2017 Application, page 6-6

YEC states "Business cases for projects greater than $1 million (i.e., "major projects") are provided in Tab 5 of this General Rate Application".

Reference: June 22, 2017 Application, page 5-7

Aishihik Elevator Shaft Structural Steel Rehabilitation ($10.116 million).

QUESTION:

a) Please provide a business case analysis for this project which contains details required pursuant to Board Orders 2009-8 and 2013-01.

b) Please confirm the total project cost from conception to completion and provide an annual breakdown by project component. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

c) Please provide a chronological history of all the decisions / approvals / consultations related to this project including Board of Director's decisions, all meetings with various First Nation governments / representatives, stakeholder meetings, etc.

d) Please provide a copy of the referenced KGS Group study dated January 2014.

ANSWER:

(a), (b) and **(c)**

The total project cost as per the Application is $10.116 million (Page 5-8, l.1). See YUB-YEC-1-62 for analysis of costs.

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process.

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization including consultants and different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is commonly across several different platforms (e.g., email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudency assessment. The request to provide a history of "all meetings with various First Nation governments / representatives, stakeholder meetings, etc." is also overly broad and is not directly

relevant to understanding whether costs for this project were reasonable or prudently incurred.

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

- Tab 5 section 5.2.1.2 provides the project justification and estimated costs.
- YUB-YEC-1-62 – detailed initial estimate of budget and explanation of variances as well as project status and alternatives reviewed.
- John Maissan-YEC-1-24 – estimated useful life of the asset.

(d)

Please see UCG-YEC-1-14 Attachment 1.

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January 27, 2014

File No.13-1404-005

Yukon Energy Corporation
2 Miles Canyon Road
P.O Box 5920
Whitehorse, Yukon
Y1A 5L6

ATTENTION: Mr. Lawrence Joudry

RE: Yukon Energy Corporation – Aishihik Power Plant Elevator

Dear Mr. Joudry:

KGS Group was retained by Yukon Energy Corporation to prepare a report setting out its opinions in relation to the electrical cables installed in the elevator shaft at Yukon Energy Corporation's Aishihik generating station. Please refer to the letter in Appendix A dated January 17, 2014 for more information.

Pursuant to Orders (I.R. No. 40-20131011-1025 and 40-20131020-0936) issued to Yukon Energy Corporation by the Yukon Workers Compensation Health and Safety Board (YWCHSB), the YWCHSB requires Yukon Energy Corporation to have a qualified independent engineer conduct a comprehensive evaluation of the 2011 installation upgrade in the conveyance shaft of the Aishihik Generating Station and produce documentation showing that the Aishihik conveyance (Elevator YE-1) meets all applicable codes, acts and regulations in regards to the installation and safe operation of the conveyance.

The purpose of the opinions contained within this report is to satisfy the requirements of these Orders and respond to the following questions:

1. **Does the cable suspension system as designed and installed comply with the manufacturer's directives and applicable codes?**

2. **If not, what modifications are required to bring the cable suspension system into compliance?**

3. **If the cable suspension system as designed or installed does not comply with the manufacturer's directives and/or applicable codes, is the cable suspension system as presently installed nevertheless capable of being certified as being safe for operation?**

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To provide opinions and answer these questions, KGS Group first undertook a review of the relevant drawings of the Aishihik Generating Station. Due to the limited and sometimes contradictory information available, KGS Group travelled to site on three separate occasions to conduct formal site reviews of the present conditions. As KGS Group was unable to ascertain and verify the adequacy of the structure during these site reviews, it was decided to conduct three full load emergency elevator braking tests performed in conjunction with KONE Elevators to assess the structure.

The information on the electrical aspects of the installation obtained from the site reviews and tests was compared to the following codes and standards:

1. National Building Code of Canada - 2010 version.

2. Alberta Electrical Utility Code – 2013 version.

3. Canadian Electrical Code – 2009 and 2012 versions. Specific code sections applicable to this facility are:

   a) 12-014 Conductors in Hoistways.
   b) Rule 2-030 Deviation or Postponement.
   c) 12-2200(4) Method of Installation.
   d) 12-120(4) Supporting of Conductors.

4. Yukon Electrical Protection Act - 2002 version. The specific section applicable to this facility is:

   a) Section 4(2) Standards for Installations.

5. Yukon Worker's Compensation Health and Safety Board Regulations. Specific sections applicable to this facility are:

   a) Section 9.21.
   b) Table 9.3.

Where applicable, KGS Group has identified deficiencies and outlined appropriate remedial actions to be undertaken by Yukon Energy Corporation to rectify these issues and satisfy these Orders. The report, Aishihik Elevator – AH3 Electrical Cabling Review was originally dated November 29, 2013. Appendix B contains a new revision of this report, which is identical to the November 29, 2013, with the exception that an engineer's seal has been added.

Our engineering opinions to the three questions posted above are as follows:

Question 1: Does the cable suspension system as designed and installed comply with the manufacturer's directives and applicable codes?

KGS Group found that the cable suspension system as designed does not comply with the Canadian Electrical Code requirements for adequate support and mechanical protection of a vertical installation of power cables within an elevator shaft.

During the course of reviewing the cable installation, various cable manufacturers and their representatives were contacted by phone to discuss the cable installation (Aetna, Okonite, and

General Cable). The cable manufacturers, and their representatives, typically defer to code requirements for installation and did not have specific written instructions for the installation of the cables. It was noted, however, that the current installation would not sufficiently support the cables to meet code, and that proper cable supports should be installed.

In addition, as a result of concerns with the structural frames in the elevator shaft, KGS Group is unable to determine that the cable suspension system, as installed and in its current condition, complies with the *National Building Code of Canada*.

Question 2: If not, what modifications are required to bring the cable suspension system into compliance?

In KGS Group's opinion, the existing cable suspension system can be brought into compliance with the *Canadian Electrical Code* by replacing the existing cable supports with modern cable clips and by installing a cable tray cover over the medium voltage power cables. KGS Group has recommended that these corrective measures be implemented within the next six months. Yukon Energy Corporation has retained KGS Group to provide engineering assistance for the design and specifications for the installation of the cable clips in compliance with the *Canadian Electrical Code*.

With respect to the shaft structure that supports the cable suspension system, KGS Group has recommended conditions, listed in the response to Question 3 below, on the use of the elevator in the short term and that repairs and upgrades be undertaken within the next 12 months to permanently rehabilitate the structure and enable long-term verification of its load bearing capacity. KGS Group has been retained by Yukon Energy Corporation to develop a concept design for this work. If the work cannot be completed before the end of the 2014, the adequacy of the structure will have to be re-assessed.

Question 3: If the cable suspension system as designed or installed does not comply with the manufacturer's directives and/or applicable codes, is the cable suspension system as presently installed nevertheless capable of being certified as being safe for operation?

To determine the adequacy of the structure, KGS Group conducted a review of the elevator shaft structural frames and support system. These structural frames support the electrical cables installed within the elevator shaft during the 2011 upgrade, as well as the elevator guide rails and various structures and services from the original 1975 installation. As a result of: (a) the limited structural drawings available for review; (b) the significant corrosion observed in some of the structural supports; (c) the vulnerability of the field welded connections to corrosion and cracking; and (d) the lack of load redundancy in the structure's design, KGS Group determined that the load bearing capacity of the "as constructed" structure would have to be verified. However, due to the limited availability of as-built drawings and our finding that many of the structural supports were field fit and field welded, KGS Group was unable to rely on a review and analysis of the drawings to conduct this verification. Another option would have been to conduct a complete physical inspection of each of the structure's support members and anchor points, however, this was not feasible based on the design and construction of the structure, which offers very limited access to the anchor points for inspection or testing.

As a result of these limitations, KGS Group designed a test to determine the adequacy of the structure in the immediate short term. This was achieved by performing a full load elevator braking test at three different points within the elevator shaft. The loads exerted on the shaft

structure by the operation of the elevator are normally minimal except in an emergency situation in which the elevator is required to apply its emergency brakes in a free fall condition. This situation represents the highest loading the structure is required to withstand, and was selected to confirm the system load capacity. Accordingly, the elevator was loaded to its rated capacity of 2500 pounds during the braking tests to demonstrate that the shaft structural supports could accommodate the highest loads the structure is likely to ever experience.

Based on the results of our review and the three emergency braking tests performed, KGS Group's opinion is that the structure is adequate for the current loads; however, certain conditions must be imposed to provide a reasonable margin of safety until the structure can be rehabilitated. Accordingly, it is KGS Group's opinion that the risk of a structural failure is as low as reasonably practicable and that the elevator can be safely operated until the corrective measures described above are implemented, if the following restrictions are imposed on its use:

1. The medium voltage power cables that are presently installed within the elevator shaft should be de-energized until the existing cable supports are replaced with modern cable clips and a cable tray cover is installed.

2. The maximum load capacity of the elevator should be de-rated (restricted) from 2500 pounds to 1000 pounds.

3. Although we understand that this is already standard Yukon Energy Corporation practice, no live loads (i.e. staff or non-permanently mounted equipment) should be present on the structure while the elevator is in use.

4. Other than the addition of the recommended modern cable clips and cable tray cover, no additional cables or new loads should be installed onto the shaft structure.

5. Yukon Energy Corporation should perform periodic inspections and monitoring of the shaft structure. KGS Group will forward details of the required inspection and monitoring procedure in the coming weeks.

6. If the recommended repairs and upgrades to the shaft structure are not completed by the end of 2014, the adequacy of the shaft structure should be re-assessed.

By de-energizing the medium voltage power cables (Restriction #1), Yukon Energy Corporation will eliminate the safety risk presented by the non-compliances with the *Canadian Electrical Code*. (A detailed report of KGS Group findings and recommendations in respect of the electrical aspects of its review was provided to Yukon Energy Corporation under a separate report dated November 29, 2013.)

The other interim measures (Restriction #2 - #6) should be implemented until the long term structural concerns of the shaft support structure have been addressed. These measures are meant to provide an adequate safety margin for the continued use of the elevator over a 12-month period. In KGS Group's opinion, there is no structural or electrical reason to limit the frequency of use of the elevator under these conditions.

This report has been prepared for Yukon Energy Corporation to whom this report has been addressed and any use a third party makes of this report, or any reliance on or decisions made based on it, are the responsibility of such third parties. KGS Group accepts no responsibility for

damages, if any, suffered by any third party as a result of decisions made or actions undertaken based on this report.

If you have any further questions or need further clarification, please feel free to contact the undersigned.

Prepared by:

Gord McPhail, P.Eng.
Senior Structural Engineer

Prepared by:

Adam Pawlikewich, P.Eng.
Senior Electrical Engineer

Approved by:

Dave MacMillan
Principal

GDM/AP/

Cc: Joel Lambert – KGS Group

TOPIC: **Aishihik Electrical and Control Ugrades ($2.511 million)**

REFERENCE: June 22, 2017 Application, page 5-8

PREAMBLE:

QUESTION:

a) Please provide a business case analysis for this project which contains details required pursuant to Board Orders 2009-8 and 2013-01.

b) Please confirm the total project cost from conception to completion and provide an annual breakdown by project component. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

c) Please provide a chronological history of all the decisions / approvals / consultations related to this project including Board of Director's decisions, all meetings with various First Nation governments / representatives, stakeholder meetings, etc.

d) Please provide a copy of the referenced KGS Group Study from 2014.

ANSWER:

(a), (b) and **(c)**

The business case for this project, including estimated costs, is provided in the Application at Section 5.2.1.3. The project is forecast to be completed in 2018.

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process.

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization, including consultants and different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is

commonly across several different platforms (e.g. email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudency assessment. The request to provide a history of "all meetings with various First Nation governments / representatives, stakeholder meetings, etc." is also overly broad and is not directly relevant to understanding whether costs for this project were reasonable or prudently incurred.

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

- Tab 5 section 5.2.1.3 provides a review of the project elements, justification, and costs.
- Further information is available in the following interrogatory responses for this proceeding:
    - **YUB-YEC-1-63 –** copy of assessment report done by KGS Group, options reviewed, and other related questions.
    - **CW-YEC-1-36** – review end of life determination.

(d)

Please see Attachment 1 provided as response to YUB-YEC-1-63(a).

TOPIC: **Communications Upgrades ($1.003 million)**

REFERENCE: June 22, 2017 Application, page 5-12

PREAMBLE:

QUESTION:

a) Please provide a business case analysis for this project which contains details required pursuant to Board Orders 2009-8 and 2013-01.

b) Please confirm the total project cost from conception to completion and provide an annual breakdown by project component. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

c) Please provide a chronological history of all the decisions / approvals / consultations related to this project including Board of Director's decisions, all meetings with various First Nation governments / representatives, stakeholder meetings, etc.

d) Please provide a copy of the referenced BBA study dated June 2016.

ANSWER:

(a), (b) and **(c)**

The business case for this project, including estimated costs for work completed before the end of 2018, is provided in the Application at Section 5.2.1.4.

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process.

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization including consultants and different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is

commonly across several different platforms (e.g. email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudency assessment. The request to provide a history of "all meetings with various First Nation governments / representatives, stakeholder meetings, etc." is also overly broad and is not directly relevant to understanding whether costs for this project were reasonable or prudently incurred.

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

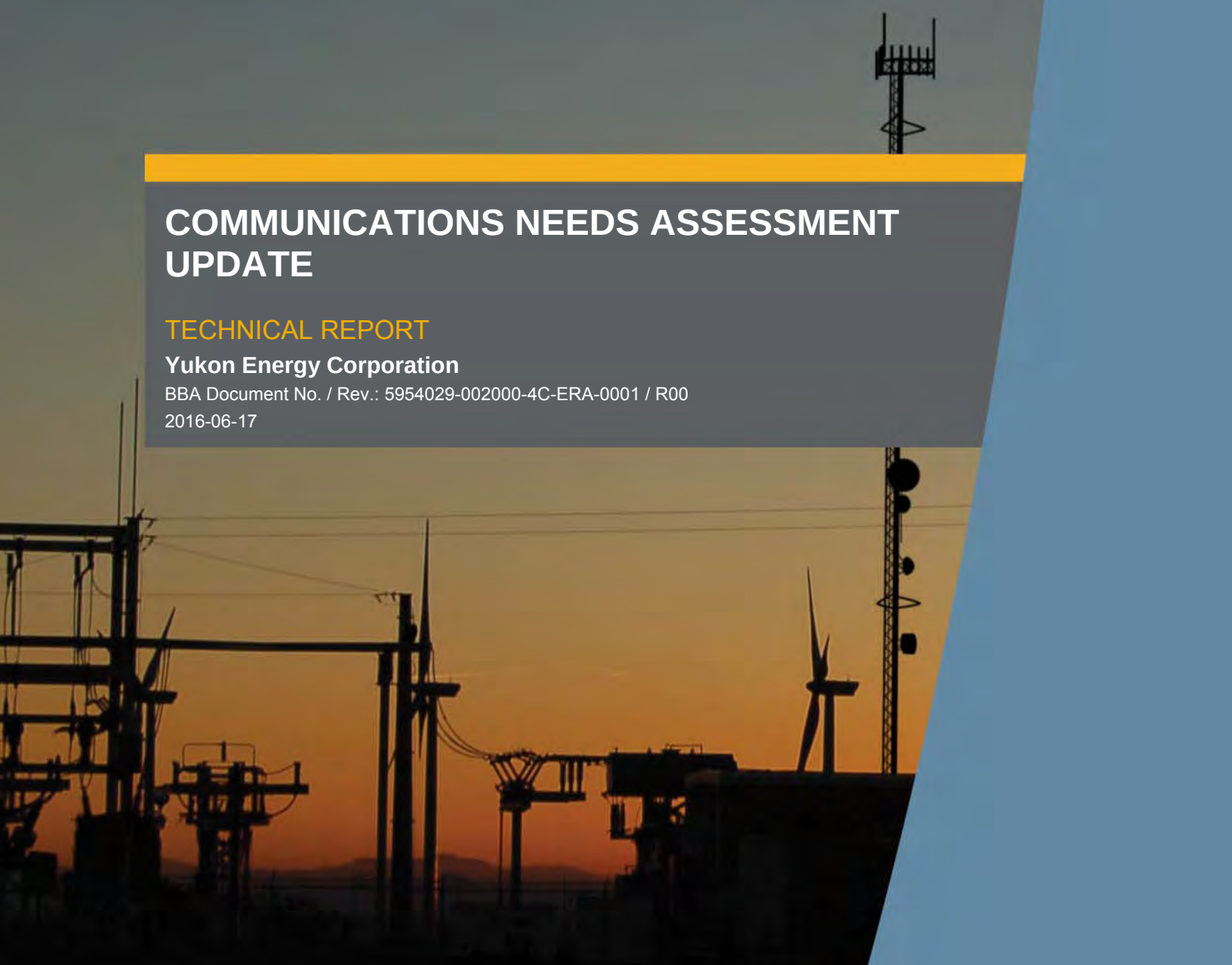
- Tab 5, section 5.2.1.4 provides a review of the project elements, justification and costs.

- YUB-YEC-1-67 – review of basis for this work, inclusion of costs in rate base in test years, and any cost changes.

- CW-YEC-1-37 & YCS-YEC-1-7– review of project benefits.

(d)

Please see UCG-YEC-1-16 Attachment 1, which provides the Executive Summary and Introduction for this report. The balance of the study has been excluded for IT security purposes.



COMMUNICATIONS NEEDS ASSESSMENT UPDATE

TECHNICAL REPORT

Yukon Energy Corporation

BBA Document No. / Rev.: 5954029-002000-4C-ERA-0001 / R00

2016-06-17

bba.ca

BBA

Yukon Energy Corporation
Whitehorse, YT

Technical Report
Communication Needs Assessment Update

BBA Document No. / Rev. 5954029-002000-4C-ERA-0001 / R00

June 17, 2016

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40-ERA-0002 / R01

REVISION HISTORY

Revision	Document Status – Revision Description	Date
R00	Final	2016-06-17

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Use of this Document acknowledges acceptance of the foregoing conditions.

EXECUTIVE SUMMARY

To YEC, the generation and distribution of electrical energy is the main source of income, which is why it is important to consolidate an operations network with high efficiency and availability levels. Over time, the technological platform was built to keep the desired service levels. However, the result of this evolution is that both environments (OT & IT) exist to support YEC operations, but they were not implemented in a unified way. Today YEC needs to maintain two different infrastructures, each requiring different technical skills and spare parts, which increases the costs to maintain it operational. Due to the mix of several technologies, The manageability and scalability of the infrastructure will be accomplished with efficiency levels that could be improved with a unified next-generation network.

Over time, new technologies have been released leading to the convergence of industrial and corporate networks. As a result, more efficient and secure networks are supported for a high performance telecommunication network.

Taking into consideration the fact that OT is the core business and that the telecommunications infrastructure is mission critical in supporting operations; the present document is a reference design that will help YEC make its transition into a unified next-generation network. Increasing performance and reducing losses related to problems on the network can be achieved by effective integration of new network technologies and a simplified infrastructure. The unified environment will settle the basis of future implementations and innovations, opening the door to concepts such as Smart Grid.

The adoption of best practices, such as NERC, help improve processes and have a positive impact on operations. The insertion of new technologies and a migration to a unified next-generation network, establishes the basis to adopt NERC practices or ones that better fit YEC's values.

BBA was mandated to conduct an update on the "Communications Needs Assessment" made in 2011. The work includes an analysis of the current communications infrastructure, a description of the available technology, and the optimisation options of the OT and IT infrastructure owned by Yukon Energy Corporation (YEC). The study will include an assessment of the current situation, future trends and recommendations.

To create the Reference Design, a revision of the recommendations and the actual implementation was conducted. As a result, a new view of the status of both networks appear and a strategic plan is developed. This new design is intended to improve critical elements, like SCADA features and performance, reliability, redundancy, and security.

The following are key focuses for the study:

- SCADA and remote data collection;
- Corporate data, voice and video communications;
- Cost effectiveness over life-cycle;

- Reliability and Redundancy;
- Security;
- Safety;
- Accessibility and availability;
- Future needs: new plants, future data collection strategies, bandwidth requirements, protocol migration, backup control center, disaster recovery.

The proposed reference design should be implemented in a transitional way by choosing the most critical assets and then including the less critical ones. In the end, this will cover the whole YEC operations system.

This design will include the V-Connect service from NwTel to deploy the solution. The MPLS service is a private infrastructure that will support the telecommunication needs of the OT network with high security levels and is separated from IT network services. A basic redundant system using the actual satellite infrastructure is proposed.

A Disaster Recovery Site (DRS) is critical for YEC's operations. Currently, the infrastructure based on serial links doesn't allow a truly seamless failover to the new site.

The new topology based on a MPLS network and satellite connections will allow YEC to plan and implement its Disaster Recovery Site, which could be placed anywhere. Furthermore, it will improve the effectiveness to recover and restore the service if a disaster occurs.

The unified next-generation network will be a new challenge to YEC's technological infrastructure custodians. In order to grant efficiency of this new network and benefit from new services, two different roles will appear during the process: OT network lead hand and IT network lead hand. In addition, training should be provided to custodians and leaders to help them better understand and take advantage of the new services of this unified network.

The costs reflected in this report are those required to upgrade telecommunications services in some areas. These seek to meet the needs of both the core and the redundant networks.

Since new services will allow remote administration and management of the OT network, the impact of investments will be reflected in the optimization of operational resources.

With an overall investment of 517K while keeping the same monthly costs, YEC will have a Technological platform of new generation. However, partial upgrades can be done to gradually achieve the final result. The initial investment of 50K corresponds to Whitehorse's upgrade plus the areas chosen to start the project, and the related monthly costs affected.

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1. INTRODUCTION

1.1 Purpose

The purpose of the Communication Needs Assessment is to provide YEC with a plan of evolution of its OT network that is supported in a robust telecommunications environment.

Based on the situation that YEC has different technologies to control and monitor its operations, including access to the corporate network, the study needs to be focused on the present aspects:

- SCADA system (remote data collection, control, metering, reliability and availability);
- Corporate network services;
- Cost effectiveness over life-cycle;
- Availability, reliability, accessibility and efficiency;
- Redundancy;
- Security;
- Future needs and scalability of the environment.

1.2 About BBA

BBA is an independent Canadian consulting engineering firm operating internationally. Its team is composed of highly-qualified experts in several engineering disciplines including electrical, civil, mechanical, industrial data processing, mining, metallurgical processes, automation, and construction management.

BBA is particularly active in the energy and mining and metals, and oil, gas and biofuels sectors.

Nowadays, the effect of telecommunications networks on a company's productivity has been proven, and industries in the electrical sector are no exception. BBA has proven experience in this sector and takes leadership roles to accompany their clients in the improvement and management of the OT/IT infrastructure. They help them to understand that the mission of the telecommunication infrastructure is to improve the efficiency, availability, management and troubleshooting of the electrical network.

1.3 Scope

The Communications Needs Assessment included the following communication systems:

- SCADA system;
- SCADA network communications support;
- Access to intranet services;
- Wide Area Network (WAN) technologies;
- Unified communications systems (voice, video and data);
- Access control system;
- Intranet services;
- Internet access.

The assessment looked at the following aspects:

- Evaluation of the previous report;
- Projects developed during the last five years;
- Actual status of the OT network;
- Present data network technology and topology;
- Operational and maintenance costs;
- Client needs analysis;
- Problems with the existing systems and critical assets;
- Anticipated needs for future projects.

1.4 Methodology

This report is based on a four-stage approach to the Communication Needs Assessment:

- Revision of the project status proposed in BBA`s previous report;
- Audit of the current communication system using documentation obtained from YEC, as well as meetings carried out with YEC IT, maintenance electricians, and SCC personnel;
- Definition of the client's needs based on information provided by the client, the service providers, and the available infrastructure;
- Development of a master plan to bring YEC's existing communication infrastructure in-line with the new communications strategy, and provide guidance for future projects and the predicted future industry trends.

TOPIC: **Hydro Unit #WH4 Overhaul ($4.3 million)**

REFERENCE: June 22, 2017 Application, page 5-15

PREAMBLE:

QUESTION:

a) Please provide a business case analysis for this project which contains details required pursuant to Board Orders 2009-8 and 2013-01.

b) Please confirm the total project cost from conception to completion and provide an annual breakdown by project component. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

c) Please provide a chronological history of all the decisions / approvals / consultations related to this project including Board of Director's decisions, all meetings with various First Nation governments / representatives, stakeholder meetings, etc.

d) Please provide details of the tendering process used to award Andritz Hydro the contract to install the new rotor spider and to perform the 10-year overhaul.

ANSWER:

(a), (b) and **(c)**

The business case for the project, including estimated costs, is provided in Section 5.2.1.5 of the Application. The project is forecast to be completed in 2017.

Please see response to YUB-YEC-1-68(a) for a current analysis of costs.

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process.

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization including consultants and different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is commonly across several different platforms (e.g. email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudency assessment. The request to provide a history of "all meetings with various First Nation governments / representatives, stakeholder meetings, etc." is also overly broad and is not directly relevant to understanding whether costs for this project were reasonable or prudently incurred.

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

- Tab 5 section 5.2.1.5 provides a review of the project elements, justification, and costs.

- YUB-YEC-1-68 – an updated review of costs now that the project is substantially completed, and other related information.

(d)

Please see response to YUB-YEC-1-68(d).

TOPIC: **Hydro Unit #MH2 Overhaul ($1.657 million)**

REFERENCE: June 22, 2017 Application, page 5-16

PREAMBLE:

QUESTION:

a) Please provide a business case analysis for this project which contains details required pursuant to Board Orders 2009-8 and 2013-01.

b) Please confirm the total project cost from conception to completion and provide an annual breakdown by project component. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

c) Please provide a chronological history of all the decisions / approvals / consultations related to this project including Board of Director's decisions, all meetings with various First Nation governments / representatives, stakeholder meetings, etc.

d) Please provide the analysis showing that the "continued operation of the Mayo A facility has been determined to be economic".

ANSWER:

(a), (b) and **(c)**

The business case for this project, including estimated costs, is provided in the Application at Section 5.2.1.6. The project is forecast to be completed in 2018.

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process.

As planning for this project is not complete, significant consultations have not been completed to date.

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

- Tab 5 section 5.2.1.6 provides a review of the project elements, justification, and costs.

- YUB-YEC-1-69 – reviews operation of Mayo A and B, the operation of the two Mayo A units, options reviewed, and other related questions.

(d)

Please see Appendix 5.6 of the 2016 Resource Plan report by KGS at link below.

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.6_Mayo_Hydro_Future_Facility_Options_Report_(KGS_2016).pdf

TOPIC: **T&D – Breaker Replacements ($1.35 million)**

REFERENCE: June 22, 2017 Application, page 5-18

PREAMBLE:

QUESTION:

a) Please provide a business case analysis for this project which contains details required pursuant to Board Orders 2009-8 and 2013-01.

b) Please confirm the total project cost from conception to completion and provide an annual breakdown by project component. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

c) Please provide a chronological history of all the decisions / approvals / consultations related to this project including Board of Director's decisions, all meetings with various First Nation governments / representatives, stakeholder meetings, etc.

ANSWER:

(a), (b) and **(c)**

The business case for this project, including estimated costs for work to be completed by the end of 2018, is provided in the Application at Section 5.2.1.7.

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process.

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization including consultants and different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is commonly across several different platforms (e.g., email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the

response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudency assessment. The request to provide a history of "all meetings with various First Nation governments / representatives, stakeholder meetings, etc." is also overly broad and is not directly relevant to understanding whether costs for this project were reasonable or prudently incurred.

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

- Tab 5 section 5.2.1.7 provides a review of the project elements, justification, and costs.

- CW-YEC-1-39 – review of end of life assessment.

TOPIC: **T&D – Line Replacement ($11.5 million)**

REFERENCE: June 22, 2017 Application, page 5-18

PREAMBLE:

QUESTION:

a) Please provide a business case analysis for this project which contains details required pursuant to Board Orders 2009-8 and 2013-01.

b) Please confirm the total project cost from conception to completion and provide an annual breakdown by project component. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

c) Please provide a chronological history of all the decisions / approvals / consultations related to this project including Board of Director's decisions, all meetings with various First Nation governments / representatives, stakeholder meetings, etc.

ANSWER:

(a), (b) and **(c)**

The business case for this project, including estimated costs for work completed to the end of 2018, is provided in the Application at Section 5.2.1.8.

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process.

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization including consultants and different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is commonly across several different platforms (e.g., email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the

response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudency assessment. The request to provide a history of "all meetings with various First Nation governments / representatives, stakeholder meetings, etc." is also overly broad and is not directly relevant to understanding whether costs for this project were reasonable or prudently incurred.

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

- Tab 5 section 5.2.1.8 provides a review of the project elements, justification, and costs.

- CW-YEC-1-40 – provides a copy of the external assessment, and other related questions.

TOPIC: **Wareham Spillway Gate Hoist Replacement ($2.7 million)**

REFERENCE: June 22, 2017 Application, page 5-21

PREAMBLE:

QUESTION:

a) Please provide a business case analysis for this project which contains details required pursuant to Board Orders 2009-8 and 2013-01.

b) Please confirm the total project cost from conception to completion and provide an annual breakdown by project component. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

c) Please provide a chronological history of all the decisions / approvals / consultations related to this project including Board of Director's decisions, all meetings with various First Nation governments / representatives, stakeholder meetings, etc.

d) Please provide the referenced International Quest Engineering study dated March 2014.

ANSWER:

(a), (b) and **(c)**

The business case for this project, including estimated costs, is provided in the Application at Section 5.2.1.9. The project was completed in 2015.

Project cost information is provided in Table 1 below.

Table 1: Wareham Spillway Gate Hoist Replacement Project Costs

($'000s)	2014	2015	Grand Total
Contractors, Materials & Services	1,189	1,376	2,564
YEC - Labour	26	45	71
YEC - Travel	8	11	18
YEC - Materials	2	5	7
YEC - AFUDC	3	36	39
Total Project Cost	**1,227**	**1,473**	**2,700**

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process.

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization including consultants and different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is commonly across several different platforms (e.g. email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudency assessment. The request to provide a history of "all meetings with various First Nation governments / representatives, stakeholder meetings, etc." is also overly broad and is not directly relevant to understanding whether costs for this project were reasonable or prudently incurred.

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

- Tab 5, Section 5.2.1.9 provides a review of the project elements, justification and costs.

(d)

Please see UCG-YEC-1-21 Attachment 1.

INTERNATIONAL QUEST ENGINEERING LTD.

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March 31st, 2014 File No. 0849–02–Rev C

YUKON ENERGY CORPORATION
P.O. BOX 5920 - #2 Miles Canyon Way
Whitehorse, Yukon Territory
Canada Y1A 5L6

Attn.: Mr. W.J.S. Haydock, P.Eng. – Supervisor, Mechanical Engineering

Re: WAREHAM LAKE SPILLWAY: GATE HOIST - LIFT SYSTEM OPTIONS

With respect to the *'Wareham Lake Spillway: Gate Hoist - Lift System Options'*, INTERNATIONAL QUEST ENGINEERING LTD. is pleased to provide YUKON ENERGY CORPORATION with ***'REVISED'*** summary of anticipated costs for the options / estimations provided earlier (May 14th, 2012 – Rev B / June 17th, 2009 – Rev C).

Should any questions arise concerning information, figures, or material presented, or if further requirements should arise that may benefit from our involvement, please do not hesitate in calling our office at any time. We look forward to our future potential involvement with YUKON ENERGY CORPORATION on this subject matter, or additional projects & requirements that may benefit from our past experiences.

Thank You.

Regards,

INTERNATIONAL QUEST ENGINEERING LTD.

Gerhard Mikolajczyk P.Eng.
Enclosures

INTERNATIONAL QUEST
ENGINEERING LTD.

WAREHAM LAKE SPILLWAY
GATE HOIST - LIFT SYSTEM OPTIONS

SUMMARY

March 22nd, 2014 - Revision C
(May 14th, 2012 - Rev B)
(June 17th, 2009 - Rev A)

Submitted to:

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Gerhard Mikolajczyk P.Eng. – Project Engineer

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1.0 DETAILED SUMMARY:

1.1 INTRODUCTION:

On Tuesday May 25th 2009, Gerhard Mikolajczyk P.Eng. of INTERNATIONAL QUEST ENGINEERING LTD. (IQE) met and discussed with William (Bill) Haydock P.Eng. of the YUKON ENERGY CORPORATION (YEC) various available beneficial upgrade / improvements options - to the existing gate lift system at the Wareham Lake Spillway.

It was discussed that either an 'existing / renovated' or 'alternative / upgraded' *Gate Lift System* would be considered as acceptable options at the existing Wareham Lake Spillway – and improvements were to be considered due to the age and inefficiency of the existing arrangement. Discussion of options for consideration involved: new design configuration similar to the *'Screw Lift Gate System'* used in 'Whitehorse Rapids Development' (replacement of the existing winch/cable configuration) or, suggestions on alternative options. IQE Ltd. had agreed to collect & assemble budget quotes / estimates for a new angle drive '*Screw Lift Gate System'*, as well as offer suggestions on alternative options.

1.2 WAREHAM LAKE SPILLWAY (see picture on previous page):

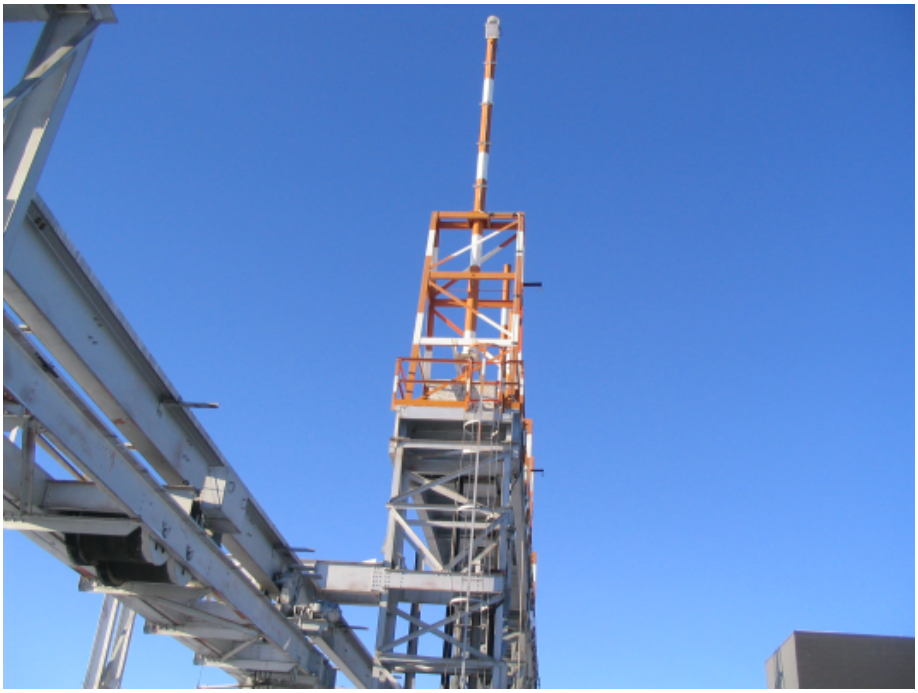
The Wareham Lake spillway was built in the early 1950's. The generation facilities main function is to supply power to Dawson City - to displace the dependency of the previous *'Diesel Power Plants'*.

Replacement options for the existing '*Gate Lift System'* is desired to be investigated due to the age of the existing (60 years old) system, and due to potential / pending issues – Eg.: When opening the gate in cold weather conditions, there is a potential for the gate to 'freeze / seize' in a closed position. If there were a situation whereby the gate was 'stuck' in the closed position, there would be a lack of dam water level control. It is also felt that the existing 'cable/winch' system does not have the capacity to overcome the forces that may be experienced in a harsh ice built-up winter (jam) condition. It has been estimated that if the gate were 'stuck / closed', only a 72 hour window would be available to open the gate before the lake level rises above the dam. Within 72 hours, and in a 'jam' situation, alternate equipment would have to be brought on site in order to 'thaw / free' the gate and force the gate to the opened position.

1.3 WHITEHORSE EXAMPLE (See reference picture on following page):

The 'Whitehorse Rapids Development' was built in mid-1950's - to replace existing Whitehorse facility *'Diesel Power Plants'*. The 'Gates' are presently controlled with an upgraded '*Screw Lift Gate System'*- the system uses two 46'-0" Lg. (ACME) threaded rods which are attached to the top of (and lift up or push down) the existing gates. The threaded rods pass through a hoist unit gear box, which in turn are 'driven'- thus allowing the gates to (positively) travel up or down. The hoist unit / gear boxes are right angle bevel gear units (one per screw) driven by a center drive unit (motor & reducer unit). When the gate is in the up position, the screw is raised above the structure, with a pipe sleeve and support structure required to support / shield the screw. The support structure and pipe sleeve is equal to the length of the screw (46'-0"), and is on top of the gate structure. The center drive unit is housed in a small building to protect against the harsh weather conditions (see following reference pictures).

Whitehorse Rapids Development Site



Pipe Sleeve / Drive Guarding and Support Structure

2.0 ALTERNATIVES:

2.1 OPTION 1: REPLACE WITH A NEW SCREW / ANGLE DRIVE SYSTEM

The initial option for consideration was to replace the existing *'Cable / Winch System'* with a new *'Screw Lift Gate System'*. The advantage of the *'Screw Lift Gate System' (*versus the standard *'Cable / Winch System')* is such that the gate would be 'balanced / powered' (positively) in both the up and down direction. The existing cable system presently depends on gravity to lower the gate – and often (as explained), the existing gate must have additional ballast added in order to increase the weight (for down direction). The screw system would allow for better control of the spillway water level and have available, additional 'drive' capacity as required, to open (or close) the gate in cold weather conditions.

Preliminary quotes were received in a recent inquiry submitted to various experienced suppliers. The preliminary investigation requested the supply of a complete design / supply / install package. Suppliers were to include: new screws, gate connections, pipe sleeves, hoist units, top frame mount components, a housing enclosure for the center drive unit for both gates, & design / engineering of the new system, complete (less final power supply & connection by YEC).

Estimations provided, concluded the following:

OPTION #1 (Area 1): $ 1.8 M
(2 Gates)

Additionally, it is expected that the existing (lattice / baton) support towers would require remedial upgrade improvements due to the additional component loads and design code upgrade requirements. IQE has suggested (based on preliminary review) that the following be allowed for these anticipated improvements:

OPTION #1 (Area 2): $ 0.2 M
(2 Gates)

Thus the preliminary revised estimate is as follows:

OPTION #1 GRAND Total Est: $ 2.0 M
(2 Gates)

2.0 ALTERNATIVES: Con't

2.2 OPTION 2: UPGRADE / REPLACE EXISTING WINCH & RE-USE CABLE SYSTEM

The second available option for consideration is: replacement / upgrade of the existing *'Cable / Winch System'* - with new / updated winch drives, leaving the existing cable system / operating method intact. The new winch system would be designed to provide more 'capacity' allowance (with built in break motor) - to overcome anticipated cold weather conditions. More importantly, the new components would replace outdated 60 year old existing mechanical items – with more modern and readily available components. (For example: The present Radicon 'BU' winch reducer has since been updated in the '70's to 'AU' units – and today Radicon worm gears are seldom used due to inefficiencies.)

A quote was again requested and subsequently provided (for budgeting purposes) – the scope, to supply a complete winch package, including: new / modern integral winch break motor / reducer, drive, and necessary equipment bases. The new bases are anticipated to be installed in the existing 'winch houses', coordinated with the location and components of the existing cable lift system. International Quest Engineering Ltd (IQE) would be most willing to potentially assist in coordination of modifications to the existing system as well as assist with potential modifications to the existing structure (to suit the new winch drive arrangement) – with budget allowance considered for this requirement.

The quote for the New Screw Hoist System is broken down as follows:

- 15 HP Hoist Rated Motor / Parallel Shaft Gear Reducer (no open gearing)
- Hoist Duty Motor Brake / Couplings /
- Grooved Hoist Drum / Drum Bearings
- Fabricated Base
- Limit Switches / Encoder
- Assembled and Shop Tested

The total budget for **'Option 2: Replace with New Winch / Drive System'** would be:

OPTION #2 Budget Estimate: $ 600 K
(2 Gates)

2.0 ALTERNATIVES: Con't

2.3 OPTION 3: NO CHANGE

A final option remains to simply leave the gate system as is - continue using and maintaining the existing antiquated winch drive and cable system. This would be the least expensive option, with only on-going testing / maintenance required – as exists today. This option would not improve the 'dependability' of water level control at the spillway and would not improve the ability to open the gate in cold weather conditions – nor would provide improvements to an antiquated system. Note: There is only an anticipated 72 hour window to open the gate before the water level rises above the dam; in this time, the gate would have to be thawed and raised by means of 'other' equipment brought on site, most likely from Whitehorse (5 hrs away).

OPTION #3 Budget Estimate: $ 0

3.0 REFERENCE

The following YUKON ENERGY CORPORATION drawings were provided for reference purposes:

2045-4DWG8 **Western Bridge & Steel Fabricators Ltd / Montreal Engineering Co.**
Lift Operating Mechanism Gates - Gears (April 4, 1952)

2045-E4 **Western Bridge & Steel Fabricators Ltd / Montreal Engineering Co.**
Lift Operating Mechanism Gates – Preliminary Layout (Jan 9, 1952)

The following INTERNATIONAL QUEST ENGINEERING LTD. drawings were also utilized for reference purposes:

0849-02-901-01D **WAREHAM GATE HOIST – NEW SCREW DRIVE – G.A.**
0849-02-901-02B **WAREHAM GATE HOIST – NEW SCREW DRIVE – ELEV & SECTION**
0849-02-901-03B **WAREHAM GATE HOIST – NEW SCREW DRIVE – ELEV & SECTION**

TOPIC: **Whistle Bend Supply/Takhini Upgrade ($11.383 million)**

REFERENCE: June 22, 2017 Application, page 5-22

PREAMBLE:

QUESTION:

a) Please provide a business case analysis for this project which contains details required pursuant to Board Orders 2009-8 and 2013-01.

b) Please confirm the total project cost from conception to completion and provide an annual breakdown by project component. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

c) Please provide a chronological history of all the decisions / approvals / consultations related to this project including Board of Director's decisions, all meetings with various First Nation governments / representatives, stakeholder meetings, etc.

ANSWER:

(a), (b) and **(c)**

The business case for this project, including estimated costs, is provided in the Application at Section 5.2.1.10. The project was completed in 2015.

Project cost information is provided in Table 1 and Table 2 below. Please note that the cost information included in Tab 5 of the Application in Section 5.2.1.10 did not include 2012 spending of $0.153 as provided in Table 1 below. Actual total project costs are $11.537 as noted in table 1 below as not $11.383 as noted in Tab 5.

Table 1: **Whistle Bend Supply/Takhini Upgrade Project Costs**

Whistle Bend Supply / Takhini Upgrade	
	($'000s)
Building Modifications	116
Electrical (Panels & Wiring)	910
Civil Work	3,110
138kV Transformer	1,775
138kV Ring Bus	1,455
34.5kV Substation	1,151
SCADA	402
Diesel Costs	6
Construction Field Cost	8,925
Preliminary Engineering & Dsign	106
Detailed Engineering	1,011
Construction Management	395
YEC Owner Costs	661
Construction Financing Costs	438
Indirect Costs	2,611
Total Project Cost	**$ 11,537**

Table 2: **Whistle Bend Supply/Takhini Upgrade Costs by Year**

Spending by Year ($'000s)				
2012	2013	2014	2015	Total
$ 153	$ 5,134	$ 6,072	$ 178	$ 11,537

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process.

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization including consultants and different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is commonly across several different platforms (e.g. email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudency assessment. The request to provide a history of "all meetings with various First Nation governments / representatives, stakeholder meetings, etc." is also overly broad and is not directly

relevant to understanding whether costs for this project were reasonable or prudently incurred.

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

- Tab 5, Section 5.2.1.10 provides a review of project elements, justification and costs.

TOPIC: **LNG Plant ($41.933 million)**

REFERENCE: June 22, 2017 Application, page 5-22

Yukon Energy Blog - Why Energy Conservation April 8, 2015
Stated: "The natural gas plant is being built purely as back-up, to be used during emergencies or during cold periods when we don't have enough renewable power to meet demand."

PREAMBLE:

QUESTION:

a) Please confirm the total project cost from conception to completion and provide an annual breakdown including the costs of feasibility studies, engineering, internal and external labour costs. Please include details of all tenders awarded related to this project. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

b) Please provide a table showing forecast and actual costs of this project by component as cost estimates have been adjusted (i.e., project cost approved by YEC Board of Directors, Part 3 application cost estimate, project cost updates provided in IR responses, costs approved by YUB, etc.).

c) Please provide a table showing how this project has reduced costs charged to ratepayers and describe where these savings are reflected in the applied for revenue requirements for 2017 and 2018. Included in this analysis, please show savings in fuel costs to date and through the test years.

d) Please provide a table showing longer terms costs and benefits of this project under various load and generation / water level scenarios.

e) Please provide a chronological history of all the decisions / approvals / consultations related to this project including Board of Director's decisions, all meetings with various First Nation governments / representatives, stakeholder meetings, etc.

f) Please explain when and how the LNG generation has been used in light of YEC's previous arguments that it would only be used as backup to other generation.

g) Please confirm that the LNG back-up plant will not be used to supply electricity to industrial (mine) loads that will be added in the short or long-term.

ANSWER:

(a) through **(e)**

The total project cost of $41.93 million (prior to the $18.3 million YDC contribution) is reviewed in section 5.2.1.11 of the GRA Application, including the following summary of factors accounting for the $5.45 million cost increase since the 2014 Part 3 LNG proceeding (please see the Application for added detail under each item):

1. Construction contracts ($31.59 million): $4.09 million increase over the Part 3 hearing estimate of $27.5 million.

2. Engineering and Management ($5.02 million): $1.54 million increase over the Part 3 hearing estimate of $3.48 million.

3. Owner's Costs ($3.03 million): $0.6 million increase over the Part 3 hearing estimate of $2.43 million.

4. Planning & Permitting ($2.69 million): $0.18 million increase over the Part 3 hearing estimate of $2.51 million

5. Demolition (no cost included): The Part 3 hearing cost estimate of $0.55 million has been redefined as a post project construction activity not required to operate the new facility.

6. Other Activities (no cost included): Costs for work on LNG transportation ($0.33 million) have been moved to feasibility studies. Costs for First Nation benefits ($0.09 million) are to be paid by YEC with offset funding by YDC.

Please see response to John Maissan-YEC-1-27 for a review of the LNG Plant costs and related estimates provided during the Part 3 LNG Application review and the updated

costs and related estimates in the current GRA. The response updates Figure 3-1 from the 2013 filing to show how this project has reduced annual YEC costs (including fuel costs) relative to the new diesel alternative since 2015 and the forecast ratepayer cost reductions for 2017 and 2018 test years.

YEC's annual fuel costs are based on LTA hydro and thermal generation for actual grid loads, and therefore are not affected by varying water level/ availability scenarios for specific years. Please see Attachment 3.4.2 of the GRA Application for a review of potential LTA thermal generation variability for a range of grid load scenarios. Ratepayer cost savings from the LNG Project are tied to savings from displaced diesel generation, which in turn are tied to overall grid loads (i.e., LNG Project cost savings increase with higher loads) and the extent to which other resource option development occurs (i.e., LNG Project cost savings decrease with other resource development that reduces LTA thermal generation at any given load).

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization including consultants and different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is commonly across several different platforms (e.g. email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudency assessment. The request to provide a history of "all meetings with various First Nation governments / representatives, stakeholder meetings, etc." is also overly broad and is not directly relevant to understanding whether costs for this project were reasonable or prudently incurred.

(f)

LNG generation has been used whenever feasible to displace higher fuel cost diesel generation that was otherwise required to meet grid loads (including for capital projects and RFID related requirements), as well as for maintenance of these thermal generation units.

(g)

LNG will be used in future when feasible to displace higher fuel cost diesel generation that would otherwise be required to meet grid loads (including industrial/ mine loads). A material share of any new loads at this time will be supplied by existing LTA hydro generation resources (see Table 3.4-1 in the GRA Application, which indicates the share of new load [in 5 GW.h increments] to be supplied by LTA thermal generation with existing hydro resources as loads increase from current GRA forecasts [about 420 GW.h/year] up to 485 GW.h/year). The 2016 Resource Plan identifies various resource projects that are being examined to enhance hydro and other renewable generation availability within the next decade.

TOPIC: **LNG Third Engine ($6.2 million)**

REFERENCE: June 22, 2017 Application, page 5-26

PREAMBLE:

QUESTION:

a) Please provide a business case analysis for this project which contains details required pursuant to Board Orders 2009-8 and 2013-01.

b) Please confirm the total project cost from conception to completion and provide an annual breakdown by project component. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

c) Please provide a chronological history of all the decisions / approvals / consultations related to this project including Board of Director's decisions, all meetings with various First Nation governments / representatives, stakeholder meetings, etc.

d) Please identify all regulatory approvals that have been received specifically for the LNG Third Engine project.

ANSWER:

(a), (b) and **(c)**

The business case for this project, including estimated costs, is provided in the Application at Section 5.2.1.12. The project is forecast to be completed in 2019.

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process.

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization including consultants and

different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is commonly across several different platforms (e.g. email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudency assessment. The request to provide a history of "all meetings with various First Nation governments / representatives, stakeholder meetings, etc." is also overly broad and is not directly relevant to understanding whether costs for this project were reasonable or prudently incurred.

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

- Tab 5 section 5.2.1.12 provides a review of the project elements, justification, and costs.
- YUB-YEC-1-71 – Updated costs for the project.
- CW-YEC-1-41 – The 2016 Resource Plan justification for the project, review of options, and related information.
- John Maissan-YEC-1-28 – The basis for looking at options, and dependable energy and capacity of the project.

(d)

The YESAB and *Public Utilities Act* Part 3 regulatory reviews were completed for this project. Permit amendments will be required under the *Environment Act* (air emissions permit) and the *Yukon Oil and Gas Act* (LNG facility licence).

TOPIC:

REFERENCE: June 22, 2017 Application, page 5-28
YEC states "Growth in net rate base reflects ongoing need to refurbish old assets and improve grid reliability. Significant re-investment in existing infrastructure has been undertaken since 2013 to ensure that the Yukon integrated grid can continue to meet the unprecedented level of growth on the system in a safe and reliable manner".

June 22, 2017 Application, Table 2.1, page 2-17
Total kWh sales are forecast to increase from 388,363 MWh in 2013 to 398,582 MWh in 2018 which equates to a less than 1.3% total growth over 5 years.

PREAMBLE:

QUESTION:

a) Please explain how 1.3% in total growth in sales over 5 years can be considered to be "unprecedented".

b) Please provide a table of capital projects that have been undertaken since 2013 that have been required to meet system growth. This table should include a description of the project, justification for the project due to system growth, total actual / estimated costs and date of completion.

ANSWER:

(a)

Please see response to YUB-YEC-1-72(a). The sentence should be amended as follows for the current GRA: "Ongoing re-investment in existing infrastructure ensures that the Yukon integrated grid can continue to meet loads on the system in a safe and reliable manner."

(b)

The Application classifies in Tab 5 the major projects (as well as projects in cost range of $0.1 to $1.0 million) undertaken since 2013 required to meet capacity shortfalls, primarily due to retirement of existing thermal units (rather than due to system growth).

TOPIC:

REFERENCE: June 22, 2017 Application, page 5-28
YEC states "This Application includes approximately $6.3 million of earlier deferred overhaul costs being bought into the property, PP&E capital works rate base as of January 1, 2017. No spending on overhauls is included for the test years".

PREAMBLE:

QUESTION:

a) Please explain why deferred overhaul costs must be added to rate base starting in 2017.

ANSWER:

(a)

Deferred overhaul costs are being added to rate base starting in 2017 because the Board directed in the last GRA that these costs be held in WIP until the next GRA, and the planned work has been completed.

TOPIC: **WAF Transmission Upgrades**

REFERENCE: June 22, 2017 Application, Appendix 5.3, page 5.3-7

PREAMBLE:

QUESTION:

a) Please provide a business case analysis of the $3.1 million in projects under this category between 2013 and 2016.

b) Please provide details of the projects to be undertaken pursuant to the $850,000 annual budget for these projects in 2017 and 2018.

ANSWER:

(a) and **(b)**

The amount for WAF Transmission Upgrades is not a single project, but reflects ongoing capital work to replace end-of-life components. A consultant conducted an assessment of pole condition and made recommendation for replacement of end-of-life components on a priority basis. The work referenced addresses the issues raise in that report. No other specific project business case is available.

The forecast spending of $0.850 million for 2017 and 2018 is prepared based on the most recent actual year spending which were at $0.892 million in 2015 and $0.881 million in 2016. This includes upgrades and replacement of components of the transmission line.

TOPIC: **Customer Extensions**

REFERENCE: June 22, 2017 Application, Appendix 5.3, page 5.3-8

June 22, 2017 Application, Table 2.1, page 2-17
Total customers increased from 2029 in 2013 to 2098 in 2016 which equates to 69 additional customers over 5 years. Forecasts include an additional 16 customers being added in 2017 and another 12 customers in 2018.

PREAMBLE:

QUESTION:

a) Please provide details of the $2.44 million in customer extensions costs over the 2013-2016 period as it is related to the additional 69 customers.

b) Please provide details of the projects to be undertaken pursuant to the $475,000 annual budget for these projects in 2017 and 2018 to accommodate the additional 28 customers.

ANSWER:

(a)

Details of the $2.44 million in customer extensions are below. Note that customer extension costs include projects for both new and existing customers and are offset by customer contributions of $1.91 million.

Table 1: Customer Extension Costs

($000's)	2013	2014	2015	2016	Total
Projects greater than $100,000					
Dawson Airport Underground Phase 2	-	-	354	31	385
Dawson Airport Upgrade Phase 1	3	278	-	-	281
YTG Ice Melt	-	4	156	-	160
Mayo C6 Subdivision Phase 2	-	142	-	-	142
Dawson C4 Subdivision Phase 2	-	-	1	134	135
	3	423	511	165	1,102
Projects less than $100,000	300	326	299	413	1,339
Total Customer Extensions	303	750	810	578	2,441

(b)

The forecast of $475,000 in customer extensions in each of 2017 and 2018 is a placeholder forecast because it is not feasible to forecast the volume, size or complexity of requested customer connections in 2017 and 2018. Note that the Application further assumes that $400,000 of this capital work will be offset by customer contributions. This forecast is consistent with the forecast in the 2012/2013 YEC GRA

TOPIC: **Building Condition Report Response**

REFERENCE: June 22, 2017 Application, Appendix 5.3, page 5.3-9

PREAMBLE:

QUESTION:

a) Please provide a copy of the referenced 2016 consultant report and details of the total cost of this report.

b) Please details of the projects included in the $299,000 budget for 2018 and related references within the consultant's report.

c) Please provide justification for undertaking all of these projects in 2018.

ANSWER:

(a)

Please refer to John Maissan-YEC-1-37. The cost of the report was $104,405.

(b)

Please see Table 1 below.

Table 1: Projects & references to Building Condition Report

Location	System	Report Reference	Cost
Aishihik Staff House	Study - Freeze Ups	Aishihik pg 13 A02.6b	$ 11,000.00
833 - 6th Ave	Study - Structural	Dawson pg 54 Imm.4C	$ 3,000.00
1136 - 5th Ave	Study - Structural	Dawson pg 54 Imm.5D	$ 5,000.00
Faro Office FD1	Fire Alarm Panel / Detectors Replacement	Faro pg 82 E06.1a & E06.2a	$ 13,800.00
Faro Plant FD7	Fire Alarm Panel / Detectors Replacement	Faro pg 82 E06.1b & E06.2b	$ 14,500.00
Mayo Office	Fire Alarm Panel / Detectors Replacement	Mayo pg 102 E05.1A & 103 E03.1A	$ 10,500.00
Lot 8 Airport Drive	Study - Water Leaks	Mayo pg 27 Imm.1E & A06.1E	$ 7,000.00
Mayo Office	Study - Roofing	Mayo pg 35 Imm.2A	$ 5,000.00
Mayo Office	Heattracing Roof/Gutters	Mayo pg 37 Imm.3A & pg 35 R01.1A	$ 18,500.00
Lot 1088 Airport Drive	Building Envelope	Mayo pg 38 Imm.5D	$ 5,150.00
Mayo Office	Study - Structural	Mayo Pg 54 Imm.6A	$ 5,000.00
Mayo Office	Structural	Mayo pg 54 S01.1A & pg 55 S02.1A	$ 20,000.00
Lot 8 Airport Drive	Study - Freeze Ups	Mayo pg 70 Imm.11E & M01.2E	$ 5,500.00
Mayo Office	Study - HVAC	Mayo pg 76 M03.1A	$ 5,000.00
Block 8 Airport Drive	Fire Alarm Panel / Detectors Replacement	Mayo pg 80 Imm12.B & pg 103 Imm21.B	$ 1,550.00
Whitehorse Fish Ladder	Study - Roofing	WH Fish pg 24 Imm.5B	$ 2,500.00
Whitehorse Fish Ladder	Waterproof exterior load bearing walls	WH Fish pg 40 S06.2B	$ 50,000.00
Whitehorse Fish Ladder	Study - Structural	WH Fish pg 41 Imm.7B	$ 3,000.00
Whitehorse Fish Ladder	Fire Alarm Panel / Detectors Replacement	WH Fish pg 66 Imm.11B	$ 1,550.00
Kulan Warehouse	Heattracing Roof/Gutters	WH Kulan pg 19 R01.2a	$ 4,400.00
Whitehorse Office	Fire Alarm Panel / Detectors Replacement	WH Office pg 95-96 E05.1A & E05.3A	$ 46,350.00
Whitehorse IT Trailer	Fire Alarm Panel / Detectors Replacement	WH Office pg 95-96 E05.1B & E05.3B	$ 8,350.00
Whitehorse Electrician Office	Fire Alarm Panel / Detectors Replacement	WH Office pg 95-96 E05.1C & E05.3C	$ 9,400.00
Whitehorse Drafting Trailer	Fire Alarm Panel / Detectors Replacement	WH Office pg 96 E05.1D & E05.3D	$ 6,300.00
Whitehorse - Diesel Plant / P126	Replace Front Gate	WH Plants pg 11 A01.10a	$ 17,200.00
Whitehorse - WH4 / P127	Study - Water Leaks	WH Plants pg 18 RAI.1b & A06.5b	$ 5,000.00
Whitehorse - Diesel Plant / P126	Downspouts	WH Plants pg 22 R01.3a	$ 5,500.00
Whitehorse - Diesel Plant / P126	Study - Structural	WH Plants pg 35 RAI.3a & S05.1a	$ 5,000.00
Whitehorse - Diesel Plant / P126	Study - Ventilation	WH Plants pg 48 RAI.7a & M.04.2a	$ 4,000.00
			$ 299,050.00

(c)

Justification is included in the report provided in John Maissan-YEC-1-37 Attachment 1. Please see also the references provided in (b).

TOPIC: **Dawson Derrick Digger**

REFERENCE: June 22, 2017 Application, Appendix 5.3, page 5.3-9

PREAMBLE:

QUESTION:

a) Please provide a business case analysis for the replacement of this truck and digger including avoided maintenance costs.

b) Please provide details of the impact of delaying this replacement until 2019 or 2020.

ANSWER:

(a) and **(b)**

The average annual repair and maintenance cost for this unit from 2014-2016 is $18,500. A major overhaul of a number of components would be required to maintain the unit at an acceptable level of reliability, resulting in a significant increase in annual repair costs. It is not feasible to continue using the unit in its current state of repair as the risk of a mechanical breakdown during an emergency or outage in Dawson is too high.

TOPIC: **Mayo Transient Trailer Unit**

REFERENCE: June 22, 2017 Application, Appendix 5.3, page 5.3-10

PREAMBLE:

QUESTION:

a) Please provide details on the impacts to Yukon accommodation, food and other service providers by replacing their services with the proposed trailer.

ANSWER:

(a)

YEC has not performed an analysis on the impacts to Yukon service providers of locating a transient staff trailer in Mayo. Please see also responses provided to CW-YEC-1-34(e), and YUB-YEC-1-87(f).

TOPIC: **Aishihik Relicensing ($2.899 million)**

REFERENCE: June 22, 2017 Application, page 5-31 and Table 5.3, page 5-56

PREAMBLE:

QUESTION:

a) Please confirm that the Work in Progress (WIP) treatment of these costs means that there will be no impact on rates paid by Yukon ratepayers in 2017 and 2018.

b) Please explain the difference between the $2.899 million cost identified at page 5-31 and the $8.9 million cost identified on Table 5.3 at page 5-56.

c) Please provide a detail breakdown by year of the $8.9 million costs shown on Table 5.3.

d) Please confirm that costs related to the Aishihik Relicensing will not be recovered in rates until approved by the YUB in a subsequent general rates application process.

e) If Aishihik Relicensing is being treated as WIP, why does Table 5.3 at page 5-56 indicate that there is accumulated amortization related to this project?

ANSWER:

(a) through **(e)**

As indicated on page 5-31, Aishihik Relicensing project is planned for completion in 2019 and the expected cost is approximately $2.899 million. For the 2017 and 2018 test years the project is expected to be in WIP with no impact to rate base or rates.

The expenditure of $8.9 million, amortization and accumulated amortization expenses for "Aishihik Relicensing" in Tables 5.3 through 5.8 relate to the previous relicensing processes to the end of 2009. These costs have been previously reviewed and approved by the Board for inclusion in rate base.

TOPIC: **Stewart - Keno City Transmission Line Project**

REFERENCE: June 22, 2017 Application, page 5-32

PREAMBLE:

QUESTION:

a) Please provide a detailed chronological list of costs incurred and decision points related to this project including a breakdown of the costs of incurred for feasibility studies, engineering, internal and external labour costs and tenders awarded related to this project. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

b) Please identify the source of all capital contributions to this project and provide related correspondence.

c) Please confirm that none of the costs incurred related to this project will be paid by Yukon ratepayers.

ANSWER:

(a), (b) and **(c)**

The costs incurred to date relate to work required to get the project to a shovel ready state as described in Section 5.3.1.1 of Tab 5. These costs are fully covered by a government contribution. For further information please see response to YUB-YEC-1-76 and YCS-YEC-1-17.

TOPIC: **Gladstone Hydro Enhancement Project ($4.521 million – project not proceeding)**

REFERENCE: June 22, 2017 Application, page 5-45

PREAMBLE:

QUESTION:

a) Please provide a detailed chronological list of costs incurred and go / no go decision points related to this project including a breakdown of the costs incurred for feasibility studies, engineering, internal and external labour costs and tenders awarded related to this project. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

b) Please provide a chronological history of all the decisions / approvals / consultations related to this project including Board of Director's decisions, all meetings with various First Nation governments / representatives, stakeholder meetings, etc.

c) Please provide meeting notes and correspondence related to discussions with Champagne and Aishihik First Nations and Kluane First Nation.

ANSWER:

(a), (b) and **(c)**

The costs incurred on this project are as follows:

Table 1: Gladstone Hydro Enhancement Project Costs

Labour	75,760
Consultants	3,326,138
Travel	17,121
Materials	147,820
AFUDC	762,346
Office Expense	890
Other	191,189
Total	$4,521,265

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process.

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization including consultants and different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is commonly across several different platforms (e.g., email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudency assessment. The request to provide a history of "all meetings with various First Nation governments / representatives, stakeholder meetings, etc." is also overly broad and is not directly relevant to understanding whether costs for this project were reasonable or prudently incurred.

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding, or other public proceedings, as follows:

- **2017/18 GRA:** Application, Tab 5 section 5.3.1.7 provides an update regarding project costs incurred since the 2012/13 GRA, the decision making process, and factors underlying the decision not to proceed with the project. Further information is available in the following interrogatory responses for this proceeding:
    - YCS-YEC-1-12 – discusses the identification of permitting issues for the project.

- **2012/13 GRA:** This project was extensively reviewed in the 2012/13 GRA review process and commented on by the Board in Order 2013-01. Section 5.3.1.2 of the 2012/13 GRA Application reviews the project concept, risks, costs and benefits, and review work undertaken to that point. Further information is available in the following interrogatory responses for this proceeding:
    - YECL-YEC-1-18 – 20-year Resource Plan: 2011-2030 recommendations regarding the project.
    - YUB-YEC-1-43 – various details relating to the project status and current stage of development. Provides a breakdown of costs for Gladstone Diversion to the end of 2011 (by task and by consultant).
    - YUB-YEC-1-40 – notes plan to reach a final determination regarding whether the project is feasible to pursue within the next 6 to 12 months based on discussions with local First Nations and regulators.
    - YUB-YEC-2-8 – discusses YEC's interactions with DFO and CAFN and decision making process for the project.
    - YUB-YEC-2-19 – provides a corrected full utilization LCOE is 5.7 cents/kW.h with estimated project cost at $40 million (2010$).
    - LE-YEC-1-25 and UCG-YEC-1-60.

TOPIC: **Marsh Lake Storage Project ($8.156 million)**

REFERENCE: June 22, 2017 Application, page 5-46

PREAMBLE:

QUESTION:

a) Please provide a detailed chronological list of costs incurred and decision points related to this project including a breakdown of the costs of incurred for feasibility studies, engineering, internal and external labour costs and tenders awarded related to this project. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

b) Please provide a chronological history of all the decisions / approvals / consultations related to this project including Board of Director's decisions, all meetings with various First Nation governments / representatives, stakeholder meetings, etc.

ANSWER:

(a) and **(b)**

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process. This project remains in WIP through the 2018 test year and has no impact on test year rates or rate base.

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization including consultants and different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is commonly across several different platforms (e.g., email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudency assessment. The request to provide a history of "all meetings with various First Nation governments /

representatives, stakeholder meetings, etc." is also overly broad and is not directly relevant to understanding whether costs for this project were reasonable or prudently incurred.

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding, or other public proceedings, as follows:

- **2017/18 GRA:** Application, Tab 5 section 5.3.1.8 provides an update regarding project costs incurred since the 2012/13 GRA. Further information is available in the following interrogatory responses for this proceeding:
  - YUB-YEC-1-84
  - YCS-YEC-1-10

- **2012/13 GRA:** This project was extensively reviewed in the 2012/13 GRA review process and commented on by the Board in Order 2013-01. Section 5.3.1.1 of the 2012/13 GRA Application reviews the project concept, risks, costs and benefits, and review work undertaken to that point. Further information is available in the following interrogatory responses for this proceeding:
  - YUB-YEC-1-42 - various details relating to the project status and current stage of development.
  - YECL-YEC-1-38 - additional details regarding capital cost expected and any additional generation upgrades needed.
  - YECL-YEC-1-18 - the Overview of the 20-year Resource Plan: 2011-2030 recommends completion of the required environmental, engineering and remediation studies related to the project in order to make a determination whether it is feasible and cost-effective to proceed.
  - YUB-YEC-2-7 and YUB-YEC-2-16.

TOPIC: **Mayo Lake Enhanced Storage Project**

REFERENCE: June 22, 2017 Application, page 5-47

PREAMBLE:

QUESTION:

a) Please provide a detailed chronological list of costs incurred and decision points related to this project including a breakdown of the costs of incurred for feasibility studies, engineering, internal and external labour costs and tenders awarded related to this project. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

b) Please provide a chronological history of all the decisions / approvals / consultations related to this project including Board of Director's decisions, all meetings with various First Nation governments / representatives, stakeholder meetings, etc.

ANSWER:

(a) and **(b)**

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process. This project remains in WIP through the 2018 test year and has no impact on test year rates or rate base.

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization including consultants and different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is commonly across several different platforms (e.g. email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudency assessment. The request to provide a history of "all meetings with various First Nation governments /

representatives, stakeholder meetings, etc." is also overly broad and is not directly relevant to understanding whether costs for this project were reasonable or prudently incurred.

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding, or other public proceedings, as follows:

- **2017/18 GRA:** Application, Tab 5 section 5.3.1.9 provides an update regarding project costs incurred since the 2012/13 GRA. Further information is available in the following interrogatory responses for this proceeding:
  - YUB-YEC-1-85
  - YCS-YEC-1-11

- **2012/13 GRA:** This project was extensively reviewed in the 2012/13 GRA review process and commented on by the Board in Order 2013-01. Section 5.3.1.4 of the 2012/13 GRA Application reviews the project concept, risks, costs and benefits, and review work undertaken to that point. Further information is available in the following interrogatory responses for this proceeding:
  - YUB-YEC-1-45 - various details relating to the project LCOE and costs.
  - YECL-YEC-1-18 - the Overview of the 20-year Resource Plan: 2011-2030 notes, in updated grid load scenarios Appendix A (page A-4), that more recent information suggests that this project's earliest in-service date is now winter 2014/15.
  - YECL-YEC-1-39
  - YUB-YEC-2-18

TOPIC: **Expenditures on Property, Plant and Equipment**

REFERENCE: June 22, 2017 Application, Tables 5.2, 5.3, 5.4 and 5.5

PREAMBLE:

QUESTION:

a) Please provide a table showing all projects and studies listed on Tables 5.2 - 5.5 with an indication whether the project is designed to meet peak demand or energy needs.

b) On the table provided in response to part (a), for the projects being added to rate base in 2013-2018, please provide evidence that YEC's Board of Directors performed a prudence review on the expenditures for each project to ensure that all costs incurred were prudent for that project.

ANSWER:

(a)

YEC generation projects typically address the supply of electricity for energy or capacity (or both) purposes. The remainder of projects are not directly related to energy or capacity; however, they are still critical for supporting the delivery of electricity to ratepayers.

The Application identifies major capital and deferred cost projects by the following groups, highlighting major projects designed specifically to meet capacity planning requirements (see Tab 5, Sections 5.2.1 and 5.3.1).

- Completion of Legacy Infrastructure Projects.
- Spending on Sustaining Capital.
- Spending to address Capacity Planning Requirements.
- Spending on planning to meet other potential Future Generation and Transmission Requirements.

(b)

The response to YUB-YEC-1-78(f) outlines YEC's Stagegate Project Development Framework, and notes that major projects are reviewed by the Board of Directors at each decision point referred to as "Stagegate". The GRA application fully explains, for review by the Yukon Utilities Board, the justification for significant projects being added to rate base.

TOPIC: YEC's distribution and transmission vegetation management policy

REFERENCE: June 22, 2017 Application, page 6-4 and Appendix 3.1 of Tab 3

PREAMBLE:

QUESTION:

a) YEC's policy states that the goal of the brushing program is to reduce reliability incidents caused by vegetation to an acceptable level at the lowest possible cost.
   i. Please describe YEC's understanding of an acceptable and sustainable level of reliability.
   ii. Please provide statistics showing reliability numbers since 2012 that have been impacted by YEC's vegetation management policy.
   iii. Has YEC identified high impact rights-of-way in which YEC's strategy will be to focus on performing vegetation management on an optimum cycle to better mitigate large outages, improve asset condition and realize the cost benefits?
   iv. Has YEC established a tactical maintenance program on lower impact rights-of-way in which YEC will manage vegetation using a flexible, risk-based approach that targets vegetation management on the worst performing and oldest assets in the inventory?

b) Please describe the "industry best practices" on which YEC operates its vegetation management program on a pre-determined cycle.

ANSWER:

(a)

(i)

YEC has a goal of achieving 10 or fewer controllable outages annually (under which vegetation caused outages are classified) and aims to sustain this on an ongoing basis.

(ii)

Tree caused outages by year are as noted in the table below.

Table 1: Tree Caused Outages

Year	Outages
2012	24
2013	22
2014	7
2015	8
2016	3

(iii)

Yes.

(iv)

Yes.

(b)

Please see Appendix 12.2 of YEC's 2012 – 2013 General Rate Application, pages 12.2-22 through 12.2-25. The 2012-13 GRA documents, including Appendix 12.2, are on the YUB website at the following link: http://yukonutilitiesboard.yk.ca/proceedings/yec-2012-general-rate-application/

TOPIC: **Updated Planning Cost Accounting Policy**

REFERENCE: June 22, 2017 Application, page 6.8 and Appendix 5.1

PREAMBLE:

QUESTION:

a) Please provide details of other jurisdictions that have allowed planning costs to be amortized as is proposed by YEC.

b) Please confirm that the updated planning cost accounting policy would not allow amortization to accumulate while a project was still within Work in Progress.

c) Under section 2.3(a) of the updated policy, please explain what is meant by the "or" at the end of the sentence "In this way, the Corporation minimizes the risk of spending capital dollars on unsupportable projects; or".

d) Please explain the choice of the 5-year and 10-year amortization periods based on project values for projects that are determined uneconomic. Please identify other jurisdictions where this practice is followed.

ANSWER:

(a)

Historically, in Yukon planning costs for studies that have been closed (or where there has been a decision not to proceed with a project) have been amortized over 5 years. Yukon Energy did not undertake an extensive study of planning cost amortization approaches in other jurisdictions. However, it is understood that treatment of planning study costs varies from jurisdiction to jurisdiction.

(b)

Amortization of deferred costs only occurs after studies are completed or a decision is made not to continue with the project and it is closed out. Costs are not included in rates until approved by the Board as part of a General Rate Application.

(c)

The “or” at the end of 2.3(a) is a typo and has no specific meaning.

