YUKON ENERGY CORPORATION

2021 GENERAL RATE APPLICATION
ROUND 1 INTERROGATORY RESPONSES FILED

March 4, 2021

City of Whitehorse
(CW)

TOPIC: **Peak Load**

REFERENCE: **2021 General Rate Application, Table 2.2**

PREAMBLE: On line 29, YEC indicates the integrated system peak.

QUESTION:

a) Please provide the peaks for each of (i) Wholesale, (ii) Industrial, and (iii) the balance of the YEC system for each of 2018 Approved, 2018 Actual, 2019 Actual, 2020 Forecast and Forecast 2021.

b) Please provide the reason for changes in peak demands for each of the years in each of (i) Wholesale, (ii) Industrial, and (iii) the balance of the YEC system.

c) Please fully explain the impact of changes in peak demand on required capital investment.

ANSWER:

(a) and **(b)**

Table 1 provides the non-industrial and the industrial peaks for 2018/19 to 2021/22 winters – additional splits requested are not readily available.

Table 1: Non-Industrial and Industrial Peak (kW)

	2018/19 Forecast*	**2018/2019 Actual**	**2019/20 Actual**	**2020/21 Forecast**	**2021/22 Forecast****
Non-Industrial	86,400	89,040	97,651	100,653	104,102
Industrial	6,500	1,900	6,200	12,035	9,262
Total	**92,900***	**90,940**	**103,851**	**112,689**	**113,364****

*No specific 2018/19 winter peak was "approved'. The forecast shown was provided for 2018 in the 2017-18 GRA.

** This winter peak is expected in 2022, i.e., beyond the 2021 test year.

Peak demand is subject to a variety of external factors, including weather, population, and saturation of electric heating. The peak record in 2019/20 reflected cold weather in particular.

(c)

Yukon's isolated grid must self-supply all its own capacity and energy, including securing reserve capacity in order to meet grid loads during winter peak periods, as it has no access to any external North American power grid to secure extra power when it is needed, or to sell surplus renewable generation when it occurs.

Seasonal generation constraints also present additional challenges to the Yukon Integrated System (YIS). Electricity demand on the YIS is highly variable with seasonal mismatch between the timing of maximum available electricity production from renewable generation (which peaks in the summer months) and maximum customer demand (which peaks during a cold period during winter months). The result is surplus renewable generation during summer (which cannot be used or sold to other jurisdictions) and reliance on thermal generation to supply peak load requirements during winter.

Yukon Energy's generation capacity planning criterion for the YIS is based on the single contingency (N-1) dependable capacity criterion, under which the YIS is required to have enough dependable capacity to supply the forecast non-industrial peak winter demand (i.e., excluding major industrial demand) under the largest single contingency.[1] Inability to supply the non-industrial peak winter demand, which is expected to occur during a period of the coldest winter temperatures, presents an obvious and acute risk to human health and safety and public and private infrastructure. Therefore, YEC's planning, including capital planning must include measures that address capacity shortfalls under capacity planning criteria.

As noted in the Application non-industrial peak load has increased from 86.4 MW in the 2018 GRA forecast to 100.7 MW forecast for 2021 (14 MW increase), accounting for most of the 17 MW growth in the N-1 dependable capacity shortfall. Diesel rental unit costs of approximately $3.8 million are forecast for the diesel rental units expected to be required for the 2021 GRA test year, Yukon Energy's ongoing capital program costs include infrastructure to accommodate the rented diesels as well as work to address longer term solutions (e.g., battery energy storage system [BESS], diesel replacement at various grid

[1] YEC also uses Loss of Load Expectation (LOLE) as system capacity planning criteria where the system is planned not to exceed a LOLE of 2 hours/year. The LOLE criterion includes industrial loads as part of the assessment. At the forecast industrial load, however, the LOLE criterion was satisfied in the test year so long as the single contingency, N-1, criterion was met.

locations, Atlin Hydro Expansion Project, and the potential development of pumped storage at Moon Lake).

TOPIC: **Sales**

REFERENCE: **2021 General Rate Application, Table 2.2**

PREAMBLE: YEC provides Actual Sales. CW requires normalized data as well.

QUESTION:

a) Please provide an updated Table 2.1, with sales, sales per customer, revenues, and cents per KWh normalized for weather.

b) Please provide the working papers that were used to do the weather normalization, and the supporting analysis and data.

ANSWER:

(a) and **(b)**

YEC does not prepare weather normalized version of its actual sales to retail and industrial customers. Therefore, YEC is unable to provide updated version of Table 2.1 as requested.

TOPIC: **Sales Forecasts – Wholesale Sales to ATCO Electric Yukon (AEY)**

REFERENCE: **2021 General Rate Application, page 2-5 (PDF page 30 of 441)**

PREAMBLE: YEC discusses its determination of its forecast sales to AEY on page 30.

QUESTION:

a) On lines 15-16, YEC discusses the AEY Fish Lake Generation Facility (AEY Facility). Please provide the maximum capacity of the AEY Facility, and the annual production, on a normalized and actual basis for 2018 and 2019.

b) Please fully explain how the AEY Facility is used in providing service. Is it the first resource that is engaged, or does it only provide peak supply?

c) On lines 18-19 YEC discusses multi-variate regression assessments of wholesale changes at normal weather conditions. Please provide the multi-variate analysis in Excel format. In the response, please also provide the source of all supporting data.

d) Please provide the calculation of normal weather.

e) On lines 19-20, YEC discusses Micro Generation. CW also notes footnote 4. Please provide:
   i. The detailed analysis of the source of the 1.5 GWh forecast for 2021.
   ii. The impact of the AEY Facility on peak demand.

ANSWER:

(a) and **(b)**

YEC does not have information such as the maximum capacity, weather normalized generation, or operation regarding AEY's Fish Lake facility nor does YEC have operational control of this plant. AEY will be in an better position to provide a response to these questions.

YEC receives Fish Lake's annual generation information from AEY for forecasting purposes as well as for the purposes of determination of LWRF and ERA. As noted in the Application [page 2-5], the actual generation from Fish Lake was at about 5.5 GW.h for 2018 and about 5.0 GW.h for 2019; the forecast for 2021 is 3.6 GWh.

(c)

Please see Attachment 1 to this response.

(d)

Please see response to YUB-YEC-1-16 (a).

(e)

(i)

The micro-generation program forecast for total delivered energy was provided by Yukon government. The actual 2020 program total is embedded in historical sales and is included in the regressed forecasted load. Therefore, only the 2021 incremental program total of 1.5 GWh has been used to reduce the 2021 load. No adjustment are made to the peak forecast related to microgen as solar installations do not provide energy during peak winter hours. Please see YUB-YEC-1-13 for the information provided by Yukon government.

(ii)

The AEY Fish Lake facility impact on peak is included in the historical actuals which are subsequently accounted for via the regression analysis used to forecast peak load.

Year	Month	Avg. Temp.	HDD 13	CDD 13	Days with Avg. Temp < -20 oC	Commercial Count	January Dummy	July Dummy	December Dummy	Darkness	Stat/Weekend
0	1	-15	1,105	0	9	2,823	1	0	0	481.19	9
0	2	-13	895	0	5	2,827	0	0	0	387.72	10
0	3	-6	762	0	2	2,831	0	0	0	330.33	9
0	4	1	513	0	0	2,835	0	0	0	228.05	10
0	5	7	345	9	0	2,839	0	0	0	129.54	11
0	6	12	186	31	0	2,843	0	0	0	15.89	9
0	7	14	124	58	0	2,847	0	1	0	94.43	9
0	8	13	175	39	0	2,851	0	0	0	205.39	11
0	9	7	326	3	0	2,855	0	0	0	292.54	9
0	10	1	540	0	0	2,858	0	0	0	389.40	10
0	11	-9	822	0	2	2,861	0	0	0	449.12	10
0	12	-13	1,019	0	10	2,864	0	0	1	503.34	10

Year	Month	Predicted Wholesales Multivariate [MWh]
0	1	37,828,488
0	2	33,825,312
0	3	31,184,131
0	4	27,850,723
0	5	25,407,240
0	6	23,096,455
0	7	23,830,615
0	8	23,746,918
0	9	25,510,225
0	10	28,694,365
0	11	32,968,114
0	12	37,518,588

ID	Weight and Unit	
b0	-6102937.015	Intercept
b1	-243428.8791	Avg. temperature
b2	5823.920775	HDD 13oC (threshold)
b3	11620.22311	CDD 13oC (threshold)
b4	35007.95276	Day with avg temp < -20
b5	2023429.87	Jan Indicator Var.
b6	1066356.647	July Indicator Var.
b7	2238463.68	Dec Indicator Var.
b8	116256.9942	# of Stat/Weekend day in a month
b9	1995.861701	hours of Darkness in a month
b10	10438.60255	Commercial customer

0	351,461.173	

CW-YEC-1-3(c) - Attachment 1

2021 no Micro no Fish Lake

Year	Month	Predicted Wholesales Multivariate [MWh]	Predicted Wholesales Multivariate after Micro Gen and Fish Lake [MWh]
2021	1	37,828	37,250
2021	2	33,825	33,198
2021	3	31,184	30,483
2021	4	27,851	27,126
2021	5	25,407	24,679
2021	6	23,096	22,376
2021	7	23,831	23,116
2021	8	23,747	23,045
2021	9	25,510	24,842
2021	10	28,694	28,063
2021	11	32,968	32,393
2021	12	37,519	36,966
Total		351,461	343,537

TOPIC: **Sales Forecasts – Wholesale Sales to ATCO Electric Yukon (AEY)**

REFERENCE: **2021 General Rate Application, page 2-6 (PDF page 31 of 441)**

PREAMBLE: On lines 1-3, YEC discusses the AEY forecast for 2021.

QUESTION:

a) Please provide copies of all communication between AEY and YEC regarding the 2020 and 2021 forecast wholesale sales.

b) Please provide a calculation of the impact on customer rates if the AEY forecast of 345.9 GW.h were used for 2021.

ANSWER:

(a)

Please see CW-YEC-1-4 Attachment 1 for the copy of the letter sent by YEC to AEY regarding 2021 test year forecast. YEC did not include the information on 2020 forecast considering Jan-June numbers for 2020 are based on preliminary actuals.

Please see CW-YEC-1-4 Attachment 2 for the copy of the AEY forecasts for 2020 and 2021, including annual power purchase forecasts as shown in Schedule 3.2, Line 10.

(b)

Based on a high level estimates the incremental wholesale sales [345.9 GW.h as noted in the question compared to 343.5 GW.h forecast by YEC for the 2021 test year = 2.6 GW.h incremental wholesale] would add approximately $0.40 million thermal fuel cost compared to approximately $0.31 million added revenues resulting in a $0.09 million incremental revenue shortfall or 0.09% additional rate increase for 2021.

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yukonenergy.ca

Chris Cullingham
Manager, Regulatory
ATCO Electric Yukon

August 31, 2020

Re: 2021 Yukon Energy GRA Wholesale Sales Forecast

Dear Chris,

This letter is an update of the letters sent to ATCO Electric Yukon (AEY) on May 16, 2019, November 26, 2019 and December 18, 2019. In those letters, Yukon Energy Corporation (YEC) stated that the Yukon Utilities Board (YUB) Order 2018-10 directed YEC to refine its methodology of forecasting Wholesale Sales to ensure its forecasts align closely with the AEY forecasts in future GRA submissions. Subsequent to that Board Order, YEC has had communications with you via email and telephone, as well as the letters sent to you referenced above. Those communications had the purpose of informing AEY of YEC's intention to file a GRA, and to directly address the YUB's direction to ensure our forecasts align closely with yours. This letter is to further formally document our discussions and determine whether or not we need to amend our forecasts.

AEY Forecast
Due to the expected timing of our 2021 GRA submission, we plan to use actuals for 2020 up to June 30, 2020 and forecasts for the remainder of 2020. The GRA year of 2021 will be based fully on forecasts. Pursuant to our previous communications, AEY indicated that your forecast was for business plan purposes and it did not necessarily undergo the same rigor as a forecast that you would file in the GRA.

You indicated that your load forecasting methodology has two key inputs, being net customer additions and forecast use per customer (UPC). Net customer additions are based on input from AEY staff that is obtained through their work in the communities, as well as consultations with the City of Whitehorse, Yukon Government and other various local stakeholders and developers. Forecast UPC is based on average, weather-normalized, historical usage.

A summary of key forecasts that AEY provided YEC is below. It is our understanding that our previous interpretation of your forecasts for 2019 and 2020 was that we quoted your Retail Sales, rather than your Purchased Power. Therefore, the below table has been updated to reflect your Purchased Power and Fish Lake Generation.

	2021
AEY Purchased Power (GW.h)	345.9
Fish Lake Generation (GW.h)	3.6

YEC Forecast
YEC's current forecast for Wholesales sales to AEY is 343.5 GW.h in 2021.

Forecast Differences
The difference between AEY and YEC's forecast is 2.4 GW.h higher by AEY, or 0.69%.

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YEC uses a similar forecasting methodology, so inputs are they key area where differences can arise. YEC performed a detailed review of AEY's inputs. The main difference for residential is AEY used a different residential number of accounts growth factor as compared to YEC. YEC used Yukon Government's number of households' growth for the residential growth factor.

Summary
The above represents YEC's understanding of the communications between YEC and AEY. Please let us know if AEY has a different interpretation. In addition, if you have any significant concerns about our forecasts, please provide to us.

We appreciate your continued support in the Yukon regulatory process.

Regards,

Jason Epp CPA, CA
Controller

Schedule 2.1

ATCO Electric Yukon
Summary of Customers, Energy Sales and Revenue

Line No.	Description	2020	2021
1	**Residential**		
2	Customers (average during year)	16,088	16,301
3	Sales in MWh	180,816	174,769
4	MWh sales per customer	11.24	10.72
5	Revenue ($000s)	25,328	24,618
6	Cents per kWh	14.01	14.09
7	**Commercial**		
8	Customers (average during year)	3,180	3,213
9	Sales in MWh	163,088	173,321
10	MWh sales per customer	51.28	53.95
11	Revenue ($000s)	26,668	28,272
12	Cents per kWh	16.35	16.31
13	**Street Lights**		
14	Customers (average during year)	5,777	6,031
15	Sales in MWh	3,886	3,914
16	Revenue ($000s)	1,034	1,060
17	Cents per kWh	26.60	27.07
18	**Private Lights**		
19	Customers (average during year)	772	749
20	Sales in MWh	454	434
21	Revenue ($000s)	122	117
22	Cents per kWh	26.81	26.98
23	**Total Company - Retail - Primary**		
24	Customers	25,817	26,076
25	Sales in MWh	348,245	352,438
26	Revenue ($000s)	53,152	54,067
27	Cents per kWh	15.26	15.33
28	**Secondary Sales**		
29	Customers (average during year)	5	5
30	Sales in MWh	-	-
31	Revenue ($000s)	-	-
32	Cents per kWh	#DIV/0!	#DIV/0!
33	**Wholesale Sales**		
34	Customers (average during year)	2	2
35	Sales in MWh	628	628
36	Revenue ($000s)	54	52
37	Cents per kWh	8.54	8.30
38	**Total Company - Base Revenue**		
39	Customers	25,824	26,300
40	Sales in MWh	348,873	353,066
41	Revenue ($000s)	53,205	54,119
42	Cents per kWh	15.25	15.33

ATCO Electric Yukon
2020 - 2021 Forecast
Schedule of Energy Losses
(MWh)

Line No.	Description	Forecast 2020	Forecast 2021
1	**Sales and Losses**		
2	Total Energy Sales - MWh	348,873	353,066
3	Losses and Company Used - MWh	17,751	17,965
4	Losses -%	5.1%	5.1%
5	Total Generation and Purchases (MWh)	366,624	371,031
		-	
6	**Sources - MWh**		
7	Hydro Generation	3,628	3,628
8	Hydro Grid Standby Diesel Generation	45	45
9	Diesel Generation	21,622	21,423
10	Purchases	341,329	345,934
11	Total Generation and Purchases (MWh)	366,624	371,031
12	**Sources - %**		
13	Hydro Generation	1.0%	1.0%
14	Diesel Generation	5.9%	5.8%
15	Purchases	93.1%	93.2%
16	Total	100.0%	100.0%

TOPIC: **Sales Forecasts – Major Industrial**

REFERENCE: **2021 General Rate Application, page 2-6 (PDF page 31 of 441)**

PREAMBLE: CW notes that YEC discusses its industrial sales forecasts, and also notes footnotes 5, 6, and 7.

QUESTION:

a) For each industrial customer, please fully discuss all communication with the customer regarding load projections and potential changes in load for 2021.

b) Please provide copies of the Power Purchase Agreement referenced in Footnote 6.

ANSWER:

(a)

Finance, Operations and/or Senior Management will have communications with each Industrial on an ongoing basis. As YEC gets closer to finalizing a GRA, YEC will reach out to the Industrial customer to determine if any changes to previous forecasts are required. Communications can be in person, by email or by telephone.

(b)

Please see Attachment 1 to this response.

POWER PURCHASE AGREEMENT

This Agreement dated November 9, 2017 is between:

YUKON ENERGY CORPORATION, a Yukon Territory corporation, having an office at P.O. Box 5920, #2 Miles Canyon Road, Whitehorse, Yukon Territory, Y1A 6S7

("**YEC**")

and:

VICTORIA GOLD CORP., a British Columbia corporation registered in the Yukon Territory under number 634192, having an office at 1050 West Pender Street, Vancouver, British Columbia, V6E 3E7

("**VGC**")

and:

STRATAGOLD CORPORATION., a British Columbia corporation registered in the Yukon Territory under number 631012, having an office at 1050 West Pender Street, Vancouver, British Columbia, V6E 3E7

("**StrataGold**")

(VGC and StrataGold are jointly and severally, the "**VGC Group**")

BACKGROUND:

A. StrataGold is a wholly-owned subsidiary of VGC;

B. VGC Group owns the Mine Site and is in the process of developing the Mine with the intent of commencing initial gold production by June 30, 2019;

C. YEC has agreed to sell to VGC Group and VGC Group has agreed to purchase from YEC Grid Electricity required by VGC Group to operate the Mine, with Commencement of Delivery in March, 2019; and

D. The Parties have agreed to enter into this Agreement to set out their respective rights and obligations with respect to the sale and purchase of Grid Electricity by YEC to VGC Group for the Mine.

AGREEMENTS:

The Parties agree:

PART 1
DEFINITIONS AND INTERPRETATION

1.1 **Definitions**. In this Agreement and in the Schedules which are attached to and form a part of this Agreement:

(a) "**Act**" has the meaning in Section 8.1;

(b) "**Affiliate**" has the meaning set out in the *Business Corporations Act* (Yukon Territory);

(c) "**ampere**" means the unit of measurement of electric current in the International System of Units;

(d) "**Business Day**" means any day which is not a Saturday, Sunday, or a statutory holiday in the Yukon Territory or the Province of British Columbia;

(e) "**Commencement of Delivery**" means for the Mine Facilities the later of the:

(i) McQuesten Substation Operation Date;

(ii) date VGC Group provides notice to YEC to confirm that the VGC Group Power Facilities are complete and the Mine Facilities and the Mine Facilities Spur are available to receive Grid Electricity from YEC; and

(iii) date the Parties execute and deliver the Operating Agreement;

(f) "**Commercial Operation Cessation Date**" means the earlier of the:

(i) Mine Facilities Shut Down Date; and

(ii) date VGC Group provides notice to YEC that the Mine Facilities no longer require, acting reasonably under normal market and operating conditions, an Electric Demand at the Point of Delivery in excess of 1,000 kW;

(g) "**Conditions**" mean the conditions listed in Section 3.1;

(h) "**Confidential Information**" has the meaning in Section 15.1;

(i) "**Defaulting Party**" has the meaning in Section 11.1;

(j) "**Dispute**" means any dispute, difference, or disagreement between the Parties as to:

(i) the meaning, application, or implementation of this Agreement; or

(ii) whether an Event of Default has occurred;

(k) "**Electric Demand**" means the capacity at which Grid Electricity is delivered by YEC to VGC Group expressed in kVA or kW, averaged over a rolling 15 minute period following YEC billing and metering practice for industrial customers receiving Grid Electricity;

(l) "**Electric Energy**" means electric energy, expressed in kWh, delivered by YEC to VGC Group under this Agreement;

(m) "**Electricity**" means Electric Energy and Electric Demand delivered by YEC to VGC Group under this Agreement;

(n) "**Event of Default**" has the meaning in Section 11.1;

(o) "**Event of Insolvency**" means any one or more of the following:

(i) if a Party files a petition for reorganization or for an arrangement under any applicable bankruptcy law or under any similar laws, now or hereafter in effect, is adjudged by a court of competent jurisdiction bankrupt, becomes insolvent,

makes an assignment for the benefit of its creditors, admits in writing its inability to pay its debts generally as they become due, is dissolved, or suspends payment generally of its obligations;

(ii) if a petition is filed proposing the adjudication of a Party as a bankrupt or its re-organization under any applicable bankruptcy law or any similar law, now or hereafter in effect and:

A. the Party consents to the filing thereof;

B. the petition is not discharged or denied within 60 days after the filing thereof; or

C. the petition is not diligently defended against; and

(iii) if a receiver, receiver-manager, trustee, monitor, or liquidator (or other similar official) is appointed to take charge of all or substantially all of the business or assets of a Party and:

A. that Party consents to such appointment; or

B. the appointment is not discharged or withdrawn, or action is not taken by that Party to secure the discharge of that official, within 60 days after the appointment;

(p) "**Firm Mine Rate**" means the rate set out in Schedule A, as may be amended by YUB from time to time;

(q) "**Fixed Charge**" means the fixed charge rate each month applicable to the VGC Group Mine Site under the Firm Mine Rate, equal to one-twelfth of the annual amount determined under Section 7.7;

(r) "**Force Majeure**" means any event or circumstance suffered by a Party which is not within the reasonable control of the Party claiming Force Majeure and includes, without limitation:

(i) acts of God, including wind, ice and other storms, forest fires, lightning, floods, earthquakes, volcanic eruptions, and landslides;

(ii) strikes, lockouts, and other industrial disturbances, it being acknowledged that the settlement of strikes, lockouts, and other labour disturbances depends upon the agreement of employees and other third Persons and therefore is not wholly within the discretion of the Party involved;

(iii) epidemics, war (whether or not declared), terrorism, blockades, acts of public enemies, acts of sabotage, civil insurrection, riots, and civil disobedience;

(iv) acts or omissions of Governmental Authorities; and

(v) explosions and fires;

(s) "**Government Approvals**" means all licences, permits, consents, authorizations, or approvals from, withholding of objection on the part of, or filing, registration or qualification with, any and all Governmental Authorities required for any particular decision, act, or event;

(t) "**Governmental Authority**" means the government of Canada, the government of the Yukon Territory, a municipality or other political subdivision thereof, including any applicable First Nations, and any entity exercising executive, legislative, judicial, regulatory, or administrative functions including, without limitation, the YUB, if applicable;

(u) "**Grid Electricity**" means Electricity delivered under this Agreement at the Point of Delivery by YEC to VGC Group from the Transmission Facilities , through the Mine Facilities Spur to the Mine Facilities;

(v) "**Initial YEC System Improvements**" means the initial system improvement facilities for YEC's power system that YEC is to design, engineer, procure, construct, and commission on YEC's power system under Schedule C;

(w) **"Interest Rate**" means the interest rate charged by the lead banker of YEC from time to time on unsecured commercial loans made to YEC or if YEC does not have any unsecured commercial loans outstanding at such time, the variable nominal interest rate per annum being the prime interest rate of Canadian Imperial Bank of Commerce (or its successor) for Canadian dollar commercial loans in Canada as publicly declared from time to time as its prime rate;

(x) "**International System of Units"** means the international system of weights and measures adopted at the 11th General Conference on Weights and Measures in 1960;

(y) "**kV**" means a kilovolt and one kilovolt equals 1,000 volts;

(z) "**kVA**" means a kV ampere and one kV ampere equals 1,000 volt-amperes;

(aa) "**kW**" means a kilowatt and one kilowatt equals 1,000 watts;

(bb) "**kWh**" means a kW hour, the common unit of electrical energy, equal to one kilowatt of power supplied to or taken from an electric circuit for one hour;

(cc) "**Major Industrial Customer**" means a customer of YEC, or of any other regulated electric utility in the Yukon Territory, engaged in manufacturing, processing, or mining whose electrical service is inter-connected with electrical service provided to any other customer of such electric utilities and whose peak Electric Demand exceeds 1,000 kW or any future replacement definition or replacement service capacity threshold applicable to manufacturing, processing, or mining activities of the VGC Group, as approved by the YUB;

(dd) "**Maximum Electric Demand**" means the maximum Electric Demand for Mine Firm Electricity that YEC is obligated to deliver to the VGC Group at the Point of Delivery under Part 5;

(ee) "**McQuesten Substation**" means the substation located along Transmission Facilities between Mayo and Keno City at approximately the junction of the South McQuesten Road and the Silver Trail Highway, and to be developed by the Parties, but owned and operated by YEC, in accordance with Schedule B and the provisions of this Agreement;

(ff) "**McQuesten Substation Operation Date**" means the date that YEC provides notice to VGC Group to confirm that the Initial YEC System Improvements are complete and the McQuesten Substation is available to deliver Grid Electricity to the Mine Facilities through the Mine Facilities Spur;

(gg) "**Mine**" means the VGC Group's "Eagle Gold Project" located on the Mine Site;

(hh) "**Mine Facilities**" means any mining or other facilities developed or operated by VGC Group at the Mine Site, which Mine Facilities include the Mine;

(ii) "**Mine Facilities Operation Date**" means the date on which VGC Group provides notice to YEC, after commissioning of the Mine Facilities, the Mine Facilities Spur, and the VGC Group Power Facilities to confirm the start of commercial operation of the Mine;

(jj) "**Mine Facilities Shut Down Date**" means the date provided by VGC Group to YEC on which YEC is to initiate permanent termination of any further delivery of Grid Electricity to the Mine Facilities under this Agreement;

(kk) "**Mine Facilities Spur**" means the approximate 44km, 69kV transmission line that VGC Group will construct, own, and operate to connect the Mine Facilities to the Point of Delivery to receive Grid Electricity from YEC under this Agreement;

(ll) "**Mine Firm Electricity**" means Grid Electricity delivered by YEC to the Mine on a firm basis;

(mm) "**Mine Site**" means those lands and premises to be used for the Mine and located on the Dublin Gulch property approximately 40 kilometers from Mayo, Yukon Territory and approximately 25 km straight line northwest from the McQuesten Substation with an approximate 44 km road access to the Mine Site from the Silver Trail Highway along the South McQuesten and Haggart Creek Roads;

(nn) "**MVA**" means thousands of kV amperes;

(oo) "**MW**" means a megawatt, being the electrical unit of power which is equal to 1,000 kW or 1,000,000 watts;

(pp) "**MWh**" means a MW hour, being the electrical energy equal to one megawatt of power supplied or taken from an electric circuit for one hour;

(qq) "**MOU"** has the meaning in Section B.2 of Schedule B;

(rr) "**Non-Defaulting Party**" has the meaning in Section 11.2;

(ss) "**Operating Agreement**" means the operating agreement for the YEC power system and the VGC Group Power Facilities that the Parties will implement under Schedule E, and any amendments to the Operating Agreement made under this Agreement;

(tt) "**Other Industrial Customer"** means a YEC Major Industrial Customer, other than the VGC Group, that receives Grid Electricity from the Transmission Facilities;

(uu) "**Other YEC System Improvements**" means system improvements for YEC's power system undertaken under this Agreement to supply Grid Electricity to the Mine Facilities in response to an agreed increase in the Maximum Electric Demand as provided for in Section 5.5, and excludes the Initial YEC System Improvements;

(vv) "**Parties**" means YEC, VGC, and StrataGold and "**Party**" means any one of them;

(ww) "**Person**" means an individual, firm, partnership, body corporate, or other legal entity, a government or any department or agency thereof, a trustee, any unincorporated organization and the heirs, executors, administrators, or other legal representatives of an individual, as the case may be;

(xx) "**Point of Delivery**" means the point at the McQuesten Substation where the slack span from the McQuesten Substation connects to the deadend insulator at the first Mine Facilities Spur transmission structure, with the insulator and jumper and all of their components being on the VGC Group side and the conductor being on the YEC side, with revenue metering for Grid Electricity located inside the McQuesten Substation at the breaker that the Mine Facilities Spur connects;

(yy) "**Power Factor**" means the ratio at the Point of Delivery of the highest metered kW demand in a billing period to the highest metered kVA demand in that same billing period;

(zz) "**Power Quality Requirements**" means YEC's power quality requirements, as set out in Schedule F, applicable to the VGC Group's operation of the Mine Facilities when receiving Grid Electricity from YEC;

(aaa) "**RAS**" remedial action schemes;

(bbb) "**SCC**" means YEC's system control centre;

(ccc) "**SPS**" means special protection schemes;

(ddd) "**Service Charge**" means the late payment charge on any overdue account of YEC as provided for in the Terms and Conditions;

(eee) "**Step Down Transformer**" means a transformer located in the McQuesten Substation and designed to step down from 138 kV to 69kV;

(fff) "**SPS**" has the meaning in Section c.1(e) of Schedule C;

(ggg) "**Stewart Crossing Substation**" means the YEC substation located south of the Stewart River at Stewart Crossing;

(hhh) "**StrataGold**" has the meaning on page one;

(iii) "**SVC/Statcom**" means voltage support equipment for reactive compensation, consisting of either a static-var compensator (SVC) or a static synchronous compensator (statcom), located at the Stewart Crossing Substation;

(jjj) "**Term**" has the meaning in Section 2.1;

(kkk) "**Terms and Conditions**" means the Terms and Conditions of Service applicable to YEC, or any future replacement terms and conditions applicable to YEC, as approved by the YUB;

(lll) "**Transmission Facilities**" means the Mayo to McQuesten Substation segment of YEC's 69 kV Mayo to Keno City transmission facilities located north of Mayo, Yukon Territory, or any Transmission Facilities Development;

(mmm) "**Transmission Facilities Development**" means any future transmission facilities developed by YEC to replace existing Transmission Facilities and to connect the McQuesten Substation with a substation at either Mayo or Stewart Crossing;

(nnn) "**Transmission Facilities Development Operation Date**" means the date provided by YEC to VGC Group to confirm that the Transmission Facilities Development has been completed and is in service to deliver Grid Electricity to the Mine Facilities through the Mina Facilities Spur;

(ooo) "**Transmission Facilities Fixed Cost**" means YEC's annual cost, as approved by the YUB from time to time, for depreciation and return on rate base related to the Transmission Facilities plus the SVC/Statcom if and when it is installed;

(ppp) "**VGC**" has the meaning on page one;

(qqq) "**VGC Group**" has the meaning on page one;

(rrr) "**VGC Group Capital Costs**" means all of the VGC Group's reasonably incurred costs incurred in the design, engineering, procurement, construction, and commissioning of the Mine Facilities Spur;

(sss) "**VGC Group Forecasts**" has the meaning in Section 5.2;

(ttt) "**VGC Group Power Bill**" means the monthly bill sent by YEC to VGC Group under Section 7.1;

(uuu) "**VGC Group Power Facilities**" means the power facilities that VGC Group is to install and operate as part of the Mine Facilities under Schedule D;

(vvv) "**VGC Group Share**" has the meaning in Section 7.7;

(www) "**volt**" means the unit of electrical potential, electrical potential difference, and electromotive force in the International System of Units;

(xxx) "**watt**" means the electrical unit of power or rate of energy transfer in the International System of Units;

(yyy) "**YEC**" means has the meaning on page one;

(zzz) "**YEC Capital Costs**" means all of YEC's reasonably incurred costs incurred in the design, engineering, procurement, construction, and commissioning of the McQuesten Substation as set out in Schedule B and the Initial YEC System Improvements as set out in Schedule C, YEC's costs reasonably incurred to negotiate and conclude this Agreement, YEC's costs reasonably incurred for the Step Down Transformer if required, and YEC's costs reasonably incurred for any Other YEC System Improvements if required;

(aaaa) "**YEC McQuesten Substation Costs**" means the VGC Group's capital costs for the McQuesten Substation development as specified in Schedule B that VGC Group will incur and recover from YEC under this Agreement;

(bbbb) "**YEC Owner's Costs**" means YEC's capital costs for the McQuesten Substation development as set out in Table B-1 of Schedule B that YEC will recover from VGC Group under this Agreement; and

(cccc) "**YUB**" means the Yukon Utilities Board.

1.2 **Schedules**. The following Schedules are attached to and form a part of this Agreement:

(a) Schedule A – Firm Mine Rate and Fixed Charge;

(b) Schedule B –McQuesten Substation;

(c) Schedule C - Initial YEC System Improvements;

(d) Schedule D - VGC Group Power Facilities;

(e) Schedule E - Operating Agreement; and

(f) Schedule F - Power Quality Requirements.

1.3 **Interpretation**. Under this Agreement:

(a) references to voltage are approximate;

(b) words importing the masculine gender include the feminine and neuter genders, and Persons, and words in the singular include the plural, and vice versa, wherever the context requires;

(c) all references to designated Parts and Sections are to the designated Parts and Sections of this Agreement;

(d) using separate Parts and Sections, providing a table of contents, and inserting headings are for convenience only and will not affect how this Agreement is interpreted;

(e) unless otherwise indicated, any reference to a currency is a reference to Canadian currency;

(f) except where otherwise specified, any reference to a statute includes a reference to such statute and to its regulations, with all amendments in force from time to time, and to any statute or regulation that may be passed which has the effect of supplementing or superseding the statute or regulation; and

(g) any reference to a Person includes a reference to any Person that is a successor to that Person.

PART 2
DURATION

2.1 **Term**. This Agreement will commence as of the date of this Agreement and, unless terminated earlier under this Agreement, will terminate on the Mine Facilities Shut Down Date (the "**Term**").

PART 3
CONDITIONS PRECEDENT

3.1 **Conditions**. The obligations of the Parties to proceed with their obligations under this Agreement (except for obligations of the Parties under this Section 3.1) are subject to fulfilment of the following conditions:

(a) on or before February 28, 2018, the YUB will have approved the VGC Group payments under Section 6.1, the Transmission Facilities Fixed Cost of $118,621, the provisions under Section 7.7 for amending the Transmission Facilities Fixed Cost and for setting the annual amount of the Fixed Charge, and amendments to the Firm Mine Rate as required to conform to Schedule A and this Agreement;

(b) on or before February 15, 2018 VGC Group will have provided evidence satisfactory to YEC, acting reasonably, that VGC Group has sufficient funds or financing available and adequate approvals to proceed with the design, engineering, procurement, construction, and commissioning of the McQuesten Substation, the Mine, the Mine Facilities, and the

Mine Facilities Spur, on the schedule set out in this Agreement to enable the Mine Facilities Operation Date to occur on or before June 30, 2019;

(c) on or before May 15, 2018 VGC Group will have provided evidence satisfactory to YEC, acting reasonably, that VGC Group has commenced site construction of the Mine Facilities, the Mine Facilities Spur, and the McQuesten Substation and is proceeding diligently and in good faith such that VGC Group is expected to achieve the Mine Facilities Operation Date under Section 3.1(b); and

(d) on or before September 30, 2018 YEC will have received all approvals reasonably required by YEC from Yukon Development Corporation, the Yukon Territorial Government, and such other approvals as YEC may reasonably require to proceed with and complete the design, engineering, procurement, construction, and commissioning of the Transmission Facilities Development as set out in Section 4.5.

Conditions 3.1(a) and (b) are for benefit of both Parties and may only be waived, altered, or the time period extended by agreement between the Parties. Conditions 3.1(c) and (d) are for the benefit of YEC with regard to YEC's obligations under Sections 4.3 and 4.5 and each of these Conditions may be waived, altered, or the time period extended by YEC, in its absolute discretion, by notice by YEC to VGC Group at any time prior to the expiry of the applicable Condition. The Parties will exercise commercially reasonable efforts, to ensure that the Conditions for which they are responsible are fulfilled on or before the date specified. If any of the Conditions set out in Sections 3.1(a), (b), or (c) are neither fulfilled, waived, altered, or the time period extended, on or before the date specified, this Agreement will terminate with immediate effect and neither Party will have any further right or obligation under this Agreement, except for the fulfilment of those obligations which arose prior to the date of termination and except for any rights or obligations which are expressly stated to survive the termination of this Agreement. If Condition 3.1(d) is not fulfilled, waived, altered, or the time period extended before the date specified, this Agreement will not terminate, but YEC will have no obligation to proceed with the Transmission Facilities Development under Section 4.5.

PART 4
INITIAL ACTIVITIES

4.1 **Filing with YUB**. Upon execution and delivery of this Agreement, YEC will proceed diligently and in good faith to file an application with the YUB seeking YUB approval of the VGC Group payments under Section 6.1, the Transmission Facilities Fixed Cost of $118,621, the provisions under Section 7.7 for amending Transmission Facilities Fixed Cost and for setting the annual amount of the Fixed Charge, and amendments to the Firm Mine Rate as required to conform with Schedule A and this Agreement. YEC will provide the YUB with such supporting documentation as required by the YUB for such application. VGC Group will support the YEC application to YUB as YEC may reasonably require to obtain the approval of the YUB under this Section 4.1.

4.2 **McQuesten Substation**. Upon execution and delivery of this Agreement, the Parties will proceed diligently and in good faith and will exercise commercially reasonable efforts to design, engineer, procure, construct, commission and turnover of the McQuesten Substation to YEC under the terms and conditions set out in Schedule B to achieve the McQuesten Substation Operation Date on or before February 28, 2019.

4.3 **Initial YEC System Improvements**. Upon execution and delivery of this Agreement, YEC will proceed diligently and in good faith and will exercise commercially reasonable efforts to design, engineer, procure, construct, and commission the Initial YEC System Improvements under the terms and conditions set out in Schedule C as required to accommodate Commencement of Delivery on a date mutually agreed to by the Parties in March 2019.

4.4 **Mine Facilities, Mine Facilities Spur, and VGC Group Power Facilities.** Upon execution and delivery of this Agreement, VGC Group will proceed diligently and in good faith and will exercise commercially reasonable efforts to design, engineer, procure, construct, and commission the:

(a) Mine Facilities;

(b) Mine Facilities Spur; and

(c) VGC Group Power Facilities as set out in Schedule D;

so as to be able to achieve Commencement of Delivery on a date mutually agreed to and presently estimated by the Parties to be in March 2019. VGC Group will from time to time, and at least once every two months, provide notice to YEC of VGC Group's progress and material milestones under this Section 4.4. VGC Group will provide notice to YEC of the date when the VGC Group Power Facilities are completed and the date when the Mine Facilities and the Mine Facilities Spur are available to receive Grid Electricity from YEC. The Parties will use commercially reasonable efforts to cooperate and coordinate their activities under this Section 4.4 to ensure the Commencement of Delivery occurs on a date mutually agreed to and presently estimated by the Parties to be in March, 2019.

4.5 **Transmission Facilities Development**. VGC Group acknowledges that the Transmission Facilities are at or near their end of life, and the Transmission Facilities must be upgraded before YEC can reliably deliver Grid Electricity to the Mine Facilities. Upon execution and delivery of this Agreement, YEC will, subject to the Condition in Section 3.1(d) being fulfilled, proceed diligently and in good faith and will exercise commercially reasonable efforts to commence, on or before October 1, 2018, the design, engineering, procurement, construction, and commissioning of the Transmission Facilities Development with the expectation that the Transmission Facilities Development Operation Date will occur within:

(a) 21 months of October 1, 2018 if the Transmission Facilities Development includes new Transmission Facilities located between McQuesten Substation and the existing Mayo substation that are to be operated at 69 kV; or

(b) 30 months of October 1, 2018 if the Transmission Facilities Development includes new 138 kV Transmission Facilities connecting the McQuesten Substation with a substation at Stewart Crossing.