(d)

The 5-year and 10-year amortization periods were included in the version of the planning cost accounting policy included as Appendix 5.1 in the 2012/13 GRA Application. Prior to the 2012/13 GRA, costs for deferred projects that were closed out were amortized over 5 years pursuant to the planning cost accounting policy that had been in place to that time. In the 2012/13 GRA Application, Yukon Energy sought Board approval of an amended Planning Cost Accounting Policy (see Appendix 5.1 of the 2012/13 GRA) that included specific transition provisions for costs in WIP that were to be closed out and amortized over the 2012 and 2013 test years. The transition measures were intended to mitigate rate impacts from 5-year amortization of existing WIP costs that were above $1 million.

While the planning cost policy included in the 2012/13 GRA was not approved by the Board, in Order 2013-1 the Board effectively applied the transition approach for projects over $1 million that were closed and included in rates at that time (e.g., Atlin and Geothermal). Yukon Energy in the current Application is seeking to apply this approach on an ongoing basis in order to continue to smooth out rate impacts when deferred cost projects over $1 million are closed out.

Yukon Energy is not aware of other jurisdictions where this practice is followed.

TOPIC: **Updated Demand Side Management (DSM) Accounting Policy**

REFERENCE: June 22, 2017 Application, page 6.8 and Appendix 5.2

PREAMBLE:

QUESTION:

a) Please provide details on the audit processes that have been completed on DSM efforts in 2013 through 2016.

b) Please provide details of YEC's DSM-related expenditures in 2013, 2014, 2015, 2016, 2017 and 2018 and their percentage of revenue requirement.

c) Please provide evidence of how YEC's DSM programming has "influenced electricity consumption patterns by reducing and/or shifting loads".

d) Please confirm that no DSM-related costs were recovered from Yukon ratepayers in 2013 through 2017.

e) Please provide a table showing a detailed breakdown of accumulated costs of DSM programs since 2013 and the related calculation of the amortized costs that will be added to rate base in 2017 ($2.694 million) and 2018 ($0.625 million).

ANSWER:

(a)

The inCharge program has been evaluated by an independent, third party evaluator in 2015 and 2016. These evaluation reports are based on the Evaluation, Measurement and Verification Plan filed with the YUB as an attachment to YUB-YECL-26(a) during AEY's 2013-2015 General Rate Application. The evaluation reports are provided as UCG-YEC-1-40 Attachment 1 and UCG-YEC-1-40 Attachment 2.

(b)

Annual DSM related expenses are outlined in YUB-YEC-1-80(f).

DSM-related expenditures were held in WIP as directed by the Board for the years 2013 to 2016, therefore, they have no impact on revenue requirement. Amortization of DSM-related expenditures commences in 2017. The percentage of revenue requirement is as follows:

	2017	**2018**
% of Revenue Requirement	0.5%	0.5%

(c)

The energy savings and coincident peak demand reduction that have resulted from the inCharge program are outlined in Table 2 of the both the 2015 and 2016 Evaluation Reports.

(d)

Not confirmed. While YEC DSM-related costs incurred to date have been held in WIP from 2011 through 2017 and have not been recovered from ratepayers, AEY DSM-related costs have been approved by the Board during that period and included in AEY rate riders.

(e)

For a detailed breakdown of accumulated costs of DSM programs since 2013 see YUB-YEC-1-80(f). Amortization of the DSM costs is shown below.

($000's)		**2017 Amortization**	**2018 Amortization**
DSM assets added to rate base January 1, 2017	2,484	248	248
DSM assets added to rate base December 31, 2017	210		21
DSM assets added to rate base December 31, 2018	625		
		248	269

August 3, 2015

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 6L3

Attention: Mr. Bruce McLennan, Chair

Re: Interim Evaluation Report - Demand-Side Management (DSM) Program Portfolio for the Yukon

Please find attached the Interim Evaluation Report for the Demand-Side Management (DSM) Program Portfolio as per our filing requirements of Board Order 2014-06. This report has been prepared by the utilities' staff with guidance, review and approval by an independent Evaluation Advisor, Iris Sulyma of Research 4 Results.

As the attached report clearly defines, the DSM Program has benefitted customers not only through financial relief from rebates, but also expanded customer's understanding of their own consumption and of the electricity system in the Yukon. In that respect, the utilities continue to support the concept of demand-side management as a resource in the future. The utilities note, however the specific direction from the Board in order #2014-06:

> *"Further the Board affirms it does not approve the program for the five year term requested and that the Utilities are to make a formal application to the Board before expanding the DSM program elements beyond that approved above or beyond 2015."*

The utilities intend to meet this fall to discuss plans for future programming as part of their respective business planning cycles. It is expected a letter communication defining these plans will be delivered to the Board after these discussions are concluded.

If you have any questions regarding the content within this report please do not hesitate to contact the undersigned.

Yours truly,

Ed Mollard
Chief Financial Officer
Yukon Energy Corporation

Jay Massie
Manager
ATCO Electric Yukon

Interim Evaluation Report

Demand Side Management Program Portfolio for the Yukon

31 July, 2015

Submitted to:
Yukon Utilities Board

Submitted by:
Yukon Energy Corporation
ATCO Electric Yukon

Executive Summary

inCharge is an electricity conservation program delivered to residential customers in the Yukon by the territory's electrical utilities, Yukon Energy Corporation and ATCO Electric Yukon. inCharge consists of three programs: the LED and Automotive Heater Timer Rebate Program, the Low Cost Energy Efficient Products Program and the Engagement, Education and Communication Program. These programs launched in October 2014 and have been well received by Yukoners.

This interim evaluation report will focus on updating the program's projected performance with the actual costs and reported energy savings achieved during the first seven months of the inCharge Program, as well as documenting learnings from the first programoffering and participant feedback. The program evaluation was completed by utility staff with guidance and review by an independent evaluation advisor. This method was chosen to keep costs at an appropriate level for the program while still ensuring that the evaluation was completed in an objective manner.

The Key Performance Indicator (KPI) results demonstrate that customers were engaged with the program; in particular the LED Lighting Program exceeded expectations. The total number of rebates redeemed by customers in year one was over 2800, surpassing the program target by over 1000 rebates. Additionally, customers reported a 93% satisfaction rate with the LED Rebate Program, 90% satisfaction rate with the Automotive Heater Timer Rebate Program and 95% satisfaction rate with the Low Cost Energy Efficient Products Program. The lifetime electricity savings achieved in 2014 were 9% higher than targeted and costs of the program delivery in 2014 were 9% lower than projected.

As directed by the Yukon Utilities Board, the program achieved an overall Ratepayer Impact Measure (RIM) ratio of 1. This shows that the program is neutral from a utility rate impact perspective. The programs also achieved a very high Participant Cost (PC) ratio and high Program Administrator Cost (PAC) ratio results, showing they are very beneficial to the participants of the program and the utilities, who are the administrators of the program. Most significantly, the program achieved a very high Total Resource Cost (TRC) ratio. This shows that in the context of the comparison with other electricity resource options, the conservation programs performed very well. The tests were conducted assuming a five year program term in order to remain consistent with methodology used in the original program filing.

Overall this evaluation has shown that the inCharge Program was well received by Yukoners, was cost effective and met or exceeded most Key Performance Indicators. The annual and lifetime electricity savings exceeded the forecast savings for the first year of program, was under the projected budget and delivered the results projected by the utilities.

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1 Program Summary

inCharge is an electricity conservation program delivered to residential customers in the Yukon by the territory's electrical utilities, Yukon Energy Corporation and ATCO Electric Yukon. inCharge consists of three programs; the LED and Automotive Heater Timer Rebate Program, the Low Cost Energy Efficient Products Program and an Engagement, Education and Communication Program. These programs launched in October 2014 and have been extremely well received by Yukoners.

2 Evaluation Context

This interim evaluation report will focus on updating the program's projected performance with the actual costs and reported energy savings achieved during the first seven months of the inCharge Program, as well as documenting learnings from the first program offering and participant feedback. This report will also assess the key performance indicators laid out in the program's Evaluation, Measurement and Verification Plan. The main goals of this evaluation is to ensure that the programs are performing as projected, that participants are happy with the program and to provide recommendations to improve program delivery and cost effectiveness.

This evaluation report will look at the results achieved by the inCharge Program from its launch in October of 2014 to the pause of the rebate program at the end of April 2015. In scoping the evaluation activities, it was recognized that the evaluation was taking place after a relatively short program delivery period. The decision to evaluate the inCharge Program at this time was in order to take advantage of the natural break in program delivery. This will ensure that learnings from the first program offering can be used to optimize the re-launch of the LED and Automotive Heater Timer Rebate Program and Low Cost Energy Efficiency Products Program in the Fall of 2015. It was also important to ensure that an evaluation of the programs was prepared for the Yukon Utilities Board in 2015.

The program evaluation was completed by utility staff with guidance and review by an independent Evaluation Advisor. This method was chosen to keep costs at an appropriate level for the program while still ensuring that the evaluation was completed in an objective manner. The evaluation included surveys of participants including cards from customers receiving low cost energy efficient products (n=63), and telephone surveys of customers receiving LED rebates (n=30) and automotive heater timers rebates (n=10).

3 Updated Cost Effectiveness Results and Program Performance

3.1 Cost Effectiveness Results

Table 1 below contains the target energy savings and costs for the inCharge program as presented in the Revised, Evaluation, Measurement and Verification Plan (December 3, 2014) Table 2 contains a summary of the updated energy savings and costs for the inCharge Program. These updated results are based on actual costs and deemed electricity savings for Year 1 and the first quarter of Year 2 and

updated projections based on the programs preliminary results for the second quarter of Year 2 through Year 5. The updates were completed in the excel-based Program Projections Model that has been used throughout the design of the program. A comparison of Tables 1 and 2 show how the programs performed in the first seven months of delivery in comparison to targeted performance. The details of the savings and costs are also discussed below in Tables 3 and 4. The following sections discuss how the actual results were incorporated into Table 2.

Table 1: Targeted Energy Savings and Costs[1]

Program Elements	Net Savings with T&D Losses							Utility Expenditure ($1,000s)							Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	1,337	5,484	5,484	5,484	5,484	23,271	Incentive:	$12	$51	$51	$51	$51	$216	6.2	5.2	20.2	1.2
	Annual MWh:	67	380	692	1,005	1,272	N/A	Non-Incen:	$82	$79	$81	$84	$83	$409				
	Coincident kW:	16	111	206	301	365	N/A	Total:	$94	$130	$132	$135	$134	$625				
Low-cost Energy Efficient Products	Lifetime MWh:	4,605	3,247	3,247	3,247	3,247	17,593	Incentive:	$78	$55	$55	$55	$55	$299	2.4	2.5	5.9	1.0
	Annual MWh:	424	723	1,021	1,225	1,457	N/A	Non-Incen:	$121	$172	$177	$183	$188	$841				
	Coincident kW:	113	192	272	288	323	N/A	Total:	$199	$227	$233	$238	$243	$1,140				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	$103	$118	$121	$125	$129	$596				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$103	$118	$121	$125	$129	$596				
Total for the Residential Program	Lifetime MWh:	5,942	8,731	8,731	8,731	8,731	40,864	Incentive:	$90	$106	$106	$106	$106	$515	2.7	2.6	9.6	1.0
	Annual MWh:	491	1,102	1,714	2,230	2,730	N/A	Non-Incen:	$306	$369	$380	$392	$400	$1,847				
	Coincident kW:	129	303	478	589	688	N/A	Total:	$396	$475	$486	$498	$506	$2,362				

Table 2: Updated Energy Savings and Costs

Program Elements	Net Savings with T&D Losses							Utility Expenditure ($1,000s)							Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	2,362	6,129	6,115	6,115	6,115	26,838	Incentive:	$19	$51	$51	$51	$51	$225	6.1	5.8	12.3	1.3
	Annual MWh:	118	463	807	1,152	1,451	N/A	Non-Incen:	$77	$82	$84	$84	$84	$410				
	Coincident kW:	29	131	234	337	409	N/A	Total:	$96	$134	$135	$135	$135	$635				
Low-cost Energy Efficient Products	Lifetime MWh:	4,092	2,885	2,885	2,885	2,885	15,632	Incentive:	$71	$50	$50	$50	$50	$272	2.3	2.4	6.2	1.0
	Annual MWh:	379	646	913	1,085	1,285	N/A	Non-Incen:	$110	$171	$173	$173	$173	$801				
	Coincident kW:	104	178	252	262	290	N/A	Total:	$181	$221	$224	$224	$224	$1,073				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	$86	$116	$121	$125	$129	$577				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$86	$116	$121	$125	$129	$577				
Total for the Residential Program	Lifetime MWh:	6,454	9,015	9,001	9,001	9,001	42,470	Incentive:	$90	$102	$102	$102	$102	$497	2.8	2.8	8.8	1.0
	Annual MWh:	497	1,109	1,720	2,237	2,736	N/A	Non-Incen:	$272	$369	$379	$382	$386	$1,789				
	Coincident kW:	133	309	485	598	699	N/A	Total:	$363	$471	$480	$484	$488	$2,285				

3.1.1 Actual Costs

Cost estimates are divided by quarter in the Projections Model. The model was updated with actual costs for each quarter from the start of program launch preparation in third quarter of Year 1 (2014) up to the end of first quarter of Year 2 (2015). The projection of costs for the remainder of Year 2 through Year 5 was checked against actuals to ensure the program administrators felt they were still accurate estimates.

3.1.2 Reported Energy Savings

The energy savings attributed to the inCharge program are calculated using a deemed savings approach. An annual and lifetime energy savings is assigned to each type of product that is included in the program and documented in the Technical Reference Manual discussed below. The energy savings projected for the LED and Automotive Heater Timer Rebate Program was based on a target number of rebates issued

[1] See page 14 of Appendix A of *2014 Annual Report – inCharge Demand Side Management (DSM) Program Portfolio for the Yukon,* Filed with Yukon Utilities Board January 29, 2015

and also included an assumption of the mix of types of bulbs that customers purchased with their rebates. The energy savings projected for the Low Cost Energy Saving Products Programs was based on the number of each of the products the utilities distributed.

In calculating the reported energy savings for the Rebate Program, the actual number of rebates and types of each bulb were tabulated and the deemed savings as per the TRM were applied. The actual number of rebates and mix of types of products were used to update the projections going forward.

In calculating the reported savings for the Low Cost Energy Efficient Products Program, the number of products purchased and distributed were tabulated and the deemed savings as per the TRM were applied. The variation from projected savings to actual savings was minimal with this program as the purchasing decisions were in the control of the program administrators.

3.1.3 Technical Reference Manual

A Technical Reference Manual (TRM) was created as a part of the Program Projections Model. The TRM is a simple document that summarizes the assumptions and inputs to the Program Projections Model related to costs and energy savings for each individual type of product included in the program. The TRM was updated in late 2014 as part of the work completed to launch the inCharge Program. In particular costs of LED bulbs were updated, as this parameter changes rapidly. The energy savings attributed to each type of product was also reviewed at that time. An example of the TRM entry for standard LEDs can be found in Appendix A.

While the energy savings that can be attributed to a particular product is quite straight forward to estimate, the behavior of customers in purchasing and installing the products is a much more complex and intangible parameter that is considered in the deemed savings. This is captured in the installation ratio and the Net to Gross (NTG) Ratio, discussed in the section below.

3.1.4 Installation Ratio

The installation ratio is an estimate of the percentage of program participants that have installed the product they received as part of an energy saving kit or purchased using a program rebate. As the product must be in use to produce the energy savings estimated, the installation ratio affects the amount of savings that can be claimed for the program. The installation ratio estimated for the program was confirmed through surveys with a sample of program participants.

3.1.5 Stipulated Net-to-Gross Ratio

The stipulated net-to-gross (NTG) ratio includes a mix of the installation ratio, discussed above, as well as the free ridership and spillover of the program. Free ridership accounts for the program participants that would have made the energy saving change without the program, but took advantage of the program anyway. On the other end of the spectrum is spillover. These are people who made the energy saving changes because they were influenced by the inCharge program in some way, such as by point-of-purchase information posters, but did not participate in the program by applying for a rebate. As discussed above, the installation ratio will be confirmed through interviews. The free ridership and spillover rates are a much more intangible and complex parameter to confirm. It is currently assumed

for the rebate program that free ridership and spillover will cancel each other out, as is a common practice. The low cost energy efficient products program includes only a spillover component. The confirmation of these parameters can only be achieved after the program has been running for a few years.

3.2 Key Performance Indicator Results

A set of key performance indicators (KPIs) and targets for each KPI were developed for each program. These KPIs are based on a logic model developed for each program. The logic model is a simple graphic and narrative that maps out the resources, activities and outcomes that are expected from each program and the linkages between those parameters that are expected to ensure the program is successful. The logic model for each program can be found in Appendix B. The KPIs are designed to test the performance of the linkages in the logic model. Tables 3 and 4 below report on how the programs are performing for each indicator and provide a brief commentary on each as appropriate. The first column references the linkage number to allow for reference to the programs logic model. Note that the results for Year 2 represent the progress made in Q1 and Q2 towards meeting the annual (2015) target.

Table 3: LED and Auto Heater Timer Program KPI Summary

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	
08	Utilities support EE workshops hosted by EE ambassadors	Suggested KPI(s): # workshops	Program documentation	-	20	2		In Q4 of 2014, 20 YEC staff acted as community ambassadors in Whitehorse and Dawson distributing kits
		# people attending workshops		-	80	8		in 2014, 80 members of the community were reached by the ambassadors and provided kits
11	Direct engagement with retail store managers	Suggested KPI(s): # of new store managers being engaged for the 1st time	Direct engagement & communication logs	20	30	-	-	In 2014, 30 new store managers throughout the territory were contacted prior to the start of the LED rebate program to encourage participation and to check available qualifying LED products.

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
		# of store managers contacted with program intel & updates		20	30	20	-	Contacts continued with the 30 new store managers during the first month of the LED rebate program to encourage participation. By November 2014 stores committed to participating had been identified and ongoing communication about the program continued for a total of 296 contacts to the end of 2014. In 2015, no new stores were added for the LED rebate and BHT Rebate was introduced with Home Hardware and Canadian Tire participating. Close contact was maintained with all participating retailers.
13	Utilities issue point of purchase materials for retail managers	Suggested KPI(s): # stores with POP materials	Program documentation	5	9	10	9	9 Retail stores received POP for a total of 514 pieces. This included rebate pads, collection envelopes, shelf talkers, bin markers, small and large posters, staff info sheets and brochures. In Q1 and Q2 of 2015, an additional 40 items were distributed to complement the existing POP material already in place. This included the addition of several pieces of material related to the new Automotive Heater Timer rebate program
		POP materials issued for all rebate-eligible products and refreshed as needed (Yes/No)		n/a	n/a	Yes	Yes	
14 & 23	Shoppers buy and install rebate-eligible products[1]	Suggested KPI(s): # of units claimed	Tracking System	1,722	2,831	7,167	2,585	Participation higher than projected in 2014 and on track to reach target in 2015

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
24	The LED lighting and automotive heater timer installations will yield long-term electricity and demand savings[2]	Suggested KPI(s): MWh of avoided lifetime electricity consumption	Estimate based on rebates processed	1,337	2,362	5,484	2,268	Lifetime savings higher than projected in 2014 and on track to reach target in 2015
		MWh of avoided annual electricity consumption		67	118	380		Annual savings higher than projected in 2014. 2015 results will be updated at the end of the year
		kW of avoided coincident electricity demand		16	29	111	63	Demand savings higher than projected in 2014 and on track to reach target in 2015
21 & 25	Participants receive a rebate[3]	Suggested KPI(s): $ of incentive disbursement for LED lighting and automotive heater timers	Tracking System	$12K	$19,817	$51K	$18,435	2014 incentive disbursements were higher than projected, however overall project budget was lower than projected. 2015 incentive disbursements are on track to reach target.
22	Shoppers learn about rebates through local media campaigns	Suggested KPI(s): # updates of web content	Tracking System	1	1	4	2	inCharge website created and launched October 1, 2014. Information on the Auto Heater Timer Rebate Program was added in early 2015, website was adjusted when rebates were paused in April 2015 and minor edits in response to customer comments completed.

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
		# newspaper/radio advertisements		1	4	1	7	2 radio ads created and aired 32 times in 2014. 4 radio ads were created and aired 77 times in Q1 and Q2 of 2015 2 newspaper ads designed and placed 22 in 2014 and text edited as needed for community events. 3 newspaper ads were created and placed 21 times in Q1 and Q2 of 2015
		# bill insert		1	0	1	0	bill inserts not used in 2014 and 2015
		# email blasts		1	0	1	1	email blasts not used in 2014, 1 e-mail blast in 2015
26	Participating shoppers will be satisfied by the products that they bought	Suggested KPI(s): % of rebates processed in time to show up on next utility bill (if applications comes in 10 business days before issuance of bill)	Tracking System	70%	99%	80%	99%	99% of the customers received the rebate on either their current bill or on the next month's bill. The remaining .5% of customers received a rebate on a bill which was 2 months from the product purchase. In all cases where the rebate was delayed it was caused by the rebate being processed 1-2 days after the customers' current bill had been processed for mailing. This was anticipated to occur in a small number of cases.
27	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	To be commented on in 2015 EM&V Process - see Part B
28	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	To be commented on in 2015 EM&V Process - see Part B
Part B -- To Be Visited, Checked and Reported On by Evaluators								

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
00	Externalities	Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	
08	Utilities support EE workshops hosted by EE ambassadors	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the workshop on average	Attendees	7/10	10/10	8/10		All Ambassador workshop participants surveyed found the information provided helpful
11	Direct engagement with retail store managers	Suggested indicator(s): % store managers who know the program	Store managers	-	-	100%	-	To be quantified in next Evaluation
		% of store managers contributed to at least one transaction	Tracking system	-	-	60%	-	To be quantified in next Evaluation
13	Utilities issue point of purchase materials for retail managers	Suggested indicator(s): % of shoppers who noticed POP materials	Shoppers and Participants	-	-	70%	83%	87% LED Rebate participants and 70% Auto Timer Rebate participants for a weighted average of 83%

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
		% of shoppers who agree that POP materials contributed to their decision to purchase a rebate-eligible product		-	-	50%	58%	57% LED Rebate participants and 60% Auto Timer Rebate participants for a weighted average of 58%
14 & 23	Shoppers buy and install rebate-eligible products	No evaluation indicator	-	-	-	-	-	
24	The LED lighting and automotive heater timer installations will yield long-term electricity and demand savings	No evaluation indicator	-	-	-	-	-	
21 & 25	Participants receive a rebate	Suggested indicator(s): % of participants who agree that the rebate contributed to them purchasing the energy efficient products rather than the base-case product	Participants	-	-	60%	LED 77% Timer 50%	Participants who rated the program influential or very influential in their decision to purchase the energy efficient product: LED Rebate - 77% Auto Timer Rebate - 50%
22	Shoppers learn about rebates through local	Suggested indicator(s):						

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
	media campaigns	% of shoppers who can recall one of the following: bill inserts, web content, or inCharge in the news	Participants & non-participants	-	-	70%	58%	58% of participants can recall media advertising
26	Participating shoppers will be satisfied by the products that they bought	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the overall rebate program	Participants	-	-	8/10	LED 93% Timer 90%	Percentage of participants who were very satisfied or satisfied with the program: LED Rebate - 93% Auto Timer Rebate - 90%
27	Word-of-mouth	Suggested indicator(s): % heard of the program positively from other past participants	Participants	-	-	30%	65%	65% of participants had heard of the program from others and 96% of those discussions were positive
		% heard of the program positively from past participants	Non-participants	-	-	10%	-	To be quantified in next Evaluation
28	Non-energy benefits	Suggested indicator(s):						

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
		1-to-10 scale, level of satisfaction with the lighting/automotive heater timer quality	Participants	-	-	9/10	LED 93% Timer 90%	Percentage of participants who were very satisfied or satisfied with their energy efficient products LED Rebate - 93% Auto Timer Rebate - 90%

Table 4: Low Cost Energy Efficient Products Program KPI Summary

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	
02	Utilities conduct outreach activities at community events	Suggested KPI(s): # of events w/Program booth	Program documentation	2	7	4	2	YEC conducted outreach at 3 events in their communities and ATCO conducted 1 public event in Whitehorse and three targeted distribution events in 2014. No additional community events were conducted in Q1 and Q2 of 2015 by YEC. In 2015, ATCO staff attended a community meeting in Old Crow and distributed 47 products to 23 customers. ATCO staff also attended a meeting at Yukon Research Center and distributed 90 products to 9 customers.
		# of kits distributed		40	220	60	222	In 2014, 31 kits were distributed at YEC Community events and 929 products were distributed to 189 customers at ATCO Whitehorse Events In Q1 and Q2 of 2015 5 kits were distributed at the YEC Office and 1253 products were distributed to 217 customers at ATCO.
04	Provide EE products free-of-charge	Suggested KPI(s):	Program documentation					

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
		# of kits/products distributed		300	356	180	222	In 2014, 31 kits were distributed at YEC Community events, 10 kits were distributed at stakeholder events, 100 kits distributed through ambassadors, 26 kits were distributed by community partners and 929 products were distributed to 189 customers at ATCO Whitehorse Events In Q1 and Q2 of 2015 5 kits were distributed at the YEC Office and 1253 products were distributed to 217 customers by ATCO staff.
04	Scorecard results will be analyzed	Suggested KPI(s): # of scorecards received	Direct engagement & communication logs	30	18	20	45	18 scorecards received by end of 2014. 45 additional scorecards were received in 2015.
08	Utilities support EE workshops hosted by EE ambassadors	Suggested KPI(s): # workshops	Program documentation	-	20	2	-	in 2014, 20 YEC staff acted as community ambassadors in Whitehorse and Dawson distributing kits.
		# people attending workshops		-	80	8	-	in 2014, 80 members of the community were reached by the ambassadors and provided kits.
10	Utilities' community engagement leads to 'behavior-based' electricity and demand savings	No associated tracked KPIs	-	-	-	-	-	

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
14 & 19	Shoppers buy and install low-cost EE products	No associated tracked KPIs	-	-	-	-	-	
20	The low-cost EE products will yield long-term electricity and demand savings	Suggested KPI(s): MWh of avoided lifetime electricity consumption MWh of avoided annual electricity consumption MW of avoided coincident electricity demand	Estimate based on free products provided	4,605 424 113	4,092 379 104	3,247 723 192	- - -	Savings slightly lower than projected due to lower than estimated installation rate. All savings for kits and products distributed to date are attributed to 2014 to align spending with savings. Savings in 2015 will be calculated for the second offering of kits/ energy efficient products.
26	Participants will be satisfied by the low-cost EE products	Suggested KPI(s): Scorecard feedback1-to-10 scale, level of satisfaction with the products	Tracking System	7/10	-	7/10	9.5/10	Percentage of participants who were very satisfied or satisfied with each product: LEDs - 96%, reflector LEDs - 100%, showerheads - 65%, powerbars 97%, DHW tank wrap - 100%, DHW pipe wrap - 100%, Auto heater timers - 100%, motion detectors - 100% for an average of 95%
05 & 27	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	See Rebate Program KPIs above (Table 3)
28	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	See Rebate Program KPIs above (Table 3)

15

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
Part B -- To Be Visited, Checked and Reported On by Evaluators								
00	Externalities	Done/Not-Done – report on externalities on an annual basis	Program documentation	Done	-	Done	-	
02	Utilities conduct outreach activities at community events	No evaluation indicator	-		-		-	Done
04	Provide EE products free-of-charge	No evaluation indicator	-		-		-	Done
04	Scorecard results will be analyzed	Suggested indicator(s): % of issued score cards that are completed and returned	Program documentation	10%	16%	10%	-	63 cards were returned from the 406 customers that received kits and products.
08	Utilities support EE workshops hosted by EE ambassadors	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the workshop on average	Attendees	7/10	10/10	8/10		All Ambassador workshop participants surveyed found the information provided helpful
14 & 19	Shoppers buy and install low-cost EE products[2]	No evaluation indicator	-		-		-	

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
20	The low-cost EE products will yield long-term electricity and demand savings	No evaluation indicator	-		-		-	
26	Participants will be satisfied by the low-cost EE products	Suggested indicator(s): 1-to-10 scale, level of satisfaction with their energy efficient products	Participants			8/10	95%	Percentage of participants who were very satisfied or satisfied with each product: LEDs - 96%, reflector LEDs - 100%, showerheads - 65%, powerbars 97%, DHW tank wrap - 100%, DHW pipe wrap - 100%, Auto heater timers - 100%, motion detectors - 100% for an average of 95%
27	Word-of-mouth	Suggested indicator(s): % heard of the program positively from other past participants	Participants			30%	65%	See Rebate Program KPIs above (Table 3)
		% heard of the program positively from past participants	Non-participants			10%	-	To be quantified in next Evaluation
28	Non-energy benefits	Suggested indicator(s):						

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
		1-to-10 scale, level of satisfaction with the low cost EE product quality	Participants			8/10	95%	Percentage of participants who were very satisfied or satisfied with each product: LEDs - 96%, reflector LEDs - 100%, showerheads - 65%, powerbars 97%, DHW tank wrap - 100%, DHW pipe wrap - 100%, Auto heater timers - 100%, motion detectors - 100%

3.3 General Program Administrator Observations

In addition to the information gathered to assess the KPIs, the staff administering the programs made the following observations and recommendations during the delivery of the first offering of the inCharge program.

3.3.1 LED and Automotive Heater Timer Rebate Program Observations

The choice of Energy Star as a qualifying criterion for LED bulbs in the rebate program caused confusion for some customers. There were a number of customers who submitted rebates for bulbs that were not Energy Star. Some were not aware of the requirement and others were confused with similar branding on the bulbs, such as *Energy Saver*. To help remedy this problem, the Energy Star logo, as opposed to simply text, was added to point of purchase material in January 2015. This was helpful, but there were still some participants that submitted rebates for non-Energy Star bulbs. Energy Star was chosen as a qualifying criterion to ensure that the rebated bulbs were high quality in an effort to make their experience with LEDs positive, resulting in a permanent switch to LEDs. Energy Star should be made much more prominent in future marketing material. Program staff are also looking to Energy Star to see if there is existing Energy Star point of purchase material the program could use.

In the seven months that the LED rebates were offered, it was noted that prices for many of the common LED bulbs continued to decrease, some coming close to the rebate amount. Packages of multiple bulbs at a much lower cost also started to become available. Before reintroducing the rebate program, staff will survey the retailers in the territory to determine if the $7 rebate level is still appropriate.

At the beginning of the program there was not a high level of flexibility available to retailers in stocking LEDs. Local retailers were very supportive of the program and were proactive in stocking eligible products as they were able. It is our expectation that as LEDs become more popular in general, more retailers will carry a wider range of LEDs. It was also noted that active participation by retailers and sales on the rebated products were a large driver of the rebate program's success.

The Automotive Heater Timer rebate was introduced in January 2015. Due to unseasonably warm temperatures, automotive heaters (e.g. engine block or oil pan heaters) were not required very often and as such the timers were also not required. January and February usually sees many customers calling to enquire on how to lower their higher winter electrical bills, providing an opportunity to discuss automotive heater timers and promote the rebate. This was not the case in early 2015 and as a result participation in the Automotive Heater Timer Rebate Program was quite low. However, a number of participants did re-purpose the timers, using them on lighting and other appliances, which resulted in electrical savings. The rebate will be offered again in the Fall of 2015.

The program was well received Yukoners and participation was higher than projected. A sample of comments on the rebate program overall from participants noted during the evaluation surveys:

- I support the utilities on this program
- Thanks!!

- Very Beneficial, thanks!
- Great Program
- Thanks for the rebate!
- Wonderful

3.3.2 Low Cost Energy Efficient Products Program Observations

The program targeted a very aggressive 100% installment rate for all products distributed. The follow-up surveys showed a lower installation rate, particularly for showerheads, hot water tank wraps and hot water pipe wraps. Many respondents indicated they intend to install the products eventually, but the more involved steps required seemed to be a deterrent. To ensure a higher installation rate going forward, it is suggested that these products be distributed through partners that have staff to complete the installation. These products could also be made available to customers at a specific request, targeting those people who are more likely to install the products. Also, ensure that clear installation instructions and estimate of effort required are provided to the participants as part of program communications. Care should be taken to provide instructions from the manufacturer to minimize program administrator liability.

Participants were very appreciative of the kits and products distributed. A sample of comments on the energy saving products program overall from participants noted during the evaluation surveys:

- Awesome program!
- Unbelievable kit
- Great idea
- Package very helpful
- Loved the program and thanks everyone
- Great idea and thank you
- Great initiative
- Great, free stuff when on a budget

4 Results and Recommendations

Overall this evaluation has shown that the inCharge Program was very well received by Yukoners, was cost effective and met or exceeded most KPIs. The lifetime electricity savings achieved in 2014 were 9% higher than targeted and costs of the program delivery in 2014 were 9% lower than projected.

Table 2 above shows a summary of the inCharge program's updated energy savings and costs as well as the four standard benefit/cost ratios updated with actuals and projected savings over the remainder of the 5 year term. The program achieved an overall Ratepayer Impact Measure (RIM) ratio of 1, with the LED and Auto Heater Timer Rebate Program achieving a RIM ratio of 1.3 and Low Cost Energy Efficient Program achieving a RIM ratio of 1. This shows that the program is neutral from a rate impact perspective. The programs also achieved a very high Participant Cost (PC) ratio and high Program Administrator Cost (PAC) ratio results, showing they are very beneficial to the participants of the

program and the utilities, who are the administrators of the program. Most significantly, the program achieved a very high Total Resource Cost (TRC) ratio. This shows that in the context of the comparison with other energy resource options, the conservation programs performed very well. The tests were conducted assuming a five year program term in order to remain consistent with methodology used in the original program filing.

Table 3 above shows how the LED Rebate and Automotive Heater Timer Rebate Program performed in relation to the targets set out for a number of KPIs. The Program saw higher than projected rebates and electricity savings in 2014 and is on track to meet projected targets in 2015. Customers had a very high satisfaction level with the rebate program as well as the bulbs and timers they purchased using the rebate. The rebate program was effective in influencing customers to switch to the more energy efficient product. The on-bill rebate processing system developed was effective in getting rebates onto customer's bills by the next bill cycle. Store managers were very receptive to the program and many customers noticed and remembered the in-store promotional material. The distribution of promotional material including advertisements in newspapers and radio went well, with a decrease from planned advertising levels in late 2014 when much higher than expected rebates were received. Many participants noticed the promotional material and could remember seeing or hearing the advertisements. Word of mouth was also found to be a very effective way of communicating, as many participants heard positively about the program from family or friends.

Table 4 above shows how the Low Cost Energy Efficient Products Program performed in relation to targets set for a number of KPIs. Distribution of the Low Cost Energy Efficient Products went well with products delivered to participants individually or in Energy Saving Kits. Electricity savings resulting from the Low Cost Energy Efficient Products Program was slightly lower than projected. This was due to a slightly lower than projected installation rates for some products. The program targeted a very aggressive installation rate and program staff took care to work with each participant to ensure they received products that they would use. Adjustments to the installation rate in the cost effectiveness tests showed the program was still cost effective with a lower installation rate projection for a subset of products. Participants were very satisfied with the products they received, with the exception of the ultra-low flow showerhead. The program also gave utility staff the opportunity to talk with customers about how they use electricity and ways to improve efficiency and reduce electricity use.

4.1 LED and Low Cost Energy Efficient Products Program Recommendations

In the next offering of the rebates, it is suggested to work with retailers to increase the amount of point of purchase promotional material displayed. Also work with retailers to plan promotional events that highlight the rebated products and their benefits. To address the customer confusion around the Energy Star criteria for LEDs ensure the Energy Star logo is more prominent on the promotional material. Due to the fast changing LED market and decrease in prices, care should be taken to survey the pricing of LEDs in local stores before the next program offering to ensure the level of the rebate remains appropriate. To ensure the program is as cost effective as possible, program staff should continue to look for transactional process efficiencies to reduce non-incentive program costs, while maintaining customer satisfaction with the program and products.

4.2 Low Cost Energy Efficient Program Recommendations

Distribution of the energy efficient products at community events was very effective and well received. This method, along with having products available for customers who come to the utilities with conservation concerns, should remain the focus of the utilities work. The distribution and installation of products through community partners was also very effective, particularly where those partners had people that were able to help participants complete the installation. The distribution of the showerheads, hot water tank wraps and pipe wraps should focus on these partnerships. To ensure the program is as cost effective as possible, program staff should continue to look for transactional process efficiencies to reduce non-incentive program costs, while maintaining customer satisfaction with the program and products.

4.3 Evaluation Summary and Evaluation Recommendations

Overall this interim evaluation has shown that the inCharge Program was very well received by Yukoners, met or exceeded most KPIs and was cost effective (as shown in Table 2 above). The linkages between activities, outputs, short-term outcomes, intermediate outcomes and long-term outcomes as laid out in the program logic models (Appendix B), are clear, well defined and plausible.

Short-term outcomes were achieved, including:

- Energy efficient products were identified and endorsed;
- Energy efficient products were available in stores;
- Customers were educated about energy efficient products
- Customers were convinced to buy and install energy efficient products; and
- The initial cost hurdle was alleviated.

Intermediate outcomes including effective communication through word of mouth and participant purchase and installation of eligible energy efficient product was achieved.

Long-term outcomes included high customer satisfaction with the programs and the majority of products, and cost effective, long-term energy and demand savings.

Overall, the program rational is sound and the results to date support the plausibility of the claimed cost effectiveness, and the energy and demand savings.

With the launch of the two residential programs and website set-up completed, many of the up-front program launch costs have already been incurred. With these costs included, the programs showed positive cost effectiveness ratios over the modelled five years. As these programs continue to be offered, opportunities to reduce non-incentive costs and increase savings should be pursued whenever possible.

In completing the inCharge program's first evaluation, the following recommendations were made by the Evaluation Advisor and program staff:

- Establish a set schedule and questionnaire for customer surveys of the program to ensure the same type of information is gathered at the same time each year. This will allow for better comparison of trends year over year. Customer surveys of the LED and Auto Heater Rebate Program should happen in November for LEDs and February for Auto Heater Timers and in April for the Low Cost Energy Efficient Products Program. Surveys with non-participants and store managers should happen in February each year.
- Schedule evaluations in June and July of each year. With an impact evaluation scheduled for July 2016. At that point, the program will have been delivered for a sufficient time and participants will have had sufficient experience with the products to provide reliable information to examine current assumptions about installation, spillover and free ridership ratios and the related net-to-gross ratio.
- Data gathered from telephone surveys with participants resulted in much more complete and consistent data in comparison to self-completed hard copy or online surveys. It is recommended that this method be used to gather data.

Appendix A: TRM Example – Standard LEDs > 9W

Energy Conservation Measure - Justification of the Incentive Level

ECM61

Inputs - Measure Considerations	
Measure Name:	Standard LEDs (>9 W)
Incentive Amount:	$7.00
Measure/Project Cost:	$7.61
Gross Consumption Savings:	40 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	43 kWh/yr
Gross Demand Savings:	.01 kW
Gross Demand Savings w/ T&D losses:	.010 kW
Participant's Savings on Year 1:	$5.74
Measure Lifetime:	20 yr

Inputs - Program Considerations		
Program Cost (% of Incentive):	192%	
Suggested Program Cost (% of Incentive):	192%	-->not us
Forecasted Freeridership:	10%	
Forecasted Participant Spillover:	0%	
Forecasted Non-participant Spillover:	10%	
Forecasted Rebound Effects:	0%	

Outputs with Program Costs	
PC - Benefit/Cost Ratio	10.64
PC - Net Present Value	$73.39
PC - Levelized Cost	$0.0174/kWh
Simple Payback w/ Incentive (yr)	0.1 yr
RIM - Benefit/Cost Ratio	*1.28*
RIM - Net Present Value	*$26.88*
RIM - Levelized Cost	*$0.1975/kWh*
TRC - Benefit/Cost Ratio	5.76
TRC - Net Present Value	$100.27
TRC - Levelized Cost	$0.0441/kWh
PAC - Benefit/Cost Ratio	*5.93*
PAC - Net Present Value	*$100.88*
PAC - Levelized Cost	*$0.0428/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.65*
RIM-YECL - Net Present Value	*-$24.06*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.93*
RIM-YEC - Net Present Value	*$63.55*
RIM-YEC - Levelized Cost	*$0.1322/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$7.61
Incentive Amount in Year 1	$7.00
Assumed Program Administration Costs in Year 1	$13.47
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership + P. Spillover + N.-p. Spillover - Rebound

Participant Cost Test (PC)

Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$74.01	$74.01
Discounted Cumulative Gross Energy Savings for 20 years	439 kWh	439 kWh
PC - Present Value of Benefits	$81.01	$81.01
PC - Present Value of Costs	$7.61	$7.61
PC - Benefit/Cost Ratio	10.64	10.64
PC - Net Present Value	$73.39	$73.39
PC - Levelized Cost	$0.0174/kWh	$0.0174/kWh
Simple Payback with Incentive	0.1 yr	0.1 yr

Ratepayer Impact Measure Test (RIM)

Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$121.35	$121.35
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$74.01	$74.01
Discounted Cumulative Net Energy Savings for 20 years	478 kWh	478 kWh
RIM - Present Value of Benefits	$121.35	$121.35
RIM - Present Value of Costs	$94.48	$81.01
RIM - Benefit/Cost Ratio	1.3	1.5
RIM - Net Present Value	$26.88	$40.35
RIM - Levelized Cost	$0.1975/kWh	$0.1693/kWh

Total Resource Cost Test (TRC)

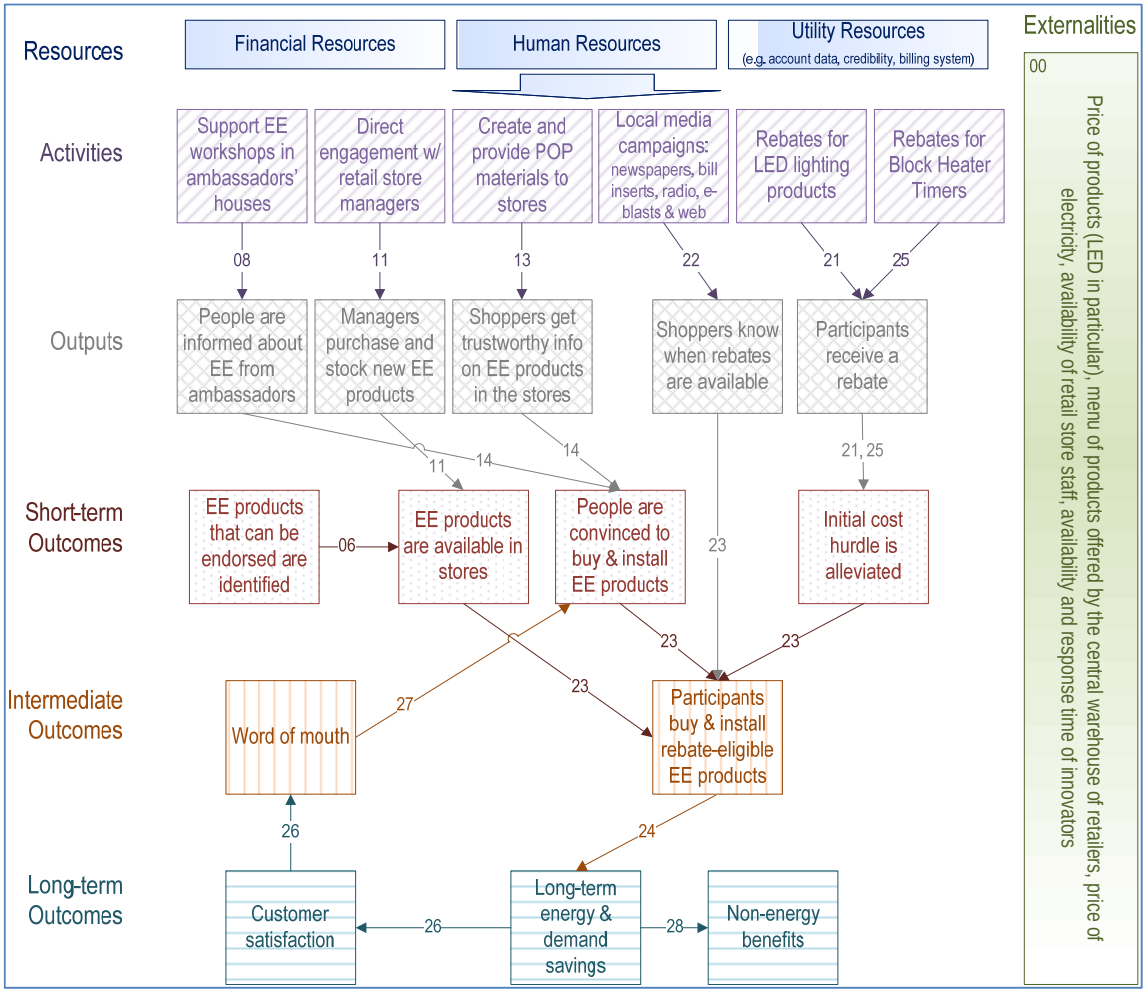
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$121.35	$121.35
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	478 kWh	478 kWh
TRC - Present Value of Benefits	$121.35	$121.35
TRC - Present Value of Costs	$21.09	$7.61
TRC - Benefit/Cost Ratio	5.76	15.9
TRC - Net Present Value	$100.27	$113.74
TRC - Levelized Cost	$0.0441/kWh	$0.0159/kWh

Program Administrator Cost Test (PAC)

Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$121.35	$121.35
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	478 kWh	478 kWh
PAC - Present Value of Benefits	$121.35	$121.35
PAC - Present Value of Costs	$20.47	$7.00
PAC - Benefit/Cost Ratio	5.9	17.3
PAC - Net Present Value	$100.88	$114.35
PAC - Levelized Cost	$0.0428/kWh	$0.0146/kWh

Appendix B: Program Logic Models

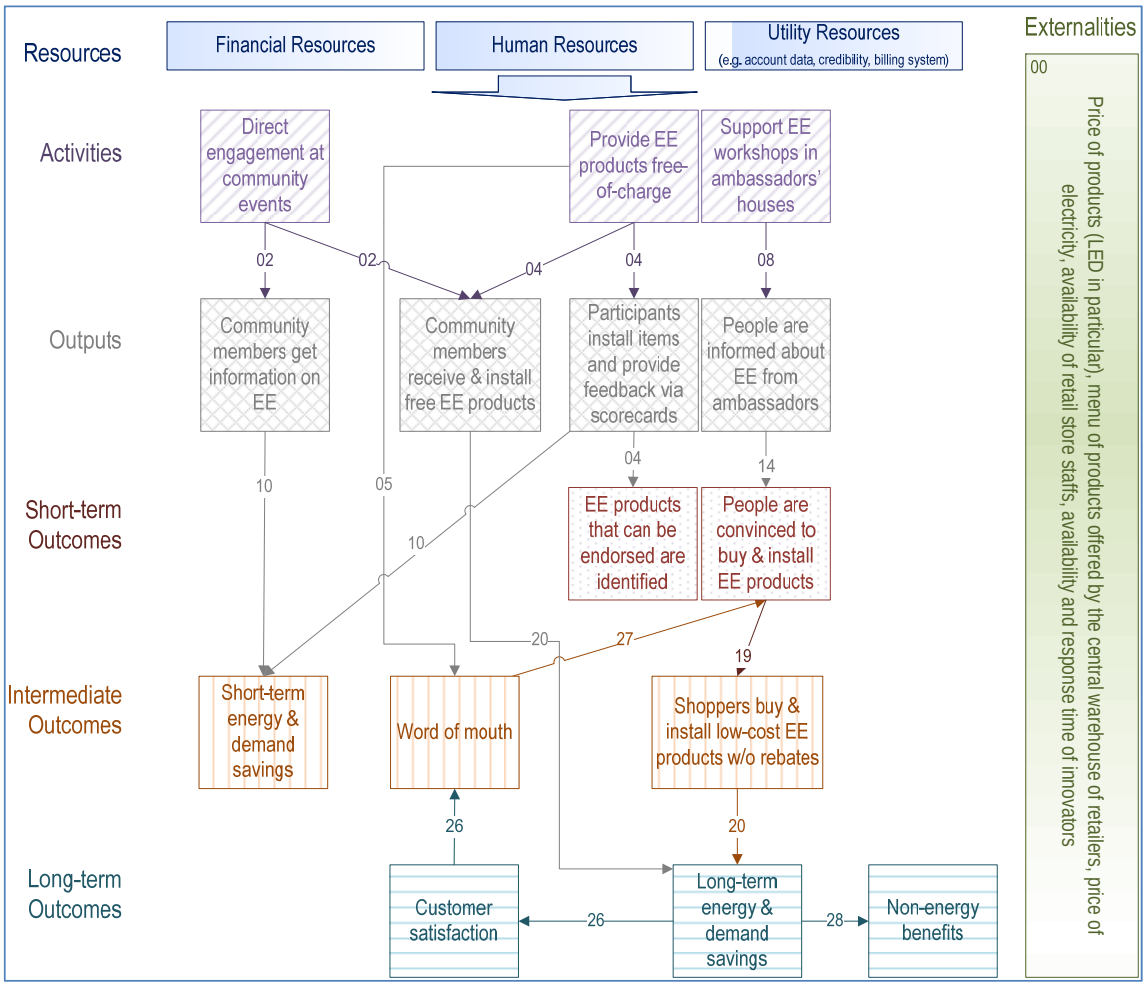
Figure B1: Logic Model for the Residential LED Lights and Automotive Heater Timer Rebate Program



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: price of products (LED technologies, in particular), menu of products offered by the central warehouse of retailers, price of electricity, and availability of retail store staff to address any questions. The program administrator should monitor these externalities and adapt the implementation approach based on them.

Link #	Narrative
08	The Utilities will support EE workshops in the homes of EE community network members or nearby community venues with approximately ten friends and relatives. The Utilities will send facilitator(s), provide communication materials and low-cost EE products to give away, and perhaps provide food and beverages. The Utilities' skilled facilitator(s) will have a few key messages regarding low-cost EE products, LED lighting products, and automotive heater timers. The facilitator will encourage the participants to share tips and information on electricity conservation. The facilitator will seek to eliminate potential sources of confusion and false beliefs in the communities by presenting hard facts.
11	The Utilities will establish partnerships with Yukon retail store managers and establish two-way communication. The Utilities will suggest new products to stock; perhaps by providing the results of the low-cost EE product piloting, by revealing in advance what products will be eligible for the LED lighting rebate and automotive heater timer rebate, or by indicating what POP materials will be created and offered to the shops.
13	The Utilities will design and procure educational Point Of Purchase (POP) materials for Yukon retail managers to display in their stores. These materials might include (but not be limited to): brochures, presentation boxes, posters, and displays stands.
14	Yukon shoppers will be informed on EE products through the community direct engagement, and through the POP materials. This will cause them to buy and install these products.
21	The Utilities will provide a flat amount of money per unit to Yukon shoppers after they purchase LED lighting lamps or fixtures selected from a prescriptive list of eligible products. The initial-cost hurdle will be alleviated which will contribute to the items being purchased and installed.
22	The "rebate" period will be extensively advertised through a media campaign through local radio, local newspapers, co-op advertisement with retailers and in stores, and electricity bill inserts. Consequently, shoppers will know when the rebates are going to be available.
23	Participating Yukon shoppers (i.e. participants) will buy and install LED lighting products or automotive heater timers and receive a rebate because these products will be available in the stores, because they were made aware of the benefits of these products, because they know when the rebate is available, and because the initial cost hurdle was alleviated by the rebate.
24	The LED lighting product installs and automotive heater timer installs will yield long-term electricity and demand savings.
25	The Utilities will provide a flat amount of money per unit to Yukon shoppers for the purchase of automotive heater timers (i.e. outdoor) selected from a prescriptive list of eligible products. The initial-cost hurdle will be alleviated and/or the rebate will make the purchase of an automotive heater timer much more enticing. This will contribute to the purchase and installation of these items.
26	Shoppers who bought low-cost EE products, LED lighting products or automotive heater timers will be satisfied by the products that they bought. They will tell their friends and relatives. This will generate word-of-mouth advertisement.
27	With time, word-of-mouth will become an important information channel that will cause Yukon residents to buy and install EE products.
28	Shoppers will perceive new non-energy benefits and/or the less maintenance related to the energy efficient products when they're compared with the baseline systems. For example, the Utilities will seek to make sure that participants will perceive that their new LED products last longer, are less sensitive to power quality issues, are more reliable, cast better light (color rendering, intensity, and visual acuity), and easier and less hazardous to dispose of than CFLs. The Utilities will seek to make sure that participants will perceive that automotive heater timers are reliable and that the use of a timer does not have negative impact on their car.

Figure B2: Logic Model for Residential Low Cost Energy Efficient Products Program



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: price of products (LED technologies, in particular), menu of products offered by the central warehouse of retailers, price of electricity, and availability of retail store staff. The program administrator should monitor these externalities and adapt the implementation approach based on them.
02	The Utilities will carry out outreach activities in community events (eg. sport events, cultural events, town hall meetings, etc.), engage with organization and people who have a natural interest in electricity conservation; hook individuals with a continuous stream of free low-cost EE products or contests; do personalized follow-ups; and promote the idea of supporting an EE workshop at their home or a at local venue.

Link #	Narrative
04	Low-cost EE products will be used by program participants. Participants will be provided with simple scorecards that will give them the opportunity to provide feedback on the various products. The Utilities will collect all of the scorecards, aggregate and analyze the results, and use the results on consumer satisfaction to improve the products that are distributed by the program in subsequent years.
05	It is expected that the volunteers and EE community network members will like the low-cost EE products and will tell their friends and relatives. This will feed the word of mouth feedback loop.
08	The Utilities will support EE workshops in the homes of EE community network members or nearby community venues with approximately ten friends and relatives. The Utilities will send facilitator(s), provide communication materials and low-cost EE products to give away, and perhaps provide food and beverages. The Utilities' skilled facilitator(s) will have a few key messages regarding low-cost EE products, LED lighting products and automotive heater timers. The facilitator will encourage the participants to share tips and information on electricity conservation. The facilitator will also seek to eliminate potential sources of confusion and false beliefs in the communities by presenting hard facts.
10	The information and tips provided to residents of the Yukon as part of the Utilities direct community engagement activities will influence their behavior and cause them to use less electricity and reduce their peak demand. However, quantifying "behavior-based" electricity and demand savings is challenging and perhaps cost-prohibitive for a small jurisdiction like the Yukon. Moreover, the persistence of "behavior-based" conservation measures is notoriously bad. It is commonly believed to be less than one year by DSM experts. Consequently, the short-term benefits of behavior-based conservation measures will not be quantified. They are considered to be outcomes that are "nice-to-have" yet not necessary to make the program viable.
14	Yukon shoppers will be informed on EE products through the community direct engagement. This will cause them to buy and install these products.
19	Yukon shoppers will buy and install low-cost EE products (even in the absence of rebate) because these products will be available in the stores, and because they were made aware of the benefits of these products. The low-cost EE products may have a certain price increment; however it is assumed that the price increment (if any) is too small to constitute the most important purchase barrier.
20	The free and purchased low-cost EE product installs will yield long-term electricity and demand savings.
26	Shoppers who received low-cost EE products or purchased LED lighting products or automotive heater timers will be satisfied by the products that they bought. As a result, they will tell their friends and relatives about their experience with these products. This will generate word-of-mouth advertisement.
27	With time, word-of-mouth will become an important information channel that will cause Yukon residents to buy and install EE products without any support from the Utilities.
28	Program participants will perceive non-energy benefits, including improved comfort and reduced maintenance, as a result of the products they installed. For example, the Utilities will seek to make sure that participants will perceive that their new LED products last longer, are less sensitive to power quality issues, are more reliable, cast better light (color rendering, intensity, and visual acuity), and are easier and less hazardous to dispose of than CFLs. The Utilities will seek to make sure that participants will perceive that automotive heater timers are reliable and that the use of a timer does not have any negative impacts on their vehicles.

2015-2016 Evaluation Report

Demand Side Management Program Portfolio for the Yukon

31 October, 2016

Submitted to:
Yukon Utilities Board

Submitted by:
Yukon Energy Corporation
ATCO Electric Yukon

Executive Summary

inCharge is an electricity conservation program delivered to residential customers in Yukon by the territory's electrical utilities, Yukon Energy Corporation and ATCO Electric Yukon. inCharge consists of three programs: the LED and Automotive Heater Timer Rebate Program, the Low Cost Energy Efficient Products Program and the Engagement, Education and Communication Program. These programs launched in October 2014 and have been well received by Yukoners.

This evaluation report will focus on the period between April 2015 and July 2016, updating the program's projected performance with the actual costs and reported energy savings achieved from the program launch in October 2014 to the end of July 2016, as well as documenting learnings from program administration and participant feedback. The program evaluation was completed by utility staff with guidance and review by an independent evaluation advisor. This method was chosen to keep costs at an appropriate level for the program while still ensuring that the evaluation was completed in an objective manner.

Evaluation data was collected through phone interviews with program participants as well as the rebate program database, which tabulates the number of rebates and types of products rebated. The results demonstrated that customers are very satisfied with the program (96% of participants for the LED rebate and kit products and 100% of participants for the AHT rebate were satisfied). Participation rates were slightly lower than projected in 2015, however in 2016 participation rates are anticipated to be higher than projected. This is a result of increased retail partner participation, program communications and increased customer awareness. Online advertising was added to the communications tactics and was well recognized by participants. The labour cost for the program has decreased in 2016 due to streamlined processes as the utilities gained experience in program delivery and is expected to stay at this level for the remaining years.

This report's recommendations and results demonstrate that the LED and Automotive Heater Timer programs were adopted well by Yukoners. It was also shown that energy efficient products were well received. Results show the KPI's are met or exceeded in most program areas. Programs performed well financially and annual budgets were respected.

As directed by the Yukon Utilities Board, the programs achieved an overall Ratepayer Impact Measure (RIM) ratio of 1.0. This shows that the program is neutral from a utility rate impact perspective. The programs also achieved a very high Participant Cost (PC) ratio and high Program Administrator Cost (PAC) ratio results, showing they are very beneficial to the participants of the program and the utilities, who are the administrators of the programs. Most significantly, the program achieved a high Total Resource Cost (TRC) ratio. This shows that in the context of the comparison with other electricity resource options, the conservation programs performed very well. The tests were conducted assuming a five year program term in order to remain consistent with methodology used in the original program filing. Overall this evaluation has shown that the inCharge Program was well received by Yukoners, was cost effective and met or exceeded most Key Performance Indicators.

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1 Program Summary

inCharge is an electricity conservation program delivered to residential customers in Yukon by the territory's electrical utilities, Yukon Energy Corporation and ATCO Electric Yukon. inCharge consists of three programs; the LED and Automotive Heater Timer Rebate Program, the Low Cost Energy Efficient Products Program and an Engagement, Education and Communication Program. These programs launched in October 2014 and have been extremely well received by Yukoners.

The LED and Auto Heater Timer Rebate Program offers a $7 rebate on Energy Star LED light bulbs and $10 rebate on mechanical automotive heater timers that are purchased in the Yukon. Participants can apply for rebates by email, mail, in person at the utilities office or by leaving the rebate form with the cashier at one of the participating retailers. Local retailers can participate in the program by stocking eligible LEDs and timers as well as displaying program advertisements. In addition, stores can also participate by having their cashiers help customers fill out the rebate forms and collect them on behalf of the utilities. Customers will see the rebate appear on their next electrical bill. Retailers have also partnered with inCharge to host events where eligible products are on sale. inCharge will help to advertise the event, to provide staff instore promote the event, to help customers find the right product and fill out the rebate forms properly. The store stocks the sale products and sets up a display area for the event. There are twelve stores in the Yukon displaying program information and collecting rebate forms.

The Low Cost Energy Efficient Products Program distributes kits containing energy saving products and information. These kits contain LED bulbs, an automotive heater timer and a smart power bar. The kits are distributed at community events and utility staff value the opportunity to talk to participants about the products and electricity conservation in general. The program also included a small number of Nest smart learning thermostats that will be distributed to homes that have central electric heat.

The Engagement, Education and Communication Program seeks to raise awareness of electricity conservation and the inCharge program with Yukoners. This includes maintaining the inCharge website, sharing electricity saving tips, answering customer questions regarding electricity conservation and advertisement of the inCharge program.

2 Evaluation Context

This evaluation report will focus on the period between April 2015 and July 2016, updating the program's projected performance with the actual costs and reported energy savings achieved from the program launch in October 2014 to the end of July 2016, as well as documenting learnings from program administration and participant feedback. This report will also assess the key performance indicators laid out in the program's Evaluation, Measurement and Verification Plan. The main goals of this evaluation is to ensure that the programs are performing as projected, that participants are satisfied with the program and to provide recommendations to improve program delivery and cost effectiveness.

The program evaluation was completed by utility staff with guidance and review by an independent evaluation advisor. This method was chosen to keep costs at an appropriate level for the program while still ensuring that the evaluation was completed in an objective manner. The evaluation involved telephone surveys of customers receiving LED rebates (n=31), automotive heater timers rebates (n=11) and energy saving kits (n=30) as well as managers from participating stores (n=7).

3 Updated Cost Effectiveness Results and Program Performance

3.1 Energy Saving and Cost Effectiveness Results

Table 1 below contains the target energy savings and costs for the inCharge program as presented in the Revised Evaluation, Measurement and Verification Plan (December 3, 2014). Table 2 contains a summary of the updated energy savings and costs for the inCharge Program. These updated results are based on actual costs and deemed electricity savings from Year 1 (2014) to end of July of Year 3 (2016). The 2015 interim evaluation reported on the costs and savings for Year 1 (2014) to April of Year 2 (2015), this current evaluation report added the actual costs and deemed savings for the remainder of Year 2 (2015) to July of Year 3 (2016). The updated projections are based on the programs' preliminary results from August of Year 3 (2016) through Year 5 (2018). The updates were completed in the excel-based Program Projections Model that has been used throughout the design and duration of the program. A comparison of Tables 1 and 2 shows how the programs performed in the two years of delivery in comparison to targeted performance. Deemed savings considers the installation rates of each type of product (for more detail see Section 3.1.4). This installation rate is verified through customer surveys and as this model input is refined each year, the deemed savings for past as well as coming years will adjust. The details of the savings and costs are also discussed below in Tables 3 and 4. The following sections discuss how the actual results were incorporated into Table 2. Note that the results in Table 2 from the previous evaluation report may differ as the installation rate for each product is refined through the participant interview process.

Table 1: Targeted Energy Savings and Costs[1]

Program Elements		Net Savings with T&D Losses							Utility Expenditure ($1,000s)						Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	1,337	5,484	5,484	5,484	5,484	23,271	Incentive:	$12	$51	$51	$51	$51	$216	6.2	5.2	20.2	1.2
	Annual MWh:	67	380	692	1,005	1,272	N/A	Non-Incen:	$82	$79	$81	$84	$83	$409				
	Coincident kW:	16	111	206	301	365	N/A	Total:	$94	$130	$132	$135	$134	$625				
Low-cost Energy Efficient Products	Lifetime MWh:	4,605	3,247	3,247	3,247	3,247	17,593	Incentive:	$78	$55	$55	$55	$55	$299	2.4	2.5	5.9	1.0
	Annual MWh:	424	723	1,021	1,225	1,457	N/A	Non-Incen:	$121	$172	$177	$183	$188	$841				
	Coincident kW:	113	192	272	288	323	N/A	Total:	$199	$227	$233	$238	$243	$1,140				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	$103	$118	$121	$125	$129	$596				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$103	$118	$121	$125	$129	$596				
Total for the Residential Program	Lifetime MWh:	5,942	8,731	8,731	8,731	8,731	40,864	Incentive:	$90	$106	$106	$106	$106	$515	2.7	2.6	9.6	1.0
	Annual MWh:	491	1,102	1,714	2,230	2,730	N/A	Non-Incen:	$306	$369	$380	$392	$400	$1,847				
	Coincident kW:	129	303	478	589	688	N/A	Total:	$396	$475	$486	$498	$506	$2,362				

Table 2: Updated Energy Savings and Costs

Program Elements		Net Savings with T&D Losses							Utility Expenditure ($1,000s)						Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	2,418	3,893	7,859	8,128	8,128	30,426	Incentive:	$19	$31	$71	$69	$69	$260	6.4	5.7	13.4	1.3
	Annual MWh:	121	331	747	1,192	1,619	N/A	Non-Incen:	$77	$73	$95	$98	$98	$441				
	Coincident kW:	29	88	200	327	442	N/A	Total:	$96	$105	$166	$167	$167	$700				
Low-cost Energy Efficient Products	Lifetime MWh:	3,208	2,313	2,313	2,313	2,313	12,461	Incentive:	$71	$51	$51	$51	$51	$274	3.0	2.8	6.0	1.0
	Annual MWh:	298	503	708	840	962	N/A	Non-Incen:	$110	$154	$48	$48	$48	$409				
	Coincident kW:	81	169	257	296	329	N/A	Total:	$181	$205	$99	$99	$99	$683				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	$86	$108	$130	$191	$191	$707				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$86	$108	$130	$191	$191	$707				
Total for the Residential Program	Lifetime MWh:	5,625	6,207	10,173	10,441	10,441	42,887	Incentive:	$90	$82	$121	$120	$120	$533	3.1	2.9	9.2	1.0
	Annual MWh:	419	834	1,456	2,032	2,582	N/A	Non-Incen:	$272	$336	$273	$337	$337	$1,556				
	Coincident kW:	110	257	457	623	771	N/A	Total:	$363	$418	$395	$457	$457	$2,089				

[1] See page 14 of Appendix A of *2014 Annual Report – inCharge Demand Side Management (DSM) Program Portfolio for the Yukon,* Filed with Yukon Utilities Board January 29, 2015

3.1.1 Actual Costs

Cost estimates are divided by quarter in the Projections Model. The model was updated with actual costs for each quarter from the start of program launch preparation in third quarter of Year 1 (2014) up to the end of July of Year 3 (2016). The projected costs for the remainder of Year 3 (2016) through Year 5 (2018) were compared to actuals to ensure estimates were still accurate.

The inCharge program administration structure has evolved since its launch in 2014. This is a result of streamlined processes as the utilities gained experience in program delivery. As a result, the labour cost for the program has decreased in 2016 and is expected to stay at this level for the remaining years.

3.1.2 Reported Energy Savings

The energy savings attributed to the inCharge program are calculated using a deemed savings approach. An annual and lifetime energy savings is assigned to each type of product that is included in the program and documented in the Technical Reference Manual (TRM) discussed below. The energy saving projections for the LED and Automotive Heater Timer Rebate Program are based on a target number of rebates issued and included an assumption of the types of bulbs that customers will purchase with their rebates. The energy saving projections for the Low Cost Energy Saving Products Program are based on the number of each of the products the utilities will distribute.

In calculating the reported energy savings for the LED Rebate Program, the actual number of rebated units and types of bulbs purchased were tabulated and the deemed savings as per the TRM were applied. The actual results were used to update the saving projections going forward. In calculating the reported energy savings for the Automotive Heater Timer program, deemed savings as per the TRM were applied.

In calculating the reported savings for the Low Cost Energy Efficient Products Program, the number of products purchased and distributed were tabulated and the deemed savings as per the TRM were applied. The variation from projected savings to actual savings was minimal with this program as the purchasing decisions were in the control of the program administrators.

3.1.3 Technical Reference Manual

A Technical Reference Manual (TRM) was created as a part of the Program Projections Model. The TRM summarizes the assumptions and inputs to the Program Projections Model related to costs and energy savings for each individual type of product included in the programs. The TRM was updated in late 2014 as part of the work completed to launch the inCharge Programs. In particular, costs of LED bulbs were updated as this parameter changes rapidly. The energy savings attributed to each type of product was also reviewed at that time. An example of the TRM entry for standard LEDs can be found in Appendix A.

While the energy savings that can be attributed to a particular product is quite straight forward to estimate. The behavior of customers in purchasing and installing the products is a much more complex and intangible parameter that is considered in the deemed savings calculation. This is captured in the installation ratio and the Net to Gross (NTG) Ratio, discussed in the section below.

3.1.4 Installation Ratio

The installation ratio is an estimate of the percentage of program participants that have installed the product they received as part of an energy saving kit or purchased using a program rebate. As the product must be in use to result in the energy savings estimated, the installation ratio affects the amount of savings that can be claimed for the program. The installation ratio estimated for the program was confirmed through surveys with a sample of program participants.

A new evaluation protocol, the uniform methods project, has been recently developed by the US Department of Energy. This protocol uses a measurement called the in-service rate. For upstream programs like the LED and Automotive Heater Timer Rebate Program, the UMP recommends the following: "In-service rates should be calculated through an in-home audit. Since program bulbs cannot be easily identified, the in-service rate can be calculated as the number of bulbs purchased in a recent 12-month period that are installed divided by the total number of bulbs purchased in the same 12-month period. If the sample size of homes with bulbs purchased in the recent 12-month period is insufficient to provide the necessary levels of confidence and precision, a long term in-service rate can be used using all bulbs regardless of the time of purchase."[2] This new method gives the same results as the installation rate. inCharge will continue to monitor the Uniform Methods Project to adjust the evaluation protocol as needed.

3.1.5 Stipulated Net-to-Gross Ratio

The stipulated net-to-gross (NTG) ratio includes effects such as free ridership and spillover. Free ridership accounts for the program participants that would have made the energy saving change without the program, but took advantage of the program anyway. On the other end of the spectrum is spillover. These are people who made the energy saving changes because they were influenced by the inCharge program in some way, such as by point-of-purchase information posters, but did not participate in the program by applying for a rebate. The free ridership and spillover rates are more difficult and complex to confirm. It is currently assumed for the rebate program that free ridership and spillover will cancel each other. According to the survey results, the program seems to have a great influence on the customers' decision to purchase the energy-efficient products. It can also be assumed that the program will generate some spillover effects because of the general marketing, promotional displays and the fact that not all participants will take time to fill in the rebate form. For the low cost energy efficient products program, the NTG ratio is assumed to be 1 considering the relatively small size of the program, the fact that it is relatively new in the market and that no other jurisdiction has established NTG ratios that would be applicable to the program.

[2] NREL, Uniform Methods Protocol Chapter 6: Residential Lighting Evaluation Protocol, February 2014, available at < http://www.nrel.gov/extranet/ump/pdfs/20140514_ump_res_lighting_draft.pdf>

3.2 Key Performance Indicator Results

A set of key performance indicators (KPIs) and targets for each KPI were developed for each program. These KPIs are based on a logic model developed for each program. The logic model is a simple graphic and narrative that maps out the resources, activities and outcomes that are expected from each program and the linkages between those parameters that are expected to ensure the program is successful. The logic model for each program can be found in Appendix B. The KPIs are designed to test the performance of the linkages in the logic model. Tables 3 and 4 below report on how the programs are performing for each indicator and provide a brief commentary on each as appropriate. The first column references the linkage number to allow for reference to the programs logic model. Note that the results for Year 3 represent the progress made to the end of July towards meeting the annual (2016) target.

Table 3: LED and Auto Heater Timer Program KPI Summary

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)										
00	Externalities	No associated tracked KPIs	-	-	-	-	-			
08	Utilities support EE workshops hosted by EE ambassadors	Suggested KPI(s):								
		# workshops	Program documentation	-	20	2	-	-	-	Ambassador workshops not part of 2015 and 2016 program.
		# people attending workshops		-	80	8	-	-		Ambassador workshops not part of 2015 and 2016 program.

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
11	Direct engagement with retail store managers	Suggested KPI(s):								
		# of new store managers being engaged for the 1st time	Direct engagement & communication logs	20	30	-	-	-	-	Store managers were contacted at the beginning of the program and efforts continue to engage them as the program continues.
		# of participating stores							12	New KPI added in 2016
		# of store managers contacted with program intel & updates		20	30	20	17	20	17	17 Retail managers were contacted in 2016. Not all participated, but were made aware of the programs and provided with contact information for the future.
13	Utilities issue point of purchase materials for retail managers	Suggested KPI(s):								
		# stores with POP materials	Program documentation	5	9	10	12	10	12	
		POP materials issued for all rebate-eligible products and refreshed as needed (Yes/No)		n/a	n/a	Yes	Yes	Yes	Yes	

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
14 & 23	Shoppers buy and install rebate-eligible products[1]	Suggested KPI(s): # of units claimed	Tracking System	1,722	LED: 2,898	7,167	LED: 4,768 Timer: 111 Tot: 4,825	7,000	LED: 7250 Timer: 13 Tot: 7263	Participation higher than projected in 2016 and anticipated to exceed estimates. See Appendix C for rebates by type of LED bulb.
24	The LED lighting and automotive heater timer installations will yield long-term electricity and demand savings[2]	Suggested KPI(s): MWh of avoided lifetime electricity consumption	Estimate based on rebates processed	1,337	2,418	5,484	3,893	5,484	7,859	Lifetime savings were lower than projected in 2015 due to lower than estimated participation, but are on track to exceed targets in 2016.
		MWh of avoided annual electricity consumption		67	121	334	331	692	747	Annual savings were lower than projected in 2015 due to lower than estimated participation, but are on track to exceed targets in 2016.
		kW of avoided coincident electricity demand		16	29	111	88	206	200	Demand savings were lower than projected in 2015 and 2016 due to low uptake in the auto heater timers as a result of warmer than average winters.
21 & 25	Participants receive a rebate[3]	Suggested KPI(s): $ of incentive disbursement for LED lighting and automotive heater timers	Tracking System	$12K	$19,817	$51K	$32,512	$51K	$35,224	It is expected that program participation will be higher than estimated for 2016 but total program dollars is not expected to be exceeded.

Link #	Narrative	Performance Indicator	Sources	Year 1 Target 2014	Year 1 Actuals 2014	Year 2 Target 2015	Year 2 Actuals 2015	Year 3 Target 2016	Year 3 Progress 2016	Progress Commentary
22	Shoppers learn about rebates through local media campaigns	Suggested KPI(s):								
		# updates of web content	Tracking System	1	1	4	4	4	10	Website updated when substantive changes made to program, events planned and in response to participant comments.
		# newspaper/radio advertisements		1	4	1	9	1	8	Radio and newspaper ads continue to be used to advertise the rebate program with the addition of online ads starting in late 2015.
		# bill insert		1	0	1	0	-	-	Bill inserts not used in 2014 and 2015.
		# online ads				1	1	4	3	Online ads were introduced in October 2015 and continue to be used to announce events and increase brand awareness due to their success.
		# email blasts		1	0	1	1	1	1	1 e-mail blast in 2015 and again in 2016 to notify past participants of planned events.

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
26	Participating shoppers will be satisfied by the products that they bought	Suggested KPI(s): % of rebates processed in time to show up on next utility bill (if applications comes in 10 business days before issuance of bill)	Tracking System	70%	99%	80%	99%	80%	99%	Nearly all customers received their rebate on their next utility bill.
27	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-			see Part B.
28	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-			see Part B.
Part B -- To Be Visited, Checked and Reported On by Evaluators										
00	Externalities	Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done			
08	Utilities support EE workshops hosted by EE ambassadors	Suggested indicator(s): 1-to-5 scale, level of satisfaction with the workshop on average	Attendees	70% scoring 4-5 out of 5	100%	-	-	-	-	Ambassador workshops not part of 2015 and 2016 program.

Link #	Narrative	Performance Indicator	Sources	Year 1 Target 2014	Year 1 Actuals 2014	Year 2 Target 2015	Year 2 Actuals 2015	Year 3 Target 2016	Year 3 Progress 2016	Progress Commentary
11	Direct engagement with retail store managers	Suggested indicator(s):								
		% store managers who know the program	Store managers	-	-	100%	-	100%		
		% of store managers the program influenced in general.	Tracking system	-	-	60%	-	60%	57%	
		% of store managers the program influenced in quantity of stocked items							71%	New KPI added in 2016
		% of store managers the program influenced in variety of stocked items							29%	New KPI added in 2016
		% of store managers that found the POP material influential							14%	New KPI added in 2016

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
13	Utilities issue point of purchase materials for retail managers	Suggested indicator(s): % of shoppers who noticed POP materials	Shoppers and Participants	-	-	70%	83%	70%	LED: 73% Timer: 100% Avg: 80%	73% LED Rebate participants and 100% Auto Timer Rebate participants for a weighted average of 80%.
		% of shoppers who agree that POP materials contributed to their decision to purchase a rebate-eligible product		-	-	50%	58%	60%	LED: 55% Timer: 73% Avg: 60%	55% LED Rebate participants and 73% Auto Timer Rebate participants for a weighted average of 60%.
14 & 23	Shoppers buy and install rebate-eligible products	% of products installed	Participants	-	-	-	-	-	LED: 99% Timer: 82% Avg: 95%	The vast majority of customers installed the LED bulbs that they purchased (94%) with the rest having installed most of the lights and having purchased a few extras, for an installation rate of 99%.. Despite an unseasonably warm winter, most if the timers were installed (82%).

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
24	The LED lighting and automotive heater timer installations will yield long-term electricity and demand savings	No evaluation indicator	-	-	-	-	-			
21 & 25	Participants receive a rebate	Suggested indicator(s): % of participants who agree the rebate contributed to them purchasing the energy efficient products rather than the base-case product	Participants	-	-	60%	LED 77% Timer 50%	60%	LED 68% Timer 72%	Participants who rated the program influential or very influential in their decision to purchase the energy efficient product: LED Rebate - 68% Auto Timer Rebate - 72%
22	Shoppers learn about rebates through local media campaigns	Suggested indicator(s): % of shoppers who can recall one of the following: bill inserts, web content, or inCharge in the news	Participants & non-participants	-	-	70%	58%	70%	64%	64% of participants can recall media advertising. Non-participants were not surveyed in this evaluation.

Link #	Narrative	Performance Indicator	Sources	Year 1 Target 2014	Year 1 Actuals 2014	Year 2 Target 2015	Year 2 Actuals 2015	Year 3 Target 2016	Year 3 Progress 2016	Progress Commentary
26	Participating shoppers will be satisfied by the products that they bought	Suggested indicator(s): 1-to-5 scale, level of satisfaction with the overall rebate program	Participants	-	-	80% scoring 4-5 out of 5	LED 93% Timer 90%	80% scoring 4-5 out of 5	LED 96% Timer 100%	Percentage of participants who were very satisfied or satisfied with the program: LED Rebate - 96% Auto Timer Rebate - 100%
27	Word-of-mouth	Suggested indicator(s): % heard of the program positively from other past participants	Participants	-	-	30%	65%	30%	46%	46% of participants heard of the program from others and 100% of those discussions were positive.
		% heard of the program positively from past participants	Non-participants	-	-	10%	-	-	-	Non-participants were not surveyed in this evaluation.
28	Non-energy benefits	Suggested indicator(s): 1-to-5 scale, level of satisfaction with the LED lighting or automotive heater timer in general	Participants	-	-	90% scoring 4-5 out of 5	LED 93% Timer 90%	90% scoring 4-5 out of 5	LED 100% Timer 84%	Percentage of participants who were very satisfied or satisfied with their energy efficient products: LED Rebate - 100% Auto Timer Rebate - 84%
		1-to-5 scale, level of satisfaction with the LED light quality							100%	New KPI added in 2016

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
		1-to-5 scale, level of satisfaction with the LED bulb lifetime							100%	New KPI added in 2016
		1-to-5 scale, level of satisfaction with the Auto Heater Timer usefulness							89%	New KPI added in 2016

Table 4: Low Cost Energy Efficient Products Program KPI Summary

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	Progress Commentary
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)										
00	Externalities	No associated tracked KPIs	-	-	-	-	-			
02	Utilities conduct outreach activities at community events	Suggested KPI(s): # of events w/Program booth	Program documentation	2	7	4	2	4	10	Program staff participated in a number of community events to discuss inCharge and distribute kits. Kits were also given to walk-in customers at utility offices.
		# of kits distributed		40	220	60	223	400	239	Kits were distributed to 223 customers in 2015 and 239 customers to the end of July 2016.
04	Provide EE products free-of-charge	Suggested KPI(s): # of kits/products distributed	Program documentation	300	356	180	223	400	239	

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	Progress Commentary
06	Scorecard results will be analyzed	Suggested KPI(s): # of scorecards received	Direct engagement & communication logs	30	18	20	45	-	-	Scorecards were not used in the 2016 program documentation and were replaced with phone interviews.
08	Utilities support EE workshops hosted by EE ambassadors	Suggested KPI(s): # workshops	Program documentation	-	20	2	-	-	-	Ambassador workshops not part of 2015 and 2016 program.
		# people attending workshops		-	80	8	-	-	-	Ambassador workshops not part of 2015 and 2016 program.
10	Utilities' community engagement leads to 'behavior-based' electricity and demand savings	No associated tracked KPIs	-	-	-	-	-	-	-	
14 & 19	Shoppers buy and install low-cost EE products	No associated tracked KPIs	-	-	-	-	-			

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	Progress Commentary
20	The low-cost EE products will yield long-term electricity and demand savings	Suggested KPI(s): MWh of avoided lifetime electricity consumption MWh of avoided annual electricity consumption MW of avoided coincident electricity demand	Estimate based on free products provided	 4,605 424 113	 3208 298 81	 2885 646 178	 2313 503 169	 2885 913 252	 2313 708 257	2015 &2016 kits were redesigned to be simpler than 2014 kits and focused on products that customers were installing at high rates. This resulted in similar savings for lower administrative costs.
26	Participants will be satisfied by the low-cost EE products	Suggested KPI(s): Scorecard feedback1-to-5 scale, level of satisfaction with the products	Tracking System	70%	-	70% scoring 4-5 out of 5	95%	-	-	Scorecards were not used in the 2016 program documentation and were replaced with phone interviews.
05 & 27	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-			See Rebate Program KPIs above (Table 3).
28	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-			See Rebate Program KPIs above (Table 3).
Part B -- To Be Visited, Checked and Reported On by Evaluators										
00	Externalities	Done/Not-Done – report on externalities on an annual basis	Program documentation	Done	-	Done	-			

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	Progress Commentary
02	Utilities conduct outreach activities at community events	No evaluation indicator	-		-		-			Done
04	Provide EE products free-of-charge	No evaluation indicator	-		-		-			Done
06	Scorecard results will be analyzed	Suggested indicator(s): % of issued score cards that are completed and returned	Program documentation	10%	16%	10%	-	-	-	Scorecards were not used in the 2015 and 2016 program documentation and were replaced with phone interviews.
08	Utilities support EE workshops hosted by EE ambassadors	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the workshop on average	Attendees	7/10	10/10	8/10	-	-	-	Ambassador workshops were not part of 2015 and 2016 program.

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	Progress Commentary
14 & 19	Shoppers buy and install low-cost EE products	% products installed			-		-		LED: 72% Timer: 46% SPB: 89%	New KPI added in 2016. Note the low installation rate of Auto Heater Timers was attributed to the warmer than average winter in 2016. This low rate will be monitored in 2017 to confirm assumption.
20	The low-cost EE products will yield long-term electricity and demand savings	No evaluation indicator	-		-		-			
26	Participants will be satisfied by the low-cost EE products	Suggested indicator(s): 1-to-5 scale, level of satisfaction with their energy efficient products	Participants			80% scoring 4-5 out of 5	95%	80% scoring 4-5 out of 5	96%	Percentage of participants who were very satisfied or satisfied with each product: LEDs - 94%, powerbars - 95%, Auto heater timers - 100%, for an average of 96%.
27	Word-of-mouth	Suggested indicator(s): % heard of the program positively from other past participants	Participants			30%	65%	30%	46%	46% of participants had heard of the program from others and 100% of those discussions were positive (from Table 3). Non-participants were not surveyed in this evaluation.
		% heard of the program positively from past participants	Non-participants			10%	-	-	-	

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	Progress Commentary
28	Non-energy benefits	Suggested indicator(s): 1-to-5 scale, level of satisfaction with their energy-efficient product	Participants			80% scoring 4-5 out of 5	95%	80% scoring 4-5 out of 5	96%	Percentage of participants who were very satisfied or satisfied with each product: LEDs - 94%, powerbars - 95%, Auto heater timers - 100%, for an average of 96%.

3.3 General Program Administrator Observations

In addition to the information gathered to assess the KPIs, the staff administering the programs made the following observations and recommendations during the delivery of the inCharge program.

3.3.1 LED and Automotive Heater Timer Rebate Program Observations

The participation in the rebate program is now closely linked to instore events and communications, particularly when the price point of LED bulbs drops. LED bulb prices have dropped significantly since the start of the program and as a result participation levels have increased allowing more customers to take advantage of the rebate program. Participation rates were lower than expected in 2015, but are now higher than projected in 2016 resulting from an increase in communication and the introduction of instore events. Ongoing education with retail staff has resulted in greater in-store support and purchasing assistance for customers. The major retailers have noted the success of the instore events and are actively seeking opportunities for events and sales. National offices of the larger retailers are now aware of the Yukon programs and include the local stores in bulk purchasing opportunities resulting in lower prices and better stock choices. Online communication was also launched in late 2015 and is the most recognized advertising method.

Participants reported being very satisfied with the quality of LEDs. A bias still remains from the negative experience some customers have had with CFLs, but that comment is heard less frequently. More customers are choosing to purchase LEDs and are influenced by the program to buy more or to buy them sooner.

The larger Energy Star logo on the program forms resulted in less participant confusion and rebates being submitted for non-eligible products. Additional retail staff education has also contributed to less confusion at point of purchase.

The winter of 2015/2016 was warmer than average with the El Nino effect and the need for block heaters was minimal. This resulted in very low uptake of the automotive heater timer program. Given the uncertainties of weather for the 2016/2017 winter, a communications push regarding block heater timers will be launched in Q4 2016.

Based on the results of the participant survey, 99% of the LED bulbs purchased through the program and 82% of the block heater timers were installed. This means that only a small number of LED bulbs were left in storage. As for the timers, the explanation given by the participants who did not install it yet was the warm winter. Considering these high installation rates and the fact that it is very likely that the participants, who had to spend a certain amount of money to purchase the products, will install them ultimately, all of the savings associated with the rebates were claimed.

Comments from participants on the LED and Auto Heater Timer Rebate Program received during the phone surveys were very positive and a sample of the comments is below.

- Good and effective program. Savings are real and significant.
- Like the program design, really easy to participate.

- Been bragging to friends about the program. Love it!
- Excellent program, told many friends about it.
- Like the program being done by the utilities.

3.3.2 Low Cost Energy Efficient Products Program Observations

The simplified kit was easy to distribute and gave utility staff more time to engage with the recipient on electricity efficiency. Many of the recipients heard about the inCharge program for the first time when they received a kit. This is an opportunity to promote the inCharge program and increase brand awareness.

Telephone surveys showed that some participants did not recall receiving a kit and that there was some confusion with how to install and use the smart power bar. The telephone surveys also showed that the installation rates for the LED bulbs was slightly lower than 2015 (92% in 2015 as compared with 72% in 2016), higher for the smart power bars (84% in 2015 and 89% in 2016) and much lower for the automotive heater timers (98% in 2015 to 46% in 2016). An average installation rate of 85% was used for these products. This assumption will continue to be tested in follow-up evaluations. The kits were given for free to participants without validating their need for the products. Therefore it is important to apply the installation rates obtained from the participant surveys.

Comments from participants on the Low Cost Energy Efficient Products Program during the phone surveys were very positive and a sample of the comments is below.

- They are excellent products.
- Excellent program, keep it going.
- Good way to raise awareness.
- Keep the information coming. Helps to keep energy efficiency in the forefront.
- Very appreciative inCharge came out to Haines Junction. Not many organizations will travel there.

4 Results and Recommendations

LED and Automotive Heater Timer Rebate Program Recommendations

Recommendations for the rebate program are to continue to increase the communications efforts, particularly enhancement of instore advertising at the point of purchase. The goal is to increase participation, particularly among customers that are not already considering the purchase of LED's.

Also recommend is to provide a higher level of feedback to retail staff and managers on how their store is contributing to the program, which products participants are purchasing and share positive comments from participants to encourage their continued support as well as assist with stocking decisions.

4.1 Low Cost Energy Efficient Products Program Recommendations

To help increase awareness around the program and reach an audience that may not already be interested in electricity conservation, information regarding the inCharge program in general should be added to the kits. As the events where the kits are distributed are an opportunity to discuss the products and electricity conservation in general, care should be taken to ensure these events provide the time and space needed to engage with participants in a meaningful way. This is also intended to increase installation rates and reduce the number of participants that do not recall receiving an energy saving kit.

Installation rates of the automotive heater timers were lower in 2016 as compared to 2015. This trend and the cause of the low installation rates will be monitored closely to see if this was influenced by the warmer than average winter or if it is because of another barrier to installation. The 2017 evaluation could include a follow-up with 2015 participants to check if they had used their timer the following year. A reminder note to the 2015 kit recipients reminding them of the benefits of their automotive heater timers could also be sent. Also, the information included in the kits should be updated with more information on how to use the products, particularly the smart power bars, to ensure all participants are aware of their proper use and benefits.

4.2 Evaluation Summary and Evaluation Recommendations

Overall, this interim evaluation has shown that the inCharge Programs were well received by Yukoners, participation met or exceeded most KPIs (as shown in Tables 3 and 4 above) and were cost effective (as shown in Table 2). The linkages between activities, outputs, short-term outcomes, intermediate outcomes and long-term outcomes as laid out in the program logic models (Appendix B), are clear, well defined and reasonable.

The following short-term outcomes were achieved:

- Energy efficient products identified and endorsed;
- Energy efficient products available in stores;
- Retail staff educated about energy efficient products and provided in-store customer support;
- Customers educated about energy efficient products
- Customers convinced to buy and install energy efficient products; and
- The initial cost hurdle was alleviated.

The intermediate outcomes that were achieved include effective communication through advertising and word of mouth and participant purchase and installation of eligible energy efficient products was achieved.

The long-term outcomes that were achieved include high customer satisfaction with the programs and products, and cost effective, long-term energy and demand savings.

Overall, the program rationale is sound and the results to date support the reasonableness of the claimed cost effectiveness, and the energy and demand savings.

The US Department of Energy, Uniform Methods Project (UMP) has been recently completed and presents updated protocols for DSM program evaluation. The inCharge program will continue to work to ensure that the program evaluation is aligned with the new UMP methods.

In the Program Projections excel workbook that was developed to model the cost effectiveness of the inCharge program, one installation rate is applied to all five years. While this simple approach works for the current program, it would be an improvement if future projections or evaluation models could apply a separate installation rate to each year.

The program administrators should start to look for cost effective ways to measure the free ridership and spillover assumptions. This may be from surveys completed by other utilities with larger programs or through a short survey in the Yukon.

Appendix A: TRM Example – Standard LEDs > 9W

Energy Conservation Measure - Justification of the Incentive Level

ECM61

Inputs - Measure Considerations	
Measure Name:	Standard LEDs (>9 W)
Incentive Amount:	$7.00
Measure/Project Cost:	$7.61
Gross Consumption Savings:	40 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	43 kWh/yr
Gross Demand Savings:	.01 kW
Gross Demand Savings w/ T&D losses:	.010 kW
Participant's Savings on Year 1:	$5.74
Measure Lifetime:	20 yr

Inputs - Program Considerations		
Program Cost (% of Incentive):	192%	
Suggested Program Cost (% of Incentive):	192%	-->not us
Forecasted Freeridership:	10%	
Forecasted Participant Spillover:	0%	
Forecasted Non-participant Spillover:	10%	
Forecasted Rebound Effects:	0%	

Outputs with Program Costs	
PC - Benefit/Cost Ratio	10.64
PC - Net Present Value	$73.39
PC - Levelized Cost	$0.0174/kWh
Simple Payback w/ Incentive (yr)	0.1 yr
RIM - Benefit/Cost Ratio	*1.28*
RIM - Net Present Value	*$26.88*
RIM - Levelized Cost	*$0.1975/kWh*
TRC - Benefit/Cost Ratio	5.76
TRC - Net Present Value	$100.27
TRC - Levelized Cost	$0.0441/kWh
PAC - Benefit/Cost Ratio	*5.93*
PAC - Net Present Value	*$100.88*
PAC - Levelized Cost	*$0.0428/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.65*
RIM-YECL - Net Present Value	*-$24.06*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.93*
RIM-YEC - Net Present Value	*$63.55*
RIM-YEC - Levelized Cost	*$0.1322/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$7.61
Incentive Amount in Year 1	$7.00
Assumed Program Administration Costs in Year 1	$13.47
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership + P. Spillover + N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$74.01	$74.01
Discounted Cumulative Gross Energy Savings for 20 years	439 kWh	439 kWh
PC - Present Value of Benefits	$81.01	$81.01
PC - Present Value of Costs	$7.61	$7.61
PC - Benefit/Cost Ratio	10.64	10.64
PC - Net Present Value	$73.39	$73.39
PC - Levelized Cost	$0.0174/kWh	$0.0174/kWh
Simple Payback with Incentive	0.1 yr	0.1 yr

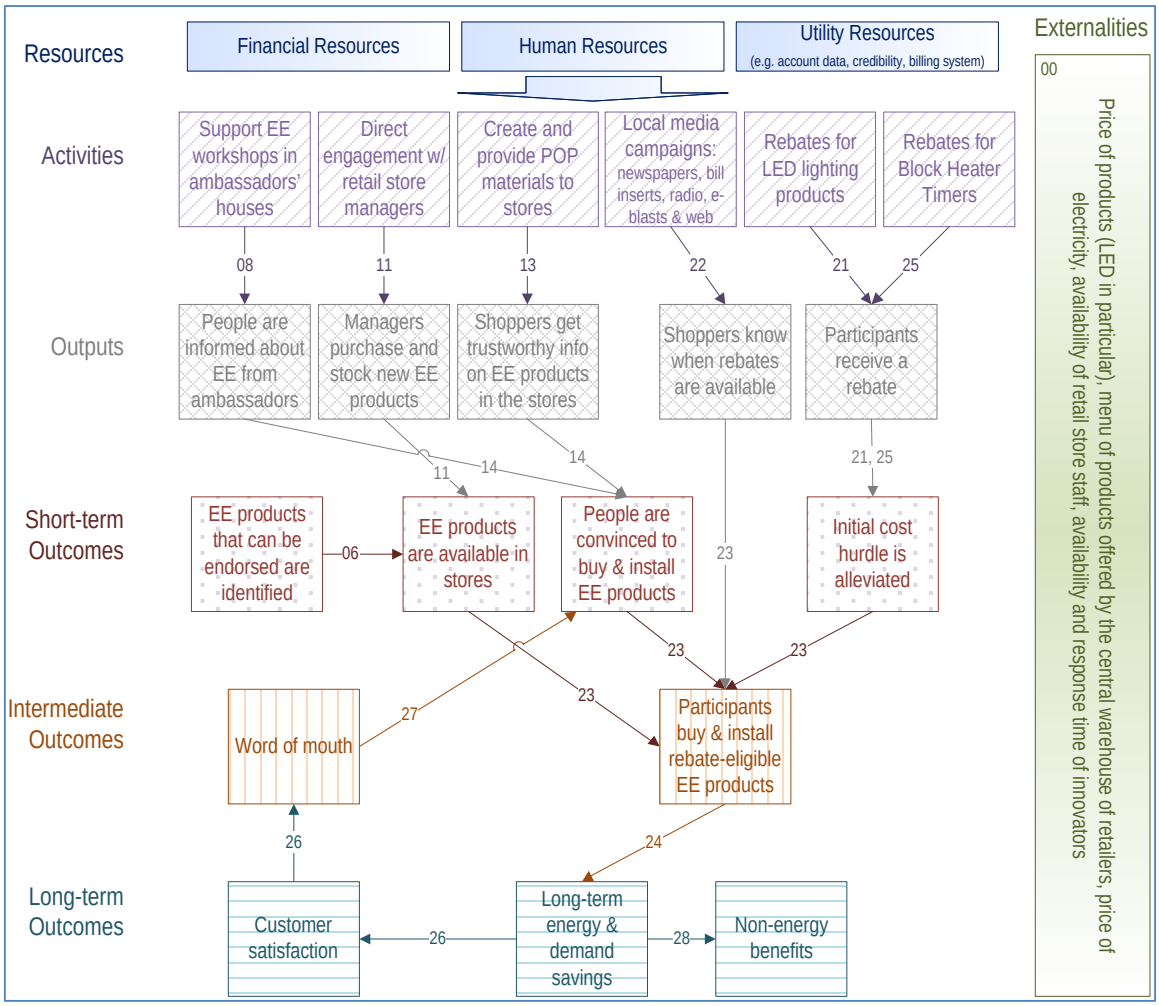
Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$121.35	$121.35
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$74.01	$74.01
Discounted Cumulative Net Energy Savings for 20 years	478 kWh	478 kWh
RIM - Present Value of Benefits	$121.35	$121.35
RIM - Present Value of Costs	$94.48	$81.01
RIM - Benefit/Cost Ratio	1.3	1.5
RIM - Net Present Value	$26.88	$40.35
RIM - Levelized Cost	$0.1975/kWh	$0.1693/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$121.35	$121.35
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	478 kWh	478 kWh
TRC - Present Value of Benefits	$121.35	$121.35
TRC - Present Value of Costs	$21.09	$7.61
TRC - Benefit/Cost Ratio	5.76	15.9
TRC - Net Present Value	$100.27	$113.74
TRC - Levelized Cost	$0.0441/kWh	$0.0159/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$121.35	$121.35
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	478 kWh	478 kWh
PAC - Present Value of Benefits	$121.35	$121.35
PAC - Present Value of Costs	$20.47	$7.00
PAC - Benefit/Cost Ratio	5.9	17.3
PAC - Net Present Value	$100.88	$114.35
PAC - Levelized Cost	$0.0428/kWh	$0.0146/kWh

Appendix B: Program Logic Models

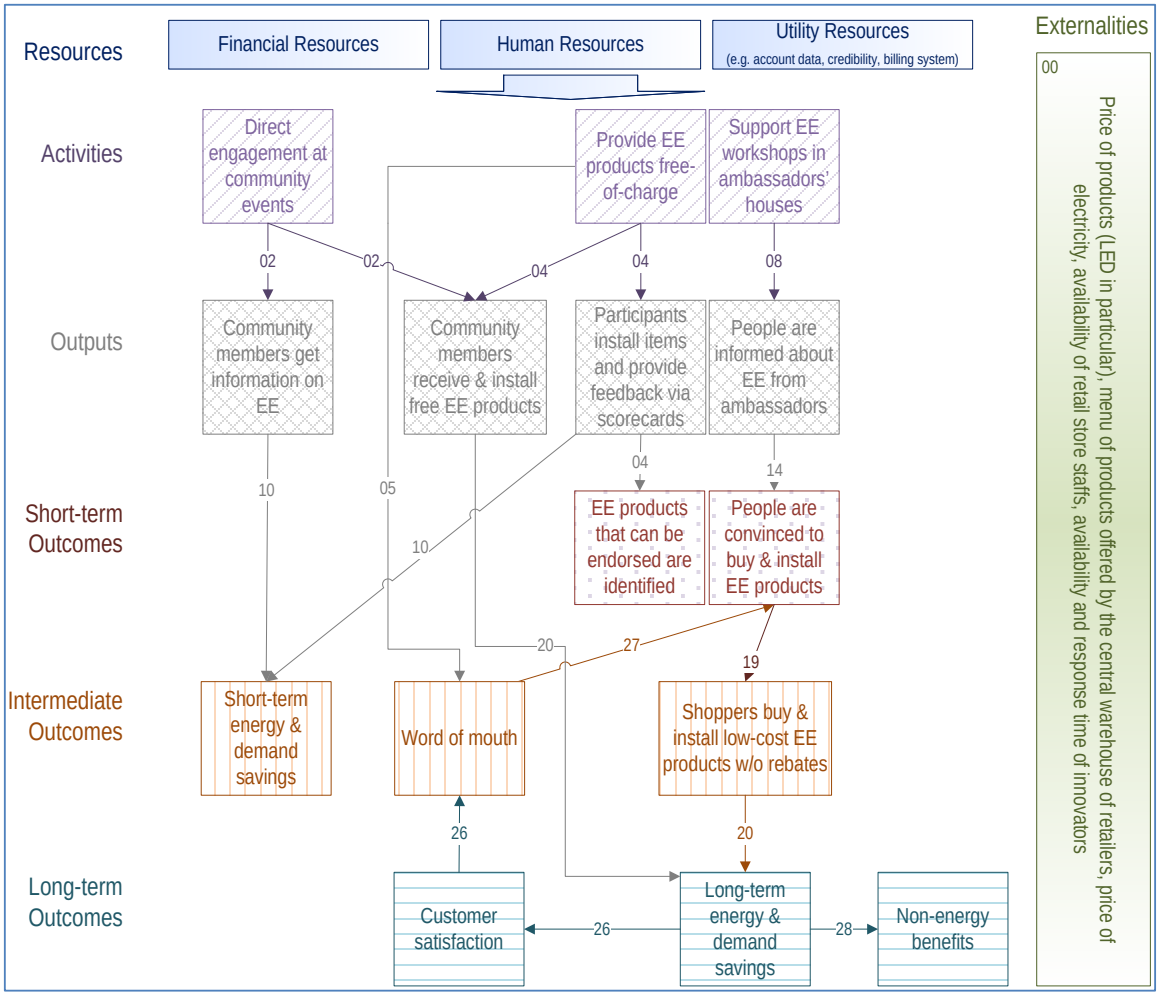
Figure B1: Logic Model for the Residential LED Lights and Automotive Heater Timer Rebate Program



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: price of products (LED technologies, in particular), menu of products offered by the central warehouse of retailers, price of electricity, and availability of retail store staff to address any questions. The program administrator should monitor these externalities and adapt the implementation approach based on them.

Link #	Narrative
08	The Utilities will support EE workshops in the homes of EE community network members or nearby community venues with approximately ten friends and relatives. The Utilities will send facilitator(s), provide communication materials and low-cost EE products to give away, and perhaps provide food and beverages. The Utilities' skilled facilitator(s) will have a few key messages regarding low-cost EE products, LED lighting products, and automotive heater timers. The facilitator will encourage the participants to share tips and information on electricity conservation. The facilitator will seek to eliminate potential sources of confusion and false beliefs in the communities by presenting hard facts.
11	The Utilities will establish partnerships with Yukon retail store managers and establish two-way communication. The Utilities will suggest new products to stock; perhaps by providing the results of the low-cost EE product piloting, by revealing in advance what products will be eligible for the LED lighting rebate and automotive heater timer rebate, or by indicating what POP materials will be created and offered to the shops.
13	The Utilities will design and procure educational Point Of Purchase (POP) materials for Yukon retail managers to display in their stores. These materials might include (but not be limited to): brochures, presentation boxes, posters, and displays stands.
14	Yukon shoppers will be informed on EE products through the community direct engagement, and through the POP materials. This will cause them to buy and install these products.
21	The Utilities will provide a flat amount of money per unit to Yukon shoppers after they purchase LED lighting lamps or fixtures selected from a prescriptive list of eligible products. The initial-cost hurdle will be alleviated which will contribute to the items being purchased and installed.
22	The "rebate" period will be extensively advertised through a media campaign through local radio, local newspapers, co-op advertisement with retailers and in stores, and electricity bill inserts. Consequently, shoppers will know when the rebates are going to be available.
23	Participating Yukon shoppers (i.e. participants) will buy and install LED lighting products or automotive heater timers and receive a rebate because these products will be available in the stores, because they were made aware of the benefits of these products, because they know when the rebate is available, and because the initial cost hurdle was alleviated by the rebate.
24	The LED lighting product installs and automotive heater timer installs will yield long-term electricity and demand savings.
25	The Utilities will provide a flat amount of money per unit to Yukon shoppers for the purchase of automotive heater timers (i.e. outdoor) selected from a prescriptive list of eligible products. The initial-cost hurdle will be alleviated and/or the rebate will make the purchase of an automotive heater timer much more enticing. This will contribute to the purchase and installation of these items.
26	Shoppers who bought low-cost EE products, LED lighting products or automotive heater timers will be satisfied by the products that they bought. They will tell their friends and relatives. This will generate word-of-mouth advertisement.
27	With time, word-of-mouth will become an important information channel that will cause Yukon residents to buy and install EE products.
28	Shoppers will perceive new non-energy benefits and/or the less maintenance related to the energy efficient products when they're compared with the baseline systems. For example, the Utilities will seek to make sure that participants will perceive that their new LED products last longer, are less sensitive to power quality issues, are more reliable, cast better light (color rendering, intensity, and visual acuity), and easier and less hazardous to dispose of than CFLs. The Utilities will seek to make sure that participants will perceive that automotive heater timers are reliable and that the use of a timer does not have negative impact on their car.

Figure B2: Logic Model for Residential Low Cost Energy Efficient Products Program



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: price of products (LED technologies, in particular), menu of products offered by the central warehouse of retailers, price of electricity, and availability of retail store staff. The program administrator should monitor these externalities and adapt the implementation approach based on them.
02	The Utilities will carry out outreach activities in community events (e.g. sport events, cultural events, town hall meetings, etc.), engage with organization and people who have a natural interest in electricity conservation; hook individuals with a continuous stream of free low-cost EE products or contests; do personalized follow-ups; and promote the idea of supporting an EE workshop at their home or a at local venue.

Link #	Narrative
06	Low-cost EE products will be used by program participants. Participants will be provided with simple scorecards that will give them the opportunity to provide feedback on the various products. The Utilities will collect all of the scorecards, aggregate and analyze the results, and use the results on consumer satisfaction to improve the products that are distributed by the program in subsequent years.
05	It is expected that the volunteers and EE community network members will like the low-cost EE products and will tell their friends and relatives. This will feed the word of mouth feedback loop.
08	The Utilities will support EE workshops in the homes of EE community network members or nearby community venues with approximately ten friends and relatives. The Utilities will send facilitator(s), provide communication materials and low-cost EE products to give away, and perhaps provide food and beverages. The Utilities' skilled facilitator(s) will have a few key messages regarding low-cost EE products, LED lighting products and automotive heater timers. The facilitator will encourage the participants to share tips and information on electricity conservation. The facilitator will also seek to eliminate potential sources of confusion and false beliefs in the communities by presenting hard facts.
10	The information and tips provided to residents of the Yukon as part of the Utilities direct community engagement activities will influence their behavior and cause them to use less electricity and reduce their peak demand. However, quantifying "behavior-based" electricity and demand savings is challenging and perhaps cost-prohibitive for a small jurisdiction like the Yukon. Moreover, the persistence of "behavior-based" conservation measures is notoriously bad. It is commonly believed to be less than one year by DSM experts. Consequently, the short-term benefits of behavior-based conservation measures will not be quantified. They are considered to be outcomes that are "nice-to-have" yet not necessary to make the program viable.
14	Yukon shoppers will be informed on EE products through the community direct engagement. This will cause them to buy and install these products.
19	Yukon shoppers will buy and install low-cost EE products (even in the absence of rebate) because these products will be available in the stores, and because they were made aware of the benefits of these products. The low-cost EE products may have a certain price increment; however it is assumed that the price increment (if any) is too small to constitute the most important purchase barrier.
20	The free and purchased low-cost EE product installs will yield long-term electricity and demand savings.
26	Shoppers who received low-cost EE products or purchased LED lighting products or automotive heater timers will be satisfied by the products that they bought. As a result, they will tell their friends and relatives about their experience with these products. This will generate word-of-mouth advertisement.
27	With time, word-of-mouth will become an important information channel that will cause Yukon residents to buy and install EE products without any support from the Utilities.
28	Program participants will perceive non-energy benefits, including improved comfort and reduced maintenance, as a result of the products they installed. For example, the Utilities will seek to make sure that participants will perceive that their new LED products last longer, are less sensitive to power quality issues, are more reliable, cast better light (color rendering, intensity, and visual acuity), and are easier and less hazardous to dispose of than CFLs. The Utilities will seek to make sure that participants will perceive that automotive heater timers are reliable and that the use of a timer does not have any negative impacts on their vehicles.

Appendix C: LED Rebates by Bulb Type

	2014		2015								2016					
Type	**Q4**		**Q1**		**Q2**		**Q3**		**Q4**		**Q1**		**Q2**		**Q3**	
Candelabra LEDs (Up to 6 W)	52	2%	61	3%	7	1%	7	8%	57	3%	29	3%	24	1%	2	0%
Standard LEDs (Up to 9 W)	300	10%	365	20%	220	24%	13	14%	658	33%	302	33%	2689	65%	1843	84%
Standard LEDs (>9 W)	2258	78%	1219	66%	623	67%	64	70%	908	45%	383	41%	1107	27%	259	12%
Reflector LEDs (Up to 9 W)	264	9%	172	9%	59	6%	3	3%	313	16%	196	21%	289	7%	87	4%
Reflector LEDs (>9 W)	24	1%	23	1%	12	1%	2	2%	41	2%	11	1%	11	0%	1	0%
Recessed LED Fixtures	0	0%	2	0%	8	1%	2	2%	40	2%	6	1%	11	0%	0	0%
Total	2898	100%	1842	100%	929	100%	91	100%	2017	100%	927	100%	4131	100%	2192	100%

TOPIC: **Reconciliation of Utility Income to Net Earnings**

REFERENCE: June 22, 2017 Application, Schedule 8, page 7-12

PREAMBLE:

QUESTION:

a) Please explain why $269,351 in cost claims by YEC that were disallowed in Board Order 2013-08 dated September 13, 2013 are not shown at line 6 (Disallowed Costs).

b) Please provide a breakdown of all costs associated with regulatory proceedings in 2012 through 2016 and identify where these costs are included within the current application.

c) Please provide a breakdown of all costs (actual to date and forecast) associated with regulatory proceedings in 2017 and 2018 and identify where these costs are included within the current application. Please include details related to in-house as well as consultant and outsourced services (labour, O&M, etc.).

ANSWER:

(a)

The cost claims disallowed in Board Order 2013-08 are included on Line 3 of Schedule 8 and disclosed in Note 2 of Schedule 6.

(b)

2012 costs are not shown in this application. Costs associated with regulatory proceedings for 2013 through 2016 are detailed below and summarized in Table 3.14.1 of the Application.

Table 1: Regulatory Proceeding Costs: 2013-2016

($000's)	2013	2014	2015	2016
2012-2013 GRA costs	387			
DSM/inCharge	58	8		
LNG Part 3		423		
DCF/ERA			213	138
	444	432	213	138

In addition, $105,000 of costs associated with the 2017-2018 GRA were incurred in 2016 and are shown in Table 5.6.

(c)

All costs are external costs/services. Forecast costs are included within the Application in Table 3.14.1, Table 5.7 (Regulatory) and Table 5.8 (Regulatory). Actual 2017 costs to June 30, 2017 are disclosed below.

Table 2: Regulatory Proceeding Costs: 2017

($000's)	
2017-2018 GRA	241
DCF/ERA	3
	244

TOPIC: **Summary of Customers, Energy Sales and Revenues**

REFERENCE: June 22, 2017 Application, Schedule 9, page 7-13

PREAMBLE:

QUESTION:

a) Please confirm that YEC is predicting a 4% increase in total sales (line 43) from 2013 allowed (383,061 MWh) to 2017 forecast (397,859 MWh) and a 15% increase in total revenues (line 51) between 2013 allowed ($42,263,000) and 2017 forecast ($48,544,000).

b) Please confirm that YEC is predicting a 0.2% increase in total sales (line 43) from 2017 forecast (397,859 MWh) to 2018 forecast (398,582 MWh) and a 2.7% increase in total revenues (line 51) between 2017 forecast ($48,544,000) and 2018 forecast ($49,864,000).

c) Please explain why significant increases to sales volumes in 2017 and 2018 still require a significant increase to riders charged to Yukon ratepayers.

ANSWER:

(a)

Confirmed.

(b)

Confirmed.

(c)

A 4% increase in sales volumes from 2013 approved to 2018 forecast requires a rate increase due to other changes that have occurred between 2013 and 2017/2018. For further details see Application pages 1-1 through 1-7.

TOPIC: **Summary of Operating and Maintenance Expenses**

REFERENCE: June 22, 2017 Application, Schedule 10, page 7-14

PREAMBLE:

QUESTION:

a) Please provide an explanation for the increases to the Administration and General expense (line 5) between 2013 approved ($8,654,000) and the expenses for 2015 actual ($8,101,000), 2016 actual ($8,509,000), 2017 forecast ($9,110,000) and 2018 forecast ($8,912,000). Also explain the proposed 7.1% increase between 2016 and 2017 and the 2.2% decrease from 2017 to 2018.

b) Please provide an explanation for the increases to the Reserve for Injuries and Damages expense (line 16) between 2013 approved ($226,000) and the expenses for 2017 forecast ($479,000) and 2018 forecast ($479,000).

c) Please provide an explanation for the increases to the Property Taxes expense (line 17) between 2013 approved ($326,000), 2015 actual ($473,000), 2016 actual ($686,000), 2017 forecast ($696,000) and 2018 forecast ($708,000).

d) Please provide an explanation for the increases to the Donations expense (line 18) between 2013 approved ($85,000), 2016 actual ($95,000), 2017 forecast ($96,000) and 2018 forecast ($100,000).

ANSWER:

(a)

See CW-YEC-1-24 and YUB-YEC-1-11.

(b)

See Application Section 3.3.6.

(c)

See YUB-YEC-1-14 and CW-YEC-1-20.

(d)

YEC Board of Directors approved an increase of $10,000 for donations in 2016. Similarly, changes in 2017 and 2018 reflect Board of Directors approved changes to YEC's scholarship policy. Note donations are excluded from revenue requirement determination.

TOPIC: **Summary of Cost of Long-Term Debt**

REFERENCE: June 22, 2017 Application, Schedule 11, page 7-15

PREAMBLE:

QUESTION:

a) Please provide a breakdown of the $92.5 million YDC debt (line 10), the $21 million YDC debt (line 11), the $12 million YDC debt (line 12), the new 2017 $23.828 million debt (line 13) and the new 2018 $7 million debt (line 14) including terms and payment requirements as well as reasons for the debt.

b) Please explain why the new long-term debt for 2017 is increasing from $13.118 million to $23.828 million.

ANSWER:

(a)

Debt is required is to maintain Yukon Energy's YUB approved capital structure. Terms and payment requirements of the $92.5 million YDC debt and the $21 million YDC debt are detailed in Tab 9 of the Application on page 9-26. The $12.1 million YDC issued debt in 2016 has an interest rate of 2.1%, payable annually, and is due December 31, 2041. The forecast 2017 and 2018 debt are assumed to have an interest rate of 2.15%.

(b)

Please see the response to YUB-YEC-1-1(b) for an explanation regarding the difference between "Existing" and "Proposed" forecasts. The forecast debt required for 2017 is higher under the "Proposed" forecast than the "Existing" forecast primarily due to a higher rate base resulting from the addition of assets previously held in WIP per Order 2013-01. For further details see the Summary of Requested Orders 1(d)(ii) and (iii), included in the Application at pages 6-7.

Yukon Conservation Society
(YCS)

TOPIC: Carbon Pricing and Social Cost of Carbon

REFERENCE:

PREAMBLE:

QUESTION:

a) Please describe YEC's understanding of the difference between carbon pricing, carbon tax and the social cost of carbon.

b) Please describe how YEC factored in carbon pricing to the models used in making decisions around thermal generation.

c) How does or will carbon pricing affect electricity rates in Yukon?
   i) Explicitly: with carbon tax rates starting at $10/T, to $50/T as has been indicated by Canada.
   ii) Implicitly: incorporating carbon reduction policies that do not rely on a direct tax, such as clean energy policies or electric vehicle policies. These policies can result in an implied carbon price as high as $210/T.
   iii) In the following scenarios:
      (1) No mines
      (2) Minto mine only
      (3) Minto plus Victoria Gold
      (4) Minto plus Victoria Gold plus Alexco

ANSWER:

(a)

YEC used the terms social cost of carbon, carbon pricing and carbon tax interchangeably in the portfolio analysis of the 2016 Resource Plan. The social cost of carbon values used in the portfolio analysis are different from the carbon tax values proposed by the federal government, since the 2016 Resource Plan analysis had been undertaken prior to the federal government carbon tax announcement. The rationale for using the social cost of carbon and selecting its values is discussed in detail in the Social Cost of Carbon section

(Section 6.2) of the Market Assessment chapter (Chapter 6) and Social Cost of Carbon appendix (Appendix 6.2) of the 2016 Resource Plan.

(b)

The social cost of carbon was translated from \$/t of CO^2 eq to \$/kWh and added to the cost of every kWh of generated energy in the portfolio analysis of the 2016 Resource Plan. Also, the upstream and downstream greenhouse gas (GHG) emissions costs were added to every asset to include the life cycle analysis of GHG emissions. The details are discussed in the Social Cost of Carbon appendix (Appendix 6.2) of the 2016 Resource Plan.

(c)

Even though the federal government announced the carbon tax starting in 2018, the carbon tax was not considered in the GRA since the implementation mechanism was not known and, consequently, the rate impact would be speculative. As well, determining an accurate rate impact depends on several factors such as load, YEC assets, and inflows. All of these factors are subject to change from one year to another.

The financial impact of a carbon tax will be paid through fuel costs. By definition, any increase in the unit price of fuel is charged to the Rider F account.

(i)

For the potential carbon tax equal to \$10/t CO^2 and \$50/t CO^2 eq, the rate increase is less than 0.2% and 1% respectively, under the assumptions of thermal generation forecast for 2018 as presented in the 2017-2018 GRA and the conservative assumption that all the thermal generation will be diesel. The simplifying assumption that all the thermal generation would be diesel was made to provide the upper bound for the rate impact. In reality, considering that the thermal generation would be split between natural gas and diesel, the rate impact might be lower.

(ii)

Under the assumption of a hypothetical carbon tax of $210/t CO^2 eq, the potential rate increase would be less than 3% under the assumptions listed in the answer to YCS-YEC-1-1(c)(i).

(iii)

Based on the assumption of the assessment of the long term annual average split between thermal and renewable generation of 2% and 98% respectively, as per the mixed portfolio for the medium industrial scenario load presented in the 2016 Resource Plan portfolio analysis, and conservative assumption that all the thermal generation would be diesel, the estimate of the rate increase for the carbon tax of $50/t CO2 eq is approximately 1%.

TOPIC: Demand Elasticity

REFERENCE:

PREAMBLE:

QUESTION:

a) What will be the predicted effect on electricity consumption (demand) when/if the rate increase is granted?

ANSWER:

The predicted effect of a rate increase would be to encourage consumers to reduce electricity consumption in order to reduce costs. No specific elasticity impact has been estimated.

TOPIC: Decentralization and Digitalization

REFERENCE:

PREAMBLE:

QUESTION:

The relationship between utilities and their rate base (customers) is rapidly changing, as customers also become suppliers. As the nature of the grid changes from a hub and spoke model to a network of multiple suppliers and customers, there will be changes to the income and expenses of YEC.

a) Please provide an analysis of YEC's understanding of this shift, and how a transition to an energy management network will be implemented by YEC.

A smart grid will be integral to accommodating the above change. This will involve smart meters and other, more complex changes to manage the rapidly changing flows of electricity from multiple intermittent sources.

b) Please provide a thorough exploration of how this will work, how much this will cost, and how will it be paid.

ANSWER:

(a) and **(b)**

At this time, the YEC grid is not mature enough for implementation of the changes listed in the above questions and, as a consequence, no corresponding studies have been completed by YEC. The resource plan is updated on an ongoing basis. YEC monitors technological changes as they become significant and will address them as required as part of future planning processes. The changes listed in the above questions are on YEC's planning horizon and once the corresponding studies are conducted, the implementation methodology, as well as technical, financial, environmental, social and economic consequences of the changes will be brought forward for consideration as part of future reviews.

TOPIC: **Cost Overruns**

REFERENCE:

PREAMBLE:

QUESTION:

a) What was the average percent cost over run for past capital projects?

ANSWER:

(a)

The question as presented does not inform the prudency of these costs, and also does not provide any limit as to which past capital projects are to be reviewed. The Application includes all information necessary for the YUB to assess capital costs for inclusion in rate base.

TOPIC: **Mayo A and Mayo B**

REFERENCE:

PREAMBLE:

QUESTION:

a) Please describe the capacity and annual yearly energy output of Mayo A prior to construction of Mayo B for the past twenty years.

b) Please describe the capacity and annual yearly energy output of Mayo B since its construction/in-service.

c) Please describe the annual yearly energy output of Mayo A and Mayo B combined since the latter's construction.

d) Was the imminent end of life of Mayo A understood at the time of Mayo B's proposal?

e) What was the net benefit or increase in capacity and energy output of Mayo A and B combined after Mayo B was constructed, considering and including various constraints of water use and availability.

f) What is the cost of the downstream flooding remediation? Please include all costs incurred by ratepayers and work done by Yukon Government.

g) What is the annual cost to service the debt?

h) After including the above costs (flooding mitigation/remediation and servicing the debt), please provide an analysis of the value of the project to ratepayers and taxpayers when the "no-cost money" of federal government grants are included.

i) After all costs (those added to rate base as well as government grants) are considered, what was the cost per MW of net increase of capacity?

ANSWER:

(a) through **(i)**

The analysis sought in these questions is not relevant to this proceeding. The Mayo B project was reviewed by the YUB prior to construction via the Part 3 process and was further assessed for prudency at the 2012/13 GRA. As a result of that process, the YUB has already approved Mayo B costs into rates.

To assist the parties in reviewing specific other issues raised, YEC can provide the following:

- Downstream flooding remediation costs – flooding issues in Mayo are not related to Mayo B development; YEC incurred one-time costs to address the flooding events in 2010 (prior to Mayo B development) but there are no additional costs in this Application related to flooding issues.

- Interest – interest on the Mayo B Note is disclosed in the Application, Tab 7, page 7-15, l.20.

TOPIC: **Aishihik Hydro 3**

REFERENCE:

PREAMBLE: According to information supplied in the GRA, cost to YEC to settle the action was $1.6M, of which $0.96M was legal fees. YEC indicates it is appealing this decision, on advice from legal counsel (which will benefit from continuing the action).

QUESTION:

a) What would the cost have been to YEC to settle instead of continuing the action with associated legal fees?

b) Please explain why it would not be more prudent to cut the losses and accept the decision now rather than incur yet more legal fees.

c) Please provide an estimate of the costs to continue to pursue this action to YEC's legal counsel's advised conclusion.

ANSWER:

(a)

YEC attempted to settle with the contractor through multiple rounds of negotiation, including a court-sponsored mediation process, but unfortunately an agreement was not reached.

(b)

The evaluation of YEC management, with the support of legal counsel, is that there is a net benefit accruing to YEC if they are successful on appeal (i.e., expected award exceeds cost to appeal).

(c)

Estimated costs to pursue the appeal to conclusion are $0.250 million.

TOPIC: **SCADA Communications Upgrade**

REFERENCE:

PREAMBLE: The SCADA project for Dawson, Faro and Carmacks is described as allowing YEC to run many new services and protocols to these sites.

QUESTION:

a) Please provide a list of these services and protocols.

b) How does the addition of these services and protocols advance the 20 year Resource Plan?

c) How will the addition of these services and protocols enable integration of EV charging, storage and dispatching, IPPs and the multiple micro gen projects likely to come on line in the near future?

ANSWER:

(a)

Protocols are as follows:

- Modbus-TCP
- DNP3
- IEC61850

Services (not limited to) are as follows:

- Time
- SNMP
- Backups
- Radius
- Remote access

These are the immediate technologies to roll-out, any other service or protocol that runs on IP can be implemented in the future.

(b)

This project was not specifically undertaken to advance the 20 Year Resource Plan.

(c)

The addition of these services helps bring YEC's communications infrastructure to a modern standard, allowing increased flexibility and opportunities to integrate various new technologies.

TOPIC: **LNG Facility**

REFERENCE:

PREAMBLE: The failure by YEC to fully consider the YESAB process and the requirements of YOGA resulted in cost overruns of approximately $5.45M.

QUESTION:

a) Please describe the lessons learned and actions taken so that future capital projects will not incur similar unanticipated but predictable cost overruns.

b) Please confirm whether the demolition costs and the transportation and FN benefit costs are part of this $5.45M or, as it was indicated that they were removed, should they be added to the $5.45M cost overrun.

c) Given that capital projects managed by YEC almost always incur unanticipated extra costs, how much confidence should we have that installing the third LNG generator will come in on budget?

d) Please summarize the reasoning behind YEC pursuing the LNG facility.

e) Does YEC believe that the LNG plant was a prudent investment?

f) During the extensive work done for the 2016 20 Year Integrated Resource Plan, YEC determined that the Levelized Cost of Capacity (LCOC) for diesel was lower than the LCOC of LNG. This is counter to what YEC argued in the LNG proceeding, when YEC was determined to construct the LNG facility as a capacity project. Please explain what has changed in the few short years that would explain why diesel is the thermal/capacity choice moving forward, as described in the new Resource Plan, when it was not at the time LNG was being actively pursued by the public utility.

g) When decisions around opting for an LNG facility were made, the price gap between the price of natural gas and diesel was at an all time high. Please provide an analysis of the payback of an LNG over diesel plant under current conditions.

h) Please include scenarios where overall demand does not increase and scenarios where increasing amounts of intermittent renewable electricity feeds into the grid.

ANSWER:

(a) through **(h)**

YEC proceeded with the LNG Project as a least cost option to meet increased capacity requirements driven in part by the retirement of two Mirrlees units at Whitehorse, in addition to short term energy needs identified at the time. The project was undertaken subsequent to a period of extensive and unprecedented (for the post 1987 era) expansion of YEC's renewable energy capability,[1] and project planning occurred in the context of grid energy load forecasts that were then accepted for GRA and other planning purposes.

The prudence of the LNG Project was reviewed in depth, and confirmed, by the YUB during the Part 3 proceeding.

Subsequent to the Part 3 proceeding several material changes occurred to affect the project's economics, including:

- Regulatory delays and change requirements that delayed proceeding on the planned schedule and design, and resulted in major increases in capital costs relative to prior forecasts;

- Reductions in grid energy loads (and therefore in long-term average thermal requirements) which acted to reduce the opportunity for fuel cost savings with LNG versus diesel generation;

- Delays in securing lower haul cost options for LNG supply to YEC; and

- YDC capital contribution that in effect removed any capital cost penalty for this initial LNG project relative to the new diesel alternative that would otherwise have been implemented.

[1] i.e., the Mayo B and Aishihik Third Turbine developments, and the connection of the WAF and MD grids subsequent to the Mayo Dawson Transmission extension).

Subsequent to this project's development, the requirements for new capacity have been confirmed and currently constitute a major ongoing challenge for the Yukon grid. Delivered fuel costs for LNG have also been confirmed to provide savings relative to diesel generation, with improvements in this regard over the past 12 months.

The final costs for the LNG Project, and the factors accounting for the cost increase (as well as any other relevant considerations) are fully reviewed in response to YUB-YEC-1-70(a). Table 1 in that response also addresses demolition costs, transportation and FN benefit costs. Updated cost estimates for the 3rd Engine are provided in response to YUB-YEC-1-71.

Please see the response to John Maissan-YEC-1-27 for review of the Part 3 proceeding forecasts and subsequent outcomes relating to capital costs, delivered fuel costs and grid load requirements through the 2017 and 2018 test years - including updates to the table and figure used in the Part 3 proceeding to review the project's overall economic costs and benefits. Based on all changes since the Part 3 proceeding, including the YDC capital contribution, all fuel cost savings from the project now represent a growing net economic benefit for ratepayers.

With regard to the 2016 Resource Plan references in the question, please see the response to YCS-YEC-1-13 regarding why LNG was initially not seen as an economic option for this large scale thermal plant expansion, and why it is now being considered as an option – as well as the option of refurbishing the Whitehorse Diesel Plant with dual fuel engines that facilitate use of the LNG and diesel fuel infrastructure already established at this location. The analysis throughout continues to focus on the same factors as were reviewed in the LNG Project Part 3 proceeding – with the objective to secure the needed new capacity as soon as practical with reliable and least cost resource options based on consideration of capital and fuel costs. Reduced energy load forecasts on the grid can limit opportunities for LNG to provide fuel cost savings of sufficient magnitude to justify a 20 MW LNG facility.

With regard to the question's references to regulatory risks related to the LNG Project, the following are noted:

- Yukon Energy did not fail to fully consider the YESAB process, which YEC had by that time had ample successful prior experience with the Carmacks Stewart Transmission and Mayo B projects.

- Regulatory risks were clearly identified in the Part 3 Application for the LNG Project and discussed in detail during the interrogatory process and the hearing process for the project.

- The draft YESAB Screening issued prior to the YUB Part 3 review report did not indicate any material environmental issues that threatened proceeding with this project, i.e., the subsequent issues relating to the final YESAB report and decision body approval delays were not foreshadowed in the draft.

- In contrast to the YESAB process, YOGA's requirements were being newly developed as the project proceeded – and the directions that created requirements for last minute material and costly changes in the project could not reasonably have been foreseen based on established Canadian criteria applicable to similar projects.

TOPIC: **Battery Project**

REFERENCE:

PREAMBLE: It is unclear from the GRA which battery option is preferred. A 4.6MW or 8MW lead acid or an 8MW Li ion option are all on the table.

QUESTION:

a) Please present: the capacity of these options, the energy available and for how long, the capital costs, the cost per MW and MWh and the discussion around arriving at a decision.

b) If a 15MW battery had been in place, the four grid failures of July/August 2017 may have been avoided. A 15MW battery would reduce or even eliminate the need for spinning reserve, preserving water for winter months. Why is the maximum battery size proposed for Takhini 8MW rather than 15MW (adequate to replace the #4 turbine at Whitehorse)?

c) Battery prices are falling by about 15% per year. The most expensive option identified is $27.4M, and its replacement cost is estimated at $22.1M. This is a reduction of $5.2M or just under 20%. What are the underlying assumptions behind this estimate?

d) The cheapest option identified appears to be the 4MW lead acid at $21.7M and the most expensive is presumably the 8MW Lithium ion at $27.4M. On the face of it, this is a very modest difference (a doubling of capacity for a 28% increase in price). Will this remarkably flat price curve continue with larger battery packs?

ANSWER:

(a)

YEC has not made a final decision on the size of the Energy Storage System (ESS) or the preferred technology. All details requested in the question can be found in the TransGrid Solutions Inc. report located in Appendix 5.19 of the 2016 Resource Plan. This document

is publicly available at the link below. Links to the 2016 Resource Plan Appendices are provided in YUB-YEC-1-83(e).

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.19_Evaluation_of_Energy_Storage_Technologies_(Transgrid_Solutions_2016).pdf

(b)

It is not possible to assume a battery of any size would have avoided the grid failures mentioned; other factors such as the location of the fault on the grid relative to the battery and the load also affects whether this supply source would be available in the specific circumstance.

As part of the planned 2017 and 2018 activities, YEC will confirm the size of the Energy Storage System and preferred technology. Details supporting the size of the ESS considered in the TransGrid Solutions Inc. report can be found in Appendix 5.19 of the 2016 Resource Plan. This document is publicly available at the link below. Links to the 2016 Resource Plan Appendices are provided in YUB-YEC-1-83(e).

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.19_Evaluation_of_Energy_Storage_Technologies_(Transgrid_Solutions_2016).pdf

(c)

Underlying assumptions behind the estimate of the various ESS options are detailed in the TransGrid Solutions Inc. report that can be found in Appendix 5.19 of the 2016 Resource Plan. This document is publicly available at the link below. Links to the 2016 Resource Plan Appendices are provided in YUB-YEC-1-83(e).

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.19_Evaluation_of_Energy_Storage_Technologies_(Transgrid_Solutions_2016).pdf

(d)

YEC is keeping appraised of the evolution of prices for energy storage systems. As part of the planned 2017 and 2018 activities, YEC will request new cost estimates to reflect

the latest market conditions. Any stipulation on the shape of the price curve of energy storage systems would be speculative at this time.

TOPIC: **Southern Lakes (Marsh Lake) Enhanced Storage**

REFERENCE:

PREAMBLE:

QUESTION:

a) Why has the estimated cost of the Marsh Lake Storage risen from $4M to $17M?

b) What does YEC anticipate paying to waterfront homeowners for mitigations for shoreline erosion, landscape architecture, septic system retrofits, etc.

c) Please break down the mitigation costs for waterfront properties on Marsh Lake, Tagish Lake, Nares Lake and Bennett Lake.

d) How do mitigation costs affect the financial viability of the project?

e) Does YEC believe any of this mitigation is required and justified even if the Southern Lakes Storage Concept does not proceed? How would YEC propose that work and those costs be covered?

f) What is the threshold and analysis that YEC will use to determine if and when the project has no net economic benefit to ratepayers?

g) Please run the calculations without an assumption that YDC will pay for the project in the way it did for the LNG project.

ANSWER:

(a)

Please see the response to YUB-YEC-1-84.

(b)

Mitigation for potential erosion-affected shoreline areas would be constructed and maintained by Yukon Energy for the duration of the operations that utilize the expanded storage range. No payments are proposed to be made to property owners.

Mitigation for shoreline properties that have project-affected subsurface infrastructure, such as septic systems, would include the purchase and installation of various pieces of equipment by Yukon Energy via qualified contractors. The installed equipment would then become the property and responsibility of the infrastructure owner. In some cases, the mitigation solution may involve on-going operational costs, such as additional electricity for sump pumps that would operate more frequently than without the project. In these circumstances property owners would be provided a one-time cash payment equivalent to the incremental cost of infrastructure operation for a 25-year period. Additional payments for such infrastructure operation would not be extended to any future licence renewal periods or in the case of property ownership changes.

(c)

The preliminary project effects assessment has identified a requirement for mitigation to be implemented at several properties on Marsh Lake and near the outlet of Tagish Lake. No potentially significant adverse effects are predicted for other parts of the Southern Lakes, although a detailed monitoring program would be implemented to track this. As such, no further mitigation for these areas is proposed. The following table provides a breakdown of the estimated mitigation costs for waterfront properties on Marsh Lake and Tagish Lake. Table 1 presents the summary of the mitigation costs for the Southern Lakes Enhanced Storage Project (SLESP).

Table 1 – Summary of Mitigation Costs for SLESP by Geographic Locale

Mitigation Category	Marsh Lake	Tagish Lake
Shoreline Erosion Protection	$4.0 million	$2.0 million
Sub-surface Infrastructure	$1 million	$0
Heritage Resources Protection/Recovery	$75,000	$75,000
Post-Implementation: (i) Monitoring (ii) Operational Costs, and (iii) Adaptive Mgt. Contingency	 $1.8 million $0.8 million $3.4 million	

(d) and **(f)**

Consideration of the planning costs to date along with those forecast to complete the remaining planning, assessment, permitting, and construction of the Project inform routine decision-making intervals regarding whether to continue to advance the project. It is reasoned that a suitable stop point for this project would be when such power benefit and economic analyses predict a levelized cost of energy greater than that of the next comparable firm energy project. Non-financial factors could also affect the decision to proceed (e.g., as in the Gladstone storage project, if YEC is not able to get key stakeholder support, the project would not be advanced).

To date, the estimated costs (and technical feasibility) of project mitigation have not resulted in rendering the Project non-viable. See also response to YUB-YEC-1-84.

(e)

If the Southern Lakes Enhanced Storage project does not proceed, YEC does not believe it has liability for mitigation.

(g)

The existing business case analysis does not assume, in any way, that YDC will pay for this project.

TOPIC: **Mayo Lake Enhanced Storage**

REFERENCE:

PREAMBLE: This project has been found to be non-viable because the outlet to the lake is silting up. Reservoir siltation is a normal feature of hydro projects.

QUESTION:

a) What is planned to address this issue and what is the cost?

b) How long will it take for siltation to affect the viability of this project again?

ANSWER:

(a)

Please see the response to YUB-YEC-1-85(c).

(b)

There are several factors that could affect the rate of future aggradation of the channel following initial dredging such that project viability would potentially be affected. The remaining engineering studies will seek to understand the mechanisms and processes that are causing the aggradation. As a consequence, Yukon Energy plans to develop a suitable engineering design to remove the sediment and minimize the frequency of future re-dredging.

TOPIC: **Gladstone Project**

REFERENCE:

PREAMBLE: The Gladstone project included a diversion of water between watersheds, which requires several significant authorizations from DFO and from First Nations. Predictably, these authorizations did not materialize, so this project is effectively dead. The 2017 GRA identifies $4.521M to be added to the rate base for this project.

QUESTION:

a) Please explain how the difficulties in permitting were not identified in advance of the work done.

ANSWER:

(a)

YEC was aware of the permitting challenges at the time of project initiation. Notwithstanding this risk, the forecast cost to execute the project would have resulted in very affordable energy for the grid particularly in winter.

The YUB has previously reviewed this justification and concurred that pursuit of this extra water made sense as long as there is economic benefit to ratepayers [YUB 2013-01, Reasons for Decision, p.344]. YEC at that time stipulated that ongoing work would be conditional on securing First Nation support for the project.

As both affected First Nations have indicated that they will not support the project, YEC has concluded there is very low probability that the regulator will approve this project and therefore it is not logical to continue with the project at this time.

TOPIC: **Future Thermal Capacity Project**

REFERENCE:

PREAMBLE:

QUESTION:

a) Please explain why the LNG option is now being explored for this 20 MW thermal capacity project (as discovered in the GRA Workshop presentation), and why these considerations were not included in the 2016 Resource Plan – which concluded without a doubt that diesel is the cheaper capacity choice of the two thermal options.

b) Is LNG back on the table for the 20MW capacity project because of possible mining loads being added to the system, and as a result, a new 20MW LNG facility would be used as an energy project to service industrial mining loads?

ANSWER:

(a)

At this time, YEC has not made any decision on the primary fuel of the potential thermal plant facility.

As presented in YEC's 2017-2018 GRA Application, YEC is examining the option of a new greenfield thermal plant and the option of refurbishing the existing Whitehorse Diesel Plant, which has LNG storage and processing facilities in place, with dual fuel engines. Please see the response to YUB-YEC-1-79(c) and to John Maissan-YEC-1-32(a).

Since completing the 2016 Resource Plan, YEC was made aware of the potential development of an LNG depot near Whitehorse. The availability of local LNG storage would enable the removal of the storage and processing facilities from the scope of a greenfield thermal plant. Consequently, it could make a new natural gas fired generating plant financially more attractive and bring its Levelized Cost of Capacity close to that of a greenfield diesel plant. Part of the planned activities for 2017 and 2018 will assess the

impact of removing the LNG storage and processing equipment from the scope of the plant and its impact on the business case.

Please see also response to YUB-YEC-1-79(b).

(b)

Please see response to (a) above, which indicates the basis for reassessment of the LNG options without regard to any change in mine loads.

The portfolio analysis completed as part of the 2016 Resource Plan showed thermal assets would be relied upon to primarily meet capacity under the single (N-1) contingency criterion. To a lesser extent, they would be used to support system energy requirements until such time as new renewable resource options could be brought online that would offer least cost solutions (2016 Resource Plan, Chapter 8, Section 8.2.7, PDF page 369). Access to adequate LNG capability during this period would help to reduce the long term average thermal generation cost requirements.

TOPIC: **DSM**

REFERENCE:

PREAMBLE: The YUB disallowed most of the proposed DSM program presented at the last GRA. YEC's analysis of the allowed programs (inCharge) indicates that they are very cost effective. AEY has nonetheless withdrawn from the program.

QUESTION:

a) Please explain how YEC is repackaging its DSM program to comply with the current YUB directives (including the stipulation that YEC and AEY jointly submit the proposals).

b) If these programs are as cost effective as indicated, please provide an analysis of why they were not as cost effective for AEY.

c) How will YEC's approach to DSM be different to address the capacity shortfalls?

ANSWER:

(a)

YEC and AEY jointly filed the 2013 Demand Side Management Program Portfolio as a part of AEY's 2013-2015 General Rate Application. Since that GRA was approved, YEC has executed the DSM program in accordance with YUB direction. YEC plans to continue the delivery of the approved inCharge program for the test years, as long as program results reach targets established by the Board. Starting in 2018, YEC plans to start the development of new DSM programs, including peak load reduction programs. The design of these programs are expected to follow the DSM program planning process outlined in Section 1.2 of the 2013 Demand Side Management Program Portfolio. Further explanation of current and future DSM programming can be found at YUB-YEC-1-80.

(b)

YEC has not conducted a cost-effectiveness analysis of the DSM programs on behalf of AEY.

(c)

As the work done on DSM to date has focused mainly on energy DSM, YEC will also perform a Capacity DSM Feasibility Study to quantify the potential cost and achievable uptake of capacity focused DSM programs. The DSM program planning process is outlined in response to YUB-YEC-1-80(g).

TOPIC: **Integrating Renewables**

REFERENCE:

PREAMBLE:

QUESTION:

a) Please describe the planning for a smart grid to manage home based PV systems, ETS, EVs and home based battery storage.

b) As more and more customers become providers of electricity as well as consumers, it is logical to assume that net sales of electricity by YEC will drop. Please provide an analysis of the effect on sales of electricity from the micro generation and the IPP programs.

ANSWER:

(a)

At this time, the impact of photovoltaic (PV) systems, electric thermal storage (ETS), electric vehicles (EVs) and home battery storage is negligible on the existing grid. In the 2016 Resource Plan, the impact of PV, ETS and home battery storage is accounted for through allowance for microgeneration; EV's are separately provided for in the forecast. As a part of the continuous preparation process for each resource plan update, YEC plans to monitor factors influencing penetration of PV systems, ETS, EVs and home battery storage and plans to address any new information as part of that ongoing update process as it becomes available.

(b)

At this time, the impact of home providers of electricity is negligible on the existing grid.

As a part of the continuous preparation for an update of the resource plan, YEC monitors factors influencing penetration of home providers of electricity. As for the independent power producers, YEC will consider them on one-to-one basis and make adjustments if needed.

TOPIC: **Transmission Line Vegetation Management**

REFERENCE:

PREAMBLE: YEC proposed to switch from mechanical brushing to herbicide treatment of brush under much of is transmission lines. After the public raised concerns, YEC contracted Yukon College to investigate more deeply the issues around using herbicides and to explore other vegetation management options.

QUESTION:

a) Please provide a copy of the Yukon College study.

ANSWER:

(a)

Please see response to John Maissan-YEC-1-14(a).

TOPIC: **Stewart-Keno Transmission Line and Mining Loads**

REFERENCE:

PREAMBLE:

QUESTION:

a) What is YEC's business case for the significant public investment in this transmission line?

b) How does YEC plan to provide electrons to existing and potential new industrial customers?

c) In YEC's 20-year Resource Plan, the values survey indicated that ratepayers held environmental concerns and considerations in the highest regard. How does YEC anticipate reconciling the wishes of ratepayers for renewable energy, and the possibility that industrial loads will be met with LNG generated electrons?

ANSWER:

(a), (b) and **(c)**

The Stewart-Keno Transmission Line project with extension of the 138 kV grid from Stewart Crossing to Keno City, which would materially expand the Yukon hydro grid capability to accommodate future loads as well as new resource options, is conditional today on government rather than ratepayer funding given current and potential loads to be supplied at this time.

A new line from Mayo to the Keno region, however, is required to replace the end of life existing 69 kV line constructed in the 1950s. The option is to have users in this region (mines, as well as non-industrial electricity users) depend solely on local fossil fuel generation. The business case for replacement of this existing line would be strengthened by additional loads required by any major industrial customers in this region. As in the past, the required generation would be supplied by the Mayo hydro facility supplemented by generation from the southern portion of the Yukon Integrated System, and any new renewable generation on the northern portion of the grid.

Providing grid generation to supply new mine loads is expected to enable utilization of existing renewable hydro generation capability, as well as potential development opportunities for enhanced renewable generation, to displace diesel and/or LNG generation that would otherwise be required if on-site power supply was required for these mine loads. In the event that LNG generation on the grid is required for a portion of the required supply, the net impact will continue to be a reduction of GHG emissions compared to the option of relying only on use of on-site power for such industrial loads.

Please also see response to YUB-YEC-1-76.

Yukon Utilities Board
(YUB)

TOPIC: **Actual Versus Forecast**

REFERENCE: Application, Tab 7 – Financial Schedules. PDF pages 277 to 292

PREAMBLE: The referenced schedules have the following column headings: "Actual 2016," "Forecast Existing" for each of 2017 and 2018 and "Forecast Proposed" for each of 2017 and 2018.

QUESTION:

a) Please confirm that any column identified as "Actual 2016," includes 12 months of actual data. If not confirmed, please explain.

b) Please clarify the difference between columns identified as "Forecast Existing" and columns identified as "Forecast Proposed." Do either of these columns contain data on actuals for 2017?

c) If the columns referred to in question (b) do not include 2017 actuals, please provide 2017 actuals based on information available to date.

d) Please clarify if any information provided in the columns identified as "Forecast Existing" has been previously provided to the Board. If so, under what circumstances was this information provided.

e) Please clarify whether YEC is seeking approval for 2017 and 2018 revenue requirement under "Forecast Proposed" columns. If confirmed, please explain why the "Forecast Existing" information was provided.

ANSWER:

(a)

Confirmed.

(b)

These columns contain only forecast numbers and do not include any actuals. The "Forecast Existing" columns reflect forecasts based on the assumption that YEC did not apply for a General Rate Application. The "Forecast Proposed" columns reflect forecasts based on the assumption that YEC has applied for a General Rate Application and the proposals by YEC are approved.

(c)

YEC is not able to provide a full update to Tab 7 tables as requested.

YEC has Q2 year to date actuals that have been reviewed and approved by management and the Board of Directors. In order to properly update Tab 7, the utility would need to re-forecast financial results for the last six months of the year. While this forecasting is not particularly onerous, the impact of updating 2017 forecasts for half-year actuals would effectively require YEC to revise and refile its entire General Rate Application based on these new forecasts.

It is not clear that this is the Board's intention and refiling would be a material update to the document and requires much time and effort from the applicant.

2017 actual results are provided in response to the following interrogatories:

Interrogatory #	**Financial Category**
CW-YEC-1-14	Secondary sales
UCG-YEC-1-41	Hearing costs
YUB-YEC-1-26 & 46	LNG purchases
YUB-YEC-1-27	Diesel purchases
YUB-YEC-1-39	LNG/Diesel generation
YUB-YEC-1-59	Energy sales

(d)

Information in YEC's prior GRAs (e.g., the 2012-13 GRA) was provided using the same format for test years (i.e., "Forecast Existing" and "Forecast Actual") in order to provide

the same analysis regarding GRA impacts. YEC has not filed with the Board prior to the GRA Application any of the specific forecast information relating to 2017 and 2018.