YEC will, from time to time, and at least once every two months, provide notice to VGC Group of YEC's progress and material milestones under this Section 4.5. YEC will provide notice to VGC Group of the Transmission Facilities Operation Date. VGC Group will provide to YEC such support as YEC may require, acting reasonably, for YEC to secure funding for the Transmission Facilities Development.

4.6 **Step Down Transformer**. If the Transmission Facilities Development includes a 138 kV transmission line connecting the McQuesten Substation with a substation at Stewart Crossing, YEC will design, engineer, procure, construct, and commission the Step Down Transformer as part of the Transmission Facilities Development.

4.7 **SVC/Statcom**. YEC will design, engineer, procure, construct, and commission the SVC/Statcom at the Stewart Crossing Substation as part of the Transmission Facilities Development that is developed under Section 4.5.

4.8 **Operating Agreement**. Upon execution and delivery of this Agreement the Parties will proceed diligently and in good faith to negotiate, execute, and deliver the Operating Agreement substantially in the form attached to this Agreement as Schedule E on or before the Commencement of Delivery.

PART 5
ELECTRICITY

5.1 **Electricity to be Delivered and Accepted**. From the Commencement of Delivery, YEC will deliver to VGC Group and VGC Group will purchase from YEC Grid Electricity as Mine Firm Electricity at the Firm Mine Rate until the Commercial Operation Cessation Date has occurred, subject to the Maximum Electric Demand and a load Power Factor requirement of 96% leading, as follows:

(a) from the Commencement of Delivery until the Transmission Facilities Development Operation Date, Maximum Electric Demand of up to 10,100 kVA;

(b) after the Transmission Facilities Development Operation Date, Maximum Electric Demand of up to 14,300 kVA; and

(c) subject to the specified Maximum Electric Demand and its constraints on Electric Energy delivered by YEC to the VGC Group, Electric Energy of approximately 51,800 MWh/year in the first twelve months after the Mine Facilities Operation Date, approximately 63,600 MWh/year in the second twelve months after the Mine Facilities Operation Date, approximately 67,400 MWh/year in the third twelve months after the Mine Facilities Operation Date, approximately 70,200 MWh/year in the fourth twelve months after the Mine Facilities Operation Date, approximately 72,600 MWh/year in the fifth twelve months after the Mine Facilities Operation Date, and approximately 74,100 MWh/year thereafter until the Commercial Operations Cessation Date; and

(d) during an approximate 90 day period that falls between December 1 and March 31 of every year during the Term, Electric Demand will be reduced so as not to exceed approximately 6,000 kVA.

5.2 **VGC Group Forecasts**. VGC Group will provide to YEC annual forecasts ("**VGC Group Forecasts**") of the Grid Electricity requirements of the Mine Facilities at the Point of Delivery in accordance with the following provisions:

(a) VGC Group Forecasts for each of the succeeding calendar years that the Mine Facilities are expected to require Grid Electricity, so as to allow YEC to forecast the future Electric Demand and Electric Energy loads on the Mine Facilities. The VGC Group Forecast will be provided to YEC eight months in advance of each calendar year end, starting upon execution and delivery of this Agreement, and will include load patterns showing the characteristics of the expected Mine Firm Electricity, including the characteristics for Electric Demand and Electric Energy on a monthly basis. With regard to Grid Electricity requirements after year six of Mine Facilities operation, the VGC Group Forecasts will update YEC on VGC Group plans related to changes in Mine Facilities, the steps and schedule to implement these plans, and the expected impacts of Grid Electricity requirements for the Mine Facilities.

(b) VGC Group will advise YEC by notice forthwith of any material change to the VGC Group Forecasts for Mine Firm Electricity, including the characteristics for Electric Energy or Electric Demand.

(c) During the first week of each month after Commencement of Delivery, VGC Group will advise YEC by notice of its estimated daily requirements for Mine Firm Electricity during the following month.

5.3 **Point of Delivery** . YEC will deliver Grid Electricity to VGC Group and VGC Group will receive Grid Electricity from YEC at the Point of Delivery.

5.4 **Maximum Electric Demand**. YEC's obligation to supply Mine Firm Electricity to VGC Group will not exceed the Maximum Electric Demand in effect at any time at the Point of Delivery, and, in accordance with Schedule E, YEC is entitled to cease delivery of Grid Electricity to the Mine Facilities if VGC Group continues to receive Mine Firm Electricity in excess of the Maximum Electric Demand after notice from YEC that VGC Group's load is exceeding the Maximum Electric Demand cap. Notwithstanding such Maximum Electric Demand, if VGC Group receives from YEC Mine Firm Electricity in excess of the Maximum Electric Demand, VGC Group will pay for the billing demand charge on all metered kVA billing demand recorded at the Firm Mine Rate.

5.5 **Increase in Maximum Electric Demand**. If VGC Group requires an increase to its Maximum Electric Demand in excess of that under Section 5.1, the following will apply:

(a) VGC Group will provide YEC with notice of the specified amount of the requested increase together with the period of time during which the increase is required and the related increase in Mine Firm Electricity requirement together with such information and documents as YEC may reasonably require to consider the request;

(b) after receipt of such notice, YEC will have a reasonable period of time to determine whether or not the Transmission Facilities and YEC's other facilities have the ability to supply and maintain that increased Electric Demand, as well as any potential requirement for an increase to the Mine Firm Rate, Other YEC System Improvements, and new YEC Capital Costs related to such increase in Mine Firm Electricity, and YEC will forthwith provide notice to VGC Group of YEC's determination;

(c) following such notice by YEC to the VGC Group, if the Parties are unable to agree on the matters set out under Section 5.5(b) within a period of 90 days from the date of such written notice by YEC to the VGC Group, no increase in Maximum Electric Demand will be provided. For greater certainty the Parties' failure to agree on the matters set out in this Section 5.5(c) will not be a Dispute and will not be subject to Part 12; and

(d) if the Parties are able to agree on the matters set out in Section 5.5(b) within 90 days then the Parties will enter such amendments to this Agreement as the Parties may reasonably require to reflect such agreements, including provision for YUB approval of any changes required to the Firm Mine Rate. If the Parties are unable to execute and deliver such agreements within a period of 120 days of the notice under Section 5.5(c), no amendments to this Agreement will occur. For greater certainty the Parties' failure to agree on such agreements will not be a Dispute and will not be subject to Part 12.

5.6 **VGC Group Standards for Usage of Electricity**. The Parties will comply with the Operating Agreement and VGC Group will regulate its electrical load in accordance with the Power Quality Requirements, including the requirement to maintain a 96% leading load Power Factor for Grid Electricity delivered to VGC Group at the Point of Delivery, or as otherwise agreed to by the Parties from time to time, acting reasonably. VGC Group will operate its equipment and use the Grid Electricity at the Mine so as not to endanger any of YEC's plant or equipment or cause any unacceptable fluctuations of YEC's electrical system. VGC Group will comply with reasonable standards of operation under the Operating Agreement or the Power Quality Requirements or as otherwise provided by YEC to VGC Group by notice from time to time. If VGC Group fails to comply with these requirements or standards of operation so as to endanger any of YEC's plant or equipment or cause any unacceptable fluctuations on YEC's electrical system, YEC may by notice to VGC Group require that VGC Group remedy the situation. Should VGC Group fail to immediately comply with this Section 5.6 upon receiving such notice regarding the Point of Delivery, YEC may immediately suspend the supply of Grid Electricity to VGC Group at such Point of Delivery and continue such suspension until the situation is remedied. Upon receipt of such notice VGC Group may provide notice to YEC that VGC Group wishes YEC to operate any such equipment endangering YEC's plant, or equipment, or electrical system at VGC Group's sole cost and expense. Upon receipt of such notice YEC will provide notice to VGC Group as to whether YEC will operate such

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equipment and in such case VGC Group will indemnify and save harmless YEC against any costs, damages, or losses associated with such operations.

5.7 **Terms and Conditions of Service**. The Terms and Conditions apply to the Parties with regard to Grid Electricity delivered by YEC to VGC Group under this Agreement including, without limitation, the provisions regarding the responsibility and liability of each Party. If there is an inconsistency between the Terms and Conditions and this Agreement the Terms and Conditions will govern.

5.8 **Commercial Operation Cessation Date**. VGC Group will provide notice to YEC of a Commercial Operation Cessation Date within 30 days of the occurrence of such Commercial Operation Cessation Date.

5.9 **Suspension of Commercial Operation**. VGC Group will provide notice to YEC as provided for in Section 4 of Schedule E of planned maintenance and scheduling for the Mine Facilities. Such notice will include the date on which Commercial Operation will cease, VGC Group's reasonable estimate of the length of the period during which Commercial Operation will be suspended, and the related adjustments to VGC Group Forecasts as required under Section 5.2. If VGC Group suspends Commercial Operation and such suspension continues for five consecutive years without VGC Group providing notice to YEC of a Mine Facilities Shut Down Date during this suspension, VGC Group will then be deemed to have provided notice to YEC that the Mine Facilities Shut Down Date has occurred as of the last day of the five years of continuous suspension. VGC Group will provide copies to YEC of any VGC Group notice to the Minister under the Quartz Mining Act regarding specified events at the Mine where such notice is required, including commencement of active operations, discontinuance or resumption of operations, and plans to bring the Mine back into operations.

5.10 **Planned YEC Maintenance**. YEC may, from time to time, for planned annual maintenance of its transmission and generation facilities, require a curtailment or suspension in the Grid Electricity supplied to the Mine for a period of up to 14 days per calendar year and YEC will provide notice to VGC Group, as provided for in Section 4 of Schedule E, of any such planned maintenance. Such notice will include the date on which such maintenance will commence, YEC's expected duration of the maintenance, and the impact on YEC's obligations to deliver Grid Electricity to VGC Group under this Agreement.

PART 6
YEC CAPITAL COSTS

6.1 **YEC Capital Costs**.

(a) As of the date of this Agreement YEC's estimate for the YEC Capital Costs not paid to date by VGC Group for the negotiation and conclusion of this Agreement is $200,000. Within 15 days of the execution and delivery of this Agreement YEC will invoice VGC Group for 50% of YEC's estimated YEC Capital Costs under this Section 6.1(a), and within 15 days of receipt of said invoice VGC Group will pay such amount to YEC. YEC will invoice VGC Group for the balance of the amount owing as soon as is reasonably practicable after YEC determines the actual amount of YEC Capital Costs incurred under this Section 6.1(a) and VGC Group will pay such amount within 15 days of receipt of such invoice.

(b) As of the date of this Agreement YEC's estimate of the YEC Capital Costs that YEC is to recover from VGC Group for the Initial YEC System Improvements is $1,677,883. Within 15 days of the execution and delivery of this Agreement YEC will invoice VGC Group for 50% of YEC's estimated YEC Capital Costs under this Section 6.1(b), and within 15 days of the date of the approval of this Agreement by the YUB VGC Group will pay such amount to YEC. YEC will invoice VGC Group for the balance of the amount owing as soon as is reasonably practicable after YEC has completed the Initial YEC System Improvements as required by Section 4.3 and has determined the actual cost of the Initial YEC System Improvements under this Section 6.1(b), and VGC Group will pay such

amount within 15 days of receipt of such invoice. Provided however that if the amount to be invoiced VGC Group for the Initial YEC System Improvements exceeds $1,677,883 then YEC will provide VGC Group with details of the increase in cost and confirm to VGC Group that such increase in cost is not caused by a change to the scope of the work for the Initial YEC System Improvements as set out in Schedule C and was otherwise a reasonably necessary increase in cost to complete the Initial YEC System Improvements.

(c) As of the date of this Agreement YEC's estimate for the YEC Owner's Costs that YEC is to recover from VGC Group for the McQuesten Substation is $483,240. Within 15 days of the execution and delivery of this Agreement YEC will invoice VGC Group for 50% of YEC's estimated YEC Owner's Costs under this Section 6.1(c), and within 15 days of the date of the approval of this Agreement by the YUB, VGC Group will pay such amount to YEC. YEC will invoice VGC Group for the balance of the amount owing as soon as is reasonably practicable after the Commencement of Delivery and after YEC has determined the actual cost of the YEC Owner's Costs, and VGC Group will pay such amount within 15 days of receipt of such invoice. Provided however that if the amount to be invoiced to VGC Group for the YEC Owner's Costs exceeds $483,240 then YEC will provide VGC Group with details of the increase in cost and confirm to VGC Group that such increase in cost is not caused by a change to the scope of the work for the YEC Owner's Costs as set out in Schedule C and was otherwise a reasonably necessary increase in cost to complete the YEC Owner's Costs.

(d) The YEC McQuesten Substation Costs under Section B.4 of Schedule B associated with the McQuesten Substation being able to operate at 138 kV is $930,563. At the time that the McQuesten Substation is transferred to YEC by VGC Group under Schedule B, VGC Group will invoice YEC for, and within 15 days after Commencement of Delivery, YEC will pay VGC Group, $930,563 for the YEC McQuesten Substation Costs. Provided however that if there is a change in the scope of the McQuesten Substation work that:

(i) is approved by YEC; and

(ii) results in VGC Group incurring an increase in the YEC McQuesten Substation Costs;

VGC Group will:

(iii) provide YEC with details of the increase in the costs due to the change in scope; and

(iv) confirm to YEC that such increase in costs was a reasonably necessary increase to complete the YEC McQuesten Substation Costs.

Subject to YEC's review and confirmation of the VGC Group submission, YEC will pay to VGC Group the reasonable increase in the costs due to the change in scope affecting the YEC McQuesten Substation Costs.

(e) If the Step Down Transformer is required to be provided by YEC under Section 4.6, YEC will invoice VGC Group when YEC orders the Step Down Transformer for 50% of all of YEC's estimated costs and expenses reasonably required for design, engineering, procurement, construction, and commissioning of the Step Down Transformer and VGC Group will pay such invoice within 15 days of receipt. YEC will invoice VGC Group for the remainder of YEC's reasonably incurred costs and expenses to design, engineer, procure, construct, and commission the Step Down Transformer within 30 days of when the Step Down Transformer is commissioned and VGC Group will pay such invoice within 15 days of receipt.

(f) If YEC incurs Other System Improvement capital costs caused by an increase in Maximum Electric Demand under Section 5.5, the related amendments to this Agreement will provide for YEC to recover from VGC Group any reasonably incurred YEC Capital Costs for the required Other System Improvements.

PART 7
BILLING/PAYMENT

7.1 **VGC Group Power Bill**. As soon as practicable following the last day of each month after the Commencement of Delivery, YEC will deliver the VGC Group Power Bill to VGC Group setting out the amount payable to YEC by VGC Group under this Agreement for all Electricity delivered by YEC to VGC Group during such month. VGC Group will pay YEC the amount set out in each VGC Group Power Bill within 15 Business Days of the date of delivery of the VGC Group Power Bill to VGC Group. Electricity provided by YEC to VGC Group will be charged to VGC Group at the rates provided for in this Agreement.

7.2 **Canadian Funds**. All payments by VGC Group to YEC will be made in Canadian funds to an office or banker of YEC, as YEC may direct to VGC Group in writing, at Whitehorse, Yukon Territory.

7.3 **Failure to Render Invoice**. Failure to render an invoice within the time periods set out in this Agreement will not abrogate YEC's right to receive payment of the VGC Group Power Bill, VGC Group Capital Cost, Decommissioning Costs, or other amounts payable under this Agreement.

7.4 **Late Payment** Any payment to be made by VGC Group to YEC under this Agreement that remains unpaid, in whole or in part, when due will be subject to a late payment charge at a rate of interest equivalent to the Service Charge calculated on the amount unpaid from the due date of payment until payment is made in full.

7.5 **Prepayments**. Any payments to be made by VGC Group to YEC under this Agreement may be prepaid by VGC Group at any time in whole or in part without penalty.

7.6 **Taxes**. All sales taxes, excise taxes, or similar charges payable on Electricity delivered to VGC Group under this Agreement will be added to the VGC Group Power Bill and paid by VGC Group under Section 7.1.

7.7 **Fixed Charge**. The Fixed Charge will be determined as follows:

(a) Prior to the Transmission Facilities Development Operation Date, the Transmission Facilities Fixed Cost used to determine the Fixed Charge is $118,621, or any amended amount approved by the YUB from time to time.

(b) After the Transmission Facilities Development Operation Date, YEC will apply to the YUB to amend the Transmission Facilities Fixed Cost based on YEC's adjusted annual costs for depreciation and return on rate base related to the Transmission Facilities plus the SVC/Statcom and YEC's McQuesten Substation Costs. The adjusted Transmission Facilities Fixed Cost will apply until otherwise amended by the YUB.

(c) The annual Fixed Charge amount will be determined by YEC as follows:

(i) in calendar years when there is no Other Industrial Customer, the annual amount for the Fixed Charge will equal 85% of the Transmission Facilities Fixed Cost as last determined by the YUB; and

(ii) in calendar years when there is one or more Other Industrial Customers, the estimated VGC Group portion of the Major Industrial Customer MWh load on the

Transmission Facilities during the calendar year (the "**VGC Group Share**") will be estimated by YEC and the Fixed Charge for months during the calendar year will equal the VGC Group Share of 85% of the Transmission Facilities Fixed Cost as last determined by the YUB. Within 60 days of the calendar year end, YEC will adjust the Fixed Charge based on the actual VGC Group Share as determined by actual MWh load during the calendar year for VGC Group and any Other Industrial Customers. The fixed charge applicable to each Other Industrial Customer in any calendar year will be determined in the same manner, based on each such customer's share of the Major Industrial Customer MWh load on the Transmission Facilities during the calendar year.

(iii) With regard to securing any required YUB approvals related to Fixed Charge amounts, including any approvals related to the VGC Group Share or the Transmission Facilities Fixed Cost, YEC will provide the YUB with such supporting documentation as required by the YUB, and will use commercially reasonable efforts to obtain the approval of the YUB, and VGC Group will use commercially reasonable efforts to support such application by YEC.

PART 8
METERING

8.1 **Metering**. The Grid Electricity purchased by VGC Group under this Agreement will be measured and recorded at the Point of Delivery by revenue meters having one hour integrating intervals, which meters, will be types approved for revenue metering by Industry Canada and will comply with the *Electricity and Gas Inspection Act* (the "**Act**").

8.2 **Testing**. YEC will test its metering equipment under Section 8.1 and field test the metering installation in compliance with the Act. If requested to do so by VGC Group, YEC will make additional tests or inspections of such installations, the expense of which will be paid by VGC Group, unless VGC Group has confirmed by such testing that the metering is faulty in which case such testing will be paid for by YEC. YEC will give reasonable written notice to VGC Group of the time when any such test or inspection is to be made. VGC Group may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate will be adjusted, repaired, or replaced by YEC to provide accurate metering. If a meter is found not to be functioning within the prescribed limit of error, the Electricity purchased will be determined under the Act.

8.3 **Backup Metering**. VGC Group may, at its cost and expense, install a backup metering system to check YEC's metering system performance and, if so, VGC Group will own, operate, and maintain this system, at VGC Group's sole cost and expense.

8.4 **Costs**. All costs and expenses incurred by YEC, beyond normal reading and testing of meters and other costs that YEC is to pay under Section 8.2, in complying with its obligations under Section 8.2 will be invoiced separately to VGC Group by YEC and will be paid by VGC Group upon receipt.

PART 9
FORCE MAJEURE

9.1 **Force Majeure**. Subject to Section 9.3, neither Party will be liable to the other Party for any delay in or inability of the first Party to perform its obligations under this Agreement if any such delay or inability is a direct result of Force Majeure.

9.2 **Notice of Force Majeure**. If a Party suffers a Force Majeure it will promptly notify the other Party in writing and within 10 days of becoming so aware will give written notice to the other Party:

(a) describing the Force Majeure in reasonable detail and stating, to the extent reasonably practicable at such time, its estimate of the duration of the Force Majeure;

(b) setting out in reasonable detail the obligations under this Agreement which it is unable to perform or will be delayed in performing as a direct result of the Force Majeure;

(c) containing particulars of the circumstances causing the Party to be unable to perform or delayed in performing its obligations under this Agreement as a direct result of the Force Majeure; and

(d) describing what needs to be done and what will be done to end the Force Majeure.

(e) During a Force Majeure a Party invoking the Force Majeure will exercise commercially reasonable efforts to end the Force Majeure.

9.3 **Exclusions**. A Party may not invoke Force Majeure:

(a) for lack of money or credit;

(b) if the Force Majeure is the result of a breach by the Party seeking to invoke Force Majeure of a permit, certificate, licence, approval, or of any applicable laws, regulations, or orders;

(c) if the Party seeking to invoke Force Majeure has failed to use commercially reasonable efforts to prevent or remedy the situation and remove, so far as possible and with reasonable dispatch, the effects of the Force Majeure; or

(d) if the Force Majeure was caused by a breach of, or default under this Agreement or a wilful or negligent act or omission by the Party seeking to invoke Force Majeure.

If a Party is required to perform an obligation by a certain date or with a specified time period and the Party is delayed in performing that obligation by a Force Majeure the date or time for the performance of that obligation will be extended by a period of time equal to the length of the Force Majeure.

PART 10
REPRESENTATIONS AND WARRANTIES

10.1 **YEC Representations and Warranties**. To induce VGC Group to enter into this Agreement YEC hereby represents and warrants to VGC Group as of the effective date of this Agreement, upon each of which representations and warranties VGC Group specifically relies, as follows:

(a) YEC Corporate Organization and Authority: YEC has been duly incorporated and is a validly existing corporation under the laws of the Yukon Territory, is in good standing with respect to all required filings in the office of the Registrar of Companies and has the full corporate power and capacity to execute and deliver this Agreement and perform its obligations under this Agreement.

(b) Authorization, Consents, and Enforceability: The execution and delivery of this Agreement by YEC and the consummation by YEC of the transactions contemplated hereby have been duly authorized by the Board of Directors of YEC and this Agreement constitutes valid and binding obligations of YEC, enforceable against YEC in accordance with its terms, subject to the availability of equitable remedies and enforcement of creditors' rights generally.

(c) Compliance: The entering into and compliance by YEC with this Agreement is legal, does not violate any provisions of any requirement of law and does not result in any breach of any of the provisions of, or constitute a default under any charter document, by-law, unanimous shareholder agreement, loan agreement, or other agreement or instrument to which YEC is a party or by which it is or its property may be bound.

10.2 **VGC Group Representations and Warranties**. To induce YEC to enter into this Agreement VGC Group hereby represents and warrants to YEC as of the effective date of this Agreement, upon each of which representations and warranties YEC specifically relies, as follows:

(a) VGC Group Corporate Organization and Authority: Each of the members of the VGC Group has been duly incorporated and is a validly existing corporation under the laws of the Province of British Columbia and is in good standing with respect to all required filings in the office of the Registrar of Companies and has the full corporate power and capacity to perform business in the Yukon Territory and to execute and deliver this Agreement and perform its obligations under this Agreement.

(b) Authorization, Consents, and Enforceability: The execution and delivery of this Agreement by VGC Group and the consummation by VGC Group of the transactions contemplated hereby have been duly authorized by the respective Boards of Directors of VGC Group and this Agreement has been duly executed and delivered by VGC Group and constitutes valid and binding obligations of VGC Group, enforceable against VGC Group in accordance with its terms, subject to the availability of equitable remedies and enforcement of creditors' rights generally.

(c) Compliance: The entering into and compliance by VGC Group with this Agreement is legal, does not violate any provisions of any requirement of law and does not result in any breach of any of the provisions of, or constitute a default under any charter document, by-law, loan agreement, or other agreement or instrument to which VGC Group is a party or by which they or their property are or may be bound.

PART 11
DEFAULT

11.1 **Event of Default**. Each of the following events constitutes an "**Event of Default**" for a Party in question (the "**Defaulting Party**"):

(a) an Event of Insolvency of such Party; or

(b) any representation or warranty of such Party contained in this Agreement being untrue in any material respect unless the default is of a nature that can be cured and it is cured within 30 days, or such reasonable time period as may be required given the default, following receipt by the Defaulting Party of written notice from the other Party specifying the nature of the default and requiring that the default be cured; or

(c) any default (other than defaults of a non-material nature) by such Party in the performance or observance of any of the covenants, agreements, and obligations on its part to be performed or observed under this Agreement, unless the default is of a nature that can be cured and it is cured within 30 days, or such reasonable time period as may be required given the default, following receipt by the Defaulting Party of written notice from the other Party specifying the nature of the default and requiring that the default be cured.

11.2 **Remedies**. If an Event of Default under Section 11.1 occurs, any Party not in default (the "**Non-Defaulting Party**") may do one or more of the following:

(a) pursue any remedy available to it in law or equity, it being acknowledged by the Parties that specific performance, injunctive relief (mandatory or otherwise), or other equitable relief may be the only adequate remedy for an Event of Default; or

(b) if the Event of Default is curable, take all actions in its own name or in the name of the Defaulting Party as may reasonably be required to cure the Event of Default, in which event all payments, costs, and expenses incurred therefore will be payable by the Defaulting Party to the Non-Defaulting Party on demand with interest at the Interest Rate; or

(c) waive the Event of Default, provided any waiver of the particular Event of Default will not operate as a waiver of any subsequent or continuing Event of Default; or

(d) in the case of an Event of Default by VGC Group under Section 7.1 YEC may upon 15 days' notice to VGC Group suspend or discontinue the supply of Grid Electricity to VGC Group, but no such suspension or discontinuance by YEC will relieve VGC Group of its obligations under this Agreement, including the obligation to make payment of any sum, nor will any such suspension or discontinuance constitute or be deemed to constitute rescission of this Agreement.

PART 12
DISPUTE RESOLUTION

12.1 **Confidentiality of Process**. The Parties will maintain the dispute resolution process set out in this Part 12 as confidential and such process will not be disclosed, unless otherwise required by law, by any Party to any other Person unless previously discussed and agreed to in writing by the Parties. For greater certainty, no part of the dispute resolution process will be open to the public.

12.2 **Stages**. Disputes that arise among the Parties will progress, until resolved, through the following stages of the dispute resolution process:

Step 1: Within 10 days of one Party providing written notice to the other Parties that a Dispute exists, the Presidents of each of the Parties, or their nominees in the first instance or themselves if they cannot resolve the Dispute, will meet and make good faith efforts to resolve the Dispute through collaborative negotiation by:

(i) identifying underlying interests;

(ii) isolating points of agreement and disagreement;

(iii) exploring alternative solutions;

(iv) considering compromises or accommodations; and

(v) taking any other measures that may assist in resolution of the Dispute.

Step 2: If the Presidents of each of the Parties are unable to resolve the Dispute themselves within 30 days of the written notice under Step 1, either Party may give written notice to the other Party of a desire to commence mediation and the Parties will jointly appoint a mutually acceptable mediator within 30 days after the date that such notice is given. If the Parties are unable to agree upon the appointment of a mediator within 30 days after a Party has given notice of a desire to mediate the Dispute, either Party may apply to the British Columbia Mediator Roster Society for appointment of a mediator. The Parties agree that the mediation will be conducted under the Mediation Rules of the British Columbia Mediator Roster Society.

Step 3: If a Dispute has not been resolved through mediation under Step 2 within 30 days of the appointment of a mediator, either Party, by notice in writing to the other Party, may refer such unresolved Dispute to binding arbitration under the *Arbitration Act*, (R.S.Y., 2002, c.8). The Parties will agree upon an Arbitrator within 30 days of the notice of arbitration being provided, failing which the Arbitrator will be selected under the *Arbitration Act*, (R.S.Y., 2002, c.8). The decision of the arbitrator will be final and binding on the Parties.

12.3 **Availability of Argument**. In any Dispute, a Party may raise any defence or argument that it would otherwise have been able to raise at law, equity, or otherwise, had the Dispute been referred to a court of competent jurisdiction, including a defence that the Dispute is statute-barred by the *Limitation of Actions Act*, (R.S.Y., 2002, c.139).

12.4 **No Further Claims**. When Disputes are settled among the Parties to the Agreement under this Part 12 no further:

(a) claim may be made; and

(b) compensation will be payable by any Party,

for the same Dispute.

12.5 **Continued Payment**. Pending resolution of any Dispute, VGC Group will continue to pay to YEC any sums payable under this Agreement and YEC may avail itself of its remedy under Section 11.2(d) in relation to a failure by VGC Group to do so.

PART 13
INDEMNITY

13.1 **Limitation of Liability**. No Party will be liable to the other Party in contract, tort, warranty, strict liability, or any other legal theory for any indirect, consequential, incidental, punitive, or exemplary damages arising under or in connection with this Agreement or in connection with the failure to perform or observe obligations under this Agreement. No Party will have any liability to the other Party except under, or for breach of, this Agreement provided, however, that this Section 13.1 is not intended to constitute a waiver of any rights of one Party against the other Party for matters which are unrelated to this Agreement.

13.2 **Indemnification**

(a) VGC Group will indemnify and save YEC harmless for any loss or damage to property, death, or injury to Persons (or any claim against YEC in respect thereof) and all expenses relating thereto (including without limitation reasonable legal fees) suffered or incurred by YEC in connection with this Agreement resulting from any negligence or wilful default of VGC Group in connection with the performance of its obligations under this Agreement or a breach by VGC Group of its obligations under this Agreement. The indemnity will not extend to any loss, damage, death, or injury (or any claim in respect thereof) or any expenses relating thereto to the extent that it was caused by the negligence or wilful default of YEC or the failure of YEC to take reasonable steps in mitigation thereof. Notwithstanding anything to the contrary contained in the preceding sentence, nothing in this Section 13.2(a) will apply to any loss, damage, cost, or expense in respect to which, and to the extent that, YEC is compensated under any insurance, agreement, or through any other means.

(b) YEC will indemnify and save VGC Group harmless for any loss of or damage to property, death or injury to person (or any claim against VGC Group in respect thereof) and all expenses relating thereto (including without limitation reasonable legal fees) suffered or

incurred by VGC Group in connection with this Agreement from any negligence or wilful default of YEC in connection with the performance of its obligations under this Agreement or a breach by YEC of its obligations under this Agreement. The indemnity will not extend to any loss, damage, death, or injury (or any claim in respect thereof) or any expenses relating thereto to the extent that it was caused by the negligence or wilful default of VGC Group or the failure of VGC Group to take reasonable steps in mitigation thereof. Notwithstanding anything to the contrary contained in this preceding sentence, nothing in this Section 13.2(b) will apply to any loss, damage, cost or expense in respect of which, and to the extent that, VGC Group is compensated under any insurance, agreement, or through any other means.

(c) If such injury or damage results from the joint or concurrent negligent or intentional acts of the Parties each will be liable under this indemnification in proportion to its relative degree of fault.

13.3 **Assertion of Claims**. No Party will be entitled to assert any claim for indemnification until such time as all claims of such Party for indemnification under this Agreement exceed an amount equal to $10,000, in the aggregate, at which time all claims of such Party for indemnification under this Agreement may be asserted; provided, however, that when such claims have been asserted the same rule will apply in respect of future claims. Notwithstanding the preceding sentence, a Party may assert a claim for indemnification regardless of amount upon the expiry or earlier termination of this Agreement or if such claim would otherwise be barred by the *Limitation of Actions Act*, (R.S.Y., 2002, c.139).

13.4 **Defence of Claims**. The indemnified Party will have the right, but not the obligation, to contest, defend, and litigate any claim, action, suit, or proceeding by any Person alleged or asserted against such Party in respect of, resulting from, related to, or arising out of any matter for which it is entitled to be indemnified under this Agreement, and the reasonable costs and expenses thereof will be subject to the indemnification obligations of the indemnifying Party under this Agreement provided, however, that if the indemnifying Party acknowledges in writing its obligations to indemnify the indemnified Party in respect of loss to the full extent provided by Section 13.2, the indemnifying Party will be entitled, at its option, to assume and control the defence of such claim action, suit, or proceeding at its expense and through counsel of its choice if it gives prompt notice of its intention to do so to the indemnified Party and, reimburses the indemnified Party for the reasonable costs and expenses incurred by the indemnified Party prior to the assumption by the indemnifying Party of such defence, and provides reasonably adequate security for any judgment for costs that might be imposed on the indemnified Party. The indemnified Party will not be entitled to settle or compromise any such claim action, suit, or proceeding without the prior written consent of the indemnifying Party, which consent will not be unreasonably withheld or delayed. The indemnified Party will have the right to employ its own counsel and such counsel may participate in such action (but the fees and expenses of such counsel will be at the expense of such indemnified Party), provided that the:

(a) employment of counsel by such indemnified Party has been authorized in writing by the indemnifying Party;

(b) indemnified Party will have reasonably concluded that there may be a conflict of interest between the indemnifying Party and the indemnified Party in the conduct of the defence of such action;

(c) indemnifying Party will not in fact have employed independent counsel reasonably satisfactory to the indemnified Party to assume the defence of such action and will have been so notified by the indemnified Party; or

(d) indemnified Party will have reasonably concluded and specifically notified the indemnifying Party either that there may be specific defences available to it which are different from or additional to those available to the indemnifying Party or that such claim

action, suit, or proceeding involves or could have a material adverse effect upon it beyond the scope of this Agreement.

If Sections 13.4(a), (b), (c), or (d) are applicable, then counsel for the indemnified Party will have the right to direct the defence of such claim, action, suit, or proceeding on behalf of the indemnified Party and the reasonable fees and disbursements of such counsel will constitute legal or other expenses under this Agreement.

PART 14
ASSIGNMENT

14.1 **Assignment**. No Party may assign this Agreement without the prior written consent of the other Party, such consent not to be unreasonably withheld.

14.2 **Sale of the Transmission Facilities** . If YEC disposes of all or any interest in the Transmission Facilities, YEC will ensure that the obligation to sell Grid Electricity from the Transmission Facilities, on the same basis as provided for in this Agreement will continue and be assumed by the purchaser of such interest, for the Term. YEC will require, as a condition of the closing of the disposition of such interest, that the purchaser sign an agreement in a form satisfactory to VGC Group, acting reasonably, which provides that the purchaser agrees to be bound by this Agreement.

14.3 **Sale of the Mine**. If VGC Group disposes of all or any interest in the Mine, the Mine Facilities, or the VGC Group Power Facilities, VGC Group will ensure that the obligation to purchase Grid Electricity from YEC on the same basis as provided for in this Agreement will continue and be assumed by the purchaser of the Mine, the Mine Facilities, or the VGC Group Power Facilities for the Term. VGC Group will require as a condition of the closing of the disposition of the Mine, the Mine Facilities, or the VGC Group Power Facilities that the purchaser sign an agreement in a form satisfactory to YEC, acting reasonably, which provides that the purchaser agrees to be bound by this Agreement for the Term.

PART 15
CONFIDENTIALITY

15.1 **Confidentiality**. Except as required by law, and subject to Section 15.1, a Party will not disclose to a third person who is not a Party any information, data, or documents, supplied by one Party to the other Parties under this Agreement (collectively, the "**Confidential Information**") without the consent of the other Party, such consent not to be unreasonably withheld.

15.2 **Exceptions**. Section 15.1 will not:

(a) extend to information that is already in the public domain or becomes, after having been disclosed to a Party, generally available to the public unless the disclosure was made directly or indirectly by a Party in breach of this Agreement;

(b) prevent a Party from divulging Confidential Information in confidence to its Affiliates and to its or their officers, directors, employees, agents, or other representatives on a "need-to-know" basis;

(c) prevent a Party from divulging Confidential Information in confidence to third parties (provided the third party is subject to similar confidentiality restrictions), in order to permit the operation of the Mine or the Transmission Facilities, as the case may be, in the ordinary course, all on a "need-to-know" basis;

(d) prevent a Party from divulging Confidential Information to the extent required by applicable legislation or stock exchange requirements;

(e) prevent a Party from divulging Confidential Information to the extent necessary in connection with any dispute resolution commenced under this Agreement or any litigation commenced in respect of this Agreement;

(f) prevent a Party from divulging Confidential Information to the extent necessary, in confidence, to any financial institution for the purpose of obtaining financing for such Party or any of its Affiliates;

(g) prevent a Party from divulging Confidential Information to the extent required by any Governmental Authority having jurisdiction to require the production of such Confidential Information; and

(h) prevent a Party from divulging Confidential Information to the extent necessary, in confidence, to a prospective purchaser of the Mine or the Transmission Facilities or YEC's other assets required to meet YEC's obligations under this Agreement, as the case may be, on a "need to know" basis.

If any Party is required to disclose Confidential Information under Sections 15.2(d), (e), or (g), such Party will advise the other Party in writing in advance of any such disclosure where reasonable so that the other Party may take such action as they consider necessary to maintain the confidentiality of such Confidential Information, and will take reasonable steps to limit the extent of the disclosure and to make such disclosure confidential under the applicable legislation, stock exchange rules, or rules of any governmental or regulatory authority having jurisdiction, as the case may be.

15.3 **Survival**. The obligations of confidentiality in Section 15.1 will survive the termination or expiry of this Agreement indefinitely, and any Party who ceases to be a Party will continue to be bound by such obligations following such termination or expiry.

15.4 **Injunctive Relief**. Each Party acknowledges that all Confidential Information is proprietary to the disclosing Party and that breach of this Agreement by a Party may result in irreparable injury to the other Party. Accordingly, in the event of any breach of Section 15.1 by a Party, the other Party will be entitled to seek and obtain an order of specific performance, restraining order, or injunctive relief, in addition to any other legal or equitable remedies provided under this Agreement.

PART 16
GENERAL

16.1 **Notices**. Except as otherwise provided in this Agreement, any notice, direction, demand, request, or document required or permitted to be given by any Party to any other Party under this Agreement will be in writing and deemed to have been sufficiently given if signed by or on behalf of the Party giving the notice and delivered or transmitted by facsimile to the other Party's address or facsimile number as shown below:

(a) To YEC:

Yukon Energy Corporation
P.O. Box 5920, #2 Miles Canyon Road
Whitehorse, YT Y1A 6S7

Attention: President

Facsimile: 867-393-5323

with a copy to:

DLA Piper (Canada) LLP
2800 - 666 Burrard Street
Vancouver, BC V6C 2Z7

Attention: John Landry

Facsimile: 604-605-3588

(b) To VGC:

Victoria Gold Corp.
1050 West Pender Street
Vancouver, BC V6E 3E7

Attention: Mark Aryanto

Facsimile: 604-682-5232

(c) To StrataGold:

StrataGold Corporation
1050 West Pender Street
Vancouver, BC V6E 3E7

Attention: Mark Aryanto

Facsimile: 604-682-5232

or to such other address or facsimile number or to the attention of such other official or individual as a Party will have most recently notified the other Party of in the manner hereinbefore provided. Any such notice, direction, request, or document will conclusively be deemed to have been received by the intended recipient on the date of delivery or transmission, as the case may be, except that if it is not received at such address or at the facsimile device by 5:00 P.M. on a Business Day (at the place of receipt) it will conclusively be deemed to have been received by the intended recipient on the next Business Day immediately following its receipt at such address or at such facsimile device.

16.2 **Coordination of Communications**. Each Party agrees to cooperate with the other Parties in order to coordinate all press, news, or other releases to private or public media groups in connection with this Agreement. Each Party will use all reasonable efforts to allow the other Parties to review such releases in advance of release and will comply with all reasonable requests from the other Parties as to the content or manner of publication of such releases.

16.3 **Amendment**. The only amendments, which may be made to this Agreement are amendments in writing which have been approved by the Parties.