(e)

YEC is seeking approval for 2017 and 2018 revenue requirement under the "Forecast Proposed" columns. As in past General Rate Applications, YEC has provided the "Forecast Existing" columns to highlight the impacts that the general rate application would have if approved.

TOPIC: **Increased Operating Expenses since 2012-2013 GRA**

REFERENCE: Application. PDF page 25, lines 28 to 29. PDF page 26, lines 1 to 2

QUOTE: "As noted in Section 1.1, material labour operating expense increases occurred in 2013 above the approved forecast and have continued to be a key cost driver since that time. The increase in labour expense reflects negotiated wage increases, changes in capital/non-capital allocations, and other increased costs without a major change in the overall number of Full Time Equivalent [FTE] positions."

QUESTION:

a) Please provide the date(s) at which the negotiation of wages were concluded, the length of the negotiated term and the per cent associated with the increase in wages.

b) Please clarify whether there were any non-negotiated wage increases and if so, indicate the per cent associated with the increase in wages and the date on which the increase came into effect.

c) Please clarify whether YEC has a vacancy rate with respect to its FTEs and if so, provide the rate for the years 2013 through to 2018. Please also indicate in which operational area[1] the vacancies occurred or are anticipated.

d) Please provide a table summarizing approved, actual and forecast key assumptions, escalation (or inflation) factors or any other indices[2] examined or used by YEC in its application for items such as labour (in scope and/or out of scope), contractors, other labour cost categories, direct operating and maintenance costs, non-direct operating and maintenance costs, and capital costs.

[1] For example, using the categories identified on YEC 2017-2018 General Rate Application, Table 3.4, PDF page 55.
[2] For example, the Consumer Price Index (CPI) for Whitehorse.

ANSWER:

(a)

The only completed collective bargaining agreement during this period was for the period commencing January 1, 2014.

i. Arbitration award was received on February 5, 2015
ii. 3 year term
iii. 2014 – 2%; 2015 2%; 2016 1.75%

(b)

The Management and Professional Group (non-union) was granted the same increments specified in (a) on the same dates.

(c)

Vacancy rates are shown in Table 1 below. YEC does not allocate forecast vacancies.

Table 1: Vacancy Rates

	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018
President	0.0	0.3	-0.3	-0.1		
Human Resources & Info. Mgmt.	-0.1	-1.2	-1.2	-0.1		
Resource Planning and Environment	-1.0	0.0	0.6	-0.1		
Finance, Cust. Acctg. & Purchasing	-0.2	1.0	0.7	-0.1		
Operations	-1.9	-0.6	-1.7	-1.2		
Engineering Services	-1.2	-0.1	0.0	-0.3		
Unallocated					-2.0	-2.0
Total	-4.4	-0.6	-1.9	-1.9	-2.0	-2.0

(d)

YEC has assumed the following labour related changes (Table 2):

Table 2: Key Labour-related Assumptions

	2017	2018
Overtime hours	4%	-2%
Standby wage increase	$0.16/hour	$0.16/hour
Standby hours	-15%	1%
Other Benefits	5%	-3%

In addition to the factors in Table 2 above, YEC also included a general provision for forecast negotiated wages. The specific rate included cannot be provided at this time as this would compromise YEC's negotiations with the unions as part of the collective bargaining process. However, YEC can confirm that rates used in lieu of the actual wages increase were developed consistent with awards granted in arbitration in the last two collective agreement settlements.

YEC did not assume any general increase for non-labour costs.

TOPIC: **Wholesale Sales to ATCO Electric Yukon, Section 2.2.1**

REFERENCE: Application, page 2-4, PDF page 33, lines 11 to 13

QUOTE: "Subsequent to finalizing YEC's forecast for this Application, Board Order 2017-01 was issued on the AEY GRA and AEY filed its Compliance Filing response for review by the Board and interveners."

QUESTION:

a) Given the above quote and the issuance of Board O[r]der 2017-03 wherein the Board accepted "the calculations and revisions to YECL's 2016 through 2017 revenue requirement as submitted by AEY in its compliance filing"[1], please provide an updated forecast for this Application.

ANSWER:

(a)

YEC's forecast firm wholesales forecast for 2017 as referenced in this question is 309.0 GW.h, which is 8.7 GW.h higher than AEY's initial GRA forecast, and 5.2 GW.h lower than AEY's approved Compliance Filing forecast of 314.2 GW.h in response to Board Order 2017-01.

Section 2.4 of YEC's Application sets out the basis for this firm wholesale forecast for 2017. Please see the response to YUB-YEC-1-59 for an additional review of the basis for YEC 2017 forecast firm wholesales, and the response to CW-YEC-1-11 for additional background information.

YEC does not have the information used by AEY to prepare its Compliance Filing forecast, or the details on this 2017 forecast by month as regards firm wholesales.

In response to this question, an updated 2017 firm wholesales forecast consistent with the 314.2 GW.h accepted by the Board in Order 2017-03 is provided in summary as follows based on the information currently available to YEC:

[1] Board Order 2017-03, PDF page 3.

- Updated Sales (Table 2.1) is attached below, based on the following changes from the Application:
  - AEY firm wholesales for 2017 as per AEY Compliance Filing as approved by Order 2017-03 (increase of 5,234 MW.h, with related increase in revenues of $0.434 million).
  - Assumed same increase for 2018 firm wholesales.
  - Assumed increase in Rider J revenues (approximately $0.083 million increase in each test year).
  - Total revenue increase of approximately $0.518 million in each test year.

- Updates re: firm generation required (Table 2.2) are summarized below:
  - Firm load generation (assumes 8.8% average losses added to sales):
    - 426,093 MW.h in 2017 (increase of 5,695 MW.h)
    - 426,879 MW.h for 2018 (increase of 5,695 MW.h)
  - LTA thermal generation (based on updated firm load generation and Table 3.4-1 of the Application):
    - 16,714 MW.h for 2017 (increase of 2,568 MW.h)
    - 17,100 MW.h for 2018 (increase of 2,620 MW.h)

- Based on the updated firm sales and LTA thermal generation, the following material changes in forecast costs are estimated (i.e., addresses two specific costs as noted without updating all revenue requirement numbers as would be required for a compliance filing):
  - LTA thermal fuel costs (assumes average thermal fuel cost of $0.1584/kW.h per the Application fuel prices and 90/10 LNG/diesel split - excludes fuel costs for annual maintenance):
    - $2.647 million for 2017 (increase of $0.407 million)
    - $2.708 million for 2018 (increase of $0.415 million)
  - Mayo Flexible Debt interest (approximate increased interest costs based on 5.46% interest impact of 5.7 GW.h added generation, based on terms for this debt - assumed to be reflected in rate base return debt cost increase)
    - Approximate added interest of $0.083 million for 2017
    - Approximate added interest of $0.088 million for 2018
  - Overall added costs from the above two items:
    - $0.490 million increase for 2017
    - $0.503 million increase for 2018

- An updated Table 4.1 of the Application is attached below. In summary, overall net impacts of this update are estimated as follows:
  - Increase of the revenue requirement
    - $0.490 million increase for 2017
    - $0.503 million increase for 2018
  - Increase of revenues at existing rates
    - $0.518 million increase for 2017
    - $0.518 million increase for 2018
  - Net decrease on additional firm rate revenue required
    - $0.027 million increase for 2017
    - $0.014 million increase for 2018

- An updated Table 4.2 of the Application is attached below. In summary, the overall impact of this update on the required Rider J increase is affected by the related estimated increase of approximately $0.756 million in each year's consolidated revenue at existing base rates [before impact of changes in Rider J and Rider R revenues]. Overall changes to the total consolidated revenues at existing rates are affected by the lower final AEY Rider R as approved by Order 2017-03 (8.3% versus the 11.62% assumed in the YEC Application). Updated Table 4.2 shows the following:
  - Rider J increase required in 2017 of 8.876% (decrease of 0.159% from the Application)
  - Rider J increase required in 2018 of 2.070% (no change)
  - Cumulative Rider J increase required by 2018 of 10.95%
  - Total cumulative 2017 and 2018 rate increase required over existing rate revenues [including Rider J and Rider R revenues] is 9.19% (versus 9.08% in YEC's Application).

It is noted that the above estimates are subject to refinements in a full compliance filing update. However, the analysis addresses the main impacts of the wholesale sales update as requested in the question.

Table 2.1 - Revised to reflect AEY Compliance Firm Wholesales for 2017
Summary of Customers, Energy Sales and Revenues

Line No.	Description	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	Forecast 2017	Forecast 2018
1	**Residential**							
2	Customers	1,536	1,559	1,561	1,588	1,609	1,624	1,635
3	Sales in MWh	12,408	13,385	13,327	13,121	13,390	13,622	13,719
4	MWh sales per customer	8.1	8.6	8.5	8.3	8.3	8.4	8.4
5	Revenue ($000s)	1,815	1,943	1,938	1,913	1,956	2,002	2,016
6	Cents per KWh	14.6	14.5	14.5	14.6	14.6	14.7	14.7
7	**General Service**							
8	Customers	467	470	475	480	488	490	490
9	Sales in MWh	22,620	22,283	23,616	24,551	24,994	25,318	25,436
10	MWh sales per customer	48.4	47.4	49.8	51.1	51.2	51.7	51.9
11	Revenue ($000s)	3,735	3,621	3,894	4,048	4,180	4,036	4,054
12	Cents per KWh	16.5	16.3	16.5	16.5	16.7	15.9	15.9
13	**Industrial**							
14	Sales in MWh	40,592	40,513	36,302	37,186	41,169	38,219	38,219
15	Revenue ($000s)	4,787	4,595	3,958	4,159	4,478	4,198	4,198
16	Cents per KWh	11.8	11.3	10.9	11.2	10.9	11.0	11.0
17	**Street lights**							
18	Sales in MWh	279	281	290	290	256	225	214
19	Revenue ($000s)	88	89	92	92	88	58	56
20	Cents per KWh	31.5	31.6	31.6	31.6	34.5	26.0	26.0
21	**Space lights**							
22	Sales in MWh	15	14	14	14	14	12	12
23	Revenue ($000s)	4	4	4	4	4	3	3
24	Cents per KWh	26.7	26.5	26.6	25.9	26.0	22.5	22.5
25	**Total Company - Firm Retail & Ind.**							
26	Customers	2,003	2,029	2,036	2,068	2,098	2,114	2,126
27	Sales in MWh	75,914	76,476	73,549	75,162	79,823	77,395	77,599
28	Revenue ($000s)	10,429	10,252	9,886	10,214	10,705	10,297	10,327
29	Cents per KWh	13.7	13.4	13.4	13.6	13.4	13.3	13.3
30	**Wholesale sales**							
31	Sales in MWh	307,147	307,927	295,284	297,961	301,207	314,234	314,753
32	Revenue ($000s)	25,487	25,546	24,503	24,725	24,994	26,075	26,118
33	Cents per KWh	8.3	8.3	8.3	8.3	8.3	8.3	8.3
34	**Total Company - Firm**							
35	Sales in MWh	383,061	384,403	368,833	373,122	381,030	391,629	392,352
36	Revenue ($000s)	35,916	35,798	34,388	34,939	35,700	36,372	36,445
37	Cents per KWh	9.4	9.3	9.3	9.4	9.4	9.3	9.3
38	**Secondary**							
39	Sales in MWh	0	3,959	5,415	7,030	4,835	11,464	11,464
40	Revenue ($000s)	0	275	410	544	371	642	642
41	Cents per KWh	0.0	6.9	7.6	7.7	7.7	5.6	5.6
42	**Total Company**							
43	Sales in MWh	**383,061**	**388,363**	**374,248**	**380,152**	**385,865**	**403,093**	**403,816**
44	Revenue ($000s)	**35,916**	**36,073**	**34,798**	**35,483**	**36,071**	**37,014**	**37,087**
45	Cents per KWh	**9.4**	**9.3**	**9.3**	**9.3**	**9.3**	**9.2**	**9.2**
46	Rider J ($000s)	6,163	6,288	6,167	6,172	6,342	6,447	6,456
47	**Total Sales Revenues[1]**	**42,079**	**42,360**	**40,966**	**41,655**	**42,413**	**43,461**	**43,543**
48	**Total Sales Revenues excluding secondary sales**	**42,079**	**42,086**	**40,556**	**41,111**	**42,042**	**42,819**	**42,901**

Note:
1. Excludes revenues from other revenues.

Table 4.1: YEC 2017/18 GRA
Yukon Energy Revenue Required from Rates ($000s)
Revised to reflect AEY Compliance Firm Wholesales for 2017

	2017	2018
Revenue Requirement	$49,034	$50,367
Less: Other Revenues	$ 253	$ 253
Less: Secondary Sales	$ 642	$ 642
Revenue Required from Firm Rates	$48,139	$49,472
Less: Revenues from Firm Sales at Existing Rates [includes Rider J]	$ 42,819	$ 42,901
Additional Firm Rate Revenues Required	$5,321	$6,571

1
2
3

Table 4.2: Calculation of Required 2017 and 2018 Rate Increases (Rider J)
Revised to reflect AEY Compliance Firm Wholesales for 2017

Line #			Forecast 2017	Forecast 2018
1a	Consolidated Firm Retail Sales Revenues - Base Rates[1]	$000	55,746	55,830
1b	Consolidated Firm Industrial Sales Revenues - Base Rates	$000	4,198	4,198
2a	Consolidated Rider J Revenues[2]	$000	6,447	6,456
2b	AEY Rider R Revenues[3]	$000	4,975	4,982
3=1+2	**Total Consolidated Firm Sales Revenues at existing rates**	$000	71,366	71,466
4=Table 1	Retail Revenue increase required in 2017	$000	5,321	
5=4/3	Required Rate Increase	%	7.46%	
6=3+4	**Total Consolidated Firm Sales Revenues with 2017 Increase**	$000	76,687	76,795
7=Table 1	Total Revenue increase required in 2018	$000		6,571
8=6-3	To Be Recovered from 2017 Increase	$000		5,328
9=7-8	Total net increase required in 2018	$000		1,243
10=9/6	Required Rate Increase in 2018	%		1.62%
11=9+6	**Total Consolidated Firm Sales Revenues with 2018 Increase**	$000		78,037
12	Total Cumulative 2017 and 2018 Rate Increases (compounded)			9.19%
	Rider J Required			
13a=4/(1a+1b)	Rider J Increase Required	%	8.876%	
13b=9/(1a+1b)	Rider J Increase Required	%		2.070%
14	Existing Rider J - non-industrial	%	11.01%	
15	Existing Rider J - industrial	%	7.36%	
16=13+14	Total Rider J with increases - non-industrial	%	19.89%	21.96%
17=13+15	Total Rider J with increases - industrial	%	16.24%	18.31%
18	**Total Consolidated Firm Sales Revenues with increases**	$000	$76,687	$78,037

Notes:
1. Total Consolidated Retail Revenues at existing Base Rates include revenues from YEC and AEY's residential, general service and streetlight sales.
2. Consolidated Rider J revenues at existing rates include YEC's Rider J at 11.01% for firm YEC and AEY retail sales and at 7.36% for firm industrial sales.
3. AEY Rider R Revenues at existing rates include AEY's final (Order 2017-03) 2018 Rider R at 8.3% for firm retail and industrial base rate sales of YEC and AEY.

4

TOPIC: **Increase in 2017 Forecast for LTA Wind Generation**

REFERENCE: Application, PDF page 47, Table 2.2

QUOTE: LTA Wind Generation

2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual
238	238	238	238	238

Existing Forecast 2017	Proposed Forecast 2017	Existing Forecast 2018
238	580	238

Proposed Forecast 2018
580

PREAMBLE: Explanation needed for the increase of LTA wind generation from 238 MWh under the existing forecast column to 580 MWh under the proposed forecast column for the test years.

QUESTION:

a) Considering that the LTA wind generation has not changed from the years 2013 to 2016 and that the existing forecast for the test years is the same as the actuals for the years 2013 to 2016, please explain the significant increase in LTA wind generation for the proposed forecast and the assumptions and factors underlying the proposed forecast for the test years is based.

ANSWER:

(a)

LTA wind generation is different from actual wind generation. LTA Wind generation for the years 2013 to 2016 is fixed and is based on the approved amount in YEC's last General Rate Application. LTA wind generation is used for the calculation of Diesel Contingency Fund costs.

YEC is seeking approval to adjust the LTA wind generation from 238 MWh to 580 MWh, based on a change in actual circumstances.

As shown at Line 11 of Table 2.2 in YEC's current Application, under the section "Actual Generation – MWh" (as opposed to the section "LTA Generation – MWh"), actual wind generation for the years 2013 to 2016 was:

	2013	2014	2015	2016
Actual wind generation (MWh)	277	337	650	509

Generation in 2015 increased over previous years due to changes made to the turbine blades, greatly increasing efficiency. The noted increase in LTA wind generation to 580 MWh is based on the average of the actual wind generation for the years 2015 and 2016.

TOPIC: **Proposed Increases to 2017 and 2018 Revenue Requirement Forecasts**

REFERENCE: Application. Page 3-2 and PDF page 50, lines 16 to 21 and Tab 7, Schedule 5, line 14, PDF page 286

QUOTE: "In general, Yukon Energy's forecast 2017 and 2018 revenue requirements primarily reflect proposed adjustments to thermal generation requirements and fuel prices, changes to labour and non-labour costs, increases in rate base, as well as changes in the proposed return on equity (ROE) relative to 2013 GRA approved forecast ("2013 approved") numbers, the last test year reviewed by the Board during Yukon Energy's 2012/2013 GRA application."

PREAMBLE: The Board requires summary information for the 2017 and 2018 test years, which identifies the reasons contributing to the proposed revenue requirement increase of $5.9 million[1] (13.7 per cent) over the 2016 actual revenue requirement and $1.3 million[2] (2.7 per cent) over the 2017 proposed forecast revenue requirement.

QUESTION:

a) Please provide a table for each of the test years summarizing the main reasons for the proposed forecast requirement increases over the 2016 actual and 2017 proposed forecast revenue requirement amounts. The tables should provide a high level summary justifying the revenue requirement increase of $5.9 million and $1.3 million while at the same time providing a breakdown of the related increase or decrease amount by each major contributing factor, such as inflation, full-time equivalent (FTE) additions, wage increases, capital/non-capital allocations, capital expenditures or those factors identified in the referenced quote.

[1] Calculated as: 2017 proposed forecast revenue requirement of $48.544 million less 2016 actual revenue requirement of $42.686 million equals $5.678 million.

[2] Calculated as: 2018 proposed forecast revenue requirement of $49.864 million less 2017 proposed forecast revenue requirement of $48.544 million equals $1.32 million.

b) Please explain what is meant by "proposed adjustments to thermal generation requirements."

ANSWER:

(a)

Please see Tables 1 and 2 below.

Table 1: Summary of Key Revenue Requirement Increases – 2016 to 2017

	Revenue Requirement ($000) 2016	2017	Change		Major Factor for Change
Fuel and Purchased Power (Table 3.2)	**$ 2,159**	**$ 2,381**	**$ 222**	**10.3%**	
Expected thermal generation (GW.h) (Table 2.2)	*10.5*	*14.1*	*3.6*	*34.3%*	*Increased firm grid load*
Average fuel cost ($/kW.h)	*0.206*	*0.158*	*(0.048)*	*-23.3%*	*Lower LNG cost, and higher LNG share of expected generation*
Non-Fuel Operating and Maintenance (Table 3.1)	**$ 20,470**	**$ 22,060**	**$ 1,590**	**7.8%**	
Brushing Costs (Table 3.6.1)	*$ 502*	*$ 1,487*	*$ 985*	*196.2%*	*Expensing all brushing related costs, deferral account impacts*
Non Labour Administration (Table 3.9)	*$ 2,726*	*$ 3,149*	*$ 423*	*15.5%*	*Env. Management, General, Union, Information Systems*
Depreciation and Amortization (Table 3.14)	**$ 7,816**	**$ 10,814**	**$ 2,998**	**38.4%**	
Fixed asset depreciation net of customer contrib.	*$ 6,497*	*$ 7,194*	*$ 697*	*10.7%*	*$941k increase re: deferred costs brought into rate base with GRA*
Amortization of deferred charges	*$ 1,581*	*$ 3,883*	*$ 2,302*	*145.6%*	*$1,731k increase re: deferred costs brought into rate base with GRA*
Return on Rate Base (Table 3.1)	**$ 12,242**	**$ 13,289**	**$ 1,047**	**8.6%**	
Mid-year Rate Base (Table 3.13)	*$ 258,060*	*$ 274,459*	*$ 16,399*	*6.4%*	*$8,955k increase re: deferred costs brought into rate base with GRA*
Return on Equity (Schedule 4B)	*$ 9,002*	*$ 9,711*	*$ 709*	*7.9%*	*Rate base growth and ROE increase from 8.69% to 8.82%*
Cost of Debt (Schedule 4B)	*$ 3,239*	*$ 3,578*	*$ 339*	*10.5%*	*Rate base growth and Av. Debt cost increase from 2.10% to 2.18%*
Revenue Requirement	**$ 42,687**	**$ 48,544**	**$ 5,857**	**13.7%**	

Table 2: Summary of Key Revenue Requirement Increases – 2017 to 2018

	2017	2018	Change		Major Factor for Change
Fuel and Purchased Power (Table 3.2)	**$ 2,381**	**$ 2,407**	**$ 26**	**1.1%**	
Expected thermal generation (GW.h) (Table 2.2)	*14.1*	*14.5*	*0.3*	*2.4%*	*Increased firm grid load*
Non-Fuel Operating and Maintenance (Table 3.1)	**$ 22,060**	**$ 22,016**	**-$ 44**	**-0.2%**	
Non Labour Administration (Table 3.9)	*$ 3,149*	*$ 3,001*	*-$ 148*	*-4.7%*	*Expected decrease in union, general, and env. Management costs*
Labour (Table 3.3)	*$ 11,770*	*$ 11,823*	*$ 53*	*0.5%*	
Non Labour Production Costs (Table 3.5)	*$ 1,750*	*$ 1,799*	*$ 49*	*2.8%*	*Hydro and LNG plant increases*
Depreciation and Amortization (Table 3.14)	**$ 10,814**	**$ 11,094**	**$ 280**	**2.6%**	
Fixed asset depreciation net of customer contrib.	*$ 7,194*	*$ 7,465*	*$ 271*	*3.8%*	Rate base growth
Amortization of deferred charges	*$ 3,883*	*$ 3,891*	*$ 8*	*0.2%*	
Return on Rate Base (Table 3.1)	**$ 13,289**	**$ 14,348**	**$ 1,059**	**8.0%**	
Mid-year Rate Base (Table 3.13)	*$ 274,459*	*$ 291,627*	*$ 17,168*	*6.3%*	
Return on Equity (Schedule 4B, 4C)	*$ 9,711*	*$ 10,290*	*$ 579*	*6.0%*	Rate base growth
Cost of Debt (Schedule 4B, 4C)	*$ 3,578*	*$ 4,058*	*$ 480*	*13.4%*	*Rate base growth and Av. Debt cost increase from 2.18% to 2.32%*
Revenue Requirement	**$ 48,544**	**$ 49,865**	**$ 1,321**	**2.7%**	

(b)

The reference to "proposed adjustments in thermal generation requirements" is that forecast long-term average thermal requirements for the test years are assumed to be supplied with a combination of 90% LNG and 10% diesel generation. (This is reviewed in Section 3.2 and Appendix 3.4 of the Application, and in response to YUB-YEC-1-25).

TOPIC: **Proposed Increases to 2017 and 2018 Non-Fuel Operating and Maintenance**

REFERENCE: Application, Table 3.1. PDF page 50

PREAMBLE: With respect to non-fuel operating and maintenance costs, the Board requires summary information for the 2017 and 2018 test years, which identifies the reasons contributing to the proposed increase of $1.59 million[1] (7.8 per cent) over the 2016 actual non-fuel operating and maintenance costs and -$0.044 million[2] (0.2 per cent) under the 2017 proposed non-fuel operating and maintenance costs.

QUESTION:

a) Please provide a table for each of the test years summarizing the main reasons for the proposed forecast non-fuel operating and maintenance cost increase or decrease over the 2016 actual and 2017 proposed forecast revenue requirement amounts. The tables should provide a high level summary justifying the revenue requirement increase of $1.59 million and decrease of $0.044 million while at the same time providing a breakdown of the related increase or decrease amount by each major contributing factor, such as inflation, full-time equivalent (FTE) additions, wage increases, capital/non-capital allocations, or any other factor identified by YEC.

ANSWER:

(a)

Please see the response provided to YUB-YEC-1-5(a).

[1] Calculated as: 2017 proposed non-fuel operating and maintenance costs of $22.060 million less 2016 actual non-fuel operating and maintenance costs of $20.470 million equals $1.59 million.

[2] Calculated as: 2018 proposed non-fuel operating and maintenance costs of $22.016 million less 2017 proposed non-fuel operating and maintenance costs of $22.060 million equals -$0.044 million.

TOPIC: **Capital/Maintenance Allocation**

REFERENCE: Application. PDF page 54, lines 19 to 23

QUOTE: "The 2013 approved revenue requirement forecasts included an allocation set at 23% capital and 77% maintenance. Actual results over the 2013 to 2016 period varied between 20:80 and 16:84. The allocation for the 2017 and 2018 forecasts have been adjusted to align with historical results and are set at 18:82."

QUESTION:

a) Please clarify which years were included in the "historical results" used to determine the 2017 and 2018 forecast capital to maintenance allocation ratio.

b) Why does YEC consider that a forecast based on a span of years of historical results would be more representative than a forecast based on the most recent year's actual results? Please explain.

c) In general, to what does YEC attribute the variation in capital to maintenance allocation ratios between the approved (23:77) and the proposed (18:82)?

d) Please provide the 2016 actual capital to maintenance allocation ratio. In general, to what does YEC attribute the variation in capital to maintenance allocation ratios of capital to maintenance between the 2016 actual allocation ratio and the proposed (18:82)?

ANSWER:

(a) through **(d)**

Please see Table 1 below. The historical results for the years 2013 to 2016 were used to determine the 2017 and 2018 forecast capital to maintenance ratio allocation. The actual results for the previous five years are shown below. 2017 and 2018 are based on an average of 2013 to 2016 actuals.

Table 1: Actual Results: 2012 to 2016

	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2013 -2016 Average
Capital	31%	17%	17%	20%	16%	18%
Maintenance	69%	83%	83%	80%	84%	82%

Actual results in any given year can be impacted by different factors such as one-time large projects that may increase or decrease the ratio. 2017 and 2018 were not forecast based on 2016 results as different projects will be worked on. Based on the variability of actual results each year, 2017 and 2018 forecasts were based on the average of historical results.

In general, YEC attributes the variation in capital to maintenance allocation ratios to a combination of factors including:

- Variability of projects worked on in any given year;
- Variability of labour time that is required on a specific project;
- Variability of maintenance issues that may arise that may delay capital work; and
- General availability of internal resources.

TOPIC: **Allocation of Employee Complement to YDC**

REFERENCE: Application. PDF pages 54 to 56 and Table 3.4, PDF page 55

PREAMBLE: YEC discusses labour expense, FTE's and labour complement beginning at PDF pages 54 and ending on 56 of its application.

Further, Table 3.4 indicates that the employee complement history provided therein, is "net of allocation to YDC."

QUESTION:

a) Please clarify that, with the exception of Table 3.4, all other information provided by YEC in PDF pages 54 to 56 is similarly, "net of allocation to YDC." If not confirmed, please explain.

b) Please prepare a table showing total actual 2016 employee complement history (before allocation to YDC) and actual 2016 allocation of employee complement to YDC and net actual 2016 allocation of employee complement after allocation to YDC.

ANSWER:

(a)

Confirmed.

(b)

Please see Table 1 provided below.

Table 1: 2016 Employee Complement History

Before Allocation to YDC	
President	5.1
Communications	1.0
Human Resources & Info. Mgmt.	5.2
Resource Planning & Environment	6.0
Finance, Cust. Acctg. & Purchasing	17.1
Operations	44.1
Engineering Services	13.0
Health, Safety	2.0
Total Before Allocation to YDC	**93.5**
Allocation to YDC	
Finance, Cust. Acctg. & Purchasing	**-0.2**
Net Allocation	
President	5.1
Communications	1.0
Human Resources & Info. Mgmt.	5.2
Resource Planning & Environment	6.0
Finance, Cust. Acctg. & Purchasing	16.9
Operations	44.1
Engineering Services	13.0
Health, Safety	2.0
Total After Allocation	**93.3**

TOPIC: **Production Costs**

REFERENCE: Application, Table 3.5. PDF page 56

QUESTION:

a) For the line item cost categories of labour, diesel, LNG and hydro, please provide reasons for differences between 2016 actual costs and 2017 proposed forecast costs, and differences between 2017 and 2018 proposed forecast costs.

ANSWER:

(a)

Please see Table 1 and Table 2 below.

Table 1: Production Costs Changes (2016/2017)

($000's)	Actual 2016	Forecast 2017	Change	Reasons for differences
Labour	$ 4,133	$ 4,010	$ (123)	Overall change in capital/maintenance labour allocation from 16/84 to 18/82
Diesel	$ 548	$ 436	$ (111)	Reduction in heating fuel
LNG	$ 224	$ 155	$ (69)	Bi-annual maintenance schedule
Hydro	$ 1,058	$ 1,075	$ 17	Not significant

Table 2: Production Costs Changes (2017/2018)

	Forecast 2017	Forecast 2018	Change	Reasons for differences
Labour	$ 4,010	$ 4,109	$ 99	Additional maintenance mechanic
Diesel	$ 436	$ 425	$ (11)	Not significant
LNG	$ 155	$ 196	$ 41	Bi-annual maintenance schedule
Hydro	$ 1,075	$ 1,093	$ 17	Not significant

TOPIC: **General Operating and Maintenance Costs**

REFERENCE: Application, Table 3.8. PDF page 59

QUESTION:

a) For the line item cost categories of labour, transportation and maintenance, please provide reasons for differences between 2016 actual costs and 2017 proposed forecast costs.

b) For the cost category identified as maintenance of company owned properties, please provide reasons for the differences between 2017 and 2018 proposed forecasts.

ANSWER:

(a) and **(b)**

Please see the Table 1 below.

Table 1: Changes in Labour, Transportation and Maintenance Costs (2016/2017)

($000's)	Actual 2016	Forecast 2017	Change	Reasons for differences
Labour	$ 366	$ 394	$ 29	Not significant
Transportation	$ 459	$ 501	$ 42	Expected increase in vehicle fuel costs
Maintenance of Company Owned Properties	$ 501	$ 535	$ 35	Increased staff housing repairs and maintenance in Dawson and Mayo

Table 2: Changes in Labour, Transportation and Maintenance Costs (2017/2018)

($000's)	Forecast 2017	Forecast 2018	Change	Reasons for differences
Maintenance of Company Owned Properties	$ 535	$ 508	$ (27)	Not significant

TOPIC: **Administrative costs**

REFERENCE: Application, Table 3.9. PDF page 61

QUESTION:

a) For the line item cost categories of labour, customer accounting, environmental management, general, information systems, training, recruitment, board of directors, union, regulatory affairs and professional development, please provide reasons for differences between 2016 actual costs and 2017 proposed forecast costs.

b) For the line item cost categories of labour, environmental management, general, information systems, recruitment and union, please provide reasons for differences between 2017 and 2018 proposed forecast costs.

ANSWER:

(a) and **(b)**

Please see Table 1 and Table 2 below.

Table 1: Administration (2016/2017)

($000's)	Actual 2016	Forecast 2017		Change	Reasons for Differences
Labour	5,783	5,961	$	178	Increase in forecast wage rate, additional IT costs
Customer Accounting	208	224	$	16	Expected increased Atco Electric Yukon fees
Environmental Mgmt	166	278	$	112	2016 was abnormally low, as well as one-time $0.040M of Hazardous Waste costs
General	613	705	$	92	Increased Engineering external consulting
Information Systems	576	631	$	55	Increased IT external consulting and license fees
Training	143	175	$	32	Annual budget of $0.175M, however, in 2016 YEC received government funding
Recruitment	231	244	$	13	Nothing significant
Board of Directors	160	182	$	22	Increased training costs
Union	0	95	$	95	2016 Collective Bargaining
Regulatory Affairs	99	33	$	(66)	Reduction in external consulting
Professional Development	3	15	$	12	Employment contract specifies $0.015 of training

Table 2: Administration (2017/2018)

($000's)	Forecast 2017	Forecast 2018		Change	Reasons for Differences
Labour	5,961	5,911	$	(50)	Elimination of receptionist position
Environmental Mgmt	278	238	$	(40)	Reduction in one-time Hazardous Waste costs
General	705	662	$	(43)	Reduction in Finance external consulting
Information Systems	631	645	$	14	Additional data circuits
Recruitment	244	229	$	(15)	Nothing significant
Union	95	20	$	(75)	Completion of 2016 Collective Bargaining

TOPIC: **Deferral and Reserve Accounts**

REFERENCE: Application. PDF page 64, lines 6 to 9, PDF page 66, lines 9 to 13, and Schedule 1, lines 6, 8, 9 and 18, PDF page 279

QUOTE: "Yukon Energy's rate base includes all investment providing service to ratepayers, as well as components of necessary working capital. It comprises property, plant and equipment (net of depreciation), deferred study and other costs, reserves set aside for various regulatory purposes and working capital as indicated in Schedule 1 of Tab 7 of this submission."

"The largest component of deferred charges relates to planning and study costs, regulatory hearing costs and licensing costs related to maintaining licenses of YEC's hydro facilities and air emission permits.

"The amortization of planning costs is the largest component of deferred costs, which is primarily studies of the existing system and options for expanding the quantity of renewable generation, as well as studies related to the safety and reliability of the system, and other small projects."

PREAMBLE: The Board has examined Schedule 1 (lines 6, 8, 9 and 18) of Tab 7 and requires information with respect to the sub-categories of costs that comprise all deferral and reserve accounts included in YEC's rate base calculations.

QUESTION:

a) Please prepare a continuity schedule for each sub-category of costs comprising YEC's deferral and reserve accounts for the years 2013 to 2018. The schedules should detail the transactions for each individual sub-category of deferral account or provision for reserve and should correspond, when totalled, to the amounts shown on the lines referenced in the preamble. For each sub-category of costs, please also provide a brief explanation of any approval YEC is seeking with respect to the costs identified (for example, elimination of the deferred balance) and the basis for any annual amortization calculation.

b) Please clarify whether any other Tab 7 schedules contain amounts for deferral or reserve accounts, and if so, please provide on a sub-category basis, the same information as requested in part (a).

ANSWER:

(a)

The continuity schedule for Miscellaneous Reserves is provided in Table 1 below.

Table 1: Miscellaneous Reserves

	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast Existing 2017	Forecast Proposed 2017	Forecast Existing 2018	Forecast Proposed 2018
Reserve for Injuries and Damages (as per Table 3.11.1)								
Opening Balance	-$152	-$330	-$300	-$267	-$1,059	-$1,059	-$1,136	-$847
Annual Appropriation	226	226	226	226	190	479	190	479
Annual Costs	-404	-196	-193	-1,018	-267	-267	-267	-267
Closing Balance	-$330	-$300	-$267	-$1,059	-$1,136	-$847	-$1,213	-$635
Deferred Gain on Fire Insurance Proceeds								
Opening Balance	$6,276	$6,014	$5,752	$5,490	$5,228	$5,228	$4,966	$4,966
Annual Amortization	-262	-262	-262	-262	-262	-262	-262	-262
Closing Balance	$6,014	$5,752	$5,490	$5,228	$4,966	$4,966	$4,704	$4,704
Miscellaneous Reserves (Schedule 1, Line 6)								
Closing Balance	$5,684	$5,452	$5,223	$4,169	$3,830	$4,119	$3,491	$4,069

YEC is seeking approval of the following as per the Application, Page 3-15:

- Line 3: amortize the 2016 RFID balance of -$1.059 million over a five-year period ($0.212 million per year). The amortization period proposed is consistent with Board Order 2013-01 which approved amortization of the 2011 balance over a five-year period).

- Line 5: increase the appropriation to the RFID from $0.190 million to $0.267 million based on the ten-year average of actual expenses from 2006 to 2015 as shown in Table 3.11.

The continuity schedule for Deferred Study Costs is provided in Table 2 below.

Table 2: Deferred Study Costs

($000's)	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast Existing 2017	Forecast Proposed 2017	Forecast Existing 2018	Forecast Proposed 2018
Vegetation Management (as per Table 3.14.2)								
Opening Balance	$0	$0	$917	$1,644	$2,215	$2,215	$3,200	$1,994
Annual Deferred Cost	$0	$917	$727	$571	$985	$0	$990	$0
Annual Amortization	$0	$0	$0	$0	$0	-$222	$0	-$222
Closing Balance	$0	$917	$1,644	$2,215	$3,200	$1,994	$4,190	$1,772
Feasibility and Licensing								
Opening Balance	$23,160	$21,196	$22,116	$18,792	$23,338	$23,338	$27,319	$25,817
Net Additions	$1,239	$2,685	-$1,557	$5,131	$4,647	$4,647	$17,006	$17,006
Net Amortization	-3,202	-1,766	-1,766	-586	-666	-2,168	-666	-2,303
Closing Balance	$21,196	$22,116	$18,792	$23,338	$27,319	$25,817	$43,660	$40,521
Dam Safety Review								
Opening Balance	$71	$47	$24	$144	$148	$148	$152	$118
Net Additions	$0	$0	$144	$3	$4	$0	$3	$0
Net Amortization	-$24	-$24	-$24	$0	$0	-$30	$0	-$30
Closing Balance	$47	$24	$144	$148	$152	$118	$155	$89
DSM								
Opening Balance	$1,183	$1,400	$1,783	$2,080	$2,484	$2,484	$2,884	$2,445
Net Additions	$217	$383	$298	$403	$400	$210	$600	$625
Net Amortization	$0	$0	$0	$0	$0	-$248	$0	-$269
Closing Balance	$1,400	$1,783	$2,080	$2,484	$2,884	$2,445	$3,484	$2,801
Hearing Cost Reserve Account (as per Table 3.14.1)								
Opening Balance	$0	-$106	-$224	-$561	-$973	-$973	-$1,523	-$1,028
Annual Appropriation	-$550	-$550	-$550	-$550	-$550	-$55	-$550	-$55
Annual Costs	$444	$432	$213	$138	$0	$0	$818	$818
Closing Balance	-$106	-$224	-$561	-$973	-$1,523	-$1,028	-$1,255	-$266
Other Regulatory								
Closing Balance	$1,569	$0	-$143	$0	$0	$0	$0	$0
Deferred Study Costs (Schedule 1, Line 8)								
Closing Balance	$24,106	$24,615	$21,957	$27,212	$32,031	$29,346	$50,232	$44,917

YEC is seeking approval of the following as per the Application:

- Page 3-19, Line 25-Page 3-20, Line 1: amortize the 2016 vegetation management deferral account balance of $2.215 million over a ten-year period ($0.222 million per year). The amortization period of ten years is proposed to be consistent with YEC policy of amortizing deferred costs greater than $1 million over ten years.

- Page 3-20, Lines 1-2: elimination of the requirement to defer brushing costs in excess of 2011 actual brushing costs.

- Page 5-30, Lines 14-19: transfer approximately $13.9 million of deferred costs to rate base at the start of 2017 (includes closing of projects as well as deferred costs carried over from the last GRA at the direction of the Board, including DSM).

- Page 5-43, Lines 16-17: project related DSM costs are proposed to be closed out and amortized each year over a ten-year period.

- Page 3-19, Lines 14-15: amortize the 2016 hearing cost reserve account balance of $0.973 million over a five-year period ($0.195 million per year). The amortization period of five years is proposed to be consistent with YEC policy of amortizing deferred costs less than $1 million over five years.

- Page 3-19, Lines 16-17: decrease the annual provision to the hearing cost reserve account, starting 2017, to $0.250 million per year.

The continuity schedule for Studies in Progress is provided in Table 3 below.

Table 3: Studies in Progress

($000's)	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast Existing 2017	Forecast Proposed 2017	Forecast Existing 2018	Forecast Proposed 2018
Feasibility and Licensing (as per Tables 5.3-5.8)								
Opening Balance	$12,169	$11,914	$14,496	$16,432	$21,394	$21,394	$25,435	$15,350
Net Additions	$2,098	$2,582	$2,448	$5,154	$4,387	$4,387	$16,021	$16,021
Net Transfers	-$2,354	$1	-$511	-$193	-$346	-$10,431	-$370	-$1,512
Closing Balance	$11,914	$14,496	$16,432	$21,394	$25,435	$15,350	$41,086	$29,859
Dam Safety Review (as per Tables 5.3-5.8)								
Opening Balance	$0	$0	$0	$144	$148	$148	$148	$0
Net Additions	$0	$0	$144	$3	$0	$0	$0	$0
Net Transfers	$0	$0	$0	$0	$0	-$148	$0	$0
Closing Balance	$0	$0	$144	$148	$148	$0	$148	$0
Regulatory (as per Tables 5.3-5.8)								
Opening Balance	$1,410	$1,704	$2,277	$2,493	$3,187	$3,187	$4,110	$818
Net Additions	$758	$1,177	$440	$694	$923	$923	$0	$0
Net Transfers	-$464	-$604	-$224	$0	$0	-$3,292	-$818	-$818
Closing Balance	$1,704	$2,277	$2,493	$3,187	$4,110	$818	$3,292	$0
Other[1]								
Closing Balance	$0	$0	$0	$0	$3,933	$0	$5,544	$0
Studies in Progress (Schedule 1, Line 9)								
Closing Balance	$13,618	$16,773	$19,070	$24,728	$33,625	$16,167	$50,069	$29,859

Note 1: The 2017 and 2018 Existing Forecasts on Schedule 1 incorrectly included certain assets in WIP

The continuity schedule for Mid-Year Regulatory Deferral is provided in Table 4 below.

Table 4: Mid-Year Regulatory Deferral

($000's)	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast Existing 2017	Forecast Proposed 2017	Forecast Existing 2018	Forecast Proposed 2018
Rate Case Assets								
Opening Balance	$2,742	$643	$2,091	$1,922	$2,200	$2,200	$3,120	$2,693
Net Change	-2,099	1,448	-169	278	920	493	-331	-972
Closing Balance	$643	$2,091	$1,922	$2,200	$3,120	$2,693	$2,789	$1,722
Mid-Year Regulatory Deferral (Schedule 1, Line 18)								
Balance	$1,693	$1,367	$2,007	$2,061	$2,660	$2,447	$2,955	$2,208

(b)

Schedule 3, Tab 7 includes a reconciliation of the Reserve for Future Removal and Site Restoration. As per the direction of the YUB in Order 2005-12, there are no further appropriations to this account. YEC is not requesting any changes to this account.

TOPIC: **Two-Part Solution to Reserve Account Balances**

REFERENCE: Application. PDF pages 63 and 67

PREAMBLE: For each of the hearing cost reserve account and RFID account, YEC is seeking approval of a "two-part solution" to the growing account balances.

For the RFID account, YEC proposes to:
"1. Amortize the 2016 negative balance of $1.059 million over a 5-year period ($0.212 million per year).

"2. Increase the annual appropriation to the RFID, starting in 2017, to $0.267 million per year. This is based on the 10-year average of actual expenses as shown in Table 3.11 below."

Table 3.11.1:
RFID Continuity Schedule
($000)

	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast Existing 2017	Forecast Proposed 2017	Forecast Existing 2018	Forecast Proposed 2018
Opening Balance	-$152	-$330	-$300	-$267	-$1,059	-$1,059	-$1,136	-$847
Annual Appropriation	226	226	226	226	190	479	190	479
Annual Costs	-404	-196	-193	-1,018	-267	-267	-267	-267
Closing Balance	-$330	-$300	-$267	-$1,059	-$1,136	-$847	-$1,213	-$635

For the hearing cost reserve account, YEC proposes to:
"1. Amortize the forecast 2016 credit balance of $0.973 million over a 5-year period ($0.195 million per year).
"2. Decrease the annual provision to the hearing cost reserve account, starting 2017, to $0.250 million per year."

Table 3.14.1:
Hearing Cost Reserve Account Continuity Schedule
($000)

	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast Existing 2017	Forecast Proposed 2017	Forecast Existing 2018	Forecast Proposed 2018
Opening Balance	$0	-$106	-$224	-$561	-$973	-$973	-$1,523	-$1,028
Annual Appropriation	-550	-550	-550	-550	-550	-55	-550	-55
Annual Costs	444	432	213	138	0	0	818	818
Closing Balance	-$106	-$224	-$561	-$973	-$1,523	-$1,028	-$1,255	-$266

QUESTION:

a) Table 3.11.1 and Table 3.14.1 show that each of the accounts have negative closing balances in the year 2016 in the amounts of -$1.059 million for the RFID account and -$0.973 million for the hearing cost reserve account, yet are referred to in the referenced quotes as "2016 negative balance of $1.059 million" and "2016 credit balance of $0.973 million." Please provide an explanation for this discrepancy.

b) Please explain why the annual costs shown in the two tables are in opposing directions. For example, the annual costs in the RFID account are shown as negative amounts, whereas the annual costs in the hearing cost reserve account are shown as positive amounts.

c) Please confirm the calculation of the annual appropriation for each of the accounts given that the amortization of the -$1.059 million RFID appears to increase the total annual amortization amount by $0.212 million and the amortization of the -$0.973 million hearing cost reserve appears to decrease the annual amortization amount by $0.195 million.

d) Has YEC requested in past applications, this same two-part solution, for any other deferral or reserve account balances? If so, please explain.

ANSWER:

(a)

The negative balances have different meaning.

The RFID is over-subscribed, i.e., the costs incurred exceed the sum of the annual appropriations. Therefore, this account is in a debit balance which is due from ratepayers. The Hearing Reserve Account is undersubscribed, i.e., the costs incurred are less than the sum of the annual appropriations. This account is in a credit balance – due to ratepayers.

(b)

The annual costs are in opposing directions as the annual costs for the RFID increase the asset position while the annual costs for the hearing cost reserve account reduce the liability position.

(c)

YEC confirms the amortization of the RFID balance increases the total annual amortization by $0.212 million and the amortization of the hearing cost reserve account decreases the total annual amortization by $0.195 million.

(d)

Yes. In YEC's 2012/2013 GRA, YEC applied for a similar solution with regard to YEC's RFID account. The Board approved the approach and the amortization of the balance over a five-year period. There was no similar approach for the hearing cost reserve account in the 2012/2013 GRA as this account was created subsequent to the GRA at the direction of the Board.

TOPIC: **Property Tax Increase**

REFERENCE: Application. PDF page 63, lines 20 to 21 and Table 3.12. PDF page 64

QUESTION:

a) Please confirm whether the increases in property taxes between the years 2014-2015 and 2015-2016 is "due primarily to the additional property for the LNG plant." If not confirmed, please explain.

ANSWER:

(a)

Confirmed.

TOPIC: **Increases in Rate Base**

REFERENCE: Application, Schedule 3. PDF page 282, line 3

QUESTION:

a) For each of the years 2013-2018, please identify the three largest projects contributing to the increases in rate base for that year. As part of the response, please provide the dollar value of the project capitalized to rate base.

ANSWER:

(a)

The Request by the Board specifically refers to rate base, however, the Reference by the Board refers to increases to PPE on the Schedule 3 of the Application. Increases to PPE do not directly relate to increases to rate base as additions to rate base do not occur until projects are completed. YEC is assuming that the Board would like further details on the additions to rate base as this is what impacts rates; therefore, YEC's response below relates to increases in rate base. Schedule 1 in the Application references the impact of PPE on rate base.

Table 1 below summarizes the three projects each year which have the largest impact on rate base. The assessment takes into account the following:

- Total project costs.
- Year when project came into service.
- All offsets against capital costs due to contributions.
- Impacts on mid-year rate base in each year – as is evident from the table, project costs affect rate base over two years owing to the mid-year rule; this is not evident for all projects in table 1, depending on the relative dollars involved in each year.

Table 1: Three Largest Project Impacts Each Year on Mid-Year Rate Base (2013-2018)

	2013	2014	2015	2016	2017	2018
	($ millions)					
Accounting Software Conversion	1.2					
Aishihik Elevator Shaft Structural Steel					5.1	5.1
Faro Diesels Switchgear		0.4				
Gladstone					2.3	2.3
LNG Plant			11.8	11.8		
Mayo Head Gate Repairs	1.0					
Mayo Substation Enhancements	5.2					
Takhini Substation Upgrade			1.8	1.8		
WAF Transmission Upgrades		0.6				
WH4 Major Overhaul					2.1	2.1
Whistlebend Takhini Subdivision Supply			3.9	3.9		
Whitehorse Spillway Improvements		0.8				

TOPIC: **Amortization and Retirements of Contributions**

REFERENCE: Application. PDF page 19, lines 25 to 26

QUOTE: "These contributions continue to reduce ongoing annual depreciation/amortization and return costs for the affected projects."

QUESTION:

a) Please provide a high level explanation describing the basis for YEC's amortization of contributions.

b) Please explain if and how YEC retires contributions, once the associated capital asset has been retired.

ANSWER:

(a)

The principle behind the basis of amortization of contributions is one of matching. The intent is to amortize the contribution at the same rate as the underlying asset that the contribution relates to. In many cases, the constructed project will include different classes of assets with different depreciation rates. In this case, the utility will calculate a weighted-average rate based on the relative dollars assigned to each asset class. This combined rate is then used to draw down the contribution over time. The objective is to ensure that the depreciation of the contribution and the underlying asset are essentially the same so that the utility income for the period is unaffected (and therefore ratepayers are not affected by the cost of this invested capital).

(b)

Contributions would be retired at the same time as retirement of the related asset. The accounting entry is:

dr. Contributions
cr. Accumulated amortization – contributions

TOPIC: **Depreciation and Amortization of Contributions Expense – Proposed Forecasts**

REFERENCE: Application, Schedule 6 (lines 7 and 8). PDF page 287

QUESTION:

a) Please provide detailed calculations supporting each depreciation and amortization expense as shown on lines 7 and 8 of Schedule 6 of Tab 7 for the years 2017 and 2018 – proposed forecasts. Please ensure that the calculation for the amortization of fire insurance recoveries is disclosed separately from the amortization of contributions.

b) As part of the response to (a) above, please include in separate columns, the currently approved depreciation parameters (and resultant depreciation rates) on an account by account basis.

c) Please provide reason(s) for the difference in depreciation expense for the years 2017 and 2018 between the "Existing Forecast" versus "Proposed Forecast" columns.

d) Please provide reason(s) for the difference in amortization of contributions for the years 2017 and 2018 between the "Existing Forecast" versus "Proposed Forecast" columns.

e) Please provide reason(s) for the difference in amortization of fire insurance recoveries for the years 2017 and 2018 between the "Existing Forecast" versus "Proposed Forecast" columns.

ANSWER:

(a) and **(b)**

Please see Table 1 and Table 2 below.

Table 1: Proposed Depreciation (Schedule 6, Line 7)

($000's)	2017			2018			
	2016 Assets	New Assets	Total	2016 Assets	New Assets	Total	Depreciation Period
Land	2	-	2	2	-	2	0-48
Hydro	3,071	502	3,573	3,071	766	3,837	10-103
Diesel	567	594	1,160	567	599	1,165	5-72
Distribution	426	9	434	423	25	449	20-55
Wind	95	-	95	95	-	95	26-30
Transmission	3,981	14	3,995	3,978	67	4,046	12-65
Buildings & Equipment	1,452	159	1,610	1,093	341	1,434	5-55
Transportation	310	17	327	308	56	365	9-31
LNG	1,021	-	1,021	1,021	7	1,027	30-72
Total	**10,922**	**1,294**	**12,217**	**10,558**	**1,861**	**12,419**	

Table 2: Proposed Amortization of Contributions and Fire Insurance Recoveries (Schedule 6, Line 8)

($000's)	2017	2018	Amortization Period
Residential	137	149	40
General Service	62	62	40
Industrial	15	15	40
Street & Sentinel Lights	1	1	40
Other Customer	3	3	40
Minto Exploration 138Kv Line	129	129	56
Minto Spur 25Kv Line	900	900	12
Yukon Development Corporation	1,674	1,674	40
Yukon Government	212	212	40
Government of Canada Green Infrastructure	991	991	60
Feasibility and Licensing	786	705	5
Regulatory	99	99	5
Total Contributions	5,007	4,938	
Fire Insurance Recoveries	262	262	45
Total Contributions and Fire Insurance Recoveries	5,269	5,200	

(c)

The primary reason for the difference in depreciation between the existing and proposed columns is due to the proposal to transfer Deferred Overhaul costs carried over from the last GRA to rate base at the start of 2017.

(d)

The primary reason for the difference in amortization of contributions between the existing and proposed columns is due to the proposal to transfer Deferred Feasibility and Regulatory Contributions carried over from the last GRA to rate base at the start of 2017.

(e)

The referenced line represents amortization of contributions and fire insurance recoveries. The variance between "Existing Forecast" and "Proposed Forecast" relates to contributions on deferred projects that were delayed from addition to rate base at the direction of the YUB in 2012/13 GRA, pending the next GRA proceeding.

TOPIC: **Approved Depreciation Parameters (and resultant depreciation rates)**

REFERENCE: Application. PDF page 65, lines 1 to 4

PREAMBLE: YEC describes increases to 2017 mid-year net plant in service as reflecting the "LNG plant" and "Aishihik elevator" in the year 2017.

QUESTION:

a) Please clarify if, in any Tab 7 calculations, YEC has used depreciation parameters (and resultant depreciation rates) that have not been presented in a depreciation study or tested in a general tariff application, or specifically approved by the Board.

b) If (a) is confirmed, please identify the specific asset accounts impacted by the described action and provide an explanation of YEC's rationale for using those specific depreciation parameters (and resultant depreciation rates), for the purposes of its forecast 2017 and 2018 depreciation expense calculations.

ANSWER:

(a)

Two assets capitalized since the last GRA are using rates not previously reviewed by the YUB nor supported by a depreciation study:

- LNG storage; and
- LNG fencing.

The majority of the LNG project was classified into the same depreciation groupings as diesel equipment. That is, YEC assessed that these new assets were similar in nature and therefore use the same depreciation rates (see (b) for asset groupings and related rates).

With respect to LNG storage, there is no similar category to assign to. Discussions with the equipment supplier indicated that this equipment should last approximately 20-30 years. Based on the relatively light usage by YEC, the rate was set at 32 years. With respect to LNG fencing, YEC has a category of assets for fencing (depreciation rate – 20

years). The fence surrounding the LNG compound is constructed to a much higher standard, so the rate was set at 30 years.

(b)

Table 1 below outlines the categories for LNG assets established by YEC. This also includes the depreciation period and rationale for using the depreciation period.

Table 1: LNG Depreciation parameters

LNG Category	Depreciation Years	Rationale
Structures and improvements	72	This is the same life as the diesel plant structures and improvements
Fuel Holders	32	The manufacturer indicated that the life would be 30 or more years
LNG Generator	40	This is the same as the diesel generator life
Accessory Electric Equipment	45	This is the same as the diesel accessory equipment life
Misc Power Plant Equipment	30	This is the same as for the diesel misc power plant equipment
Fencing	30	The life of a substation fence is 20 years. As the LNG fence used higher quality materials, the life of this asset is expected to be longer.

TOPIC: **Yukon Energy Vegetation Management Policy**

REFERENCE: Application, Appendix 3.1 – Yukon Energy Vegetation Management Policy, PDF pages 75 to 79

QUESTION:

a) From whom will YEC receive approval when it states "If approved for use, the following herbicide methods will be considered for use by YEC…"?

b) Under what circumstances might a herbicide application method be considered for use by YEC.

c) Please describe YEC's process for studying the use of herbicides for transmission vegetation management in the Yukon.

d) Has YEC contemplated a ranking of the assessment criteria in order to select a specific brushing method for a given area?

ANSWER:

(a)

The application of a registered herbicide requires a Pesticide Use Permit from Environment Yukon. The Minister will determine if a technical review is required. As well, herbicides are classified as restricted or non-restricted. Restricted herbicides would likely also be subject to review under the *Yukon Environmental and Socio-economic Assessment Act* (*YESAA*).

(b)

Yukon Energy might consider a herbicide application program in the case that:

- The program is considered to be safe by regulators;
- The program achieves the required vegetation management to safely maintain transmission line right of ways;

- The herbicide program is cost effective in comparison to traditional mechanical methods or as a combination of traditional mechanical methods and herbicide program; and

- The program has stakeholder acceptance.

The past studies (filed with YUB as part of 12/13 GRA) demonstrated that herbicide application could be a very effective and cost-efficient approach to vegetation management. This has also been demonstrated in numerous jurisdictions in North America. The challenge to implement chemical vegetation management is a resistance from stakeholders. A recent application for a Pesticide Use Permit in the territory was met with “significant public and First Nation concerns regarding the potential contamination of drinking water and harvestable flora and fauna” – this concern resulted in a permit denial. As described above in a), the regulatory environment requires significant study and concrete support for this use. From a utility and ratemaking perspective, herbicides provide the best solution. However if stakeholder acceptance is not achievable, the company will continue with traditional mechanical methods.

(c)

YEC has partnered with Yukon College to study this approach in Yukon. A number of potential herbicides have been identified and field tests are being conducted over multiple years to determine the effectiveness and impacts.

(d)

The assessment criteria have not been ranked as part of the policy and therefore, the listed order does not imply relative importance or consideration. Depending on the specific characteristics of the sites to be brushed in a given year, the relative importance of a given criteria may change (e.g. FN considerations would be higher for brushing on settlement land v. crown land).

TOPIC: **Reserve For Injuries and Damages (RFID) Policy**

REFERENCE: Application, Appendix 3.2 – Reserve for Injuries and Damages (RFID) Policy. PDF pages 80 to 82

QUESTION:

a) Given that the policy was issued in March 2012 and reviewed in February 2015, please clarify whether it is YEC's intention that this policy be updated each time YEC proposes to adjust its annual appropriation amount.

ANSWER:

(a)

Please note that prior to filing the 2017/18 GRA, the policy was updated as follows to reflect the outcomes of the 2012/13 GRA and Board Order 2013-01:

- **Section 2 – Background:** was updated to reflect the outcomes of the 2012/13 General Rate Application and more specifically directions provided in Board Order 2013-01 regarding the 2013 approved appropriation amount of $0.190 million.

- **Section 3 – Annual Appropriation to the RFID**: this section was revised to note that "subject to the approval of any increase in the annual appropriate to the RFID by the Board as part of future Yukon Energy General Rate Applications, the RFID will be funded and raised through an approved annual appropriation of $0.190 million, with no specific limits on surpluses or deficits."

As the policy specifically references the annual appropriation, the policy will be updated if this amount changes (and is approved by the YUB).

TOPIC: **Measures to Defer the Requirement for the Application**

REFERENCE: Application, page 2. PDF page 3

QUOTE: "… and adjusted thermal fuel costs related to Diesel Contingency Fund operation …"

QUESTION:

a) Please explain in greater detail how adjusted thermal fuel costs related to the Diesel Contingency Fund operation have helped defer the requirement for a GRA. Please quantify this impact for each of the non-test years 2014-2016 inclusive.

ANSWER:

(a)

The DCF operation has enabled YEC thermal generation fuel costs to be adjusted in response to load changes.

In the 2014-2016 non-test years, when loads fell below the forecasts approved in the last GRA for setting YEC's rates, the reduced loads reduced YEC's revenues. The DCF in 2014 and 2016 in particular reduced YEC thermal generation fuel costs based on LTA assessments as approved by the Board (changes in system losses in 2015 moderated the DCF assessments for that year relative to the sales changes).

Table 1 below summarizes related information from the Application.

Table 1: Changes in YEC Sales, Revenues and Fuel Costs 2014-2016

	2013 Approved	2014	2015	2016
Firm Rate Revenues ($000)	42,079	40,556	41,111	42,042
Change from 2013 Approved		-1,523	-968	-37
Fuel Costs ($000)	3,160	1,528	2,720	2,114
Change from 2013 Approved		-1,632	-440	-1,047
LTA Thermal Generation (MW.h)	11,006	5,288	10,011	10,536
Change from 2013 Approved		-5,718	-995	-470
Firm Generation (MW.h)	416,387	396,502	410,304	412,812
Change from 2013 Approved		-19,885	-6,083	-3,575
Firm Sales (MW.h)	383,061	368,833	373,122	381,030
Change from 2013 Approved		-14,228	-9,939	-2,031

TOPIC: **Energy Reconciliation Adjustment (ERA)**

REFERENCE: Application, page 7. PDF page 8

QUOTE: "No proposal regarding the Rate Schedule 42 Energy Reconciliation Adjustment (ERA) is provided at this time in the Application as the ERA is currently the subject of an appeal to the Court (the Appeal) from the Board's Order 2015-06 of August 18, 2015. At such time as the Court's decision is provided, Yukon Energy will review the ERA and provide the Board with a filing as required on this matter."

QUESTION:

a) Does the exclusion of the ERA from this application indicate that the DCF and ERA are separate and discernible entities?

b) Can the DCF operate without any finding in regards to the ERA? Please explain.

ANSWER:

(a)

Determination of the DCF has never been dependent on the ERA. However, determination of the ERA has in the past been affected by DCF determinations (when DCF determinations affect YEC changes in thermal generation costs related to changes in wholesales).

(b)

Yes, the DCF can operate without any findings in regards to the ERA. This has been demonstrated by all DCF filings since the 2012/13 GRA.

As demonstrated in Appendix 3.5, DCF operation relies on the following variables (none of which require any ERA determinations related to wholesales and/or cost recoveries from AEY):

- Total actual grid load excluding secondary sales (YEC firm grid load plus AEY Fish Lake hydro).

- Actual grid generation by sources (specifically re: AEY Fish Lake Hydro, YEC diesel and LNG generation, YEC wind generation), with exclusion of thermal generation for activities not related to firm loads, e.g., capital, RFID and maintenance).

- Expected LTA thermal generation for the actual grid load (determined based on the approved DCF Term Sheet table and actual firm grid load less expected wind and expected Fish Lake Hydro).

- Approved thermal fuel costs per kW.h.

TOPIC: **Secondary Sales**

REFERENCE: Application, page 1-4. PDF page 20, lines 7 to 9

QUOTE: "… and annual secondary sales from 2013 to 2016 have ranged between 3.9 GW.h and 7.0 GW.h with revenues as follows: $0.275 million in 2013; $0.410 million in 2014; $0.544 million in 2015; $0.371 million in 2016."

QUESTION:

a) Please provide the corresponding volumes for secondary sales for each of the years 2013-2016 inclusive.

ANSWER:

(a)

Please see Table 1 below for the requested information.

Table 1: YEC Secondary Sales

Unit	2013	2014	2015	2016
Sales (MWh)	3,959	5,415	7,030	4,835
Revenues ($000)	$275	$410	$544	$371

TOPIC: **Mine Closure and Capacity**

REFERENCE: Application, page 1-7. PDF page 23, lines 11 to 13

QUOTE: "Looking beyond the test years, updated load forecasts and the anticipated end of Minto mine operations within a few years highlight ongoing pressure for added dependable capacity notwithstanding limited growth opportunities for new energy requirements unless new mine connections occur."

QUESTION:

a) Please explain how the closure of a mine (reduced load and capacity) relates to the requirement for additional dependable capacity.

ANSWER:

(a)

The referenced quote is making the point that there is ongoing pressure for added dependable capacity after the test years, even though (i.e., "notwithstanding" that) there are expected to be limited growth opportunities for new energy requirements "unless new mine connections occur". In different words, the closure of a mine is not creating the requirement for additional dependable capacity, i.e., this requirement derives from non-industrial load growth in peak winter demands.

Mine loads are not currently affecting the requirement for additional dependable capacity (and therefore closure of a mine does not reduce this requirement):

- Under the single contingency (N-1) planning criterion for determining dependable capacity surplus or shortfall, mine loads are excluded from the referenced winter peak demand (and therefore closure of a mine does not provide any reduction in the referenced winter peak demand).

- Under the LOLE planning criterion for determining dependable capacity surplus or shortfall, overall grid loads are not sufficient with the Minto mine to result in this criterion overriding the single contingency planning criterion.

TOPIC: **Thermal Fuel Mix**

REFERENCE: Application, page 3-3. PDF page 51, lines 30 to 31

QUOTE: "… and forecast long-term average thermal requirements for the test years are assumed to be supplied with a combination of 90% LNG and 10% diesel generation."

QUESTION:

a) Please provide details as to how the 90:10 LNG: Diesel proportion was established. Is this ratio statistically based? If so, please provide the statistical calculation.

b) Please show separately the actual and proposed maintenance fuel costs for each of the years 2015-2018 inclusive (include both dollars and forecast litres of fuel).

c) Please provide actual diesel/LNG ratios for 2015 and 2016.

ANSWER:

(a)

Details on establishing the 90:10 LNG: Diesel proportion are reviewed in Section 1.3 of Appendix 3.4 of the Application. This ratio is not statistically based, but reflects experience and expectations related to thermal generation to supply the long-term average (LTA) requirement over all water years.

Key points reviewed on this matter in Appendix 3.4 include:

- YEC's LNG Part 3 Application provided simulations and analysis to support the assumption that the initial two LNG units (8.8 MW) would be expected to displace all LTA diesel generation at LTA thermal requirements of up to 17 GW.h/year. This assessment assumed operation of the LNG units as required during low water conditions (i.e., during the water years accounting for the vast majority of the LTA thermal generation requirement at grid loads then forecast) to enhance hydro storage for use in wintertime.

- LTA thermal generation requirements on the grid remained below 17 GW.h in 2015 and 2016, and remain below 17 GW.h in each of the test years, indicating that an assumption of 100% LNG displacement of LTA diesel generation during these years would be consistent with the Part 3 determinations.

- Addition of a third LNG unit in 2019 will expand considerably the overall LNG capability to displace LTA diesel generation on the grid.

- Actual LNG unit operation to date has been constrained by unit size at 4.4 MW (see response to YUB-YEC-1-38 for review of these constraints); however, these constraints are not considered to have a material impact on the ability of LNG (with operation during low water conditions to enhance hydro storage) to supply overall LTA thermal generation at the grid loads relevant to the Application.

    - Appendix 3.4.2 (Figure 3.4-1 and Table 3.4-4) highlights the extent that LTA thermal is affected by years with below average water levels.

    - At a grid load of 420 GW.h/year, 75% of the thermal generation requirement over 35 water years occurs in the 20% of the 35 water years with the worst drought conditions, and less than 1% of this thermal generation occurs in the 46% of the 35 water years with the best water conditions.

- The Application proposes that LTA thermal generation be assumed, for revenue requirement purposes at this time, to be supplied 90% by LNG-supplied natural gas generation and 10% by diesel generation. This approach is proposed to ensure that revenue requirement costs used to set rates provide some recognition of the current limits on actual LNG ability to displace all diesel generation.

(b)

The available information on actual and proposed maintenance costs is summarized below in Table 1.

Table 1: Actual and Proposed Thermal Generation Maintenance: 2015-2018

	Actuals		2017/18 GRA Forecast	
	2015	2016	2017	2018
MW.h				
Diesel	224.9	319.4	312.5	229.2
LNG	123.6	55.4	133.3	100.0
Total	348.5	374.8	445.8	329.2
Litres of Fuel				
Diesel	60,910	86,584	87,400	64,093
LNG	26,878	12,052	51,914	38,935
	87,788	98,636	139,313	103,029
Cost ($000)				
Diesel	64.6	91.7	82.3	60.3
LNG	23.3	10.1	19.6	14.7
Total	87.8	101.8	101.8	75.0

(c)

Actual diesel/LNG ratios for 2015 and 2016 are as follows (see Appendix 3.5, Table 1):

- 2015
  - 27/73 LNG/Diesel including capital and RFID.
  - 21/79 LNG/Diesel excluding capital and RFID.
  - LNG was not available until after mid-year, at which point only about 15% of the annual LTA thermal generation would be expected to occur.

- 2016
  - 53/47 LNG/Diesel including capital and RFID.
  - 55/45 LNG/Diesel excluding capital and RFID.

TOPIC: **LNG Prices and Energy Content**

REFERENCE: Application, page 3-4 and footnote 1. PDF page 52

QUOTE: Footnote 1: "Reflects the September to December 2016 average delivered LNG cost from the Ferus facility in Elmworth, Alberta, and the forecast that test year LNG requirements will be supplied from facilities at no greater distance from Whitehorse than Elmworth. Assumed energy content (HHV) per litre of LNG approximates 0.02369GJ."

QUESTION:

a) Please provide the average actual delivered cost of LNG for the period January 1 to July 31, 2017. Please provide in tabular format indicating volumes acquired, commodity price, delivery price and supply location.

b) Please provide the actual or realized heat content per litre of LNG for 2015, 2016 and January 1 to July 31, 2017. Please show all calculations.

ANSWER:

(a)

Please see Table 1 below.

Table 1: Actual LNG Delivery Costs for 2017 - January to end of July

LNG Source: Fortis BC - Delta, BC

Month	LNG Volume Delivered [litres]	LNG Costs [$]	Transportation Costs [$]	Total Cost per Load (LNG & Transportation) [$]	Total Cost per Load (LNG & Transportation) [$/Litre]
January	154,247.18	$ 40,654.04	$ 56,100.96	$ 96,755.00	$0.63
February	80,576.19	$ 16,216.85	$ 28,002.31	$ 44,219.16	$0.55
March	157,603.13	$ 27,153.21	$ 51,024.75	$ 78,177.96	$ 0.50
April	0.00	$ -	$ -	$ -	$ -
May	0.00	$ -	$ -	$ -	$ -
June	0.00	$ -	$ -	$ -	$ -
July	0.00	$ -	$ -	$ -	$ -
August	0.00	$ -	$ -	$ -	$ -
September	0.00	$ -	$ -	$ -	$ -
October	0.00	$ -	$ -	$ -	$ -
November	0.00	$ -	$ -	$ -	$ -
December	0.00	$ -	$ -	$ -	$ -
Total	392,426.50	$ 84,024.10	$ 135,128.02	$ 219,152.12	$ 0.56

LNG Source: Ferus - Elmworth, AB

Month	LNG Volume Delivered [litres]	LNG Costs [$]	Transportation Costs [$]	Total Cost per Load (LNG & Transportation) [$]	Total Cost per Load (LNG & Transportation) [$]
January	499,161.07	$ 128,206.55	$ 100,608.50	$ 228,815.05	$0.46
February	388,113.31	$ 91,776.02	$74,177.14	$ 165,953.16	$ 0.43
March	457,684.07	$ 105,184.58	$ 85,807.54	$ 190,992.12	$ 0.42
April	43,909.67	$ 10,062.43	$6,600.00	$ 16,662.43	$ 0.38
May	38,436.73	$ 9,087.20	$6,600.00	$ 15,687.20	$0.41
June	0.00	$ -	$ -	$ -	$ -
July	0.00	$ -	$ -	$ -	$ -
August	0.00	$ -	$ -	$ -	$ -
September	0.00	$ -	$ -	$ -	$ -
October	0.00	$ -	$ -	$ -	$ -
November	0.00	$ -	$ -	$ -	$ -
December	0.00	$ -	$ -	$ -	$ -

(b)

Please see Table 2 below.

Table 2: Calculated Heat Content per Litre of LNG – 2015 to end of July 2017

LNG Source: Fortis BC - Delta, BC

Year	LNG Mass Delivered [kg]	LNG Volume Delivered [litres]	LNG Heat Content [GJ/litres]
	[A]	[B]	[A x HHV_{BC} / B]
2015	490,915.04	1,121,033.11	0.0241
2016	368,845.00	840,895.42	0.0242
2017	171,609.00	392,426.50	0.0241
Total	1,031,369.04	2,354,355.04	0.0241

LNG Source: Ferus - Elmworth, AB

Year	LNG Mass Delivered [kg]	LNG Volume Delivered [litres]	LNG Heat Content [GJ/litres]
	[A]	[B]	[A x HHV_{AB} / B]
2015	N/A	N/A	N/A
2016	335,427.00	783,847.13	0.0237
2017	610,778.00	1,427,304.85	0.0237
Total	946,205.00	2,211,151.98	0.0237

LNG High Heating Value

FortisBC	0.0551 GJ/kg	(HHV_{BC})
Ferus	0.0554 GJ/kg	(HHV_{AB})

TOPIC: **Diesel Prices**

REFERENCE: Application, pages 3-4 to 3-5. PDF pages 52 to 53

QUESTION:

a) Please provide actual diesel prices for the period January 1, 2017 to July 31, 2017 for each of Whitehorse, Faro, Dawson and Mayo. Please include purchase volumes with the prices for each location.

ANSWER:

(a)

Please see Table 1.

Table 1: Diesel Purchased (Litres & Prices) - January 1, 2017 to July 31, 2017

FUEL PURCHASES LITRES	(Actual units purchased)							
	JAN	FEB	MAR	APR	**MAY**	JUN	JUL	TOTAL
Faro	30,100	0	24,962	0	9,816	0	38,001	102,877
Dawson	48,113	0	0	0	0	47,223	0	95,335
Mayo	0	0	0	0	7,010	0	0	7,010
Whitehorse	168,846	178,866	250,427	0	0	18,349	0	616,487
Total	**247,058**	**178,866**	**275,388**	**0**	**16,826**	**65,571**	**38,001**	**821,710**

FUEL PURCHASES DOLLARS	(Actual Cost paid for purchases not including GST)							
	JAN	FEB	MAR	APR	**MAY**	JUN	JUL	TOTAL
Faro	$ 27,797.17	$ -	$ 22,777.37	$ -	$ 8,858.49	$ -	$ 32,737.52	$ 92,170.55
Dawson	$ 47,237.15	$ -	$ -	$ -	$ -	$ 43,765.91	$ -	$ 91,003.06
Mayo	$ -	$ -	$ -	$ -	$ 6,453.68	$ -	$ -	$ 6,453.68
Whitehorse	$ 154,670.47	$ 151,374.13	$ 219,198.58	$ -	$ -	$ 15,803.65	$ -	$ 541,046.83
Total	**$ 229,704.79**	**$ 151,374.13**	**$ 241,975.95**	**$ -**	**$ 15,312.17**	**$ 59,569.56**	**$ 32,737.52**	**$ 730,674.11**

FUEL PURCHASES PER LITRE	(Actual cost/L)							
	JAN	FEB	MAR	APR	**MAY**	JUN	JUL	TOTAL
Faro	$ 0.9235	$ -	$ 0.9125	$ -	$ 0.9025	$ -	$ 0.8615	$ 0.8959
Dawson	$ 0.9818	$ -	$ -	$ -	$ -	$ 0.9268	$ -	$ 0.9546
Mayo	$ -	$ -	$ -	$ -	$ 0.9206	$ -	$ -	$ 0.9206
Whitehorse	$ 0.9160	$ 0.8463	$ 0.8753	$ -	$ -	$ 0.8613	$ -	$ 0.8776
Total	**$ 0.9298**	**$ 0.8463**	**$ 0.8787**	**$ -**	**$ 0.9100**	**$ 0.9085**	**$ 0.8615**	**$ 0.8892**

TOPIC: **Labour Rates**

REFERENCE: Application, page 3-6. PDF page 54

QUOTE: "The average annual negotiated increase in wages approximates 1.9% from 2013 approved to 2016, and is forecast to increase at approximately this same annual rate to 2018."

QUESTION:

a) Please provide the latest edition of the Yukon Economic Outlook.

b) How does the YEC forecast labour escalation compare to the latest forecast from the Yukon Economic Outlook?

ANSWER:

(a)

Please see YUB-YEC-1-28 Attachment 1.

(b)

The Yukon Economic Outlook forecasts Whitehorse CPI to be up 1.9% in 2017 and 1.8% in 2018. The specific rate for negotiated wages cannot be provided at this time as this would compromise YEC's negotiations with the unions as part of the collective bargaining process. However, YEC can confirm that rates used in lieu of the actual wages increase were developed consistent with awards granted in arbitration in the last two collective agreement settlements. See also, YUB-YEC-1-2.

YUKON ECONOMIC OUTLOOK

APRIL 2017

Yukon
Finance

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ECONOMIC FORECASTING AND RISK

The forecast discussed in this document, examines medium term expectations for Yukon's economy, focusing on the anticipated performance of key economic indicators and sectors. As with all forecasts, the results are dependent on the information available at the time the forecast was completed and the key assumptions incorporated into the forecast. Assumptions such as the level and timing of mining development activity, estimates around annual mineral production and estimates around construction spending can all impact the forecast results, particularly for an economy as small as that of Yukon.

While best efforts are made to develop assumptions that capture Yukon's potential economic performance in the near term, there is always a degree of risk and uncertainty associated with these assumptions, and ultimately the forecast results. For a more detailed discussion of key assumptions and risks, please refer to the last section.

THE WORLD IN BRIEF

The Road to Recovery

Elevated levels of public and private debt, an aging population and political uncertainty in a number of countries continues to weigh on the near term outlook for global economic growth.

While the current outlook is clouded by uncertainty around U.S. policy under the new administration, the International Monetary Fund (IMF) is projecting stronger near term global growth. Following estimated growth of 3.1% in 2016, the IMF's January 2017 update[1] to the World Economic Outlook includes projections of growth of 3.4% in 2017 and growth of 3.6% in 2018. The forecast is unchanged from the IMF's October 2016 Outlook, but the update did note that key assumptions of the forecast should be clearer in the April 2017 World Economic Outlook*, specifically noting the expectation of more clarity around policies of the new U.S. administration.

Growth in emerging markets and developing economies[2] is expected to continue to drive global growth projections with the IMF growth forecasts of 4.5% in 2017 and 4.8% in 2018, building on estimated growth of 4.1% in 2016. While remaining strong, growth prospects have marginally worsened for many of the economies in question due to tightening financial conditions.

China's economy remains in a period of transition, moving from an economy supported substantially through manufacturing activities and large scale industrial development to development of services and retail in support of its domestic demand. Even with a recent slowdown, China (along with India) will continue to lead the way for emerging market countries. Following estimated growth of 6.7% in 2016, China's economy is expected to grow 6.5% and 6.0% over the next two years. India's growth is forecast to be even stronger with growth of 6.8% in 2016, followed by growth of 7.2% and 7.7% in 2017 and 2018, respectively.

Following growth of 1.7% in 2016, advanced economies are forecast to grow by 1.9% and 2.0% annually over the next two years. The near term outlook for advanced economies has improved, reflecting stronger activity in the last six months of 2016 as well as the expectation of U.S. stimulus spending.

*Not released at time of writing.

U.S. growth is expected to be the prominent driver of growth in advanced economies with U.S. growth rates in both 2017 (2.3%) and 2018 (2.5%) exceeding the overall growth rates of advanced economies. Strong growth forecasts for the U.S. are related to the assumption of fiscal stimulus in the form of reduced taxes and increased infrastructure spending. The IMF's January update does note that the U.S. outlook has a wide range of possible scenarios given uncertainties surrounding future policy choices of the new U.S. administration.[3]

The Canadian economy continues to adjust to lower oil prices and a generally weaker global economy. Canada's estimated GDP growth of 0.9% in 2015 was the worst performance since a contraction of 3.2% in 2009. Growth in 2016 was only marginally stronger, estimated at 1.4%.

Much of recent performance is related to weaker commodity prices, particularly the price of oil, which has declined significantly in the last 18-20 months as a result of oversupply in the global market, falling below $30 per barrel in early 2016. Prices for many key mineral exports are also down substantially from recent levels which has contributed to mine closures, layoffs, reduction in mineral exports and lower levels of investment in Canada's mining sector. The IMF's January 2017 update includes forecasts of stronger Canadian growth of 1.9% and 2.0% in 2017 and 2018, respectively.

Growth forecasts from the Bank of Canada are very similar to that of the IMF. The January 2017 *Monetary Policy Report** notes that Canada's GDP will grow by 2.1% in both 2017 and 2018. The Bank notes that the Canadian economy continues to adjust to past declines in commodity prices with the worst appearing to be over for resource-related industries.

At the same time, investment and employment are being reallocated to other sectors of the economy which are growing, in particular the service sector.[4] Like the IMF, the Bank of Canada notes that the current outlook is subject to considerable uncertainty, given the unknowns around policy actions by the incoming U.S. administration, particularly concerning trade.[5]

Resource extraction activities continue to be a significant contributor to Canada's economy, and the performance of commodity prices will have a significant impact on growth prospects for the country. Recent modest GDP growth is very much related to weakness in oil and natural gas prices, as well as lower prices for a number of prominent metals, including gold and silver. Lower prices for these key commodities, particularly for oil, have resulted in far lower levels of investment in the resource sector and lower levels of mineral and oil exports, negatively impacting the value of Canada's economy.

While the outlook remains uncertain for gold and silver, the outlook for oil and natural gas prices is generally positive. At the time of writing, the World Bank was calling for oil prices to average US$55 per barrel in 2017, up from US$42.80 in 2016.[6] While expected to remain well below recent record highs, the current outlook from the World Bank was for oil prices to increase in every year, reaching US$80 per barrel by 2030.

The World Bank notes a very similar story for natural gas, with prices expected to average US$3.00 per MMBTU[7] (Henry Hub) in 2017, up from US$2.50 per MMBTU in 2016. The World Bank is projecting the price of natural gas will grow annually, eventually reaching $5.00 per MMBTU in 2030.[8]

Future growth prospects for Canada are also tied to interest rates. The overnight rate has rested at 1.0% or lower since September 2010. At its rate announcement on January 18, 2017, the Bank of Canada opted to continue to keep the cost of borrowing low, maintaining the overnight rate at 0.5%, a level it has been at since July 2015. Canadian interest rates are expected to remain low throughout 2017, before increasing in 2018, but remaining at relatively low rates.

*April 2017 Monetary Policy Report not released at time of writing.

Outlook for Global, U.S. and Canadian Economies: IMF January 2017

- Global Growth: 3.4% (2017) and 3.6% (2018).
- U.S. Growth: 2.3% (2017) and 2.5% (2018).
- Canadian Growth: 1.9% (2017) and 2.0% (2018).

2016 Highlights

- Real GDP by industry in 2016 is estimated at $2.295 billion, up 4.6% from $2.193 billion in 2015.
- Growth in 2016 follows two consecutive years of GDP contraction, and is primarily related to increased mineral production at the Minto mine.
- 2016 population of 37,858 was up 1.4% from 2015 – 13 straight years of growth.
- Labour market continued to perform well in 2016:
  - Average employment 20,200, up 800.
  - Labour force averaged 21,400, up 700.
  - Unemployment rate averaged 5.6% - the lowest in the country.
- Retail sales reported at over $740 million, up 7.0% from $692 million.
- A good year for tourism, with international travellers reported up 3.5%.
- At nearly $171 million, the value of building permits in 2016 was up 45.1% – mostly related to government and institutional projects.
- Consumer Price Index (CPI) for Whitehorse increased 1.0% in 2016, following a contraction of 0.2% in 2015.

A CLOSER LOOK AT YUKON

Signs of strength in the economy, despite flat GDP growth

GDP to remain flat, then regain ground

Gross Domestic Product (GDP) is a widely used measurement of the economic performance of a region. GDP represents the market value of final goods and services produced within a defined region (e.g., country, province, territory) over a specified period of time (usually over the course of a year).

While an imperfect measure of economic progress, an increase in real GDP is generally interpreted as a sign that the economy is doing well, while a decrease indicates that the economy is under-performing. In many jurisdictions, gains in real GDP are closely tied to gains in other variables such as employment, population, and retail sales. In Yukon, correlation between GDP changes and other indicators is often not as strong.

Revised data released by Statistics Canada in November 2016 estimates that Yukon's real GDP by industry in 2015[9] contracted by 6.0% to $2.193 billion. This was the second consecutive year that real GDP fell after a modest decline of 0.2% in 2014.

2017 Highlights

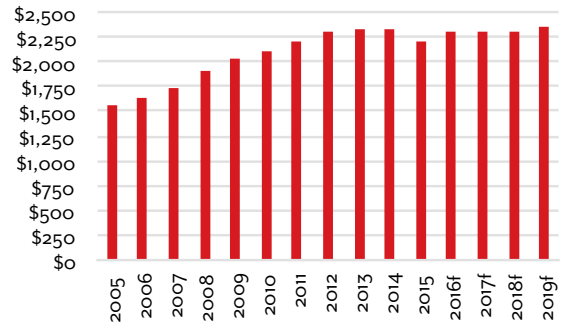
- Real GDP in 2017 is forecast to remain flat at 0.1% over 2016, with lower production from the Minto mine offset by increased government investment.
- Population will continue to increase by 1.4%, growing to almost 38,400.
- The number of employed Yukoners and the size of the labour force are both expected to increase to 20,600 and 21,900, respectively.
- The unemployment rate in 2017 is expected to rise slightly to 5.7%.
- Following strong gains in 2016, retail sales are expected to remain strong in 2017, growing about 5% to $777 million.
- Indications are that 2017 will be another positive year for Yukon's tourism sector.
- Stronger growth in the Whitehorse CPI, expected to be up 1.9% in 2017.

Prior to 2014, Yukon's real GDP had recorded 10 consecutive years of growth, after revisions to 2013 GDP numbers by Statistics Canada which saw Yukon's annual GDP change revised from a 1.2% contraction to 1.5% growth.

Yukon's contraction of 6.0% represented the lowest performance of all the provinces and territories with Saskatchewan (-1.3%), Newfoundland and Labrador (-1.8%) and Alberta (-3.7%) also posting contractions in 2015.

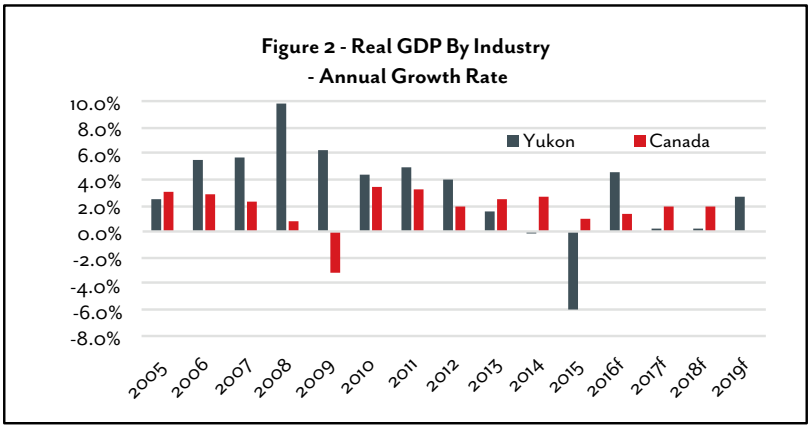
The primary driver of the 2015 decline was weakness in the mining sector, which included the suspension of production of the Wolverine mine in January 2015. A 42%, or $198 million, decline in the mining, quarrying and oil and gas extraction component of GDP was noted in 2015 and was the primary contributor to the annual decline in total industry GDP.

Figure 1 - Real GDP By Industry (2007$ millions)



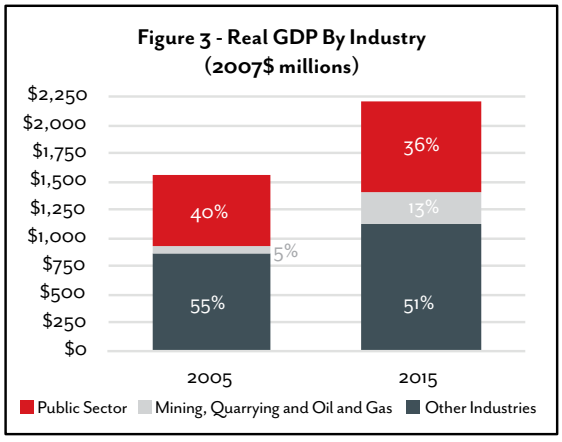
Source: Department of Finance; Statistics Canada

Recent history has seen the percentage contribution of mining in excess of 20% annually, averaging about 22% from 2012/14. While down from recent highs, Figure 3[10] illustrates that the current contribution of mining related activities still remains well above estimates from a decade ago. At almost 13% of total real GDP, the 2015 contribution of mining, quarrying and oil & gas extraction is more than double the contribution of 5.2% noted in 2005.



Source: Department of Finance; Statistics Canada; IMF

Declines in the mining component in 2015 were partially countered by GDP gains in other industries. Supported by a tight rental market and a strong housing market, the finance, insurance, real estate, rental and leasing component grew for the 13th straight year, up 2.6% to $391 million, and is projected to continue to grow throughout the forecast horizon. Notable growth was also recorded in professional, scientific and managerial component, growing to $108 million, up 5.3% from 2014; growth is expected to continue through 2019. GDP contribution from health and social services also posted an increase of $5 million to $180 million, up 3.1% from 2014.



Source: Department of Finance; Statistics Canada

Most industries are estimated to have experienced GDP growth in 2016, with the largest change related to increased mineral production with development of the Minto North pit. Of the estimated increase of $100 million in real GDP in 2016, more than 70% is associated with an increase in the mining, quarrying and oil &

Beyond 2017

- GDP expected to contract remain essentially flat at 0.2% for 2018, as a result of the closure of the Minto mine at the end of 2017 offset by government investment.
- Development spending for two new mines (Eagle Gold, Coffee) and the start of production from the Eagle Gold mine expected to drive real GDP growth of 2.6% for 2019.
- Steady population growth to continue with gains of 1.1% in 2018 and 1.4% in 2019.
- Strength in labour market expected to continue, with growth in employment and the labour force, with the unemployment rate expected to remain relatively low.
- Growth in retail sales anticipated in the medium term, increasing to exceed $790 million in 2018 and nearing $820 million in 2019.
- Continued growth in the Whitehorse CPI, averaging 1.8% over 2018 and 2019.

gas extraction component. Construction also saw significant gains with growth of 7.7%. Overall, real GDP growth is estimated at 4.6% in 2016, higher than the May 2016 forecast of 2.8%. Preliminary GDP numbers for 2016 will be released by Statistics Canada in early May.

Looking forward, Yukon's GDP performance in the medium term remains very much linked to the performance of Yukon's mining sector. For 2017, mineral production is expected to be stronger than noted in the May forecast as Capstone Mining Corp. has stated that its Minto mine will now likely mill until the end of the year. On an industry basis, construction-related real GDP is forecast to be up 13.6%, increasing to $207 million in 2017. As a result, real GDP is now expected to increase slightly by 0.1%, a substantial improvement from the May 2016 forecast (-5.7%).

GDP is expected to remain essentially flat in 2018 at +0.2%, primarily the result of lower mineral production due to the anticipated closure of the Minto mine at the end of 2017, offset by government investment. The expected start of development activities at the Eagle Gold mine will counter some of the drag on Yukon's GDP in 2018, which (together with increased government investment) will offset the effect of a year-over-year decline in mineral production.

For 2019, further development spending on the Eagle Gold project, the start of development spending on the Coffee project and the start of Eagle Gold mine production are the largest contributors to forecasted real GDP growth of 2.6%, with most industries expected to continue expansion in 2019.

Outlook for GDP

GDP

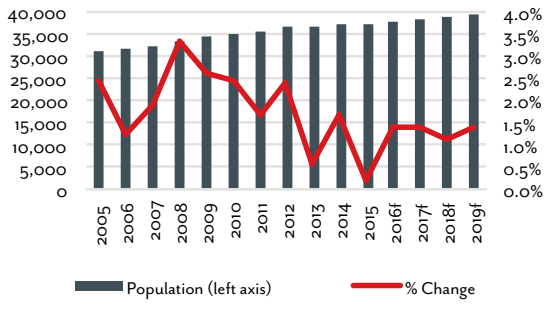
- Revised estimates from Statistics Canada note a second straight decline in 2015 in Yukon's real GDP by industry, with the estimate of $2.193 billion representing a 6.0% contraction from 2014.
- Growth in mineral production in 2016 is expected to contribute to real GDP gains, with forecasted growth of 4.6%.
- The medium term outlook is mixed, with 2017 and 2018 remaining flat, followed by real GDP growth in 2019.

Slow and steady population growth

The population is estimated to have grown for the 13th consecutive year in 2016. The annual population[11] of 37,858 was up 1.4% from 37,343 in 2015.

Whitehorse[12] – at 29,258 – accounted for more than 77% of Yukon's total population in 2016. Serving as Yukon's primary goods and services hub, population gains in Whitehorse have accounted for the majority of Yukon's recent population gains. Growth in the Whitehorse population of 386 in 2016 represented 75% of the total gains of 515.

Figure 4 - Yukon Population (June)



Of the remaining Yukon communities, eight were noted as recording population gains in 2016, led by Dawson City, which added 91 people, and Teslin, which grew by 27. Of these communities, only two had populations above 1,000, Dawson City at 2,158 and Watson Lake at 1,460.

Buoyed by a resilient local labour market and expectations of further mining development, the population is expected to continue to grow. The current outlook[13] is for population to grow by a further 1.4% in 2017 followed by growth of 1.1% in 2018 and 1.4% in 2019, bringing Yukon's population to more than 39,300 in 2019.

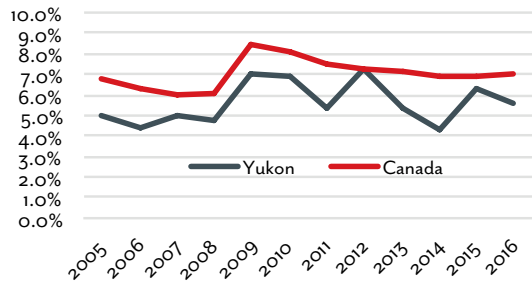
Outlook for Population

- Population is estimated to have grown for the 13th consecutive year in 2016, up 1.4% from 2015.
- Continued population growth is projected in the current outlook, with Yukon's population topping 39,300 by 2019.

Continued strength in the labour market

Yukon's labour market has generally performed well in recent years, with the unemployment rate tracking below the national average for over a decade. During this time, record levels of employment and labour force have been recorded with Yukon's unemployment rate among the lowest in the country.

Figure 5 - Average Annual Unemployment Rate

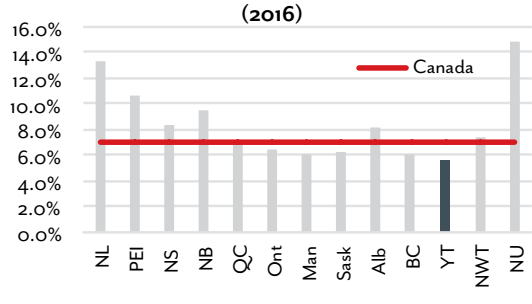


Preliminary data from Statistics Canada[14] suggests that Yukon's labour market remained healthy in 2016, outperforming the previous forecast from May 2016.

Both employment and the labour force were up in 2016 with employment averaging 20,200, up 4.1%, and the labour force averaging 21,400, up 3.4%. As growth in employment outpaced labour force gains, the unemployment rate declined to 5.6%, down from 6.3% in 2015.

At 5.6%, Yukon's unemployment rate was well below the Canadian average, and the lowest of all the provinces and territories.

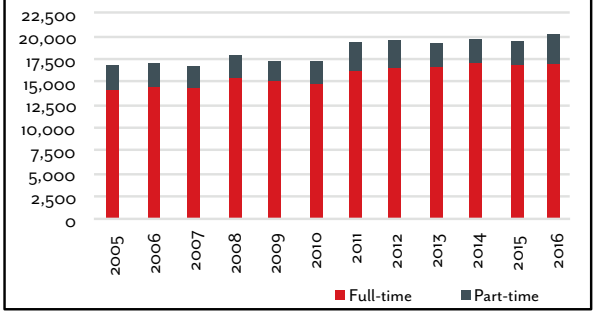
Figure 6 - Average Annual Unemployment Rate (2016)



Beyond having the lowest unemployment rate in the country, data for 2016 also shows that Yukon has a higher proportion of workers employed full-time, versus part-time. Last year, there were 17,100 (85.1%) full-time workers and 3,000 (14.9%) part-time workers in Yukon. At 14.9%, Yukon's proportion of part-time workers was the third lowest in the

country, behind NWT (12.4%) and Nunavut (12.6%). The highest proportion of part-time workers in Canada was in B.C. (21.7%).

Figure 7 - Full-time and Part-Time Employment



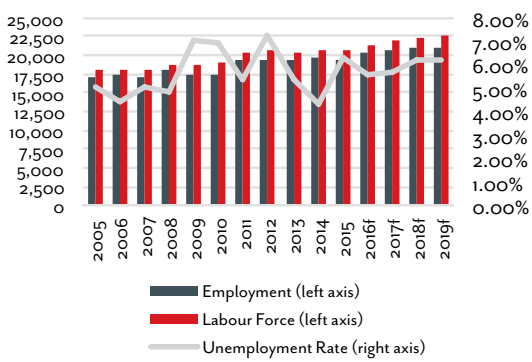
Source: Department of Finance; Statistics Canada

Nationally, the proportion of full-time workers was 80.8%. Since 2002, Yukon's proportion of full-time workers has been higher than of Canada as a whole. Over the 2002 to 2016 period full-time employment in Yukon accounted for an average 85.4% of total employment, while nationally, an average of 81.1%.

Yukon's labour market is expected to continue to perform well in 2017, with forecasts of gains for both employment and the labour force. The current forecast is for employment to grow 2.2% to 20,600, with the labour force growing 2.3% to 21,900. With labour force growth expected to be slightly stronger than employment growth, the unemployment rate is expected to see a slight uptick to 5.7%.

The medium term outlook is also generally positive for Yukon's labour market, with gains expected in employment and the total labour force in both 2018 and 2019.

Figure 8 - Labour Market



Source: Department of Finance; Statistics Canada

By 2019, Yukon employment is projected to be 21,100, with a total labour force of 22,500, resulting in an unemployment rate that continues to be relatively low at 6.2%.

Medium term employment gains are generally expected to be broad based, with gains in a number of key industry classifications[15], including Transportation and Warehousing, Trade, and Professional, Scientific and Management.

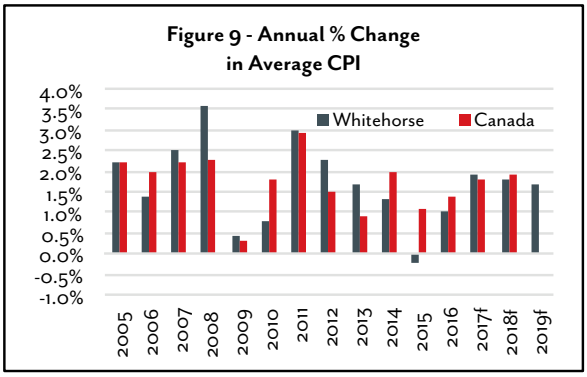
Outlook for Labour Market

- Yukon's labour market continued to perform well in 2016 with gains in both employment and the labour force, contributing to a notable decline in the unemployment rate to 5.6%, the lowest in the country.
- The medium term outlook for Yukon's labour market is positive, with gains in employment and the labour force forecast in 2017, 2018 and 2019 and an average unemployment rate of 6.0% over those three years.

CPI edging upward after a 2015 decline

The annual change in the Whitehorse[16] CPI, often used as an indicator of local price inflation, has generally been low in recent years. From 2000 to 2015, the annual change in the Whitehorse CPI averaged about 1.7%, below the 2.0% average for Canada over the same period.

Figure 9 - Annual % Change in Average CPI



Source: Department of Finance; Statistics Canada; Bank of Canada

Following deflation in 2015, the Whitehorse CPI increased by 1.0% in 2016. Notable gains were recorded in Clothing and Footwear (2.8%), Alcoholic Beverages and Tobacco Products (2.4%), Household Operations, Furnishings and Equipment (2.0%) and Health and Personal Care (1.7%).

Countering some of the growth in 2016 was a reduction in CPI for the Energy component (down 5.7%). The Energy component includes Gasoline, which was down 3.2%. This decline is supported by a 2.9% annual decline in the average price of regular unleaded self-service gasoline in Whitehorse in 2016.

Expectations are for the Whitehorse CPI to increase by 1.9% in 2017, little changed from the May 2016 forecast of 2.0%, and near the Bank of Canada's forecast[17] of 1.8% for Canada in 2017. The Bank's January 2017 *Monetary Policy Report* notes upward pressure on consumer energy prices in 2017, stemming from higher commodity prices and new regulations related to carbon use, but this will be more than offset by falling food prices and excess capacity in the Canadian economy.[18]

Beyond 2017, the outlook is for similar levels of growth in the Whitehorse CPI with gains of 1.9% and 1.7% in 2018 and 2019, respectively.

Outlook for CPI

CPI

- Following deflation in 2015,the Whitehorse CPI grew at a modest 1.0%in 2016.
- Moderate growth of the Whitehorse CPI is expected with annual growth to average 1.8% over 2017 to 2019.

Sector performance varies

Mining to pick up steam in 2018, 2019

Mining related activities have been a key driver of Yukon's economic performance with annual gains and contractions, particularly of GDP, often explained by what is happening in the mining sector.

Following a period of high levels of development and exploration spending where three mining projects were brought into production, lower mineral prices in recent years have contributed to decreased spending and mine closures.

Yukon's mining sector will continue to play a prominent role in Yukon's economy in the medium term, with the current outlook for real GDP tied to expectations for the mining sector.

Mineral exploration driven by prices

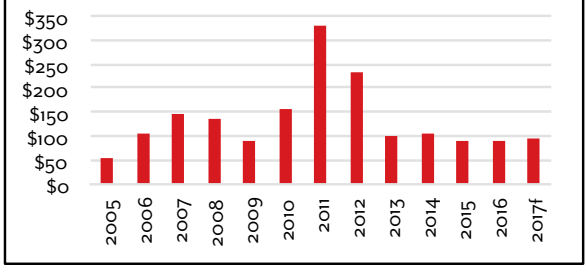
The fortunes of Yukon's mining sector are invariably linked to the performance of mineral prices, in particular the price of gold. As gold prices saw a rapid run-up, reaching all-time highs in 2012, record annual levels of exploration spending were noted in Yukon.

Following the peak in 2012, gold prices fell in each of the next three years, contributing to notable declines in mineral exploration expenditures. Lower prices made it more difficult for mining companies, particularly junior mining companies, to raise capital to finance exploration activities. With much of the exploration undertaken in Yukon completed by junior miners, this contributed to a dramatic decline in annual exploration expenditures.

Prices for metals of interest for Yukon recovered somewhat in 2016. The average price of gold was up 7.6% from 2015 and silver prices increased by 9.1% in 2016. Copper prices, while down overall in 2016, saw significant gains in the last two months of the year.

Natural Resources Canada's (NRCAN) latest *Survey of Mineral Exploration, Deposit Appraisal and Mine Complex Development Expenditures*, released in February 2017, estimates that exploration spending[19] decreased to $87.9 million in 2016, down from $92.2 million in 2015.

Figure 10 - Mineral Exploration Expenditures ($ millions)



Source: Department of Finance; Natural Resources Canada

Recent years have seen a shift from a greater proportion of spending on exploration[a] activities to more spending on deposit appraisal[b] work. NRCAN's spending estimate for 2016 includes an estimated $38.2 million related to deposit appraisal and the remaining $49.6 million for exploration. At $38.2 million, spending on deposit appraisal accounted for almost 44% of the total spending figure, much higher than during the last exploration boom (2010/12) which saw the share of deposit appraisal spending at about one-quarter[C] of the total. Spending intentions for 2017[20], as compiled by NRCAN, have exploration spending in Yukon increasing for the first time since 2014. While remaining well below the robust spending of the 2010/12 period, anticipated spending of $94.1 million in 2017 would represent an increase of 7.1% from 2016.

An improved outlook for the global mining community, based in part on improved outlooks for global growth and growth in key countries, is fueling hope of increased demand for minerals. Spending by Goldcorp. Inc., owner of the Coffee property, is expected to account for almost a third of total spending in 2017.

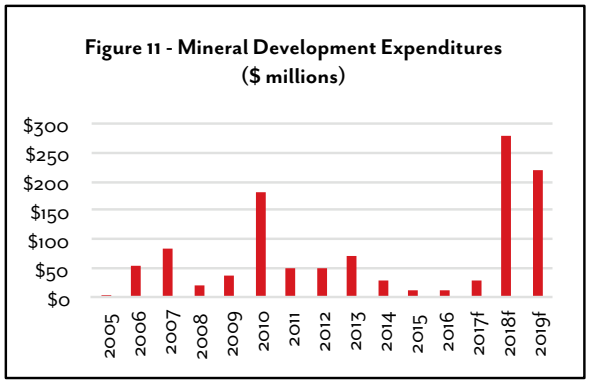
Mineral development spending remains low, but is expected to pick up

With no mines in development, expenditures on development remain modest, averaging less than $20 million over the last three years. Estimates from NRCAN have development expenditures in 2016 at just under $12 million, up slightly from $10 million in 2015. Spending by GoldCorp Inc. on its Coffee property accounted for much of the spending in 2016. NRCAN's forecast for 2017 anticipates spending will increase to more than $28 million, similar to what was recorded in 2014.

Development spending related to Victoria Gold Corp's Eagle Gold project and the Coffee project account for almost all of the spending expected in 2017.

The current forecast includes the development of the Eagle Gold and Coffee projects, which would result in significant development expenditures over 2018 and 2019, estimated at almost $500 million.

[a] Defined as the search for, discovery and first delimitation of a previously-unknown mineral deposit, or a re-evaluation of a deposit to enhance its potential economic interest.
[b] Defined as the steps undertaken to bring a delimited deposit to the stage of detailed knowledge required for a complete feasibility study that will fully justify and support a production decision and the large investment required.
[c] $40.7 million (26%) in 2010, $76.0 million (23%) in 2011 and $52.9 million (23%) in 2012.



Source: Department of Finance; Natural Resources Canada

The Eagle Gold project is fully permitted and is currently looking to secure financing to begin construction[21]. Development costs are estimated at about $370 million, with John McConnell, President and CEO of Victoria Gold noting publically that the company will need US$300 million to begin construction.[21] In January 2017, it was announced that a major French bank, BNP Paribas had committed US$220 million in financing for the project, and that with Victoria Gold having US$40 million of its own money, they were looking to raise the remaining US$40 million.

The Eagle Gold mine is projected to have a ten-year lifespan with production of almost 1.9 million ounces of gold over that period. It is anticipated that the project would employ 350-400 people annually during operation.

GoldCorp Inc. submitted a proposal for the Coffee project to the Yukon Environmental and Socio-economic Assessment Board (YESAB) on March 31, 2017.[22] Mine General Manager, Buddy Crill, suggested that construction could begin as early as 2018 with the project producing for 12 years. Timeline in a GoldCorp presentation from February 2017 shows development beginning in the third quarter of 2019 and continuing through to the end of 2020.[23] Crill also noted that construction would support 400 jobs, and the mine would employ 320 people annually during operation.[24]

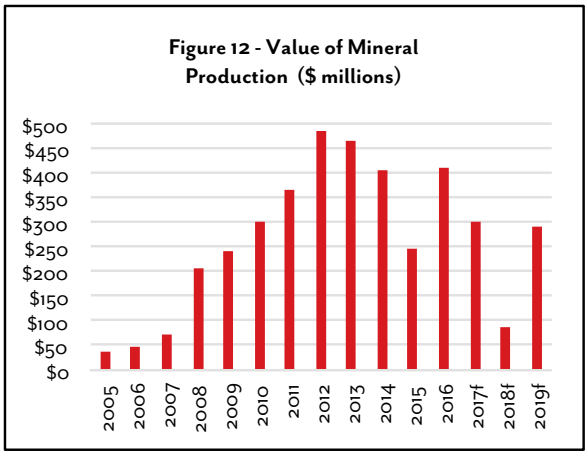
Mineral production to dip in 2018

After reaching a peak in 2012, lower mineral prices and lower annual production contributed to declines in 2013, 2014 and 2015. Closures of the Bellekeno mine in September 2013 and the Wolverine mine in January 2015 account for much of the recent decline.

Production increased markedly in 2016 on the strength of higher production from the Minto mine as well as increased placer gold production. The addition of production from the Minto North pit contributed to significant production gains at the Minto mine. Preliminary estimates from NRCAN have 2016 mineral production at more than $409 million, up 66% from $246 million in 2015.

Looking to 2017, expectations for metal prices are mixed. While the outlook for base metals such as copper, zinc, lead and nickel are for growth, the outlook is for a retreat in gold and silver prices. In terms of production, expectations are for underground mining at Minto to continue into early Q4, after which the mill will process stockpiled material, with milling currently scheduled to run at full capacity until the end of 2017.

The value of mineral production in 2017 is expected to be down significantly, in the area of $300 million.



Source: Department of Finance; Natural Resources Canada

Placer gold mining continues to make significant contributions to Yukon's mining sector, supporting local employment and accounting for a significant portion of annual mineral production. In 2016, there were an estimated 170 placer mine sites that directly employed about 700 people.[25] In terms of production, after averaging near $70 million annually from 2012 to 2015, the value of placer gold production is estimated at about $90 million in 2016. Estimated at about 70,000 crude ounces in 2016, placer gold production would be the highest since 2004. Placer gold production in 2017 is expected to be similar to the level of production in 2016.

With the Minto mine expected to cease operations in late 2017, mineral production is expected to decline dramatically in 2018, falling below $100 million, with placer gold accounting for most of the value. There is some upside risk in 2018 as Capstone Mining has indicated that they are continuing to review the economics of additional mining which could extend into 2018 and beyond.[26] An additional few months of production in 2018 could boost GDP growth by 1-2%.

With first production from the Eagle Gold project expected in 2019, the value of mineral production is expected to approach the current forecast for 2017.

While not included in the forecast, there is upside risk related to the development of the Kudz Ze Kayah mine, a zinc, lead, copper, gold and silver project. On March 27, 2017 YESAB indicated that BMC Minerals Ltd. had submitted a project proposal and that a 60 day adequacy review of the project had begun. BMC has publically indicated intentions to have a final decision to proceed with construction in late 2019, with commissioning of the mill to begin in late 2021 with commercial production in 2022. The project calls for a two-year construction period at a cost more than $420 million. The project would employ about 400 people during construction and support approximately 400 jobs annually during operations.[27]

Outlook for Mining

- Exploration spending in 2017 is expected to be the highest since 2014, increasing 7.1% from 2016.
- Development expenditures are expected to be down in the short term, but development of the Eagle Gold and Coffee projects is expected to boost development going forward.
- Lower production from the Minto mine is the primary contributor to a decline in mineral production in 2017. With Minto expected to cease operations in late 2017, the value of mineral production is expected to dip in 2018, before Eagle Gold production begins in 2019.

Energy potential abounds

A growing population, a desire for less reliance on imported fuels, and interest in exploring options to provide energy to potential mining projects are all contributing to the ongoing exploration of local options of energy production.

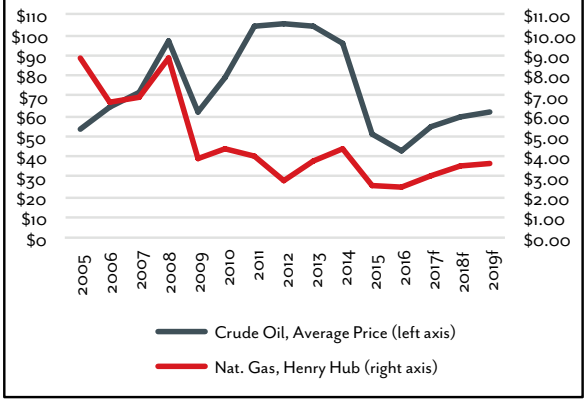
Yukon has been investigating options for renewable power, including development of a biomass energy strategy for district and home heating and an Independent Power Production policy, including a micro-generation program allowing individuals to produce and sell electricity to the grid. The government's platform also committed to explore options for expansion of renewable energy sources.

Oil and Gas

While there has been no commercial hydrocarbon production in Yukon since production ceased at the Kotaneelee field in the Liard Basin in September 2012, there is significant hydrocarbon potential in the territory,

both onshore and offshore. Yukon's onshore sedimentary basins contain an estimated 14.77 trillion cubic feet (Tcf) of conventional natural gas and 663 million barrels (MMbbls) of conventional oil. Offshore conventional resources in the Beaufort Sea include an additional estimated 40 Tcf of natural gas and 4,500 MMbbls of oil.

Figure 13 - Oil (U.S.$/bbl) and Gas Price (U.S.$/MMMBTU)



Source: World Bank

Interest has also been shown in the hydrocarbon potential of the Kandik and Eagle Plain sedimentary basins in Northern Yukon. The fall 2016 Request for Postings closed on July 13, 2016, and the Yukon Government received 15 requests for oil and gas rights located in the Kandik (13) and Eagle Plain (2) oil and gas basins. Consultation with affected First Nations and a review by government departments is currently being conducted and will be followed by a 60-day public review process.

Concerning Yukon's offshore resources in the Beaufort Sea, in December 2016, Canada designated all Arctic waters as indefinitely off limits to oil and gas licensing, to be reviewed every five years through a climate and marine science-based life-cycle assessment. Existing rights holders can continue to apply for and acquire licenses to undertake oil and gas activity, however, offshore rights will be indefinitely off-limits in the Beaufort Sea (to be reviewed every five years).[28] There will be no call for nominations during that time period.

Potential exists for development of local natural gas resources for both export and domestic use. Domestic production could help provide power for future mining projects; there has been interest in the potential of using LNG for the purposes of powering some operations, creating further interest.

Renewable Energy

As well as hydrocarbon, significant geothermal potential has been identified in Yukon. A report released by the Canadian Geothermal Energy Association[29] in 2016 noted that Yukon's geothermal energy potential could be more than 1,700 MW of energy, or about 18 times the current energy supplied by Yukon's renewable electrical system. There has also been recent discussion about drilling test wells to assess geothermal capacity in specific areas.[30]

Hydro generation accounts for almost 95% of Yukon's total annual electricity generation and expansion of hydroelectric capacity is expected to continue in partnership with First Nations, along with considering smaller hydroelectric sites and exploring other forms of renewable energy. Some local efforts are already underway, with a solar project in Old Crow nominated for an Arctic Inspiration Prize[31], given to projects with real-world applications that benefit the Canadian Arctic.

Outlook for Energy

- Yukon has significant energy potential from a variety of sources. Development of these resources would provide a boost to Yukon's economic prospects, both with an increase to GDP and by improving energy security in the territory, building a stable foundation for future development and potentially higher energy needs.

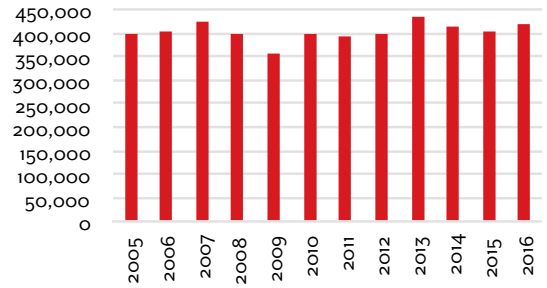
Tourism performing well

Tourism activities have long been an important contributor to Yukon's economy, often acting as a stabilizing force during times when the mining sector has struggled. Tourism-related activities add to the diversity of the local economy, help promote the territory, and support employment across a wide variety of local goods and services providers. Retailers, grocery stores, restaurants, accommodations providers, providers of sports and recreational activities and providers of arts and culture all benefit annually from the activities of visitors to the territory.

Tourism activities overlap a number of industries, making it difficult to determine the overall economic contribution. Accommodations & Food Services, Retail Trade and Transportation & Warehousing are three industry classifications where tourism activities are reflected strongly. In the 2015 Yukon Business Survey, Yukon businesses estimated that $226.9 million of their gross revenue in 2014 was attributable to tourism; based on these revenues, total GDP contribution of tourism is estimated at $95.9 million, almost 4% of Yukon's total GDP in 2014.[32]

While an imperfect indicator of tourism performance, international border crossings have often been used as a performance measure for Yukon's tourism sector. Based on reporting from the Canada Border Services Agency (CBSA), Statistics Canada reports that total international travellers[33] to Yukon numbered 419,244 in 2016, an increase of 14,124 (3.5%) from 2015. Since falling to below 360,000 in 2009 during the height of the last global economic downturn, the number of international travellers to Yukon has averaged more than 409,000 annually.

Figure 14 - Number of International Travellers



Source: Statistics Canada

The proportion of non-resident travellers is very stable from year to year, at about 80% of all travellers annually. In 2016, non-resident travellers totaled almost 346,000, or 79.7% of the total number of international travellers.

Looking only at the number of international travellers does not provide a complete picture of Yukon's tourism performance, and only when examining other indicators and data sources can one get a better understanding of how the sector is performing. Other indicators also suggest that 2016 was a solid year for Yukon's tourism sector:

- Air arrivals at Erik Nielsen Whitehorse International Airport in 2016 were up 8.6% from 2015, with almost 170,000 passengers arriving at the airport[34] – the third consecutive annual increase recorded.
- The Canadian Tourism Research Institute (CTRI) estimates that tourism spending in Yukon rose by 7.0%, including an estimated 6.0% increase in spending by domestic tourists and a 7.6% increase in spending from international travellers. Tourism sector revenues in Yukon are estimated to have increased by 5.1% in Yukon in 2016 – third highest in Canada, behind only B.C. (6.5%) and P.E.I. (5.4%), and 1.2 percentage points higher than the national average.
- Also from CTRI, the growth in revenue from what was classified as tourism activity (6.4%) outpaced

that from non-tourism (local) activity (4.0%) for Yukon.

- CTRI's most recent Travel Markets Outlook[35] notes that overnight visitation of about 322,000 was up 5.2% from 2015, with growth coming from all areas, domestic (up 3.3%), U.S. (up 5.0%) and overseas (up 7.6%).
- Related expenditures are also noted as being up in 2016, with spending associated with these overnight visits increasing 6.7% to $303 million – the fourth highest increase in Canada, behind only P.E.I. (10.1%), B.C. (8.4%), and Ontario (7.0%).
- For both overnight visitation and the spending associated with these stays, Yukon's gains outpace Canadian growth of 3.0% and 6.1% for both measures, respectively.

Looking forward, a number of factors have the potential to affect Yukon's tourism sector, including the performance of the Canadian dollar, gasoline prices, and geopolitical concerns.

After averaging just over US$0.75 in 2016, expectations are for a further decline in 2017 to about US$0.73. The persistence of a weaker Canadian dollar makes visitation to Yukon relatively more affordable for U.S. and some overseas visitors, potentially contributing to increased visitation and spending in 2017, as well as giving Canadians an incentive to travel within Canada, as the cost of international travel becomes relatively more costly.

Weakness in oil prices has contributed to lower gasoline prices in the last two years, but oil prices are expected to increase in 2017, putting upward pressure on gasoline prices. With many visitors to Yukon arriving by car (particularly from the U.S.), this could have a negative impact on Yukon's largest source of visitors. Higher fuel prices could also be passed along to customers in the form of higher costs for motorcoach and air travel to Yukon, which could also dampen visitation in 2017.

Geopolitical uncertainty, particularly that associated with potential policy decisions of the new U.S. administration, could impact travel in the near term. Recent policy direction, in the areas of immigration, trade of goods and services and restrictions on travel from certain countries to the U.S., has created significant concern in other countries and may deter travel to the U.S. This, along with Canada's reputation as a safe travel destination resonating with overseas travellers, could bode well for travel to Canada, and possibly Yukon.

CTRI's latest Travel Markets Outlook suggests that 2017 will be another positive year for Yukon's tourism sector. The CTRI forecast has total overnight visits at about 331,000, up 3.0%. Growth is noted in all areas with the strongest gains in overseas visitation, expected to increase 5.1% to 56,000, which may in part be fuelled by the current uncertainty regarding policy direction in the U.S. Expenditures by overnight visitors are forecast to increase 5.9% to $321 million, but some of these increases are price-related, as a significant increase in the travel price index in 2017 is noted.

Looking beyond 2017, CTRI forecasts increased overnight visitation and associated expenditures in every year out to 2020. Growth is reported in domestic, overseas and U.S. visitation, with the strongest gains noted in oversea visitation.

Outlook for Tourism

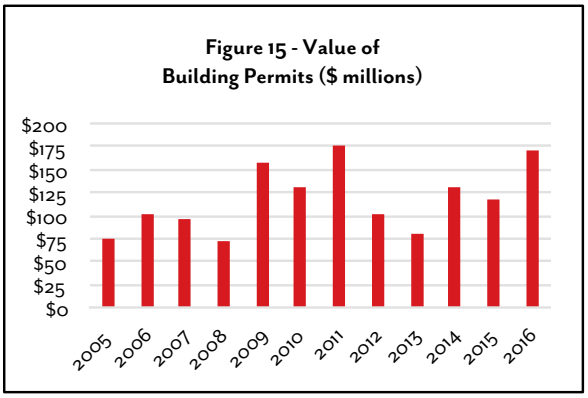
- Indications are that 2016 was another positive year for Yukon's tourism sector with growth noted in the number of international travellers and tourism-related spending and revenues.
- Expectations are that the near term will build on recent positive results.

Construction gains with public sector spending

Given the relatively small size of Yukon's economy, construction of a school or hospital, development of a new retail store or mine development activities can have a large impact on the territory's GDP. Forecast for the construction sector incorporates planned government capital spending in the 2017/18 Budget, which can have a significant effect in an economy as small as Yukon's.

While not all construction activity requires a building permit, the value of building permits can provide valuable information about the performance of the construction sector and is a commonly used indicator of performance.

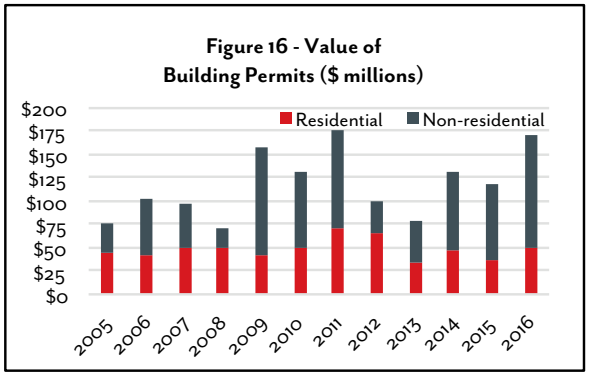
Following a 9.7% contraction in 2015, the value of building permits in 2016 are reported as growing 45.1% to almost $171 million, the highest value since 2011.



Source: Department of Finance; Yukon Bureau of Statistics

While gains were noted in both residential and non-residential permit value, the majority of the gains were on the non-residential side.

The value of non-residential permits increased substantially in 2016, up 49.0% to $121.7 million. Non-residential permits continued to account for the majority of building permit value, representing over 71% of the annual total. Since the start of 2010, non-residential building permit value has accounted for 61% of the total of almost $910 million.



Source: Department of Finance; Yukon Bureau of Statistics

Contributing to the increase in non-residential permits in 2016 was strong growth in the value of government/ institutional permits, up 68.9% to $91.0 million. Commercial permit value also grew in 2016, totalling $30.7 million, up 13.7% from 2015. Countering a portion of the gains was a small decrease in industrial permit value, which fell from $769,000 in 2015 to $0 in 2016.

The value of residential permits also posted strong growth in 2016, up 36.3% to $49.2 million. For the period 2010 to 2016, residential building permits accounted for 39% of building permit value, totalling more than $350 million.

Public sector investment has historically been a prominent driver of construction activity in Yukon. Capital spending by the Government of Yukon is estimated at $306.6 million in 2016/17, up from spending of $238.5 million in 2015/16. Prominent projects that contributed to this spending[36] include:

- Continued work on a 150-bed continuing care facility in Whitehorse ($42.7 million);
- $60 million related to transportation infrastructure, including more than $38 million on improvement and rehabilitation of Yukon highways, $4.3 million for various bridge work, and almost $4.1 million for work on Yukon airports;
- Emergency department expansion and MRI at the Whitehorse General Hospital ($22.0 million);

- Further work on the new Salvation Army building in Whitehorse ($10 million);
- Work on phase 3 of the Whistle Bend sub-division ($9.8 million);
- Activities related to investing in affordable housing ($9.4 million);
- Continued work on the replacement of the Sarah Steele alcohol and drug detox centre ($8 million);
- Activities related to the continued replacement of the old F.H. Collins school in Whitehorse ($5.1 million) as well as construction of the new school's technical education wing ($3.5 million);
- Archives Vault Expansion ($5.6 million); and
- Replacement of fire hall in Carcross ($2.6 million).

Construction activity in 2017 will be driven in large part by capital projects identified in the 2017/18 Government of Yukon budget, which notes $309.4 million in capital spending[37]. Key projects in the latest budget include:

- Further work on the continuing care facility in Whitehorse ($68.5 million);
- More than $57 million related to transportation infrastructure, including more than $36 million for improvement and rehabilitation of Yukon highways, $15.3 million for various bridge work, and almost $6.5 million for work on Yukon airports;
- $30.3 million for work in various Yukon communities to improve sewage and wastewater services including Whitehorse ($4.1 million), Haines Junction ($3.3 million), Ross River ($3.0 million), Old Crow ($3.0 million), Mayo ($2.9 million), Watson Lake ($2.8 million), Carcross ($2.8 million) and Dawson City ($2.2 million);
- Emergency department expansion and MRI at the Whitehorse General Hospital ($17.8 million);
- Work associated with phases 3 ($9.8 million) and 4 ($14.3 million) of Whistle Bend;
- Activities related to construction of a new Francophone school in Whitehorse ($8.0 million);
- Activities related to investments in affordable housing ($6.9 million);
- Upgrades to the MacBride Museum (total project cost of $6 million shared between Yukon and federal governments);
- Activities related to demolition ($2.9 million) of the old F.H. Collins and development of the track and field and recreation site ($2.0 million); and
- Construction of 6-plex residential building in Ross River ($2.4 million).

Beyond capital spending by the Government of Yukon, the City of Whitehorse's building consolidation project is a large capital project that will impact the local economy in 2017. The City of Whitehorse's Capital Budget 2017/20 notes total investment in this project of $45 million, with more than $39 million budgeted to be spent in 2017. Driven by spending associated with the consolidation project, the City's total capital budget of $46.6 million in 2017 is well above estimated capital spending of just under $16.2 million in 2016.

Local construction activity will continue to be supported primarily by public spending, particularly on key infrastructure such as highways, water and sewage services, hospitals and schools. The development of new mining projects, as noted in the discussion of mining, could also result in substantial levels of private sector spending locally and has the potential to positively impact Yukon's construction industry in the medium term.

Outlook for Construction

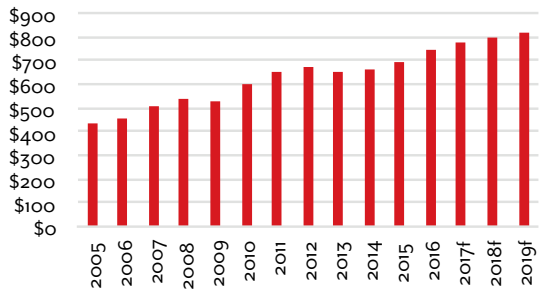
- The 2017/18 Government of Yukon Budget notes capital spending of about $310 million, up from estimated spending of $306.6 million in 2016/17.
- Spending identified in the most recent budget will support a number of local construction projects.
- Development of new mines in the medium term could result in substantial construction related spending in 2018 and 2019.

Strong gains in retail trade

Yukon's retail sales have recently been strong, with increasing population, robust employment numbers and growing household incomes contributing to higher sales.

Retail sales for Yukon are estimated to have grown for a third consecutive year in 2016, with more than $740 million in sales, a 7.0% increase from $692 million in 2015.

Figure 17 - Value of Retail Sales ($ millions)



Source: Department of Finance; Yukon Bureau of Statistics

Of the total annual increase of more than $48 million, almost one third of the increase was a $14.8 million increase in sales from Gasoline Stations. Much of the remaining increase falls within industry classifications with some data suppressed[38] in the last two years. These industries represent more than 76% of the total retail sales reported for 2016 with sales from *Motor Vehicle and Parts Dealers* accounting for more than 23% of that value. While the value was suppressed in 2016, historical data suggests that *Food and Beverage Stores* would likely represent 35-40% of the total value of retail sales.

For all categories without data suppression in the past two years, reported sales increased in 2016. Reported sales for *Gasoline Stations* increased 13.8% to $122.6 million. Sales from *Health and Personal Care Stores* changed little in 2016, with the estimated value of $37.7 million up slightly from $37.5 million in 2014. *Furniture and Home Furnishings Stores* sales of $14.2 million in 2016 were up 10.2% from 2015.

Supported in part by the expectation of population gains, retail sales are anticipated to grow in the medium term. Retail sales are forecast at nearly $780 million in 2017, with further gains in the following two years, totalling almost $820 million in 2019.

Outlook for Retail Trade

- Retail sales grew for a third consecutive year in 2016, increasing 7.0% to more than $740 million.
- Expectations are for further growth in Yukon retail sales in each of the next three years, bringing the value of retail sales to over $817 million by 2019.

ASSUMPTIONS AND RISKS

As noted at the beginning of this document, forecasts are developed based on the best information available at the time and on the assumptions deemed most realistic. The following highlights some of the key assumptions that helped to shape the current forecast.

Mineral Production – In recent years, Yukon's real GDP performance has been driven by mineral production, and this remains the case for this forecast. Higher production from the Minto mine was a key driver of growth in 2016, and expectations of lower annual production in 2017 and 2018 explain much of the expected weakness in GDP during those years. The development of other mining projects, such as the Eagle Gold and Coffee mines, would also impact Yukon's economic fortunes beyond 2017.

Commodity Prices – Where available, World Bank metal price forecasts are used. If not available, forecasted growth of similar products is applied to historical data to develop a forecast. For energy prices, the U.S. Energy Information Administration's (EIA) long term forecast is used, adjusted in the near term for their short term forecast. Forecasts may be adjusted with reference to other prominent energy forecasts (e.g. Sproule, a leading global petroleum consultant).

Exchange Rates and Interest Rates – Exchange and interest rate forecasts are generated by a Yukon macroeconomic model used to develop this forecast. U.S. interest rates come from publically available sources (e.g. the Organization for Economic Co-operation and Development, or OECD).

Economic Forecasts – The US Energy Information Administration's (EIA) long term forecast is used for U.S. GDP growth, adjusting the short term based on the latest consensus forecast from the survey of professional forecasters of the Federal Reserve Bank of Philadelphia. For other major trading partners the current OECD forecast is generally used.

Capital Spending – As spending on large capital projects can impact GDP growth, this forecast is aligned with planned upcoming projects (based on information available), including the Government of Yukon's capital plan and the City of Whitehorse's current capital budget. Examples of prominent projects considered in this forecast include the City of Whitehorse Municipal Building and the Whistle Bend Extended Care Facility. Spending related to the development of the Eagle Gold and Coffee mines are also key drivers of the real GDP forecast beyond 2017.

Government – this economic forecast incorporates the government's planned spending as outlined in the 2017/18 Budget. Public sector spending has a significant economic impact in a small jurisdiction such as Yukon, so any changes in the rate of spending would likely have an impact on a number of economic indicators (including GDP).

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There is always a degree of risk and uncertainty associated with these assumptions, and ultimately the forecast results. Key risks to consider include:

Global Economy – Yukon's economy is tied to the performance of other economies, such as the U.S., China, Canada, and the global economy as a whole. Economic performance elsewhere affects the demand for Yukon goods and services, including minerals and local tourism activities. Recent developments such as the outcomes of the Brexit vote and the U.S. election could have an impact on Yukon's future economic performance.

Metal Prices – Metal prices are determined on the global market and are a key driver of mining activity. During the last global economic downturn, prices for minerals, particularly gold, saw a rapid increase and record highs, spurring interest in Yukon resources and contributing to record levels of exploration spending and substantial development spending (three mines brought into production). Weaker prices since then have contributed to two mine closures and reduced levels of exploration and development spending. Gold and silver prices were higher in 2016 while the price of copper fell. The outlook for mineral prices is mixed, with prices of

gold and silver expected to fall over the forecast period, but prices of base metals such as copper and zinc are expected to increase. Higher or lower prices would likely impact mining activity and ultimately the GDP forecast.

Energy Prices – Oil and gas prices can influence local economic activity, in particular mining sector activity (fuel for project operations and equipment) and tourism (fuel for travelers' vehicles). Fuel prices also affect construction costs and the cost of local purchases, as most goods are transported in from outside Yukon. This forecast notes a decline in oil and natural gas prices in 2016, before annual gains out to 2019. Higher or lower prices than forecast could impact actual results.

Exchange Rates – The Canadian/U.S. dollar exchange rate can affect spending decisions by tourists and investment decisions by resource-based companies. After a decline in the exchange rate in 2016, this forecast projects a further decline in 2017 to be followed by gains in each of the next two years, which would bring the Canadian dollar to US$0.77 in 2019. Variation from the current projections could have an impact on actual results.

Interest Rates – Lower interest rates can contribute to increased investment as the cost of borrowing is reduced, and, conversely, higher interest rates may dampen investment spending. The cost of borrowing in Canada has been low for a prolonged period, with the Bank of Canada's daily overnight target for the bank rate not exceeding 1.0% since January 19, 2009. This forecast assumes that interest rates will remain low over the forecast horizon, but unforeseen increases could affect investment in Yukon.

Population and Labour Market – Population and labour market forecasts include the assumption that the proportion of fly-in/fly-out versus resident workers remains the same for future mining projects as in previous experience. If this proportion were to shift significantly (in either direction), there would likely be an impact on the employment forecast in particular.

KEY ECONOMIC INDICATORS

Indicator	2015	2016	2017f	2018f	2019f
Economic Output					
Real GDP by Industry (2007$ billions)	$2.193 (r)	$2.295 (e)	$2.296	$2.301	$2.361
Annual percent change	-6.0%	4.6%	0.1%	0.2%	2.6%
Population					
Population	37,343	37,858	38,380	38,810	39,360
Annual percent change	0.2%	1.4%	1.4%	1.1%	1.4%
Labour market†					
Labour force	20,700	21,400	21,900	22,300	22,500
Employment	19,400	20,200	20,600	20,900	21,100
Unemployed	1,300	1,200	1,300	1,400	1,400
Unemployment rate	6.3%	5.6%	5.7%	6.2%	6.2%
CPI (Annual % Change)	-0.2%	1.0%	1.9%	1.9%	1.7%
Commodity Prices~					
Gold ($U.S./ounce)	$1,160	$1,249	$1,167	$1,153	$1,142
Silver ($U.S./ounce)	$15.70	$17.15	$16.70	$16.60	$16.60
Copper ($U.S./pound)	$2.50	$2.21	$2.49	$2.54	$2.59
Zinc ($U.S./pound)	$0.87	$0.95	$1.22	$1.27	$1.27
Oil – WTI ($U.S./barrel)	$48.67	$43.07	$50.66	$53.99	$57.43
Natural Gas – Henry Hub ($U.S./MMBTU)	$2.63	$2.49	$3.27	$3.45	$3.96
Key Rates					
Three month Treasury Bill rate	0.50%	0.50%	0.50%	0.50%	0.50%
Canada/U.S. exchange rate	$0.782	$0.754	$0.733	$0.747	$0.770
Mining					
Value of mineral production ($ millions)	$246.2 (r)	$409.1 (p)	$303.0	$86.0	$291.0
Exploration expenditures ($ millions)	$92.2	$87.9	$94.1	--	--
Development expenditures ($ millions)	$10.0	$11.9	$28.6	$280.0	$220.0
Construction					
Value of building permits ($ millions)	$117.8	$170.9			
Retail Trade					
Value of retail sales ($ millions)	$692.2	$740.5	$777	$792	$818

e = estimate, f = forecast, p = preliminary, r = revised, -- = not available
^CPI increase for Whitehorse only
† = Annual averages rounded to the nearest 100. Totals may not add due to rounding.
~Annual averages

DATA SOURCES FOR KEY ECONOMIC INDICATORS TABLE

Indicator	Source
Economic Output (Real GDP)	Statistics Canada, Yukon Department of Finance
Population	Yukon Bureau of Statistics
Labour Force Indicators	Statistics Canada, Yukon Labour Force Survey, Yukon Department of Finance
Commodity Prices	World Bank, U.S. Energy Information Administration, Yukon Department of Finance
Interest Rates	Bank of Canada, Yukon Department of Finance
Exchange Rates	Bank of Canada, Yukon Department of Finance
Value of Mineral Production	Natural Resources Canada, Yukon Department of Finance
Mineral Exploration Expenditures	Natural Resources Canada
Mineral Development Expenditures	Natural Resources Canada, Yukon Department of Finance
Permitted Building Construction	Yukon Bureau of Statistics, Yukon Department of Finance
Retail Trade	Statistics Canada, Yukon Department of Finance

ENDNOTES

[1] World Economic Outlook - Update. (January 2017). International Monetary Fund. http://www.imf.org/external/pubs/ft/weo/2017/update/01/pdf/0117.pdf

[2] Caribbean countries, Latin America, Africa, rest of Asia, parts of Eastern Europe (including Baltic states, Russia, and Turkey), Middle Eastern countries excluding Israel, Oceania excluding Australia and New Zealand.

[3] World Economic Outlook - Update. (January 2017). International Monetary Fund. http://www.imf.org/external/pubs/ft/weo/2017/update/01/pdf/0117.pdf

[4] Monetary Policy Report (January 2017). Bank of Canada. http://www.bankofcanada.ca/wp-content/uploads/2017/01/mpr-2017-01-18.pdf

[5] Monetary Policy Report (January 2017). Bank of Canada. http://www.bankofcanada.ca/wp-content/uploads/2017/01/mpr-2017-01-18.pdf

[6] World Bank Commodities Price Forecast (January 24, 2017). World Bank. http://pubdocs.worldbank.org/en/926111485188873241/CMO-January-2017-Forecasts.pdf

[7] MMBTU refers to a million British thermal unit (Btu)

[8] World Bank Commodities Price Forecast (January 24, 2017). World Bank. http://pubdocs.worldbank.org/en/926111485188873241/CMO-January-2017-Forecasts.pdf

[9] Real GDP for 2015 represents the most recent data available from Statistics Canada. It is anticipated that preliminary data for 2016 will be released in May 2017.

[10] "Public Sector" is an aggregation of industry classifications Public Administration, Educational Services and Health Care & Social Assistance.

[11] Population as of June 30th is treated as the annual figure.

[12] Includes City of Whitehorse and surrounding area as well as the community of Marsh Lake.

[13] The outlook for population is based on the population projections produced by the Yukon Bureau of Statistics.

[14] Data is from the Labour Force Survey.

[15] Industry classifications are based on the North American Industry Classification System (NAICS). Business establishments are classified to an industry according to the primary business activity of the establishment.

[16] Consumer Price Index data is only available in Yukon for Whitehorse.

[17] Monetary Policy Report (January 2017). Bank of Canada. http://www.bankofcanada.ca/wp-content/uploads/2017/01/mpr-2017-01-18.pdf

[18] Monetary Policy Report (January 2017). Bank of Canada.
http://www.bankofcanada.ca/wp-content/uploads/2017/01/mpr-2017-01-18.pdf

[19] Exploration and deposit appraisal expenditures include on-mine-site and off-mine-site activities; field work, overhead costs, engineering, economic and pre- or production feasibility studies, environment, and land access costs. Expenditures also include only the search for and appraisal of deposits and do not include work for extensions for known reserves.

[20] Survey of Mineral Exploration, Deposit Appraisal and Mine Complex Development Expenditures (February 2017). Natural Resources Canada.

[21] Victoria Gold reaches tentative financing deal for Eagle Gold mine near Mayo (January 26, 2017). CBC News.
http://www.cbc.ca/news/canada/north/victoria-gold-mayo-mine-financing-deal-1.3953490

[22] Goldcorp showcases Dawson mine project (February 17, 2017). CKRW96.1FM.
http://www.ckrw.com/news/local-news/goldcorp-showcases-dawson-mine-project/

[23] GoldCorp Inc. Corporate Presentation (February 27, 2017).

[24] Goldcorp showcases Dawson mine project (February 17, 2017). CKRW96.1FM.
http://www.ckrw.com/news/local-news/goldcorp-showcases-dawson-mine-project/

[25] Yukon Exploration & Geology Overview 2016. Department of Energy, Mines and Resources.
http://ygsftp.gov.yk.ca/publications/yeg/yeg16/overview/YEG_Overview2016.pdf

[26] Capstone Mining 2017 Operating and Capital Guidance. http://capstonemining.com/news/news-details/2017/Capstone-Mining-2017-Operating-and-Capital-Guidance/default.aspx

[27] Mine would eventually employ 400 people.
http://whitehorsestar.com/News/mine-would-eventually-employ-400-people

[28] http://pm.gc.ca/eng/news/2016/12/20/united-states-canada-joint-arctic-leaders-statement

[29] In partnership with Canadian Northern Economic Development Agency, the Government of Yukon's Department of Energy, Mines and Resources' Energy Branch (the Energy Solutions Centre), Yukon Energy and the Yukon Geological Survey: http://www.energy.gov.yk.ca/pdf/Yukon-Geothermal-Opportunities-and-Applications-Report.pdf

[30] http://www.cbc.ca/news/canada/north/yukon-geothermal-energy-1.4009917

[31] http://www.arcticinspirationprize.ca/finalists/2016finalists.php

[32] Yukon Business Survey 2015. Yukon Bureau of Statistics.
http://www.eco.gov.yk.ca/stats/pdf/2015_Business_Survey_Report.pdf

[33] Cansim Table 427-0001. Statistics Canada.

[34] Department of Tourism and Culture.

[35] Travel Markets Outlook – National Focus (Autumn 2016). Canadian Tourism Research Institute. Conference Board of Canada

[36] Spending figures rounded to the nearest one decimal.

[37] Spending figures rounded to the nearest one decimal.

[38] Data for the following is suppressed, but is included in the total for retail sales: Motor Vehicle and Parts Dealers; Electronics & Appliance Stores; Building Material & Garden Equipment; Clothing & Clothing Accessories Stores Sporting Goods, Hobby, Book & Music Stores; General Merchandise Stores; and Miscellaneous Store Retailers, and Supplies Dealers.

TOPIC: **Non-Labour Costs**

REFERENCE: Application, pages 3-8 to 3-13. PDF 56 to 61

QUESTION:

a) Was any escalator applied to non-labour costs in section 3 of the Application? Please explain.

b) If an escalator (s) was/were applied, please quantify the escalator(s), where it/they were applied and the base numbers it was applied to.

ANSWER:

(a) and **(b)**

No escalator was applied to non-labour costs referenced in Tab 3, pages 3-8 to 3-13 of the Application. Costs for these items were individually forecast giving consideration as to what each specific cost would be.

TOPIC: **Reserves for Injuries and Damages (RFID)**

REFERENCE: Application, page 3-15, PDF page 63, lines 1-6

QUOTE: "… Yukon Energy is seeking approval of a two-part solution to the RFID [reserve for injuries and damages] account:

…

2. Increase the annual appropriation to the RFID, starting in 2017, to $0.267 million per year. This is based on the 10-year average of actual expenses …"

QUESTION:

a) Please provide the 10-year average of actual expenses in relation to the RFIDF for the years 2007 to 2016.

ANSWER:

(a)

The 10-year average of actual expenses in relation to RFID for the years 2007-2016 is $306,000 based on the following details:

($000's)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	10 Year Average
Annual Charges	$63	$101	$159	$415	$302	$204	$404	$196	$193	$1,018	$306

TOPIC: **YDC Mayo B Promissory Note**

REFERENCE: Application, page 3-22. PDF 70, lines 1 to 2

QUOTE: "… which forgives the interest expense if the Integrated Grid is lower than the Minimum Grid Load as set in Schedule 1 of the Mayo B Promissory Note…"

QUESTION:

a) Please provide a copy of the referenced Schedule 1 with respect to the Mayo B Promissory Note.

b) Please provide a continuity schedule of interest payments with respect to the Mayo B Promissory Note for the period 2013-2016 inclusive.

ANSWER:

(a)

Please see YUB-YEC-1-31 Attachment 1, which provides Appendix 5.3 from the 2012/13 GRA Application. This includes the Mayo B Promissory note (as well as the referenced Schedule 1).

(b)

Please see the table provided below.

($000's)	2013	2014	2015	2016
Interest on Mayo B Flex Note	$ 130	-$ 112	$ 128	$ 167

APPENDIX 5.3
MAYO B FLEXIBLE NOTE

APPENDIX 5.3: MAYO B FLEXIBLE NOTE

PRIOR COMMITMENTS

Yukon Energy, when seeking approval to proceed with the Mayo B Project, committed in the Mayo B Part 3 Application that it would secure (via Yukon Development Corporation [YDC]) flexible debt financing for the Mayo B Project (i.e., measures to reduce overall return on rate base in order to mitigate specific near-term rate impact concerns), and at that time outlined as follows the rationale and broad approach for this financing.

The Mayo B flexible debt will allow the interest rate on the debt to change, based on the IS [Integrated System] grid generation load, as required to prevent, in any fiscal year during the short-term, the cost of Mayo B net generation used to displace diesel generation from exceeding a 10 to 11 c/kW.h range (2012$). [YEC's Mayo B Project Part 3 Application, page 45].

Additional commitments for this flexible debt included in the Mayo B Part 3 Application (page 45) were as follows:

- YDC funding at no cost to YEC for the additional interest rate reductions (including cash injections through 'negative' interest rate payments) required in this regard (i.e., to prevent net generation cost from exceeding the stipulated unit cost range) to mitigate any delays in connecting the Carmacks Copper mine load to the grid – these no cost arrangements for YEC were to apply in the short-term for years before the Carmacks Copper assumed operating load of approximately 50 GW.h/year was to be supplied from the grid.

- The face interest for this flexible debt (i.e., the rate charges when no interest rate reductions apply) will be set above YEC's then applicable long-term borrowing costs in order to enable YDC an opportunity to earn an overall return on the load over its life equal to YDC's long-term borrowing costs when the flexible debt is established.

The specific methodology for implementation of the above financing was not developed at the time of the Part 3 hearing. The YUB noted in its Report and Recommendations to the Minister following the Mayo B hearing (page 45) that it expects "...the complete details of the flexible debt financing with YDC and illustrative examples of how the flexible debt financing works will be provided by YEC in its next GRA."

OVERVIEW OF FLEXIBLE DEBT NOTE

The YDC Mayo B Flexible Debt (long-term promissory note – the "Note") with YEC for $21.9 million[1] that was concluded effective December 31, 2011 is attached at Attachment 5.3. Illustrative examples of how the flexible debt financing works are provided in Schedule 2 of the Note.