16.4 **Governing Law and Language**. This Agreement will be governed by and construed under the laws of the Yukon Territory and applicable Canadian law and will be treated in all respects as a Yukon Territory contract.

16.5 **Submission to Jurisdiction**. Each of the Parties will:

(a) submit to the jurisdiction of the Yukon Territory courts;

(b) if not incorporated or registered in the Yukon Territory appoint an agent to receive service of any process in the Yukon Territory; and

(c) if any appointed agent is required, notify the others of the name and address of its appointed agent.

16.6 **Severability**. Each provision of this Agreement is intended to be severable and if any provision is illegal or invalid, such illegality or invalidity will not affect the validity of this Agreement or the remaining provisions.

16.7 **Entire Agreement**

(a) This Agreement and any other arrangement in writing between any of the Parties, which is entered into substantially contemporaneously with this Agreement constitute the entire agreement between the Parties relating to the subject matter of this Agreement and supersedes all prior negotiations and agreements, whether written, oral, implied or collateral, between the Parties, provided, however, that any confidentiality agreements, or confidentiality provisions contained in any agreements, executed between the Parties in connection with the transactions contemplated in this Agreement will continue in full force and effect and will survive any termination of this Agreement.

(b) No representation or inducement whether made by statement or delivery of data or other information of any kind or nature whatsoever and whether in writing, orally or in any other manner conveyed by any Party to any other Party survives the execution of this Agreement unless expressly made in this Agreement.

16.8 **Further Assurances**. As and so often as any Party may reasonably require, the Parties agree to execute and deliver further and other documents, assurances and conveyances as may be necessary to properly carry out the intention of this Agreement.

16.9 **Successors and Assigns**. This Agreement enures to the benefit of and will be binding upon the Parties and their respective permitted successors and permitted assigns.

16.10 **Waivers**. No provision of this Agreement may be waived except by a written instrument and any waiver of a provision:

(a) is valid only in respect of the specific instance to which it relates and is not a continuing waiver; and

(b) is not to be construed as a waiver of any other provision.

16.11 **Time**. Subject to Part 9, time is of the essence of this Agreement.

16.12 **Counterparts**. This Agreement may be executed in any number of counterparts with the same effect as if the Parties had signed and delivered the same document. All counterparts will be construed together and will constitute one and the same agreement. This Agreement will be duly executed and delivered if facsimile signature pages are exchanged by the Parties.

16.13 **Joint and Several**. The obligations of VGC Group under this Agreement are joint and several obligations of VGC and StrataGold.

This Agreement is executed by the Parties in multiple originals effective as of the day and year first written above.

YUKON ENERGY CORPORATION

By: _____

President & CEO
Authorized Signatory

Dated: 9 November 2017

VICTORIA GOLD CORP.

By: _____

Authorized Signatory

Dated: November 10, 2017

STRATAGOLD CORPORATION

By: _____

Authorized Signatory

Dated: November 10, 2017

Effective: 2018 02 28
Supercedes: 2012 01 01

SCHEDULE A

RATE SCHEDULE 39

INDUSTRIAL PRIMARY

AVAILABLE: Throughout the service areas of Yukon Energy Corporation ("**YEC**") and The Yukon Electrical Company Limited ("**YECL**") served by the Yukon Integrated Grid.

APPLICABLE: To all major industrial customers engaged in manufacturing, processing or mining with an electric service capacity in excess of 1,000 kW.

RATE: Charges in any one billing month will be the sum of the following:

(a) Demand Charge of $15.94/kVA of Billing Demand

(b) Energy Charge of 8.08¢/kWh for all energy used.

(c) Fixed Charge

For service to Minto mine site, the Fixed Charge each month shall equal the payments required under the amended Power Purchase Agreement (the "**Minto PPA**") dated May 14, 2007 between YEC and Minto Explorations Ltd. ("**Minto**") for monthly Capital Cost Contributions for transmission connection to the mine.

For service to Alexco mine and mill sites, the Fixed Charge each month will equal the amounts under the Power Purchase Agreement (the "**Alexco PPA**") dated September 1, 2010 between YEC and Alexco Resource Corp. ("**Alexco**") for existing transmission connection to the mine and mill sites, until such time as this amount is amended by the YUB based on the VGC Group PPA.

For service to VGC Group mine site, the Fixed Charge each month will equal the amounts under the Power Purchase Agreement (the "**VGC Group PPA**") dated November 9, 2017 between YEC, Victoria Gold Corp., and StrataGold Corporation ("Victoria Gold Corp. and StrataGold Corporation are collectively, the "**VGC Group**") for transmission connection to the mine site, subject to

amendment from time to time as provided for in Section 7.7 of the VGC Group PPA.

PEAK SHAVING CREDIT:

For customers with an established Winter Contract Load in good standing, a Peak Shaving Credit in each billing month equal to 50% of the Demand Charge times the Peak Shaved Load.

MINIMUM MONTHLY BILL:

The minimum monthly bill will be the sum of the Demand Charge and the monthly Fixed Charge, less any applicable Peak Shaving Credit.

PEAK SHAVED LOAD:

Peak Shaved Load in any billing month is the amount by which then nominated Winter Contract Load is less than the Billing Demand for the month.

BILLING DEMAND:

The Billing Demand will be the greater of:

(a) the highest metered kVA demand recorded in the current billing month; or

(b) the highest metered kVA demand recorded in the previous 12-month period including the current billing month, excluding the months April through September; or

(c) the contract minimum demand.

WINTER CONTRACT LOAD:

A customer may, by six month written notice to YEC, nominate a Winter Contract Load at not less than two-thirds of the customer's contract maximum demand subject to the following conditions:

(a) The customer will thereby contract with YEC not to exceed the nominated Winter Contract Load whenever the temperature at Whitehorse is below -30 degrees Centigrade, based on YEC informing the customer by phone, fax or e-

mail as to forecast and actual winter temperatures at Whitehorse as provided for in paragraph (b);

(b) YEC will inform the customer at least one hour in advance, and not more than one day in advance, of a forecast temperature at Whitehorse being below -30 degree Centigrade; thereafter, until YEC informs the customer otherwise, the customer will be responsible for ensuring that its metered kVA demand does not exceed the Winter Contract Load during any hour when the actual temperature at Whitehorse is below -30 degrees Centigrade; YEC will inform the customer forthwith when the temperature at Whitehorse is no longer forecast to be below -30 degree Centigrade within the next 24 hours;

(c) The customer agrees that the contract for the nominated Winter Contract Load will continue until terminated by written notice of not less than 12 months by the customer to YEC;

(d) If during such contract period for the Winter Contract Load the customer's metered kVA demand recorded, after YEC has provided notice as specified in paragraph (b) above, exceeds the Winter Contract Load when the temperature at Whitehorse is less than -30 degrees Centigrade, the Winter Contract Load contract will be terminated forthwith, the customer will forthwith be required to repay to YEC all Peak Shaving Credits determined within the previous 12 billing months, and the customer will also pay for that billing month to YEC as penalty an amount equal to four times the Demand Charge on the metered kVA demand recorded in excess of the Winter Contract Demand; in addition, YEC reserves the right if so required to meet system loads when the temperature at Whitehorse is less than - 30 degrees Centigrade during the then current month and the following 12 months to interrupt electricity supplied to the customer in excess of the previous Winter Contract Load.

BASE LOAD ENERGY:

A Base Load Energy amount per month may be established for a customer at 90% of forecast use when YEC expects to require diesel fuel generation to service use in excess of such a Base Load Energy amount. At such time, Rate Schedule 39 will be submitted to the Yukon Utilities Board for amendment to adjust the Energy rate as required for a two part rate that yields the same overall energy charge at forecast energy use, with all energy consumed in excess of the Base Load being charged at a rate reflecting the

incremental cost of service using diesel fuel generation and all other energy being charged at the reduced rate required to yield the same overall energy charge at forecast energy use.

RATE MODIFICATIONS APPLICABLE:

For fuel adjustment rider, see Rider F. Rider F applied to energy charges only, set to $0.0 for fuel price forecast filed November 20, 2006 and changed as follows:

a) Fixed Rider F of 0.211 cents per kWh charged only to Rate Schedule 39 customers to account for fuel price variance from price forecast filed November 20, 2006 to fuel price forecasts for 2009 as approved by the Board in Order 2009-08 and Order 2009-10 for Yukon Energy; plus

b) Ongoing Rider F per kWh as required to ensure consistency, after consideration of the Fixed Rider F as provided for in (a) herein, with the Rider F applied to all applicable rate schedules to account for fuel price variance from price forecasts as last approved by the Board for Yukon Energy and Yukon Electrical GRAs.

TERMS AND CONDITIONS OF SERVICE :

The Company's Terms and Conditions of Service approved by the Yukon Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Terms and Conditions of Service are available for inspection in the offices of the Company during normal working hours.

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Schedule B

McQuesten Substation

B.1 **McQuesten Substation Planning to Date.** The McQuesten Substation project to be connected to the existing grid powerline between Mayo and Keno City is designed to accommodate the future Transmission Facilities Development. The McQuesten Substation project and the Transmission Facilities Development have completed Yukon Environmental and Socio-economic Assessment Act screening followed by a decision document issued by the Yukon Government to allow all required construction and operating permits for the Stewart-Keno City Transmission Project (or components thereof) to be issued. YEC can secure access from the Yukon Government to use of the required right of way. Detailed engineering design of the McQuesten Substation project has been largely with funding from the Yukon Government and VGC Group.

B.2 **McQuesten Substation MOU**. A copy of the McQuesten Substation MOU (the "**MOU**") that was signed by VGC and YEC on September 19, 2017 is attached in Appendix B-1 to this Schedule B, setting out a formal relationship between the Parties and commitments to enable the Parties to work together on the successful tendering, procurement, construction, commissioning and turnover of the McQuesten Substation to YEC. The MOU notes that the McQuesten Substation design has been directed and reviewed by YEC, and has been frozen after the 85% design review and the agreement of the Parties to the design. VGC Group is authorized under the MOU to order long lead equipment, and is responsible under the MOU for issuing request for tender proposals, construction management, and pre-commissioning activities. YEC is responsible under the MOU for actual commissioning of the McQuesten Substation. The MOU provides for the Parties to develop an acceptance test or protocol for determining that the McQuesten Substation has been commissioned, and that deficiencies identified during commissioning will be rectified by VGC and approved by YEC before the McQuesten Substation is released to YEC for commercial operation. When the Substation has passed the agreed upon acceptance test or protocol and all deficiencies are rectified by VGC to the satisfaction of YEC, the MOU specifies that VGC will execute and deliver a document agreed to by the Parties transferring legal and beneficial title to the McQuesten Substation to YEC free and clear of all liens, charges, and encumbrances.

B.3 **McQuesten Substation Capital Costs funded by VGC Group:** Except as otherwise specified in this Agreement, VGC Group will fund all of the costs, fees and expenses for development of the McQuesten Substation, including actual final YEC's Owners Costs (see Table B-1 for YEC's estimate of these costs as of the current date). The YEC's Owner's Costs will be recovered from VGC Group after the Commencement of Delivery under Section 6.1(c) of this Agreement.

Table B-1: YEC's Owner's Costs for McQuesten Substation Development

Project Manager	$68,640
Owner's Engineer	$93,600
Site Supervision	$186,000
SCC SCADA	$16,000
Overhead (management, reporting)	$15,000
Commissioning (Internal)	$44,000
Commissioning (External)	$60,000
Total	**$483,240**

B.4 **McQuesten Substation Capital Costs funded by YEC**: YEC is responsible for the YEC McQuesten Substation Costs for incremental fees, costs and expenses associated with the McQuesten Substation being able to operate at 138 kV voltage at such time after the Commencement of Delivery when the Transmission Facilities Development is completed and energized at 138 kV YEC McQuesten Substation Costs are set at **[$930,563]**, as detailed in Table B-2. The YEC McQuesten Substation Costs will be payable by YEC to VGC Group after the Commencement of Delivery under Section 6.1(d) of this Agreement.

Table B-2: YEC McQuesten Substation Costs

5258 McQuesten & 5249 Mayo	YEC	
Construction	**$**	**605,931**
Supervision	$	36,000
Site Prep (Civil works)	$	325,350
Foundations	$	174,081
Structure and Bus Work	$	8,000
Electrical / Telecontrol / Telecom	$	62,500
Material	**$**	**240,036**
Switch Yard	$	132,770
Major Equipment	$	87,266
Delivery	$	20,000
Commissioning	**$**	-
On-site		
Owner's Costs	**$**	-
Overall owner's costs		
Subtotal	$	845,967
Contingency (10%)	$	84,597
TOTAL	**$**	**930,563**

Appendix B-1: McQuesten Substation MOU

Eagle Gold Project – McQuesten Substation

Memorandum of Understanding ("MOU")

BETWEEN

YUKON ENERGY CORPORATION (**"YEC"**)

AND

VICTORIA GOLD CORP. (**"VGC"**)

(collectively the **"Parties"**)

WHEREAS, VGC is a leading gold exploration and development company whose Eagle Gold Project (the "**Project**") is located within proximity to YEC's grid, is fully permitted and under construction to be Yukon's next and largest gold mine;

WHEREAS, YEC is a crown owned, regulated utility with a mandate to plan, generate, transmit, and distribute a continuous and adequate supply of energy in the Yukon;

WHEREAS, VGC and YEC have finalized detailed design of the McQuesten Substation (the "**Substation**"), finalized a system impact study and are actively working on the development of a power purchase agreement which provides the technical and commercial terms for connecting the Project to YEC's grid;

WHEREAS, YEC is currently planning for the replacement and upgrade of the Stewart-Keno Transmission Line; and

WHEREAS, YEC and VGC seek to work together on the successful tendering, procurement, construction, commissioning and turnover of the Substation to YEC.

NOW THEREFORE, YEC and VGC agree to the Eagle Gold Project – McQuesten Substation MOU as outlined below:

Objective

The objective of the Parties is to construct a quality Substation on scope as per the detailed design through quality workmanship in supply and installation, on schedule to meet the Project schedule, and in the most cost-effective manner possible.

Intent

The intent of this MOU is to establish a formal relationship between the Parties and secure commitments to enable the Parties to work together on the successful tendering, procurement, construction, commissioning and turnover of the Substation to YEC by:

- Sharing and exchanging information that is relevant to discussions as outlined in this MOU,
- Committing to the principles of collaboration and time is of the essence,
- Developing a work plan to track and summarize all responsibilities and activities undertaken through this MOU,
- Scheduling regular meetings to ensure ongoing meaningful dialogue, resolution of any issues, formalizing key decisions and reporting on progress,
- Implementing the Substation Construction Execution Plan with the schedule, file No. S258 Construction Schedule R2,
- Developing a genuine atmosphere of collaboration and alliance in the support of an effective and efficient partnership and leadership meant to maintain, safeguard and sustain sound and optimal managerial, financial and administrative commitment with regards to all matters related to the Substation,
- Recognizing that by implementing any contract, license, or other agreement entered into between the Parties subsequent hereto shall supersede any conflicting provision of this MOU.

Workplan

A workplan will be established to detail the implementation of the Substation through the draft Work & Responsibility Matrix attached to this MOU as Schedule 1.

Workplan Assumptions

1. Funding

Except as set out below VGC will fund all the full fees, costs, and expenses, including YEC's non-executive labour costs, external fees, costs, and expenses of the design, engineering, procurement, construction, project management, site supervision, SCADA changes, operations orientation and commissioning of the Substation. Notwithstanding the foregoing YEC will be responsible for all incremental fees, costs, and expenses associated with Substation being able to operate at 138 kV voltage, which amount will be payable by YEC to VGC at the time the Substation is transferred to YEC under Section 7 below.

2. Design Approval

The Substation design has been directed and approved by YEC.

The 85% design review of August 22, 2017, has frozen the design fully meeting YEC's requirements and both Parties agree to the design.

3. Long Lead Equipment Procurement

Orders for long lead equipment are, as of Aug. 22, 2017, being progressed by VGC, which ATCO will issue for tender with ordering prior to year-end 2017. The equipment will be ordered for delivery to ensure the Substation project schedule is maintained.

All of the long lead equipment vendors, save the E-house, have already been approved by YEC and VGC.

4. Preparation of Installation Tender Documents

A tender document for the contract is required. The type of contract (fixed price lump sum, cost plus, unit rate, etc.) to be mutually agreed by the Parties. ATCO will provide a construction work package which includes substation drawings, technical specifications, and tendering documents. YEC may require general and special conditions of contract and evaluation criteria, including provisions which provide for the assignment of all manufacturer warranties to YEC when YEC becomes the owner of the Substation under Section 8 below. YEC will provide VIT with any special conditions prior to VIT ordering any long lead equipment and prior to VGC preparing the tender document. VGC will be responsible for assembly of the document.

5. Tendering & Evaluation of Proposals

VGC, in conjunction with YEC, will be responsible for assembling a list of pre-approved tenderers. Tendering will be on the basis that any or no successful tenderer may be accepted, but in general the principle will be to select a complying proposal that meets all technical and construction requirements, has a competitive price and is by a tenderer with a good utility performance record and is in a solid financial position.

The subject of bid and performance bonds is to be mutually agreed upon by the Parties.

VGC will be responsible for issuing the request for tender proposals (RFPs) and formally answering questions as may arise during tendering.

VGC, with assistance of ATCO, will be responsible for the tender technical and schedule evaluation, with approval from YEC pursuant to the tender document.

VGC will be transparent with YEC for the economic evaluation of the tenders.

6. Permits

The Parties will identify all permits required for the construction and operation of the Substation and allocate responsibility for obtaining such permits.

7. Construction Management & QA/QC

VGC will be responsible for construction management. YEC may review the construction materials and methods and will be kept fully up to date, receive all reports, and make site visits as required and appropriate.

The contractor will be required to retain a pre-approved substation electrical testing contractor. Concrete and similar civil testing will be made available to YEC.

VGC will be responsible for oversight of the QA/QC process, from the results of which will be made available to YEC.

VGC will, in conjunction with the testing subcontractor, be responsible for pre-commissioning and preparation of "punch lists." (See also Section 8, Acceptance & Commissioning below.) This list will be reviewed and approved by YEC.

8. Acceptance & Commissioning

VGC or its designate will complete "pre-commissioning" which consists of all the tests done by the testing subcontractor. These tests will be specified and recorded by VGC, and approved by YEC before proceeding to substation commissioning.

Actual commissioning will be the responsibility of YEC, with assistance from Substation contractor and other parties as involved in Substation installation and testing. The Parties will develop an acceptance test or protocol for determining that the Substation has been commissioned. Deficiencies identified during commissioning will be rectified by VGC and approved by YEC before the Substation is released to YEC for commercial operation. When the Substation has passed the agreed upon acceptance test or protocol and all deficiencies are rectified by VGC to the satisfaction of YEC, VGC will execute and deliver a document agreed to by the Parties transferring legal and beneficial title to the Substation to YEC, free and clear of all liens, charges, and encumbrances.

Duration

The term of this MOU shall extend until March 31, 2019.

Extent of the Agreement

The signing of this MOU doesn't create any legal or financial obligations on the part of either Party. No rights or limitation of rights shall arise or be assumed between the Parties as a result of the terms of this MOU.

Assignment

Neither Party to this MOU may assign or transfer the responsibilities or agreements made herein without the prior written consent of the non-assigning Party, which approval shall not be unreasonably withheld.

Legal and Regulatory Authority

Any future agreements and projects will be subject to any and all legal and regulatory approvals under any applicable legislation.

Acts of Parties and Agents

Each Party shall be responsible for the acts of its own employees, agents and contractors in carryout the provisions of the MOU.

Amendment

Any amendments to the MOU will be made in writing upon the consent of both Parties.

Termination

Either Party may terminate this MOU by providing thirty (30) days written notice to the other Party.

The Parties have executed, and made effective, this MOU as of the ____ day of September, 2017.

VICTORIA GOLD CORP

_____

Mark Ayranto, Executive VP

YUKON ENERGY CORPORATION

_____

Andrew Hall, President & CEO

Schedule 1

Work & Responsibility Matrix

[NTD: Matrix to be reviewed and updated by Parties.]

Item	Description	Responsibility / Approval Milestones
1	Design completion including S258 and by-pass lines. The design is now 85% with all significant items agreed to by all.	VGC and YEC
2	Purchase of long lead "engineered" equipment	VGC
3	Preparation of tender documents	VGC, YEC
4	Pre-qualification of tenderers	VGC and YEC
5	Installation contract: tendering, contractor selection, and award.	VGC and YEC
6	Construction management	VGC
7	Strategy for QA/QC, third party inspection, etc.	VGC, YEC
8	Strategy to meet the recently published schedule	VGC
9	First Nations participation	VGC
10	Coordination with Northwestel and others	VGC (construction manager)
11	Temporary facilities as required	VGC (construction manager)
12	Contractor mobilization to site	VGC (construction manager)
13	Contractor invoicing and payment	VGC (construction manager)
14	Schedule maintenance	VGC
15	Safety plan with zero accidents objective	VGC (construction manager)

Item	Description	Responsibility / Approval Milestones
16	Field material and free issue equipment, control plan	VGC (construction manager)
17	Parties to identify additional permits required for the Substation and allocate responsibility for obtaining permits.	VGC and YEC
18	Environmental including temporary site drainage control, etc.	VGC (construction manager)
19	Contractor detailed schedule, labour (manpower) plan, review and approve	VGC (construction manager)
20	Site security	VGC (construction manager)
21	Testing & pre-commissioning (by approved subcontractor)	VGC (construction manager), YEC
22	Final inspection and turn over	YEC & VGC
23	Commissioning	YEC
24	Transfer of legal title of Substation to YEC	VGC and YEC
24	Keno outage and line change-over	YEC

Schedule C

Initial YEC System Improvements

C.1 The Initial YEC System Improvements that YEC is to design, engineer, procure, construct and commission on YEC's existing power system prior to Commencement of Delivery, to accommodate the sale of Grid Electricity by YEC to VGC Group for the Mine, are as follows:

a) Update YEC Under Frequency Load Shedding (UFLS) Scheme:

UFLS settings changes are to be implemented in certain locations throughout the YEC system, as set out in Table C-1 (the specific settings in this table are subject to ongoing change by YEC at its sole discretion as needed for system impact management). Some changes are required to third party equipment (Minto and ATCO). Mayo F1 and Minto will both require relay installations. Testing and tuning will be completed as required following real life system contingencies.

Table C-1: Under Frequency Load Shedding Settings

Item Tripped	Relay Settings			Simulation Parameters		
	f (hz)	df/dt (hz/s)	T_d (4)	T_m+T_d (s)(3)	T_b (s)(2)	T_t (s)(1)
Minto Block 1 – 50% of Load	59.5	-3.4		.25	.083	0.333
Minto Block 1 – 50% of Load	56	----		.25	.083	0.333
Minto Block 2 – 50% of Load	59.5	-4.2		.1	.083	0.183
Minto Block 2 – 50% of Load	56	----		.75	.083	0.183
Minto Capacitor Bank	59.5	-3.4		.1	.083	0.183
Minto Capacitor Bank	56	----		.25	.083	0.183
S170 S6838	59.5	-1.0		0.6	.083	0.683
S150-52-22, S150-52-21	59.5	-1.8		0.4	.083	0.483
S170 S6837	59.5	-2.6		0.2	.083	0.283
S164 52-7	56.5	----		0.1	.083	0.183
EG F1 Block 1– 50% of F1Load + Caps(5)(6)	59.5	-1.0		0.55	.083	
EG F1 Block 2 – 50% of F1 Load +Caps	59.5	-2.4		0.25	.083	
EG F2 Block 3– 50% of F2 Load + Caps	59.5	-3.2		0.10	.083	
EG F2 Block 4 – 50% of F2 Load + Caps	59.5	-1.8		0.4	.083	.483
Dawson F1	56	----	1.		.083	
Dawson F2	56	----	2.		.083	
Mayo F1	58	----	5.		.083	
Callison (Hunker Creek)	56	----	1.		.083	
Keno/Elsa	59.5	-3.4		0.4	.083	.483
McQuesten Capacitor Stage1 (2 MVAr)	59.5	-1.8		.25	.083	.333
McQuesten Capacitor Stage2 (2 MVAr)	59.5	-2.4		.10	.083	.183

(1) Total clearing time. Includes all intentional and non-intentional delays and breaker interrupting time.
(2) Breaker interrupting time. This may be reduced to observed times.
(3) T m+Td is the relay measurement delay plus the delay set on the relay. Tm will vary with the specific relay and the settings and must be determined.
(4) Td must be determined by the relay engineer to achieve to Tt indicated (TBD).
(5) F1- Crusher & Conveyers, F2 – Process Plant and Pumping.
(6) Capacitors are shed in proportion to the amount of load shed so the resulting load power factor remains close to unity.

b) Confirm timing of Mayo Breaking Resistors:

Timing test to be performed on the breaking resistors for both insertion and removal.

There are two banks of resistors (2 MW each) each with four stages of 250 kW and two stages of 500 kW. They engage and disengage on frequency and have a limited insertion time of 70 and 12 seconds for the 250 and 500 kW units respectively. Once the thermal limit is reached they disconnect and then are precluded from engaging for the next 15 minutes.

Once timing is determined they are to be compared to the desired settings. Settings changes may be required which will require additional modeling. Current estimated settings are as follows (the specific settings provided below are subject to ongoing change by YEC at its sole discretion as needed for system impact management):

- Stage 1 – >61.5 Hz, >+0.2 Hz/s, >0.1 s (250 kW, 60 seconds).
- Stage 2 – >61.8 Hz, >+0.2 Hz/s, >0.1 s (250 kW, 60 seconds).
- Stage 3 – >62.1 Hz, >+0.2 Hz/s, >0.1 s (250 kW, 60 seconds).
- Stage 4 – >62.4 Hz, >+0.2 Hz/s, >0.1 s (250 kW, 60 seconds).
- Stage 5 – >62.7 Hz, >+0.2 Hz/s, >0.1 s (500 kW, 10 seconds).
- Stage 6 – >63.0 Hz, >+0.2 Hz/s, >0.1 s (500 kW, 10 seconds).

c) Commission LV Reactor Insertion/Trip (Minto/Faro):

The purpose of this is to add or remove the reactors from the system during system contingencies. The existing protection relays at Faro and Minto do not have the functionality to accommodate this. They will need to be replaced. There is limited space in the Minto e-house meaning that the panels will need to be reworked. The Minto relay installation will require more than average engineering and installation time. The required scheme is as follows:

- Automatic insertion of the 2.5 MVAr reactors at Minto and Faro on detection of sustained voltages greater than 107% (positive sequence or phase-to-phase) with time delays of not less than 2 seconds and less than the over-voltage trips set on L178 at Carmacks, L173 at Minto and L174 at Stewart (staggered insertions). Initial settings can be 2 and 2.5 seconds.
- With two 2.5 MW reactors in service at Minto a trip of either L173 or the trip of L174 at Minto must also cross-trip one reactor with no intentional delay. One of two reactors should also be tripped upon detection of open breaker contacts opening for L173 or L174 breakers at Minto. With only one 2.5 MVAr reactor in service at Minto no action is taken.

d) Confirm Aishihik/Mayo over-frequency trips:

Over-frequency trips for Mayo-B units and Aishihik units to limit over-frequency in the event of a separation south of Takhini. This work requires settings changes and testing only. Over frequency trips as set are to remain:

- Aishihik1 - >62.7Hz, >0.3 seconds
- Mayo B1 - >66Hz, >0.3 seconds

e) Engage Over frequency trips on WG1,2,3:

As backup and to cover isolations south of Minto where SPS and RAS are not practical due to lack of communications. This is due to the increases in the south to north flow resulting from the Mine development and generation supplied from Whitehorse. This work requires equipment replacement, testing and settings changes as per the following current assessments (the specific settings provided below are subject to ongoing change by YEC at its sole discretion as needed for system impact management):

- LNG1>61.5 Hz, >+1.8Hz/s, >.6s AND Also >63.5 Hz, 0.6s.
- LNG2>61.5 Hz, >+2.4Hz/s, >.4s, AND Also >63.5 Hz, 0.4s.
- LNG3>61.5 Hz, >+3.2Hz/s, >.2s, AND Also >63.5 Hz, 0.2s.

f) Confirm over-voltage trips on MD interconnect and L173:

This work requires settings changes and testing only. Protection settings to be set as follows (the specific settings provided below are subject to ongoing change by YEC at its sole discretion as needed for system impact management):

L174 or L175 at Stewart - 138kV Voltage

- 140% for 0.15s OR
- 127% for 7s OR
- 117% for 40s

L173 at Minto - 138kV Voltage

- 140% for 0.15s OR
- 127% for 6s OR
- 117% for 30s

L178 at Carmacks - 138kV Voltage

- 140% for 0.10s OR
- 127% for 5s OR
- 117% for 30s

g) SPS/RAS1 - Shed Mine load for loss of Mayo:

The loss of units at Mayo can cause unacceptable voltage depressions. SPS/RAS1 executes a high speed load rejection on L250, L180 and the Mine feeders. Operating instructions will need to be written for the YEC System Control Centre. Mayo B and S249 will need some fiber work (fiber already existing but not connected). Programmable Logic Controller (PLC) will need to be

installed at S249. Assuming that no work needed at MH0. Heavy engineering is needed for design and programing of this scheme. SCADA component is also significant.

h) SPS/RAS2 – L172 Riverside Generation Rejection Whitehorse

Ensures that system frequency deviation is limited to within tolerable bounds and can be brought back to 60 Hz. SPS/RAS2 monitors L172 MW at Whitehorse and arms selected units for rejection upon detection of trip or open breakers on the Whitehorse end of L172. Units available for selection are three LNG units (preferred trip - assumes LNG third unit installed) and WH3. This work requires some equipment changes to accommodate fiber communications (fiber is already installed). PLC needed at Riverside substation and engineering is needed for design and programing of this scheme. SCADA component is also significant.

i) SPS/RAS3 – L172 Takhini: Generation Rejection Whitehorse
SPS/RAS4 – L170 Takhini: Generation Rejection Whitehorse

Ensures that system frequency deviation is limited to within tolerable bounds and can be brought back to 60 Hz. SPS/RAS3 and SPS/RAS4 monitors L172 and L170 MW at Takhini and arms selected units for rejection upon detection of trip or open breakers on the Whitehorse end of L172 and L170. Units available for selection are three LNG units (preferred trip) and WH3. This work requires some equipment changes to accommodate fiber communications (fiber from Whitehorse to Takhini is being installed by another YEC project, however if that project is canceled then this project would need to pick up that work). PLC needed at Takhini substation and heavy engineering is needed for design and programing of this scheme. SCADA component is also significant.

j) SPS/RAS5 – MacIntyre: Generation Rejection Whitehorse

Ensures that system frequency deviation is limited to within tolerable bounds and can be brought back to 60 Hz. SPS/RAS5 Monitors load at MacIntyre substation and arms selected units at Whitehorse for rejection upon detection of trip or open breakers that disconnect the load from the system. Rejection would include the three LNG units (preferred trip) and WH3. This work requires some equipment changes to accommodate fiber communications (fiber from Whitehorse to MacIntyre is being installed by another YEC project, however if that project is canceled then this project would need to pick up that work). PLC needed at MacIntyre substation and heavy engineering is needed for design and programing of this scheme. SCADA component is also significant.

k) SPS/RAS6 Loss of Mine Load – Tripping Mayo Generators

The loss of load at the Mine can cause unacceptable voltage spikes. SPS/RAS6 monitors L250 at Mayo substation and arms selected Mayo units for rejection upon detection of trip or open breakers for L250, L180 and the Mine. Operating instruction will need to be written for the YEC SCC. Mayo B and S249 will need some fiber work (fiber already existing but not connected). PLC will need to be installed at S249. Significant programming time. Assuming that no work needed at MH0. Mayo Diesel requires SCADA and Automation systems to be installed along with some fiber work.

l) Verify the Mine SPS design, settings and commissioning

YEC to verify VGC Group design, settings and commissioning of SPS's at the Mine as required pursuant to Schedule D.

m) Out of Step – Protection Review L171

The Mine development increases the speed requirements of protection and backup protection operations for faults near Takhini and in particular L171. Settings, backup clearing times and coordination to be reviewed. This requires system studies, installation of new settings and testing.

n) SPS/RAS7 L172 Riverside Trip: On High Load - Cross Trip Takhini Terminal L172

SPS/RAS7 mitigates lower transient voltages that result for certain contingencies with the reactors in service. Monitors L172 MW at Riverside and Takhini. The setting will depend on the amount of generation on line in the north.

- Arming Parameter = L172 North at Riverside – L172 North at Takhini
- Arm at 0 MW with Aishihik off line
- Arm at the lesser of 4 MW or the regulating reserve at Aihihik when Aishihik is on line
- Requires high-speed communications between Whitehorse and Takhini

o) Dispatch YEC thermal generators to limit MD Import from south <11 MW

Programmed alarms for YEC SCC; minimal effort required.

C.2 The estimated YEC Capital Costs of $1,677,883 for the Initial YEC System Improvements are provided in Table C-2.

Table C-2: Estimated YEC Capital Costs for Initial YEC System Improvements

	Initial YEC System Improvements	Estimated Capital Cost				
		Contractor	Labour	Material	Contingency	Total
a	Update YEC UFLS Scheme	$94,200	$24,880	$7,000	$50,432	$176,512
b	Mayo Breaking Resistors	$19,400	$4,000	$0	$9,360	$32,760
c	Minto/Faro LV Reactor Intersection/Trip	$81,000	$8,880	$2,500	$36,952	$129,332
d	Aishihik/ Mayo Over-frequecy Trips	$11,200	$1,600	$0	$5,120	$17,920
e	Over-frequecy trips on WG 1,2,3	$17,600	$5,600	$10,000	$13,280	$46,480
f	Over-voltage trips on MD interconnect and L173	$17,600	$4,000	$2,500	$9,640	$33,740
g	SPS/RAS1 - Shed EG load for loss of Mayo	$54,025	$12,880	$10,000	$30,762	$107,667
h	SPS/RAS2 - L172 Takhini: Generation Rejection WH	$100,200	$28,400	$40,000	$67,440	$236,040
i,j	SPS/RAS3/4/5 - L172/L170 Takhini & MacIntyre: Generation Rejection WH	$240,000	$78,800	$20,000	$135,520	$474,320
k	SPS/RAS6 - Loss of EG Load - Trip Mayo	$85,000	$40,000	$50,000	$70,000	$245,000
l	Verify EG SPS Design, Settings, Commissioning	$6,400	$6,800	$2,500	$6,280	$21,980
m	Out of Step - Protection Review L171	$48,000	$20,880	$2,500	$28,552	$99,932
n	SPS/RAS7 L172 Riverside Trip: On High Load - Cross Trip Takhini Terminal L172	$0	$30,500	$2,500	$13,200	$46,200
0	Dispatch YEC Thermal Generators to Limit MD Impart from south <11 MW	$0	$10,000	$0	$0	$10,000
	Total	$774,625	$277,220	$149,500	$476,538	$1,677,883

Schedule D

VGC Group Power Facilities

D.1 The VGC Group Power Facilities that VGC Group is to install at the Mine Facilities prior to Commencement of Delivery, and to operate thereafter as set out herein as part of the Mine Facilities in order to manage impacts on the YEC power system from the sale of Grid Electricity by YEC to VGC Group for the Mine, are as follows:

a) Measures in Substitution of McQuesten Capacitor Bank Installation

The following equipment-related measures will be undertaken in substitution of McQuesten Capacitor Bank installation:

- Ensure that Mine UFLS sheds capacitors in proportion to the Mine load.
- Trip Mine load in response to capacitor bank trips. (i.e., loss of capacitor bank trips two main feeders).

b) Coordinate Mine Voltage and Tap Changer Controls

Normally the transformer tap-changers will regulate the 13.8kV bus (presumably to nominal voltage). This approach cannot be applied with the Mine generation online. The following operation will be adopted at the Mine Facilities and can be changed if mutually agreed by YEC and VGC Group:

- Mine capacitor banks are switched to produce a net load power factor of unity measured on the feeders or on the LV side of transformers but netting out the reactive load on the generators.
- Tap-changers control 13.8 kV bus voltage with generation off.
- With the Mine generators on, the tap-changers are moved to nominal taps and further operation blocked.
- The Mine generators regulate the 13.8 kV bus voltage between 100 and 105% of nominal and YEC has control of this set-point. Generators reactive output will be adjusted by YEC in real time, to regulate the 69kV system voltage, by pulsing the AVR voltage set-points. The Mine sets the acceptable range that YEC can adjust voltage within it.
- YEC must have full SCADA visibility of the Mine substation and control of critical elements.

c) Install over-voltage protection

To prevent feeder/load trips at the Mine from creating sustained over-voltages the following protections are required at the Mine Facilities:

- On loss of either of the two main Mine feeders, directly trip a proportionate share of the Mine capacitors with no intentional delay.
- Capacitor stages also must have over-voltage protection set to trip when voltage exceeds threshold on the 69kV bus. The trips are to be staggered with time delays settable, as specified by YEC. The delays are expected to be in the 0.1 to 20 second range. Initial settings are 108% for 1 second and 1.25 and 1.75 seconds assuming shedding in blocks, one allocated to each main feeder.

- Trip of capacitor bank blocks must also trip associated feeder with no intentional delay.

d) Mine Reactive support

VGC Group will install and operate the following as part of the Mine Facilities:

- Capacitors must be shed with load and load shed with capacitors
- Install SPS and RAS Loss of the Mine capacitors – Trip Mine load
- Install SPS/RAS Loss of the Mine Load – Trip Mine capacitors pro-rata
- Maximum size of switched elements 1.4 MVAr
- Subject to Power Quality requirements, VGC Group may choose to maintain 1MW of load when shedding in order to maintain power supply to critical loads.

e) SPS/RAS6 Loss of Mine Load – Tripping Mayo Generators

The loss of load at the Mine can cause unacceptable voltage spikes. SPS/RAS6 monitors L250 at Mayo substation and arms selected Mayo units for rejection upon detection of trip or open breakers for L250, L180 and the Mine. Equipment with the necessary metering and communication capabilities including high speed communication to be installed at the Mine Site or McQuesten Substation as required.

f) Mine Generators equipped with Utility Grade Speed and Voltage Controls

The Mine Facilities generators must provide the same frequency and voltage ride-through as utility generators. In addition the controls must provide the same operational modes as those found on similar utility generators as follows:

- AVR/Exciters will operate in voltage control mode. This is the mode they will invariably operate in.
- Speed Governor – The governor will operate in speed droop (not kW-droop). Any constant kW mode that is included (for troubleshooting) must have trips to Droop that are set by YEC. The governors must be set up to maximize response to frequency deviation, both loading and unloading. YEC must receive test results and modeling information.

g) Under Frequency Protection

Under Frequency Load Shedding (UFLS) is required at the Mine site to minimize the negative effects of contingency events on the YEC system. The settings will be as per YEC discretion.

h) YEC Inspections

YEC will have access to the Mine equipment for periodic testing and verification of the SPS/RAS functionality.

Schedule E

Operating Agreement

E.1 **Operating Agreement.** Prior to the Commencement of Delivery and throughout the balance of the Term, YEC and VGC Group will maintain an operating agreement (the "**Operating Agreement**") to coordinate electric power operations of YEC and the Mine.

E.2. **Draft Operating Agreement.** Appendix E-1 to this Schedule E provides a draft Operating Agreement that the Parties will finalize prior to the Commencement of Delivery. The following are noted regarding terms used in the Draft Operating Agreement:

- "L251" means the Mine Facilities Spur; and
- "Operational Boundary/Interface Point of Point of Common Coupling (PCC)" means the Point of Delivery

E.3 **Amendments to Operating Agreement**. The Parties will review the provisions of the Operating Agreement on a regular basis, and amend the Operating Agreement form time to time as required to reflect changing conditions and requirements.

Appendix E-1: Draft Operating Agreement

YUKON ENERGY	OPERATING AGREEMENT	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		ISSUED DATE	Review Date	Victoria Gold / Yukon Energy Operating Agreement

1.0 Purpose

1.1 This procedure outlines the steps to take to ensure a reliable and safe supply of power to the Mine through a variety of circumstances.

2.0 General Information

2.1 Breaker Identification
S258 52-1 – Connection between the McQuesten bus and S249 (Mayo) bus
S258 52-2 – Connection between the McQuesten bus and S257 (Keno) bus
S258 52-3 – Connection between the McQuesten bus and L251
VGC 52-T1 – Connection between L251 and the VGC bus
VGC 52-T2 – Connection between L251 and the VGC bus

2.2 Interlocks
Identified break interlocks with sequence information

Operating Authority: The organizational unit assigned responsibility for operating a portion of the electrical system. For YEC the SCC operator is the operating authority. For the VGC Group the ??? is the operating authority.

Operational Boundary/Interface Point or Point of Common Coupling (PCC): The location on the electrical system at which responsibilities between Operating Authorities meet. The breaker S258 52-3 is the interface point between the Mine and YEC.

2.3 Contact Information
SCC – phone 867-393-5355 or 867-393-5324 (recorded lines)

Mike Hannah (Leadhand SCC)	393-5399, cell 334-6759
Myles O'Brien (Operation Coordinator)	393-5352
Ed Peake (Manager Operations)	393-5383, cell 334-6586
Guy Morgan (Director of Operations)	393-5366, cell 334-6904

Mine – Contact Information ########

2.4 Normal Operation
Under normal operating conditions the Mine will be supplied from the YEC grid. The breakers status under normal operating conditions is as follows.

Breaker	**Status**
S258 52-1	Closed
S258 52-2	Closed

S258 52-3	Closed
VGC 52-T1	Closed
VGC 52-T2	Closed

3.0 Operating Procedures

3.1 L### (S258 to the Mine Site) Isolation

L### isolation requires the minimum notification defined in section 4.3, with the exception of emergency repairs. YEC will provide a condition guarantee on breaker S258 52-3. The condition guarantee is used in communications between external parties. It is a formal method of communication that switching has been completed. It ensures the status of the breaker/device will not change until the work is complete, the lock out tag out is surrendered and all workers are clear.

3.2 Voltage Support/Load Reduction

Based on the power quality conditions defined in Schedule F of this Agreement and system security requirements, SCC may request voltage support and/or a mine load reduction. Voltage support and a Mine load reduction can be accomplished by placing the Mine generation on line, or other means such as capacitor banks or transformer tap changing.

- When the Mine has generation online, the generators regulate the 13.8 kV bus voltage between 100 and 105% of nominal and YEC will have control of this set-point. Generators reactive output will be adjusted by YEC in real time, to regulate the 69kV system voltage, by pulsing the AVR voltage set-points. VGC Group sets the acceptable range that YEC can adjust voltage within it.
- YEC must have full SCADA visibility of the Mine substation and control of critical elements.

3.3 SCC Remote Monitoring and Control

SCC will have visual indication of the Mine breakers, generator status, capacitor status and electrical measurement information for the Mine Site Single Line Diagram (SLD) including transformers, feeders and breakers. Control will be limited to approving load step requests from the Mine to SCC. Load step requests will be approved by SCC based on the generation dispatch and system status. Load changes of more than 1000 kW must be communicated and approved by YEC.

YEC will have control (open and close) of incoming 69kV line breakers at the Mine.

If VGC Group exceeds the Maximum Electric Demand load limitations specified in Section 5.1 of this Agreement, the following procedure will be followed.

a) SCC will contact VGC Group to notify them that their load is exceeding the cap.
b) VGC Group has 30 min to reduce load below the cap.
c) If VGC Group does not comply within 30 mins, SCC will contact VGC Group again to provide a final warning.
d) If the Mine still does not comply within 30 mins, SCC operator may exercise the right to disconnect the Mine by opening S258 52-3.

4.0 Operational Notification

4.1 Daily Operating Communications
Under normal operating conditions the Mine will be supplied from the YEC grid. Load changes supplied to the Mine of more than 1000 kW must be communicated and approved by YEC.

4.2 The transition from winter to summer and conversely summer to winter loading needs to be established with SCC with a minimum of 30 days' notice.

4.3 Mine Planned Maintenance and Scheduling
To meet changing operating conditions and coordinate maintenance efforts, maintenance shutdowns by the Mine need to be communicated to SCC at least one week in advance for shutdowns of up to 12 hours and 30 days for shutdowns longer than 12 hours.
Changes in the availability and capacity of the onsite generation needs to be communicated to SCC at least 30 days in advance of such changes.
The Parties will share annual shutdown/maintenance plans in February of each year.

4.4 YEC Transmission and Generation Maintenance and Scheduling
YEC performs annual line maintenance on the transmission lines and generation facilities, during which Grid Electricity to the Mine may be curtailed or suspended. The duration of this annual transmission and generation maintenance can be up to 14 days per calendar year.
YEC will provide a minimum of 30 days' notice of the start date and expected duration of work that will curtain or otherwise interrupt the supply of Grid Electricity to the Mine.

5.0 Loss of Supply Procedures

5.1 Loss of Supply - Short Term
In the event of a disturbance that results in the loss of Grid Electricity to the Mine Site, SCC will make one attempt to re-energize the line to the Mine Site. If successful the following steps apply to resume the Mine operation with Grid Electricity.

a) SCC will confirm the status of the breakers located in the S258 switching station.

Breaker	Expected Status
S258 52-1	Closed
S258 52-2	Closed
S258 52- 3	Closed
VGC 52-T1	Open
VGC 52-T2	Open

b) SCC will request closed breakers VGC 52-T1 and VGC 52-T2.

c) Once complete and with confirmation from SCC the Mine may proceed with the restarting of their operation. VGC Group will communicate to SCC on load pickups greater than 1000 kW. The request to load up may be communicated verbally or via SCADA.

5.2 Loss of Supply - Long Term
In the event of a disturbance that results in the loss of Grid Electricity to the Mine Site and SCC is unsuccessful in re-energizing the line the following steps will apply.

b) SCC will confirm the status of the breakers.

Breaker	Expected Status
S258 52-1	Closed
S258 52-2	Closed
S258 52- 3	Open
S258 52-4	Closed
VGC 52-T1	Open
VGC 52-T2	Open

c) At the direction of SCC the Mine personnel will start and stage their diesels on line supplying power to the Mine.

d) Once the line to the Mine has been re-energized, with confirmation that breaker S258 52-3 is closed.

e) SCC will request the Mine synchronize and close breakers VGC 52-T1 and VGC 52-T2.

f) The Mine is now connected to YEC Grid Electricity. Once complete and with confirmation from SCC the Mine may proceed with the restarting of their operation. VGC Group will communicate to SCC on load pickups greater than 1000 kW. The request to load up may be communicated verbally or via SCADA.

g) At the direction of SCC the Mine personnel will be requested to unload and shutdown some or all Mine Site diesel generation

7.0 Revision and Approval

7.1 This Agreement comes into effect once it is signed by VGC Group and YEC.

7.2 This Agreement will remain in effect unless cancelled upon the mutual agreement of both Parties.

7.3 The Parties will provide 90 days notice in writing of the intention to modify this Agreement.

7.4 The Agreement may be revised upon mutual agreement of both Parties. This agreement will be formally reviewed every two (2) years.

Approved by: _____
Guy Morgan
Yukon Energy Corporation

Approval Date: _____

Approved by: _____
X
Victoria Gold Corporation

Approval Date: _____

Approved by: _____
X
Stratagold Corporation

Approval Date: _____

Schedule F

Power Quality Requirements

F.1 **Power Quality Requirements**. Starting with the Commencement of Delivery and throughout the Term when receiving Grid Electricity from YEC, VGC Group will operate the Mine Facilities in accordance with the power quality requirements of YEC as set out in this Schedule F and in Section 5.6 of this Agreement. In this Schedule F "PCC" means the Point of Delivery.

F.2 **Power Factor**. VGC Group will maintain a 96% leading load power factor for Grid Electricity supplied to the Mine at the PCC, that is computed from real load (total 13.8 kV real load less the power generated) and reactive load (total 13.8 kV reactive load net of the capacitors and ignoring any reactive power produced by on-line generators) and will be controlled, as nearly as possible, by the capacitor bank steps of 1.4MVAR.

F.3 **Frequency Variation.** The continuous or quasi-continuous variations in the Mine load should not create a variation in system frequency by more than 0.25 Hz. This includes jogging and variation in load. Infrequent load pickups and trips should not cause more than a 0.5 Hz deviation. This is set to ensure that variations do not risk under-frequency load shedding operations without the SCC having to operate with frequency above 60 Hz.

F.4 **Perceptible Lamp Flicker**: Lamp flicker results from voltage variations caused by the operation and switching of equipment and load variations. The short-circuit strength of the 69 kV bus at the Mine can be between 50 and 33 MVA. At McQuesten Substation, the PCC, short-circuit levels vary between 65 and 40 MVA. The Mine shall design equipment and manage operations to meet the following requirements for flicker at the PCC:

a) Pst < 0.8, Plt<0.6 at McQuesten Substation with the 65 MVA normal YEC short-circuit conditions.

b) Pst< 0.9, Plt<0.7 at the McQuesten Substation with reduced 40 MVA normal YEC short-circuit conditions.

c) Based on standards IEEE 1546 (adopted from IEC 61000).

d) Based on 120v 60Hz lamps.

e) Should the Mines operation produce unacceptable variations then dynamic voltage control equipment can be installed.

TOPIC: **Sales Forecasts – Residential Sales.**

REFERENCE: **2021 General Rate Application, page 2-7 (PDF page 32 of 441)**

PREAMBLE: YEC provides one paragraph explaining its residential sales forecast.

QUESTION:

a) Please provide the monthly actual and normal sales, monthly actual and normal sales per customer, and monthly customers for each community for 2015, 2016, 2017, 2018, and 2019 in Excel format.

b) Please provide an explanation for changes in use per customer and number of customers in each community.

c) Please provide the forecast sales, sales per customer, and customers for each community for 2020 and 2021 in excel format.

d) Please provide the calculation of historical averages referred to in line 18,

e) Please provide the actual and normal weather (Temperatures and degree days) by month for each community.

f) Please YEC's definition of normal weather, and the calculation of normal weather for each month for each community.

ANSWER:

(a) through **(d)**

Please see CW-YEC-1-6 Attachment 1 for YEC retail sales for 2018 and 2019 actuals, 2020 and 2021 forecasts. The actuals sales for 2015 through 2017 are not included in Table 2.1 for the 2021 GRA.

As illustrated in CW-YEC-1-6 Attachment 1 the annual sales and sales per customer are steady without any notable changes year over year, except for two instances:

- The annual changes for Mayo general service sales are impacted by Alexco sales. As noted on page 2-8, for the years 2018 through 2020 Alexco was a general service customer with 2.4 GW.h sales in 2018, 1.8 GW.h sales in 2019 and 1.6 GW.h sales forecast in 2020. Starting in 2021 Alexco was included as an industrial customer which resulted in a decrease in average sales per customer for general service in this community in 2021.

- The increase in Faro general service sales reflects changes for the largest General Service customer - Faro Mine remediation project. As noted on page 2-7, the sales for this customer are forecast to grow to 14.4 GW.h in 2020 and 2021 resulting in an increase in average sales per customer.

(e) and **(f)**

YEC does not prepare weather normalized level sales for retail and industrial sales. Therefore, the requested information cannot be provided.

Yukon Energy uses the Environment Canada Canadian Climate Normal for Whitehorse Airport for the definition of normal weather as noted in response to YUB-YEC-1-16 (a). See also CW-YEC-1-3(d) which provides YEC's definition of normal weather.

YEC Retail Sales by Community Level

Residential Sales, MW.h

	Champagne	Faro	JC	Braeburn	Mayo	Dawson	N Klondike Hwy	Total
2018	863	2,845	48	291	3,276	8,224	79	15,626
2019	813	2,869	51	258	3,217	8,114	63	15,384
2020	873	3,188	42	297	3,450	8,811	69	16,730
2021	849	3,115	47	293	3,307	8,529	70	16,210

General Service Sales, MW.h

	Champagne	Faro	JC	Braeburn	Mayo	Dawson	N Klondike Hwy	Total
2018	244	9,973	81	62	5,292	11,419	99	27,171
2019	214	11,975	80	36	4,512	12,238	93	29,148
2020	237	14,947	79	44	4,828	12,022	94	32,250
2021	236	16,902	80	47	2,869	12,078	111	32,323

Residential Annual Average Number of Customers

	Champagne	Faro	JC	Braeburn	Mayo	Dawson	N Klondike Hwy	Total
2018	101	263	9	29	291	991	6	1,689
2019	100	280	9	29	295	1,012	6	1,730
2020	99	288	9	29	299	1,026	6	1,756
2021	100	289	9	29	301	1,046	6	1,780

General Service Annual Average Number of Customers

	Champagne	Faro	JC	Braeburn	Mayo	Dawson	N Klondike Hwy	Total
2018	11	76	3	7	69	333	7	506
2019	11	76	3	7	71	341	8	517
2020	11	75	3	7	72	341	7	516
2021	11	75	3	7	68	341	8	514

Residential Annual Average Usage per Customer, MW.h

	Champagne	Faro	JC	Braeburn	Mayo	Dawson	N Klondike Hwy	Total
2018	9	11	5	10	11	8	14	9
2019	8	10	6	9	11	8	11	9
2020	9	11	5	10	12	9	12	10
2021	8	11	5	10	11	8	12	9

General Service Annual Average Usage per Customer, MW.h

	Champagne	Faro	JC	Braeburn	Mayo	Dawson	N Klondike Hwy	Total
2018	22	131	27	9	77	34	14	54
2019	19	157	27	5	63	36	12	56
2020	22	198	26	7	67	35	13	62
2021	21	224	27	7	42	35	15	63

TOPIC: **Sales Forecasts – General Service Sales**

REFERENCE: **2021 General Rate Application, page 2-7 (PDF page 32 of 441)**

PREAMBLE: YEC provides one paragraph explaining its General Service sales forecast in general and one discussing Faro Mine remediation.

QUESTION:

a) Please provide the monthly actual and normal sales, monthly actual and normal sales per customer, and monthly customers for each community for 2015, 2016, 2017, 2018, and 2019 in Excel format.

b) Please provide an explanation for changes in use per customer and number of customers in each community.

c) Please provide the forecast sales, sales per customer, and customers for each community for 2020 and 2021 in Excel format.

d) Please provide the calculation of historical averages referred to in lines 23-24.

e) If different than residential, please provide the actual and normal weather (Temperatures and degree days) by month for each community.

f) If different than for residential, please YEC's definition of normal weather, and the calculation of normal weather for each month for each community.

ANSWER:

(a) through **(f)**

Please see response to CW-YEC-1-6.

TOPIC: **Sales Forecasts – General Service Sales – Faro Mine remediation**

REFERENCE: **2021 General Rate Application, page 2-7 (PDF page 32 of 441)**

PREAMBLE: YEC provides one paragraph explaining its General Service sales forecast in general and one discussing Faro Mine remediation.

QUESTION:

a) Please provide the referenced "forecasts provided to Yukon Energy by the customer, the Government of Canada". In the response please fully explain any efforts undertaken by YEC to vet or validate the forecasts.

ANSWER:

(a)

The customer provided YEC with forecasts for fiscal 2019 and 2020 (see Attachment 1 to this response). Subsequently by email, the customer provided an update that "our 2021 projection should be in line with what we projected for 2020." YEC reviewed the reasonableness of the forecast and compared it to actual historical results.

Faro Mine Complex | 100 Mine Road | Faro, Yukon, Canada Y0B 1K0
PARSONS
Main: +1 867-994-2600 | www.parsons.com

October 10, 2019
Crown-Indigenous Relations and Northern Affairs Canada Northern Contaminated Sites Branch
Government of Canada Room 415C
300 Main Street Whitehorse, Yukon Y1A 2B2
Email: cam.malloch@canada.ca
Attention: Cam Malloch, P.Eng.
Senior Engineer - Faro Mine Remediation Dear Mr. Malloch:

Re: Draft Electrical Demand Forecast, FY2019 and FY2020
Faro Mine Complex, Faro, Yukon

INTRODUCTION

Pursuant to your request, Parsons Inc. (Parsons) is pleased to provide the following information pertaining to the estimated future demand for electricity at the Faro Mine Complex (FMC). New electrical equipment such as that associated the X13 pumping and conveyance system is now operable and certain other electrical components will be operational over a longer period of time; both activities will increase the amount of electricity consumed at FMC. Although certain older equipment such as the existing IP pumping system will be retired in future years, the demand of the new equipment exceeds the previous demand so the annual cost of the electricity will increase.

This forecast identifies the existing demand and predicts the forecast demand for certain operational scenarios. The forecast is based on actual consumption since April 2016.

EXISTING AND FORECAST DEMAND

The current and future demand is based on the operation of site facilities as summarized in the following tables for FY2019 and FY2020, respectively.

envision more SM
Parsons PLUS

FY2019 FORECAST

Site Facility	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	March
Faro Side Facilities												
Faro Water Facilities												
- Cornell Pumping												
- IWTP												
- IP Pumping												
- Miller Skid Pumping												
- X13 Sump Pumping												
- X13 Other Pumping												
CVPTP Operation												
Van Gorda Side Facilities												
Van Gorda Water Facilities												
- VGWTP												
- VG Pumping												
- Grum Pumping												
Construction Camp												
Legend	Active											

Monthly Energy Summary

Actual Consumption, MWh	612	672	720	864	960	-	-	-	-	-	-	-
Total Actual Consumption, MWh	612	1,284	2,004	2,868	3,828							
Forecast Consumption, MWh	583	583	1,069	1,069	1,110	1,483	1,195	1,114	1,075	1,075	1,075	860
Total Forecast Consumption, MWh	583	1,166	2,235	3,304	4,414	5,897	7,091	8,205	9,280	10,354	11,429	12,289

FY2020 FORECAST

Site Facility	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	March
Faro Side Facilities												
Faro Water Facilities												
- Faro Pit Pumping												
- IWTP												
- IP Pumping												
- Miller Skid Pumping												
- X13 Pumping												
CVPTP Operation												
Van Gorda Side Facilities												
Van Gorda Water Facilities												
- VGWTP												
- Van Gorda Pit Pumping												
- Grum Pit Pumping												
Construction Camp												
Legend	Active											

Monthly Energy Summary

Forecast Consumption, MWh	1,082	1,082	1,676	1,730	1,500	1,500	996	915	876	876	876	661
Total Forecast Consumption, MWh	1,082	2,164	3,840	5,570	7,070	8,571	9,567	10,482	11,358	12,234	13,110	13,771

Cam Malloch
Crown-Indigenous Relations and Northern Affairs Canada October 10, 2019

Based on the assumed equipment and operation schedule we predict that the FMC will consume approximately 12,300 MWh in FY2019 and approximately 13,800 MWh in FY 2020. At historic rates, the FY2019 and FY2020 annual cost for electricity should be approximately $2.40million and $2.60million, respectively.

CLOSURE

We trust that the information presented herein is satisfactory for your present requirements. If you have any questions, please do not hesitate to contact the undersigned.

Respectfully submitted,
PARSONS INC.
James Carss, P.Eng.
Program Director
PARSONS

TOPIC: **Power Generation**

REFERENCE: **2021 General Rate Application, page 2-9 (PDF page 34 of 441) and Table 2.2**

PREAMBLE: CW notes that there is a pattern of increased thermal generation in 2019 and 2020, but this is forecast to decline in 2021. Further, CW notes that the LTA predicts a higher use of thermal. CW requires information as to how the different forecasts would impact customers.

The following table is taken from data in Table 2.2

	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	Forecast 2021
Actual					
Hydro Generation	411,397	413,052	370,819	436,725	506,483
Wind Generation	0	0	0	0	0
IPP Generation	0	0	0	56	1,983
Thermal Generation	11,109	37,316	69,858	71,199	30,260
Total Actual Generation	422,506	450,368	440,676	507,980	538,726
Total Sales	388,332	412,470	403,492	465,788	495,151
Losses	34,173	37,898	37,185	42,193	43,575
	422,506	450,368	440,676	507,980	538,726
LTA					
LTA Hydro Generation	403,910	418,695	415,377	438,905	452,437
LTA Wind Generation	0	0	0	0	0
IPP Generation	0	0	0	56	1,983
LTA Thermal Generation	16,355	31,391	25,300	69,019	84,306
Total LTA Generation	420,265	450,086	440,676	507,980	538,726
Actual					
Hydro Generation	97.37%	91.71%	84.15%	85.97%	94.01%
Wind Generation	0.00%	0.00%	0.00%	0.00%	0.00%
IPP Generation	0.00%	0.00%	0.00%	0.01%	0.37%
Thermal Generation	2.63%	8.29%	15.85%	14.02%	5.62%
Total Actual Generation	100.00%	100.00%	100.00%	100.00%	100.00%
LTA					
LTA Hydro Generation	96.11%	93.03%	94.26%	86.40%	83.98%
LTA Wind Generation	0.00%	0.00%	0.00%	0.00%	0.00%
IPP Generation	0.00%	0.00%	0.00%	0.01%	0.37%
LTA Thermal Generation	3.89%	6.97%	5.74%	13.59%	15.65%
Total LTA Generation	100.00%	100.00%	100.00%	100.00%	100.00%

QUESTION:

a) Please fully explain why the LTA forecasts were not used in the preparation of the GRA forecast.

b) Please explain the impact of a scenario where the actual is closer to the LTA, yet the GRA forecast is approved. What will the impact be on the various deferral accounts and on base rates?

c) CW notes that on lines 21-26 of page 2-9, CW [sic] briefly discusses its sourcing strategy. This addresses years with normal water conditions. Please fully explain the YEC strategy for sourcing energy in years that do not have normal water conditions. What assets are engaged first, second, third, etc. Why is this the appropriate strategy?

d) On lines 17-20 of page 2-9, YEC discusses that 2018 and 2019 experienced unfavourable water conditions, and that actual hydro generation is currently forecast to reflect water availability at about LTA in 2020 and above LTA in 2021. Please fully explain the current water levels, and the likelihood that the GRA forecast generation mix will be achieved.

ANSWER:

(a)

The LTA forecasts as provided in Table 2.2 were used to prepare the GRA forecast, as stated in Sections 2.3 and 3.2 of the Application. Section 3 of OIC 2021/16 also now directs that forecast fuel costs to be included in rates for thermal generation to meet forecast customer requirements are to be based on long-term average annual renewable resource availability.

(b)

The GRA forecast is based on LTA hydro. The scenario in this question cannot occur.

(c)

Yukon Energy optimizes the hydro system within the license requirements to maximize the hydro system capabilities and minimize thermal energy. The typical dispatch order used by Yukon Energy for the system is: (1) hydro, (2) LNG, and (3) diesel, subject to operational restrictions and reliability limitations. This dispatch order is based on minimizing generation costs for ratepayers while maintaining system reliability.

(d)

As quoted above, YEC currently expects better than LTA hydro generation in 2021. However, the GRA forecast is based on LTA hydro generation. To the extent that actual hydro generation results differ from LTA and are caused by water supply issues, these amounts will be charged to the LWRF in accordance with the rules established for that fund and approved by the YUB. The 2021 GRA rate determination is not affected by the current reservoir conditions.

Please also see responses to CW-YEC-1-43 (c) and YUB-YEC-1-27 (a).

TOPIC: **Resource Plan**

REFERENCE: **2021 General Rate Application, page 2-14 (PDF page 39 of 441)**

PREAMBLE: On lines 5-8. YEC discusses a 2016 resource plan that was used in the 2017-18 GRA. CW requires information regarding how the 2016, or subsequent, resource plan was used in the preparation of this GRA.

QUESTION:

a) Please confirm that there is no newer resource plan that was prepared by YEC subsequent to the referenced 2016 Resource Plan. If not confirmed, please provide the most recent resource plan.

b) Please fully discuss how the 2016 (or more recent) resource plan was used in the preparation of this GRA.

ANSWER:

(a)

The 10 Year Renewable Electricity Plan was developed in 2020 (referenced as "10 Year Renewable Energy Plan" in Appendix 5.4, Section 5.4.3). Please see Attachment 1 to response to CW-YEC-1-36(a) for a copy of this most recent plan.

(b)

The 10-Year Renewable Electricity Plan has guided Yukon Energy in selection of potential new renewable generation and related transmission projects to be pursued over the coming decade. In this regard, it has influenced some of the capital and deferred projects being planned and addressed in Tab 5 of this GRA Application – however, in all important instances (beyond the Plan itself) the relevant capital and deferred costs are forecast to remain in WIP through the 2021 test year and therefore do not affect the forecast 2021 revenue requirement.

TOPIC: **Long-Term Average Hydro Generation (2021)**

REFERENCE: **2021 General Rate Application, Appendix 2.1, Table 2.1-1**

PREAMBLE: In Appendix 2.1, YEC discusses its LTA forecasts. CW requires information to assess the LTA and how it is used.

QUESTION:

a) Please provide the year that each line number in Table 2.1-1 relates to. In the response, please also provide Table 2.1-1 in Excel format.

b) Please confirm that the LTA is a simple average of years. If not confirmed, please fully explain.

c) If (b) above is confirmed, please fully discuss whether any trend or regression analysis was conducted on the LTA data. If any such analysis was conducted, please provide it.

ANSWER:

(a) through **(c)**

Please see CW-YEC-1-11 Attachment 1 for the copy of Table 2.1-1 in MS Excel format. There are no years associated with line numbers. The lines just reflect the loads with 5 GW.h increments. The table is designed to show long-term average hydro and thermal generations at various load ranges. No trend or regression analysis was conducted on the LTA data.

Please see the detailed example included in the notes to the table with steps on how to use the table and identify thermal generation based on long-term average hydro generation to the given load.

Table 2.1-1:
Expected Thermal Generation Based on Long-Term Average Hydro Generation (2021)

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	475.0	433.735	41.265			
2	480.0	435.293	44.707	5.0	3.441	69%
3	485.0	436.810	48.190	5.0	3.484	70%
4	490.0	438.277	51.723	5.0	3.532	71%
5	495.0	439.690	55.310	5.0	3.587	72%
6	500.0	441.043	58.957	5.0	3.647	73%
7	505.0	442.334	62.666	5.0	3.710	74%
8	510.0	443.557	66.443	5.0	3.776	76%
9	515.0	444.713	70.287	5.0	3.844	77%
10	520.0	445.800	74.200	5.0	3.913	78%
11	525.0	446.819	78.181	5.0	3.982	80%
12	530.0	447.769	82.231	5.0	4.049	81%
13	535.0	448.654	86.346	5.0	4.115	82%
14	540.0	449.477	90.523	5.0	4.177	84%
15	545.0	450.242	94.758	5.0	4.235	85%
16	550.0	450.954	99.046	5.0	4.288	86%
17	555.0	451.618	103.382	5.0	4.335	87%
18	560.0	452.243	107.757	5.0	4.375	88%
19	565.0	452.836	112.164	5.0	4.407	88%
20	570.0	453.406	116.594	5.0	4.430	89%
21	575.0	453.963	121.037	5.0	4.443	89%
22	580.0	454.519	125.481	5.0	4.444	89%
23	585.0	455.085	129.915	5.0	4.434	89%

Notes:
1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid net of IPP generation, secondary sales related generation and Fish Lake hydro generation. The load will also be adjusted for WH2 and WH4 uprates as noted in #7 below.
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, 38 "water years" on record (1981-2018) 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), current Mayo Lake operation rule (no additional storage, impact of sedimentation at the outlet of Mayo Lake) and restricted Mayo GS winter flows (based on new Mayo Ice Protocol Mayo GS outflows are restricted at max 19 cms in November and 15 cms in December, after which restrictions are relaxed by 1.75 cms/week reaching 20 cms by early January and 24 cms by February [compared to 20 cms restriction through winter used in the 2017/18 GRA]. The model aslo assumes Whitehorse GS winter max flows at 170 cms compared to 160 cms in 2017/18 GRA.

5. The simulation model results are based on 2021 forecast load and IPP distributions, and requires modifications when new mines, industrial loads or IPP generation are connected to [or disconnected from] the grid.

6. The table assumes max YEC Grid Load (i.e., excluding IPP generation) at 585 GW.h and minimum YEC Grid Load at 475 GW.h. If the YEC Grid Load exceeds these limits then the table needs to be updated.

7. YEC is undertaking capital projects that will increase hydro generation output in Whitehorse GS [WH2 and WH4 uprates]. The preliminary estimates show that these capital projects will increase generation output by 7.1 GW.h/year [4.2 GW.h for 2021 considering expected in service date effective July 1, 2021 - monthly allocation based on Whitehorse GS monthly generation forecast]. Therefore, the YEC Grid Load is reduced to reflect increased output from these capital projects [not all incremental generation will directly displace LTA thermal].
8. Numbers are subject to rounding.

Example
Expected YEC Thermal Generation for the YEC generation at 536.743 GW.h (net of expected IPP & Fish Lake)

Remove Expected Generation for WH uprates [estimate for 2021 at 4.213 GW.h] to get net load at 532.530 GW.h

Step 1. Find the closest load from Column A that is less than 532.530 GW.h = 530 GW.h (Line 12).

Step 2. Find the thermal generation from Column C = 82.231 GW.h (Line 12).

Step 3. Find the difference between the given load (532.530 GW.h) and load from Step 1 (530 GW.h) = 2.530 GW.h

Step 4. Apply the percentage from Column F (Line 12, 82%) to the difference from Step 3 (2.530 GW.h) = 2.075 GW.h

Step 5. Add numbers from Step 2 (82.231 GW.h) and Step 4 (2.075 GW.h) = 84.306 GW.h

The expected thermal generation at 536.743 GW.h load [net of Fish Lake and IPPs] is 84.306 GW.h.

TOPIC: **Fuel Costs**

REFERENCE: **2021 General Rate Application, Table 3.2.1 and Table 2.2**

PREAMBLE: In Table 2.2, it appears that the forecast 2021 generation is based on a forecast that is different than the LTA, yet in Table 3.2.1, it appears that the fuel costs are based on LTA thermal generation. The following table taken from Table 2.2 demonstrates the difference between the 2021 forecast and the LTA.

	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	Forecast 2021
Actual					
Hydro Generation	411,397	413,052	370,819	436,725	506,483
Wind Generation	0	0	0	0	0
IPP Generation	0	0	0	56	1,983
Thermal Generation	11,109	37,316	69,858	71,199	30,260
Total Actual Generation	422,506	450,368	440,676	507,980	538,726
Total Sales	388,332	412,470	403,492	465,788	495,151
Losses	34,173	37,898	37,185	42,193	43,575
	422,506	450,368	440,676	507,980	538,726
LTA					
LTA Hydro Generation	403,910	418,695	415,377	438,905	452,437
LTA Wind Generation	0	0	0	0	0
IPP Generation	0	0	0	56	1,983
LTA Thermal Generation	16,355	31,391	25,300	69,019	84,306
Total LTA Generation	420,265	450,086	440,676	507,980	538,726
Actual					
Hydro Generation	97.37%	91.71%	84.15%	85.97%	94.01%
Wind Generation	0.00%	0.00%	0.00%	0.00%	0.00%
IPP Generation	0.00%	0.00%	0.00%	0.01%	0.37%
Thermal Generation	2.63%	8.29%	15.85%	14.02%	5.62%
Total Actual Generation	100.00%	100.00%	100.00%	100.00%	100.00%
LTA					
LTA Hydro Generation	96.11%	93.03%	94.26%	86.40%	83.98%
LTA Wind Generation	0.00%	0.00%	0.00%	0.00%	0.00%
IPP Generation	0.00%	0.00%	0.00%	0.01%	0.37%
LTA Thermal Generation	3.89%	6.97%	5.74%	13.59%	15.65%
Total LTA Generation	100.00%	100.00%	100.00%	100.00%	100.00%

QUESTION:

a) Please fully explain and reconcile the apparent discrepancy.

b) Please provide an adjusted fuel cost forecast using the generation mix incorporated in the 2021 forecast in Table 2.2.

ANSWER:

(a) and **(b)**

There is no discrepancy; fuel cost for rate making purposes is based on LTA thermal generation as previously approved by the YUB and consistently applied in this application. Table 2.2 shows hydro and thermal generation levels for 2018-2021 years based on the following:

- **"Actual":** These reflect actual generation for 2018 and 2019 years as well as forecast generation for 2020 and 2021 based on known/expected reservoir conditions for these years at the time of preparation of forecasts.

- **"LTA":** These generation numbers reflect hydro and thermal generations based on long-term average water conditions [1981-2018].

Section 2.3 of the Application provides explanations for actual and LTA generation. The LTA forecasts as provided in Table 2.2 were used to prepare the GRA forecast, as stated in Sections 2.3 and 3.2 of the Application. Section 3 of OIC 2021/16 also now directs that forecast fuel costs to be included in rates for thermal generation to meet forecast customer requirements are to be based on long-term average annual renewable resource availability as stated in response to CW-YEC-1-9 (a).

TOPIC: **Labour**

REFERENCE: **2021 General Rate Application, page 3-8 and 3-9 (PDF pages 54-55) and Table 3.4**

PREAMBLE: On page 3-9 YEC provides a discussion of reasons for increases in labour. In Table 3.4, YEC provides a summary of employment history. On lines 11-13 of page 3-8, YEC discusses overtime, vacancies and capital allocation. CW requires information to analyse the employment levels and verify the assertions of the causes of increases in headcount.

QUESTION:

a) Please fully explain whether the headcount in Table 3.4 is total complement, O&M only, includes vacancies or excludes vacancies, and whether it includes or excludes allocations to capital.

b) Please provide the calculation of total headcount, allocations to capital, and vacancies arriving at total O&M headcount, net of vacancies, in a form similar to Table 3.4, and in Excel format.

c) Please provide an analysis that lists the positions that directly work in:
   i. Reading meters;
   ii. Maintaining and operating assets;
   iii. Customer billing and responding to customer calls;
   iv. Providing customer service in the field;
   v. Transmission;
   vi. Generation; and
   vii. Other administrative functions.

d) For each of the positions listed in the response to (c) above for please provide the headcount for each YEC community in Excel format for each of:
   i. 2018 Approved;
   ii. 2018 Actual;
   iii. 2019 Actual;
   iv. 2020 Forecast; and
   v. Proposed 2021

Please ensure that the total reconciles to the totals related to O&M as provided in response to (b) above. Where a position provides a number of the functions listed in (c) above, please allocate the headcount between the functions, and provide an explanation of the allocation.

e) Please provide total customers by community and by customer class for each of:
   i. 2018 Approved;
   ii. 2018 Actual;
   iii. 2019 Actual;
   iv. 2020 Forecast; and
   v. Proposed 2021.

f) Please provide the kilometres of line, number of transformers, number of meters, number of substations, number of poles, number of towers, and number of generation assets by community and/or location of facility for each of:
   i. 2018 Approved;
   ii. 2018 Actual;
   iii. 2019 Actual;
   iv. 2020 Forecast; and
   v. Proposed 2021

ANSWER:

(a)

The headcount in Table 3.4 is total complement; it includes permanent, casual and temporary employees, regardless of whether their time is spent on admin, O&M or capital. Vacancies are not deducted from this headcount.

(b)

For forecasting purposes, YEC translates the expected vacancy rate into a percentage reduction which is applied to each position's loaded charge out rate. There is no obvious method to apply this rate to the position counts in Table 3.4. Actual vacancies for 2018 and 2019 are noted in Table 1 that follows.

Table 1: Actual Vacancies for 2018 and 2019

	Actual 2018	Vacancy Allocation 2018	Net 2018 Allocation	Actual 2019	Vacancy Allocation 2019	Net 2019 Allocation
President	5.14	(0.25)	4.89	4.82	(0.45)	4.37
First Nations Relations	-	-	0.00	-	-	-
Communications & Customer Acct.	1.00	-	1.00	1.00	(0.04)	0.96
Human Resources & Info. Mgmt.	5.27	(0.64)	4.63	5.34	(0.07)	5.27
Resource Planning & Environment	5.00	(0.41)	4.59	5.75	(2.04)	3.71
Finance & Purchasing	16.89	(0.47)	16.42	17.24	(0.57)	16.67
Operations	46.58	(2.07)	44.51	47.12	(3.86)	43.26
Engineering Services	13.03	(2.21)	10.82	15.16	(2.88)	12.28
Health, Safety & Environment	2.00	-	2.00	2.00	-	2.00
Total	**94.91**	**(6.05)**	**88.86**	**98.44**	**(9.91)**	**88.53**

Capital allocation is forecast on an employee by employee basis based on the supervisors' assessment of hours worked in O&M v. Capital. As such, YEC is not able to provide an employee complement with adjustments for capital allocation on a departmental basis. However, YEC can provide the capital allocation on a company wide basis (see Table 2 below):

Table 2: Capital Allocation

	Capital	Maintenance
2018 Approved	17.0%	83.0%
2018 Actual	14.7%	85.3%
2019 Actual	16.0%	84.0%
2020 Actual	18.2%	81.8%
2020 Forecast	17.5%	82.5%
2021 Forecast	17.6%	82.4%

(c)

A position analysis is provided as Attachment 1 to this response.

(d)

As the table requested in part (b) is not possible, it is not possible to provide a Table in part (d) that reconciles to it. However, a headcount per community is provided as Attachment 1 to this response.

(e)

The sales and number of customers are not approved by community level. Please see response to CW-YEC-1-6 for actual and forecast sales and number of customer by community.

(f)

Please see the tables that follow which provide a list where feasible of the different equipment requested by location as of December 31, 2020. The data provided is for equipment commissioned by end 2020. No historical trend or growth data exists for previous years.

The following information is available on number of meters by community[1]:

- Dawson = 1501
- Faro = 402
- Mayo = 398
- Johnson's Crossing = 12
- Mendenhall = 76
- Braeburn = 39
- Other = 39

Separate tables have not been provided for 2018 approved or actual, 2019 actual, 2020 forecast, or 2021 forecast. Adjustments to reflect 2018 and 2019 actual are as follows:

- In 2018 LNG unit #3 was added
- In 2019 the McQuesten Substation was added
- In 2020 the Faro Substation to connect rental diesel units was added
- In 2020 the Van Gorda Substation was added
- In each year a number of distribution poles and transformers were added

[1] A number of customers disconnect power on a seasonal basis. The total of 2736 in the attached table includes all meters (including seasonally disconnected) whereas the count by community of 2467 meters only includes "active" meters.