[1] The budget for the Mayo B project is $120 million. The majority of the financing for the Mayo B project is derived from other sources (Federal Infrastructure Fund payments of $53.35 million and Yukon Government Contributions of $30.15 million), resulting in this project being expected to add $36.5 million to YEC's asset base. In keeping with the 60:40 debt:equity structure, this asset addition requires a debt component of $21.9 million (60% of $36.5 million). At the time that the Note was concluded in November/December 2011, commissioning of Mayo B was scheduled for completion during December, 2011, and this Note was therefore required to be in place by December 31, 2011.

Simplified terms for the Mayo B Flexible Debt have been established that in summary reflect the following. The simplified terms and other revisions are summarized below:

- **Debt Amount** – The Note is for the full $21.9 million, assuming that the ultimate net rate base for Mayo B is $36.5 million.
- **Term** – 40 years (reflects maximum term of other flexible debt in the past for YDC with YEC). The following are noted with regard to the Term:
    - Flexible interest terms extend to the Expiry Date, which is January 1, 2021 if the Mayo Lake Project is in service, and otherwise is January 1, 2023.
    - Annual principal repayment is calculated based on an assumed 65 year project life (depreciation), with a balloon payment for the outstanding balance at the end of the Term.
- **Interest Rate** – The 5.46% annual rate was determined as the rate estimated to achieve a forecast interest IRR of 5% over the Term, taking into account forecast Maximum Interest Payable under grid loads as currently forecast by YEC assuming connection of Victoria Gold by late 2014, and assuming connection to the grid at a minimum of at least 52 GW.h/year of new mine load (compared to forecast Minto and Alexco loads) at the start of 2012 and remaining for six years (i.e., to the end of 2017).
- **Simplified Approach to determine Maximum Interest Payable Prior to the Expiry Date** – The simplified approach follows the Canada Flexible Debt mechanics that rely on readily available grid generation records, and avoids the complexities of requiring annual reviews of actual YEC costs and estimates of annual net generation used to displace diesel or other fossil fuel generation on the grid.
    - The simplified approach assumes a ceiling on interest payments in any year at 11 cents/kW.h in 2012$ (adjusted after 2012 by annual Yukon CPI escalation) times the estimated grid diesel generation displaced by Mayo B based on the actual grid generation load and long term average annual grid hydro generation at that load assuming renewable generation capability in place and as licensed in December 2012, i.e., no Mayo Lake project and Aishihik FAA as at this time[2].
    - "Actual Grid Generation" is to be determined for this purpose after adding back the estimated reduction, if any, in grid generation in that years due to DSM/SSE (as defined in the Note) undertaken since December 31, 2012[3].
    - The assessments of maximum and minimum grid loads adopted in the simplified approach (Schedule 1 attached) were calibrated and tested using detailed model calculations of the applicable **maximum grid load** (i.e., load at which full interest payable) and **minimum grid load** (i.e., load at which no interest payable) based on

[2] The Note is not varied in the event that new renewable generation is added to the grid, or the existing licences are modified, after December 31, 2012, i.e., the assistance that was committed related solely to load-related risk affecting diesel displacement by Mayo B and was independent of impacts on such diesel displacement as a result of subsequently approved new generation projects.
[3] The Note is not varied by the impacts of DSM/SSE, i.e., the assistance that was committed related solely to load-related risk independent of impacts of DSM/SSE.

forecast annual Mayo B operating and maintenance costs, 65 year depreciation of the assumed $36.5 million net rate base cost, and equity at 40% of rate base with an allowed ROE of 8.49%/year.

- Figures 5.3A-1 and 5.3A-2 provide further information on this analysis.

Figure 5.3-1

Mayo B Grid Load at Full Interest, at 5%, no more than 11 cents/kW.h in $2012

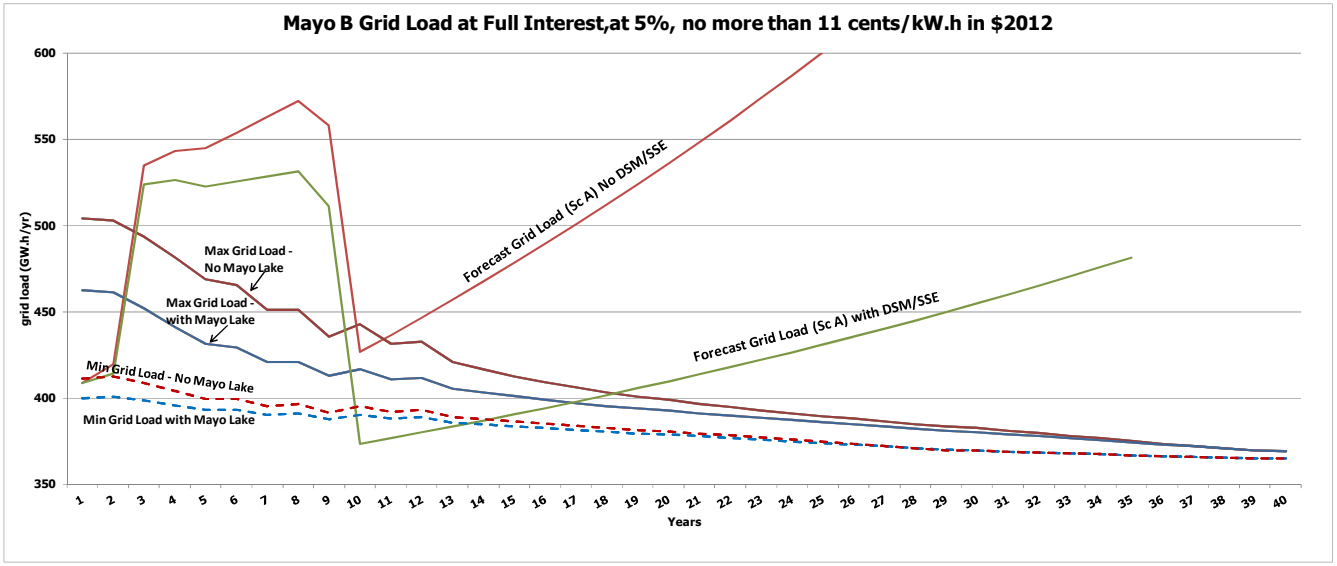

Figure 5.3A-1 shows detailed calculated estimates (i.e., not using the simplified approach) by year (year 1=2012) of **Maximum Grid Load** (at and above this level full interest is paid) and **Minimum Grid Load** (at this level zero interest is paid, and below this level negative interest is paid), assuming interest is constrained as required to ensure Mayo B annual costs do not exceed 11 cents per kW.h (2012$) of net generation (diesel displaced) by Mayo B, and based on assumed forecast annual Mayo B costs for O&M, depreciation and return on equity. Max and Min Grid Loads are shown by year both (a) with no Mayo Lake Project and (b) with Mayo Lake Project enhanced storage (1 metre lower bottom storage) – including the Mayo Lake Project reduces the Max and Min Grid Loads. Figure 5.3-1 also shows forecast grid loads by year, indicating years when full interest is expected to be paid versus years when interest is expected to be reduced. Current [as at November/February 2011] forecast loads are shown for the first two years (2012 and 2013); after 2013, the forecast shows the currentt [as at November/February 2011] longer-term planning YEC grid generation forecast with Victoria Gold. Separate grid load forecasts are provided with no DSM/SSE, as well as the lower loads with maximum DSM/SSE as assumed in current long-term resource planning forecasts.

In summary, Figure 5.3A-1 shows that full interest would be paid each year that Victoria Gold is on the grid, as well as each year after 2021 with only non-industrial forecast grid loads, i.e., no mines connected to the grid, assuming no reductions for DSM/SSE are considered. Without Victoria Gold loads, however, only minimal interest would be paid for many years prior to 2022. Further, if DSM/SSE impacts materially reduce grid loads the period with no or reduced interest would be greatly extended in the absence of new mine loads and/or adjustment to remove the effects of DSM/SSE when determining Mayo B Flexible Debt interest payments.

The Mayo B Flexible Debt commitments were made based only on Mayo B and the grid resources and licences at the time of the Mayo B commitment, and are not intended to reflect changes due to subsequent resource investments such as DSM/SSE or new renewable generation resources on the grid.

Figure 5.3-2
Mayo B Grid Load at 40 Years Flex Term Debt (lump sum payment in year 40), 65 years depreciation, no more than 11 cents/kW.h in $2012

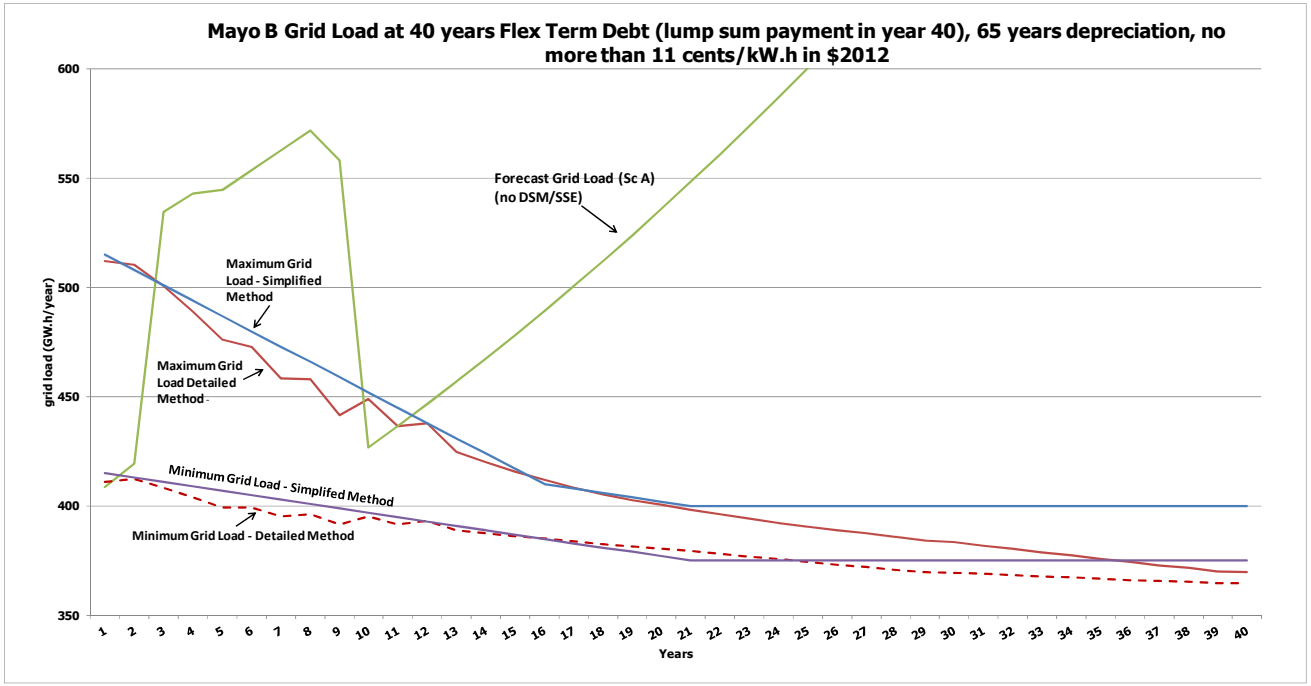

Figure 5.3-2 shows **Maximum Grid Load** (at and above this level full interest is paid) and **Minimum Grid Load** (at this level zero interest is paid, and below this level negative interest is paid), comparing the Simplified Method and the Detailed Calculation Method (see Figure 5.3-1). Forecast grid loads are also shown by year assuming no DSM/SSE (the current [as at November/February 2011] YEC forecast loads are shown for the first two years [2012 and 2013]; after 2013, the forecast shows the current [as at November/February 2011] long-term resource planning grid generation forecast with Victoria Gold).

Figure 5.3-2 shows that the Simplified Method in almost every year results in Max and Min Grid loads that are equal to or higher than those determined with the Detailed Calculation Method.

The Interest Rate of 5.46% was determined as the rate estimated to achieve a forecast interest IRR of 5% over the 40-year term, taking into account forecast Maximum Interest Payable under the grid loads shown in Figure 5.3-2 (with "Carmacks Copper" minimum loads assumed in 2012 and 2013 per commitments by YEC in the Part 3 proceeding, i.e., assuming connection to the grid at a minimum of at least 52 GW.h/year of new mine load [compared to forecast Minto and Alexco loads)]at the start of 2012 and remaining for six years [i.e., to the end of 2017]). In the event that the Mayo Lake Project is approved, Figure 5.3-1 demonstrates that the 11 cent per kW.h cost ceiling would be met by 2020/21 at grid loads with no mines connected.

ATTACHMENT 5.3: MAYO B PROMISSORY NOTE

December 31, 2011 $21,900,000
Due in installments

1. Promise to Pay

1.1 Effective as of December 31, 2011, in consideration of the advance by way of loan of the sum of $21,900,000 from Yukon Development Corporation ("**YDC**") to Yukon Energy Corporation ("**Yukon Energy**") Yukon Energy promises to pay to YDC, the principal amount of, and interest on, $21,900,000 in lawful money of Canada as follows:

(a) 40 equal annual installments of principal of $336,923.07 each, payable on December 31 of each calendar year commencing on December 31, 2012 and continuing up to and including December 31, 2051; and

(b) a final payment of principal of $8,423,078, payable on December 31, 2051;

(c) subject to Sections 1.2 below, interest at the Interest Rate, calculated annually, and not in advance, on the principal amount from time to time remaining unpaid as of December 31 of each calendar year of this Note prior to the payment of principal in that calendar year. Such interest is to accrue from January 1 to December 31 and include each calendar year of this Note. Interest is payable on December 31 of each calendar year commencing on December 31, 2012 up to and including December 31, 2051.

1.2 **Limitation on Interest.** Notwithstanding Section 1.1(c), prior to the Expiry Date, the amount of interest payable in each calendar year of this Note will not be more than the Maximum Interest Payable in that year (as defined below), determined as of December 31 of each calendar year of this Note. If the Interest Rate exceeds the Maximum Interest Payable in a calendar year then the terms set out in Section 3.1 will apply. For greater certainty, if the Maximum Interest Payable under this Note is a negative number then YDC will pay to Yukon Energy the positive dollar amount of that number on or before March 31 of the next calendar year.

1.3 **Application of Payments.** Payments received will be applied firstly in payment of unpaid interest and the balance, if any, in reduction of principal.

1.4 **Sample Calculation.** A sample calculation of the annual interest payment (Maximum Interest Payable) is attached to this Note as Schedule 2.

2. Definitions and Interpretation

2.1 **Definitions.** In this Note the following terms have the following meanings:

(a) **"Actual Grid Generation"** means in any calendar year commencing with 2012, the total GW.h in that year of Yukon Energy generation and purchased power on the electrical grid system connected with Mayo B based upon metered readings (or based upon reasonable estimates thereof consistently applied from year to year where it is unreasonable or impractical to base grid generation or purchased power upon metered readings), plus the estimated reduction, if any, in such grid generation in that year due to DSM/SSE undertaken since December 31, 2012;.

(b) **"Business Day"** means any day other than a Saturday, Sunday, or a statutory holiday in the Yukon Territory;

(c) "**DSM/SSE**" means the estimated amount by which Actual Grid Generation in any calendar year has been reduced due to demand side management and supply-side enhancement measures undertaken by the Yukon Territorial Government, Yukon Energy, or Yukon Electrical Company Limited since December 31, 2012, based on reasonable estimates thereof by Yukon Energy consistently applied from year to year; for this purpose,

(i) "**demand side management**" measures include any load reduction measures undertaken specifically by the Yukon Government, Yukon Energy or the Yukon Electrical Company Limited to reduce the electrical sales to customers required to be supplied by Yukon Energy or the Yukon Electrical Company Limited on the electrical grid system connected with Mayo B; and

(ii) "**supply-side enhancement**" measures include any generation or transmission efficiency improvement measures undertaken specifically by Yukon Energy or the Yukon Electrical Company Limited, other than demand side management measures, to reduce the electrical generation required to be supplied by Yukon Energy or the Yukon Electrical Company Limited on the electrical grid system connected with Mayo B;

(d) "**Expiry Date**" means the earlier of:

(i) if the Mayo Lake Project is in service, January 1, 2021; or

(ii) January 1, 2023.

(e) **"Interest Rate"** means in each calendar year of this Note that annual rate of interest equal to **[5.46%]**;

(f) "**Mayo Lake Project**" means the enhancement of the storage upstream of the Mayo B Project by adding additional drawdown to YEC's authorized storage

range at Mayo Lake beyond the storage range authorized as at December 31, 2011;

(g) **"Maximum Grid Load"** for each calendar year is as established in Schedule 1 to this Note;

(h) **"Maximum Interest Payable"** means for any calendar year:

(i) The Interest Rate if Actual Grid Generation for the calendar year is at or above the Maximum Grid Load established in Schedule 1 of this Note for that calendar year; or

(ii) If Actual Grid Generation for the calendar year is below the Maximum Grid Load established in Schedule 1 of this Note for that calendar year, an amount arrived at by applying the following formula for the Actual Grid Generation, Minimum Gird Load and Range values for that calendar year:

$$\frac{\text{(Interest Rate) x (Actual Grid Generation – Minimum Grid Load)}}{\text{(Range)}}$$

(i) **"Maximum Interest Payable Statement"** has the meaning set out in Section 3.2;

(j) **"Mayo B"** means Yukon Energy's Mayo Hydro Enhancement Project;

(k) **"Minimum Grid Load"** for each calendar year is as established in Schedule 1 to this Note;

(l) **"Note"** means this Promissory Note;

(m) **"Parties"** means Yukon Energy and YDC and **"Party"** means any one of them;

(n) **"Range"** for each calendar year is as established in Schedule 1 to this Note; and

(o) **"YUB"** means the Yukon Utilities Board.

2.2 **Headings.** The headings are inserted for convenience of reference only and will not affect the construction or interpretation of this Note.

2.3 **Governing Law.** This Note will be governed by, and construed under the laws of the Yukon Territory.

2.4 **Invalidity of Any Provision.** If any covenant, obligation, or provision contained in this Note is invalid or unenforceable, the remainder of this Note will not be affected and each covenant, obligation, or provision of this Note will separately be valid and enforceable to the fullest extent permitted by law.

2.5 **Amendments.** This Note may only be amended from time to time in writing and any such amendment may be evidenced by a document signed by an authorized officer of each of the Parties.

2.6 **Included Words.** Whenever the singular or the masculine is used the same will be considered to include the plural or the feminine or the body corporate where the context or the Parties so require.

3. Maximum Interest Payable

3.1 **Interest Abatement.** The amount of interest, if any, which is payable under this Note as a result of the Interest Rate exceeding the Maximum Interest Payable will abate forever and will not be payable by Yukon Energy to YDC, it being the clear intention of the Parties that the amount of interest payable by Yukon Energy as a result of the Interest Rate payable by Yukon Energy to YDC will not exceed the Maximum Interest Payable.

3.2 **Maximum Interest Rate Statement.** Yukon Energy covenants and agrees to provide YDC on or before March 31 in each year of the Note commencing March 31, 2013 and continuing until the whole of the principal and interest under the Note is paid, with a statement (the "**Maximum Interest Payable Statement**") certified by the Chief Financial Officer of Yukon Energy as to the Maximum Interest Payable for the preceding calendar year, including explanation of any estimates (including any DSM/SSE estimates) used in the determination of the Maximum Interest Payable. If the Maximum Interest Payable Statement at March 31 of each year differs from the interest paid under Section 1.1 as at December 31 of the preceding calendar year, payment of the difference will be made forthwith by either YEC or YDC, as the case may be, together with simple interest at the Interest Rate computed from January 1 to the date of payment.

3.3 **Dispute.** If YDC does not object in writing to the Maximum Interest Payable Statement within 30 days of receipt of such statement from Yukon Energy the Maximum Interest Payable Statement will be final and binding on YDC. If YDC does object in writing to the Maximum Interest Rate Statement within such 30 days the Parties will negotiate in good faith a resolution to the dispute for a period of 15 days. If the dispute is not resolved by the Parties the matter will be referred to a single arbitrator under the *Arbitration Act* (Yukon Territory), whose decision will be final and binding on the Parties. If the arbitrator's decision differs from the Maximum Interest Rate Statement, payment of the difference will be made forthwith by either YDC or Yukon Energy, as the case may be, together with simple interest at the Interest Rate computed from January 1 to the date of payment.

3.4 **Access to Books and Records.** Yukon Energy will allow YDC and YDC's representatives access to the books, records, and other documents of Yukon Energy at all reasonable times for the purpose of verifying the Maximum Interest Payable.

4. General

4.1 **Disposition of Project.** If Yukon Energy sells, transfers, or otherwise disposes of Mayo B without the prior written approval of YDC, which may be arbitrarily withheld, then YDC may,

at any time thereafter, demand payment of the entire principal and interest owing under the Note, whereupon the entire principal and interest then remaining will become due and payable notwithstanding any other provision of this Note.

4.2 **Insurance Proceeds.** If there is damage to all or part of the Project for which insurance proceeds are paid to Yukon Energy and which are not used to repair or replace such damage within a reasonable time with work commencing within six months of the damage having occurred, Yukon Energy will be required to pay to YDC the amount of such proceeds first, in reduction of any outstanding interest under the Note and then in reduction of any outstanding principal under the Note.

4.3 **Prepayment.** The principal amount due under the Note may be paid by Yukon Energy in whole or in part with mutual agreement of the Parties on one year's written notice without bonus or penalty.

4.4 **Default.** Upon default in payment of any payment when due under this Note, the entire unpaid balance of the principal amount and accrued interest will become immediately due and payable without notice or demand and the undersigned covenants to pay interest on it and on subsequent overdue interest at the Interest Rate, both before and after judgment, until paid in full. The covenants to pay interest will not merge on the taking of a judgment or judgments with respect to any of the obligations stipulated for this Note.

4.5 ***Interest Act* of Canada.** For the purposes of the *Interest Act* (Canada), whenever any interest is calculated in respect of this Note on the basis of a period of time other than a calendar year, the annual rate of interest to which each rate of interest determined pursuant to such calculation is equivalent to such rate as so determined multiplied by the actual number of days in the calendar year in which the same is to be ascertained and divided by the number of days used in the basis for such determination.

4.6 **Notices.** In this Note:

(a) any notice or communication required or permitted to be given under this Note will be in writing and will be considered to have been given if delivered by hand, transmitted by facsimile transmission or mailed by prepaid registered post in Canada, to the address or facsimile transmission number of each Party set out below:

(i) if to YDC:

206A Lowe Street
Whitehorse, YT Y1A 1W6

Attention: President
Fax No.: 867-393-7071

(ii) if to Yukon Energy:

#2 Miles Canyon Road

Whitehorse, YT Y1A 6S7

Attention: President
Fax No.: 867-393-5323

or to such other address or facsimile transmission number as any Party may designate in the manner set out above; and

(b) notice or communication will be considered to have been received:

(i) if delivered by hand during business hours on a Business Day, upon receipt by a responsible representative of the receiver, and if not delivered during business hours, upon the commencement of business on the next Business Day;

(ii) if sent by facsimile transmission during business hours on a Business Day, upon the sender receiving confirmation of the transmission, and if not transmitted during business hours, upon the commencement of business on the next Business Day; and

(iii) if mailed by prepaid registered post in Canada, upon the fifth Business Day following posting; except that, in the case of a disruption or an impending or threatened disruption in postal services every notice or communication will be delivered by hand or sent by facsimile transmission.

4.7 **Assignment by Yukon Energy.** Yukon Energy may not to assign this Note, except with the prior written consent of YDC.

4.8 **Assignment by YDC.** YDC may assign this Note without the consent of Yukon Energy.

4.9 **Enurement.** This Note and all its provisions will enure to the benefit of and be binding upon the Parties, their successors and permitted assigns.

4.10 **Yukon Energy Waiver.** Yukon Energy waives demand and presentment for payment, notice of non-payment, protest, notice of protest, notice of dishonour, bringing of suit, and diligence in taking any action.

4.11 **Set-off.** Yukon Energy will not be entitled to set-off against any payments payable to YDC under this Note any amounts owing or alleged to be owing by YDC to Yukon Energy.

Executed at Whitehorse, Yukon Territory, on December _____, 2011.

YUKON ENERGY CORPORATION

Per:

_____
Authorized Signatory

_____
Authorized Signatory

YUKON DEVELOPMENT CORPORATION

Per:

_____
Authorized Signatory

_____
Authorized Signatory

SCHEDULE 1

	Year	Maximum Grid Load (GWh)	Minimum Grid Load (GWh)	Range
1	2012	515	415	100
2	2013	508	413	95
3	2014	501	411	90
4	2015	494	409	85
5	2016	487	407	80
6	2017	480	405	75
7	2018	473	403	70
8	2019	466	401	65
9	2020	459	399	60
10	2021	452	397	55
11	2022	445	395	50
12	2023	438	393	45
13	2024	431	391	40
14	2025	424	389	35
15	2026	417	387	30
16	2027	410	385	25
17	2028	408	383	25
18	2029	406	381	25
19	2030	404	379	25
20	2031	402	377	25
21	2032	400	375	25
22	2033	400	375	25
23	2034	400	375	25
24	2035	400	375	25
25	2036	400	375	25
26	2037	400	375	25
27	2038	400	375	25
28	2039	400	375	25
29	2040	400	375	25
30	2041	400	375	25
31	2042	400	375	25
32	2043	400	375	25
33	2044	400	375	25
34	2045	400	375	25
35	2046	400	375	25
36	2047	400	375	25
37	2048	400	375	25
38	2049	400	375	25
39	2050	400	375	25
40	2051	400	375	25

SCHEDULE 2 – EXAMPLE: RE ANNUAL INTEREST PAYMENT

Assume for 2012:

- Balance of debt outstanding at start of fiscal year $21.9 million
- Maximum Grid Load (Schedule 1) 515 GW.h
- Minimum Grid Load (Schedule 1) 415 GW.h
- Range (Schedule 1) 100 GW.h
- Maximum Interest Payable at different Actual Grid Loads:
    - Assume Actual Grid Load at 520 GW.h
        - Actual Grid Load>Max Grid Load
        - Maximum Interest Payable at 5.44% (full interest)
        - Amount Payable:
          $1,195,740.00=5.46% x $21.9 million (paid by YEC to YDC)
    - Assume Actual Grid Load at 450 GWh
        - Actual Grid Load<Max Grid Load
          Max Interest Rate = $\frac{\text{(Interest Rate) x (Actual Grid Generation – Minimum Grid Load)}}{\text{(Range for the year as established in Schedule 1)}}$
        - Maximum Interest Payable: 5.46%x(450-415)/100=0.35x5.46%=1.911%
        - Amount Payable
          $418,509.00 =1.911%x$21.9 million (paid by YEC to YDC)
    - Assume Actual Grid Load at 400GWh
        - Actual Grid Load<Max Grid Load
          Max Interest Rate = $\frac{\text{(Interest Rate) x (Actual Grid Generation – Minimum Grid Load)}}{\text{(Range for the year as established in Schedule 1)}}$
        - Maximum Interest Payable: 5.46%x(400-415)/100=-0.819%
        - Amount Payable
          -$179,361.00= -0.819%x$21.9 million (indicates YDC amount paid to YEC)

TOPIC: **Formula for Calculating Interest Expense, Debt Instruments**

REFERENCE: Application, page 3-22. PDF page 70

QUESTION:

a) Please provide a full explanation of the term "Range for the year" included in the formula for calculating interest expense for the Mayo B Promissory Note.

b) Please provide a continuity table, listing each debt instrument separately, of all actual and forecast debt instruments for the years 2013 to 2018 inclusive.

c) For forecast borrowings, please provide the inputs used to determine the forecast debt interest rate of 2.15%.

ANSWER:

(a)

Please see the response to YUB-YEC-1-31(a) for a copy of Schedule 1 from the Mayo B Promissory Note.

The "Range for the year" is the difference between the minimum and maximum grid load for the applicable year.

As per the definitions in the Mayo B Promissory Note, grid generation refers to "the total GW.h in that year of Yukon Energy generation and purchased power on the electrical grid system connected with Mayo B based upon metered readings, plus the estimated reduction, if any, in such grid generation in that year due to DSM/SSE undertaken…"

(b)

Please see Table 1 for a continuity table of actual and forecast debt instruments.

Table 1: Continuity Schedule of Actual and Forecast Debt Instruments

2013 Actual	Balance, beginning of year	New Debt		Principal repayments	Balance, end of year
YDC $81.9M	75,891		-	3,000	72,891
TD $12.4M	3,939		-	993	2,946
YDC $17.1M	16,411		-	684	15,727
YDC $2.1M	2,053			-	2,053
YDC $21.9M	21,563		-	337	21,226
TD $11M	11,000		-	313	10,687
YDC $5.5M	-	5,471		-	5,471
Minto Decommissioning Reserve	2,522	31			2,553
	133,379	5,502	-	5,326	133,554

2014 Actual	Balance, beginning of year	New Debt		Principal repayments	Balance, end of year
YDC $81.9M	72,891		-	3,000	69,891
TD $12.4M	2,946		-	1,033	1,912
YDC $17.1M	15,727		-	684	15,044
YDC $2.1M	2,053			-	2,053
YDC $21.9M	21,226		-	337	20,889
TD $11M	10,687		-	321	10,366
YDC $5.5M	5,471			-	5,471
YDC $5.5M	-	5,505		-	5,505
Minto Decommissioning Reserve	2,553	33			2,586
	133,554	5,538	-	5,376	133,717

2015 Actual	Balance, beginning of year	New Debt		Principal repayments	Balance, end of year
YDC $81.9M	69,891		-	69,891	-
TD $12.4M	1,912		-	1,076	837
YDC $17.1M	15,044		-	15,044	-
YDC $2.1M	2,053		-	2,053	-
YDC $21.9M	20,889		-	337	20,552
TD $11M	10,366		-	330	10,036
YDC $5.5M	5,471		-	5,471	-
YDC $5.5M	5,505	-		-	5,505
YDC $92.5M	-	92,458	-	3,684	88,775
YDC $21.0M	-	20,984		-	20,984
Minto Decommissioning Reserve	2,586	26			2,612
	133,717	113,469	-	97,885	149,301

Table 1: Continuity Schedule of Actual and Forecast Debt Instruments (Continued)

2016 Actual	Balance, beginning of year	New Debt		Principal repayments	Balance, end of year
TD $12.4M	837		-	837	-
YDC $21.9M	20,552		-	337	20,215
TD $11M	10,036		-	339	9,697
YDC $5.5M	5,505			-	5,505
YDC $92.5M	88,775		-	3,684	85,091
YDC $21.0M	20,984		-	839	20,145
YDC $12.1M	-	12,136		-	12,136
Minto Decommissioning Reserve	2,612	23			2,636
	149,301	12,159	-	6,036	155,425

2017 Forecast	Balance, beginning of year	New Debt		Principal repayments	Balance, end of year
YDC $21.9M	20,215		-	337	19,878
TD $11M	9,697		-	348	9,348
YDC $5.5M	5,505			-	5,505
YDC $92.5M	85,091		-	3,684	81,407
YDC $21.0M	20,145		-	839	19,306
YDC $12.1M	12,136			-	12,136
New debt 2017	-	23,828		-	23,828
Minto Decommissioning Reserve	2,636	24			2,659
	155,425	23,851	-	5,208	174,068

2018 Forecast	Balance, beginning of year	New Debt		Principal repayments	Balance, end of year
YDC $21.9M	19,878		-	337	19,542
TD $11M	9,348		-	358	8,991
YDC $5.5M	5,505			-	5,505
YDC $92.5M	81,407		-	3,684	77,723
YDC $21.0M	19,306		-	839	18,466
YDC $12.1M	12,136			-	12,136
New debt 2017	23,828			-	23,828
New debt 2018	-	7,004		-	7,004
Minto Decommissioning Reserve	2,659	24			2,683
	174,068	7,028	-	5,218	175,877

(c)

The forecast interest rate of 2.15% was provided to YEC directly from YEC's Relationship Manager at TD Bank.

TOPIC: **DCF – LNG Costs**

REFERENCE: Application, page 3-25. PDF page 73

QUOTE: "It in principle addresses all YEC thermal generation requirements (i.e., includes LNG as well as diesel generation)."

QUESTION:

a) Please provide the direct quotes in Board Order 2015-01 (Appendix A: Reasons for Decision) that specifically make reference to LNG costs.

ANSWER:

(a)

Board Order 2005-01 approved the DCF amendments as proposed by YEC, which included reference to "thermal generation cost" changes resulting from variations in LTA hydro availability. Section 2.1.1.4 of Board Order 2015-01 (Appendix A: Reasons for Decision) approved the DCF use "…for variations in LTA hydro availability" without specifically making reference to LNG costs.

Section 2.4 of Board Order 2015-06 (Appendix A: reasons for Decision) subsequently approved the Revised DCF Term Sheet as set out in Attachment 1 of YEC's April 7, 2015 Compliance Filing related to Board Order 2015-01. The Revised DCF Term Sheet as approved referenced LNG (see quote below from this Term Sheet's statement re: "function and purpose"):

PURPOSE & FUNCTION: The Diesel Contingency Fund ("DCF") operates to smooth customer rate changes from thermal (diesel, LNG and other thermal) generation cost impacts caused by fluctuation of hydro generation due to water conditions or changes in wind conditions.[1]

[1] Appendix A to Board Order 2015-01, section 2.1.1.4, page 11.

Yukon Energy Corporation (YEC) manages the DCF as a ratepayer "trust fund". The Fund is only to be used for variations from long-term average (LTA) water and wind availability.[2]

[2] Appendix A to Board Order 2015-01, section 2.1.1.4, page 14. The Board directed as follows: "Any application to utilize the fund in some other fashion will require the closing of the fund, the refunding of any balances to customers, and the direction for YEC to use short-term forecasts for its hydro generation in future GRAs."

TOPIC: **DCF**

REFERENCE: Application, Appendix 3.4, page 3.4-3. PDF page 102

QUOTE: "YEC's LTA hydro generation continues to be based on the power benefits system simulation model as used in the last GRA (i.e., the YECSIM model), updated to reflect the load shape for the test years (with basically the same Minto mine loads being forecast in each of these years) and the following information related to Yukon Integrated System hydro operations:" [Footnote omitted]

QUESTION:

a) Two subsequent bullets to the above-noted quote refer to additional water year records and updated reservoir and generation station water flow requirement changes. Please confirm that there were no other changes in the base assumptions or parameters used in the YECSIM model.

b) If Part (a) cannot be confirmed, please provided a side by side detailed listing of all changes by listing the assumption or input parameter used in the 2012/2013 GRA, the similar assumption or input parameter in the 2017/2018 GRA and the reason for the difference.

ANSWER:

(a) and **(b)**

Confirmed.

TOPIC: **Vista Model**

REFERENCE: Application, Appendix 3.4, page 3.4-3, Footnote 3. PDF page 102

QUOTE: "Yukon Energy continues at this time to use the YECSIM model for the LTA assessments for this Application and the 2016 Resource Plan (see Attachment 3.4.3 for information on the YECSIM model). YEC is currently examining another system planning model (VISTA) for potential future use in assessing LTA hydro and thermal requirements."

QUESTION:

a) Please explain why YEC is reviewing another system planning model.

b) What are the potential benefits of the VISTA model?

c) What are the current shortfalls of the YECSIM model?

d) If YEC were to convert to the VISTA model, in what timeframe would such a conversion take place?

ANSWER:

(a), (b), (c) and **(d)**

YEC continues to examine options for future improvement in its planning. Optimization models such as VISTA offer opportunities to introduce more advanced methodologies, provide higher resolution of outputs (e.g., daily versus weekly outputs), more detailed representation of resources, additional outputs, and support for a wider range of new system resources. These added features can assist in the assessment of new resource options and planning issues. However, broader use of a new model will be considered after gaining experience on the model use and testing the model to confirm its adequacy.

The 2016 Resource Plan and the current GRA continue to rely on YECSIM for assessment of expected long-term average hydro and thermal generation requirements under different load and system facility conditions. No specific timeframe has been established for potential conversion to use of an alternative model to YECSIM for these purposes.

YEC will update the Board in future filings on the status of its examinations of planning model options.

TOPIC: **DCF – Thermal Generation Requirements**

REFERENCE: Application, Appendix 3.4, page 3.4-4. PDF page 103

QUOTE: "Other thermal generation requirements (i.e., expected generation not addressed by the LTA assessments) that may occur under higher-than-median water conditions will be assessed as required in future GRAs."

QUESTION:

a) Please provide a detailed explanation of the above-noted statement.

ANSWER:

(a)

Prior to the quoted sentence, the paragraph noted that the "LTA thermal requirements as determined pursuant to the YECSIM model and Table 3.4-1 addresses thermal generation requirements for firm loads". The paragraph went on to explain that this YECSIM determination excludes thermal generation needed for capital projects, emergencies/grid interruptions, RFID requirements, and ongoing maintenance-related run-ups.

The Application's separate treatment of ongoing maintenance-related thermal generation recognizes that this separate generation is required even when firm loads are insufficient to require ongoing thermal generation. Higher-than-median water conditions also tend to reduce requirements for thermal generation to supply firm loads - and increase the need for separate thermal generation solely for ongoing maintenance-related run-ups.

The above-noted statement references ongoing review to assess other possible separate thermal generation that may tend to be needed under higher-than-median water conditions when no thermal generation is otherwise forecast in YECSIM determinations. YEC is not aware of any such specific requirements that could be forecast at this time.

The basis for ongoing interest in this matter is outlined below, based on recent experience during years with above average water conditions:

- As reviewed at page 3.4-7 of the Application and Appendix 3.5, actual diesel and LNG thermal generation in 2015 and 2016 during above average water conditions directly affects YEC expenses.
    - Actual thermal generation required (excluding capital projects and RFID) was 2.8 GW.h in 2015 and 5.1 GW.h in 2016.
    - These actual thermal generation requirements occurred notwithstanding that actual annual firm grid load (net of expected wind and Fish Lake Hydro) was only 410 to 412 GW.h in these two years and that above average water conditions also existed.

- As reviewed in Appendix 3.4 of the Application, determinations of LTA thermal requirements at any specific firm grid load are based on simulated assessments of thermal generation needed over each of the 35 water years of record.
    - Figure 3.4-1 and Table 3.4-4 demonstrate the extent to which actual thermal generation is expected to be minimal during above average water conditions when grid loads are less than 420 GW.h/year.
    - Table 3.4-4 shows, for example, an expectation that under 2015 actual water conditions the thermal generation requirement would approximate only 0.2 GW.h at a grid load of 420 GW.h/year.
    - Actual thermal generation in 2015, however, was 2.8 GW.h (excluding capital projects and RFID thermal generation requirements), and therefore much higher than expected based on the simulations.
    - A similar situation appears to have occurred in 2016.
    - In the event that actual thermal requirements in above average water years are higher than estimated in the LTA simulations, the estimated LTA requirement would be increased above the levels currently estimated.

TOPIC: **LNG Cost per kW.h**

REFERENCE: Application, Appendix 3.4, page 3.4-5. PDF page 104

QUOTE: "3. The LNG fuel cost per kW.h to be assumed for DCF cost assessments (equivalent to the 28.7 c/kW.h diesel generation fuel cost used to date for the DCF based on the last approved GRA fuel price and average diesel generation efficiency for the 2012/13 GRA)."

QUESTION:

a) Please show the derivation of the 28.7 c/kW.h diesel generation fuel cost.

ANSWER:

(a)

The 28.7 c/kW.h diesel generation fuel cost is the last approved GRA fuel price from YEC's 2012/13 GRA. This average diesel fuel cost per kW.h was derived from the following:

- Forecast diesel fuel prices for the 2012/2013 test years are $1.0513 per litre for Whitehorse, $1.0885 per litre for Faro, $1.1168 per litre for Dawson (as corrected in CW-YEC-1-15 in that proceeding) and $1.0966 per litre for Mayo and are based on the (then) most recent fuel prices paid by YEC.

- YEC average fuel efficiency forecasts of 3.77 kW.h/litre in Whitehorse, 3.83 kW.h/litre in Faro, 3.72 kW.h/litre in Dawson and 3.37 kW.h/litre in Mayo based on 2011 averages.

- The resulting cost per kW.h for each location is 27.86 c/kW.h for Whitehorse, 28.42 c/kW.h for Faro, 30.02 c/kW.h for Dawson and 32.54 c/kW.h for Mayo.

- The average diesel fuel cost of 28.71 c/kW.h is the average YEC cost based on the 2012/13 GRA Compliance Filing, and is referenced as such in the DCF Term Sheet as approved in Board Order 2015-06.

TOPIC: **Capability to Supply LTA Thermal Generation**

REFERENCE: Application, Appendix 3.4, page 3.4-7. PDF page 106

QUOTE: "Emergency thermal loads, which typically require quick response and may continue for only a short duration, are excluded from LTA assessments; and

"Other small or short duration loads of the type affecting actual current LNG use are not important factors affecting LNG unit ability to supply overall LTA thermal generation at the grid loads relevant for this review."

QUESTION:

a) For each of the constraints listed in the last paragraph of page 3.4-7 and the above-noted considerations, please explain why LNG is not the preferred generation method.

ANSWER:

(a)

The last paragraph of page 3.4-6 references the following constraints on actual LNG 4.4 MW unit operation (there are two units commissioned at this time):[1]

- The manufacturer recommends not running the individual LNG units for loads below 2.6 MW. Therefore, YEC relies on smaller existing diesel units for thermal generation loads less than 2.6 MW and between 4.4 and 5.2 MW, rather than starting up one or both of the 4.4 MW LNG units.

- Similarly, the manufacturer recommends a minimum run time of 4 hours for LNG units; existing diesel units are relied upon for short duration loads (less than a few hours).

[1] The last paragraph of page 3.4-7, as referenced in the question, does not note any specific constraints related to LNG unit operation.

- These constraints mainly reflect the size and nature of the generation units selected, which are best suited to base load operation, rather than the use of LNG fuel versus diesel fuel. YEC expects peaks to continue to grow on the system, both in terms of the size (MW) and duration; this growth will positively improve the usage of the LNG units.

The two above-noted considerations in the question address a separate matter, namely the extent to which LTA thermal generation requirements (which drive GRA expected thermal generation and fuel cost requirements) are not materially affected by the above noted constraints on actual LNG unit operation of the existing LNG units:

- Emergency thermal loads (where a short-duration and quick response is required) are excluded from LTA thermal forecasts; and

- Overall LTA thermal generation at the GRA forecast grid loads are driven mainly by sustained thermal generation required during low water or drought conditions, and therefore other small or short duration loads of the type affecting current LNG unit use are not important factors affecting LNG unit ability to supply these overall LTA thermal generation requirements.

TOPIC: **Limitations on LNG Unit Operation**

REFERENCE: Application, Appendix 3.4, page 3.4-7. PDF page 106

QUESTION:

a) Please provide a detailed explanation and an illustrative example of how DCF Annual Reporting and GRA Test Year Revenue Requirement determinations limit LNG unit operation.

b) What was the actual 12 month performance of LNG generation to diesel generation for the period July 1, 2016 to June 30, 2017?

ANSWER:

(a)

References in Appendix 3.4 to limitations on LNG unit operation reference small and short duration loads, as reviewed in response to YUB-YEC-1-38.

GRA Test Year Revenue Requirement determinations as provided in this Application specify, starting with the 2017 test year, an assumed 90/10 LNG-diesel share or split related to the forecast LTA thermal generation for each test year. This approach is proposed to ensure that revenue requirement costs used to set rates provide some recognition of the current limits on actual LNG ability to displace all diesel generation (see response to YUB-YEC-1-25 for more detailed review). No such LNG/diesel split was specified in prior GRA Test Year Revenue Requirement determinations (see response to YUB-YEC-1-42).

DCF Annual Reporting addresses actual diesel and LNG generation as recorded for a fiscal year, and thereby reflects actual limitations on LNG unit operation during that year, including any of the limitations reviewed in Appendix 3.4 and YUB-YEC-1-36. This reporting by itself does not limit LNG unit operation.

DCF Annual Reporting also determines the following:

1. LTA (expected) thermal generation for the actual firm load based on the DCF Term Sheet table approved by the Board.

2. The gap for the year between LTA (expected) thermal generation and actual thermal generation that determines the amount that YEC pays into or receives from the DCF for the fiscal year (the "DCF Transfer").

3. In determining the DCF Transfer amount, it is necessary to specify the portion assigned to LNG versus diesel generation (see response to YUB-YEC-1-40 for examples relating to 2015 and 2016). The current Application proposes that the Board approve rules going forward as of January 1, 2017 for determining the LNG/diesel split for the DCF Transfer. The proposed approach focuses on seeking to set YEC's annual fuel mix costs as close as possible to the GRA approved assumptions adopted to set the approved revenue requirement and rates. (See response to YUB-YEC-1-42 for more detailed review of the proposed DCF fuel mix determination approach.)

(b)

Please see Table 1 below.

Table 1: Actual LNG and Diesel Generation

		Diesel	LNG	Total Thermal	% Diesel	% LNG
2016	JUL	507,074	23,950	531,024	95%	5%
2016	AUG	125,687	6,800	132,487	95%	5%
2016	SEP	637,993	1,234,000	1,871,993	34%	66%
2016	OCT	50,968	198,400	249,368	20%	80%
2016	NOV	71,203	-	71,203	100%	0%
2016	DEC	1,113,601	1,480,100	2,593,701	43%	57%
2017	JAN	880,076	1,820,900	2,700,976	33%	67%
2017	FEB	549,099	1,244,800	1,793,899	31%	69%
2017	MAR	980,908	1,478,100	2,459,008	40%	60%
2017	APR	20,667	-	20,667	100%	0%
2017	MAY	110,059	-	110,059	100%	0%
2017	JUN	155,927	-	155,927	100%	0%
		5,203,262	7,487,050	12,690,312	41%	59%

TOPIC: **Actual LNG Use and Year-end DCF Determinations**

REFERENCE: Application, Appendix 3.4, page 3.4-7. PDF page 106

QUOTE: "The 2016 DCF Annual Report (Appendix 3.5) shows the actual LNG generation in 2015 and 2016, net of capital and RFID generation (based on this Application, future DCF Annual Filing years will also exclude maintenance run-up generation). In each of these years, expected thermal generation exceeded actual thermal generation, and the balance (approximately 7.2 GW.h in 2015 and 5.1 GW.h in 2016) was thermal generation for which YEC transferred fuel cost into the DCF. Due to limits in LNG unit availability, only 15% of the 2015 thermal generation included in the DCF transfer by YEC was assumed to be supplied by LNG - however, in 2016, 100% of the thermal generation included in the DCF transfer by YEC was assumed to be supplied by LNG." [underlining added]

QUESTION:

a) Why were the amounts of thermal generation referred to above for 2015 and 2016 assumed? Why can't YEC calculate actual amounts?

ANSWER:

(a)

Actual LNG and diesel generation amounts are determined and reported in the year-end DCF Annual Reports for 2015 and 2016.

DCF final determinations are based on "expected thermal generation" (i.e., LTA thermal generation for the actual grid generation load). Transfers into or out of the DCF at year end address differences between expected and actual thermal generation (with the result that YEC's final thermal generation cost expense for the year is based on expected rather than actual thermal generation).

In 2015 and 2016, as noted in the above quote, expected thermal generation exceeded actual thermal generation:

- **2015:** Expected thermal generation at 10.0 GW.h versus actual thermal generation of 2.8 GW.h, resulting in a difference of approximately 7.2 GW.h thermal generation for which YEC transferred fuel cost into the DCF.

- **2016:** Expected thermal generation at 10.536 GW.h versus actual thermal generation of 5.087 GW.h, resulting in a difference of approximately 5.449 GW.h thermal generation for which YEC transferred fuel cost into the DCF. [Note that the 5.1 GW.h referenced at page 3.4-7 of Appendix 3.4 is not correct, and that the correct number from Appendix 3.5 for thermal generation transferred to the DCF in 2016 is 5.449 GW.h.]

These 2015 and 2016 transfers into the DCF were based on the amounts by which expected thermal generation (LTA) exceeded actual thermal generation. Assumptions are therefore required to determine the share of this balance that is assigned to LNG versus diesel generation. The assumptions adopted in the 2015 and 2016 DCF Annual Reports reflected YEC's evidence to the Board at the Part 3 LNG Project proceeding.

In summary, the referenced "assumptions" related in each case to the share of each transfer to the DCF that was assumed to be supplied by LNG generation versus by diesel generation:

- In 2015, due to in-service of the LNG units occurring only after mid-year, only 15% of the 2015 expected thermal generation was assumed to be eligible to be supplied by LNG generation (i.e., only 15% of the 10.0 GW.h expected thermal generation, or 1.5 GW.h); in this instance, the 7.2 GW.h transfer to the DCF was then estimated at 0.909 GWh LNG [1.5 GW.h expected less actual LNG generation] and 6.280 GW.h diesel [the balance equals expected diesel less actual diesel].

- In 2016, 100% of the 2016 expected thermal generation was assumed to be eligible to be supplied by LNG generation (i.e., 100% of the 10.536 GW.h expected thermal generation); expected thermal generation included in the transfer (i.e., 100% of the 5.449 GW.h that expected thermal generation exceeded actual thermal generation) was assumed to be supplied by LNG.

TOPIC: **Actual LNG Use and Year-end DCF Determinations**

REFERENCE: Application, Appendix 3.4, page 3.4-7. PDF page 106

QUOTE: "The 2016 DCF Annual Report (Appendix 3.5) shows the actual LNG generation in 2015 and 2016, net of capital and RFID generation (based on this Application, future DCF Annual Filing years will also exclude maintenance run-up generation). In each of these years, expected thermal generation exceeded actual thermal generation, and the balance (approximately 7.2 GW.h in 2015 and 5.1 GW.h in 2016) was thermal generation for which YEC transferred fuel cost into the DCF. Due to limits in LNG unit availability, only 15% of the 2015 thermal generation included in the DCF transfer by YEC was assumed to be supplied by LNG - however, in 2016, 100% of the thermal generation included in the DCF transfer by YEC was assumed to be supplied by LNG."

QUESTION:

a) Please explain the significance of the above-quoted paragraph.

ANSWER:

(a)

As reviewed in Section 1.1 of Appendix 3.4, the Board has directed that it is to review procedures for including LNG in the DCF as part of the next GRA.

In response to this direction, the above-quoted paragraph summarizes for review by the Board the procedures and assumptions adopted for including LNG in the 2015 and 2016 DCF Annual Reports. Details related to these procedures and assumptions are reviewed in response to YUB-YEC-1-40.

TOPIC: **Actual LNG Use and Year-end DCF Determinations**

REFERENCE: Application, Appendix 3.4, page 3.4-8. PDF page 107

QUOTE: "YEC's final fuel expense for annual expected thermal generation after DCF transfers is affected by the LNG/diesel mix for actual thermal generation as well as by the LNG/diesel mix adopted for transfers into or out of the DCF. In 2016, due to the actual generation mix being 45% diesel, YEC's final expense for all expected (LTA) thermal generation showed 21.8% being supplied by diesel (2.293 GW.h out of 10.536 GW.h), notwithstanding that 100% of the thermal generation included in the DCF transfer by YEC (to address the difference between LTA thermal generation and actual thermal generation) was assumed to be supplied by LNG."

QUESTION:

a) Has the Board previously approved any LNG/diesel fuel mix for expected thermal generation?

b) Has the Board previously approved any LNG/diesel fuel mix for transfers into or out of the DCF?

c) How can the assumption for 2016 be made that 100% of the thermal generation included in the DCF transfer by YEC was supplied by LNG?

ANSWER:

(a) and **(b)**

The Board has not previously approved any specified LNG/diesel fuel mix for expected thermal generation, or any specific LNG/diesel fuel mix for transfers into or out of the DCF.

(c)

The referenced assumption reflected the Board's 2014 review of YEC's LNG Project.

Section 3.1.3 of the Board's May 14, 2014 Report to the Minister on YEC's Part 3 Application for the LNG Project accepted YEC's submission that the new LNG units would displace through to 2018 at least 95% of the expected [LTA] grid diesel generation requirements (assuming LTA hydro generation).

YEC's submissions during that 2014 proceeding estimated 100% LNG displacement of expected diesel generation at grid loads comparable to the actual 2015 and 2016 loads. Prior to the next GRA review, YEC in 2015 retained these prior assumptions as presented to the Board. The 2016 DCF Annual Report retained without review the assumptions adopted in the 2015 DCF Annual Report.

TOPIC: **Actual LNG Use and Year-end DCF Determinations**

REFERENCE: Application, Appendix 3.4, page 3.4-8. PDF page 107

QUOTE: "As noted under item #1 above, this Application proposes that test year thermal generation be assumed to be supplied 90% by LNG generation and 10% by diesel generation. In order to enable final year-end YEC LTA fuel expense to reflect this same LNG/diesel mix to the extent possible, it is proposed in this Application that subsequent DCF Annual Filings (for 2017 and 2018, and subsequent years until changed by approval of the Board) adjust YEC's year-end DCF payment into (or receipt from) the DCF as required so that YEC's final fiscal year expense for the total expected thermal generation (i.e., YEC expense after all transfers) is 90% LNG and 10% diesel, subject to the constraint that the LNG share of any transfer into or out of the DCF cannot exceed 100%. This proposed approach is reflected in the DCF example in Appendix 3.4-1 (Table 3.4-3)."

QUESTION:

a) Please explain why the fuel mix ratio for the DCF needs to be fixed. What is the impact if the actual fuel mix is used versus the assumed fuel mix?

b) Please explain the situation where the LNG share of any transfer into or out of the DCF could exceed 100%. Provide an example where this is demonstrated.

ANSWER:

(a)

As reviewed in response to YUB-YEC-1-40, assumptions are required to determine the fuel mix ratio applicable for transfers into and out of the DCF.

The Application proposes that the fuel mix ratio adopted for the 2017 and 2018 test years be retained for DCF annual determinations starting with 2017. This approach focuses on seeking to set YEC fuel mix costs as close as possible to the GRA approved assumptions adopted to set the approved revenue requirement and rates.

Adoption of the actual fuel mix for actual generation versus the assumed 90/10 LNG/diesel fuel mix would have varying impacts depending on the actual fuel mix and its share of expected thermal generation in a fiscal year. The example set out in Tables 3.4-2 and 3.4-3 of Appendix 3.4 looks at a range of such potential situations over five years, indicating the impact of the proposed approach as summarized below to contrast with assuming the actual fuel mix in each year:

- Year 1 of example:
  - Actual fuel mix assume 50/50 LNG/diesel (actual < expected by 9.9 GW.h)
  - Proposed DCF; yields 90/10 LNG/diesel

- Year 2 of example:
  - Actual fuel mix assume 25/75 LNG/diesel (actual < expected by 14.4 GW.h)
  - Proposed DCF; yields 83.7/16.3 LNG/diesel

- Year 3 of example:
  - Actual fuel mix assume 96.8/3.2 (actual < expected by 19.0 GW.h)
  - Proposed DCF; yields 90/10 LNG/diesel

- Year 4 of example:
  - Actual fuel mix assume 71.4/28.6 LNG/diesel (actual > expected by 42.1 GW.h)
  - Proposed DCF; yields 90/10 LNG/diesel

- Year 5 of example:
  - Actual fuel mix assume 60/40 LNG/diesel (actual > expected by 68.1 GW.h)
  - Proposed DCF; yields 90/10 LNG/diesel

(b)

The proposed approach will not allow the LNG share of any transfer into or out of the DCF to exceed 100%. As a result, under certain factual situations (e.g., the year 2 example in Table 3.4-3 as reviewed above), the final fuel mix for expected generation after DCF transfers will not equal the 90/10 LNG/diesel fuel mix assumed for the Application.

Absent the proposed procedures, in order to secure a 90/10 LNG/diesel mix would require under certain factual situations an LNG share of any transfer to exceed 100%. Under the above referenced example for year 2:

- Assumed actual thermal generation of 4 GW.h, with fuel mix 25/75 LNG/diesel.
- Assumed expected thermal generation of 18.446 GW.h.
- The transfer of funds to the DCF is based on 14.446 GW.h gap between expected and actual thermal generation.
- The target 90% LNG would require 90% of expected, or 16.6 GW.h (or 15.6 GW.h more than actual LNG generation).
- To achieve this target, the LNG share of the DCF transfer would need to equal 108% of the 14.446 GW.h to be transferred.

TOPIC: **Diesel and LNG Fuel Cost per kW.h**

REFERENCE: Application, Appendix 3.4, page 3.4-8. PDF page 107

QUOTE: "2015 average delivered LNG fuel cost of 18.83 cents/kW.h assumed 40% energy conversion efficiency as per the LNG Part 3 Application."

QUESTION:

a) Please provide the actual energy conversion for LNG for each of 2015, 2016 and January 1 to June 30, 2017.

b) Please show how the energy conversion costs were calculated for each of the years 2015, 2016 and 2017 inclusive.

ANSWER:

(a) and **(b)**

Please see Tables 1, 2 and 3 below and related notes.

Table 1: 2015 Actuals Energy Conversion

Month	NG Generation [kWh]	LNG Volume for Generation [Litre]	Fuel Energy [kWh]	Conversion Efficiency [%]
January				
February				
March				
April				
May				
June				
July				
August				
September				
October	112,702	41,834	280,641	40%
November	60,147	27,934	187,390	32%
December	420,100	159,234	1,068,205	39%
Total	592,949	229,001	1,536,236	39%

Fortis BC

LNG Density	438.634	kg/m3
HHV	0.055	GJ/kg

Table 2: 2016 Actuals Energy Conversion

Month	NG Generation [kWh]	LNG Volume for Generation [Litre]	Fuel Energy [kWh]	Conversion Efficiency [%]
January	135,300	50,554	335,728	40%
February	68,200	27,058	179,694	38%
March	47,900	18,565	123,290	39%
April	36,000	14,490	96,227	37%
May	10,900	4,356	28,930	38%
June	9,650	3,860	25,634	38%
July	23,950	9,215	61,199	39%
August	6,800	2,385	15,837	43%
September	1,234,000	470,089	3,121,858	40%
October	198,400	79,379	527,154	38%
November				
December	1,480,100	562,250	3,733,901	40%
Total	3,251,200	1,242,201	8,249,450	39%

Fortis BC		
LNG Density	438.63	kg/m3
HHV	0.055058	GJ/kg
% Volume Delivered in 2016	52%	
Ferus		
LNG Density	427.92	kg/m3
HHV	0.055353	GJ/kg
% Volume Delivered in 2016	48%	

Table 3: 2017 Actuals Energy Conversion

Month	NG Generation [kWh]	LNG Volume for Generation [Litre]	Fuel Energy [kWh]	Conversion Efficiency [%]
January	1,820,900	708,155	4,679,432	39%
February	1,244,800	486,362	3,213,845	39%
March	1,478,100	536,011	3,541,918	42%
April				
May				
June				
July				
August				
September				
October				
November				
December				
Total	4,543,800	1,730,528	11,435,195	40%

Fortis BC		
LNG Density	438.63	kg/m3
HHV	0.055058	GJ/kg
% Volume Delivered in 2016	22%	
Ferus		
LNG Density	427.92	kg/m3
HHV	0.055353	GJ/kg
% Volume Delivered in 2016	78%	

TOPIC: **LNG Haul Units**

REFERENCE: Application, Appendix 3.4, page 3.4-9. PDF page 108

QUOTE: "This has included continuing to pursue licencing and development of larger configurations of LNG haul units that would materially reduce the per unit costs for delivery, as well as opportunities to secure LNG from potential new or enhanced LNG facilities that are much closer to Whitehorse."

QUESTION:

a) Please provide a status update on the licensing and development of larger configurations of LNG haul units. When does YEC expect that these larger units will be operational?

b) Please provide total to date costs by year for the licensing and development of the larger configurations of LNG haul units.

ANSWER:

(a)

The objective remains to develop a safe, high payload (more efficient) configuration that can be permitted under a bulk haul permit in BC and Yukon. The design of this larger trailer is complete and is fully compliant with bulk haul parameters – specifically to avoid the requirement for a pilot car. The updated King B-Train design was received from the design firm in October 2016 and submitted to the University of Ontario Institute Of Technology (UOIT) for a "Vehicle Dynamic Performance Assessment." UOIT reported that the configuration passed all performance measures. The BC regulator subsequently reviewed the report and approved the configuration. The next step in the regulatory approval process is to undertake a route analysis which will include an assessment of all bridges and culverts. Analysis of the identified route will give the regulator all the information required for a formal assessment. The updated King B-Train design still provides for a payload of over 85m^3 which translates into approximately 2000 GJ, which is 60% more than the largest tridem trailer currently in operation, and more than double a standard tandem trailer. All LNG industry players are watching the King B-Train

development with great interest and at least one LNG supplier is known to be in commercial discussions with CVA (the designer of the King B-Train) for the construction of several units. The King B is now available for commercial development. BC Highways has initiated the route analysis in 2017 and will include the Federal and Yukon Governments for their portion of the highway between Fort Nelson and Whitehorse. YEC expects that these larger units will be operational when LNG volumes increase to meet new markets in Alaska, Inuvik or new mining loads.

(b)

Annual YEC spending in support of trailer design and permitting activities is as follows:

Table 1: Trailer Design & Permitting: 2013-2016

2013	$32,333
2014	161,244
2015	53,987
2016	30,136
	$277,700

Note that Table 5.4 shows total spending of $193,577 for 2014; this reflects the creation of the feasibility study out of the LNG project in that year. Table 1 above reflects the actual spending timing.

TOPIC: **LNG Assumptions**

REFERENCE: Application, Appendix 3.4, page 3.4-9. PDF page 108

QUOTE: "This Application assumes a forecast delivered fuel cost of LNG for the 2017 and 2018 test years of $0.1467 per kW.h, based on a delivered average fuel cost of $0.3767 per litre and average efficiency for LNG generation of 2.57 kW.h/litre (assumes 0.02369 GJ/litre of LNG [HHV]). This LNG fuel cost reflects the average delivered LNG cost from September to December 2016 from the Ferus facility in Elmworth, and the forecast that test year LNG requirements will be generally supplied from facilities at no greater distance from Whitehorse than Elmworth."

QUESTION:

a) Please provide the following for the January 1 to June 30, 2017 period:
   i.) Actual delivered litres of LNG and delivery costs of that LNG and the conversion of those costs to $/kW.h
   ii.) The delivered fuel cost in $/litre
   iii.) The actual efficiency for LNG generation in kW.h/litre
   iv.) Actual fuel purchases in litres and $/litre
   v.) LNG fuel costs in $/kW.h.

b) Please provide the basis of 0.02369 GJ/litre of LNG [HHV].

c) Please explain the acronym "LNG [HHV]".

ANSWER:

(a)

Please see Table 1 below.

Table 1. Actual LNG Delivery Costs for 2017 - January to end of July

Month	LNG Volume Delivered	LNG Costs	Transportation Costs	Total Cost per Load (LNG & Transportation)	Total Cost per Load (LNG & Transportation)	Total Cost per Load (LNG & Transportation)	NG Generation Actuals	LNG Consumption Volume	LNG Consumption Actuals
	[litres]	[$]	[$]	[$]	[$/Litre]	[$/kWh]	[kWh]	[Litre]	[kWh/Litre]
January	653,408.25	$ 168,860.59	$ 156,709.46	$ 325,570.05	$ 0.50	$ 0.19	1,820,900.00	708,154.70	2.57
February	468,689.50	$ 107,992.87	$ 102,179.45	$ 210,172.32	$ 0.45	$ 0.17	1,244,800.00	486,362.40	2.56
March	615,287.20	$ 132,337.79	$ 136,832.29	$ 269,170.08	$ 0.44	$ 0.17	1,478,100.00	536,010.80	2.76
April	43,909.67	$ 10,062.43	$ 6,600.00	$ 16,662.43	$ 0.38	$ 0.15	0.00	0.00	0.00
May	38,436.73	$ 9,087.20	$ 6,600.00	$ 15,687.20	$ 0.41	$ 0.16	0.00	0.00	0.00
June	0.00	$ -	$ -	$ -	$ -	$ -	0.00	0.00	0.00
July	0.00	$ -	$ -	$ -	$ -	$ -	0.00	0.00	0.00
August	0.00	$ -	$ -	$ -	$ -	$ -	0.00	0.00	0.00
September	0.00	$ -	$ -	$ -	$ -	$ -	0.00	0.00	0.00
October	0.00	$ -	$ -	$ -	$ -	$ -	0.00	0.00	0.00
November	0.00	$ -	$ -	$ -	$ -	$ -	0.00	0.00	0.00
December	0.00	$ -	$ -	$ -	$ -	$ -	0.00	0.00	0.00
Total	1,819,731.35	$ 428,340.88	$ 408,921.20	$ 837,262.08	$ 0.46	$ 0.18	4,543,800.00	1,730,527.90	2.63

1 * Assumes conversion of 2.57 kWh/litre

(b) and **(c)**

The energy content per litre for LNG is as provided by Ferus for its LNG supplied from Elmworth, Alberta. It is calculated as follows:

HHV = 427.92 kg/m^3 x 0.055353 GJ/kg = 23.69 GJ/m^3 or 0.02369 GJ/litre

The acronym "HHV" represents "Higher Heating Value" which takes into account the latent heat of vaporization of water in a fuel[1]; HHV is contrasted with "LHV" representing "Lower Heating Value" which excludes the latent heat of vaporization of water in a fuel. For consistency in comparison of diesel and LNG fuels, costs have been consistently assessed based on HHV. For LNG, LHV per litre approximates 97.7% of the HHV per litre.

[1] The High Heating Value is defined as "the total heat obtained from the combustion of a specified amount of fuel and its stoichiometrically correct amount of air, both being at 60°F when combustion starts, and the combustion products being cooled to 60°F before heat release is measured." (https://www.fortisbc.com/NaturalGas/Business/PriceAndMarketInformation/Pages/Heat-content-values.aspx).

TOPIC: **DCF Cap Update**

REFERENCE: Application, Appendix 3.4, Section 1.4, page 3.4-9. PDF page 108

QUOTE: "No specific option to modify this cap is proposed in the Application."

QUESTION:

a) Please explain why YEC is not making any recommendation to modify the DCF cap in this application.

ANSWER:

(a)

YEC has provided updated information and assessment of the DCF cap, but has declined to provide any specific recommendation on a matter which ultimately addresses ratepayer interests as to the appropriate DCF cap under current grid conditions.

YEC understands that the prime purpose of the DCF is to enhance long-term rate stability for ratepayers and to reflect the underlying long-term valuation of renewable hydro and wind resources.

The Board noted in Order 2015-01 (Appendix, page 11) that all Parties to that proceeding agreed that there is a need for a mechanism that effectively protects ratepayers from diesel generation cost impacts caused by fluctuation of hydro generation due to water conditions or changes in wind conditions. The Board noted in this Order that rate stability is achieved by limiting the requirement for separate rider collections/refunds to ratepayers and by enhancing the ability to handle material (drought) changes in hydro availability. In effect, rate stability is achieved by enabling ratepayers (to the extent practical) to pay the same LTA cost during droughts as during floods.

YEC has provided updated information in Appendix 3.4 (and Attachment 3.4.4) on the adequacy of the existing DCF cap in order that the Board and intervenors can assess options to the current +/-$8 million cap last approved by the Board. YEC's observations in Appendix 3.4 based on this updated information include the following:

- There is no reasonable basis today to consider any lower DCF cap.

- Potential benefits today of a higher DCF cap include reduced Rider E frequency and enhanced robustness of the DCF in dealing with severe drought (with reduced rate instability for ratepayers).

- A specific comparison of the above potential benefit impacts relative to the current $8 million cap was provided for a $16 million cap, based on GRA forecast loads of approximately 420 GW.h/year and potential higher loads of 450 GW.h/year that could occur if an additional mine load is connected.

TOPIC: **YEC Expected Thermal Generation**

REFERENCE: Application, Appendix 3.4, Table 3.4-1, page 3.4-17. PDF page 116

QUESTION:

a) Please recreate Table 3.4-1 removing the 35-year water history, using the previous 28-year water history, and removing the restrictions for Mayo that were not included in the 2012-2013 filing of the table. Keep all other assumptions the same.

b) Please recreate Table 3.4-1 showing only the 35-year water history change (the change from the previous 28-year water history). Keep all other assumptions the same.

c) Please recreate Table 3.4-1 showing only the change with respect to the Mayo restrictions. Keep all other assumptions the same.

ANSWER:

(a)

Please see the table provided below.

Table 3.4-1 using 28 year water history, without Mayo restrictions

Table 1. Expected YEC Thermal Generation Based on Long-Term Average Hydro Generation

Line Number	YEC Grid Load Net of Wind (GWh)	YEC Hydro Generation (GWh)	YEC Thermal Generation (GWh)	Increase in Load (GWh)	Increase in Thermal Generation (GWh)	Thermal as % of Increased Load
	Column A	Column B	Column C	Column D	Column E	Column F = E/D
1	370.0	368.868	1.132			
2	375.0	373.231	1.769	5.0	0.637	13%
3	380.0	377.410	2.590	5.0	0.821	16%
4	385.0	381.403	3.597	5.0	1.007	20%
5	390.0	385.209	4.791	5.0	1.194	24%
6	395.0	388.827	6.173	5.0	1.382	28%
7	400.0	392.258	7.742	5.0	1.569	31%
8	405.0	395.502	9.498	5.0	1.755	35%
9	410.0	398.564	11.436	5.0	1.939	39%
10	415.0	401.445	13.555	5.0	2.119	42%
11	420.0	404.150	15.850	5.0	2.295	46%
12	425.0	406.684	18.316	5.0	2.466	49%
13	430.0	409.053	20.947	5.0	2.631	53%
14	435.0	411.265	23.735	5.0	2.788	56%
15	440.0	413.327	26.673	5.0	2.938	59%
16	445.0	415.247	29.753	5.0	3.079	62%
17	450.0	417.037	32.963	5.0	3.210	64%
18	455.0	418.706	36.294	5.0	3.331	67%
19	460.0	420.266	39.734	5.0	3.440	69%
20	465.0	421.730	43.270	5.0	3.536	71%
21	470.0	423.111	46.889	5.0	3.619	72%
22	475.0	424.424	50.576	5.0	3.687	74%
23	480.0	425.684	54.316	5.0	3.740	75%
24	485.0	426.907	58.093	5.0	3.777	76%

Notes:

1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid, excluding actual less expected Fish Lake hydro generation.
2. The thermal generation and increase for the added load are based on a polynomial equation derived from "YECSIM" - the simulation model developed for the Integrated Grid by KGS Group.
3. The model calculates expected hydro plant generation for each load scenario. It incorporates, on a weekly time step, 28 "water years" on record (1981-2008) and 20 "load years" (each examines a different hypothetical scenario to evaluate generation under different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this removes results distorted by starting or ending year volumes). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.
4. The simulation model results used for this table assume the current operation rule in effect at Aishihik Lake (i.e., 10-year rolling average spring elevation no lower than 913.7 m for 2006-2015 period), Mayo Lake operation rule considered during the 2012-2013 GRA (no additional storage, no impact of sedimentation at the outlet of Mayo Lake and no restricted Mayo GS winter flows).
5. The simulation model results are based on the 2018 forecast load distributions, and requires modifications when new mines or industrial loads are connected [or disconncted from] to the grid.
6. This table assumes max load at 485 GW.h and minimum load at 370 GW.h. If the load exceeds these limits then the table needs to be updated.
7. Numbers are subject to rounding.

Example

Expected YEC Diesel Generation for the YEC generation at 417 GW.h (net of expected (GRA) Wind)

Step 1. Find the closest load from Column A that is less than 417 GW.h = 415 GW.h (Line 10).

Step 2. Find the diesel generation from Column C = 12.123 GW.h (Line 10).

Step 3. Find the difference between the given load (417 GW.h) and load from Step 1 (415 GW.h) = 2 GW.h

Step 4. Apply the percentage from Column F (Line 11, 42%) to the difference from Step 3 (2 GW.h) = 0.840 GW.h

Step 5. Add numbers from Step 2 (12.123 GW.h) and Step 4 (0.840 GW.h) = 12.963 GW.h

The expected diesel generation at 417 GW.h load is 12.963 GW.h.

(b)

Please see the table below.

Table 3.4.1 with only the 35 year water history change (from "a")

Table 2. Expected YEC Thermal Generation Based on Long-Term Average Hydro Generation

Line Number	YEC Grid Load Net of Wind (GWh)	YEC Hydro Generation (GWh)	YEC Thermal Generation (GWh)	Increase in Load (GWh)	Increase in Thermal Generation (GWh)	Thermal as % of Increased Load
	Column A	Column B	Column C	Column D	Column E	Column F = E/D
1	370.0	368.923	1.077			
2	375.0	373.349	1.651	5.0	0.573	11%
3	380.0	377.687	2.313	5.0	0.663	13%
4	385.0	381.917	3.083	5.0	0.770	15%
5	390.0	386.024	3.976	5.0	0.893	18%
6	395.0	389.994	5.006	5.0	1.030	21%
7	400.0	393.816	6.184	5.0	1.178	24%
8	405.0	397.479	7.521	5.0	1.337	27%
9	410.0	400.975	9.025	5.0	1.504	30%
10	415.0	404.298	10.702	5.0	1.677	34%
11	420.0	407.445	12.555	5.0	1.854	37%
12	425.0	410.412	14.588	5.0	2.033	41%
13	430.0	413.200	16.800	5.0	2.212	44%
14	435.0	415.812	19.188	5.0	2.389	48%
15	440.0	418.249	21.751	5.0	2.562	51%
16	445.0	420.519	24.481	5.0	2.730	55%
17	450.0	422.629	27.371	5.0	2.890	58%
18	455.0	424.588	30.412	5.0	3.041	61%
19	460.0	426.409	33.591	5.0	3.179	64%
20	465.0	428.105	36.895	5.0	3.304	66%
21	470.0	429.691	40.309	5.0	3.414	68%
22	475.0	431.185	43.815	5.0	3.506	70%
23	480.0	432.607	47.393	5.0	3.578	72%
24	485.0	433.978	51.022	5.0	3.629	73%

Notes:

1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid, excluding actual less expected Fish Lake hydro generation.
2. The thermal generation and increase for the added load are based on a polynomial equation derived from "YECSIM" - the simulation model developed for the Integrated Grid by KGS Group.