Forecasted changes to equipment list for 2021 are as follows:

- Commission new Mayo-McQuesten Transmission line and decommission old line.
- Net addition of poles for L177 re-route

YUKON ENERGY - Count of customer meters
2736

1

YUKON ENERGY - TRANSMISSION LINES					
Name	From	To	Tower Count	Pole Count	Length (m)
L127	WH4 - Unit 4	S150 - Whse Hydro Sub	8 (steel)	0	794
L150	S150 - Whse Hydro Sub	S171 - Riverside Sub	0	0	200
L151	WG0 (S151)	S150 - Whse Hydro Sub	8	8	384
L169	tap from L172 (str. 48)	S170 - McIntyre Sub	30	74	6543
L170	S164 - Takhini Sub	870S - Faro Sub	724	1480	152000
L171	S164 - Takhini Sub	S167 - Aishihik Sub	591	1222	129862
L172	S171 - Riverside Sub	S164 - Takhini Sub	112	236	25355
L173	S255 - Carmacks Airport Sub	S253 - Minto Landing Sub	387	1104	70891
L174	S253 - Minto Landing Sub	S252 - Pelly Crossing Sub	165	330	30044
L174	S252 - Pelly Crossing Sub	S251 - Stewart Crossing South Sub	371	842	64823
L175	S251 - Stewart Crossing South Sub	S256 - Stewart Crossing North Sub	32	64	5704
L176	S249 - Mayo Hydro Sub	S256 - Stewart Crossing North Sub	353	363	52000
L177	S256 - Stewart Crossing North Sub	S250 - Callison Sub	1375	1389	172000
L178	S255 - Carmacks Airport Sub	870S - Faro Sub	748	1288	190000
L248	S248 - Mayo B Substation	S249 - Mayo Hydro Substation	55	55	3505
L250 (Old Line)	S249 - Mayo Hydro Sub	S257 - Keno Sub	?	752	52000

2 Note: L250 Mayo to McQuesten is being replaced and the new line will be commissioned in 2021. Count of poles and structures is for the
3 old line.

1

YUKON ENERGY -Substations		
Name	Location	Count
S167	Aishihik	1
S163	Carmacks	2
S255	Carmacks	
S250	Dawson	1
870S	Faro	5
S146	Faro	
S162	Faro	
S140	Faro	
S178	Faro	
S248	Mayo	4
S249	Mayo	
S257	Mayo	
S258	Mayo	
S253	Minto	2
S254	Minto	
S252	Pelly	1
S251	Stewart	2
S256	Stewart	
S150	Whitehorse	5
S151	Whitehorse	
S164	Whitehorse	
S170	Whitehorse	
S171	Whitehorse	

YUKON ENERGY - Distribution assets Note: length of distribution line assets is not available.		
Distribution District	Pole Count	Distribution Transformers Count
Haines Junct	62	3
Johnsons Crossing	40	21
Champagne	136	17
South Fox Lake	117	23
Mendenhall	482	71
Braeburn	80	12
Faro area	515	99
Drury Creek	47	9
Mayo	849	161
Dawson	1762	320
Small Taps	323	Unknown
L355 Feeder	500	0

YUKON ENERGY - Count of Generators by Location	
Location	Count
Aishihik	3
Dawson	6
Faro	2
Mayo	7
Whitehorse	12
Grand Total	**34**

CW-1-13 (c)- Position Analysis

Position Name	i. Reading Meters	ii. Maintaing & Oper. Assets	iii. Cust. Billing/Service	iv. Providing Cust. Service in field	v. Transimission	vi. Generation	vii. Other Admin. Functions
Manager, Communications & Customer Service			✓				✓
Sr. Office Administrator			✓				
Customer Service Rep.			✓				
Meter Reader/Admin. Asst.	✓		✓				
Communication Coordinator			✓				✓
VP, Finance & Chief Financial Officer							✓
Manager, Procurement							✓
Procurement Specialist							✓
Sr. Procurement Specialist							✓
Warehouse Administrator							✓
Warehouse Assistant							✓
Controller							✓
Sr. Regulatory Analyst							✓
Financial Administrator							✓
Accounts Payable Clerk							✓
Assistant Controller							✓
Financial Administrator							✓
Payroll Analyst							✓
Financial Administrator							✓
Procurement Specialist							✓
Manager, Health & Safety							✓
Safety Coordinator							✓
Manager, Human Resources							✓
Manager, IT							✓
Network Administrator							✓
Web Developer & Systems Administrator							✓
Web Developer & Systems Administrator							✓
VP, Operations	✓	✓		✓	✓	✓	✓
Operations Coordinator					✓	✓	✓
CMMS/Operations Administrator							✓
Distribution Coordinator				✓			
Leadhand, SCC					✓	✓	✓
SCC Operator I					✓	✓	
SCC Operator II					✓	✓	
SCC Operator I					✓	✓	
SCC Operator I					✓	✓	
SCC Operator I					✓	✓	
Manager, Operations	✓	✓		✓	✓	✓	✓
Leadhand, T&D		✓			✓		✓
Powerline Technician		✓			✓		
Sr. Powerline Technician		✓			✓		
Sr. Powerline Technician		✓			✓		
Sr. Powerline Technician	✓	✓			✓		
Powerline Technician	✓	✓			✓		
Sr. Powerline Technician		✓			✓		
Powerline Technician	✓	✓			✓		
Lead hand, Electrical Maintenance		✓			✓		✓
Maintenance Electrician		✓			✓		
Electrical Instrumentation Coordinator		✓			✓		
Metering Coordinator Mntce Electrician		✓		✓	✓		
Electrical Protection & Control Coordinator		✓			✓		
Maintenance Electrician		✓			✓		
Maintenance Electrician		✓			✓		
Maintenance Electrician		✓			✓		
Electrical Protection & Control Coordinator		✓			✓		
Leadhand, Mechanical Maintenance		✓				✓	✓
Sr. Maintenance Mechanic		✓				✓	
Maintenance Mechanic		✓				✓	
Maintenance Mechanic		✓				✓	
Maintenance Mechanic		✓				✓	
Maintenance Mechanic		✓				✓	
Apprentice Trades Person		✓				✓	
Maintenance Mechanic		✓				✓	
Sr. Plant Operator		✓				✓	
Plant Operator	✓	✓				✓	
Plant Operator	✓	✓				✓	
Plant Operator	✓	✓				✓	
Plant Operator-Aishihik		✓				✓	
Plant Operator	✓	✓				✓	
Plant Operator	✓	✓				✓	
Plant Operator-Mayo		✓				✓	
Plant Operator-Mayo		✓				✓	
Manager, Property & Projects		✓					✓

Position Name	i. Reading Meters	ii. Maintaing & Oper. Assets	iii. Cust. Billing/Service	iv. Providing Cust. Service in field	v. Transimission	vi. Generation	vii. Other Admin. Functions
President & CEO							✓
VP, Business and Corporate Development							✓
Corporate Secretary							✓
Records Management Analyst							✓
VP, First Nations Relations							✓
VP, Resource Planning & Regulatory Affairs							✓
Manager, Environment							✓
Environment Coordinator							✓
Resource Planner							✓
Resource Planning Engineer							✓
Project Manager – Planning & Regulatory Affairs							✓
Project Manager – Moon Lake							✓
VP, Engineering & Capital Projects		✓			✓	✓	✓
Asset Manager		✓					
Job Planner		✓					
Administrative Assistant- Eng.							✓
Manager, Civil Engineering & Projects		✓			✓	✓	✓
Program Manager		✓			✓	✓	✓
Coordinator, Mechanical Projects		✓				✓	✓
Mechanical Engineer		✓				✓	✓
Draftsperson/ Land Use Administrator							✓
Draftsperson/ Land Use Administrator							✓
Capital Program Manager		✓			✓	✓	✓
Electrical Engineer		✓			✓	✓	✓
Electrical Engineer		✓			✓	✓	✓
Mech. Engineer-Engineer in Training		✓			✓	✓	✓
Protection & Systems Engineer		✓			✓	✓	✓
Coordinator, Electrical Projects		✓			✓	✓	✓
Casual Admin.							✓
Casual Warehouse Worker							✓
Casual IT Help Desk							✓
Casual IT							✓
Temp Plant Operator		✓				✓	
Temp Plant Operator		✓				✓	
Casual LNG Off Loader						✓	
Casual LNG Off Loader						✓	
Casual Plant Operators		✓				✓	
Casual Plant Operators		✓				✓	
Casual Diesel Plant Operator		✓				✓	
Diesel Plant Operator-Casual		✓				✓	
Casual Labourer		✓					
Yard Worker		✓					
Student Labourer		✓					
Student Labourer		✓					

CW1-13(d)- Employee Complement by Community

	2018 Approved				
	Whitehorse	**Dawson**	**Mayo**	**Faro**	**Total**
President	4.16				4.16
First Nations Relations					-
Communications & Customer Acct.	1.00				1.00
Human Resources & Info. Mgmt.	5.25				5.25
Resource Planning & Environment	5.00				5.00
Finance, Cust. Acctg. & Purchasing	14.69	2.10			16.79
Operations	36.00	3.00	5.00	0.50	44.50
Engineering Services	15.00				15.00
Health, Safety & Environment	2.00				2.00
Totals	**83.10**	**5.10**	**5.00**	**0.50**	**93.70**

2018 Actual					2019 Actual				
Whitehorse	**Dawson**	**Mayo**	**Faro**	**Total**	**Whitehorse**	**Dawson**	**Mayo**	**Faro**	**Total**
5.14				5.14	4.82				4.82
				-					-
1.00				1.00	1.00				1.00
5.27				5.27	5.34				5.34
5.00				5.00	5.75				5.75
14.79	2.10			16.89	15.14	2.10			17.24
38.70	2.77	5.00	0.11	46.58	39.19	2.54	5.00	0.40	47.13
13.03				13.03	15.16				15.16
2.00				2.00	2.00				2.00
84.93	**4.87**	**5.00**	**0.11**	**94.91**	**88.40**	**4.64**	**5.00**	**0.40**	**98.44**

2020 Forecast					2021 Proposed				
Whitehorse	**Dawson**	**Mayo**	**Faro**	**Total**	**Whitehorse**	**Dawson**	**Mayo**	**Faro**	**Total**
4.01				4.01	4.16				4.16
				-	1.00				1.00
1.00	2.10			3.10	2.00	2.60			4.60
5.32				5.32	5.25				5.25
5.51				5.51	7.05				7.05
13.54				13.54	14.79				14.79
40.25	3.00	5.00	0.50	48.75	40.75	3.00	5.00	0.50	49.25
15.63				15.63	15.50				15.50
2.00				2.00	2.00				2.00
87.26	**5.10**	**5.00**	**0.50**	**97.86**	**92.50**	**5.60**	**5.00**	**0.50**	**103.60**

TOPIC: **Labour**

REFERENCE: **2021 General Rate Application, page 3-8 (PDF page 54) and Table 3.4**

PREAMBLE: On page 3-8 YEC provides a discussion of reasons for increases in labour. On lines 11-13 of page 3-8, YEC mentions overtime, vacancies and capital allocation. In Table 3.4, YEC provides total labour. CW requires information to analyse the employment levels and verify the assertions of the causes of increases in headcount.

QUESTION:

a) Please provide the total Labour provided in Table 3.4 separating base labour, overtime, benefit costs and incentive compensation.

b) For each new position where YEC asserts that the increased position is needed as a result of overtime, please provide an analysis that clearly demonstrates that there was a pattern of overtime, and that there is a reduction in overtime that is included in the forecast for 2021 to offset that new position.

ANSWER:

(a)

Table 3.4 Employee Complement History as defined is total position count (number of employees). Table 1 below provides the Employee Complement with Total Labour by Department. Please note that it is not possible to provide Table 3.4 broken out by employee base labour, benefits and overtime, as YEC does not track employee actual benefits at the employee level. The cost of benefits are pooled and spread across all departments; and each employee base labour rate is multiplied by a F&B (fringe and burden) rate to get the labour expense. The F&B rate is determined by forecasting all employee's annual benefits in Business Planning process.

Also, as some departments have one or a few employees providing the level of detail requested may raise privacy concerns.

Table 1: Employee Complement with Total Labour by Department

	Approved 2018	Actual 2018	Actual 2019	Forecast 2020	Proposed 2021
President	$ 964	$ 936	$ 952	$ 959	$ 953
First Nations Relations	$ -	$ -	$ -	$ -	$ 248
Communications & Customer Acct.	$ 177	$ 185	$ 181	$ 382	$ 522
Human Resources & Info. Mgmt.	$ 811	$ 687	$ 825	$ 815	$ 858
Resource Planning & Environment	$ 918	$ 840	$ 667	$ 932	$ 1,266
Finance & Purchasing & Customer Acct. & Property Mang.	$ 2,355	$ 2,299	$ 2,459	$ 1,760	$ 1,942
Operations & Property Mang.	$ 6,443	$ 6,643	$ 6,659	$ 7,415	$ 7,528
Engineering Services	$ 2,417	$ 2,011	$ 2,071	$ 2,627	$ 2,517
Health, Safety & Environment	$ 310	$ 311	$ 325	$ 325	$ 317
Total	**$ 14,394**	**$ 13,912**	**$ 14,139**	**$ 15,215**	**$ 16,152**

(b)

As stated in the Application, none of the new positions are created solely to reduce overtime. YEC noted there were increases in positions in an effort to reduce overtime per employee for the Operations department (Maintenance Mechanic and Plant Operators), as well as in the Engineering department (Electrical Engineer). Below is a table of actual overtime cost for the last three years.

Table 2: Actual Overtime Costs: 2018-2020

	Overtime $
2018	$ 901,416
2019	$ 938,858
2020	$ 992,155

Notwithstanding wage rate increases, overall overtime is forecast to reduce in 2021 to a cost of $761,000.

TOPIC: **Labour**

REFERENCE: **2021 General Rate Application, page 3-10 (PDF page 56)**

PREAMBLE: On line 21, YEC discusses an increase related to a meter reader. CW requires information to assess efforts to improve productivity.

QUESTION:

a) Please fully discuss all research, analysis or other investigations that YEC has done in the areas of Automated Meter Reading (AMR) or Advanced Metering Infrastructure (AMI). In the response please fully discuss any plans YEC has to implement AMR or AMI, and the timeframes for any implementation. If YEC is not planning on implementing any AMR or AMI technology please fully explain why not, and provide all economic analysis that YEC has performed related to AMR or AMI.

ANSWER:

(a)

YEC has no plans at the current time to implement AMI or AMR and no current analysis of this technology. The request for additional staffing in this area reflects current need; any technology implementation would be several years away in Yukon. YEC notes that previous utility applications to implement AMR in Yukon have been denied by the YUB.

In the future, YEC expects that, as greater understanding of grid modernization unfolds, including progress on YG's "Our Clean Future" strategy actions and a broader deployment of demand-side management programs, YEC will continue to assess AMR/AMI and its potential to provide a cost-effective alternative for ratepayers, its benefits and potential barriers.

TOPIC: **Labour Rates**

REFERENCE: **2021 General Rate Application, page 3-8 (PDF page 54)**

PREAMBLE: In lines 2-8, YEC states:

> Labour Rates – This includes factors such as base pay, benefit cost, annual increments (performance increments, cost of living adjustments), etc. This is heavily influenced by collective bargaining agreements (CBA). The last settled CBA covered fiscal periods 2017 to 2019 inclusive; the actual annual negotiated increase in base pay from 2018 to 2019 was 2.0%. To date, the CBA has not been settled for fiscal periods 2020 and 2021; an arbitration hearing is scheduled for April 2021. Forecast 2020 and 2021 labour rates include estimated economic increments of 2%; these estimates were developed by YEC management based on prior settlements.
>
> CW requires information to understand how increases have been applied.

QUESTION:

a) Please provide a working paper that identifies the cost of living adjustment, performance increments and any other adjustments for each of:
   i. 2018 Approved;
   ii. 2018 Actual;
   iii. 2019 Actual;
   iv. 2020 Forecast; and
   v. Proposed 2021.

b) Please fully discuss the increases awarded to employees not subject to the CBA.

ANSWER:

(a)

Cost of Living and Performance Increments are rolled up in overall wage costing.

Regarding performance increments, employees subject to the Collective Bargaining Agreement can have up to two increments per year (every six months) if they are not capped at their maximum salary level. With many new hires recently this means a lot of performance increments. Management and Professional employees are eligible for performance increments annually if they are not capped at their maximum salary level. As union employees can have different dates for increments based on their start dates throughout the year, YEC forecasts performance increments by using an average wage for that position for the year. Additionally, due to the timing of the performance increase being dependent on the timing of the performance review, we also get into situations were increments are late and run between different years, but the retro ends up in year it is paid. As such, a calculation of cost of performance increments would be extremely difficult.

For GRA forecast purposes, performance increments are similar to cost of living as they are buried in the overall costs, which are referred to as economic increments. For 2018, the cost of living increase was 1.50%, equal to the 2018 approved amount. The 2019 cost of living increase was 2.00%, equal to the rate required in the collective bargaining process. YEC has forecast an economic increase (cost of living and performance increment) of 2.00% for 2020 and 2021.

(b)

For the 2017 to 2019 CBA, increases awarded to employees not subject to the CBA were consistent with increases awarded to employees subject to the CBA. For the 2021 forecast, the assumption is the same.

TOPIC: **Production**

REFERENCE: **2021 General Rate Application, Section 3.3.2, and Table 3.5**

PREAMBLE: On lines 4-8 of page 3-14, YEC discusses diesel rentals, and an increase of $3.834 million.

QUESTION:

a) Please provide copies of all analysis or business cases that YEC has done or prepared comparing the cost of owning diesel generation compared to rentals. If no such analysis or business cases have been prepared, please fully explain why not.

b) Please provide the number of diesel generation units that would be rented, and the amount of use each would experience (Months per year).

c) Please describe the rental terms. As an example, are the units rented on a month to month basis or on an annual basis? In the response, please provide an analysis that clearly identifies the number of months of rental payments YEC has forecast for each unit it is renting in 2021. Also, are the rentals under long term leases, or can the rental be cancelled with 30 days notice or no notice at all?

d) Please provide the capacity of each unit.

e) Please explain what operating costs YEC is responsible for, compared to the costs the lessor is responsible for.

f) Please describe the characteristics of each unit, for example, are the all the units mobile or are any fixed in place?

g) Please provide YEC's estimated cost of purchasing each rental unit that is forecast to be rented in 2021.

ANSWER:

(a)

Yukon Energy's 2016 Resource Plan included action plans focusing on short and long-term options to reduce the capacity shortfalls, including building a new 20 MW diesel plant.

However, based on feedback received from Yukoners as well as to address impacts of the Yukon government Climate Change Strategy Yukon Energy's Board of Directors decided not to pursue a new 20 MW thermal plant at this time and look at options to replace capacity at Yukon Energy's existing generation facilities as diesel engines reach end-of-life.

Yukon Energy is pursuing the new renewable generation capacity options as outlined in the 10-Year Renewable Electricity Plan [please see CW-YEC-1-36 (a) Attachment 1 for the copy of the Plan], including battery energy storage system, Atlin Hydro Expansion Project, and the potential development of pumped storage at Moon Lake. Until the new renewable resource options are developed, diesel rentals are continuing to be the best available option at this time to address capacity shortfalls.

Please also see YUB-YEC-1-40 (a).

(b)

For the 2021/22 winter YEC forecast to rent 17 diesel units, including a spare unit in each location [Faro and Whitehorse]. The usage of the units will depend on peak in the system and condition of the existing generation capacities. The diesel rentals are primarily in place to provide for the N-1 contingency event and would not normally be called upon to use fuel in order to generate electricity.

(c)

The diesel units are rented through an annual contract for the winter heating season period, from December through April. The rental rates are based on a 28 day cycle.

(d)

Each diesel unit has a capacity of 1.8 MW.

(e)

Per the supply contract, YEC is responsible for periodic operations checks including monitoring and maintaining consumables (fuel, oil, antifreeze, etc.). YEC is not charged maintenance if the individual units are run less than 100 hours per 28 day rental cycle. At the end of the contract, YEC pays a maintenance charge based on the pro rata hours run. CAT is responsible for the cost of any breakdowns.

(f)

The units are installed at the beginning of rental period [November/December] in two locations with rental unit infrastructure [Faro and Whitehorse] and decommissioned at the end of rental period [April].

(g)

YEC is not planning to purchase the rental diesel units and, as far as YEC is aware, the vendor is not offering these units for sale.

TOPIC: **Brushing Costs**

REFERENCE: **2021 General Rate Application, page 3-15 (PDF page 61) Table 3.6.1 and following paragraph**

PREAMBLE: CW notes that YEC discusses brushing and its related policy. Also, CW notes that there appears to be a marked reduction in costs in 2019 for distribution. CW is concerned that there be no arbitrary reductions in brushing to maintain corporate profits.

QUESTION:

a) Please fully explain the YEC brushing policy, and how the 2019 actual Distribution brushing expenditure was consistent with the policy.

b) CW notes that the 2019 actual Distribution brushing was only $28,000. Please fully explain why the 2019 Distribution Brushing was so low. In the response please also confirm that YEC follows its brushing policy, and does not reduce brushing to avoid costs and maintain returns. If not confirmed, please fully explain.

ANSWER:

(a) and **(b)**

The YEC brushing policy was developed at the direction of the YUB (Order 2013-01) and was reviewed as part of the 2017/18 GRA (Order 2018-10).

The policy was developed as follows: utilizing the information gathered in aerial and ground surveys and supplemented with line maintenance history provided by YEC, ECI (contractor) developed a recommended cyclic maintenance schedule based on 10 year cycle guideline for each line. The growth rates vary per line and per year so the priorities are adjusted based on line patrols.

ECI recommended the following:

1. Remove trees under the conductors in locations designated as Critical as soon as possible.

2. Remove trees under the conductors in locations designated as Priority before the next growing season (June 2011).

3. Remove all trees designated as Hazard over the next two years.

4. Establish a schedule of cyclic maintenance by right-of-way including separate schedules for Critical, Priority and Hazard tree locations.

5. Budget funds to address Critical locations as they are identified. This will be reduced each subsequent year of the maintenance cycle.

6. Establish a list or database of danger and hazard tree locations and develop a priority program to determine which trees should be removed first.

7. Develop vegetation maintenance clearance specifications for transmission and sub-transmission voltages and policy and standards specific to YEC needs and conditions. ECI has developed a draft TVMP for YEC"s consideration.

8. Consider contracting alternatives to reduce maintenance cost as well as developing additional qualified vendors to perform vegetation maintenance on the YEC system (including herbicide application).

9. Implement Integrated Vegetation Management (IVM) as the guiding maintenance principle on the YEC system.

10. Establish an herbicide test plot area. Develop specification and guidelines on the use of herbicides on the YEC system. After an initial test period of various products and application methods and upon development of specification/procedures for herbicide use, (2012-2013), integrate the use of herbicides as a major component of the YEC vegetation maintenance program.

Distribution brushing priorities are identified using ground patrol data.

The vegetation management budget is typically about 80/20 split transmission/distribution. In 2019, the distribution portion was less due to the TLR work and the requirement to prioritize the brushing on the transmission system where the work was to take place.

TOPIC: **Distribution Costs**

REFERENCE: **2021 General Rate Application, page 3-16 (PDF page 62) Table 3.7 and following paragraph.**

PREAMBLE: CW notes that YEC has forecast "Other Non-Labour" to increase from $204,000 in the 2018 approved forecast to $279,000 in 2021. This is an increase of approximately 37%.

QUESTION:

a) Please fully explain why "Other Non-Labour" reduced to $80,000 in 2019. In the response, please fully explain why that level of costs could not be maintained in 2021.

b) Please fully explain what costs are included in "Other Non-Labour" and why the forecast increased by 37% from 2018 to 2021.

ANSWER:

(a)

There was an error in the table that affected the 2019 actuals. The corrected table is below.

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Labour	$ 856	$ 801	$ 625	$ 617	$ 629	$ 629
Brushing Cost	331	212	28	249	212	212
Other Non-Labour	204	236	265	287	279	279
Total Distribution	$ 1,391	$ 1,250	$ 918	$ 1,154	$ 1,120	$ 1,120

With this correction, the 2019 actual cost of Other Non-Labour is in line with previous and subsequent results. The low brushing total for 2019 is explained in CW-YEC-1-18.

(b)

Costs included in 'Other Non-Labour' include the following:

- Response to distribution events (i.e., trees on lines, distribution transformer/pole replacement);

- Call outs (i.e., customer complaints, refusing, house fires, power quality);

- High loads; and

- Outage response.

This work is forecast to be higher in 2021 as compared to 2018 as we expect 2021 to be fairly similar to costs in 2020.

TOPIC: **General Operating and Maintenance**

REFERENCE: **2021 General Rate Application, pages 3-16 and 3-17 (PDF pages 62 and 63) Table 3.8 and following paragraph.**

PREAMBLE: In the paragraph following Table 3.8, YEC explains what areas the cost increases are in, but now why the costs increase.

QUESTION:

a) Please fully explain why costs related to Transportation, Maintenance of Company Owned Properties, and Scada Communication are forecast to increase by 10%, 18%, and 15% respectively.

ANSWER:

(a)

See response to YUB-YEC-1-42.

TOPIC: **Administration**

REFERENCE: **2021 General Rate Application, pages 3-17 and 3-18 (PDF pages 63 and 64) Table 3.9 and following paragraph.**

PREAMBLE: YEC discusses changes in Administration costs.

QUESTION:

a) On lines 1-5 of page 3-18, YEC discusses cost increases due to a 3 year water license. Please provide the term of the referenced license (i.e. what years are covered by the license).

ANSWER:

(a)

The term of Aishihik Generating Station Water Use License HY19-016 is from March 1, 2020 to December 31, 2022.[1]

[1] Water Use Licence HY19-057 was effective January 1, 2020 to February 29, 2020.

TOPIC: **LWRF Stabilization Mechanism**

REFERENCE: **2021 General Rate Application, page 3-31 (PDF page 77)**

PREAMBLE: On lines 11-19, YEC discusses why it has not updated its LWRF Term Sheet.

QUESTION:

a) Please fully explain what COVID conditions prevented the completion of an updated term sheet.

b) Please fully explain what other factors prevented the completion of the updated term sheet.

c) Please fully explain when YEC expects to complete an updated term sheet.

d) Please fully explain why YEC did not file to be given relief from filing an updated term sheet.

ANSWER:

(a) through **(d)**

As reviewed in Section 1.1 of the Application, Yukon Energy faced ongoing difficulties in proceeding with the next GRA required as soon as feasible after final approvals for the 2017-18 GRA. After having to cancel a 2019/20 GRA, the effort to implement any rate change in 2020 had to be suspended in response to COVID-19 conditions.

Late in 2020, Yukon Energy was able to develop and proceed with the proposed approach for the 2021 GRA as set out in the Application. As stated at the referenced lines on page 3-31, in order to get the Application filed in November, Yukon Energy was required to focus first on completion and filing of its 2021 forecast revenue requirement and rates Application.

The Application recognizes the need to file an updated LWRF Term Sheet to assess the reasonableness of the LWRF for addressing transactions or amounts with respect to the LWRF deferral account following the end of the 2021 test year. The LWRF Term Sheet,

however, does not have any impact on review and assessment of the 2021 GRA revenue requirement forecasts.

Yukon Energy is working to provide an updated LWRF Term Sheet in March 2021, along with related LWRF Annual Reports for 2019 and 2020.

TOPIC: **Timing of Rate Increases**

REFERENCE: **2021 General Rate Application Introduction, page 2 (PDF page 3)**

PREAMBLE: YEC states that it proposes to implement interim rates on July 1, to coincide with the expected reduction in Rider F. Further, YEC proposes to implement final rates on December 1 to coincide with the removal of Rider J1.

QUESTION:

a) Please provide a detailed analysis of Rider F, and the expected rate for July 1, 2021.

b) Please provide the current Rider F.

c) Please fully explain why Rider J1 is still being used in 2021, some 3 years after the last test period.

d) Please confirm that Rider F could increase in the future, depending on fuel prices. If not confirmed, please fully explain.

ANSWER:

(a) and **(b)**

The current Rider F rate is at 1.371 cents/kW.h.

Please see CW-YEC-1-23 Attachment 1 and Attachment 2 for the copies of the Advisory of Rate Change filed with the Board on September 23, 2020. Although, the actual balance of the Fuel Price Variance Account will depend on volume of actual thermal generation and fuel prices for YEC and AEY, the advisory filed by the companies on September 23, 2020 was the best information available for the companies at the time of filing which aimed to get Fuel Price Variance Account balance to zero by July 1, 2021.

(c)

A true-up rider Rider J1 relates to the 2017-18 GRA shortfalls which is in effect until November 30, 2021, or such earlier month end when the $12.557 million 2017-18 GRA shortfall has been recovered. In the 2017/18 GRA Compliance Filing YEC proposed to collect the shortfall over 24 months period to reduce bill impact to customers which was accepted by the Board.

(d)

Confirmed - Rider F will increase or decrease in future in response to change in actual fuel prices relative to approved forecast fuel prices.

ATCO Electric
YUKON

yukon energy

September 22, 2020

Bonnie King, Vice Chair
Yukon Utilities Board
Box 31728
Whitehorse, Yukon Y1A 6L3

Dear Ms. King:

RE: Rate Change- Rider F, Fuel Adjustment Rider

On January 1, 2020, ATCO Electric Yukon and Yukon Energy Corporation (the "Companies") adjusted the Diesel Fuel Price Variance Rider ("Rider F') from a refund of 0.011 cents per kWh to a charge of 0.970 cents per kWh.

Pursuant to the Rider F Policy, if the Companies' Fuel Price Variance Account ("FPVA") is fluctuating over a broad range, the Companies must refine the forecast to reflect changing economic conditions to arrive at a new Rider F rate.

Accordingly, the Companies have determined that Rider F rate is required to change from a charge of 0.970 cents per kWh to a charge of 1.371 cents per kWh, effective November 1, 2020.

The Companies have enclosed an Excel spreadsheet to provide further detail regarding this rate change. We trust that if the Board or any interested party has questions regarding this Rider F rate change, they will contact one of the undersigned.

Sincerely,

ATCO ELECTRIC YUKON

Jaspreet Kaur

Digitally signed by Jaspreet Kaur
DN: cn=Jaspreet Kaur, o, ou, email=jaspreet.kaur@atco.com, c=CA
Date: 2020.09.22 11:49:59 -06'00'

Jaspreet Kaur Senghera
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YUKON ENERGY CORPORATION

Ed Mollard
Chief Financial Officer
Ed.Mollard@yec.yk.ca

ATCO Electric Yukon and
Yukon Energy Corporation
Rider F Calculation

		Combined Company Balance				
		Total Monthly Fuel Price Variance, $	RS 32 Secondary Sales Adjustment, $	Rider F Surcharge at current rate 0.97 cents/kW.h, $	Cumulative Balance, $	Monthly Change, $
	Due (From)/To Customers - as at June 30, 2020				(5,060,713)	
2020	July	23,237	-	303,002	(4,734,474)	326,239
	August	63,894	-	287,992	(4,382,589)	351,886
	September	27,494	-	322,782	(4,032,313)	350,276
	October	13,895	-	372,336	(3,646,082)	386,231
	November	(337,255)	-	405,550	(3,577,787)	68,295
	December	(563,338)	-	450,647	(3,690,478)	(112,691)
2021	January	(43,625)	-	506,496	(3,227,606)	462,872
	February	(35,485)	-	437,549	(2,825,543)	402,063
	March	(35,256)	-	451,954	(2,408,845)	416,698
	April	(29,844)	-	396,008	(2,042,681)	366,164
	May	(26,485)	-	362,603	(1,706,562)	336,119
	June	(25,173)	-	343,537	(1,388,198)	318,364
	Estimated Combined YEC/AEY Ending Balance				**(1,388,198)**	
	Nov 2020-June 2021 Forecast Retail Sales (MWh)				345,809	
	Incremental Rider F Rate (¢/kWh)				**0.401**	
	Existing Rider F Rate (¢/kWh)				0.970	
	New Rider F Rate (¢/kWh) effective November 1, 2020				**1.371**	

Notes:
1. Positive balances represent amounts to the benefit of ratepayers.
2. Negative balances are amounts owing to the utilities.

TOPIC: **Depreciation**

REFERENCE: **2021 General Rate Application, page 3-22 (PDF page 68), Alliance Consulting Group Depreciation Study, PDF pages 241, 249, and 250.**

PREAMBLE: On lines 18-21 of page 3-22, YEC states:

> Forecast "Existing" fixed asset depreciation expense in 2021 of $12.945 million (as compared to $12.196 million in 2018 approved), reflects changes in the assets in service. Forecast "Proposed" fixed asset depreciation expense in 2021 of $13.581 million also reflects changes resulting from the depreciation study.

On PDF page 241, Alliance Consulting Group states:

> The term "depreciation" as used in this study is considered in the accounting sense, that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

On PDF page 249, Alliance Consulting Group states no net salvage analysis was performed.

On PDF page 250, Alliance Consulting Group provides a flowchart of the process.

QUESTION:

a) Please fully explain why no net salvage analysis was performed. In the response please fully explain how any actual net salvage is treated in YEC asset accounts, and how it was dealt with in the Alliance Consulting Group study.

b) Please confirm that the difference between $12.945 million in 2021 based on existing rates and $13.581 million on proposed rates is solely due to the impact of the Alliance Consulting Group depreciation study. If not confirmed, please fully explain.

c) Please provide an analysis that separates the impact of (i) changes in lives, (ii) amortization of reserve differences, (iii) any consideration of net salvage, and (iv) other. For any other, please fully explain what it is.

d) Please fully discuss all life extension efforts or initiatives that YEC:
   i. Is considering;
   ii. Is planning on implementing after the test period;
   iii. Is planning on implementing in the test period; or
   iv. Has implemented prior to 2021.

   In the response please fully explain the costs of each initiative, and the expected impact, including lengthening service lives, and impact on reduced depreciation.

e) If there are no life extension efforts or initiatives, please fully explain why not.

ANSWER:

(a)

YEC does not accrue or book net salvage in their accumulated provision for depreciation and no provision for net salvage is incorporated in the Company's current depreciation rates. As such, Alliance did not include net salvage in its depreciation rate calculations so no net salvage analysis was necessary or performed. In YEC actual accounts, when an item is disposed of that has salvage value, that salvage value becomes part of the calculation of net gain or loss on disposal.

(b)

Confirmed

(c)

The details of (i) changes in lives and (ii) amortization of reserve differences are shown in the Application in Tab 7, Schedule 3A, on a Class line item basis and can be calculated by comparing the '2021 Existing Forecast Depreciation' column with the '2021 Proposed Forecast Depreciation' column. The summation of the impact of changes in lives is $0.458 million and the impact of depreciation study differences is $0.178 million.

(d) and **(e)**

As part of YEC's annual capital budgeting process, a portion of the budget is set aside for Maintenance Capital, which overall has the purpose of maintaining assets in healthy operating conditions. In addition, as discussed in the Application at section 5.4.1.1 on page 5-28, YEC details its Enterprise Asset Management System Purchase and Implementation which will also assist in this initiative.

TOPIC: **Rate Relief**

REFERENCE: https://globalnews.ca/news/7584771/altalink-alberta-refund

PREAMBLE: In Alberta, AltaLink has proposed to refund over collected depreciation and future income taxes in an effort to provide rate relief to customers. CW understands that YEC, as a crown corporation will not have any income taxes. Having said that, CW is interested in understanding what efforts YEC has undertaken to identify and implement measures that would provide rate relief to customers.

QUESTION:

a) Please fully discuss and provide copies of any and all research YEC has conducted into ways to provide rate relief to customers, including, but not limited to extending service lives for utility assets.

ANSWER:

(a)

YEC has not conducted research specifically into ways to provide rate relief to customers. However, YEC has completed depreciation update studies for this and prior GRAs to assess (among other matters) opportunities to extend service lives for utility assets (see Tab 9 of GRA Application). YEC also continues to assess least cost resource options for future development of required generation and transmission - including options to secure federal and other government funding that will reduce ratepayer costs, e.g., as demonstrated for the proposed Battery Energy Storage Project and the Atlin Hydro Expansion Project.

TOPIC: **LNG Third Engine/ Critical Spares**

REFERENCE: **2021 General Rate Application, page 5-8 (PDF page 121)**

PREAMBLE: On lines 5-6 of page 5-8, YEC states, with respect to the Faro Thermal Rental Site Infrastructure project, "[t]he project is expected to be completed in 2020 at an estimated budget of $2.037 million. The project is on track for a mid-November 2020 in service date."

QUESTION:

a) Please confirm that the project is complete. If not please provide the estimated completion date.

b) Please provide the actual cost of the project, and an explanation of any variances.

ANSWER:

(a)

Confirmed.

(b)

Please see response to YUB-YEC-1-49 for project cost breakdown.

Actual project costs totaled $2.446 million, compared to the estimated budget of $2.037 million included in the application (approximately $0.408 million increase in costs). Major variances are noted as follows:

- Additional materials were needed after completion of the detailed design, including: power and control cables, cold shrink cable terminations, rigid bus bar connectors, PTs for ground fault protection, lightening arrester and materials for line and gantry construction.

- Higher market prices were also a factor, the cost to procure of a 138kV disconnect switch, 25kV breaker and the refurbishment of the spare transformer were higher than budgeted, the lowest prices were selected through RFQ process.

- The added scope was due to a safety requirement to install a ground grid in the generator area, and an environmental requirement to install generator berms for the purpose of containing fuel and/or oil spill from the generators.

- The added scope of work included: relocation of warehouse materials at the substation and generator bay area, cost to install ground grid in generator area, rental generator prep, pulling and termination of cables to rental generators, and unit transformers and installation of generator berms.

- Construction and installation were also impacted by higher market prices, the budget for crane rental and SCADA commissioning were higher than budget.

- A rented crane was needed on site for an additional day due to the delayed arrival of the rental tanks. Furthermore, 3.5 additional days were needed to establish communication with the Finning units.

- Overage for internal cost is because more internal manpower for construction, testing and commissioning was required than initially envisioned at the beginning of the project.

- Project management overage is because more responsibility was assigned to an external consultant during a 4 week absence of the YEC Project Manager, due to unforeseen circumstances.

While the actual costs exceeded the estimate included in the application, it is important to note that the final project costs of $2.446 million were lower than the lowest bid received from the EPC RFP process ($3.335 million).

TOPIC: **Mayo – McQuesten Transmission Line Upgrade**

REFERENCE: **2021 General Rate Application, Section 5.2.1.3**

PREAMBLE: On line 11 of page 5-9 (Pdf page 122), YEC indicates this project was reviewed in the 2017/18 GRA. In Table 5.2.1-2, YEC provides project costs and contributions.

QUESTION:

a) Please provide specific reference to where this project was approved in the 2017/18 GRA.

b) Please provide the cost estimates that were reviewed and approved in the 2017/18 GRA.

c) Please provide a variance analysis comparing the cost estimates approved in the 2017/18 GRA to the forecast costs included in Table 5.2.1-2. In the response please provide explanations for all material variances.

ANSWER:

(a) and **(b)**

The reference provided notes that the project details have previously been subject to review by the Board as part of two separate proceedings: the 2017 VGC Group Power Purchase Agreement proceeding; and as part of the 2017/18 General Rate Application. As the project was not complete and in service during the 2017/18 GRA, project costs were not approved as part of that proceeding.

(c)

Detailed cost estimates were not reviewed as part of the 2017/18 GRA. The 2017 VGC Group PPA proceeding estimated costs for the L180 Mayo to McQuesten 138 kV line

(assumed to be operated at 69 kV) at $32.2 million, including costs that VGC Group and/or YEC will have funded for the McQuesten Substation pursuant to the PPA.[1]

Tab 5, page 5-8 notes a total project cost for the Mayo – McQuesten Transmission Line Upgrade of $31.701 million, offset by contributions of $23.674 million.

[1] See response provided in the VGS Group PPA proceeding to YUB-YEC-1-14.

TOPIC: **Transmission Line Refurbishment**

REFERENCE: **2021 General Rate Application, Section 5.2.1.5**

PREAMBLE: On lines 2-4 of page 5-15 (PDF page 128), YEC states "[t]he Transmission and Distribution Line replacement project was initially reviewed as part of the 2017/18 GRA; and project components were capitalized as completed and placed into service, with approved costs forecast to the end of 2018 included in ratebase." CW requires information to understand the prudence of the investment.

QUESTION:

a) Please provide an analysis that compares approved costs and actual costs with explanations of significant variances.

b) Please provide an analysis that compares the approved assets and components to be replaced with the actual assets and components that were replaced.

ANSWER:

(a)

Actual 2018 costs were materially higher than approved costs. The quantity of work accomplished in 2018 was significantly more than was forecasted, as a large portion of the overall 5 year planned work was completed in one year. The increase in work scope and 2018 spending was justified due to lower unit costs; the reduced customer impact of the transmission outage number and duration; and reduced mobilization and demobilization costs for the contractor.

Table 1: Approved and Actual Transmission Line Refurbishment Costs

	Cost
2018 Approved	$ 2,000,000
2018 Actual	$ 6,280,165

(b)

Table 2 below compares the approved assets and components to be replaced with the actual assets and components that were replaced.

Table 2: Approved and Actual Scope of Work (2018)

	Full structure replacement	Crossarm replacement	Insulator replacement
2018 Approved	21	112	251
2018 Actual	61	254	489
Change (Actual vs Approved)	40	142	238

TOPIC: **Transmission Line Refurbishment – L178**

REFERENCE: **2021 General Rate Application, Section 5.2.1.6**

PREAMBLE: On line 12 of page 5-15 (PDF page 128), YEC states "[t]he final phase of the Transmission Line Refurbishment Project will commence in 2021."

QUESTION:

a) Please provide evidence from the 2017/18 GRA that clearly demonstrates that this component of the line was NOT included in the costs approved in the 2017/18 GRA.

ANSWER:

(a)

Section 5.2.1.8 of the YEC's 2017/18 GRA noted that the T&D Line Replacement project would address replacement of key components of the following YEC transmission lines which are approaching the end of their economic life:

Line #	Route	Install Date
L170	Takhini Sub to Carmacks	1968
L171	Aishihik plant to Takhini Sub	1975
L178	Carmacks to Faro	1968

In that section, YEC also noted that the required replacements would be carried out over five years beginning in 2018 at an estimated total cost of $11.5 million. YEC forecast spending in the 2018 test year at $2.0 million [the remaining estimated $9.5 million spending was forecast after 2018].

On page 5-15 of the 2021 GRA Application, YEC provides an update to the project noting that remaining components requiring replacement on lines L170, L171 and L172 were completed by the end of 2019 with total cost of $4.272 million and included refurbishment of 255 structures (58 full structures, 80 crossarms, and 117 insulators) and the final phase

of the Transmission Line Refurbishment Project will commence in 2021 for the Carmacks to Faro Transmission Line (L178).

As reviewed above, Transmission Line Refurbishment – L178 project is part of $11.5 million Transmission and Distribution Line Replacement Project noted in the 2017/18 GRA section 5.2.1.8, however, the cost for this project was not included in the 2017 or 2018 test year revenue requirements as the 2018 test year included only $2 million out of $11.5 million total project cost estimate at that time.

TOPIC: **Breaker Replacement Program**

REFERENCE: **2021 General Rate Application, Section 5.2.1.7**

PREAMBLE: On line 12 of page 5-16 (PDF page 129), YEC states the project "was reviewed as part of the 2017/18 GRA".

QUESTION:

a) Please provide an analysis that compares approved costs and actual costs with explanations of significant variances.

ANSWER:

(a)

The approved 2017 and 2018 budgets were $110,519.61 and $1,250,000, respectively. The actual expenditures for 2017 and 2018 were $110,519.61 and $1,167,329.46 respectively. No significant variances for this project are noted.

TOPIC: **Replacement of P125 Head Gate**

REFERENCE: **2021 General Rate Application, Section 5.2.1.8**

PREAMBLE: On page 5-18 (PDF page 131), YEC states "[i]t is expected that the WH2 headgate will be completed in 2020 at a forecast cost of $2.3 million; and that the WH1 and WH3 headgates will be completed in 2021 at a forecast cost of $3.5 million."

QUESTION:

a) Please provide the status of the WH2 headgate. Is the project complete, and what is the actual cost?

b) Please provide the status of the 2021 project.

ANSWER:

(a)

The project to replace the WH2 headgate (1 of 3) is complete and the total cost was $1,958,118.

(b)

The 2021 project has been delayed. YEC is in the early planning and design stages for the WH1 and WH3 Headgate Replacements which will commence in 2022.

TOPIC: **WH2 Uprate**

REFERENCE: **2021 General Rate Application, Section 5.2.1.9**

PREAMBLE: On line 19 of page 5-18, YEC refers to the 2016 Resource Plan. On lines 23-27 of page 5-18 (PDF page 131), YEC states:

> In 2017, Hatch completed an economic assessment of various uprate options at the Whitehorse Rapids Generating Station (WRGS). The report concluded that the uprating of the WH1 or WH2 units would be the most cost-effective option and provide the best payback of the WRGS hydro units. Management selected the uprating of WH2 over WH1 since there are existing known issues with the WH2 governor, and the uprating project would resolve these issues.

CW requires information to understand what was approved compared to what was actually implemented.

QUESTION:

a) Please provide the evidence from the 2017/18 GRA, and related decision sections, that clearly indicate what was requested and approved in the 2017/18 GRA.

b) Please provide an analysis of the forecast and approved costs from the 2017/18 GRA compared to the actual costs incurred for 2017, 2018, and 2019 with variances explained.

ANSWER:

(a) and **(b)**

The 2017/18 GRA included $0.450 million forecast spending in 2018 for the Whitehorse Hydro Uprate [see page 5.4-4 of Appendix 5.4 of the 2017/18 GRA]. The following was noted:

> As part of the Resource Plan, a preliminary assessment of the Whitehorse hydro units was completed which identified a number of potential uprating (or re-runnering) scenarios. An uprate project was identified to provide both additional

firm energy and dependable capacity. Additional benefits of the project could potentially include an improved efficiency curve allowing increased operational flexibility.

Spending of $0.450 million in 2018 will be used for a detailed investigation of which alternative to proceed with as well as selecting an owner's engineer to represent YEC throughout the project. A scope of work will be created and the construction contract could possibly be awarded by the end of the year. This project is expected to be complete and in service by 2020.

In Tab 5, Table 5.8 of the 2017/18 GRA notes the forecast cost of $0.450 million remained in WIP, i.e., it was not part of the requested 2017/18 revenue requirement. The project was forecast to be complete and come into service in 2020 (Appendix 5.4 of 2017/18 GRA). In paragraph 527 of Appendix A to Board Order 2018-10, the Board stated that it denied YEC's proposed Whitehorse hydro uprate project and directed YEC to remove any forecast expenditures and cost recovery related to this project in its compliance filing. As YEC had not applied to include these costs in rates, this Order had no effect on final approved recoveries.

The actual spending for this preliminary assessment in 2018 was at $0.208 million as shown in Tab 5, Table 5.3 of the current GRA [see "WH2 Uprate Assessment"] compared to $0.450 million forecast in the 2017/18 GRA. The 2018 actual costs covered procurement of an Owner's Engineer and the issuance of an RFP for the turbine & generator contractor.

By end of 2019, the cost incurred for this project is $3.297 million [$3.044 million as shown in Table 5.2-1 plus $0.252 million in Table 5.4].

TOPIC: **WH2 Uprate**

REFERENCE: **2021 General Rate Application, Section 5.2.1.9**

PREAMBLE: In lines 28-30 of page 5-18 (PDF page 131), YEC states:

> The project is planned to be implemented over a three year period (2019-21), and is expected to add 6.4 GWh/yr additional hydraulic generation to the grid [starting in the third quarter of 2021]. The project is also expected to increase dependable capacity of WH2 by 0.94 MW.
>
> CW requires information to understand how distributed energy was factored into the need for a capacity increase.

QUESTION:

a) Please provide a copy of the business case for the project. In the response please provide specific references to how YEC considered the implementation and use of distributed and micro generation over the life of the asset.

ANSWER:

(a)

The 2016 Yukon Energy Resource Plan (YEC, 2017) identified hydro uprate projects as an economically attractive option to help address YEC's existing and forecast capacity shortfall, as well as providing a cost effective incremental source of firm renewable energy. As such, uprating of the Whitehorse hydro units were included in the recommended near-term action plan under the 'base case' load scenario. Table 1 below summarizes WH2 Uprating economics and alternatives reviewed. Distributed generation and microgeneration were not considered in the assessment.

The economics of the WH2 uprating project were calculated for a number of scenarios in order to assess the sensitivity of the project economics to the following factors:

1. **Unit Output:** incremental energy production of 6.4, 6.2 and 3.2 GWh/year were assessed as 'High', 'Expected' and 'Low' output scenarios. The 'Expected' unit

output 6.2 GWh/year was based on the performance of the new turbine guaranteed by Litostroj Power.

2. **Deferred Maintenance Costs:** Since the WH2 Uprating project has a benefit of deferring planned maintenance on the WH2 unit to a later time, the economics of this benefit was also assessed.

A summary of the WH2 Uprating economics when compared to near thermal and renewable generation is provided below. The 'Base Case' scenario is shaded in blue. The calculated increases in annual energy and capacity for the project under the base case assumptions are 5.6 GWh and 0.94 MW respectively. The data shows that the WH2 Uprating project is an economic option to add firm energy and dependable capacity to YEC's portfolio in the near term. This is favourable when compared with other options presented in the 2016 Resource Plan.

See also Hatch study provided as YUB-YEC-1-57 (d) Attachment 1.

Table 1: WH2 Uprating Economics and Summary of Alternatives

WH2 uprating economics and summary of alternatives available

Source	Increase in Dependable Capacity	Increase in Firm Energy	LCOE ($/kWh)	LCOC ($/kW.yr)
WH-2 Uprate 2016 Resource Plan	0.3 MW	1.4 GWh/yr	0.04	361
WH2 Uprate 2017 Hatch Study	0.4 MW	1.9 GWh/yr	N/A	N/A
WH2 Uprate Case 1: High Output With Contingency With Deferred Maintenance Benefit OEM Quoted Performance[1]	0.94 MW	6.4 GWh/yr	0.052	387.49
WH2 Uprate Case 2: Expected Output With Contingency Without Deferred Maintenance Benefit OEM Quoted Performance[1]	0.94 MW	6.2 GWh/yr	0.072	482.60
WH2 Uprate Case 3: Expected Output With Contingency With Deferred Maintenance Benefit OEM Quoted Performance[1,2]	0.94 MW	6.2 GWh/yr	0.059	387.49
WH2 Uprate Case 4: Low Output With Contingency With Deferred Maintenance Benefit OEM Quoted Performance[1]	0.94 MW	3.2 GWh/yr	0.109	387.49
Takhini LNG Plant – Incremental Capacity 2016 Resource Plan	5 MW	41.6 GWh/yr	0.26	812
Takhini Diesel Permanent Installation – Midgard 2019 Thermal Generation Planning Report	20 MW	5 GWh/yr	0.83	138
Drury Small Hydro	8.1 MW	31.7 GWh/yr	0.19	700
Atlin/Pine Creek Small Hydro	5 MW	22.3 GWh/yr	0.13	806

Notes:

[1] Based on total project budget including contingency

[2]Based on post uprate performance guarantees from Litostroj Power.

TOPIC: **Demand Side Management (DSM)**

REFERENCE: **2021 General Rate Application, Section 5.3.1.2**

PREAMBLE: On lines 1-2 of page 5-23 (PDF page 136), YEC states "[t]he 2016 Resource Plan determined that DSM programs are a cost-effective way to meet energy and capacity demand that should be included in the proposed future portfolio of energy supply projects." Pursuant to government direction, YEC has included DSM costs. CW requires information to assess how DSM benefits have been factored into YEC cost forecasts.

QUESTION:

a) Please provide a copy of all research, studies, business cases, and other analysis that YEC has conducted that demonstrates DSM is "a cost-effective way to meet energy and capacity demand."

b) Please provide an analysis that demonstrates how DSM will reduce the need for incremental assets and capacity over the next 40 years.

c) Please fully explain how YEC has factored the potential benefits of DSM into each capital project that results in increased capacity of the asset or system.

ANSWER:

(a)

Please see response to YUB-YEC-1-47(a) and (b).

(b) and **(c)**

Yukon Energy's 10-Year Renewable Electricity Plan provides updated analysis as to forecast DSM impacts on reducing the need for incremental assets and capacity over the next decade, demonstrating that YEC has factored the potential benefits of DSM into each major capital project that is being considered to provide increased capacity.

Please see response to CW-YEC-1-36 (a) [Attachment 1] and (b).

TOPIC: **Investments to Ensure Dependable Capacity**

REFERENCE: **2021 General Rate Application, Appendix 5-1, Section 5.1-2**

PREAMBLE: YEC proposes to spend $25,000,000 in 2021 (with a $16,500,000 contribution) on a Battery Energy Storage System.

QUESTION:

a) Please provide a full business case for the Battery Energy Storage System.

b) Please provide a detailed analysis that clearly demonstrates how the inclusion of a Battery Energy Storage System was considered in determining the need for each capital project that results in increased capacity of the asset or system.

ANSWER:

(a)

Please see the response to YUB-YEC-1-71.

(b)

The Battery Energy Storage System project has been designated by OIC 2020/180 as a "regulated project" under Part 3 of the *Public Utilities Act.* Based on this requirement, Yukon Energy has filed an application for an energy project certificate and an energy operation certificate with the Minister of Justice.

Section 4.2.1 of the Part 3 Application reviews "Alternatives to the Project". Table 4-1 from the Application summarizes Forecast Non-Industrial Peak and Dependable Capacity under N-1 Capacity Planning Criterion: 2021/22-2030/31 Winter (MW) and is excerpted below.

Table 1: Forecast Non-Industrial Peak and Dependable Capacity under N-1 Capacity Planning Criterion: 2021/22-2030/31 Winter (MW)

	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Non-industrial Peak	**104,102**	**107,372**	**110,546**	**113,952**	**117,030**	**120,515**	**124,517**	**129,214**	**133,769**	**138,676**
Non-industrial Peak	*103,284*	*106,277*	*109,078*	*111,985*	*114,393*	*116,982*	*119,783*	*122,870*	*125,268*	*127,285*
EV Peak	*818*	*1,096*	*1,468*	*1,968*	*2,637*	*3,533*	*4,734*	*6,344*	*8,501*	*11,391*
Existing Resource Dependable Capacity	**112,100**	**112,100**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**
YEC Hydro	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*
YEC Thermal	*36,050*	*36,050*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*
AEY Thermal	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*
N-1 Event [Lost of AH GS or L171]	**-37,195**	**-37,194**	**-37,193**	**-37,192**	**-37,191**	**-37,190**	**-37,189**	**-37,188**	**-37,187**	**-37,186**
Loss of AH GS	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*
Loss of AEY Haines Junction diesel	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*
Haines Junction peak	*1,305*	*1,306*	*1,307*	*1,308*	*1,309*	*1,310*	*1,311*	*1,312*	*1,313*	*1,314*
Capacity Shortfall/Surplus under N-1	**-29,197**	**-32,466**	**-40,839**	**-44,244**	**-47,321**	**-50,805**	**-54,806**	**-59,502**	**-64,056**	**-68,962**
Committed and Planned Supply Options	**2,843**	**12,047**	**26,752**	**35,318**	**35,385**	**35,452**	**35,521**	**70,589**	**70,659**	**70,729**
Diesel Replacements	*0*	*0*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*
Whitehorse #2 Uprate	*638*	*638*	*638*	*638*	*638*	*638*	*638*	*638*	*638*	*638*
BESS	*0*	*7,000*	*7,000*	*7,000*	*7,000*	*7,000*	*7,000*	*7,000*	*7,000*	*7,000*
Atlin Hydro EPA	*0*	*0*	*0*	*8,500*	*8,500*	*8,500*	*8,500*	*8,500*	*8,500*	*8,500*
DSM	*2,205*	*4,409*	*6,614*	*6,680*	*6,747*	*6,814*	*6,883*	*6,951*	*7,021*	*7,091*
Moon Lake Pump Storage Phase 1	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*35,000*	*35,000*	*35,000*
Capacity Shortfall/Surplus under N-1	**-26,355**	**-20,419**	**-14,087**	**-8,926**	**-11,936**	**-15,352**	**-19,285**	**11,087**	**6,603**	**1,767**

The discussion in Section 4.2.1 of the Part 3 Application notes, “Many of these options do not provide dependable capacity; and the new resources that will provide dependable capacity would generally not displace what the BESS option can provide, i.e., the identified permanent resource capacity options are generally all needed to remove reliance on rented diesels for addressing the forecast capacity shortfall reviewed in Table 4-1. Moon Lake pumped storage, when developed, is the only identified resource option aside from default new thermal fossil fuel generation that has the capability to remove the forecast N-1 dependable capacity shortfall.”

Further, Section 4.2.1 of the Part 3 Application notes: “aside from the potential Moon Lake pumped storage project in the future, the temporary rental diesel option or permanent new diesel development remain the only feasible alternatives that would provide dependable capacity required to address the N-1 shortfall.”

TOPIC: **Investments to Ensure Dependable Capacity**

REFERENCE: **2021 General Rate Application, Appendix 5.1, Section 5.1-2, page 5.1-7 (PDF page 164)**

PREAMBLE: YEC proposes to spend $3,000,000 on a "Whitehorse Interconnection." In the explanation YEC discusses a 10-year Renewable Energy Plan and a number of new projects being planned over the next decade.

QUESTION:

a) Please provide a copy of the 10-year Renewable Energy Plan.

b) Please provide a list of the "number of new projects being planned over the next decade." In the response, please provide YEC's assessment of the probability of each project proceeding.

ANSWER:

(a)

See Attachment 1 to this response.

(b)

The quote references the 10-Year Renewable Electricity Plan's outline of "a number of potential new projects being planned over the next decade to meet Yukon's growing electricity needs." The potential future resources for the Plan portfolio include the following:

- Atlin Hydro Expansion (6 MW) – for 2024/25.
- A potential 20 MW wind resource for 2025/26 under only the High Case.
- Tutshi-Moon Pumped Storage Project – Phase 1 – 2028/29 (this includes upgrade and expansion of transmission in the Southern Lakes region).

The Action Plan includes the following:

- **Stage 1: Committed resources –** Includes Whitehorse Hydro #2 and #4 (WH2 and WH4) Uprate projects, Battery Storage System, SOP IPP and Micro-Generation projects.

- **Stage 2: Completion of planned work and final decisions to proceed with planned resources –** Includes SLESP (Southern Lakes Enhanced Storage Project), MLESP (Mayo Lake Enhanced Storage Project), the Incremental Diesel Replacement, and DSM (Demand Side Management).

- **Stage 3: Development and implementation of the Future Potential Projects –** Includes the three future potential projects outlined above (Atlin Hydro Expansion, Moon-Tutshi Pumped Storage, and (for the High Case only) a potential 20 MW Wind Project. The Plan highlights that these projects are dependent on securing significant federal funding in order to proceed. Other risks are also identified for these projects. YEC at this time has no specific assessment of the probability of each project proceeding – the Atlin Hydro Expansion is the first of these potential projects, and YEC during 2021 is in active discussions and planning to address the requirements that would enable this project to be committed prior to the end of 2021.

10-Year Renewable Electricity Plan Technical Report

DECEMBER 2020

yukon energy

Executive Summary

Demand for electricity is growing in Yukon. There is an existing gap today between the available dependable capacity on the grid and the amount of electricity Yukoners require during a winter peak under emergency conditions. To continue providing most of the territory's energy from renewable sources and to accommodate the increased demand for electricity, Yukon Energy Corporation (YEC, Yukon Energy) must invest in new dependable renewable electricity sources that add firm winter capacity to the grid. This will allow YEC to continue meeting Yukoners' growing demands for renewable electricity – even on the coldest and darkest of days – while also supporting Yukon government's emission reduction targets.

This plan outlines a portfolio of key projects and partnerships needed by 2030 to address the substantial demand for renewable electricity that will result from ongoing economic growth of the Territory, and from the policies and actions outlined in the Yukon government's draft *Our Clean Future: A Yukon strategy for climate change, energy and a green economy*. In this strategy, the government has mandated that an average of 93% of electricity generated on the grid must be produced from renewable sources and includes specific actions to electrify the territory's transportation and heating sectors.

In order to conduct this analysis, YEC updated its load forecast (the projected energy and demand requirements of Yukoners) based on recent learnings from cold weather peaks and incorporated the electrification actions of the Yukon government's *Our Clean Future* strategy to estimate the resulting increased demand. YEC used this load forecast, along with the inventory of existing generation and projects under development, to calculate the gap between the energy and demand requirements and available resources. Using updated technical and cost information on potential resources, the company then conducted a portfolio analysis to evaluate which renewable resource options could best address this gap, across a range of scenarios. The goal of this portfolio analysis was to develop an optimal set of projects capable of addressing both the energy and peak capacity shortfalls over the 10-year planning horizon.

The result is the updated Future-Focused Portfolio. Included in this portfolio are resources which are planned or currently under development. These ongoing projects include: Whitehorse Hydro uprates at WH2 and WH4, the battery energy storage system, renewable energy purchases from Independent Power Producers through the Standing Offer Program, solar energy from the Micro-Generation program, the Southern Lakes and Mayo Lake enhanced storage projects, replacement of diesel generators as they retire, and demand side management programs. The three new projects YEC is proposing are: electricity purchases from the planned Atlin Expansion Project, construction of a pumped storage facility at Moon Lake, and upgrading and expansion of the Southern Lakes Transmission Network. The combination of these three future potential projects not only stores and uses excess renewable power generated in the summer to decrease dependency on fossil fuels during the winter, but also makes connecting potential sources of First Nations-owned renewables in the Southern Lakes region more viable, and creates potential future electricity sales opportunities.

First Nations governments, development corporations and Citizens will have a key role in helping to shape and deliver this plan over the next 10 years. YEC recognizes First Nations as governments and potential energy proponents, partners and investors. In developing this plan, YEC will work pro-actively and collaboratively with First Nations governments and development corporations to forge partnerships and create opportunities for project ownership, investment, contracting, employment and training. First Nations will also be at the forefront of project assessments, permitting and approvals.

The cost of projects in this plan are estimated to be in excess of $500 million, one of the largest investments ever in the Yukon electricity system. Federal funding for the plan will be key to keeping the plan affordable and minimizing risks for Yukon customers.

The 10-Year Renewable Electricity Plan presents a generational opportunity for Yukon to invest in the critical renewable electricity projects needed to fuel Yukoners' lives, work and economy with clean energy. It creates opportunities for Yukon Energy, First Nations governments and development corporations, the Yukon and federal governments, and Yukoners to jointly shape the territory's electricity future.

A clean future lies ahead. Let's work together to meet Yukon's climate goals.

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Glossary of Key Terms

CAPACITY (DEMAND)	The supply (or consumption) of electrical power at a given instant in time. Usually measured in megawatts (MW) in long-term planning context.
DEMAND SIDE MANAGEMENT (DSM)	The attempt to reduce overall electrical consumption at customer sites via initiatives or implementation of codes/standards. Demand side management, if used during peak demand periods, can provide an alternative to supply-side dependable capacity additions.
DEPENDABLE CAPACITY	The maximum generation output that a resource can reliably provide in a specific time frame, expressed in megawatts (MW), typically during the period of greatest demand. YEC defines dependable capacity as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months (November to February) based on the inflows in the five driest inflow years in history. For thermal resources, dependable capacity was assumed to be equal to the installed capacity, since fossil fuels can be stored. For wind resources, dependable capacity is considered zero, as there is no guarantee that there will be the required wind speeds for the two consecutive weeks within the winter period.
DISPATCHABLE GENERATION	Refers to sources of electricity that can be dispatched at the request of power grid operators; that is, generating plants that can be turned on or off, or can adjust their power output on demand. Resource options such as thermal power plants and hydro power plants with reservoirs are dispatchable and they can meet changing electricity loads. In contrast, intermittent resources, such as wind are non-dispatchable because they can only generate electricity while their energy source is available.

ENERGY	The supply (or consumption) of electrical power over a period of time. Usually measured in kilowatt-hours (kWh) for residential usage or gigawatt-hours (GWh) for territorial usage. The annual energy supply must at least cover the annual energy consumption.
GENERATION RESOURCE	Refers to sources of energy that are converted to electrical power and provide energy and/or dependable capacity. Common generation resources include hydro, wind, solar, or thermal (e.g. natural gas or diesel).
INDEPENDENT POWER PRODUCER (IPP)	An energy producer who generates electricity for sale to utilities or consumers.
INSTALLED CAPACITY	The maximum amount of generating capacity that a generation resource is capable of providing, expressed in megawatts (MW).
LOAD	The electrical energy required to power homes, businesses and industrial processes. Sometimes referred to as demand.
N-1 (SINGLE CONTINGENCY) PLANNING CRITERION	A reliability planning criterion used to determine the capacity requirements of the system. YEC's N-1 criterion requires that each part of the YEC transmission grid should be able to carry the forecast peak winter demand, excluding major industrial demand, under the largest single contingency. The single largest contingency is defined as loss of the largest single element which could be either a transmission line or generating station. This criterion considers the ability to interrupt large industrial customers during an emergency event, which is why only non-industrial peak demand is included.
RENEWABLE ENERGY	Energy that comes from sources renewed on an ongoing basis through natural processes. Examples include sun (solar), wind, and flowing water (hydro).

1 Introduction

1.1 Yukon Energy Corporation

Yukon Energy Corporation (YEC) is a public electric utility owned by the Yukon Government through the Yukon Development Corporation (a Crown Corporation). YEC's mandate is to plan, generate, transmit and distribute a continuing and adequate supply of cost-effective, sustainable, clean and reliable electricity for customers in Yukon.

YEC owns and operates the Yukon's integrated transmission system, generating almost 100% of the electricity on this isolated, northern Canadian, electric grid. It is the electric utility with primary responsibility for planning and development of new generation and transmission facilities in Yukon. YEC is incorporated under the Business Corporations Act and regulated by the Public Utilities Act and the Yukon Waters Act.

1.2 Background: Drivers for a 10-Year Renewable Electricity Plan

In July 2019, YEC released its 5-year strategic plan with a bold 10-year vision to be a Canadian leader in sustainable energy by 2030. Later that year, based on the input of Yukoners, YEC's Board of Directors also decided not to move forward with the development of a new 20-megawatt thermal generation facility that would address Yukon's current and forecast capacity shortfall. This decision commenced the re-examination of potential renewable capacity resources.

In November 2019, Yukon government released a draft of its *Our Clean Future* strategy, with a vision for addressing climate change by building thriving, resilient communities powered by clean energy and supported by a sustainable green economy. In it, the government proposed that an average of 93% of electricity generated on the grid be produced from renewable sources and included specific actions to promote the electrification of the territory's transportation and heating sectors. These policy actions triggered the need for an update to YEC's long term load forecast.

These increased electricity requirements to enable a clean Yukon future and the Corporation's commitment to provide renewable capacity solutions to serve this demand formed the need to develop an updated plan for future renewable generation and transmission projects.

1.3 Yukon Integrated System

At present, the Yukon electrical system shown in Figure 1 comprises:

» One (1) large hydroelectric based grid called the Yukon Integrated System (YIS);

» One (1) medium-sized diesel-based grid serving Watson Lake; and

» Three (3) smaller isolated communities with diesel generation (Beaver Creek and Destruction Bay/ Burwash Landing) and solar/diesel generation (Old Crow).

Figure 1: Yukon Electrical Systems

1.4 YEC Resource Planning Criteria

Reliability means that electricity is available when customers demand it. Generation resources exist to supply electricity, and transmission resources exist to move electricity from generators to customers. Planning generation resources involves consideration of two primary supply aspects: energy and capacity. Energy is the total quantity of electricity produced over a period of time (e.g. a day or a year), while capacity is how much electricity can be produced at one time.

Being an islanded system, YEC must ensure there is always an adequate supply of both energy and capacity, including in the event of contingencies (i.e. loss of generation or transmission). Achieving these supply objectives is made more challenging by the islanded nature of the YIS, since YEC cannot rely on its neighbours to provide additional energy and capacity in times of need.

To address YEC's planning requirements, YEC used the following criteria in the resource planning process:

- **Energy Planning Criterion.** This criterion is defined as having firm energy equal to or greater than forecast future energy loads. The energy planning criterion must be met on an annual basis. It should be noted that although YEC plans for firm energy, YEC has excess firm energy available from thermal generation resources to meet the firm energy planning criterion over the planning period. As a result, the 10-Year Renewable Electricity Plan has been modeled on the basis of average energy for renewable generation resources which assumes average water, wind and solar irradiance.
- **Capacity Planning Criterion.** This criterion ensures that the system has sufficient capacity to meet peak demand (peak capacity) for two consecutive weeks under extreme cold winter conditions. The capacity planning criterion is based on the single contingency (N-1) criterion, which states that each part of the YEC transmission grid shall supply the forecast non-industrial peak winter demand, excluding major industrial demand, under the largest single contingency. Yukon's current largest single contingency corresponds to the loss of the 37 MW Aishihik Generation Station, either through an outage of the generating station itself or an outage of the L171 transmission line that interconnects the Aishihik Generating Station to the Takhini Substation.

Please refer to *Section 4.3: Resource Planning and Reliability Criteria* in the 2016 Integrated Resource Plan (IRP) for further details.

2 Context

2.1 Yukon Challenges

» **Islanded Grid.** Yukon cannot rely on adjacent Canadian provinces, territories or the State of Alaska to supply electricity, and must self-supply all its own capacity and energy.

» **Predominantly Hydroelectric Energy Generation.** Most Yukon electricity is generated using renewables, and as recently as 2016 more than 98% of Yukon's electric energy was supplied by renewable (primarily hydroelectric) generation, with the remaining 2% provided by thermal generation (diesel and natural gas fired generation). Hydroelectricity relies on the availability of water to generate electricity, and as a result YEC must anticipate and plan for potential drought conditions.

» **Mismatched Generation Supply and Electricity Demand.** Electricity demand in the Yukon is highly variable, and changes considerably over the course of each day and across seasons. Primarily driven by residential demand for services such as space heating, lighting, cooking and appliance loads, Yukon's electricity demand typically peaks during cold winter days during and shortly after dinner time (typically between 4pm and 6pm). There is a seasonal mismatch between the timing of maximum available electricity production from hydroelectric generation (which peaks in the summer months) and maximum customer demand (which peaks in the winter months). As a result, YEC regularly relies on thermal generation to fill the gap between available hydroelectric generation and electricity demand during the winter peak periods.

» **Industrial Load Changes & Ratepayer Protections.** Yukon's small customer base means that the addition or loss of a major industrial load (e.g. a mine) on the grid has a substantial effect on both overall electricity demand and the total electricity sales volumes. This impacts how YEC's costs are divided amongst ratepayers. This volatility in industrial customer demand makes it challenging for YEC to forecast its future generation supply requirements, or to mitigate potential step changes in electricity rates which can occur with the loss of industrial customer demand.

2.2 Federal Funding to Enable Renewable Capacity

YEC is subject to price regulation and may only charge electricity prices approved by the Yukon Utilities Board (YUB). Since the YUB is an economic regulator, this implies that YEC must select the lowest cost resource options to meet future demand, while still meeting applicable regulations and laws.

Planning for future capacity resource investments is a key outcome of the 2016 Integrated Resource Plan and this current plan. Since thermal generation resources typically offer the lowest cost source of new capacity, this typically leads to the inclusion of new thermal facility investments. For example, a new 20 MW diesel plant was included in the recommended portfolio of the 2016 Integrated Resource Plan.

YEC's 2016 Resource Plan involved a "blank sheet" planning process that evaluated all generation options available to YEC without being constrained or influenced by planning pre-conditions. The 10-Year Renewable Electricity Plan, however, is focused on prioritizing renewable electricity solutions, which strongly influenced the generation resource options that were considered.

Accordingly, in order to meet the objectives of the 5 Year Strategic Plan and the policy objectives set out in the Yukon government's *Our Clean Future* strategy, Federal funding was assumed to support the development of renewable capacity sources that would otherwise not be selected as the lowest cost capacity resources. Federal funding also serves to reduce the impact of large infrastructure development on Yukon electrical rates, thus keeping residential and industrial rates affordable. This will allow Yukon to maintain an affordable quality of life, and ensure Yukon remains a competitive jurisdiction for future industrial development.

In Yukon, there is a long history of the Federal government funding support for large electrical infrastructure development (e.g. Carmacks-Stewart Transmission Project, Mayo B, etc.) to protect ratepayers and keep rates affordable. For the purposes of this plan, it is assumed that new generation and transmission projects will receive Federal funding, to a typical maximum of 75% of total capital cost.

2.3 Relevant Government Policy and Initiatives

YEC is accountable for meeting policy directives issued by the Yukon government and its agencies. Key recent policy developments include:

1) Micro-Generation Policy

2) Independent Power Producer Policy

3) Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy

2.3.1 Micro-Generation Policy

Issued by the Yukon government in October 2013, this policy aims to encourage the small-scale generation of electricity by individuals, small businesses and communities to meet their own needs, as alternatives or supplements to centralized grid-connected power. The policy is applicable to micro-generation projects up to 50 kW. YEC has included micro-generation-sourced energy in its committed resource assumptions for future supply options in the 10-Year Renewable Electricity Plan.

2.3.2 Independent Power Producer (IPP) Policy

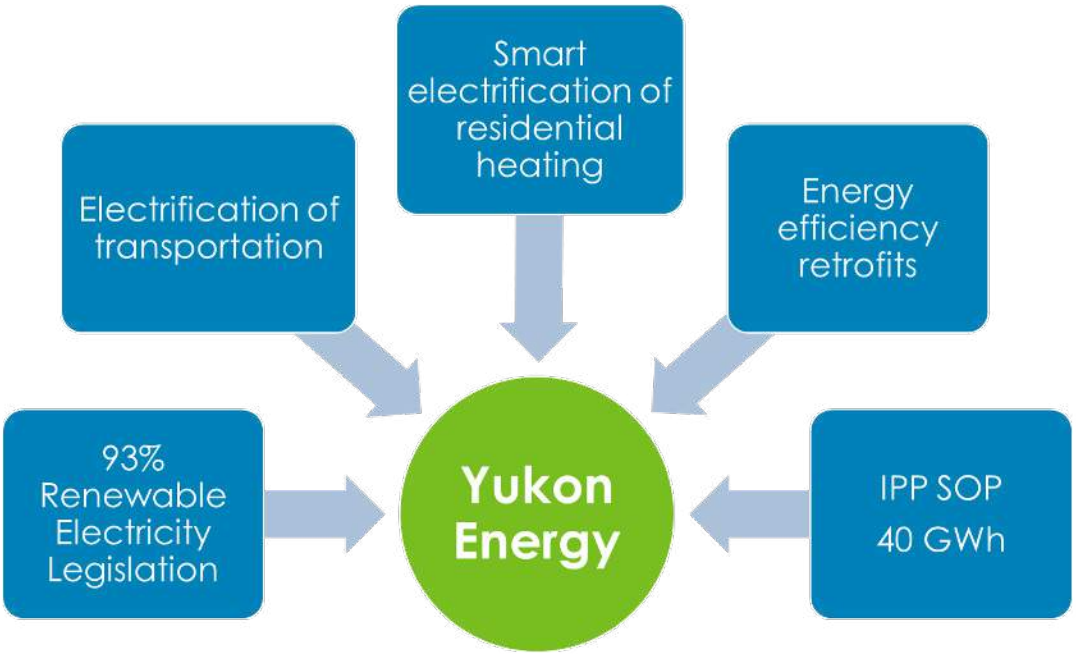
Issued by the Yukon government in October 2015, the IPP policy aims to provide opportunities for non-utility entities to develop new generation resources that can assist the utilities in meeting the demand for affordable, reliable, flexible and clean electrical energy.

YEC and ATCO are actively working with the government to structure a Standing Offer Program (SOP), which is a key element of the IPP Policy. The SOP is intended to provide a standardized technical and commercial framework to facilitate grid connection of new small capacity generation (in the 30 – 2,000 kW range). YEC included 40 GWh of annual IPP-sourced energy in its committed resource assumptions for future supply options in the 10-Year Renewable Electricity Plan.

2.3.3 Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy

Yukon government released a draft of its *Our Clean Future* strategy for public review in November, 2019. The strategy was formally launched in September, 2020. Key goals of the strategy include reducing greenhouse gas emissions, ensuring Yukoners have access to reliable, affordable and renewable energy, adapting to the impacts of climate change, and building a green economy. Figure 2 provides an overview of the various elements of the Yukon government strategy which influenced YEC's expected load and generation requirements.

Figure 2: *Our Clean Future* Strategy Influence on YEC 10-Year Renewable Electricity Plan



The *Our Clean Future* strategy states that Yukon government will develop legislation by 2023 that will require at least 93% of the electricity generated on the Yukon Integrated System to come from renewable sources, calculated as a long-term rolling average, while aiming for an aspirational target of 97% renewable electricity by 2030. This minimum requirement, and the long-term aspirational target, impacted the generation requirements used in the development of the 10-Year Renewable Electricity Plan.

The electrification of transportation and smart heating called for by the strategy is expected to increase the amount of electricity required by Yukoners, while energy efficiency retrofits may reduce or change electricity requirements for some entities. The impact of these actions was reflected in the load forecasts developed for this Plan. The changes to the IPP Standing Offer Program, and the support of Demand Side Management (DSM) programming, were also reflected in the energy portfolio modeling.

The *Our Clean Future* strategy is focused on six priorities: Transportation; Homes and Buildings; Energy Production; Communities; Innovation; and Leadership. Within these priorities, a number of strategies and related actions for energy conservation and the development of renewable energy resources were identified. Table 1 summarizes the key electricity-related initiatives relevant to YEC which were accounted for in the development of the 10-Year Renewable Electricity Plan.