3. The model calculates expected hydro plant generation for each load scenario. It incorporates, on a weekly time step, 35 "water years" on record (1981-2015) and 20 "load years" (each examines a different hypothetical scenario to evaluate generation under different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this removes results distorted by starting or ending year volumes). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.

4. The simulation model results used for this table assume the current operation rule in effect at Aishihik Lake (i.e., 10-year rolling average spring elevation no lower than 913.7 m for 2006-2015 period), Mayo Lake operation rule considered during the 2012-2013 GRA (no additional storage, no impact of sedimentation at the outlet of Mayo Lake and no restricted Mayo GS winter flows).
5. The simulation model results are based on the 2018 forecast load distributions, and requires modifications when new mines or industrial loads are connected [or disconncted from] to the grid.
6. This table assumes max load at 485 GW.h and minimum load at 370 GW.h. If the load exceeds these limits then the table needs to be updated.
7. Numbers are subject to rounding.

Example

Expected YEC Diesel Generation for the YEC generation at 417 GW.h (net of expected (GRA) Wind)

Step 1. Find the closest load from Column A that is less than 417 GW.h = 415 GW.h (Line 10).

Step 2. Find the diesel generation from Column C = 12.123 GW.h (Line 10).

Step 3. Find the difference between the given load (417 GW.h) and load from Step 1 (415 GW.h) = 2 GW.h

Step 4. Apply the percentage from Column F (Line 11, 42%) to the difference from Step 3 (2 GW.h) = 0.840 GW.h

Step 5. Add numbers from Step 2 (12.123 GW.h) and Step 4 (0.840 GW.h) = 12.963 GW.h

The expected diesel generation at 417 GW.h load is 12.963 GW.h.

(c)

Please see the table below.

Table 3.4-1 with only the Mayo restriction change (from "a")

Table 2. Expected YEC Thermal Generation Based on Long-Term Average Hydro Generation

Line Number	YEC Grid Load Net of Wind (GWh)	YEC Hydro Generation (GWh)	YEC Thermal Generation (GWh)	Increase in Load (GWh)	Increase in Thermal Generation (GWh)	Thermal as % of Increased Load
	Column A	Column B	Column C	Column D	Column E	Column F = E/D
1	370.0	368.545	1.455			
2	375.0	372.824	2.176	5.0	0.721	14%
3	380.0	376.840	3.160	5.0	0.984	20%
4	385.0	380.611	4.389	5.0	1.229	25%
5	390.0	384.153	5.847	5.0	1.458	29%
6	395.0	387.483	7.517	5.0	1.670	33%
7	400.0	390.616	9.384	5.0	1.868	37%
8	405.0	393.565	11.435	5.0	2.051	41%
9	410.0	396.345	13.655	5.0	2.220	44%
10	415.0	398.968	16.032	5.0	2.377	48%
11	420.0	401.446	18.554	5.0	2.522	50%
12	425.0	403.791	21.209	5.0	2.656	53%
13	430.0	406.011	23.989	5.0	2.779	56%
14	435.0	408.119	26.881	5.0	2.893	58%
15	440.0	410.120	29.880	5.0	2.998	60%
16	445.0	412.025	32.975	5.0	3.096	62%
17	450.0	413.839	36.161	5.0	3.186	64%
18	455.0	415.569	39.431	5.0	3.270	65%
19	460.0	417.221	42.779	5.0	3.348	67%
20	465.0	418.798	46.202	5.0	3.422	68%
21	470.0	420.306	49.694	5.0	3.492	70%
22	475.0	421.746	53.254	5.0	3.559	71%
23	480.0	423.122	56.878	5.0	3.624	72%
24	485.0	424.434	60.566	5.0	3.688	74%

Notes:

1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid, excluding actual less expected Fish Lake hydro generation.
2. The thermal generation and increase for the added load are based on a polynomial equation derived from "YECSIM" - the simulation model developed for the Integrated Grid by KGS Group.
3. The model calculates expected hydro plant generation for each load scenario. It incorporates, on a weekly time step, 28 "water years" on record (1981-2008) and 20 "load years" (each examines a different hypothetical scenario to evaluate generation under different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this removes results distorted by starting or ending year volumes). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.
4. The simulation model results used for this table assume the current operation rule in effect at Aishihik Lake (i.e., 10-year rolling average spring elevation no lower than 913.7 m for 2006-2015 period), current Mayo Lake operation rule (no additional storage, impact of sedimentation at the outlet of Mayo Lake and restricted Mayo GS winter flows).
5. The simulation model results are based on the 2018 forecast load distributions, and requires modifications when new mines or industrial loads are connected [or disconncted from] to the grid.
6. This table assumes max load at 485 GW.h and minimum load at 370 GW.h. If the load exceeds these limits then the table needs to be updated.
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Example

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Step 5. Add numbers from Step 2 (12.123 GW.h) and Step 4 (0.840 GW.h) = 12.963 GW.h

The expected diesel generation at 417 GW.h load is 12.963 GW.h.

TOPIC: **YECSIM Model**

REFERENCE: Application, Appendix 3.4, page 3.4-26. PDF page 125

QUOTE: "Being a planning model, YECSIM is not structured in a way that lends itself to retrospective verification per se. Detailed test year verifications are not typically undertaken as such a verification or "test" would not normally be seen as a verification that is required or appropriate for this type of a planning model. If the model was to be reviewed for an historic test year it would be necessary to use the actual loads and inflows as input, and consider as well any special conditions that could have occurred during the test year." [footnote omitted]

QUESTION:

a) Has YEC ever retrospectively tested the YECSIM model? If not, please explain why not? If it has, what were the results?

b) If YECSIM is not structured in a way that lends itself to retrospective verification, how can YEC have confidence in its output? Please explain.

c) How does YEC test the veracity of the YECSIM model?

ANSWER:

(a), (b) and **(c)**

As reviewed in Attachment 3.4.3 (which notes similar hydro planning models such as the Manitoba Hydro SPLASH planning model), detailed retrospective verifications or tests are not typically undertaken for hydro system planning models similar to YECSIM. Accordingly, YEC has not done such tests of YECSIM.

As described in Attachment 3.4.3, the structure of the YECSIM model was prepared to follow other well-established precedents in the field. Key features related specifically to YECSIM are reviewed at pages 3.4-25 to 3.4-29. "Testing" has focused on verifying the accuracy of individual components of the model, including algorithms that compute power generation at each facility based on differential water levels at each structure. YEC's

confidence in the model's outputs is based on consideration of all of these factors as well as ongoing adjustments to reflect new information affecting specific elements of the hydro grid.

Actual system operation will differ from planning model simulations in response to operator assessments of, and responses to, specific conditions. Planning models provide a consistent basis to simulate the system operation within the conditions imposed by physics, regulation and operational priorities, in order to supply the estimated loads with the available hydrologic inputs. Such simulations are required for long-term evaluation of system operation under different loads and with varying generation resource options.

TOPIC: **YECSIM model**

REFERENCE: Application, Appendix 3.4, page 3.4-26. PDF page 125

QUOTE: "Expected thermal generation as provided by YECSIM based on LTA hydro and wind generation for specified grid loads assumes that thermal generation is dispatched only as required to meet energy load requirements, i.e., it does not include or assess options for thermal generation to enhance hydro storage for wintertime use. The LNG Part 3 Application (Appendix D) stipulated specific scenarios for LNG operation in order to assess such potential storage opportunities and impacts."

QUESTION:

a) Operationally, does YEC avail itself of opportunities to enhance hydro storage for wintertime use? Please explain.

b) If yes to (a), how often does YEC avail itself of opportunities to enhance hydro storage for wintertime use?

c) Do opportunities such as hydro storage enhancement affect DCF calculations?

ANSWER:

(a) and **(b)**

YEC assesses opportunities to enhance hydro storage for wintertime use through the inflow forecast, load forecast, its ongoing rules of operation, and in response as required to specific circumstance, e.g., capital works and/or interruptions affecting hydro unit operation.

Given recent load and water conditions, there have been few opportunities to assess hydro storage for wintertime use beyond opportunities defined by normal ongoing rules of operation.

(c)

Yes – opportunities such as hydro storage enhancement affect YECSIM calculations, and therefore the LTA assessments of hydro and thermal generation used in the GRA and to establish the DCF Term Sheet table approved by the Board.

As noted in the above quote, however, the YECSIM model is limited to specific operation rules when it is used for LTA hydro generation assessment related to GRA hydro and thermal generation forecasts, assessment of new generation resource options, and for GRA-related determinations.

TOPIC: **YECSIM Model**

REFERENCE: Application, Appendix 3.4, pages 3.4-27 to 3.4-28. PDF pages 126 to 127

QUOTE: "The historical operation of the system was revised at the developing stages to obtain a general understanding of YEC's operation. At those stages, simulations were carried out to verify in general that the model results properly corresponded to the operation of the WAF system. Model results were discussed with YEC at that stage. However, the YECSIM model is not set to replicate the past; but to simulate the system operation within the conditions imposed by physics, regulation and operational priorities, in order to supply the estimated loads with the available hydrologic inputs."

QUESTION:

a) Does YECSIM mirror day-to-day operational decisions of the YEC system? If yes, please explain. If no, please explain.

ANSWER:

(a)

YECSIM, as a planning model, includes information and decision rules that affect ongoing operational decisions for operation of the YEC system, such as for example, fish flows and lake elevations as per water use licenses. However, as reviewed in detail in Attachment 3.4.3, a long term planning model such as YECSIM does not set to replicate actual past short term operational decisions or to address future short term operational planning.

TOPIC: **BCUC Decisions and Orders**

REFERENCE: Application, page 8-3, footnote 9. PDF page 296

QUOTE: "BCUC Generic Cost of Capital (GCOC) benchmark rate as set in BCUC Decision and Order G-129-16."

QUESTION:

a) Please provide copies of the BCUC decisions and Orders G-158-09, G-75-13, G-47-14 and G-129-16 for the record of this proceeding.

ANSWER:

(a)

Please see YUB-YEC-1-52 Attachments 1 through 4.

YUB-YEC-1-52 Attachments 1-4

(Large attachment – please see 2017/2018 General Rate Application Round 1 Interrogatory Responses Appendix A)

TOPIC: **Return on Equity**

REFERENCE: Application, Tab 8. PDF pages 294 to 302

QUESTION:

a) What makes YEC comparable to FortisBC Electric? Please explain.

b) What makes YEC comparable to PNG West? Please explain.

c) Since the benchmark utility for the BCUC is FortisBC Energy, how does YEC compare to the BCUC benchmark utility?

ANSWER:

(a) and **(b)**

FortisBC Electric and PNG West have been used as comparable utilities for determining the ROE for Yukon Energy since the 2005 Required Revenues and Related Matters review. The following is specifically noted regarding why these are appropriate comparator utilities for determining a fair ROE for Yukon Energy in the context of the BCUC benchmark ROE:

- **Fortis BC (Electric) and PNG-West are BCUC Regulated Utilities:** The Board has repeatedly noted the BCUC model for determining ROE is most appropriate for Yukon; FortisBC Electric and PNG West are each BC-based utilities that have a BCUC approved risk premium over and above the BCUC-approved benchmark ROE of 8.75%. Other utilities outside of BC, and that do not have a BCUC approved risk premium, are not useful comparators.

- **Fortis BC (Electric) and PNG-West have a BCUC determined Risk Premium:** The BCUC approved benchmark ROE for a low risk utility is 8.75% (approved for FortisBC Energy). FortisBC (Electric) and PNG-West are not considered to be low risk utilities and each have a BCUC-approved risk premium above the low risk utility benchmark of 8.75%. Yukon Energy's comparability to FortisBC Energy (the low risk benchmark utility) is summarized in part (c) below and indicates that Yukon

Energy is a small, northern utility with greater operating and business risk compared to the low risk benchmark utility.

- **Prior Yukon Precedents have considered FortisBC (Electric) and PNG-West to be comparable utilities for determining Yukon Energy's risk premium:** Since 2005, FortisBC (Electric) and PNG-West have been considered to provide a reasonable benchmark range for determining Yukon Energy's risk premium (compared to the low risk benchmark utility). In Order 2005-12 and Order 2009-8, the Board approved a risk premium of 52% for Yukon Energy. In each application, this risk premium was based on being at the mid-point of the range between FortisBC Electric (40%) and PNG West (65%). This range was considered reasonable as Yukon Energy was considered more risky than FortisBC Electric (at the lower end of the range) and less risky than PNG-West (at the top end of the range). As reviewed in the relevant applications and decisions, "risk" has been assessed based on utility size of operations (revenues, rate base, customers) and financial structure (capital structure), and nature of business (e.g., exposure to generation-related risks, including hydroelectric generation, and industrial customer loads).

Yukon Energy's current comparability to FortisBC Electric and PNG West is summarized in Tab 8, pages 8-4 to 8-7, and Tables 8.1 (Comparison of YEC to BC Utilities Size of Operations and Financial Structure) and Table 8.2 (Comparison of YEC to BC Utilities – Nature of Business).

(c)

ForitsBC Energy is a large, privately owned, southern natural gas distribution utility that owns no generation assets and has 982,000 retail customers, and is regulated using Performance Based Regulation. Based on information available at the time of the AEY 2016/17 GRA, FortisBC Electric had a 2014 rate base of $2.765 billion and 2014 regulated revenues of $1.489 billion. This is significantly larger than Yukon Energy's rate base and revenues as noted below.

Yukon Energy is less comparable to FortisBC Energy (and in certain cases more comparable to Fortis BC Electric and PNG-West) for the following reasons:

- Yukon Energy is a small, northern utility that operates on an isolated grid that has no interconnections to other jurisdictions. Yukon Energy operates in a relatively small market with limited diversity, which carries more risk than a utility serving a large southern Canadian market with greater economic diversity and strength.

    - As summarized in Tab 8, Table 8-1, Yukon Energy has a rate base of $257.6 million and revenues of $42.7 million. This is significantly smaller than FortisBC Energy (Yukon Energy is also smaller in size compared to FortisBC Electric).

    - FortisBC Energy has a more diverse customer base with about 982,000 distribution customers. In contrast, about 70% of Yukon Energy load relates to a single wholesale customer and about 12.4% of Yukon Energy's load relates to a single mine (Minto mine). Yukon Energy is subject to risks related to serving large industrial loads on an isolated grid (i.e., mine loads can come on and off the system impacting generation requirements and revenues). In this respect, Yukon Energy may be considered comparable [although likely less risky] to PNG-West which has a greater reliance on industrial customer load.

- Yukon Energy is a vertically integrated utility with generation, transmission and distribution functions, and must plan and generate the power required to serve the Yukon Integrated System (i.e., it cannot purchase additional power from outside the grid, and cannot sell surplus power to other jurisdictions). In contrast, FortisBC Energy is a distribution gas utility with no generation. In this respect, Fortis BC Electric [a vertically integrated electric utility that meets 45% of its load requirements with its own generation] is more comparable to Yukon Energy. However, it is noted that Yukon Energy carries relatively more risk as it meets 100% of its load requirements with its own generation.

TOPIC: **Return on Equity, Risk premium**

REFERENCE: Application, Tab 8. PDF pages 294 to 302

QUESTION:

a) Has YEC's risk profile materially changed since its last GRA in 2012/2013? Please explain.

b) Please rank the types of risks faced by YEC in order from the greatest risk to the least risk.

c) For any of the risks listed in (b), what has YEC done to mitigate those risks?

ANSWER:

(a), (b) and **(c)**

Yukon Energy's risk profile is influenced by the same factors that have been discussed since the 2005 Required Revenues and Related Matters hearing – with the most notable risk factors being the lack of interconnection with external electricity grids, Yukon Energy's reliance on its own generation, and fluctuating industrial loads.

The following are noted regarding the types of risk factors identified in YEC submissions since 2005 for determining Yukon Energy's risk profile relative to comparable BC utilities:

- **2005 Required Revenues and Related Matters**: Yukon Energy was considered to have roughly similar business risk to FortisBC Electric (related to mix of customers) as at the time the Faro mine was closed and there were no industrial customers connected to the Yukon grid (i.e., Yukon Energy no longer faced risks related to relatively high reliance on large industrial customers). Yukon Energy was considered to have a similar financial risk to FortisBC Electric and a greater business risk based on all measures of utility size (YEC is much smaller), reliance on its own generation and lack of interconnections with external electricity markets. This last set of factors was seen as conclusive evidence that YEC's risk was materially greater than FortisBC Electric.

- **2008/09 General Rate Application and 2012/13 General Rate Application**: Yukon Energy noted that many of the risk factors identified compared to FortisBC Electric remained (i.e., no material change in statistics regarding customers, size, revenue or rate base compared to the 2005 Application), Yukon Energy continued to have greater risk than comparable BC utilities based on reliance on its own generation (far higher than FortisBC Electric) and lack of interconnection to external electricity markets. Since the 2005 GRA, Yukon Energy's business risk had increased due to connection of a new Industrial customer (Minto mine). As noted for the 2012/13 GRA, Yukon Energy relied on the AUC benchmark of 8.75% for the test years. While Yukon Energy sought a risk premium of 52% (based on risk premium applied in prior years), the Board did not approve this as the AUC approach did not apply a risk premium.

The above risk factors have not changed materially since the 2012/13 Application.

- **Comparison of Yukon Energy to BC utilities size of operations and financial structure** continues to indicate that Yukon Energy is smaller compared to FortisBC Energy (the low risk benchmark). YEC's customer count and rate base is also smaller than FortisBC Electric's; however the financial structure for both utilities is the same (40% equity).

- **Comparison of nature of business to BC utilities** indicates that Yukon Energy continues to have a greater business risk based on its reliance on its own generation (far higher than FortisBC Electric) and its lack of interconnection with external markets. The business risk related to industrial customers has fluctuated with the connection of new industrial customers in 2008 (Minto) and 2011 (Alexco) and the loss of Alexco after the 2012/13 GRA (after rates were set based on its forecast load). Further, as noted in Tab 1 and Tab 2 of the current Application, in preparing the 2017/18 GRA the forecast for Minto mine load changed significantly.

There is little that Yukon Energy can do to mitigate risks that arise due to its size, the isolated nature of the Yukon grid (i.e., a grid interconnection is not a feasible, near term risk mitigation measure), its material hydroelectric generation, and its service of industrial customer loads. Negotiation of Power Purchase Agreements (PPAs) with industrial customers to require recovery up front of connection capital costs is one specific mitigation adopted by YEC to remove "hang-over" cost risks related to connecting new industrial customer loads. Flexible debt financing with YDC for the Mayo B project rate base to adjust

interest rates based on actual grid loads is another mitigation measure adopted related to generation related capital costs and load related risks. Capital grant contributions and renegotiated interest costs are other mitigation measures adopted to reduce specific risks related to generation and transmission asset costs. Implementation of the DCF to address water-related variability risks for hydroelectric generation, and updating of the DCF to address impacts of changing loads and generation facility capability, is another mitigation measure adopted to address generation and load-related risks.

TOPIC: **Generation Risk**

REFERENCE: Application, page 8-7. PDF page 300

QUOTE: "YEC continues to have a greater business risk than the relevant BC utilities based on its reliance on its own generation (far higher than for FortisBC Electric), and its lack of any interconnection with external electricity markets. These material differences have not changed from the assessments provided in 2005 and 2009."

QUESTION:

a) What is the level of generation of FortisBC Electric versus YEC in terms of absolute level of generation (nameplate capacity) and as a percentage of load?

b) Is there a linear relationship between level of generation risk and the level of generation (capacity)? Please explain.

ANSWER:

(a) and **(b)**

Please see Table 1 below for the information related to level of generation for Fortis BC and YEC.

Assessments have not suggested a strict linear relationship between level of generation risk and the level of generation (capacity). The nature of the risk can vary depending on the generation and related cost risks (e.g., fixed costs versus variable costs, new versus very depreciated assets, risks related to renewable energy variability, and risks related to load variation and related cost versus revenue variability), and the relative importance of generation and related costs within the total utility revenue requirement. On all related grounds, YEC's hydro-based generation with new as well as old assets on an isolated grid displays a high level of generation risk.

Table 1: Fortis BC and YEC Generation Levels[1]

	2016	
	Fortis BC	**YEC**
Total Gross Load, GW.h	3,477	413
Own Generation	1,599	413
Own generation as % of total load	46%	100%
Installed Capacity (MW)	225	133
Capacity Factor	81%	36%
Available/Dependable Capacity (MW)	208	110
Capacity Factor	88%	43%

Notes:

1. Information for Fortis BC:
   a. The total load information for Fortis BC is based on Appendix A-2 of Fortis BC Annual Review for 2018 Rates [available at http://www.bcuc.com/Documents/Proceedings/2017/DOC_49776_B-2_FBC_Annual_Review_2018_Rates_Application.pdf]
   b. Own generation is based on response to Information Request #8 [available at http://www.bcuc.com/Documents/Proceedings/2016/DOC_47674_B-5_FBC-Response-to-BCOAPO-IR1.pdf]
   c. Installed capacity based on information from Fortis BC which notes that FortisBC owns four hydro-electric generating plants on the Kootenay River with an installed capacity of 225 MW [available at https://www.fortisbc.com/About/ProjectsPlanning/ElecUtility/ElecFacilitiesOperations/Pages/default.aspx]
   d. Available generation based on Table 5.1. FBC's 2016 Available Energy and Capacity Resources [available at https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf
   e. On page 74, Section 5 of the 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan) Fortis BC notes that

[1] The total load information for Fortis BC is based on Appendix A-2 of Fortis BC Annual Review for 2018 Rates [available at http://www.bcuc.com/Documents/Proceedings/2017/DOC_49776_B-2_FBC_Annual_Review_2018_Rates_Application.pdf]; own generation is based on response to Information Request #8 [available at http://www.bcuc.com/Documents/Proceedings/2016/DOC_47674_B-5_FBC-Response-to-BCOAPO-IR1.pdf]; installed capacity vailable generation based on Table 5.1. FBC's 2016 Available Energy and Capacity Resources [available at https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf]. On page 74, Section 5 of the The FBC Plants supplied about 50 percent of FBC's energy requirements and about 27 percent of the Company's peak demand in 2015.

"FBC Plants supplied about 50 percent of FBC's energy requirements and about 27 percent of the Company's peak demand in 2015."

2. Information for YEC:
   a. 2016 load is based on Table 2.2 and includes secondary related load.
   b. Installed capacity is based on Figure 4-7: Yukon Power Grid and Load Centers, 20-Year Energy and Peak Demand Forecast of the 2016 Resource Plan update.
   c. Dependable capacity as noted on page 2-16 of Tab 2 of the 2018/19 GRA.

TOPIC: **ROE Risk Premium**

REFERENCE: Application, page 8-4. PDF page 297; Appendix A to Board Order 2017-01: Reasons for Decision, page 43.

QUOTE: "As described above, the Board in Order 2005-12 approved Yukon Energy's proposal to set its fair return at 52 basis points (0.52%) above the BCUC low-risk benchmark utility ROE being the mid-point between FortisBC Electric (40 basis points) and PNG-West (65 basis points)."

QUESTION:

a) What factors did the BCUC consider in determining the equity premium for PNG-West?

b) In Board Order 2017-01(paragraph 211- Appendix A) the Board concluded that in determining relative risk for AEY, the Board should look at size and generation risk. Please comment on the applicability of this finding to determining YEC's risk premium.

ANSWER:

(a)

The BCUC approved an equity level of 46.5% and a risk premium of 75% above the low risk utility benchmark of 8.75% for PNG-West [see Page 113-14 of Decision G-47-14]. In approving the 75% risk premium, the BCUC determined that PNG-West faces significantly more risk than the benchmark with respect to customer growth, market demand and throughput risk. The following factors were specifically noted in Decision G-47-14:

- PNG-West serves customers in 11 municipalities close to its transmission lines which traverses BC from the Westcoast Energy system mainline connection near Summit Lake to Prince Rupert. The total population of the service area is under 100,000.

- The highest weighted risks identified by PNG West were operating and size, demand and throughput, competitive position and regulatory.

- The BCUC noted that PNG-West size and operating risk are higher than Benchmark; PNG West is 1/20 the size of the benchmark and in comparison to FEI it "operates in a northern, mountainous and generally harsher environment, where the company assets are subject to significant weather, geographic and geologic factors."

- PNG-West experienced negative customer growth for 9 consecutive years (2003-2012) amounting to a close to 10% decline in overall accounts over this period. In contrast, the benchmark experienced steady growth in customer accounts. PNG-West's throughput has also declined by 87% over the 2003-12 timeframe with a significant part of this decline related to the loss of a major customer; a 42% decline continued over the 2006-2012 timeframe following the loss of this customer.[1]

(b)

Yukon Energy agrees that size and generation risk are important risks to consider in assessing the risk premium applicable for Yukon Energy; however, the nature of the operating environment (i.e., isolated northern grid) is also an important factor to be considered. Key factors that have been considered in prior reviews to determine Yukon Energy's risk relative to BC comparable utilities and that remain applicable for determining the risk premium for Yukon Energy at this time are as follows:

- **The isolated nature of the Yukon grid** – i.e., unlike BC utilities, Yukon Energy operates on an isolated grid and cannot purchase power from other electrical systems (or sell surplus power into such systems). This is a critical risk for Yukon Energy that sets it apart from other southern utilities, as well as AEY.

- **Yukon Energy is the main generator and transmission utility in Yukon** – and generation risk is a key risk for Yukon Energy. Yukon Energy has significantly higher generation (100% of supply requirements) than FortisBC Electric (45% of supply requirements) and AEY (9% of supply requirements).

- **Business Risks related to industrial loads** – Yukon Energy has historically been the utility supplying industrial load that connects to the Yukon grid. The business risk related to industrial customers has fluctuated with the connection of new

[1] Decision B-47-14, page 97-98; 102-103.

industrial customers in 2008 (Minto) and 2011 (Alexco) and the loss of Alexco after the 2012/13 GRA (after rate were set based on its forecast load). Further, as noted in Tab 1 and Tab 2, in preparing the 2017/18 GRA, the forecast for Minto mine load changed significantly.

- **Size relative to larger, southern utilities –** Yukon Energy is relatively small in terms of customers, rate base and revenues compared to larger utilities such as FortisBC Energy and FortisBC Electric.

Overall, Yukon Energy is a small, northern utility (similar to AEY), but also carries much higher risks compared to AEY related to generation, related to connected industrial load, and related to being the main transmitter and generator on an isolated northern grid.

See also the response to YUB-YEC-1-53, YUB-YEC-1-54, YUB-YEC-1-55 and CW-YEC-1-28.

TOPIC: **System Sales and Generation**

REFERENCE: Application, page 2-2. PDF page 31, lines 2 to 7

QUOTE: "Industrial sales under Primary Industrial Rate Schedule 39 currently include only sales to the Capstone Mining Corp (Minto mine). No other industrial customer sales are forecast for the test years. Since 2013, firm grid load supplied by Yukon Energy to industrial customers has fallen below the actual and approved forecast load for 2013, except 2016, reflecting early shut down of the Alexco Resources Bellekeno mine the last half of 2013. The Whitehorse Copper Tailings industrial load that was forecast to be supplied by AEY in the 2013 YEC Compliance Filing has not to date materialized."

QUESTION:

(a) Please provide an explanation for why the firm grid load supplied to industrial customers was above the actual and approved forecast load for 2016, while all other years it was below the actual and approved forecast.

b) Provide a status update regarding the Whitehorse Copper Tailings industrial load that was forecast to be supplied by AEY in the 2013 YEC compliance filing.

ANSWER:

(a)

It is assumed that the question is referencing the actual and approved forecast industrial load for 2013.

The actual and approved YEC industrial load for 2013 included load supplied to Alexco Resources Bellekeno mine for the first half of the year. However, due to an early shut down, there has been no subsequent industrial load supplied to Alexco. As a result, the only industrial customer since 2013 has been Capstone Mining Corp (Minto Mine). YEC's understanding is that Minto's load for 2016 was abnormally high as they were also considering an upcoming shut down and were trying to produce as much as possible before it was shut down.

(b)

YEC has had no recent contact with this proposed customer and has no knowledge of the status of the project beyond what has been publicly reported. The company has acknowledged via its website that the drop in ore price in 2014 made the project unsustainable. No provision has been made in YEC test year forecasts for this customer.

TOPIC: **Installed dependable grid capacity**

REFERENCE: Application, page 2-16. PDF page 45, lines 1 to 6

QUOTE: "Installed YEC and AEY 1 dependable grid capacity for the winter peak in both 2017 and 2018, based on existing capacity today and any planned retirements and excluding Fish Lake hydro, is approximately 115.0 MW (70.5 MW of YEC hydro, 39.1 MW of YEC diesel, and 5.4 MW of AEY diesel).

For the single contingency (N-1) criterion assessment of the dependable capacity, excluding Fish Lake hydro, to meet the YEC load…"

QUESTION:

a) Please explain why the dependable grid capacity shortfall calculation does not include Fish Lake hydro.

ANSWER:

(a)

AEY Fish Lake Hydro is a facility connected to the distribution grid, directly serving the local demand in Whitehorse. As such, YEC is serving the demand net of AEY Fish Lake Hydro contribution.

Consequently, the load and peak demand forecast completed as part of the 2016 Resource Plan and the 2017-2018 GRA Application excluded the contribution of the AEY Fish Lake Hydro. Adding the dependable capacity of AEY Fish Lake Hydro into the single contingency (N-1) criterion would require an increase in non-industrial loads by the same amount to account for the demand it serves as a part of the distribution grid. Considering the added dependable capacity and added demand, the resulting dependable capacity shortfall (or surplus) would be similar to the dependable capacity shortfall (or surplus) calculated for the case without the AEY Fish Lake Hydro contribution. This approach is consistent with past assessments of dependable grid capacity provided to the Board.

TOPIC: **Energy Sales**

REFERENCE: Application, Table 2-2, page 2-18, PDF page 47

QUESTION:

a) Please explain the significant increase in total energy sales from 2016 actuals to 2017 forecast sales when compared to increases in previous years.

b) Please provide 2017 actual total energy sales to date.

ANSWER:

(a)

Total energy sales in Table 2.2 includes secondary sales as well as firm sales. The 12.0 GW.h increase in total energy sales from 2016 to 2017 reflects the following:

- 6.6 GW.h increase in secondary sales (which were relatively low in 2016 compared with 2015);
- 7.8 GW.h increase in firm wholesales (see discussion below – 2016 showed 3.2 GW.h increase over 2015, but remained 6.7 GW.h below 2013 actual); and
- 2.4 GW.h decrease in other firm sales, reflecting a 3.0 GW.h reduction in firm industrial sales.

As indicated above, the fluctuation in total firm energy sales from 2013 to 2016 actual sales and 2017 forecast sales is due primarily to fluctuations in Wholesale sales. Fluctuations in firm Wholesales sales during this period were caused primarily by fluctuations in temperatures, plus impacts of changing Fish Lake Hydro generation.

Warmer than normal temperatures in 2014, 2015 and the first half of 2016 reduced Wholesale sales. As reviewed at page 2-5 of YEC's Application, it is estimated that the magnitude of the above normal temperature impact likely reduced AEY's wholesale purchases from YEC by about 6.4 GW.h in 2015 and by a higher amount in 2016 (relative to AEY's original GRA forecast). It was concluded in YEC's Application that actual AEY

firm wholesales in 2016 were at least 2 to 3 GW.h below what could be expected based on normal temperatures (indicating a minimum 2016 firm wholesales at normal weather of about 304 GW.h).

As reviewed at pages 2-5 and 2-6 of YEC's Application, the 2017 Wholesales firm sales forecast has been based on normal long-term average temperatures and a range of model assessments, and also takes into account AEY's expected changes in Fish Lake Hydro generation between 2016 and 2017.

YEC's forecast firm wholesales for 2017 at 309.0 GW.h is 8.7 GW.h higher than AEY's initial GRA forecast, and 5.2 GW.h lower than AEY's approved Compliance Filing forecast of 314.2 GW,h in response to Board Order 2017-01.

Please also see response to YUB-YEC-1-3 regarding the difference between YEC's GRA and the AEY Compliance Filing as approved by Board Order 2017-03.

(b)

The total 2017 actual energy sales to July 31, 2017 is 242.1 GWh, as detailed below, and compared to the GRA forecast in Table 2.1 for the same period.

	January to July Actual	GRA Forecast (Table 2.1)
Residential	9.3	8.3
General Service	14.4	14.0
Street Lights	0.1	0.1
Industrial	24.6	22.6
Wholesale	188.6	176.7
Secondary	5.0	6.8
	242.1	228.7

TOPIC: **Power Generation**

REFERENCE: Application, page 2-10. PDF page 39, lines 21 to 22

QUOTE: "Total generation is based on the sum of total sales plus losses. Losses are forecast at 8.8% for each of the test years."

QUESTION:

a) Please explain how the forecast level of losses (8.8%) was determined. Please provide actual levels of losses for the years 2012 to 2016 inclusive.

ANSWER:

(a)

As reported in the 2016 Resource Plan (Chapter 4, page 4-17, lines 17 to 19), the forecast level of losses was defined using the average of historical levels of losses for the 2012 to 2015 period. Actual levels of losses for the years 2012 to 2016 inclusive are presented in the table below.

Table 1: Actual Levels of Losses (% of YEC Sales on Grid) – 2012 to 2016

Year	Losses
2012	8.8%
2013	9.0%
2014	7.5%
2015	10.0%
2016	8.3%

TOPIC: **Aishihik AH3, Section 5.2.1.1**

REFERENCE: Application, pages 5-6 to 5-7. PDF pages 177 to 178

QUOTE: "The Aishihik hydro facility 7 MW third turbine (AH3) came into service in December 2011. Yukon Energy has incurred $2.715 million of costs after 2012 for wrap up activities related to this project, including $2.574 million of costs from a dispute with a contractor on this project. Total spending in 2016 was $2.117 million, the majority being legal costs required to be expensed during the year for accounting purposes."

"A decision on the dispute was provided in August 2016 by the Yukon Supreme Court, awarding the contractor a net amount of $1,623,565 plus interest and costs. The amount awarded by the Court included $1,308,462 that consisted of holdbacks and extra works done where the price had been agreed upon, but not yet paid due to YEC's claims for set-off rights. The final cost of the claim dispute includes YEC legal fees of $0.962 million. Based on the advice of legal counsel, YEC has filed the necessary documentation to appeal the court decision."

QUESTION:

a) Please explain why the amount of $1,308,462 which consisted of holdbacks and extra works done is being expensed during the 2016 year for accounting purposes, rather than being capitalized to the project.

b) Please provide any cost-benefit analysis YEC undertook regarding legal fees before proceeding with litigation.

c) YEC indicates it had a claim for setoff against the contractor of at least $1,623,565, which was denied by the Yukon Supreme Court. Are the costs that YEC attempted to set-off included in the $0.665 million capital costs already expensed, or are they in addition to those costs?

ANSWER:

(a)

YEC is not at this time seeking to add any amount to rate base in this Application related to this issue. The utility will carry related costs until such time as the legal process has run its course at which time the utility will consider amounts for review by the YUB.

To help with understanding, the following chronology is provided:

The AH3 project was put into service effective December 2011. Subsequently, the installation contractor advised Yukon Energy of a dispute under the contract. After several rounds of negotiation without success, the contractor filed a claim with the Yukon Supreme Court. YEC filed its defense and a counter claim. Total claims as filed:

Contractor claim	$3,674,000
YEC counter claim	$2,442,045

At this time, the parties had agreed that a total of $1.165 million ($0.746 holdbacks; $0.419 change orders) were legitimate claims by the contractor. YEC accrued these amounts to the project, however, withheld payment due to the material counterclaims outstanding against the contractor. Subsequent to commencement of the court action, but prior to the trial, the parties agreed to further change order settlement of $0.143 million (this amount is not accrued to the project to date and is accounted for in capital WIP; see below for accounting analysis). The sum of these amounts equals $1.308 referenced in the application (page 5-7, l 10). The case went to trial in early Q2 2016 with judgement issued August 1 2016. The judgement awarded some amounts to both parties, with the net result in favour of the contractor. YEC management reviewed the reasons for decision produced by the court and, in consultation with legal counsel, concluded that several legal errors existed in the judgement. Based on this conclusion, the decision was made to appeal.

The table below details the components of the settlement, as well as other spending since 2011.

Description			$000's	Notes
Judgement				
Holdback Release			746	1
Change Orders				
Previously agreed		419		1
Pre-Trial settlement		143		2
Awarded at trial		724	1,286	2
Award to contractor			2,032	
Awarded to YEC			- 409	2
Net judgement payment			1,623	
Legal Expenses		962		3
YEC Labour		20		2
Travel		12		2
Contract		161		2
AFUDC		64		2
Misc		2	1,221	2
			2,844	

1	Amount accrued to project cost at construction; approved into rate base during 12/13 GRA
2	Amount held in capital work-in-progress
3	Amount written off to income statement at the direction of auditors.

In summary the accounting for these costs is as follows:

Costs included in original project costs[1]	$1.164 million
Project costs included in Capital WIP	$0.718 million
Legal costs expensed per audit direction	$0.962 million
Total	**$2.844 million**

[1] These costs were part of the $13.8 million of rate base costs approved by the YUB as part of the order on YEC GRA 2012/13.

With respect to legal costs, YEC was forced to expense these amounts under GAAP based on the previous disallowance of costs by the YUB with respect to the Mayo-Dawson transmission project contract settlement from the 2005 Required Revenues and Related Matters proceeding. It remains YEC's position that these are valid costs for recovery from ratepayers and these costs will be applied for at the next proceeding following resolution.

(b)

From the beginning of this dispute, both parties were motivated to find a settlement outside of a court process. Several negotiation sessions were held, including a court-sponsored mediation. Although some progress was made on some of the issues, overall settlement was not achieved.

(c)

The amount $1,623,565 is the award from the trial judge issued in 2016 (page 5-7, ll 8-9). This is a net award; the contractor was awarded $2.091 million and YEC was awarded $0.408 million for a net award to the contractor of $1,624 million. The amount identified as capital costs of $0.665 million does not include any of the YEC claims against the contractor.

The AH3 project discussed in this GRA is made up of two distinct activities – project wrap-up and the contract dispute. The $0.665 million represents the amount allocated to these two activities during the years 2013 through 2016. For clarity, the following table breaks down the separate activities and shows total costs including 2012.

Activity	2012	2013-2016	Total
AH3 Wrap-up	$148,695	$141,135	$289,830
AH3 Contract Dispute	$183,510	$523,703	$707,213
Total AH3	$332,205	$664,838	$997,043

AH3 Wrap-up activities involved normal work required to address project deficiencies after the unit was put into service. The total for that activity of $289,830 was added to rate base at the end of 2014 and YEC is seeking approval of these costs during the current GRA. The total costs of the contract dispute of $707,213 are being held in WIP. YEC is not seeking approval of these costs during the current GRA.

TOPIC: **Aishihik Elevator Shaft Structural Steel Rehabilitation, Section 5.2.1.2**

REFERENCE: Application, pages 5-7 and 5-8. PDF pages 178 to 179

QUOTE: "Following the addition in 2011 of a second feeder cable in the Aishihik elevator shaft, the Yukon Workers Compensation Health and Safety Board required YEC to have an independent engineer conduct a comprehensive evaluation of the installation to ensure the elevator meets all applicable codes, acts, and regulations. The engineering firm reviewed the elevator structural frames and support system in 2013 and observed degradation of the steel integrity. The report recommended permanent rehabilitation of the structure and a list of conditions imposed on the use of the elevator to provide a reasonable margin of safety until the work is completed. Since regular elevator access to the underground generator floor is required for continued operation of the plant, and the plant is critical to the operation of the Yukon Integrated System, there was no reasonable alternative to completing this project."

"The project is forecast to be completed in 2017 with a forecast cost of $10.116 million."

QUESTION:

a) Has this project been completed?

b) Please confirm that YEC is not asking for approval to put the costs of this project into rate base for the test period.

c) With respect to the report, were other alternatives provided in the report? If so, please discuss the other alternatives.

d) Please provide the original forecast cost of this project, and explain any variances between the original forecast cost, and the current forecasted cost of $10.116 million.

e) When was the elevator installed?

ANSWER:

(a)

Yes, the project is complete and the elevator was returned to service at the end of June 2017.

(b)

Not confirmed. YEC is seeking approval to put the costs of this project into rate base in 2017.

(c)

No other alternatives were provided in the report.

(d)

Table 1 below provides a comparison between the GRA forecast cost of $10.116 million and the original forecast cost of $9.512 million. Table 2 and the description below it provide an explanation of variance by project subcomponent.

Table 1 – AH Elevator - GRA vs Original Forecasts ($000)

	GRA Forecast	Original Forecast (May 2015)	GRA vs Original Forecast
Site Preparation and Modifications	890	425	(465)
Structural Steel	6,163	5,138	(1,025)
Lead Abatement Costs	749	-	(749)
Construction Field Costs:	**7,802**	**5,563**	**(2,239)**
Engineering and Design	482	674	192
Construction Management	637	300	(337)
YEC Owners Costs	759	550	(209)
Construction Financing Cost	198	302	104
Thermal Generation Costs	238	100	(138)
Indirect Costs:	**2,314**	**1,926**	**(388)**
Contingency:	-	2,024	2,024
Total Cost (Project Deficit)	**10,116**	**9,513**	**(603)**

Table 2 – AH Elevator - Variance Explanations

	($' 000's)
Elevator Contractor	(145)
Other Contractors & Services	(320)
Site Preparation and Modifications	(465)
Construction Change Orders	(787)
Schedule Extension Overhead Costs	(238)
Structural Steel Contract	(1,025)
Lead Abatement Costs	(749)
Engineering and Design	192
Construction Site Manager	(290)
Other Consultants & Engineers	(48)
Construction Management	(337)
Camp Rental	(36)
YEC - Labour	(66)
YEC - Non Labour	(106)
YEC Owners Costs	(209)
Construction Financing Cost	104
Thermal Generation Costs	(138)
Variances from Original Forecast	**(2,627)**
Contingency within Original Forecast	$ 2,024
Project Deficit	**$ (603)**

The following reviews the variances as reported in Table 2 – AH Elevator Variances Explanation:

- **Site Preparation and Modifications** – Costs for the elevator contractor to remove from service and return to service the elevator at the beginning and end of each phase were underestimated by $145k. Other Contractors and Services were greater than forecast by $320k as the costs were underestimated for preparation for construction, maintenance costs for the camp and crane, and numerous other miscellaneous materials and services that were required during the project.

- **Structural Steel Contract** – 46 construction change orders were issued for a value of $787k with the bulk of related costs being incurred to address unforeseen conditions such as additional rock chipping, adjustments to design and changes to work plans to address shaft dimensions and bracing. The additional works also

extended the construction schedule resulting in payment to the contractor of an overhead claim in the amount of $238k.

- **Lead Abatement Costs** – Early in the project it was determined that the existing structural steel was painted with lead paint which necessitated special handling procedures during removal.

- **Engineering & Design** – The actual cost was less than forecast by $192k due to using the same engineer for the preliminary and detailed engineering phase and also due to a construction site manger being on the site for the duration of the project reducing the supervisory and inspection role of the Owner Engineer.

- **Construction Site Manager** – The project was forecast to be delivered over 2 phases each with a duration of 5 months per year. The actual duration for the two phases was 17 months - 7 months for the first year and 10 months for the second year. During the second phase the Construction Manager also fulfilled the regulatory requirement mandated by OH&S regulations that a certified frontline supervisor be in attendance at all times when working underground.

- **YEC Owner Costs** – Were greater than forecast due to the duration for both phases of the project being longer than forecast resulting in higher camp rental, YEC Labour and YEC Non-Labour costs.

- **Construction Financing Cost** – There costs were lower than forecast as the outflows as dispersed during Phase 1 were less than forecast resulting in lower financing costs.

- **Thermal Generation Costs** – A provision was made within the forecast but actual costs exceeded budget by $138k.

(e)

The Aishihik hydro facility with its related elevator was commissioned in 1975.

TOPIC: **Aishihik Electrical and Control Upgrades, Section 5.2.1.3**

REFERENCE: Application, pages 5-8 to 5-11. PDF pages 179 to 182

QUOTE: "The Aishihik Control Systems and Electrical Upgrades project includes a number of specific control systems and electrical upgrades that are being undertaken to ensure ongoing safe and reliable operation of the Aishihik Generating Station. Approximately $2.511 million of upgrades are planned to be completed before the end of 2018.

"In 2014, a formal asset assessment was completed by KGS."

"A project to replace equipment and complete a number of specific associated plant control system upgrades and electrical upgrades was developed for execution over multiple years, with most of the upgrades planned to be completed in 2017 and 2018. The need for each planned upgrade (based on currently available upgrade options) was addressed versus the do-nothing alternative."

QUESTION:

a) Please provide a copy of the assessment that was completed by KGS respecting this project.

b) For each of the control system upgrades, as well as each of the electrical upgrades, please provide:
   i.) the report that outlines the upgrade options available at the time.
   ii.) the original forecasted cost of each alternative that was chosen, and explain any variances between the costs that were originally forecast and the current forecast cost total of $2.511 million.

c) Does YEC review control system drawings and operator interfaces on a regular basis? If so, when was the last time that drawings and interfaces were updated?

ANSWER:

(a)

Please see YUB-YEC-1-63 Attachment 1.

(b)

There were no other option reports prepared for this project aside from KGS assessment. Other than a number of minor allocations between project components, there has not been any significant change in the forecast cost.

(c)

Operator interfaces and system drawings are not reviewed on a regular basis, only when required by a specific issue or shortcoming. In this case, the issues are legacy deficiencies from the original AH3 project.

YUB-YEC-1-63 Attachment 1

(Large attachment – please see 2017/2018 General Rate Application Round 1 Interrogatory Responses Appendix A)

TOPIC: **AH Reactor Cable Replacement**

REFERENCE: Application, page 5-11. PDF page 182, lines 10 to 17

QUOTE: "During the AH3 project in 2011 the cables between the breakers and reactors within the S-167 (AH0) substation were replaced. However, the new cables are undersized and need to be replaced. There is a risk that constant heavy load between the reactors and breakers will eventually result in a cable failure which could damage equipment and cause an unscheduled outage of the Aishihik hydro plant."

QUESTION:

a) Please provide the average life expectancy of cable installed and used by a utility for AH reactor cables.

b) Please explain why customers should be paying for undersized cables that were installed in 2011.

c) Please explain the process used during the AH3 project in 2011 that was used to determine what size was needed for the new cables.

d) Please explain why the process described in (c) resulted in cables that were undersized, and are in need of replacement six years later.

e) Notwithstanding the answer to (c) above, please explain the process used to verify that the cables that will be installed in 2017 are now of the correct size.

ANSWER:

(a)

Average life expectancy is between 25 and 40 years.

(b)

See part (d); certain assumptions about the nature of application were proven to be misunderstood at the time of construction.

(c)

Proper cable size was confirmed with YEC's engineering department.

(d)

The cable replacement was not part of the original scope of work and was a result of a change order caused by design complications with the pipe bus. A length of wire that was being removed as part of the project was repurposed for the reactor cable and YEC engineering department was asked to determine if it was adequate. The cable was deemed to be adequate for a similar free-air installation, however, the change order resulted in the cable instead being place underground in conduit. In this arrangement, the cable size was too small.

(e)

Proper cable size was confirmed with YEC engineering department after ensuring full and accurate information about the installation type and location.

TOPIC: **AH3 Lube Oil Pump Battery Installation**

REFERENCE: Application, page 5-11. PDF page 182, lines 18 to 26

QUOTE: "Isolating this pump onto its own backup power supply would enable AH3 to operate independently from the main AH0 backup battery bank, reduce the drawdown and extend the life of the main AH0 backup battery bank during a station service outage. Failure to install this backup increases the risk of the AH0 backup battery bank being drawn down too quickly, which could compromise the ability to recover the AH plant following an extended outage."

QUESTION:

a) Please discuss if the situation described in the quote above (AH0 backup battery bank being drawn down too quickly) has occurred in the past. What is the likelihood of this occurring in the future if a new battery for AH3 is not installed?

ANSWER:

(a)

The situation described has not yet happened, the batteries are only used during a station service outage. This project is being performed as a preventative action after determining that the AH3 lube oil pump places significant demand on the main AH0 battery bank. The main battery is designed to last 16 hours, however, with the additional draw of the AH3 lube oil pump this is reduced to approximately 1 hour. Although even a 1 hour station service outage is unlikely, the consequences of fully discharging the battery are severe. Furthermore, under the current scenario, the plant does not meet its design criteria for battery backup.

TOPIC: **Aishihik Black Start Modifications**

REFERENCE: Application, page 5-11. PDF page 182, lines 27 to 33

QUOTE: "The black start generator of the Aishihik plant can be improved in order to take on additional loading to run more efficiently when it is called into service. It would also be beneficial to increase the number of Aishihik station services served by the black start generator. This project will involve first determining the optimal underground station services that could be shifted to the black start diesel, then performing the work to physically relocate them to the centralized underground station service points supported by the black start diesel."

QUESTION:

a) Please provide the genesis for this project.

b) Please explain how the number of optimal underground services that can be shifted to the black start diesel will be determined.

c) Please discuss the impact on black start services if these modifications were not completed.

ANSWER:

(a)

The Aishihik black start generator was at end of life in 2014 and was replaced with a new and slightly larger unit. This project is required to take advantage of the increased generation capacity and to decrease wear on the asset caused by under loading.

(b)

Services will be prioritized based on their criticality to plant reliability during a station service outage. Once the list of services is ranked and the load demand of each is determined, as many as possible will be added up to the generator's capacity.

(c)

With the generator being significantly under-utilized, there is an increased risk of it not performing during a station service outage. Furthermore, if these modifications are not completed, certain services will continue to rely solely on their own dedicated backup power (batteries, diesel engine, etc.) adding to the risk of failure. These modifications will significantly increase the likelihood that the Aishihik plant will be able to continue operating during a station service outage.

TOPIC: **Communications Upgrades, Section 5.2.1.4**

REFERENCE: Application, pages 5-12 to 5-14. PDF pages 183 to 185

QUOTE: "The Communications upgrades project includes a number of specific communications network upgrades that will replace end of life communication network infrastructure with new technology and implement a simplified network infrastructure which will increase performance and improve reliability of the network. The new network environment will also support other modernization projects that may be undertaken in the future (e.g., Smart Grid Technology). Approximately $1.003 million of upgrades are planned to be completed by the end of 2018."

"In 2016, an independent consultant completed a Communications Needs Assessment and made recommendations to improve critical elements such as Supervisory Control and Data Acquisition (SCADA) system features, and improve network performance, reliability, redundancy and security. A proposed system design was provided with recommendations for staged implementation focusing on the most critical assets or initiatives first, and progressing towards the less critical ones, with the eventual goal of covering the whole YEC communications system.

"A project to replace communication network infrastructure and complete a number of specific communications upgrades was developed for execution over multiple years, with some of the upgrades planned to be completed in 2017 and 2018. The need for each planned upgrade (based on currently available upgrade options) was addressed versus the do-nothing alternative. Each specific upgrade comes into service (and into rate base) when it is completed."

QUESTION:

a) Please indicate whether YEC is not asking for approval to put communication upgrade costs into rate base in the test years.

b) Please explain what precipitated the need for the above noted Communications Needs Assessment. How often has YEC undertaken such an assessment in the past?

c) For each of the Communications upgrades, please provide the original forecasted cost of each project, and explain any variances between the original forecasted costs, and the current forecasted costs that total $1.003 million.

ANSWER:

(a)

YEC is seeking approval to put communication upgrade costs into rate base as the work will be completed and in service.

(b)

The previous study was 5 years old at the time the current needs assessment was requested. Within those 5 years, there have been significant changes in communications technology and YEC recognized the need for an update on the current state of the communications assets. A strategic roadmap was required in order to best allocate resources to address future technologies and operational requirements.

(c)

There have been no cost changes from the estimates provided in the BBA assessment to the YEC forecasts other than the addition of YEC internal labour to support each project.

TOPIC: **Hydro Unit #WH4 Overhaul, Section 5.2.1.5**

REFERENCE: Application, pages 5-15 to 5-16. PDF pages 186 to 187

QUOTE: "The Whitehorse #4 (WH4) hydro unit (20 MW installed capacity commissioned in 1984) is a critical hydro generation asset to YEC. As part of YEC's on-going preventative maintenance program for hydro units, a 10 Year Major Overhaul of the WH4 hydro unit is scheduled for spring 2017 (from April to June) at a forecast total cost of approximately $4.3 million ($3.7 million forecast in 2017)."

"The forecast cost in 2017 for the 10-Year Major Overhaul is approximately $1.9 million, including $0.978 million intended to cover a variety of potential contingency events ranging from overruns on key contracts, significant additional "discovery" work and/or thermal generation costs due to extension of schedule.

"During the 10-Year Major Overhaul process the following two additional replacement activities related to the WH4 hydro unit will also be undertaken as part of this project.

- "WH4 Rotor Spider Replacement – ($1.439 million) – Stress cracks, which required immediate and extensive repair, were observed on the rotor spider during overhauls and inspections performed in 2007, 2012 and 2016. The original equipment manufacturer (OEM), Andritz Hydro, has confirmed that the original rotor design is flawed and recommended that during the next overhaul YEC install a new replacement rotor spider of more durable design in order to improve the long term reliability of this unit."
- "WH4 Excitation Replacement – ($0.977 million) – Technical support and parts to maintain the existing excitation system are becoming more difficult to procure. In 2014, two outages of WH4 occurred. The post-event analysis of these outages resulted in a recommendation to replace the WH4 excitation system. Subsequently, another

> outage occurred on February 18, 2017 that was a direct result of a failure of a component of the MH4 exciter.
>
> "YEC has awarded a contract to Andritz Hydro (the original equipment manufacturer) to install the new rotor spider and to perform the 10-Year Major Overhaul. Andritz will be responsible for providing technical advisory services and for overseeing the mechanical services contractor performing the work." [footnotes omitted]

QUESTION:

a) Assuming that this project has been completed, please provide the final costs and explain any variances from the above-noted $4.3 million forecast. If the project is not complete, please indicate the new completion date and the reasons this project was not completed as indicated in the above-noted quote.

b) Please explain what the 2016 actual costs ($0.581 million)[1] relate to.

c) Given that the original rotor design was flawed, was any compensation from Andritz Hydro pursued?

d) Please discuss the process used to award the contract to Andritz Hydro to install the new rotor spider. Were other equipment manufacturers considered? What factors were evaluated prior to awarding the contract?

ANSWER:

(a)

The WH4 Overhaul project was substantially completed and returned to service at June 28, 2017. At the time of responding to GRA IRs there are some minor deficiency activities that are scheduled for completion in September 2017. The forecast cost to complete the project is presented in Table 1:

[1] Application, Table 5.2. PDF page 224.

Table 1: WH4 Major Overhaul Costs

WH4 Major Overhaul ($,000s)	Forecast To Complete (Aug 2017)	BOD Budget (Nov 16)	Forecast Vs. BOD Budget
Design & Supply of Spider	574	574	0
Installation & Overhaul Services	1,288	1,400	211
Owner's Engineer	285	270	(15)
Exciter System - Supply & Installation	617	703	86
YEC - Labour	370	241	(129)
YEC - Materials & Services	513	100	(413)
Contingency	-	977	977
Construction Financing	31	35	3
Project total	3,678	4,300	721

The project is forecast to be completed as scheduled and within budget. The Forecast to Complete values reflected in the table above are the expected final costs. Provisions were made within Contingency for "discovery works" that could not be determined until the unit was dismantled. The variances reported for the Installation and Overhaul, Labour, and Materials categories reflect the net effect of budgeting for, then completing, the discovery works during the project.

(b)

The 2016 actual costs ($0.581 million) are as per Table 2:

Table 2: WH4 Overhaul Expenditures for 2016

WH4 Overhaul - Expenditures for 2016	
Fabrication of Rotor Spider	315,678
Owner Engineer Services	64,553
Supply of Exciter System	154,251
YEC – Labour	37,728
YEC - Materials & Supplies	7,190
Construction Financing (AFUDC)	1,587
Total	**580,988**

(c)

Compensation was not pursued. The original installation was in 1984 and the "flawed" design was only recognizable in hindsight with modern computer modelling.

(d)

With regard to the award of the rotor spider fabrication contract to Andritz, other equipment manufacturers were considered. A significant impediment to proceeding in that direction is that the OEM specifications for an improved design of the rotor would not be available to a non-OEM fabricator. This would have necessitated reverse engineering of the rotor design before tendering the design and fabrication. This approach would have increased the risk that some minor aspect of the rotor design could be overlooked by the non-OEM engineer or fabricator. To go with any contractor other than Andritz would also have resulted in a longer duration to design and manufacture the rotor which would have pushed the overhaul project into 2018. This timeline was not acceptable due to the increased risk of a WH4 failure as the cracks on the existing rotor were getting longer which once hitting a specific size would result in the unit being removed from service until repairs were effected. Choosing Andritz to manufacture the rotor provided assurance the project could be executed in 2017.

In regard to awarding the Installation and Overhaul contract to Andritz, the alternative approach of YEC hiring multiple contractors for the overhaul still required Andritz participation as a condition of the rotor warranty. YEC negotiated favorable discounted rates with Andritz (20% discount) and the turn-key solution achieved efficiencies in engineering and project management, and also resulted in a one year warranty on the rotor installation and overhaul works performed by Andritz.

TOPIC: **Hydro Unit #MH2 Overhaul, Section 5.2.1.6**

REFERENCE: Application, pages 5-16 to 5-17. PDF pages 187 to 188

QUOTE: "The Mayo #2 (MH2) hydro unit (2.55 MW installed capacity commissioned in 1952 at the Mayo A facility) was fitted with new runners in 2002 and is currently rated at 2.9 MW. A 10 Year Major Overhaul of the MH2 hydro unit and general facility upgrades is scheduled in 2018 at a forecast total cost of $1.655 million."

"As reviewed in the 2016 Resource Plan (Chapter 5), a study of four options for the future of the Mayo A facility was completed for Yukon Energy by KGS Group in 2016 to address the fact that many components in this facility were coming to end of life. A conceptual, high level cost estimate and economic analysis was prepared for each option (i.e., replacement, refurbishment, removal of the facility with return of site to near greenfield condition, and decommissioning of the facility with abandonment insitu). This study found that the optimal solution in terms of the cost and energy generation would be to replace the existing two units with a new single 2.3 MW unit. The 2016 Resource Plan action plan assumes that this Mayo Hydro Refurbishment project will proceed for in-service in 2022."

QUESTION:

a) Please explain what is meant by the "Mayo A" and "Mayo B" facility.

b) Do the planned MH2 unit upgrades have continuing value for the future planned refurbishment of the Mayo A facility?

c) Please explain the operation of MH1 and MH2. Can either of the units, each with an installed capacity of 2.5 MW, be operated at any one time when Mayo B is in operation? Has YEC considered operation of the plan with only one of the existing units, rather than replacement of both units with a 2.3 MW unit?

d) Respecting the 2016 Resource Plan action plan assumption that the Mayo Hydro Refurbishment project will proceed for in-service in 2022, please provide the expected completion date and associated costs.

ANSWER:

(a)

"Mayo A" is the original Mayo hydro facility in service since 1951; this facility contains two hydro units, MH1 and MH2 with total capacity of 5.8 MW. "Mayo B" is the new hydro facility completed in 2011 with two hydro units, MBH1 and MBH2 with total capacity of 10 MW.

(b)

Yes, this work will have continuing value. The optimal generation configuration in Mayo is two Mayo B units plus one Mayo A unit. Since MH2 has been assessed as the better of the two Mayo A units, YEC intends to complete a standard overhaul in 2018 in accordance with established overhaul policy. Please see page 5-18, lines 4-14 for a description of work that will have continuing value for the future refurbishment.

In conjunction with the MH2 overhaul, YEC will undertake a condition assessment of the unit. This will determine the scope of work for the refurbishment of the facility (including rebuilding MH2) and what components (if any) can be reused.

(c)

The Mayo B plant has higher operational efficiency than Mayo A. Therefore, for maximum output, YEC runs the Mayo B plant at maximum. For higher load scenarios, there is enough water available through the Wareham Lake intake to also run one unit at Mayo A (attempts to run two units creates a negative pressure situation that could compromise the penstock). Either of MH1 or MH2 can be operated at any one time when both Mayo B units are in operation. For clarity, YEC does not anticipate installing a brand new unit in 2022; the focus of this work will be upgrades to peripheral systems not directly related to the unit overhaul (e.g. switchgear replacement, ….) as well as upgrades to certain components of MH2 to ensure it reaches a target capacity of 2.3MW. These upgrades will be determined as part of the overhaul scheduled for 2018.

(d)

The Mayo Hydro Future Facility Options Concept Design Report commissioned as part of the Resource Plan assessed four options for the facility and concluded that a refurbishment of the facility had the greatest economic benefit. The overhaul and upgrades to be performed in the test years will aid in determining the specific scope of work for the refurbishment project. Project timing may also be influenced by load growth over the next 2-3 years, however the current forecast is for the plant to be online for the winter of 2022-2023. The forecast cost for the project has not changed from the Resource Plan report ($28.6 million) and is not expected to be updated until preliminary engineering is performed.

TOPIC: **LNG Plant, Section 5.2.1.11**

REFERENCE: Application, pages 5-22 to 5-26. PDF pages 193 to 197

QUOTE: "The LNG Plant project at the Whitehorse Thermal Generating Station (WTGS) came into service July 1, 2015 with two new natural gas engines (8.8 MW), provision for a third natural gas engine, and liquefied natural gas (LNG) offloading, storage, vapourization and other related infrastructure."

- "The two natural gas-fired units (8.8 MW total capacity) were anticipated to be in service before the end of Q4 2014 to provide capacity and fuel cost savings during the winter of 2014/2015, with an estimated capital cost (2013$) of $36.5 million."

"The final completion costs for the project were approximately $41.933 million. However, the net impact of the project on ratebase is considerably lower due to YDC contributions of $18.3 million that were applied to the LNG project in 2015. This reduces the total project costs funded by ratepayers to $23.63 million."

QUESTION:

a) Please provide a summary table highlighting the $5.45-million increase in the final project capital costs. Please ensure that the table shows YEC's assertions related to construction costs, engineering and management costs, owners' costs, planning and permitting, demolition and other activities on pages 5-24 to 5-26.

ANSWER:

(a)

Please see summary table below, which details these costs as provided at pages 5-24 to 5-26 of the Application.

Table 1: LNG Project – Part 3 Estimate vs. Final Costs

($ 000's)	Part 3 (Feb 14 Update)	Costs at Completion	Variance
Construction Contracts			-
Final Tender Costs	6,777	9,256	(2,479)
Firewater Pump & Enclosure	-	572	(572)
Construction Start Delay	-	560	(560)
Additional Works	-	446	(446)
Impoundment Pit	-	403	(403)
Dewatering	-	363	(363)
Vapour Fence	-	90	(90)
Pilings	-	45	(45)
LNG - Site Development	6,777	11,736	(4,959)
Base Contract	10,751	10,751	-
Glycol & E-house Redesign	-	318	(318)
Delays in construction	-	153	(153)
Permitting Requirements	-	60	(60)
Consumables & Miscellaneous	195	339	(144)
LNG Gen - Engines	10,946	11,621	(675)
LNG Plant - Equipment	6,750	6,700	50
Grid Connection	2,033	1,534	499
Contingency	1,000	-	1,000
Construction Contracts - subtotal	27,507	31,591	(4,084)
Engineering & Project Management			
Preliminary Engineering	189	250	(61)
Detailed Engineering	1,244	1,253	(9)
Redesign (Glycol & Site Layout)	-	358	(358)
Construction Support	-	223	(223)
Engineering for permitting	-	219	(219)
Procurement & QA Activities	-	101	(101)
Detailed Engineering	1,244	2,155	(911)
Project Management	1,850	1,876	(26)
Construction Management Servic	-	670	(670)
Permitting Support	-	70	(70)
Project Management	1,850	2,616	(766)
Contingency	200	-	200
Engineering & PM - subtotal	3,483	5,021	(1,538)
Owner Costs			
YEC - Non Labour	1,365	1,327	38
YEC - Labour	618	1,145	(526)
AFUDC	450	577	(127)
Owners Costs - subtotal	2,433	3,049	(615)
Planning & Permitting	2,506	2,687	(182)
Demolition	553	-	553
Descope Transportation Costs	-	(326)	326
FN Benefits (offset by YDC)	-	(90)	90
Other Activities - subtotal	-	(416)	416
Total - All Costs	**36,482**	**41,933**	**(5,451)**

TOPIC: **LNG Third Engine, Section 5.2.1.12**

REFERENCE: Application, pages 5-26 to 5-27. PDF pages 197 to 198

QUOTE: "The LNG Third Engine project will provide a third natural gas-fired generation unit at the Whitehorse thermal plant of approximately 4.4 MW to assist in reducing the current capacity shortfall in a cost effective manner by early 2019.

"The forecast capital cost for this project is approximately $6.2 million, with $3.04 million forecast in 2017 and $2.7 million forecast in 2018 (approximately $0.2 million was spent prior to 2017 for foundation work completed in the first stage of development, and the balance of approximately $0.5 million is forecast in Q1 of 2019).

"The 2016 Resource Plan identified a dependable capacity shortfall for the Yukon Integrated System under its single contingency (N-1) capacity reliability criterion that approximates 6 MW in 2017, increasing to 10-11 MW by 2019. Yukon Energy is required to provide sufficient dependable winter capacity to meet the single contingency capacity reliability criterion, i.e., there is no acceptable "do nothing" option…"

"The 2016 Resource Plan identifies construction of the LNG Third Engine as one of the preferred options for addressing a portion of the dependable capacity gap in a cost-effective manner in the near term, i.e., for use by 2019."

"YEC commissioned a small study in late 2016 to review options for commercially available gas-fired engines to meet desired performance requirements with the third LNG engine at the current LNG facility. The results of the assessment will support YEC's decision with respect to the selection of the single engine or multiple engines with total installed capacity of 4.4 megawatts, and confirm current costs and schedule for commercially available options.

"The project to design, procure and install a third LNG engine will be completed mainly during 2017 and 2018, with the engine currently

planned to be in service in Q1 2019. Other activities to be completed in 2017 include preliminary engineering, development of equipment specification documents, grid impact study, detailed engineering and procurement of long-lead equipment."

QUESTION:

a) Please provide updated costs to design, procure and install the third LNG engine and provide a variance analysis compared to initial forecast costs for this engine.

ANSWER:

(a)

Please see Table 1 provided below.

Table 1: LNG Third Engine Project Budget Update ($000's)

	Initial Forecast	Updated Forecast	Variance
Engineering and Construction Management	$520	$491	$(29)
Engine Package and Transportation	$4,100	$5,769	$1,669
Balance of Plant Installation	$975	$1,372	$397
Commissioning	$150	$160	$10
YEC – Owner Costs	$495	$608	$113
Contingency	$260	$500	$240
Total Project Cost	**$6,500**	**$8,900**	**$2,400**

The following is specifically noted regarding changes from the initial forecast:

- *Engine Package and Transportation* - The updated budget of $5.769M for supply and installation of the GE Jenbacher engine is based on the fixed price quotation (effectively a Class 1 estimate) provided by Gas Drive in September 2017, whereas the prior budget for this item was based on a Class 4 estimate by the owner's engineer, which was in turn based on a preliminary proposal submitted by the engine supplier in February 2017. The $1.669M increase in costs for the engine package is largely due to the omission of key cost items from the Class 4 cost

estimate including installation, engineering, project management, and commissioning. The owner's engineer had assumed that these items were included in scope of the preliminary proposal submitted by the supplier. Additional cost increases resulted from an increase in shipping costs and the inclusion of spare parts and anticipated change orders in the supplier's final fixed price quotation.

- *Balance of Plant* – The updated budget of $1.372M for the Balance of Plant work is based on the updated Class 3 estimate of prepared by the owner's engineer (based on contractor quotations). The increase in Balance of Plant costs is driven primarily by an increase Civil construction costs arising from the inclusion of $0.213M for Phase 1 foundation costs currently held in Work in Progress (not included in the Stagegate 3 cost estimate), an increase in the electrical installation costs, and the inclusion of a General Contractor premium management of the Balance of Plant contract which was also omitted from the Stagegate 3 estimate.

- *YEC-Owner Costs* – The $0.113M increase in Owners Costs is comprised of an increase in forecast labour and the addition of construction support costs, partially offset by reductions in Insurance, Permitting, and AFUDC.

- *Contingency* – a comprehensive risk-based contingency was developed for the updated project cost estimate, resulting in a $0.240M increase in the project contingency.

TOPIC: **Projects $100,000 to $1 million, Section 5.2.2**

REFERENCE: Application, page 5-28. PDF page 199, lines 4 to 7

QUOTE: "Growth in net rate base reflects ongoing need to refurbish old assets and improve grid reliability. Significant re-investment in existing infrastructure has been undertaken since 2013 to ensure that the Yukon integrated grid can continue to meet the unprecedented level of growth on the system in a safe and reliable manner."

QUESTION:

a) Please explain and provide examples of what YEC means when it refers to an "unprecedented level of growth on the system" in the above quote.

ANSWER:

(a)

The sentence should be amended as follows for the current GRA: "Ongoing re-investment in existing infrastructure ensures that the Yukon integrated grid can continue to meet loads on the system in a safe and reliable manner."

TOPIC: **L170 Line Access**

REFERENCE: **Application, Appendix 5.3, page 5.3-6. PDF page 249**

QUOTE: "YEC requires access to transmission lines for maintenance, inspection, and brushing activities. Currently a number of temporary access points are used that lack the necessary permitting and may not be constructed to an acceptable standard. This project will complete the required assessment process in order to obtain the necessary permits for both new and existing accesses. It also includes the construction of new accesses and upgrades to existing ones, resulting in faster response times for emergency line work and reliable access to key YEC assets."

PREAMBLE: The Board notes that $350,000 is to be spent in each of the test years. Further information is required.

QUESTION:

a) Please explain who issues the permits respecting the access points. Please provide a copy of a sample permit.

b) What does YEC mean when it states that this project "will complete the required assessment process in order to obtain the necessary permits"?

c) Is YEC completing the assessment? Why has this not been done previously?

d) Can YEC provide examples where responses times were slow? What is the comparator when YEC says "faster response times"? How long has this been a problem?

e) How has YEC been able to operate in the past without the necessary permits?

ANSWER:

(a)

Please note that this project began in 2016 and included spending of $350,000. A presentation error occurred in the Application in Table 5.2 and Appendix 5.3. The costs appear on Table 5.2 as "L170 Access Construction Between S164 and Structure 524" under the General Plant & Equipment heading.

The following permits are required to build a new access point or modify an existing one:

- Construction or modification of an access – issued by Yukon Highways and Public Works;
- Access Permit Agreement – issued by Little Salmon Carmacks First Nation;
- Forest Resources Permit – issued by Yukon Energy, Mines and Resources;
- Land Use Permit – issued by Yukon Energy, Mines and Resources.

(b) and **(c)**

In order to obtain the necessary Land Use Permit, a YESAB assessment was required (see YESAB project 2016-0021). This was completed by YEC staff with the assistance of a consultant to perform the heritage assessment work. The assessment was not done previously as YEC had not sought to obtain a Land Use Permit.

(d)

In 2015 the failure of an insulator caused part of a structure to burn and require replacement. As there was no existing access to this section of line, a road was constructed over the course of 3 days, adding significant time to the replacement of the structure.

Line access in emergency situations has typically been performed on and ad-hoc basis and has been a challenge since the original construction of the WAF line. Staff have regularly been required to access transmission line structures via unofficial routes that often pose safety (and occasionally environmental) risks. Upon completion of this project, every structure will have a designated access point that is properly constructed and avoids any risk of environmental damage (water crossings, sensitive terrain, etc.).

(e)

In the past YEC would access power line right of ways through existing roads or trails without permit. In 2016, as a result of investigations into brushing contractor access issues, the regulator (YG) advised that permits were required for all accesses.

TOPIC: **Whitehorse-Aishihik-Faro (WAF) Transmission Upgrades**

REFERENCE: Application, Appendix 5.3, page 5.3-7. PDF page 250

QUOTE: "The WAF transmission system allows low cost hydro generation supplied from Aishihik, Whitehorse, or Faro to be transmitted to other locations on the grid. A failure of a transmission line structure would interrupt this supply, potentially resulting in a wider grid collapse. The structures on this transmission line were built in the 1960s through 1970s and are in various stages of deterioration. A recently performed test and treat program has identified the structures that are at the highest risk of failure. This project replaces the identified structures, along with any end-of-life cross arms and insulators that are discovered."

PREAMBLE: The Board notes that $3.068 million was spent in the period 2013 to 2016 (approximately $750,000 per year). Moreover $850,000 is to be spent in each of the test years on this project.