Table 1: Government Energy & Climate Change Strategy: Electricity-Related Initiatives for YEC

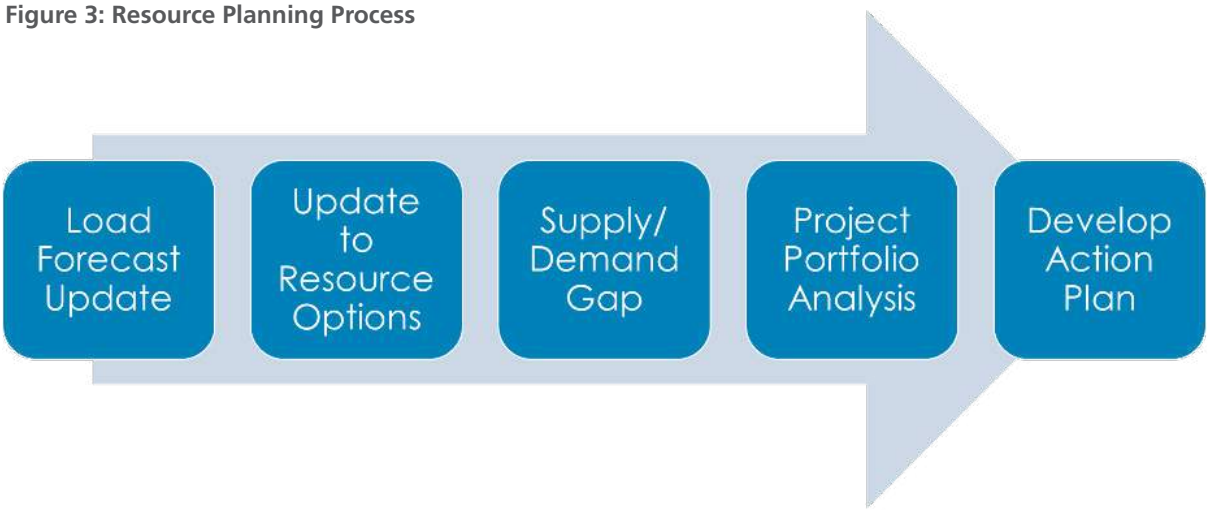
PRIORITY	ACTION NUMBER	ELECTRICITY RELATED INITIATIVE	TARGET	ACCOUNTED FOR IN 10-YEAR RENEWABLE PLAN?
Transportation	Actions #T1, #T2, #T4, and #T6	Increase the availability and use of zero emission vehicles, install fast-charging stations across Yukon, and require new residential buildings in greater Whitehorse area to support Level 2 electric vehicle charging.	4,800 EVs by 2030	Yes (included 5,000 EVs by 2030, based on November 2019 Draft Strategy).
Homes and Buildings	Action #H18, #H21, #H22	Replace residential fossil fuel heating systems with smart electric heating systems.	1,300 buildings over 10 years	Yes
Homes and Buildings	Action #H26, #H27, #H28	Allow Yukon's public utilities to partner with Government of Yukon to pursue cost-effective demand-side-management measures, and collaborate on delivery of capacity and energy DSM programs.	No specific target.	Yes

PRIORITY	ACTION NUMBER	ELECTRICITY RELATED INITIATIVE	TARGET	ACCOUNTED FOR IN 10-YEAR RENEWABLE PLAN?
Energy Production	Action #E7, #E8, #E10	Continue to implement the IPP Policy and the Micro-generation Program and increase the SOP limit to support additional community-based renewable energy projects.	Increase the SOP limit from 20 GWh to 40 GWh, 7 MW of installed Micro-generation capacity by 2030	Yes
Energy Production	Action #E1	While aiming for an aspirational target of 97% by 2030, develop legislation by 2023 that will require at least 93% of the electricity generated on the Yukon Integrated System to come from renewable sources, calculated as a long-term rolling average.	93% long-term rolling average	Yes
Energy Production	Action #E12	Conduct research into the potential to use geothermal energy in Yukon for heating and/or electricity.	No specific target.	No

3 Resource Planning Methodology

The goal of the resource planning process is to develop recommended actions for meeting Yukon's energy and capacity electricity demand requirements over the 10-year horizon.

Figure 3: Resource Planning Process



The planning process was built on the 2016 Resource Plan and followed these steps:

1. **Load Forecast Update**. Forecast future electricity demand for both energy and peak capacity (Section 4);
2. **Supply/Demand Gap.** Create an inventory of existing, committed and planned generation resources (Section 5), then determine potential shortfalls between future demand and generation supply resources in terms of both energy and capacity (Section 6);
3. **Update to Resource Options.** Create an inventory of future potential generation resource options (Section 7);
4. **Project Portfolio Analysis.** Analyze and develop a portfolio of options to address the energy and capacity shortfalls (Section 8); and
5. **Action Plan**. Develop a recommended action plan (Section 9).

It should also be noted that although the planning horizon for the 10-Year Renewable Electricity Plan is from 2020 to 2030, the resource planning process was completed based on a longer timeframe (i.e. 2020 to 2035) to allow for the phased development of certain resource options included in the portfolio analysis. Each step of the planning process is described further in the following sections.

4 Load Forecast

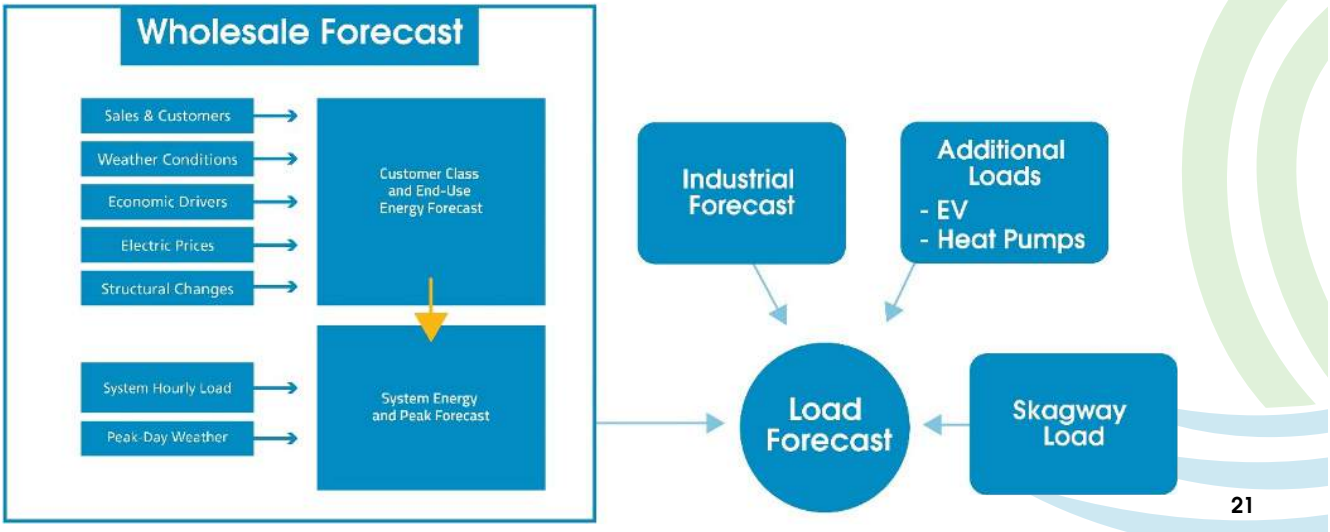
4.1 Load Forecasting Overview

The energy and peak capacity demand forecast estimates YEC's electricity needs over the planning horizon. The forecasting process used multiple inputs provided by external expert sources and inputs from the Yukon government, as well as production forecasts for major industrial customers.

Energy and peak capacity demand forecasts were developed in two parts:

1. **Part 1.** The energy and peak capacity demand forecasts from the 2016 Integrated Resource Plan were updated by Itron using their SAE MetrixND econometric model. The updated forecasts capture a range of input data, including historical sales and energy data by customer class, economic activity, population projections, average expected weather conditions, electricity prices, and improvements in end-use efficiency and standards. The economic activity input assumptions were based on the Yukon government economic model. This included an industrial activity forecast, reflection of the state of the economy in 2019 based on actual population and household numbers, and updated Gross Domestic Product (GDP) statistics.
2. **Part 2.** Additional loads not captured in Part 1 of the demand forecasts were added separately to the demand forecast output. These additional loads included industrial grid-connected mining loads, incremental loads from specific climate policy incentives such as the adoption of electric vehicles and the electrification of space heating in buildings, and the incremental load associated with the potential electrification of cruise ships in Skagway.

Figure 4: Load Forecast - Process Overview



4.2 Load Forecast Scenarios

Yukon's small customer base means that the addition or loss of a major industrial mining load on the grid has a material impact on overall energy requirements. In order to recognize and quantify this volatility, scenarios describing credible potential alternative futures were developed by making specific assumptions concerning the future loads of existing grid-connected mines. Other factors, such as increased loads from the electrification of cruise ships in Skagway and future energy policy actions, were also incorporated into the scenarios.

There are a number of prospective mining projects located far from the Yukon grid (e.g., Coffee Gold Project, BMC Minerals Kudz Ze Kayah project) that could be developed during the planning period. However, since these projects are assumed to be off-grid operations with no direct impact to on-grid electricity demand, and there is limited visibility on the probability or timing of these projects, they were not considered as part of this analysis. The scenarios also did not consider any new large on-grid mining projects being developed in the 10-year planning period as there is limited visibility on the certainty of any of these potential projects coming to fruition. Should new mining developments emerge, future long-term resource plan updates would contemplate how to address the resulting load impact.

The four (4) scenarios considered were:

1. Low Case;
2. Base Case (without Skagway);
3. Base Case (with Skagway); and
4. High Case.

The third scenario in the list, Base Case (with Skagway), represents the expected Base Case for the YEC load forecast, and is referenced as the "Base Case" throughout the remainder of this report. Note that this analysis was conducted prior to the COVID-19 pandemic. YEC will assess the timing and extent of the recovery of the cruise ship industry as part of its evaluation of the Skagway business opportunity.

Table 2: Load Forecast Scenarios - Assumptions

	LOW CASE	BASE CASE (WITHOUT SKAGWAY)	BASE CASE	HIGH CASE
Wholesale Forecast	YG Economic Model Energy Policy Actions	YG Economic Model Energy Policy Actions	YG Economic Model Energy Policy Actions	YG Economic Model Energy Policy Actions
Eagle Gold Load	Operation to 2029 2019 updated forecast	Operation to 2029 2019 updated forecast	Operation to 2029 2019 updated forecast	Operation to 2035 2018 load forecast
Minto Load	None	3 MW average to 2022	3 MW average to 2022	3 MW average to 2031
Alexco Load	None	2.5 MW average to 2035	2.5 MW average to 2035	2.5 MW average to 2035
EV Load	2,000 EVs by 2030; L2 charging; no Time of Use (TOU) rates	6,000 EVs by 2030; L2 charging; no TOU	6,000 EVs by 2030; L2 charging; no TOU	6,000 EVs by 2030; L2 charging; no TOU
Skagway Load	None	None	35 GWh/yr summer demand from 2026 to 2035	35 GWh/yr summer demand from 2026 to 2035

4.3 Energy Forecasts

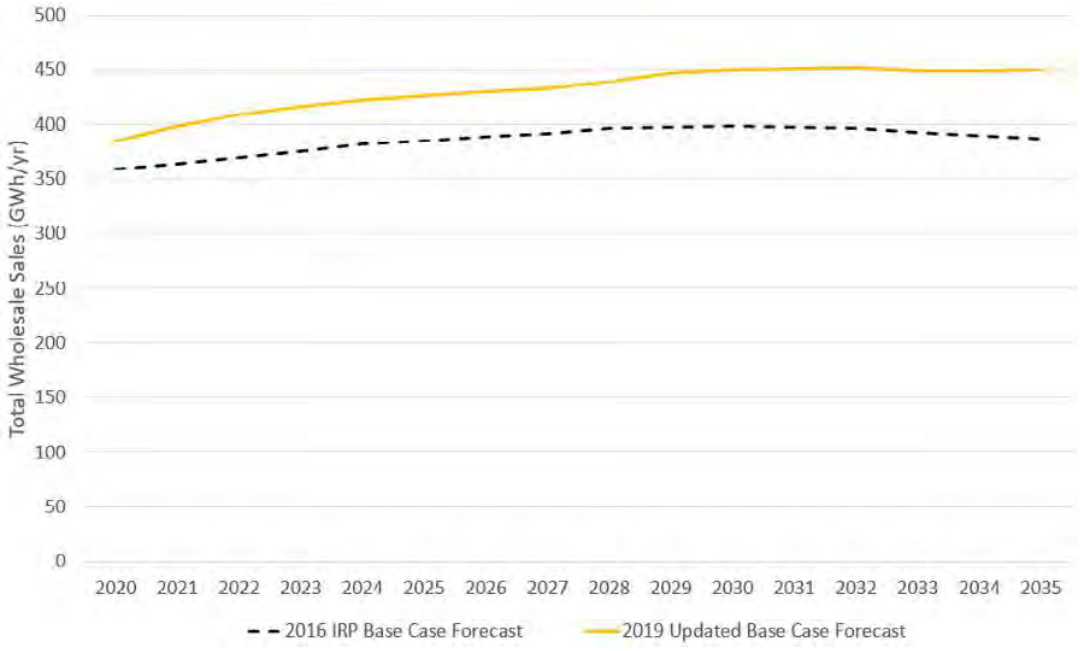
This energy forecast for the Yukon Integrated System (YIS) (see Section 1.3) is for the Base Case scenario. Energy refers to the quantity of electricity, expressed in gigawatt-hours (GWh) that is sold over a specified period of time.

The YIS energy forecast comprises two major elements, wholesale load and industrial (i.e. mining) load, which are combined to produce the total energy forecast. To show how the load forecasts have changed over time, the previous forecast values from the 2016 IRP are included in each of the following graphs.

4.3.1 Annual Energy Forecast

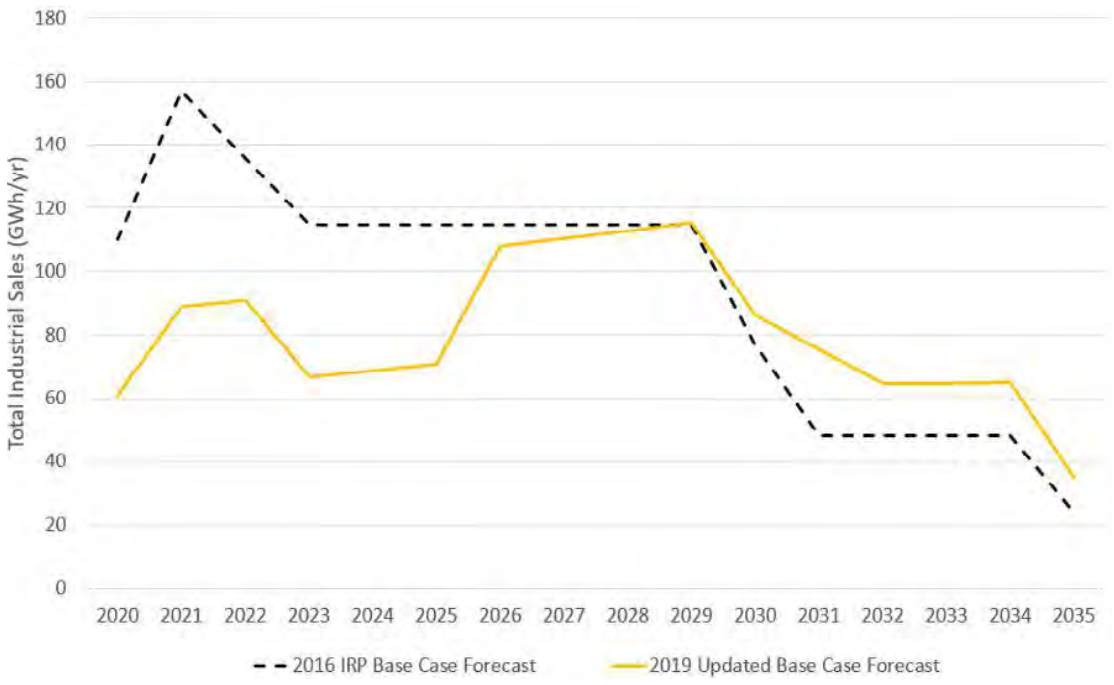
The annual wholesale energy forecast, which includes the incremental Yukon Energy Policy Action loads for the Base Case scenario relative to the 2016 IRP Base Case forecast, is shown in Figure 5. The updated 2019 energy forecast is higher than the 2016 forecast for the entire planning period, including the initial 2020 year. Energy load is higher in 2020 due to higher than forecast economic and population growth over the 2016-2019 period. In addition, the data in Figure 5 illustrates that energy demand is forecast to grow at a higher rate than forecast in the 2016 IRP due to impacts of Yukon government electrification policy actions which include electric vehicles and electrification of space heating.

Figure 5: Base Case - Wholesale Forecast Relative to 2016 IRP Base Case Forecast



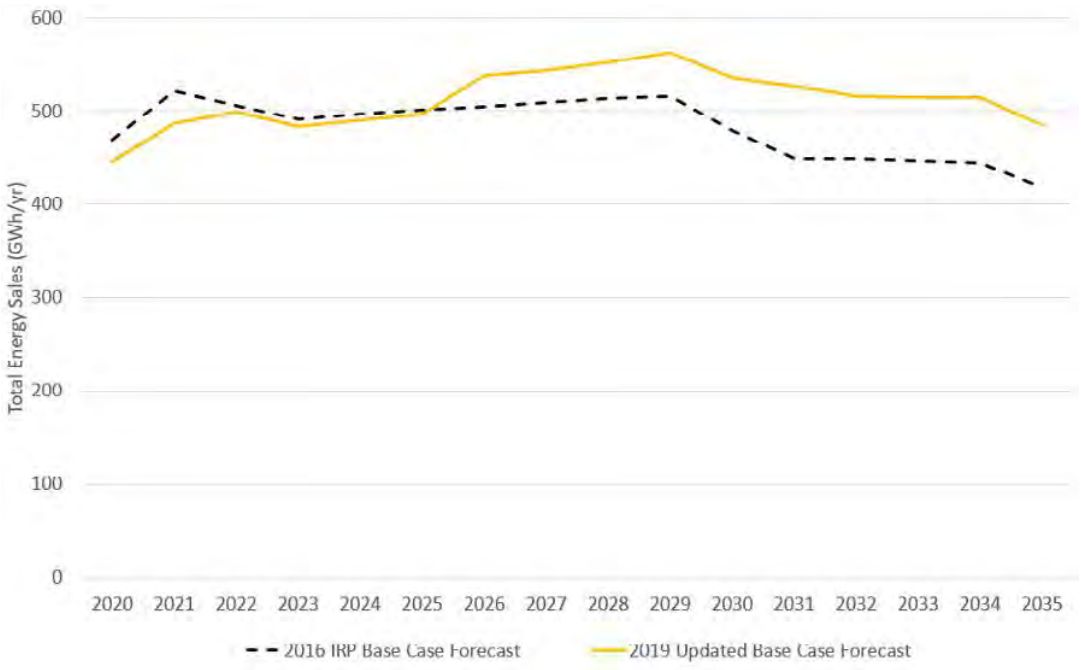
The annual industrial forecast for the Base Case scenario relative to the 2016 IRP Base Case forecast is shown in Figure 6. It should be noted that the 2019 industrial forecast also includes an additional 35 GWh/year load from year 2026 onwards for the assumed electrification of cruise ships in Skagway under this scenario. The observed decrease in forecast industrial load at the start of the planning period (2020-2025) relative to the 2016 forecast is primarily driven by a reduction in the forecast Victoria Gold mining load. The observed increase in forecast industrial load from year 2026 onwards is due to the additional load associated with the electrification of cruise ships in Skagway. Finally, the observed drop-off in industrial load from year 2029 onwards is due to the assumed shut-down of the Eagle Gold mine.

Figure 6: Base Case - Industrial + Skagway Forecast Relative to 2016 IRP Base Case Forecast



The total energy forecast (i.e. wholesale + industrial + Skagway) for the Base Case scenario relative to the 2016 IRP Base Case scenario is shown in Figure 7. The forecast increase in wholesale load is partially offset by the reduction in mining load at the beginning of the planning period, but an increase in total energy is observed from year 2026 onwards due to the addition of the Skagway load. As a result, the updated total energy forecast for the Base Case scenario remains very similar to the 2016 forecast, with slightly lower energy demand in the near-term years, and higher energy demand in the latter years of the planning period.

Figure 7: Base Case – Total Energy Forecast Relative to 2016 IRP Base Case Forecast



4.3.2 Seasonal Profiles

Seasonal energy profiles help demonstrate how energy demand changes over the course of a year and identifies which months have the highest and lowest energy demand. Figure 8 shows forecast monthly energy profiles for the year 2030 (with and without Skagway load). The figure does not account for any potential summer "load" from a pumped storage resource (e.g. energy consumption to pump water into the upper storage reservoir). Although the shape of the monthly energy profile will vary over the planning period, the YIS will remain a winter peaking system with maximum energy demand occurring in the winter months and lower energy demand in the summer months. Electricity policy changes in Yukon are not expected to change the fundamental challenge of meeting Yukon's increased energy demand in the winter months.

Figure 8: Monthly Demand Shape for 2030 (With & Without Skagway Load)

4.4 Peak Capacity Demand Forecast

Peak capacity demand is the maximum instantaneous quantity of electricity that customers require (and YEC must supply), expressed in megawatts (MW). For forecasting and planning analyses, which are conducted using the single-contingency (N-1) planning criterion, industrial demand is excluded from the peak capacity demand as it is assumed during an emergency event industrial customers could be interrupted.

A new peak capacity demand record of 103.84 MW (97.6 MW non-industrial peak) was set on January 14, 2020. The previous record peak was 92.99 MW (90.5 MW non-industrial peak). As a result of this record-breaking peak, YEC was required to update its non-industrial peak capacity demand forecasting model to account for updated information on the actual peak demand of the Yukon system during prolonged cold weather events.

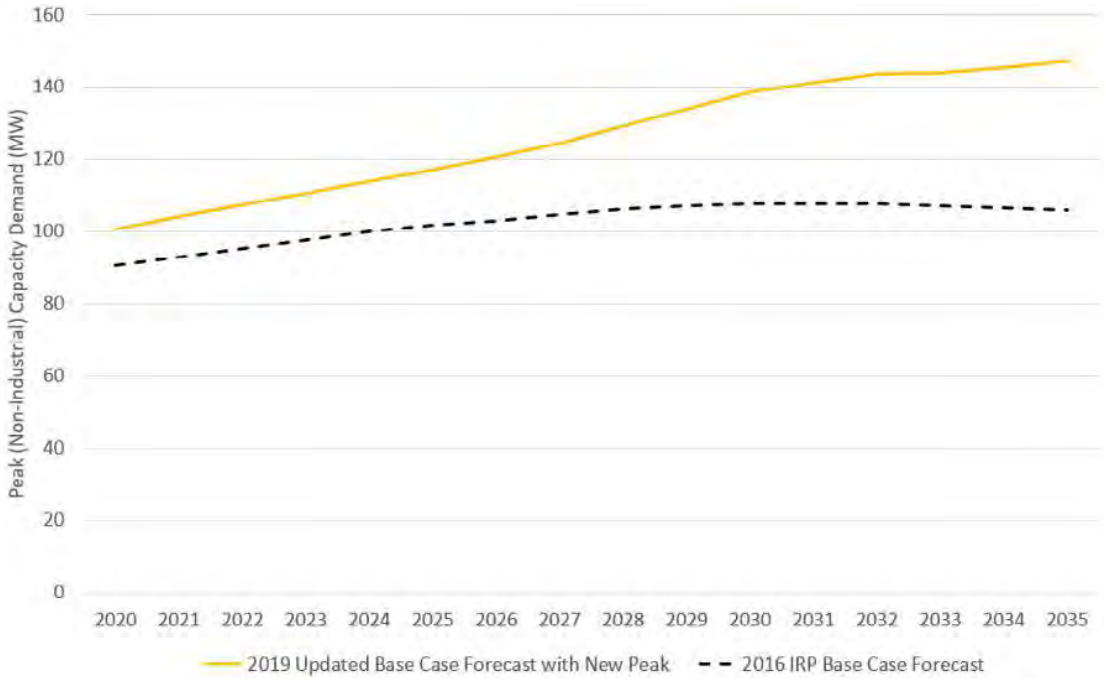
It should be noted that including Skagway in the Base Case does not impact the non-industrial peak capacity demand forecast. Skagway is assumed to add approximately 35 GWh of summer energy per year from year 2026 onwards, but it does not impact the peak capacity demand which occurs in the winter.

The updated non-industrial peak demand for the YIS relative to the 2016 IRP Base Case scenario is shown in Figure 9. The significant growth in the peak non-industrial demand forecast relative to the 2016 IRP Base Case forecast was primarily driven by:

» increased wholesale demand (e.g. population growth) and

» government policy actions related to electrification (e.g. electric heating, electric heat pumps and the adoption of electric vehicles).

Figure 9: Base Case – Updated Peak (Non-Industrial) Capacity Demand Forecast vs. 2016 IRP



5 Update to Resource Options

Generation resources considered as part of the 10-Year Renewable Electricity Plan are described in terms of their average energy and dependable capacity, where:

» **Average Energy**, expressed in GWh/year, is the total quantity of energy that the resource option produces in an average year. An average year is defined as having historically average fuel availability, such as water, wind, or solar irradiance. The fuel supply for a thermal generation station (i.e. diesel or natural gas) is available with a high degree of certainty. Because these fuels can be reliably stored, they are assumed to have 100% fuel availability.

» **Dependable Capacity**, expressed in MW, is the maximum generation output that a resource can reliably provide in a specific timeframe, typically during the period of greatest demand. YEC defines dependable capacity as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months (November to February) based on fuel availability. For hydroelectric generation this means the average of water inflows for the five driest years in the hydrological record. For thermal resources, dependable capacity is equal to the installed capacity, since fossil fuels can be reliably stored. For wind and solar resources, dependable capacity is considered zero, since there is no guarantee that there will be available fuel (e.g. sun or wind) for the two consecutive weeks within the winter period.

The four (4) categories of generation resources considered as part of the 10-Year Renewable Electricity Plan, and described further in the following sub-sections, are:

1. Existing Resources;
2. Committed Resources;
3. Planned Resources; and
4. Future Potential Resources.

5.1 Generation Resources by Type

5.1.1 Existing Resources

These include YEC's legacy hydroelectric and thermal (diesel-fired and natural gas-fired) generation resources. The thermal diesel-fired resources owned and operated by ATCO in the communities connected to the Yukon Integrated System are also included in the category of Existing Resources. ATCO's generation resources are assumed to contribute to the dependable capacity of the system, with the underlying expectation that ATCO will provide backup power whenever needed.

The retirement of diesel generators that reach end of life over the planning period were also included in this category. Over the planning period, YEC anticipates the retirement of the sole remaining Mirrlees diesel engine in Faro (FD1) and two diesel engines from the Dawson Diesel Plant (DD2 and DD5) in 2023.

The inventory of the existing and retiring YEC and ATCO resources and their technical attributes are presented in Appendix A:.

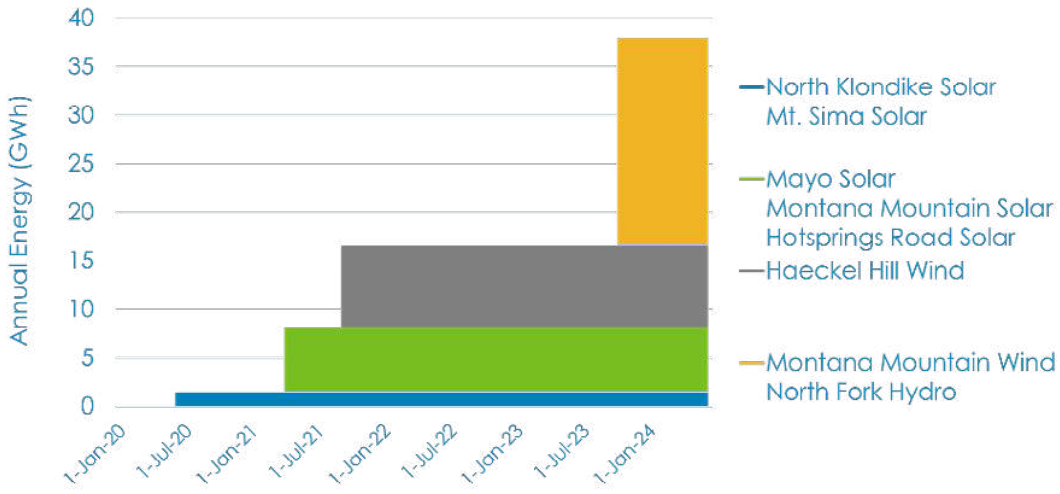
5.1.2 Committed Resources

These include generation resources that have secured YEC Board approvals and for which YEC is in the process of planning and/or constructing. That is, there is no turning back on the commitment to building these generation resources. YEC considers the following as committed resources:

1. **Whitehorse Hydro #2 (WH2) Uprate Project.** The Whitehorse Hydro WH2 Uprate Project will increase the efficiency and maximum capacity of the WH2 generation unit, resulting in more generated electricity for the same water throughput. The WH2 Uprate Project at the Whitehorse generating station will provide 6.2 GWh of annual energy and at least 0.64 MW of dependable capacity.
2. **Battery Storage System.** On September 5, 2019, the Government of Canada committed $16.5 million towards the construction of a new battery storage system in Yukon. The new battery, which is currently projected to be sized at 8 MW/ 40 MWh, will help meet growing peak demands for power while displacing diesel and improving grid reliability.

3. **Standing Offer Program (SOP).** The SOP is outlined in the Independent Power Production (IPP) Policy of the Yukon territorial government issued in 2015. The SOP included in the 10-Year Renewable Electricity Plan envisions 40 GWh/year of energy delivered by the IPP sector by the year 2024 and continuing past the end of the planning period. Figure 10 illustrates the current forecast of the projects anticipated to participate in the program and the resulting expected profile of renewable energy contribution growth from the SOP between 2020 and 2024. Since it is assumed that the SOP projects will most likely be intermittent renewable resources such as wind and solar, no dependable capacity is assigned to these resources.

Figure 10: IPP Standing Offer Program Anticipated Projects



4. **Micro-Generation Program.** The Micro-Generation policy issued by the Yukon government in October 2013 outlines this program. The policy is applicable to projects up to 50 kW. The micro-generation included in the 10-Year Renewable Electricity Plan envisions 6.5 GWh/year of delivered energy by the year 2024 and continuing past the planning period. Similar to the SOP, no dependable capacity is assigned to micro-generation projects because they will be comprised of intermittent renewable resources such as wind and solar.

5.1.3 Planned Resources

These include generation resources which have reached advanced planning stages but have yet to secure all necessary YEC Board approvals. YEC considers the following projects to be Planned Resources:

1. **Whitehorse Unit #4 (WH4) Uprate Project.** This project will increase the maximum water flow at WH4, resulting in an increased maximum output. The WH4 Uprate Project at the Whitehorse generating station will provide 0.9 GWh of annual additional energy. Although this project increases the maximum capacity of the unit, it does not provide additional dependable capacity. This is because water flow in the winter is limited by downstream Yukon River system ice flow restrictions. Subsequent to the completion of this report, the YEC Board of Directors approved the WH4 Uprate Project to proceed in May 2020.

2. **Southern Lakes Enhanced Storage Project (SLESP).** The SLESP will expand the storage range on the Southern Lakes system, which provides water (i.e. fuel) storage for the Whitehorse generating station. This will be achieved by decreasing the licensed Low Supply Level by up to 10 cm and increasing the licensed Full Supply Level by up to 30 cm. Although the SLESP is a water storage project that does not generate electricity itself, it will enable generation of an additional 6.5 GWh of electricity each year at the Whitehorse Hydro facility.

3. **Mayo Lakes Enhanced Storage Project (MLESP).** This project seeks to enhance water storage at Mayo Lake by lowering its current licensed minimum level by up to one metre. The MLESP would generate an additional 4 GWh of electricity each year.

4. **Diesel Replacement.** By replacing retired diesel generator units at existing generation facilities, YEC can reduce the need for rental diesel generators from November through March. The total replacement diesel assumed over the planning period amounts to 12.5 MW.

5. **Demand Side Management (DSM).** DSM involves using incentives, electricity rate structures, and building and appliance codes and standards to encourage customers to reduce the amount of electricity they use. In 2014, YEC and ATCO Electric Yukon jointly launched and operated a DSM program called inCharge which provided rebates and electricity savings kits. However, the YUB denied the costs of this program in its decision on YEC's 2017-2018 General Rate Application. As a result, YEC's DSM activities are on hold pending confirmation that future DSM costs will be allowed. The focus of a relaunched DSM program would be on measures that deliver peak capacity savings (i.e. reductions in peak electricity consumption). A suite of programs has been developed which will be implemented once there is regulatory certainty about allowing of future DSM-related costs. The DSM programming is forecast to provide up to 6.7 GWh of annual energy and 7 MW of dependable capacity by 2030.

For the purposes of this report, it was assumed that Planned Resources will be constructed and operational as planned, and therefore are treated similarly to Committed Resources.

5.1.4 Future Potential Resources

These are potential generation resource options available to meet the needs of YEC's customers over the next 10 years that have not yet advanced into development. These generation resources are described in Section 7.

5.2 Summary: Existing, Committed and Planned Generation Resource Forecast

In Figure 11 and Figure 12, the Existing Resources are shown as blue bars and the Committed and Planned Resources are shown in darker and lighter shades of grey, respectively.

Figure 11: Energy Forecast from Existing, Committed and Planned Resources

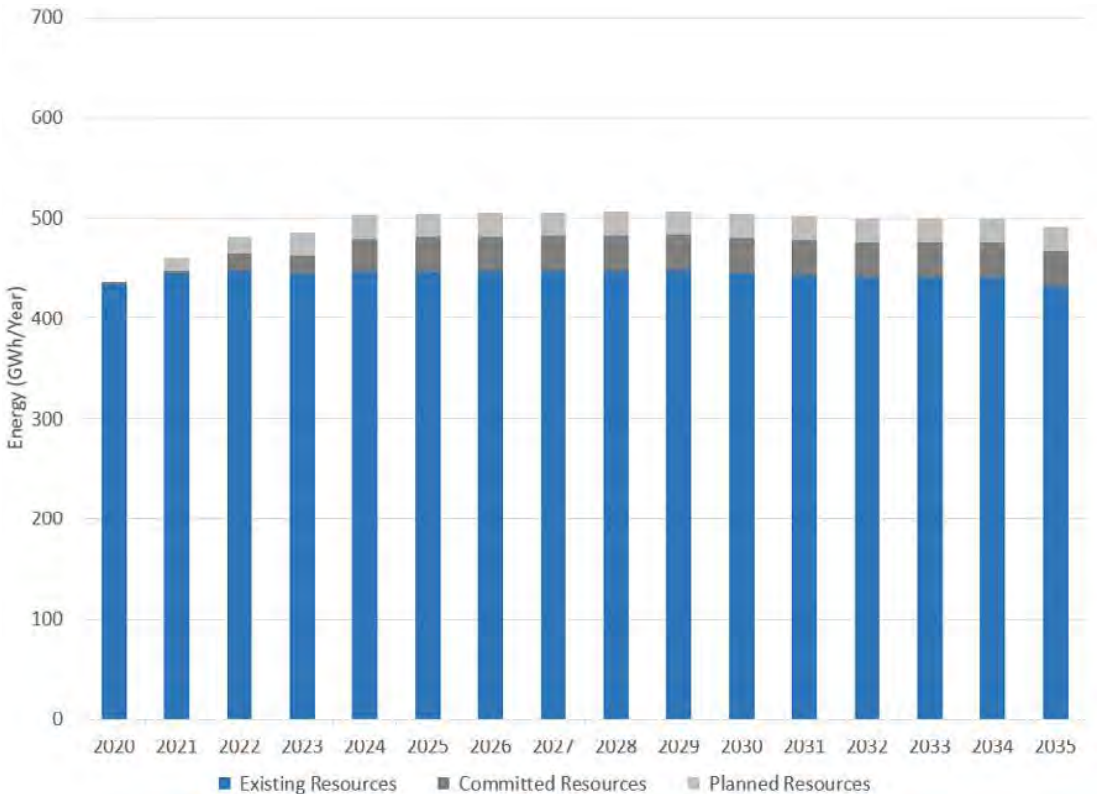
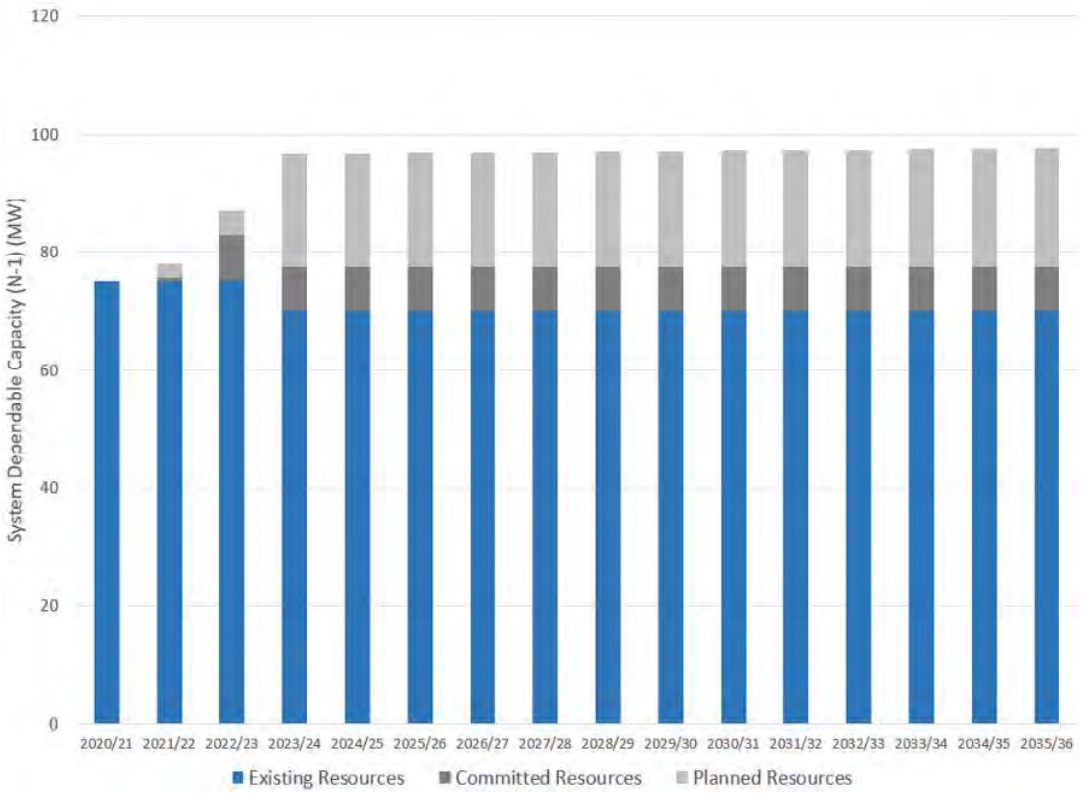


Figure 12: Dependable Capacity (N-1) from Existing, Committed and Planned Resources



6 Supply & Demand Gap

6.1 Methodology

The goal of the resource planning process was to develop recommended actions for YEC to both meet YIS's electrical energy needs and satisfy the capacity gaps over the 10-year horizon. The difference between electrical demand and generation supply is the gap, or "Need", as shown in Figure 13.

Figure 13: Gap Analysis Overview

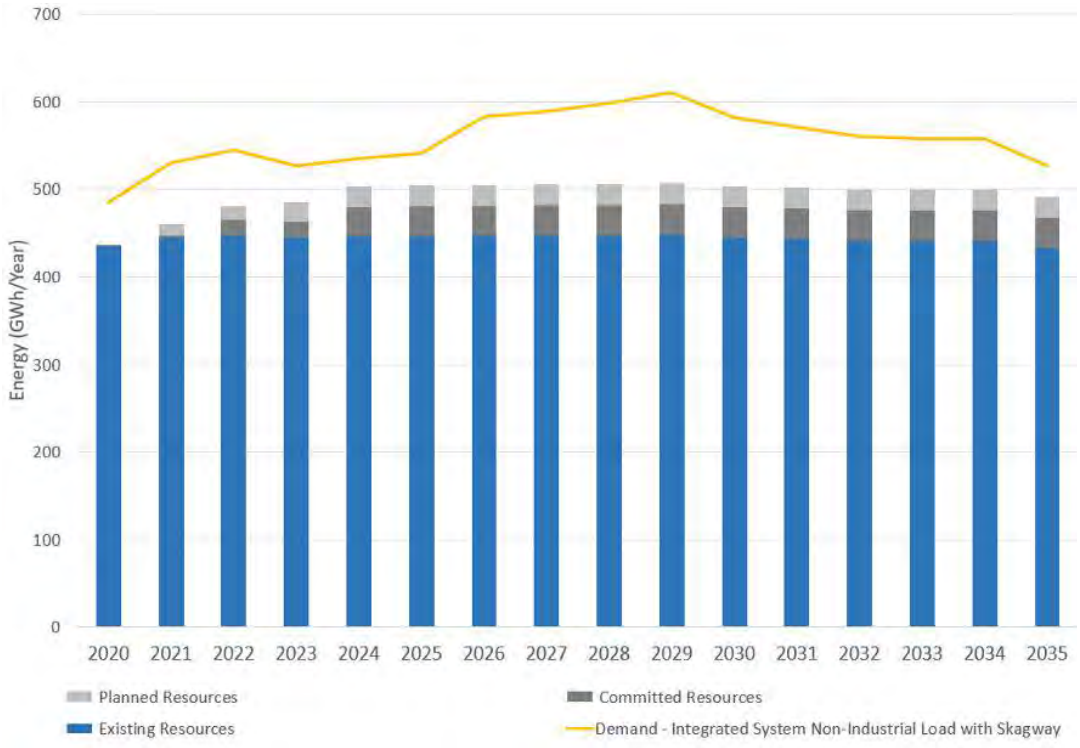
This gap analysis calculates the difference between the forecast energy and peak capacity demand and the expected future resource capability (including Existing, Committed and Planned Resources). The analysis is for the expected Base Case for the 10-Year Renewable Electricity planning evaluations.