QUESTION:

a) Considering that YEC's test and treat program has recently identified structures that are at the highest risk of failure, please indicate and explain when YEC expects this project to be completed.

ANSWER:

(a)

Depending on the timing of certain stages of the work, all of the elements of this project are expected to be completed in 7 – 10 years, with costs for each portion being brought into rate base as it is completed. Work on L170 (Whitehorse – Carmacks) will be prioritized, followed by L171 (Whitehorse – Aishihik). Once all structures and components on those lines have been brought up to an acceptable standard, L178 (Carmacks – Faro) will see similar work performed. Note this work differs from T&D Line Replacement which is described in section 5.2.1.8 which addresses other components of these lines.

TOPIC: **Deferred costs, Section 5.3**

REFERENCE: Application, page 5-30. PDF page 201

QUOTE: "Deferred costs include feasibility studies for a wide range of projects (focused mainly on potential new generation or transmission options and includes the 2016 Resource Plan Update), continued relicensing work (for this Application, this grouping includes water licence renewal activities as well as water licence amendment projects, e.g., Mayo Lake Storage Enhancement Project), regulatory work (includes DSM), and dam safety review work. Overhauls, which in prior GRAs were included as a separate deferred cost, are now included under PP&E capital works (see Table 5.2) as per new accounting regulations."

"The Application includes, as appendices to this section for approval by the YUB, Yukon Energy's Planning Cost Accounting Policy (Appendix 5.1) and DSM Accounting Policy (Appendix 5.2) to address amortization of these cost for regulated revenue requirement purposes." [footnote omitted]

QUESTION:

a) With respect to YEC Planning Cost Accounting Policy and DSM Accounting Policy, has YEC previously submitted these policies for approval?

b) If the answer to (a) is yes, please list the changes and the reasons for the change.

ANSWER:

(a) and **(b)**

Yukon Energy previously submitted an updated Planning Cost Accounting and a DSM Accounting Policy for the Board's review and approval as part of the 2012/13 General Rate Application (see Appendix 5.1 of the 2012/13 GRA for the Planning Cost Accounting Policy filed at that time; and Appendix 5.2 for the DSM Accounting Policy filed at that time). The Board in Order 2013-01 noted as follows regarding the approval of these policies [as applied for at that time]:

- The Board did not accept the planning cost accounting policy [see paragraph 405 of Order 2013-01]. The Board specifically noted that the Board and interveners must be given the opportunity to test the prudence of all costs incurred by YEC in respect of deferred costs "… and considered "the policy as proposed would allow the inclusion of these costs without any prior scrutiny by the Board and interveners."

- The Board deferred its findings and directions regarding YEC's DSM Accounting Policy until YEC and YECL have jointly filed a DSM plan [see paragraph 407 of Order 2013-01].

The Planning Cost Accounting policy was subsequently revised to take into consideration the concerns raised by the Board in Order 2013-01. Overall, in many cases wording was changed/ added to provide greater clarity compared to provisions included in the 2012/13 version [this applies to section 2.1 and new section 2.2]. Key changes to the policy compared to the 2012/13 version are as follows:

- **Removal of reference to "Reasonable Assurance Test":** Section 2.3 in the 2017/18 version was altered to review reference to the "Reasonable Assurance Test" for deferral of planning costs without amortization[1] that was included in the 2012/13 version of the Planning Cost Accounting Policy. Reference to this has been removed to address the Board's concerns noted in Order 2013-01.[2] Section 4 was added to provide greater clarity that while YEC will close out and begin amortization of studies as prescribed by the policy, all deferred costs will be subject to a prudency review by the YUB prior to any change in customer rates.

- **Insertion of new Section 2.3:** Addressing how viability of planning cost projects will be assessed on an ongoing basis.

[1] "planning costs deferred without amortization must meet a "Reasonable Assurance Test": (a) Future expenditures will not be recognized as work-in-progress assets until such time as there is reasonable assurance that a Corporation commitment to construction will be made; (b) in the event a project is abandoned after this step, accrued costs will be amortized over 10 years."

[2] The 2012/13 version of this provision [including the Reasonable Assurance Test] did not seek, or intend, to include in rates any deferred or other costs that had not been subject to review and approval by the Board. However, there was significant confusion regarding this element at the 2012/13 GRA which led to the amendments included in Appendix 5.1 of the 2017/18 GRA.

- **New Section 2.5**: Added to clarify how planning costs will be amortized in the event a project does not proceed. The 2012/13 version of the policy included provision for a "transition policy for 2012 & 2013 Test Years". This was considered a "one-time" transition approach for cost in WIP at that time and intended to mitigate rate impacts from 5-year amortization of existing WIP costs for projects incurred that exceeded $1 million. The current section 2.5 seeks to continue with this approach in order to continue to mitigate rate impacts from projects in WIP that are being closed out and that have costs in excess of $1 million.

The only change to the DSM Accounting Policy from the version filed in the 2012/13 GRA is an edit to section 2.3 which simply notes "qualifying expenditures will be closed out on an annual basis" as opposed to the wording included in the 2012/13 version which is now deleted: "a. Over each year eligible DSM program expenditures will be deferred. (b) At the end of each year eligible deferred DSM program expenditures will be closed out and amortized over the following ten years."

TOPIC: **Stewart Keno City Transmission Line Project, Section 5.3.1.2**

REFERENCE: Application, pages 5-32 to 5-33. PDF pages 203 to 204

QUOTE: "The Stewart Keno Transmission Line (SKTL) project will improve the electrical transmission infrastructure in central Yukon between Stewart Crossing and Keno City; reinforce and strengthen the grid between Stewart Crossing and Mayo; and replace and remove deteriorated and 'end of life' transmission infrastructure between Mayo and Keno City. The project is being planned to ensure continued safe and reliable service and to facilitate future economic development within the territory.

"An initial $5.3 million tranche of funding was provide by the Yukon Government for the costs required to advance the project to a shovel ready stage by Q4 2016."

…

"…a material component of the Project costing cannot be confirmed with reasonable certainty until the Project is tendered.

"Detailed line design and detailed substation design contracts were competitively tendered and awarded in 2016, with this work to be completed in Q1 2017.

"A decision to advance the project will be undertaken once Yukon Energy has confirmed the project costs and potential funding availability. Yukon Energy is considering options for a staged project development, with the initial stage to remove and replace deteriorated and 'end of life' transmission infrastructure between Mayo and Keno City, in the event that third party funding is not available."

QUESTION:

a) Has YEC made any decision with respect to advancing this project? Please explain any issues, problems or constraints that YEC faces in relation to the above-noted project.

b) YEC states that staged development may take place and refers to an initial stage. Please describe and explain further stages related to this project.

c) Is YEC looking for 100% funding outside of the revenue requirement? Please explain.

d) Will this project require a Part 3 certificate?

e) Please confirm that no costs for the Stewart Keno City Transmission Line Project are forecast to be included in rates for the 2017 to 2018 test period. If not confirmed, please provide a detailed breakdown and explanation of the past actual costs and forecast costs from 2017 onwards for the Stewart Keno City Transmission Line Project.

ANSWER:

(a)

No decision has been made with respect to advancing this project.

The Stewart-Keno Transmission Line Project (SKTP) with extension of the 138 kV grid from Stewart Crossing to Keno City, which would materially expand the Yukon hydro grid capability to accommodate future loads as well as new resource options, is conditional today on government rather than ratepayer funding given current and potential loads to be supplied at this time.

A new line from Mayo to the Keno region, however, is required to replace the end of life existing 69 kV line constructed in the 1950s. The option is to have users in this region (mines as well as non-industrial electricity users) depend solely on local fossil fuel generation. The business case for replacement of this existing line would be strengthened by additional loads required by any major industrial customers in this region. As in the past, the required generation would be supplied by the Mayo hydro facility supplemented by generation from the southern portion of the Yukon Integrated System, and any new renewable generation on the northern portion of the grid.

Full replacement of the Mayo to Keno City line could have a material impact on rate base and therefore rates for all Yukoners. YEC is investigating different replacement

configurations and funding options to minimize this impact while maintaining acceptable service levels to affected customers.

(b)

YEC is evaluating an option for full development of the SKTP in the event that government funding can be secured for the full project, and options for proceeding in the event that government funding cannot be secured for the full SKTP.

In this context, YEC is examining an option to replace just the Mayo-McQuesten portion of the Mayo to Keno City transmission line, which is at end of life and is considered the worst section of line between Mayo and Keno City. This initial step will ensure reliability of service for the prospective Victoria Gold connection, while addressing the section of line which is in poorest condition. This option ensures reliability of service for customers on this portion of line including the prospective Victoria Gold connection, while addressing the section of line which is in poorest condition. Subsequent to this initial stage of development, YEC could plan the further stages of the project which would involve replacing the line between McQuesten and Keno, and at some time thereafter installing a new 138kV line between Stewart Crossing and Mayo. The objective of this subsequent phase of the project would be to improve reliability along the whole length of line (i.e. replace the McQuesten-Keno section), and increase the total transmission capacity of the line in response to additional (future) industrial load and/or local renewable resource supply development.

(c)

YEC is investigating options to secure funding for the full SKTP (or portions thereof) up to 100% of full revenue requirement impact. A number of Federal infrastructure programs have been identified under which this project could qualify, and YEC expects to work further with YDC and the Yukon government in pursuit of these options within the next six months.

(d)

The designation as a regulated project under part 3 of the Act is the responsibility of the Commissioner in Executive Council. YEC is not aware today whether the Commissioner will make such a designation.

(e)

Confirmed that no costs for the SKTP are forecast to be included in rates for the 2017 to 2018 test period.

TOPIC: **Aishihik Generating Station Water Use Licence Renewal, Section 5.3.1.2**

REFERENCE: Application, pages 5-33 to 5-34. PDF pages 204 to 205

QUOTE: "A licence renewal is required for the continued operation of the 37 MW hydro facility, which provides the only multi-year hydro storage and the largest winter peak hydro generation capability on the Yukon Integrated System. Yukon Energy plans to seek a 25-year licence renewal (the maximum allowed term).

"The total budget for the project is forecast at $3.569 million spread over five years (2015 – 2019). Total deferred costs to the end of 2018 are forecast at $2.899 million. The last Aishihik licence renewal project cost approximately $8.791 million.

"The licence renewal process will include undertaking environmental and socio-economic studies required to support a YESAA Project Proposal (currently targeted for a Designated Office filing in mid-2018), followed by the development and securing of a Yukon Water Board Application and an application for a Fisheries Act Authorization."

QUESTION:

a) Please provide a detailed breakdown and explanation of the actual costs from 2015 and 2016 and forecast costs from 2017 onwards for the Aishihik licence renewal project.

b) Considering that the above is a five-year project, please describe and explain what has been accomplished from 2015 to date, with respect to this project.

c) Please explain what is meant by a "Designated Office filing".

d) Have issues arisen as a result of working with the Champagne and Aishihik First Nations (CAFN) towards a water license use renewal? If so please explain.

e) Considering that YEC is almost three years into the project, are there updates to the total forecast cost of $3.569 million for this project?

ANSWER:

(a)

Table 1 provides a breakdown of the actual and forecast expenditures per spending category for the Aishihik water use license renewal project. The actual expenditures for 2015 and 2016 are combined since the expenditures were minimal in 2015 due to a delay in the project start. The delay was caused by longer than expected negotiations with the Champagne and Aishihik First Nations (CAFN) related to the novel co-management approach in developing the regulator submissions. The co-management approach is discussed in more detailed in answer to YUB-YEC-77(b).

The total project expenditure forecast, as presented in column 2015-2019 in Table 1, is based on the budget approved by YEC's Board of Directors in September 2015. As discussed in more details in the answer to YUB-YEC-77(e), the 2015-2019 forecast is expected to increase.

The project management costs are YEC internal costs related to the work on planning and executing the project.

The CAFN and stakeholder engagement costs are related to: 1) engagement with the CAFN, including funding the Champagne and Aishihik Community Advisory Committee (CACAC) and traditional knowledge project, discussed in more details in the answer to YUB-YEC-77(b); and 2) public engagement, discussed in more details in the answer to YUB-YEC-77(b).

The Aishihik Advisory Committee (AAC) costs are related to the activities of AAC discussed in more details in the answer to YUB-YEC-77(b).

The Impact assessment studies costs are related to the planning and execution of the environmental and social impact assessment studies discussed in more details in the answer to YUB-YEC-77(b).

The permitting process costs are related to development of: 1) the project proposal to the Yukon Environmental and Socio-economic Assessment Board (YESAB); 2) regulatory application to the Department of Fisheries and Oceans (DFO); and 3) regulatory application to the Yukon Water Board (YWB).

The CAFN compensation costs are related to: 1) the compensation to the CAFN due to the loss of use of the lake for the duration of the future water use license; and 2) negotiation costs to reach a compensation agreement with the CAFN.

Table 1: Actual and Forecast Expenditures for the Aishihik Water Use License Renewal Project

Expenses in $'000	Actual 2015-2016	Actual Jan - Jun 2017	Forecast Jul 2017 - Dec 2019	Forecast 2015-2019
Project management	79	34	440	553
CAFN and stakeholder engagement	126	36	222	384
Aishihik Advisory Committee (AAC)	81	6	66	153
Impact assessment studies	703	426	630	1759
Permitting process			300	300
Total	**989**	**502**	**1658**	**3149**

In addition to the above forecast, YEC anticipates payment of compensation to affected lake users, however, the quantum is not known at this time.

(b)

Project accomplishments since its inception until the end of August 2017 are presented in the following categories: establishment of co-management framework; establishment and activities of the AAC; planning and execution of environmental and social impact assessment studies; public engagement; and building relationship with the CAFN. Each of those categories is discussed in the following paragraphs.

Establishment of co-management framework.
Considering the importance of the Aishihik Generating Station (AGS), the fact that the facility is located at the CAFN traditional territory, and complexities encountered during the previous water use licence renewal process due to misaligned expectations between the CAFN and YEC, YEC deemed it prudent to engage the CAFN at the beginning of the

current water use license renewal process. The objective of engagement was to increase participation by the CAFN in the water use relicensing regulatory process, increasing collaboration between YEC and CAFN and reducing the risk of conflict and/or adversarial legal action during the formal regulatory proceedings. As a consequence, CAFN and YEC signed the Aishihik Hydroelectric Power Generation License Renewal Co-Management Protocol Agreement that provided a formal framework for the co-management of the water use licence renewal process between CAFN and YEC. The document stipulates the roles and responsibilities of the parities in the relicensing process, as well as the governing and advisory bodies, such as the Steering Committee, AAC, and CACAC. As a part of the co-management process to develop the assessment and permitting regulatory submissions, CAFN set up the CACAC to provide advice on the introduction of CAFN's values and traditional knowledge to the process to influence the scope and interpretation of the environmental and social impact assessment studies. In the spirit of the co-management agreement, YEC provided funding for the CACAC, as well as the CAFN-led traditional knowledge project that will be a part of the regulatory submissions.

Establishment and activities of AAC.

Since, in addition to CAFN, the water use licence renewal process includes external stakeholders, YEC also engaged the major stakeholders in the process through the AAC. The AAC is co-chaired by the CAFN and YEC.

The AAC's role is to provide ongoing advice and feedback as Yukon Energy and CAFN develop a project proposal targeted for submission to the Yukon Environmental and Socio-economic Assessment Board (YESAB), as well as regulatory applications to the Department of Fisheries and Oceans (DFO) and Yukon Water Board (YWB). In addition, the AAC reconciles potential opposing interests and values of the YEC, CAFN, external stakeholders, and public related to the use of Aishihik Lake.

Eight AAC meetings have been held since the beginning of the project until the beginning of August 2017, and all the major project activities have been proposed, discussed and approved at AAC meetings.

The activities of the AAC included:

1. Consideration of the Federal and Yukon Government policies and regulations related to the water use license renewal process;

2. Building a common understanding of inputs, analysis methodologies, and deliverables related to the water use license renewal process;
3. Development of potential AGS operational alternatives;
4. Identification of potential information gaps to define required environmental and social impact assessment studies and their scopes, impact assessment planning, mitigation and monitoring plans;
5. Development of the list of the environmental and social impact assessment studies required for the regulatory submissions;
6. Development of the list of valued components to be used to evaluate operational alternatives; and
7. Preliminary evaluation of the operational alternatives.

Planning and execution of environmental and social impact assessment studies.
As a consequence of the AAC activities, environmental and social impact assessment studies are being executed. To inform the execution of the impact assessment studies, three technical groups were established to execute the decisions made by the AAC. The activities of the technical groups are related to lake issues, downstream river issues and the traditional knowledge project, all of which create a base for development of the documents needed for the regulatory submissions. The technical groups consist of members from YEC, CAFN, and subject matter experts.

Public engagement.
As a part of the public engagement strategy, two public meetings, one in Whitehorse, another in Haines Junction, were jointly planned, organized and held by YEC and CAFN. The goal of the meetings was to inform public on the objectives and progress of the project, co-management process and to solicit feedback.

Building relationship with the CAFN.
In addition to joint YEC and CAFN activities discussed in paragraphs on establishment of co-management framework, establishment and activities of AAC, planning and execution of environmental and social impact assessment studies, and public engagement, as a part of building relationship with the CAFN, YEC participated in two culture camps organized by the CAFN. The objective of the participation was to familiarize with CAFN values related to water, land and fish.

(c)

A 'Designated Office Filing' refers to a project proposal submitted to a Designated Office for an assessment pursuant to the Yukon Environmental and Socio-economic Assessment Act (YESAA). In this case, the Haines Junction Designated Office is expected to conduct the project evaluation. This level of assessment differs from a project proposal required to be submitted to the more intensive Executive Committee Screening or Panel Review processes of Yukon Environmental and Socio-Economic Assessment Board.

(d)

Please refer to the answer to YUB-YEC-77(b) for details related to relationship with the CAFN.

(e)

Largely due to the known increased quantum and scope of the impact assessment studies required for the project proposal to YESAB, as well as the funding of the CACAC and CAFN traditional knowledge project, the project is expected to exceed the initial budget of $3.569 million. Due to unknown costs related to potential increase in the scope of regulatory proceedings, and compensation to the CAFN, the final project cost cannot be accurately estimated at this time. YEC will continue to monitor the development of costs related to unknowns and adjust the budget accordingly.

TOPIC: **Battery Project – Energy Storage System, Section 5.3.1.3**

REFERENCE: Application, pages 5-34 to 5-36. PDF pages 205 to 207

QUOTE: "The Battery project will provide a Battery Energy Storage System (BESS) to assist in addressing the current dependable capacity shortfall in a cost-effective manner by 2020."

"Depending on the option selected, the TGS [TransGrid Solutions Inc.] study indicates forecast costs for the Battery project between $21.7 and $27.4 million (including costs for planning, permitting and construction) for an initial 15 to 20 year life, after which a replacement battery is estimated to cost between $17.4 and $22.1 million (2016$)."

PREAMBLE: The Board notes that "Completion of environmental and socio-economic base line studies, stakeholder engagement and consultation, preliminary engineering, grid impact study followed by a Stagegate 3 project review in the 4th quarter of 2017"[1] were to be undertaken in 2017.

QUESTION:

a) Please provide a copy of the TransGrid Solutions Inc. Study.

b) Can YEC provide examples of utilities, in particular northern utilities, which have employed battery energy storage systems to address dependable capacity shortfall?

c) Are there limitations, such as limitations related to charging of the batteries, with respect to the use of the battery storage systems? Please explain.

d) Please provide a detailed year-by-year breakdown, with explanations, of the forecast costs for the battery project.

[1] Application, page 5-36, PDF page 207, lines 10-13.

e) Please indicate what has been undertaken to date in relation to the steps identified in the preamble of this question.

f) Please explain what is meant by a "Stagegate 3 project review."

ANSWER:

(a)

The TransGrid Solutions Inc. study can be found on the 2016 Resource Plan website at the link below.

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.19_Evaluation_of_Energy_Storage_Technologies_(Transgrid_Solutions_2016).pdf).

(b)

Yukon Energy is not aware of a northern utility using an energy storage system for electric supply capacity or energy time shift. Examples of energy storage systems used for electric supply capacity, energy time shift or any other usage worldwide can be found on the US Department of Energy Global Energy Storage Database.

(c)

The project is in early stages of its development. As Yukon Energy completes the planned activities leading up to Stagegate 3, it will investigate operational limitations associated with energy storage systems.

(d)

Forecast year-by-year costs for the Energy Storage System project are provided in the table below. The costs assume that the 4MW/40MWh Lead-Acid option is chosen; however, work to be completed during the test years will confirm ESS size and technology. The forecast costs are subject to change as the project definition evolves.

Table 1: Forecast Energy Storage System Costs

Costs ($000)	2017	2018	2019
Preliminary Engineering	$ 375	$ -	$ -
Assessment & Permitting	$ 100	$ -	$ -
Consultation	$ 25	$ 25	$ -
YESAA Review	$ -	$ 50	$ -
Regulatory Authorizations	$ -	$ 415	$ -
Detailed Engineering	$ -	$ 2,000	$ -
Procurement, Construction & Commissioning	$ -	$ 5,866	$ 13,852
Total	$ 500	$ 8,356	$ 13,852

(e)

As of the end of August 2017, YEC has completed internal work on the Energy Storage System Project. Specifically, an updated schedule leading up to the Stagegate 3 project review was prepared and scope of work for the system impact study, preliminary engineering and environmental and socio-economic base line studies were developed.

(f)

YEC uses a Stagegate Project Development Framework (Application, page 5.1-3. PDF, page 240. Appendix 5.1 Planning Cost Accounting Policy) to advance major projects from early planning to commissioning. This approach requires a review of the project by the Board of Directors at each decision point referred to as “Stagegate”. “Stagegate 3” is a Board of Directors review and go/no go decision based on preliminary engineering, socio-economic and environmental assessments, First Nation engagement and public engagement, and defining of a procurement strategy.

For the Energy Storage System, Yukon Energy, as part of the planned activities for the 2017 and 2018 test years, would complete environmental and socio-economic base line studies, stakeholder engagement and consultation, preliminary engineering, and a grid impact study. These studies would provide YEC with an updated business case, schedule and risk register for review by the YEC Board of Directors. A decision to continue advancement or cease further spending on the project would be done as part of the “Stagegate 3 project review”. Planned work is subject to approval of YEC’s overall capital plan and associated access to the necessary debt financing.

TOPIC: **Thermal Plant, Section 5.3.1.4**

REFERENCE: Application, pages 5-36 to 5-39. PDF pages 207 to 210

QUOTE: "The Thermal Plant project will provide up to 20 MW of new diesel or natural gas thermal generation capacity to assist in addressing the current dependable capacity shortfall in a cost-effective manner by 2021. Forecast spending during 2017 and 2018 is on planning, preliminary engineering, environmental permitting, and the start of detailed design for this project."

- "Planning for the 20 MW Diesel Plant option for in-service by 2021 involves the following schedule and budget:
  - "2017: Completion of environmental and socio-economic baseline studies, stakeholder engagement and consultation, preliminary engineering and grid impact study ($0.75 million).
  - "2018: Stagegate 3 project review in the first quarter of 2018; subject to the project successfully passing the Stagegate 3 review, followed by the submission of a YESAB proposal, start of detailed design and procurement of long-lead equipment near end of year ($3.46 million).
  - "2019: Permitting, procurement and start of construction ($38 million).
  - "2020: Construction and commissioning ($20.1 million).

"In addition, the 2017 work plan for the Thermal Plant project will include a final review of all new fossil fuel thermal generation options as required for proceeding on a timely basis … One of the options to be considered will be a greenfield LNG option with third party gas supply; with LNG storage managed by others, it is possible this option could result in low enough CAPEX to enable use of natural gas in a greenfield facility.

"Specifically, the 2017 work will review options to refurbish the existing Whitehorse thermal plant as discussed in YEC's 2013/14 Part 3 Application and YUB hearing for the Diesel to Natural Gas Conversion Project (initial LNG Project)."

QUESTION:

a) Please confirm that no costs for the thermal plant project are forecast to be included in rates for the 2017 to 2018 test period. If not confirmed, please provide a detailed breakdown and explanation of the past actual costs and forecast costs from 2017 onwards for the thermal plant project.

b) With respect to the above, has YEC determined whether it will proceed with diesel or natural gas thermal generation capacity to address the current dependable capacity shortfall.

c) Please explain what YEC has learned from its review of the options to refurbish the existing Whitehorse thermal plant that informs its answer to (b).

ANSWER:

(a)

Confirmed.

(b) and **(c)**

At this time, YEC has not made any decision regarding the primary fuel of the potential thermal plant facility. Since completing the 2016 Resource Plan, YEC was made aware of the potential development of an LNG depot near Whitehorse. The availability of local LNG storage would enable the removal of the storage and processing facilities from the scope of a greenfield thermal plant. Consequently, it could make a new natural gas fired generating plant financially more attractive and bring its capital cost and Levelized Cost of Capacity close to that of a greenfield diesel plant. Part of the planned activities for 2017 and 2018 will assess the impact of removing the LNG storage and processing equipment from the scope of the plant and its impact on the business case.

There are two other options being studied for this new generation in conjunction with the LNG alternative above:

- A greenfield, diesel fired thermal plant at an alternate site within the City of Whitehorse; and

- YEC will further study the option of removing the two retired Mirrlees engines and a third engine nearing end of life, and replacing them with dual-fuel engines at its existing Whitehorse thermal plant. Since the original BBA study (2013) excluded certain aspects of the plant retrofit, the new study aims at updating and building upon the work completed in 2013 to reduce remaining uncertainties.

All options will be evaluated as part of YEC's Stagegate process where a decision whether to cease activities or to pursue a specific option for further development will be made.

TOPIC: **Demand Side Management, Section 5.3.1.5**

REFERENCE: Application, pages 5-39 to 5-41. PDF pages 210 to 212

QUOTE: "**inCharge Program Development and Delivery**

"Beginning in 2010, Yukon Energy, in partnership with AEY and in consultation with stakeholders, developed a Five Year Demand Side Management Plan for the Yukon (the Plan)."

"The programs … are very beneficial to the participants of the program and the utilities, who are the administrators of the programs."

"Yukon Energy plans to continue the delivery of the approved inCharge program for the test years. Funding as proposed for 2017 and 2018 reflects that AEY has chosen to discontinue partnership in program delivery resulting in YEC carrying the full cost of these programs.

"The net cost of conducting initial research into potential for electricity conservation programming, designing the DSM Plan, in consultation with stakeholders and delivering the inCharge program until the end of 2016 was $1.291 million. The costs for continuing delivery of the inCharge program in 2017 and 2018 are $0.190 million and $0.290 million for 2018.

"New Program Development

"The 2016 Resource Plan recommends that additional DSM programs are a cost effective way to meet energy and capacity demands and should be included in the proposed future portfolio of energy supply projects. These additional DSM programs must be designed prior to submission to the YUB for approval. To have sufficient Yukon-specific data to use in program design, YEC plans to develop residential and commercial customer end use surveys to be conducted by Yukon Bureau of Statistics."

"Using the End-Use Survey data, Capacity DSM Feasibility Study and updated CPR model, the next step will be to design a suite of new DSM programs to complement the existing inCharge program."

"The cost of new program development will be $0.190 million in 2018.

"Pilot DSM Projects

"The learnings from these pilots helped to lay the groundwork for the launch of the inCharge program and build capacity within Yukon Energy to administer DSM programs … Yukon Energy plans to continue to [contribute] to the Yukon Government's commercial lighting program in 2018."

QUESTION:

a) Please explain what subsidies are provided through YEC's DSM program and those provided by the Yukon Government DSM program. Is there an overlap between the two subsidy programs?

b) Please explain YEC's statement that "DSM programs are a cost effective way to meet energy and capacity demands." Does this statement apply to all YEC customers or to participants of the program?

c) Please provide YEC's rationale for its submission that DSM programs are beneficial to the participants of the program and the participating utilities.

d) Please explain how the benefit/cost ratios provided in figure 5.1 are calculated.

e) Please provide figure 5.1 in Excel format with all formulas intact.

f) Please provide a table outlining the annual expenditures (i.e. conducting initial research into potential for electricity conservation programming, designing the DSM Plan, in consultation with stakeholders and delivering the inCharge program) until the end of 2016. In the same table outline the costs included in the continuing delivery of the inCharge program for the test years.

g) With respect to new program development and considering YEC's experience, does YEC have any preliminary thoughts as to new programs that may be developed?

h) Please confirm that the cost of new program development is a deferred costs, which YEC will bring before the Board for approval in its next GRA. Is YEC willing to take the risk that expenses may be denied?

i) Please explain what YEC means when it states that it "plans to continue to contribute to the Yukon Government's commercial lighting program in 2018."

ANSWER:

(a)

The following subsidies are provided to homeowners by YEC's inCharge DSM Program:

- Up to $7 per bulb or lamp on ENERGY STAR® LED bulbs and lamps;
- Up to $10 on mechanical block heater timers; and
- A free energy saving kit that include two LED bulbs, one block heater timer and one smart power bar.

The following subsidies are provided to homeowners by the Yukon Government's Good Energy DSM Program:

- $100 to $250 on a home energy assessment;
- $50 per old refrigerator retired, as well as free pick-up and landfill tipping fees;
- $100 on ENERGY STAR® washers, refrigerators, freezers, dishwashers and ventless dryers;
- $300 to $1,500 on various energy efficiency home heating systems;
- Up to $1,200 on solar domestic hot water heating systems and $150 on drain water heat recovery systems;
- $65 on EPA WaterSense® toilets;
- $500 on Heat Recovery Ventilators;
- $100 on ENERGY STAR® Zone 3 windows and doors;

- Up to $2,000 for basic insulation upgrades and up to $10,000 for high performance insulation upgrades to homes;
- Up to $10,000 for super-insulated new homes; and
- A free energy saving kit that includes window film, a CFL bulb, a water saving showerhead, a bathroom faucet aerator, a fridge/freezer thermometer, kitchen faucet tap aerator, a shower timer, a hot water gauge, LED night light, Teflon tape for plumbing installations and weather stripping.

The following subsidies are provided to business owners by the Yukon Governments Commercial Energy Incentive Program:

- Up to $10,000 on LED lighting and lighting controls; and
- Up to $50,000 on thermal enclosure upgrades.

The Yukon Housing Corporation's Home Repair Loan program allows homeowners to borrow up to $50,000 at a low interest rate to improve the quality of their homes with energy efficiency upgrades being one of the eligible upgrades.

The only overlap in DSM program subsidies offered from YEC through inCharge and the Yukon Government is the inclusion of an energy efficient light bulb in both the Good Energy and inCharge free energy saving kits. In the design of the inCharge program, care was taken to ensure programs complimented already existing programs.

(b)

DSM programs reduce the amount of electricity customers use and/or shift the timing of when customers need power. Instead of delivering new electricity supply, DSM focuses on changing the demand for electricity as a way of ensuring that the utility is able to meet future load requirements, either replacing the need for, or deferring, the construction of new supply projects. In this way, all Yukon ratepayers benefit from avoiding higher cost new supply at the current time.

At the resource planning stage, to analyze if DSM programs are a cost effective way to help meet electrical and capacity needs, the cost of conserved energy and cost of peak reduction of DSM measures is compared to the levelized cost of energy and levelized cost of capacity of supply projects. During the program design process, the four industry best practice benefit-cost ratios are analyzed. This is a method of analyzing the balance of

benefits to costs from a DSM program for various stakeholder groups. In general, the Total Resource Cost (TRC) Test demonstrates the benefit, or detriment, of DSM to the cost of electricity in the service territory. The Participant Cost (PC) Test demonstrates the overall benefit, or detriment, to customers participating in the DSM program. These benefit-cost ratios are used as a design tool to design cost-effective programs.

(c)

The benefit-cost ratios calculated for the inCharge program and presented in Figure 5.1 of the 2017-2018 GRA are an industry best practice method of analyzing the balance of benefits to costs from a DSM program for various stakeholder groups. A ratio greater than 1.0 indicates a net benefit. The RIM and TRC both met this objective at 1.1 and 3.1 respectively. As well, the results of the Participant Cost (PC) ratio and Program Administer Cost (PAC) ratio results were 3.0 and 9.4 respectively, indicating that the inCharge program is beneficial to both participants and the utilities as program administrator.

(d)

The benefit/cost ratios are calculated using a proprietary, customized, mathematical model developed by ICF Marbek for the inCharge program. This model is a complex Excel based file that includes multiple project inputs and assumptions. The calculations of the individual benefit-cost tests for each measure originally proposed for the inCharge program was presented in Appendix D of the 2013 Demand Side Management Program Portfolio. The model incorporates individual measure calculations, such as a program uptake, and costs to generate the overall program benefit-cost ratios. ICF Marbek discussed the cost/benefit ratios, also referred to as cost-effectiveness tests, in section 1.2 of the 2013 Demand Side Management Program Portfolio as follows “The cost effectiveness results that are presented in this report are consistent with industry best practices and are based on the methods outlined in the California Standard Practice Manual. The four standard tests used were originally developed by the California Public Utilities Commission (CPUC) and defined by the California Standard Practice Manual.”

The cost-benefit analysis was reviewed and approved by an independent evaluation advisor, Econoler, as part of the 2015-2016 inCharge Evaluation Report. Please see YUB-YEC-1-80 Attachment 1.

(e)

As discussed in (d) above, Figure 5.1 was generated using a proprietary, customized, Excel based model developed by ICF Marbek for the inCharge program. As discussed in (d), the cost benefit analysis was reviewed and approved by an independent evaluation advisor, Econoler, as part of the 2015-2016 inCharge Evaluation Report.

(f)

Please See Table 1 below.[1]

Table 1: Annual DSM Expenditures: 2011 (Actual) to 2018 (Forecast)

	2011	2012	2013	2014	2015	2016	2017	2018
inCharge Program Development and Delivery	$ 427,188	$ 135,557	$ 91,337	$ 220,022	$ 157,453	$ 259,080	$ 190,000	$ 290,000
Industrial DSM	$ 23,766	$ 3,314	$ 48,847	$ 2,573	$ 1,608	$ 1,569		
Pilot DSM Projects	$ -	$ -	$ -	$ 8,155	$ 17,891	$ 24,806		$ 20,000
LED Streetlight Retrofits	$ 61,525	$ 11,897	$ 51,274	$ 12,701	$ 81,246	$ 91,130		$ 80,000
Internal Energy Conservation	$ 121,301	$ 58,748	$ 142,493	$ 18,950	$ 6,053	$ 5,905		$ 25,000
Administration		$ 70,503	$ 179,385	$ 93,349	$ 34,567	$ 19,680	$ 20,000	$ 20,000
New Program Development								$ 190,000

(g)

Yukon Energy has not completed any preliminary design of new programs. The Conservation Potential Review, which had key sections updated as part of the 2016 Resource Plan, will be used as the basis for identifying the potential savings and costs that can be achieved using DSM. As indicated in the Application (page 5-41 ll 3-5), YEC recognizes the challenges with capacity growth on the system; as part of program design, YEC will conduct the necessary studies to quantify what the conservation potential is and what programs could be introduced to achieve these savings.

(h)

Confirmed; similar to the program approved by the regulator as part of the AEY 2013/15 GRA, YEC would invest in program design in advance of review by the regulator. As described in the Application (page 5-43, line 15), Yukon Energy currently intends to file with the YUB in advance of program delivery.

[1] An error in the allocation of contributions was made. It was assumed that a contribution was used prior to 2013, however, it was used from 2011 to 2014. This correction has no impact to revenue requirements or rates.

(i)

Yukon Energy contributed to the Yukon Government's Energy Solutions Centre LED Lighting Upgrade for Commercial Buildings Rebate program in 2016. These contributions were not continued in 2017, however, YEC plans to continue contributions to the LED Lighting Upgrade program in 2018.

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CANADA

MEMORANDUM

To: Stephanie Whitehead, Energy Conservation Advisor, Yukon Energy Corporation

From: Marie Couture-Roy, Director – Program Evaluation, Econoler

Date: October 25, 2016

Subject: Approval of the 2015-2016 inCharge Evaluation Report

Econoler was retained by the Yukon Energy Corporation (YEC) to act as an independent evaluation advisor for the 2015-2016 evaluation of its DSM program portfolio. Econoler worked with the Energy Conservation team to deliver high-quality and high-level evaluation of industry standards for the inCharge program.

The scope of work of the assignment was to provide general advice and support for the evaluation, as well as to review the evaluation work plan, data collection instruments, cost-benefit analysis and savings calculations. At the end of this process, the 2015-2016 inCharge evaluation report was submitted to Econoler for review.

Ms. Marie Couture-Roy, team leader for this assignment, confirms that Econoler has reviewed and approved the final 2015-2016 inCharge evaluation report submitted on October 25, 2016.

Sincerely,

Marie Couture-Roy
Director – Program Evaluation
Econoler

TOPIC: **LED Streetlight Retrofits**

REFERENCE: **Application, page 5-42. PDF page 213, lines 10 to 16**

QUOTE: "In 2015, Yukon Energy decided to move forward with the retrofit of their streetlight assets with LEDs [light-emitting diodes]. A consultant was retained to develop a technical specification that was used in a competitive bidding process. Streetlights in downtown Dawson and Mayo were retrofit in 2016 with plans to retrofit the remaining streetlights in Faro, Mendenhall and Champagne in 2018.

"The net cost of piloting LED streetlights to 2016 is $0.142 million and the cost for retrofitting the streetlights in Dawson and Mayo with LEDs in 2016 was $0.168 million. The cost of completing the retrofits will be $0.080 million in 2018."

PREAMBLE: The Board in Board Order 2017-01 (page 57) set out the following:

> … the initial light asset cost was contributed by the customer when the light was originally installed in accordance with the approved Terms and Conditions of Service at the time. At the end of useful life when the asset needs replacement the customer is not required to contribute again and the cost becomes a system cost.
>
> 292. Accordingly, the Board directs that all capital costs associated with the end-of-life streetlight conversions be treated as a system cost.
>
> 293. With respect to LED streetlight installations that are not end-of-life conversions, the Board directs AEY to treat the costs related to new installations or requested conversions as capital costs that attract a full customer contribution in aid of construction. [footnotes omitted]

QUESTION:

a) With respect to the retrofit of streetlight assets with LED assets prior to their end-of-life, in consideration of the Board's findings in Board Order 2017-01, who should be bearing the costs of retrofitting the streetlights in Dawson and Mayo with LEDs? Please explain fully.

b) If assets are removed before their end-of-life, who should bear the costs of premature removal?

ANSWER:

(a) and **(b)**

With respect to YEC projects to replace streetlights in its franchise area, the utility intended to absorb any existing rate base costs for existing lamp fixtures. This decision was based on the assessment of the vintage of the streetlight asset pool as well as the relatively small size of this asset grouping relative to YEC's total portfolio. Based on a review of asset depreciation records, YEC determined that most of the streetlights in its fleet were at or near end of life. For example, with respect to Dawson, YEC estimated that the value of streetlight fixtures was <$1,000 in total (lamp head only, not including pole, wiring, civil works etc; approximately 200 lights in service). No further action was taken and the application essentially requests that the system pay for the installed cost of the replacement LED streetlights.

TOPIC: **Administration**

REFERENCE: Application, page 5-43. PDF page 214, lines 16 to 17

QUOTE: "Pursuant to the DSM [demand side management] Accounting Policy provided in Appendix 5.2, project related DSM costs are proposed to be closed out and amortized each year over a ten year period."

PREAMBLE: Per YEC's DSM Policy (Appendix 5.2), the Board notes YEC's assertion that the following DSM-related costs shall be expensed as incurred:

a. Administrative and other general overhead expenditures are expensed unless the expenditure can be directly attributed to a specific DSM program.
b. Expenditures related to information programs and advertising unless directly attributed to a specific DSM program.
c. Expenditures on training staff shall be expensed.

QUESTION:

a) Please explain YEC's rationale underpinning its proposal related to expensing DSM-related costs as they are incurred.

b) With respect to its proposal, please explain what opportunity is there for the Board and interveners to review these expenses and how will Board approval of these expenses be sought?

ANSWER:

(a) and **(b)**

Prior to any deferred costs being included in rates they will need to be reviewed by the Board and intervenors as part of a General Rate Application.

This policy addresses only the accounting treatment for DSM costs. Yukon Energy recognizes that in keeping with standard regulatory processes, it is required to file an application with the YUB any time it seeks to adjust rates due to changes in its revenue

requirement. Any DSM costs not previously approved by the Board to be included in rates would be subject to review by the Board and would need to be approved as part of YEC's revenue requirement before they could be included in rates.

TOPIC: **Resource Plan Update, Section 5.3.1.6**

REFERENCE: **Application, pages 5-43 to 5-44. PDF pages 214 to 215**

QUOTE: "In late 2005, Yukon Energy completed a 20-year Resource Plan for the years 2006-2025 and the Yukon Utilities Board recommended that YEC file an update to its resource plan within five years.

- "An update was undertaken in 2011 covering the period from 2011 to 2030."
- "A second update to the 20-Year Resource Plan was undertaken starting in 2015 and 2016 to address planning requirements for the period from 2016 to 2035."

"The 2016 Resource Plan update is forecast to cost $2.004 million and will be completed in 2017."

…

"The 2016 Resource Plan document is provided for references as Volume 2 of this filing (absent the Appendices). The 2016 Resource Plan Appendices are available on Yukon Energy's website at the following link: http://resourceplan.yukonenergy.ca/more/."

QUESTION:

(a) Please indicate if the 2016 Resource Plan update filed in this application is the complete update referred to in the above quote. If not, when does YEC expect to complete the update?

(b) What was the final cost of YEC's first update to the 20-Year Resource Plan?

(c) Please compare final costs of the second update with the first update and explain variances.

(d) Please summarize and explain significant findings of the second update which have arisen since YEC filed its first update, and explain the reasons for any variances which may have risen in respect to the following:

i.) Assessment of available resource options for analysis by assigning technical, financial, environmental and socio-economic attributes;

ii.) Development of a preferred resource portfolio for the short and long term as well as some contingency portfolio options;

iii.) Documentation of external risks and uncertainties and how they could impact preferred options;

iv.) Generation of a short-term (five-year), long-term (20-year) and contingency action plan for YEC to act upon in its resource planning activities.

(e) Please provide the 2016 Resource Plan Appendices which YEC refers to in the above quote.

ANSWER:

(a)

The 2016 Resource Plan update filed as volume 2 in this Application is the complete update.

(b)

The final cost of the 2011 Resource Plan update was $978,388 [see Tab 5, Table 5.3 which shows $740,164 closed in 2013 and amortized over five years; and Table 5.7 which shows $238,223 in WIP ($219,615 of this was in WIP at end of 2013) that was closed in 2017].

(c)

The 2016 Resource Plan update cost is approximately $2.0 million (Application, section 5.3.1.6), which compares with the 2011 Resource Plan update cost of approximately $1.0 million.

Each of these updates included updating grid load forecasts, updating estimates of system energy and capacity capability, and assessments of available resource options to address

relevant potential load scenario requirements. As reviewed in section 1.6.1.5 of the 2016 Resource Plan, the two updates used similar methodologies with the objective of minimizing the present value of all system expenditures while meeting energy and capacity planning criteria.

The 2016 Resource Plan update included several added features compared with the 2011 update, including:

- Established models were specifically applied to the Yukon for assessing load forecast scenarios, with development of more detailed assessments presented in separate appendices.

- A wide range of resource options were separately examined in a number of different consultant reports, presented in separate appendices. In many cases, options for a specific technology were examined for several different sites and also at many different scales of development, using standard methods for assessing levelized costs for energy and capacity.

- An industry-standard capacity expansion optimization model was used for the portfolio analysis of resource options and financial assessments of options which enabled evaluation of a much larger number of potential combinations (portfolios).
- A Social Cost of Carbon (SCC) was applied to the economics of resources.

- An environmental, social and economic evaluation was prepared for the full range of resource options and presented in a separate appendix report.

- The 2016 update included a more extensive public engagement process than had occurred with the 2011 update.

In comparing costs for the two updates it is noted that the 2011 update costs do not reflect the extensive separate and concurrent consultant assessments then carried out for a range of specific resource options (these separate study costs were reviewed during the 2012/13 YEC GRA); in contrast, scaled down versions of similar assessments were addressed in the costs directly reported for the 2016 update.

(d)

A detailed comparison of the 2011 and 2016 Resource Plans in terms of planning principles and methodology key input assumptions and conclusions and recommendations is discussed in Section 1.6 of the 2016 Resource Plan. Specifically, Section 1.6.3.1 documents the major findings of the 2016 Resource Plan and contrasts with the 2011 update. In summary, the findings are as follows:

- YEC currently needs new capacity to meet requirements under the N-1 criterion and without remedial measures the capacity shortfall is expected to increase each year. Given the lead time in constructing new resources, the expected electricity demand under all load cases is expected to exceed YECs generating capacity until the year 2021. The 2006 and 2011 Resource Plans each identified a need for new future resources, but neither of these resource plans faced the capacity shortfall immanency as that identified in the 2016 Resource Plan.

- The 2016 Load Forecast identified an expected long-term flat-line in peak demand and decline in energy load after about 2030. This trend was not identified in either the 2006 or 2011 Plans.

- Both the 2016 and 2011 Resource Plans identified industrial (specifically mining) electricity demand as a key uncertainty facing YEC, and that this potentiality was the primary theme of the load sensitivities/scenarios undertaken. One new mining load could increase YEC electricity demand by 25% or more.

- Both the 2016 and 2011 Resource Plans highlighted the need for flexibility within an uncertain future, particularly due to the continued need to consider potential new mine loads that would not be sustained to the end of the 20-year planning horizon.

- The 2016 Resource Plan recommended both Short and Long Term Action Plans, while the 2011 Resource Plan recommended Near Term and Longer Term resources planning.

To summarize, these findings were influenced by the added features noted in part (c) above as well as by other factors such as updates to existing unit capabilities and expected retirement dates [which would impact the dependable capacity requirements], load forecast updates and updated information regarding each of the resource options/ technologies considered. The following is specifically noted regarding specific features of the 2016 Resource Plan:

- **Load forecasting methodology -** The 2016 Resource Plan load forecast used a more sophisticated econometric approach that integrated demographic, economic, and technological trends. It also considered a broader range and scope of scenarios than the previous YEC Plan.

- **Resource portfolio analysis -** The 2016 Resource Plan portfolio analysis applied sophisticated optimization modeling to select the lowest cost resource solution, while meeting required planning criteria.

- **Engagement methodology -** The 2016 Resource Plan applied a broader, and more sophisticated public consultation approach, specifically enabled through the Electricity Values Survey.

- **Social Cost of Carbon -** The 2016 Resource Plan used the social cost of carbon in evaluation of resource options in the portfolio analysis.

- **Existing unit capabilities -** Updates to existing unit capabilities and expected retirement dates were made in the 2016 Resource Plan to reflect current information.

(e)

The Resource Plan Appendices are available on Yukon Energy's website at the link below.
http://resourceplan.yukonenergy.ca/more

Links to specific appendices are as follows:

Appendix 3.1 – Electricity Values Survey Report
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_3.1_Electricity_Values_Survey.pdf

Appendix 3.2. Communication Methods and Materials
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_3.2_Public_Engagement_Methods_and_Materials.pdf

Energy and Peak Demand Forecast 2016-2035
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.1_-_Energy_and_Peak_Demand_Forecast_Data_2016-2035.pdf

Appendix 4.2 Yukon Macroeconomic Model 2016-2035
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.2_-_Yukon_Macroeconomic_Model.pdf

Appendix 4.3 Long Term Load and Demand Forecast 2016-2035
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.3_Long_Term_Load_and_Demand_Forecast_2016-2035.pdf

Appendix 4.4 Industrial Energy and Peak Demand Forecast 2016-2035
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.4_Industrial_Energy_and_Peak_Demand_Forecast_2016-2035.pdf

Appendix 4.5 Electric Vehicle Investigation
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.5_Electric_Vehicle_Investigation.pdf

Appendix 4.6 Home Heating Retrofit Business Case Study
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.6_Home_Heating_Retrofit_Business_Case.pdf

Appendix 4.7 Mirrlees Assessment Report
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.7_Mirrlees_Assessment_Report.pdf

Appendix 4.8 Generation Adequacy Evaluation (Karki, 2017)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.8_Generation_Adequacy_Evaluation.pdf

Appendix 5.1 Greenhouse Gas Emission Life Cycle Assessment of Resource Options (ArcticCan Energy Services 2016)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.1_Greenhouse_Gas_Emission_Life_Cycle_Assessment_of_Resource_Options_(ArcticCan_Energy_Services_2016).pdf

Appendix 5.2 Environmental, Social and Economic Attribute Evaluation of Resource Options (InterGroup, EDI, Ecofor and CNC 2016)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.2_Environmental__Social_and_Economic_Attribute_Evaluation_of_Resource_Options_(Intergroup_et_al._2016).pdf

Appendix 5.3 Southern Lakes Enhanced Storage Concept Studies
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.3_Southern_Lakes_Concept_Project_Proposal.pdf

Appendix 5.4 Mayo Lake Enhanced Storage Concept Project Proposal
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.4_Mayo_Lake_Enhanced_Storage_Project.pdf

Appendix 5.5 Aishihik Turbines Uprate Study (KGS 2016)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.5_Aishihik_Turbines_Uprate_Study_(KGS_2016).pdf

Mayo Hydro (MH0) Future Facility Options Concept Design Report FINAL – REV 0 KGS 16-1404-002 August 2016
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.6_Mayo_Hydro_Future_Facility_Options_Report_(KGS_2016).pdf

Appendix 5.7 Small Hydro Screening Assessment (Knight Piesold 2016)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.7_Small_Hydro_Screening_Assessment_(Knight_Piesold_2016).pdf

Appendix 5.8 Atlin Hydro Expansion Study
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.8_Atlin_Hydro_Expansion_Study_(Morrison_Hershfield_2016).pdf

Appendix 5.9 Wind Site Inventory (CBER, Envint and V3 Energy 2016)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.9_Wind_Site_Inventory_(CBER__Envint_and_V3_Energy_2016).pdf

Appendix 5.10 Geothermal Review and Site Inventory (KGS 2016)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.10_Geothermal_Review_and_Site_Inventory_(KGS_2016).pdf

Appendix 5.11 Solar Site Inventory (Solvest 2016)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.11_Solar_Site_Inventory_(Solvest_2016).pdf

Appendix 5.12 Final FEED Report Front End Engineering Design (FEED) Study Yukon Bioenergy Demonstration Project in Haines Junction, Yukon
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.12_Biomass_Front_End_Engineering_Design_Study_(Stantec_2016).pdf

Appendix 5.13 Biogas Feasibility Study (WSP 2016)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.13_Biogas_Feasibility_Study_(WSP_2016).pdf

Appendix 5.14 Waste-to-Energy Design Basis and Business Case Analysis (Morrison Hershfield 2012)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.14_Waste-to-Energy_Design_Basis_and_Business_Case_Analysis_(Morrison_Hershfield_2012).pdf

Appendix 5.15 Thermal Energy Plan Development Study (Stantec 2016)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.15_Thermal_Energy_Plan_Development_Study_(Stantec_2016).pdf

Appendix 5.16 Pumped Storage Assessment (Knight Piesold 2016)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.16_Pumped_Storage_Assessment_(Knight_Piesold_2016).pdf

Appendix 5.17 Moon Lake Pumped Storage Conceptual Study Report (Midgard 2015)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.17_Moon_Lake_Pumped_Storage_Conceptual_Study_Report_(Midgard_2015).pdf

Appendix 5.18 Faro Mine Pumped Storage Conceptual Assessment (EMC2 and Picacho and Associates 2015)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.18_Faro_Mine_Pumped_Storage_Conceptual_Assessment_(EMC2_and_Picacho_and_Associates_2015).pdf

Appendix 5.19 Evaluation of Energy Storage Technologies (Transgrid Solutions 2016)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.19_Evaluation_of_Energy_Storage_Technologies_(Transgrid_Solutions_2016).pdf

Appendix 5.20 Updates to Yukon Electricity Conservation and Demand Management Potential Review (ICF 2016)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.20_Updates_to_Yukon_Electricity_Conservation_and_Demand_Management_Potential_Review_(ICF_2016).pdf

Appendix 5.21 Transmission Options Evaluation (Midgard 2016)
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.21_Transmission_Options_Evaluation_(Midgard_2016).pdf

Appendix 6.1 Liquefied Natural Gas: Potential Supply Options
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_6.1_Fuel_Price_Forecast.pdf

Appendix 6.2 Social Cost of Carbon
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_6.2_Social_Cost_of_Carbon.pdf

Appendix 8.1 Portfolio Analysis Data
http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_8.1_Portfolio_Analysis_Data.pdf

TOPIC: **Marsh Lake Storage, Section 5.3.1.8**

REFERENCE: Application, pages 5-46 to 5-47. PDF pages 217 to 218

QUOTE: "The Marsh Lake Storage Project (recently renamed the Southern Lakes Enhanced Storage Project, or SLESP) is a means of enhancing winter energy at the Whitehorse Rapids generating station to displace higher cost thermal generation that would otherwise be required. As reviewed in the 2012/13 GRA …"

"In Order 2013-01, the Board found that Marsh Lake Storage was currently a viable project, and as such, all Marsh Lake-related project costs were to be held in WIP, until the project was completed. The Board noted that YEC was to cease work on the project if and when YEC concludes that there is no net economic benefit of the project to ratepayers.

"Work completed since the 2012/2013 GRA includes technical studies and assessments, engagement and consultation with various stakeholders, and extensive meetings with property owners that will be directly impacted by the project… The next major milestone is obtaining First Nations support for the project in order to progress to the YESAB assessment stage. Without such support the project will be cancelled … It is expected that a decision to proceed to the YESAB assessment phase will be made at a Stagegate 3 project review planned for the 4th quarter of 2017.

"The deferred cost forecasts in the Application assume that the project continues, with spending in WIP increasing from $6.517 million at the end of 2015 to $8.156 million by the end of 2018. Potential in-service for this project in 2022 is provided in the 2016 Resource Plan."

QUESTION:

a) Please provide a detailed breakdown and explanation of the actual costs to date and forecast costs for the Marsh Lake Storage project (renamed Southern Lakes Enhanced Storage Project). Please provide variance explanations for costs that have diverged from forecast.

b) With respect to (a), please indicate at what stage of the project are First Nations' approvals sought? Please provide a detailed explanation.

c) From an economics perspective, does YEC have a stop point for this project? Please explain.

ANSWER:

(a)

Table 1 below shows a summary of Southern Lakes Enhanced Storage Project (SLESP) costs to date and currently forecast costs to complete the project.

Costs to date for the project have included expenditures on baseline environmental and socio-economic studies necessary to support an effects assessment and the development of mitigation for identified significant adverse project effects. Early planning and engagement identified valued environmental and socio-economic components in a very large project study area. Prior to undertaking planning of the Project, very little comprehensive data regarding the identified valued components of the physical and human environment along the roughly 1,000 km of study area shoreline had been collected and compiled.

The fact that the Southern Lakes and the Yukon River are relatively densely developed required intensive studies of the shore and subsurface along the perimeter of these watercourses. Complementary public and property owner engagement was also conducted in a highly intensive and repetitive fashion throughout the planning to date. It is the latter aspect of planning that has demanded much of the further technical investigation and examination of the potential effects of the project following the initial years of study. The level of effort and time necessary to undertake engagement and consultation expected by stakeholders and governments as part of the planning was not

anticipated. Resource expenditures related to both technical and non-technical engagement and consultation exceed $1M and are mostly related to the human resources necessary to reach the large number of organizations and individuals involved and to respond to their concerns. While project planning outcomes are expected to be better for it, overall it is the extra time and resource use related to stakeholder engagement that have driven up the planning portion of the project costs from early planning cycle estimates.

Regarding the forecasts costs to implement the project, early predictions of the extent of sensitive shorelines that would require protection has increased. In addition, engineering concepts have been influenced by public and regulatory engagement activities. Finally, costs estimates made when the project planning first began have increased due to inflation over the 8-year planning period.

Table 1: Summary of Southern Lakes Enhanced Storage Project Planning and Implementation Costs

Cost Centre	Costs to Date	Forecast Remaining Costs	Total Forecast Costs	2012 GRA Forecast	Variance
Effects Assessment (Baseline Studies, Analysis, Engineering, Engagement & Consultation)	$6,799,235	$1,151,000	$7,950,235	$4,950,000	$3,000,235
YESAA Assessment & Permitting	$0	$300,000	$300,000	$300,000	$0
Mitigation Implementation	$0	$7,126,830	$7,126,830	$5,250,000	$1,876,830
Total	$6,799,235	$8,577,830	$15,377,065	$10,500,000	$4,877,065

(b) and **(c)**

As noted in Tab 5, Section 5.3.1.8, the next major milestone for this project is obtaining First Nations support; and this milestone is to be achieved in order for the project to progress to the YESAB assessment stage. It is expected that a decision to proceed to the YESAB assessment phase will be made at a Stagegate 3 project review planned for the 4th quarter of 2017. As noted in Tab 5, if this is not achieved the project would be cancelled.

Once the above milestone is achieved, all project authorizations would be formally sought following the conclusion of a project assessment pursuant to the Yukon Environmental & Socio-economic Assessment Act and the subsequent issuance of Decision Documents from the assessment Decision Bodies.

The Kwanlin Dun First Nation (KDFN) and Carcross/Tagish First Nations (C/TFN) both have low-lying settlement lands along the Southern Lakes that currently experience inundation during both the regulated and unregulated periods of the year. Inundation of settlement land during the regulated period is allowed under the current water use licence and recognized as an encumbering right duly considered during the development and settling of the comprehensive land claim and self-government agreements with both the KDFN and C/TFN.

With the SLESP the duration and extent of this inundation would increase and an authorization for this land use is required from the aforementioned First Nations. Applications for those land use authorizations will follow the format as set out by each First Nation at the time.

Going forward, after the planned Stagegate 3 project review, decision-making at each Stagegate would consider planning costs to date along with those forecast to complete the remaining planning, assessment, permitting, and construction of the Project. Future stagegates would consider whether the results of power benefit and economic analyses predict levelized cost of energy greater than that of the next comparable firm (renewable) energy/capacity project.

TOPIC: **Mayo Lake Storage, Section 5.3.1.9**

REFERENCE: Application, pages 5-47 to 5-49. PDF pages 218 to 220

QUOTE: "The Mayo Lake Enhanced Storage Project (MLESP) will amend the Mayo Generation Station Water Use Licence to provide for up to one metre of additional draw down of Mayo Lake…"

"… a recent study by external engineers ha[s] shown that sediment in the Mayo Lake outlet channel is constraining water flow through the channel … and preventing any benefit from being realized by the MLESP …"

"The MLESP proposal was submitted to the YESAA [Yukon Environmental and Socio-economic Assessment Act] Designated Office in August 2015 (noting that a Mayo Outlet Dredging Project would be pursued separately in the future), with provision for the full one metre of added drawdown after an initial 0.5 metre drawdown and subject to adaptive management provisions that was co-developed, and would be implemented, with the First Nation of Na-Cho Nyak Dun. The YESAA Designated Office suggested that review of the MLESP be grouped with an unrelated YG project proposed for the lower Mayo River, and also required that the Mayo Lake Outlet Dredging Project be included in the MLESP review as an accessory project. In order to let the YG proposal move forward in a timely way the Yukon Energy MLESP proposal was withdrawn, on the understanding that it would be resubmitted at a later time with additional information regarding the Mayo Lake Outlet Dredging Project.

"Project spending during 2016 includes environmental monitoring and phase 1 of the dredging work, a desktop analysis. Environmental monitoring makes up the majority of the 2017 costs and will continue through 2018. Phase 2 of the dredging work, detailed modelling and design, will take place during 2018. Once phase 2 of the dredging work is complete, YEC will have a much better estimate of the total costs to complete the project."

> "The deferred cost forecasts spending in WIP increasing from $2.406 million at the end of 2016 to $3.356 million by the end of 2018. Potential in-service for this project in 2022 is provided in the 2016 Resource Plan." [footnote omitted]

QUESTION:

a) Has YEC resubmitted the Mayo Lake storage project (renamed Mayo Lake Enhanced Storage Project), including the Mayo Lake Outlet Dredging Project to YESAA Designated Office?

b) Please explain what environmental monitoring spending includes and how this might influence project costs.

c) Please explain what phase 1 and phase 2 of the dredging work include and the related costs.

d) Has YEC commenced discussions with the First Nation of Na-Cho Nyak Dun with respect to the full one metre of added drawdown? Please explain.

e) For each of the years 2016 to 2018, please provide a table that includes a breakdown and explanation of the cost totals for each year.

ANSWER:

(a)

No.

(b)

The Mayo Lake Enhanced Storage Project (MLESP) proposal includes a detailed monitoring and adaptive management plan (MAMP) co-developed with the First Nation of Na-Cho Nyak Dun. This plan requires the collection of pre-project baseline data regarding specific ecosystem components for the purposes of post-project confirmation of effect predictions, mitigation effectiveness, and potential management response requirements. The required environmental monitoring has been minimized to only those key data

necessary to maintain a suitable pre-project baseline for future use under the MAMP should the project proceed. The program currently includes annual juvenile fish surveys designed to assess spawning and overwintering success of Lake Whitefish and Lake Trout, and maintenance of a basic weather station

(c)

The Mayo Lake Outlet Channel Erosion, Sedimentation, and Dredging Study included a series of initial tasks (Phase I), which were deemed necessary in order to move to a subsequent erosion/sediment transport modeling stage (Phase II) where the key project concerns respecting whether an efficient, effective, and reasonably long-lasting dredging design can be developed and at what cost.

Phase I included a review of the existing related studies, as well as a proposed plan on appropriate methodology to address the outstanding project concerns/uncertainties (how, where, how much to dredge). Specific tasks of Phase 1 included:

- Review of available operational and project research information
- Analysis and provision of opinion on sediment sources and sedimentation rates
- Identifying potential data gaps
- Proposing dredging alternative improvements in Phase II
- Developing Scope, Budget and Schedule for Phase II
- Phase I Report Preparation

Phase II has yet to be executed, but would involve the following tasks:

- Data Collection, Review, and Interpretation
    - Sub-Aerial Mapping
    - Site Exploration
    - Sub-Aqueous Exploration
    - Sediment Core Dating
    - Additional Channel Surveying
- Lake Sediment Transport Modelling
- Fluvial Sediment Transport Modelling in Outlet Channel
- Dredging Approach and Conceptual Level Design
- Regulatory and Contractor Engagement
- Phase II Report Preparation

The cost for Phase I was $92,590 and the estimated cost to compete Phase II is $670,000.

(d)

Yes. Discussions with the First Nation of Na-Cho Nyak Dun (NND) regarding the Enhanced Storage Project (including the full one metre drawdown) have been ongoing since 2008. A project steering committee and technical working group were established early in the planning process to collaborate on the project planning and design. Numerous engagement activities have also been undertaken with the NND Government personnel and citizens. The Project Proposal that was submitted to YESAB was reviewed by NND prior to it being finalized and the Project Mitigation, Monitoring, and Adaptive Management Plans were developed in cooperation with the NND Government.

(e)

Table 1 below shows the MLESP actual and forecast costs per activities. The costs for 2017 and 2018 are forecast

Table 1. Summary of Annual Costs – Mayo Lake Enhanced Storage Project

Cost Centre	Year		
	2016	Forecast 2017	Forecast 2018
Environmental Baseline Maintenance	$137,579	$45,000	$45,000
Phase I - Erosion, Sedimentation, & Dredging Study	$92,590	$0	$0
Phase II Dredging - Erosion, Sedimentation, & Dredging Study	$0	$0	$670,000
Assessment and Permitting	$0	$0	$50,000
YEC Labour	$6,414	$5,000	$15,000
AFUDC	$48,459	$50,000	$70,000
Total	$285,042	$100,000	$850,000

TOPIC: **Projects between $100,000 and $1 Million, Section 5.3.2, Appendix 5.4**

REFERENCE: Application, Tab 5, page 5-49. PDF page 220

QUOTE: "The projected total 2017 and 2018 spending in deferred cost activities excluding major projects over $1 million (as described in Section 5.3.1) totals approximately $2.2 million in 2017 ($0.7 million in closed projects), as set out in detail in Table 5.7, and a total of approximately $2.9 million for 2018 ($1.5 million in closed projects for 2018 spending and $0.7 million in closed projects from 2017 spending) as set out in detail in Table 5.8. Total increase to rate base from deferred cost activities excluding major projects over $1 million, but including transfers from WIP spending prior to 2017, is $4.9 million in 2017 and $3.3 million in 2018."

PREAMBLE: The Board requires further information regarding the following projects:

Project	Prior to 2017	Forecast 2017	Forecast 2018
Development of Asset Management Program1		**$200,000**	**$150,000**
Time of Use Rate Structure and Smart Grid2		**$100,000**	
Mt Sumanik Wind Feasibility Study3	**$540,280**	**$50,000**	**$250,000**
Northern Diesel Plant4			**$100,000**
Whitehorse Hydro Uprate5			**$450,000**
Small Hydro6			**$625,000**

Source: Application, Appendix 5.4. PDF pages 257 to 259

[1] Application, Appendix 5.4 PDF page 257
[2] Application, Appendix 5.4 PDF page 258
[3] Application, Appendix 5.4 PDF page 258
[4] Application, Appendix 5.4 PDF page 258
[5] Application, Appendix 5.4 PDF page 259
[6] Application, Appendix 5.4 PDF page 259

QUESTION:

a) With respect to YEC's proposed asset management program, please explain what does YEC mean when it states that an "asset management methodology or plan …" will "… systematically assess major asset groups … and manage the planning of investments to meet overall corporate goals."[7]

i.) Please explain what YEC is doing presently to manage its assets. Will customers see offsetting operating and management savings? Please provide a detailed explanation.

ii.) Please explain whether or not the asset management program is a one-time project or if it will be ongoing.

iii.) If the asset management program is intended to be an ongoing project, please explain why YEC has included it in capital costs instead of as an operating cost.

b) Do customers throughout the Yukon have the necessary infrastructure in place (i.e. meters, etc.) to allow for a time of use rate structure? Please explain.

c) Please provide the results of the planning studies for potential wind farm sites throughout the Yukon. Please provide the capacity factor(s) of current wind facilities in the Yukon. Please fully explain what the test year expenditures relate to.

d) Respecting YEC's northern diesel plant initiative, has YEC investigated any alternatives other than relocation to mitigate issues related to plant noise and flood risk at the current locations? If not, please explain why it has not done so. If yes, please provide the results of the investigations.

e) Please provide further details regarding the $450,000 that is to be spent in 2018 related for the Whitehorse Hydro uprate project. Is an outside agency/consultant performing the investigation? For this project, please explain why is it necessary to select an owner's engineer to represent YEC throughout the project. Please explain the financial benefits realized on previous uprate projects.

[7] Application, Appendix 5.4, page 5.4-2. PDF page 257.

f) Relative to the small hydro project, please provide a breakdown of the $625,000 total cost forecast. Please provide a full explanation of what geotechnical investigations are and how they might influence the project. Considering that the small hydro resource option is at a pre-feasibility stage, will a third party consultant be undertaking further studies to confirm site selection and project need? Please explain.

ANSWER:

(a)

(i)

Current asset management methodology at YEC consists of a combination of internal and external reviews. Internally, all staff are encouraged to take note of equipment issues for follow up to ensure issues are addressed. Externally, YEC has commissioned a number of asset assessment projects over the last several years to build an inventory of asset conditions for key asset classes. The recommendations from these reports are transferred into a checklist of prioritized actions that can then be budgeted and addressed in an orderly manner. This is still an ad hoc system with reliance on manual spreadsheets to track recommendations and limited ability to cross reference these sheets to other relevant data (e.g. maintenance schedules, test results, historical costs). The goal of the AMP is to integrate these different information sources into an asset health index that will allow YEC more complete information for capital planning.

(ii) and (iii)

The costs referenced in the Application are on-time expenditures related to the development of an asset management program. Once developed the program will provide value over a number of future years and therefore is treated as a capital project.

(b)

No. Smart meters are critical infrastructure to properly implement time-of-use rate programs.

Please also see response to John Maissan-YEC-1-34(a).

(c)

Please see the 2016 Resource Plan Appendix 5.9 – Wind Site Inventory publicly available at link below.

http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.9_Wind_Site_Inventory_(CBER__Envint_and_V3_Energy_2016).pdf

Capacity factors for current YEC wind generation are 11% for 2015 and 9% for 2016.

Test year spending includes continued monitoring in 2017 and the completion of a feasibility study in 2018.

(d)

The test year spending does not include physically moving the plants, only studying the various options. The study will investigate alternatives to moving the plants, other mitigation options to address noise and flood risk, and potential uses for the space if the plant(s) are moved.

(e)

The 2016 Resource Plan update identified hydro turbine uprates as an economical solution for capacity and energy. The 2018 spending will hire an owner's engineer to conduct preliminary design work and assist YEC with permitting activities. The external engineer is required because uprate studies are a specialized skillset that YEC does not employ internally. YEC has never previously completed a specific hydro uprate project.

(f)

Table 1 provides a breakdown of the 2018 spending for the small hydro project:

Table 1: Small Hydro Project 2018 Forecast Spending

Stakeholder consultation	$100,000
Environmental and geotechnical	$500,000
Water gauging	$25,000

Geotechnical investigations involve analyzing the properties of the soil and rock at a given site to determine such things as location and extent of permafrost, distance to bedrock, or the competency of rock. This information will be used to determine if the project is feasible and will influence the detailed design of the structure.

The potential need for this project was established by the resource plan process. A third party consultant will undertake the necessary studies to confirm the site selection and project economics in order for YEC to make an informed decision at the appropriate stage gate.

TOPIC:

REFERENCE: Application, Tab 5, Appendix 5.3

PREAMBLE: The Board requires further information in respect to the following projects:

Project	Prior to 2017	Forecast 2017	Forecast 2018
Aishihik Generator Fire Protection[1]			$125,000
Whitehorse Local HMI/Historian Upgrade[2]		$180,000	
Dawson P158 T1/T2 Transformer[3]			$200,000
Transmission System Protection Upgrades[4]		$100,000	
Critical Spares – System Requirement[5]	$200,000	$100,000	$100,000
Mayo Transient Trailer Unit[6]			$250,000
Stewart-Minto Local SCADA[7]			$165,000

QUESTION:

a) Is there a link between the "Aishihik Generator Fire Protection" project and the previous "AHO Deluge System" project?

[1] Application, Appendix 5.3, PDF page 245
[2] Application, Appendix 5.3, PDF page 247
[3] Application, Appendix 5.3, PDF page 249
[4] Application, Appendix 5.3, PDF page 250
[5] Application, Appendix 5.3, PDF page 252
[6] Application, Appendix 5.3, PDF page 253
[7] Application, Appendix 5.3, PDF page 253

b) Please explain the benefits accruing to customers from the "Whitehorse Local HMI/Historian Upgrade" project.

c) Is the Dawson P158 T1/T2 transformer connected to the Mayo to Dawson project?

d) Please explain how a tripping scheme for L178 will eliminate grid separation by faults on L178.

e) Please provide the prioritized list of the components (generation, transmission, and communications equipment) that are to be purchased during the test period.

f) Are there any carrying costs associated with the "Mayo Transient Trailer Unit" project? Please explain.

g) With respect to the Stewart-Minto Local SCADA project, please provide the key performance indicator improvements and an explanation of the benefits will accrue to YEC's customers from this project?

ANSWER:

(a)

Yes. The AHO Deluge System project was the preliminary design report that assessed different suppression agent options and costs.

(b)

The current HMI has been deemed end of life and must be replaced. The addition of a local historian to the plant will benefit customers by providing faster outage analysis (resulting in faster restoration), labour cost savings during troubleshooting, and lower asset maintenance costs due to better planning.

(c)

Yes.

(d)

YEC currently has protection relays at Takhini, Minto Landing, and Faro substations. By using these existing relays to detect a fault on L178 and communicate via powerline carrier, a transfer trip can be issued to the existing circuit switcher at the Carmacks Airport substation. This would result in L178 (east of Carmacks) becoming isolated while maintaining the grid connection north and south of Carmacks.

(e)

Please see Table 1 below.

Table 1: Prioritized List of the Components

Description	Estimate
2017 Spending	
seal repair kit for Mayo B	$ 22,200.00
slip rings for WH4	$ 35,000.00
brush holder fo AH1&2	$ 12,000.00
hydro governor parts for Mayo B, WH3,WH4, AH3	$ 30,000.00
	$ 99,200.00
2018 Spending	
lift pumps for hydro bearing lubrication - MH	$ 15,000.00
lift pumps for hydro bearing lubrication - AH	$ 15,000.00
lift pumps for hydro bearing lubrication - WH	$ 15,000.00
sliprings AH1&2	$ 30,000.00
brush holders for AH3	$ 5,000.00
various PLC parts - Mayo	$ 12,500.00
various PLC parts - Whitehorse	$ 3,000.00
HMI	$ 5,000.00
	$ 100,500.00

(f)

Annual carrying costs are estimated between $6,000 and $8,000 and include electricity, heat, water delivery, snow removal, and routine maintenance.

(g)

YEC customers will benefit from increased reliability due to easier protection setting modifications and faster outage restoration due to enhanced substation control by SCC. Travel time will decrease as diagnostic work will be able to be performed remotely, resulting in increased labour efficiency.