6.2 Energy Gap Analysis

6.2.1 Annual Energy Gap

Figure 14 shows the gap between forecast annual energy demand (from Figure 7 in Section 4) and forecast generation (from Figure 11 in Section 5). A detailed breakdown, including individual resources, is included in Appendix A. The annual energy gap increases from 49 GWh in 2020 to 100 GWh in 2029.

Figure 14: Annual Energy Gap Analysis (Base Case)



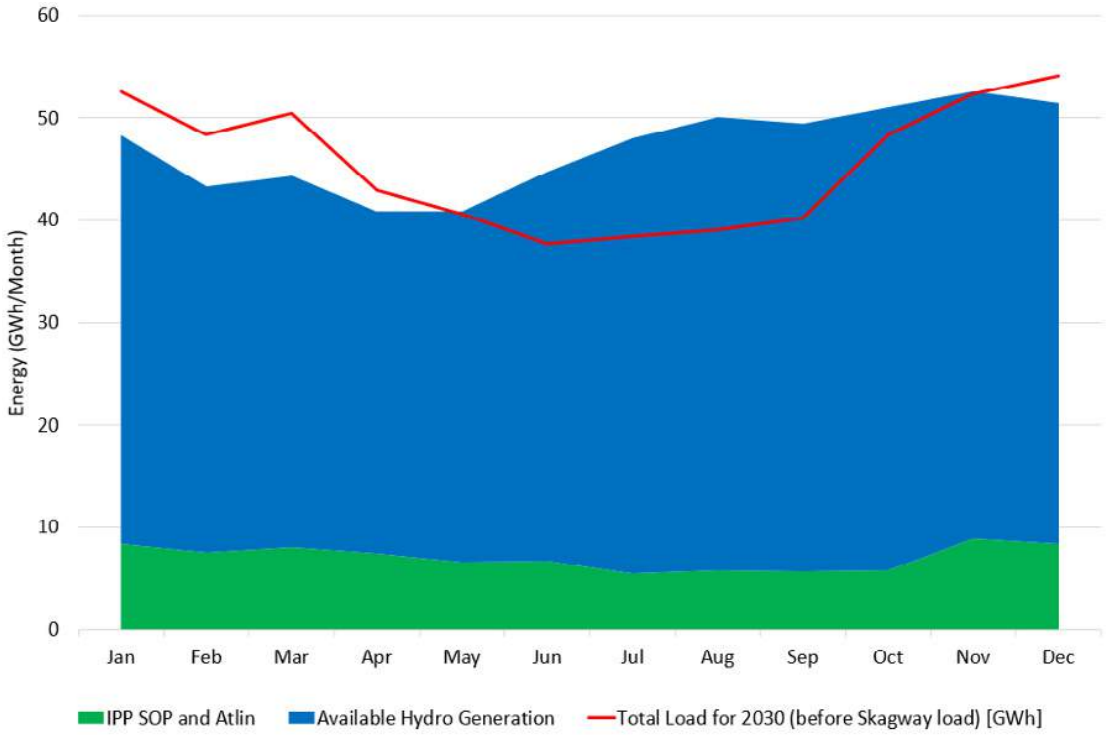
The energy gap between YEC's future expected resource capability and forecast load under average water conditions (as illustrated in Figure 14) implies that in some years YEC will need to utilize thermal resources if it does not develop any new renewable resources. In those years of average or below average water, YEC will need to run LNG, and potentially some diesel, to meet Yukon's energy needs.

This energy gap creates an opportunity for YEC to develop new renewable generation resources. These have the potential reduce reliance on thermal resources (LNG and diesel) to meet the forecast energy gap needs, particularly in low water years. It will be necessary to develop these new renewable energy resources if YEC is to meet the target specified in Yukon government's *Our Clean Future* strategy (a 93% rolling average in renewable energy).

6.2.2 Monthly Energy Gap & Summer Spilled Energy

Figure 15 shows the forecast monthly energy demand compared to the supply of hydroelectric and IPP SOP renewable energy supply for the year 2030.

Figure 15: Monthly Renewable Supply vs Demand (2030)



This figure illustrates that YEC will have surplus energy available during the summer but insufficient energy available during winter months to meet forecast energy demand. Additional data on the monthly and annual energy gap is provided in Appendix B.

Perhaps the most important conclusion to be drawn from Figure 15 is that Yukon is forecast to have surplus energy available in the summer months that will be permanently lost. Typically, this will be in the form of water spilled over the dam at the Whitehorse generating facility. Because other renewables such as solar and wind sourced from IPPs are not dispatchable, their energy must be accepted by YEC. YEC must then use its dispatchable hydroelectric assets (i.e. Whitehorse hydro during the summer) to balance supply and demand. Therefore, YEC will be forced to spill water over the Whitehorse dam whenever excess generation is supplied into the YIS. This seasonal mismatch between potential electricity production from hydro generation and the timing of maximum customer demand is a key planning constraint for YEC.

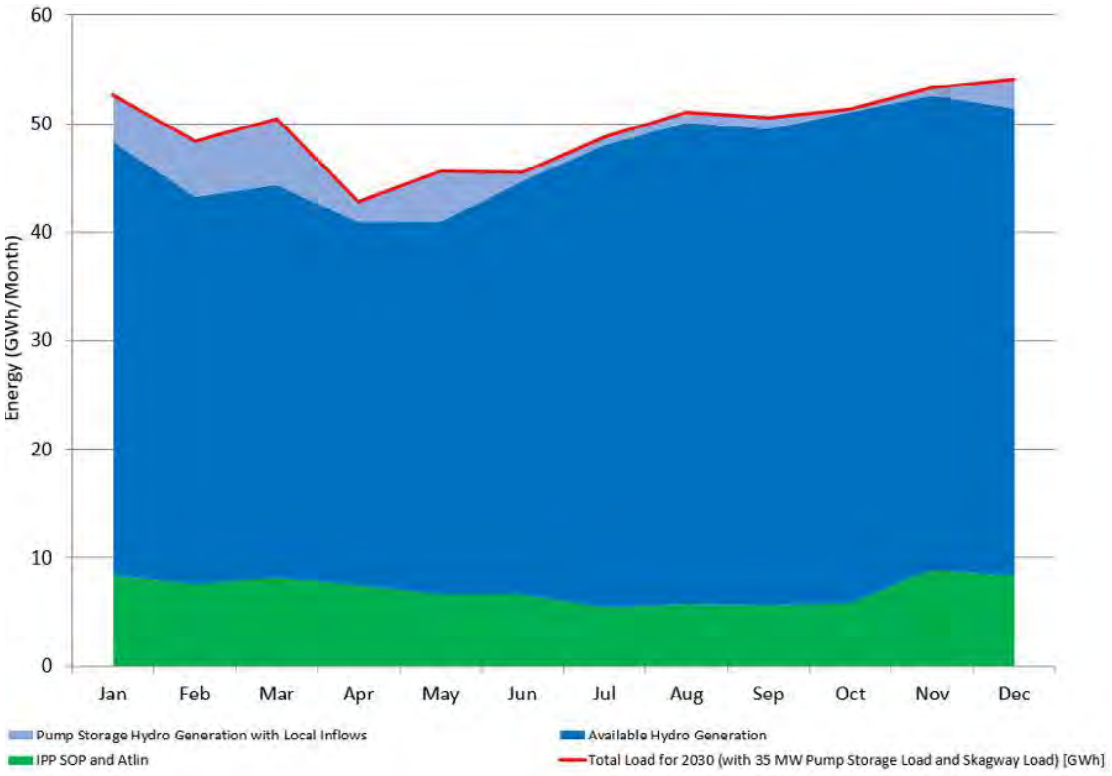
Two development options that would help address this issue are considered in this plan:

1. **Development of Seasonal Storage.** Since YEC has surplus energy available in the summer months and a deficit in winter months, there is a potential to use seasonal storage to store excess summer energy. That is, water spilled at YEC's existing hydro facilities could be stored and used for generation during the winter to meet winter loads. The only commercially available renewable technology for long term fuel storage in the quantities required by YEC (i.e. 40+ GWh) is pumped storage hydro.
2. **Securing New Customers for Summer Energy.** Another option to reduce summertime spilled water (i.e. wasted energy) is to secure new customers looking to purchase summer energy. By developing and investing in the Southern Lakes area as part of the 10-Year Renewable Electricity Plan, YEC has the potential opportunity to sell surplus summer energy to Skagway for the provision of clean shore-side power to cruise ships. The Skagway pier can interconnect up to four (4) cruise ships at once, which can amount to approximately 35 GWh/year of summer energy demand. Currently, cruise ships visiting Skagway in the summer burn diesel to generate shipboard electricity while at port. The electrification of shore-side power is one of the leading strategies that cruise ship operators employ to reduce their greenhouse gas (GHG) emissions while at port. This is an opportunity to utilize YEC's otherwise spilled water (i.e. wasted energy) to increase revenues to offset Yukon electricity costs, while also reducing GHG emissions in Skagway.

By capturing the surplus energy from otherwise spilled water through a combination of seasonal storage development and new summer energy customers, monthly energy supply and demand will be better matched.

This is illustrated in Figure 16 where the increased summer energy demand would reduce the excess amount of hydro generation in the summer months, as demonstrated previously in Figure 8. Additionally, summer demand would be further increased by the pumped storage facility utilizing energy to pump water from the lower reservoir into the upper reservoir. The excess hydro generation would then be available for use in the winter months due to this seasonal storage. The additional energy highlighted in light blue in Figure 16 is the energy provided by the pumped storage facility, which would also help close the energy gap in the winter months. The forecast in this Figure is based on the Tutshi-Moon pumped storage project, which has hydrologic inflows that make it a net energy producer rather than a net energy consumer, as detailed in Section 7.

Figure 16: Monthly Renewable Supply vs Demand – Modified (2030)

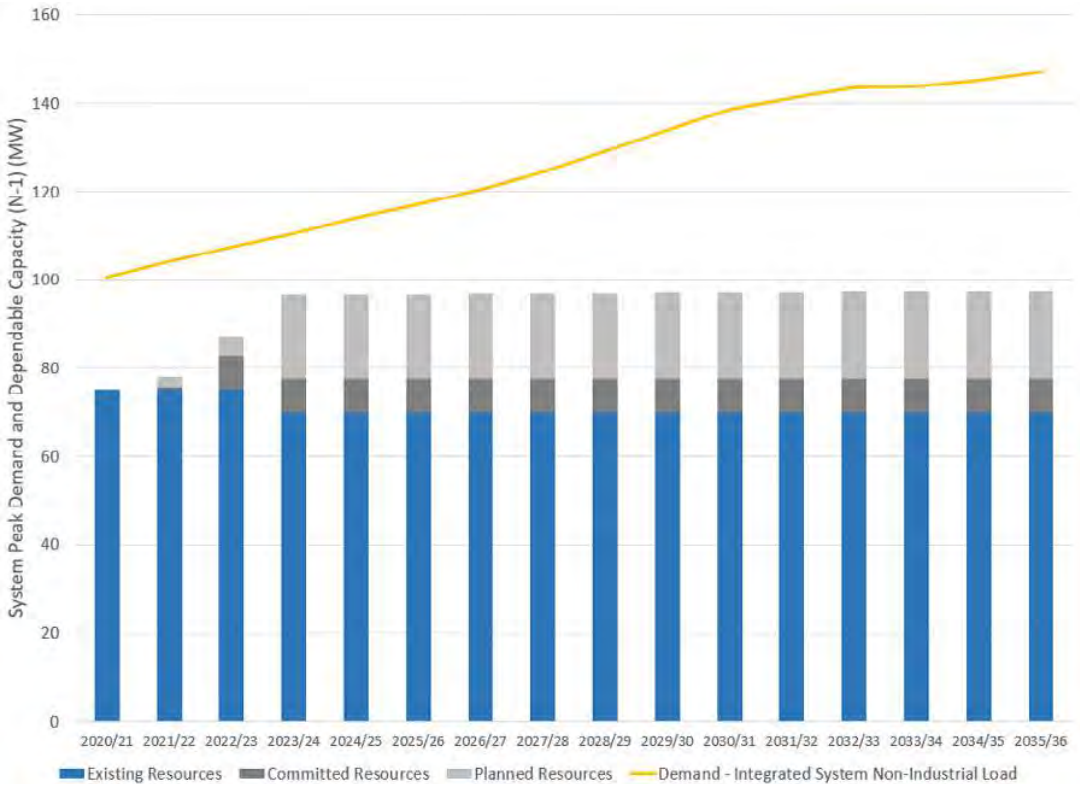


The benefits associated with the productive use of forecast summer surplus energy were the main drivers for incorporating a seasonal pumped storage hydroelectric project and the electrification of Skagway cruise ships as key elements of the 10-Year Renewable Electricity Plan.

6.3 Capacity Gap Analysis

Figure 17 shows the annual gap between the forecasted peak (non-industrial) capacity demand (from Figure 9 in Section 4) and the dependable peak capacity (from Figure 12 in Section 4) under N-1 conditions. The forecast peak capacity gap is significant, growing to approximately 40% of YEC's existing, committed and planned capacity resources. YEC can fill the forecast gap on an interim basis by temporarily renting diesel generators. However, temporary diesel generators have lower reliability and have a higher future availability risk than other resource options. Therefore, finding renewable resource options to fill this peak capacity gap is a priority of the 10-Year Renewable Electricity Plan.

Figure 17: Annual Capacity Gap Analysis under N-1 Conditions (Base Case)



7 Future Potential Resource Options

7.1 Future Potential Resource Options Update Process

The next step in the resource planning process was identifying a list of Future Potential Resource Options to be included in a portfolio that would address the energy and peak capacity gaps identified in Section 6. In order to develop a list of Future Potential Resource Options, the resource options from YEC's 2016 Integrated Resource Plan were updated in three (3) stages:

» **Stage 1:** Refined List of Resources;

» **Stage 2:** Updated Technical Attributes; and

» **Stage 3:** Updated Financial Attributes.

It is important to acknowledge that a comprehensive evaluation of environmental and socio-economic attributes of each resource option was included in the 2016 IRP. Since no showstoppers prohibiting the resource options under consideration in this report were identified during that analysis, these environmental and socio-economic attributes were not re-evaluated as part of the 10-Year Renewable Electricity Plan. If the projects identified in the Plan move forward, detailed environmental and socio-economic analyses and assessments will be carried out as part each project's planning.

7.1.1 Stage 1: Refined List of Resources

In Stage 1, all resource options considered in the 2016 IRP were refined into a subset of preferred resource options. Resource options that were deemed to be fundamentally uneconomic, located too far from existing or proposed transmission infrastructure, too large for the need, or that have been superseded by other options were eliminated from the list. The Committed and Planned Resources described in Sections 5.1.2 and 5.1.3 were also removed from the list because they are assumed to be in operation as per previous plans. The refinement process reduced the 92 resource options evaluated in the 2016 IRP down to 19 resource options (excluding DSM and transmission options).

7.1.2 Stage 2: Technical Attribute Update

In Stage 2, the technical attributes of the refined resource options identified in Stage 1 were updated to reflect current available information. Updates were made to the technical attributes considered in the 2016 IRP such as annual energy, firm energy, installed capacity, dependable capacity, project life, lead time, and resource dispatchability.

The technical attributes from the 2016 IRP were used for the refined list of resource options from Stage 1, except for options which have been studied further since that time. The updated resource options included:

- **Small Hydro.** Knight Piésold Ltd. (KP) was engaged by YEC to update and further develop a desktop review of the potential hydroelectric projects in Yukon and northern BC, provided in Appendix E. This study resulted in a refined and updated list of five (5) small hydroelectric projects of interest, with capacities ranging from 8 MW to 13 MW.
- **Pumped Storage Hydro.** KP was engaged by YEC to update and further develop the Tutshi-Moon pumped storage project. As part of this study, four separate development options with varying levels of installed capacity and winter generating capability were evaluated. The study is provided in Appendix F.
- **Wind.** Although the wind resources have not been studied further since the 2016 IRP, indicative wind sites with varying installed capacities are included in the refined list of resource options. Future wind resources could be implemented either by YEC or by IPPs via a Call for Power.
- **Geothermal.** EAVOR was approached to provide technical and financial details regarding a new geothermal technology being developed in Alberta called the Eavor-Loop technology. The technology was assessed as not being sufficiently mature and commercially proven for consideration as a potential utility resource option. Therefore, an assumption was made that early implementations of the technology would be made via the IPP SOP program. As a result, the technology was excluded from the refined list of resource options.
- **Thermal-Diesel.** Generic permanent and temporary diesel options are included as part of the refined list of resources. They are flexible, scalable, and can be used to help bridge dependable capacity gaps (but not long-term energy gaps). The updated technical attributes associated with these projects were extracted from a series of thermal generation project assessments completed by Midgard Consulting Inc. (Midgard).

7.1.3 Stage 3: Financial Attribute Update

In Stage 3, the financial attributes of the refined list of resource options identified in Stage 1 were updated. The financial attributes considered in the 2016 IRP included the Levelized Cost of Energy (LCOE) and the Levelized Cost of Capacity (LCOC). These were calculated utilizing inputs that include the annualized estimated capital (CAPEX) and operating & maintenance (O&M) costs for each project.

The process for updating these attributes is summarized below:

» **CAPEX Update**. For mature technologies such as hydro and thermal, the CAPEX from the 2016 IRP were inflated to 2019 dollars assuming a 2% inflation rate. The CAPEX for the Small Hydro and Pumped Storage Hydro projects were estimated separately by KP. For maturing technologies including solar and wind, a desktop study was completed to evaluate recent trends in total installed costs. It should be noted that:

- The capital costs of the Atlin Hydro Expansion and the Tutshi-Moon Pumped Storage Hydro Projects were considered with and without Federal funding. Since the completion of this analysis, further work has indicated that additional costs for the Atlin-Jakes Corner transmission must be considered as art of the Atlin Hydro Expansion Project, adding approximately $50 million in capital costs. This will increase the required Federal funding for the project.

- A new 138 kV transmission line from Whitehorse to Skagway (AK) via Carcross (YT), which would be required to connect projects in the Southern Lakes area, was assumed to be supported with up to 75% Federal funding. The transmission cost assumptions associated with projects located near the new transmission line assume an interconnection to this proposed line.

» **O&M Update.** The annualized O&M for the Small Hydro and Pumped Storage Hydro projects in the KP studies were updated. The O&M cost assumptions for all other options were taken from the 2016 Resource Plan, inflated to 2019 dollars assuming a 2% inflation rate.

» **Financial Modelling Update.** Based on the updated set of technical and financial attributes, YEC completed financial modelling to determine the updated LCOE and LCOC associated with the refined list of resource options.

7.2 Future Potential Resource Options

Table 3: Refined List of Future Potential Resource Options

IRP Resource	Options	Installed Capacity (MW)	Dependable Capacity (MW)	Lead Time (Years)	
Hydro Uprate	Aishihik Hydro 1 & Hydro 2 Uprate	1.3 MW	1.3 MW	3 Years	
Small hydro	Primrose (Storage)	13.0 MW	13.0 MW	6 Years	
	Drury (Storage)	10.0 MW	10.0 MW	6 Years	
	Tutshi Windy Arm (Storage)	10.0 MW	10.0 MW	6 Years	
	Wolf River (ROR)	11.0 MW	4.0 MW	6 Years	
	Atlin Hydro Expansion (Storage)	6.0 MW	6.0 MW	5 Years	
	Atlin Hydro Expansion (Storage) with Federal funding	6.0 MW	6.0 MW	5 Years	
Wind	Wind Resource 1	6.0 MW	0.0 MW	5 Years	
	Wind Resource 2	10.0 MW	0.0 MW	5 Years	
	Wind Resource 3	20.0 MW	0.0 MW	5 Years	
Solar	Whitehorse Solar 1	1.0 MW	0.0 MW	2 Years	
	Whitehorse Solar 2	5.0 MW	0.0 MW	2 Years	
	Whitehorse Solar 3	10.0 MW	0.0 MW	2 Years	
Diesel (Comparator)	Generic Greenfield Permanent @ Takhini	10.0 MW	10.0 MW	4 Years	
	Generic Rental @ Whitehorse Substation S150	2.0 MW	2.0 MW	0 Years	
Pumped Storage	Tutshi-Moon (15MW-25GWh)	15.0 MW	15.0 MW	6 Years	
	Tutshi-Moon (15MW-45GWh)	15.0 MW	15.0 MW	6 Years	
	Tutshi-Moon (25MW-50GWh)	25.0 MW	25.0 MW	6 Years	
	Tutshi-Moon (35MW-50GWh)	35.0 MW	35.0 MW	6 Years	
	Tutshi-Moon (15MW-25GWh with Federal Funding	15.0 MW	15.0 MW	6 Years	
	Tutshi-Moon (15MW-45GWh with Federal Funding	15.0 MW	15.0 MW	6 Years	
	Tutshi-Moon (25MW-50GWh with Federal Funding	25.0 MW	25.0 MW	6 Years	
	Tutshi-Moon (35MW-50GWh) with Federal Funding	35.0 MW	35.0 MW	6 Years	
Energy Storage	Lithium-ion	8.0 MW	8.0 MW	2 Years	

Table 3 is a summary of the 19 Future Potential Resources considered in the 10-Year Renewable Electricity Plan along with their associated technical and financial attributes.

	Annual Energy (MWh/Yr)	CAPEX ($2019)	O&M		LCOC ($/kW-Yr)	LCOE ($/kWh-Yr)
			Fixed ($2019/Yr)	Variable ($2019/MWh)		
	2,700 MWh	$5,300,000	$0	$5.31	$185	$0.09
	74,100 MWh	$177,500,000	$3,900,000	$5.00	$797	$0.14
	30,600 MWh	$110,500,000	$2,400,000	$5.00	$635	$0.21
	49,300 MWh	$135,600,000	$3,700,000	$5.00	$860	$0.17
	79,700 MWh	$165,100,000	$3,600,000	$5.00	$2,417	$0.12
	44,700 MWh	$131,000,000	$2,900,000	$5.00	$1,270	$0.17
	44,700 MWh	$32,750,000	$2,900,000	$5.00	$708	$0.10
	18,100 MWh	$39,500,000	$280,000	$27.26	Not supplied	$0.17
	29,500 MWh	$49,200,000	$290,000	$21.81	Not supplied	$0.13
	57,300 MWh	$73,500,000	$340,000	$21.40	Not supplied	$0.10
	1,100 MWh	$2,300,000	$30,000	$0.00	Not supplied	$0.13
	5,600 MWh	$8,100,000	$150,000	$0.00	Not supplied	$0.10
	11,500 MWh	$16,100,000	$340,000	$0.00	Not supplied	$0.10
	2,500 MWh	$25,600,000	$170,000	$22.00	$131	$0.53
	2,500 MWh	$0.00	$280,000	$0.00	$243	Not Supplied
	19,900 MWh	$182,500,000	$2,020,000	$0.00	$552	$0.42
	14,000 MWh	$194,200,000	$2,050,000	$0.00	$581	$0.62
	12,000 MWh	$245,000,000	$2,100,000	$0.00	$421	$0.88
	10,000 MWh	$280,000,000	$2,150,000	$0.00	$336	$1.18
	19,900 MWh	$45,625,000	$2,020,000	$0.00	$239	$0.18
	14,000 MWh	$48,550,000	$2,050,000	$0.00	$248	$0.27
	12,000 MWh	$61,250,000	$2,100,000	$0.00	$168	$0.35
	10,000 MWh	$70,000,000	$2,150,000	$0.00	$130	$0.46
	2,800 MWh	$29,500,000	$280,000	$0.00	$280	Not Supplied

7.3 Future Potential Resource Observations

1. **Intermittent renewables do not contribute capacity.** Resources such as wind and solar offer relatively low levelized costs for energy (LCOE), but do not provide dependable capacity to the Yukon system. This is because they can only generate electricity while their energy source is available (e.g. the sun is shining and/or the wind is blowing). As a result, these resources cannot address YEC's key challenge of closing the existing and forecast peak capacity gap. In addition, since solar resources are summer peaking generation resources, integrating more solar resources increases the quantity of surplus summer energy.

2. **Small Hydro.** In general, this is an attractive resource because it offers reasonably priced energy and capacity in a single project. The Atlin Hydro Expansion project is preferred based on its shorter project development timeline when compared to the other small hydro options.

3. **Tutshi-Moon Pumped Storage Hydro Inflows & Seasonal Shifting.** This project would be used for seasonal energy storage, storing excess summer energy (in the form of water held in the upper reservoir) for generation during the winter. This means that pumping water into the reservoir for storage will occur during the summer months when there is surplus energy available, and generation will occur during the winter months when electricity demand increases. In addition, the Tutshi-Moon pumped storage project is expected to have hydrologic inflows that make it a net energy producer. Typical pumped storage hydro projects are net energy consumers due to the energy losses associated with the water pumping process. Since the pumped storage hydro options evaluated are not cost competitive on a LCOC basis compared to greenfield diesel generation or diesel generator rentals without grant funding, Federal funding is required to bring the LCOC of pumped storage hydro in line with that of diesel. Finally, there are economies of scale with regards to the LCOC for the Tutshi-Moon pumped storage project, such that upscaling the project to reduce the project LCOC is justifiable.

4. **Federal Funding**. Securing Federal funding to help finance the Atlin Hydro Expansion and Tutshi-Moon pumped storage hydro projects is required to bring the cost of energy and capacity from these projects down, thereby reducing the impacts of these projects on electricity rates in Yukon. Without Federal funding, these projects are not considered cost-competitive and would most likely not be approved by the Yukon Utilities Board.

5. **Aishihik Uprate Capacity.** The 1.3 MW dependable capacity associated with the Aishihik Hydro 1 and Hydro 2 uprate projects is only considered available if the loss of Aishihik is no longer the largest single contingency event (N-1 Event) on the YIS.

7.4 Southern Lakes Transmission Project

Given the limitations of existing transmission in the Southern Lakes area and the requirement to connect new projects, upgrading and expanding the transmission infrastructure in the Southern Lakes area is a necessary element of this plan.

This plan assumes that a new transmission line from Skagway (AK) to Whitehorse through Carcross (YT) will be built in a phased manner to support the development of the Southern Lakes area as illustrated in Figure 18. This is a 138 kV transmission line with sufficient transmission capacity to accommodate the full portfolio of future planned projects. In order to minimize intrusion into the natural environment, the proposed line will follow existing rights of way where possible (e.g. highway, transmission or rail).

Figure 18: Southern Lakes Transmission Network

The proposed development of this line follows a phased approach:

» **Phase 1.** This phase includes the construction of the Whitehorse -> Carcross -> Jakes Corner section of the line transmitting power from the Atlin Hydro Expansion project to the load centre at Whitehorse. It should be noted that the viability of connecting the Atlin Hydro Expansion project to the existing ATCO distribution system at Jakes Corner is currently being assessed as an interim measure. By decoupling the timing of the Atlin Hydro Expansion project from that of the Southern Lakes Transmission Project, the Atlin Hydro Expansion project can move forward as soon as possible

» **Phase 2.** This would extend the line from Carcross (YT) to Moon Lake (BC) to interconnect the proposed Tutshi-Moon Pumped Storage Hydro project. The execution of this phase is contingent on the timing and implementation of the proposed Tutshi-Moon Pumped Storage Hydro project.

» **Phase 3.** The final phase of the project would involve an extension of the line from Moon Lake (BC) to Skagway (AK) to complete the 138 kV interconnection from Whitehorse (YT) to Skagway (AK). This final phase will only proceed if and when YEC secures summer energy sales to Skagway for the purposes of providing shore-side power to cruise ships.

Some flexibility is assumed in the sequencing of the transmission construction phases outlined above. For example, it is conceivable that the Whitehorse-Carcross-Skagway line could be constructed in a single step if Yukon Energy is able to advance the business opportunity to sell power to cruise ships in Skagway.

8 Preferred Resource Portfolios

8.1 Portfolio Analysis Methodology

The goal of portfolio analysis is to develop an optimal set of projects capable of addressing both the energy and peak capacity shortfalls over the 10-year planning horizon. YEC's methodology was to follow a directed portfolio development that focused on projects clustered in the Southern Lakes area, facilitated by a Federally supported build-out of transmission infrastructure in that area.

The following assumptions were made in the development of the project portfolio:

1. **Federal Funding.** An assumption was made that Federal funding would be available to protect ratepayers from the impacts of developing significant new infrastructure projects. In order to achieve or exceed the 93% renewable portfolio standard policy objective, Federal funding is also necessary to improve the economics of certain renewable resource options (e.g. pumped storage hydro) relative to the lowest cost fossil fuel-based options.

2. **Committed and Planned Resources Will Happen.** The portfolios assume that the Committed and Planned Resources (previously described in Sections 5.1.2 and 5.1.3), including demand side management programs, are developed and implemented in their respectively planned years.

3. **Atlin Hydro Expansion.** This project is included in the portfolio because of its ability to supply both dependable capacity and firm energy, and because of its significantly shorter project development timeline when compared to other greenfield hydro options.

4. **Tutshi-Moon Pumped Storage Hydro.** This project will provide a significant increase in renewable dependable capacity to address Yukon's existing and forecast capacity shortfall. At the same time, it presents an opportunity to utilize surplus summer energy to meet the forecast winter energy shortfall.

5. **Southern Lakes Transmission build-out.** A new transmission line is required to connect identified projects in the plan (Tutshi-Moon Pumped Storage Hydro; Atlin Hydro Expansion) to the Yukon grid. The development of a new transmission line also facilitates the connection of renewable energy projects developed under the IPP SOP in the Southern Lakes Area, and enables the potential for future sales of surplus summer energy to Skagway for the provision of shore-side power to summertime cruise ships.

6. **Intermittent Renewables (Wind).** These are included as required to meet any residual energy gaps not filled by Tutshi-Moon Pumped Storage Hydro and Atlin Hydro Expansion projects (e.g. in the high load scenario).

7. **Bridging Residual Energy Gaps.** Existing thermal LNG generation is assumed to be available to bridge any small outstanding gaps between average energy and forecast energy demand over the planning period.

8. **Bridging Residual Capacity Gaps.** Temporary rental diesel units are assumed to be available to bridge any outstanding gap between the forecast dependable capacity generation and peak capacity demand over the planning period.

9. **Portfolio Economics Check.** Once the portfolios were built, the Net Present Value of each portfolio was compared to find the lowest cost portfolios which are presented in this report.

The output of the portfolio analysis was an optimum set of resource options that meets the energy and capacity planning criteria under each scenario. The preferred portfolios for the expected Base Case scenario as well as the High Case are presented in the following section. Preferred portfolio analysis results for the Low Case and the Base Case (without Skagway) are provided in Appendix C:

8.2 Preferred Portfolios

The portfolios for the Base Case and High Case scenarios, are presented in the following format:

» **Planning Horizon.** Although the planning horizon for the 10-Year Renewable Electricity Plan is from 2020 to 2030, the annual energy and peak demand forecasts are shown over a longer timeframe (i.e. 2020 to 2035) to show the phased development of certain resource options included in the portfolio (e.g. Tutshi-Moon Pumped Storage Hydro).

» **Annual Energy.** These forecasts show the annual energy demand and average energy generation for Existing, Committed, Planned, and Future Potential Resources over the planning horizon.

» **Peak Capacity Demand.** These forecasts show the peak capacity demand requirement under the N-1 planning criterion, and the dependable capacity for Existing, Committed, Planned, and Future Potential Resources over the planning horizon.

» **Portfolio Summary**. This table lists Future Potential Resources with their respective in-service dates and installed capacities.

» **Portfolio Capital Cost.** This table shows the simple (undiscounted) value of the capital expenditures for Future Potential Resources and the Southern Lakes Transmission Project over the 10-year planning period, both with and without Federal funding (assumed to be the typical maximum 75% of capital cost). For the Base Case and High Case, all three phases of the Southern Lakes Transmission Project are included (e.g. the line extends from Whitehorse, YT to Skagway, AK). These costs include future projects that may be developed by both YEC and/or independent power producers. This does not include the costs of the Committed and Planned Resources in each plan. The Portfolio Capital Cost was presented for illustrative purposes to show the magnitude of undiscounted capital investment over the planning period.

8.2.1 Base Case Portfolio

Figure 19: Base Case Portfolio, Energy

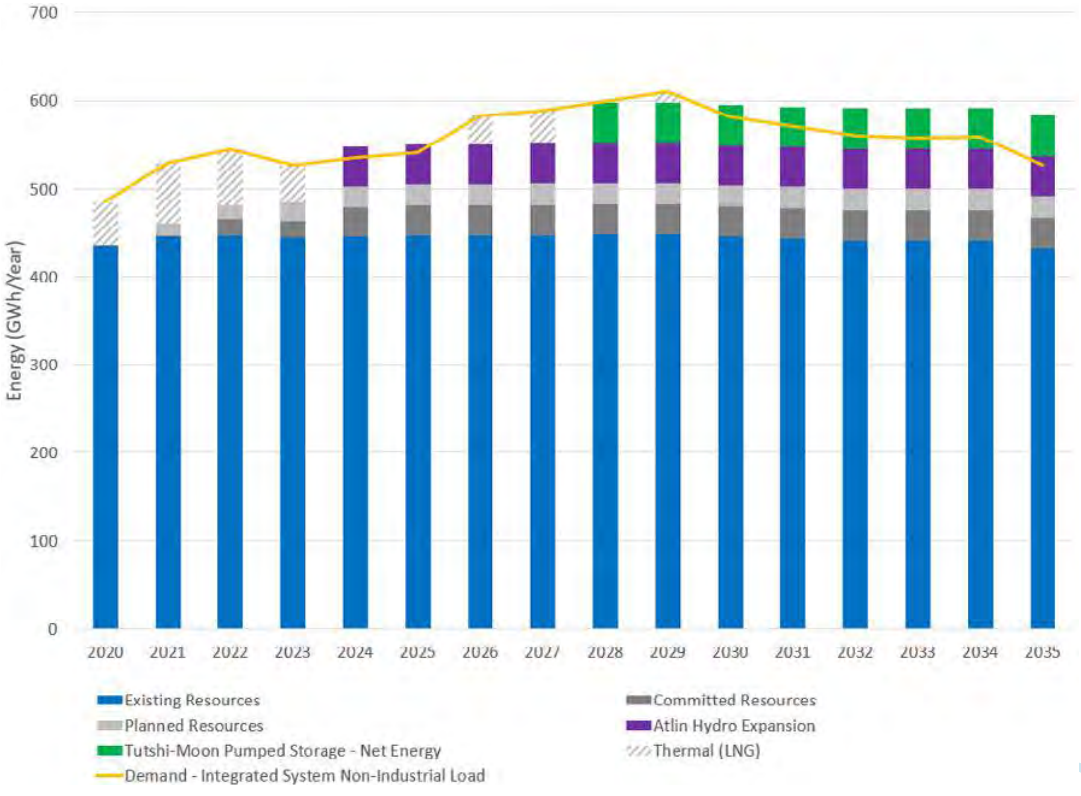


Figure 20: Base Case Portfolio, Capacity

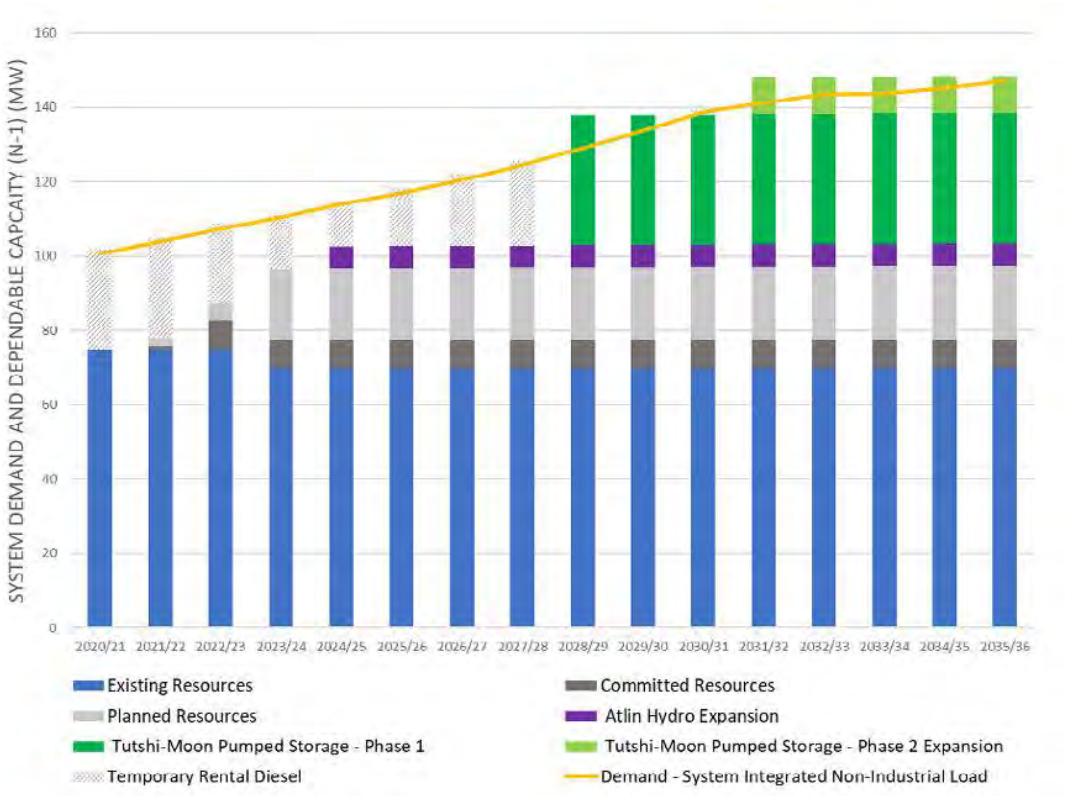


Table 4: Base Case Portfolio Summary (2020 - 2030)

	INSTALLED CAPACITY [MW]	DEPENDABLE CAPACITY [MW]
Committed Resources	8.6	7.6
Planned Resources	20.3	19.5
Sub-total (Committed & Planned)	**28.9**	**27.1**
FUTURE RESOURCES:		
2024/25 Atlin Hydro Expansion Project	6	6
2028/29 Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total (Future Projects):	**41**	**41**
GRAND TOTAL:	**69.9**	**68.1**

Table 5: Base Case Portfolio Cost Summary (2020 – 2030)

COST COMPONENT	COST [2019$ MILLIONS]
Portfolio Capital Cost without Federal Funding:	$ 577 million
Portfolio Capital Cost with Federal Funding:	$ 144 million

Appendix D: provides a more detailed breakdown of the cost and capacity components for the Base Case.

8.2.2 High Case Portfolio

Figure 21: High Case Portfolio, Energy

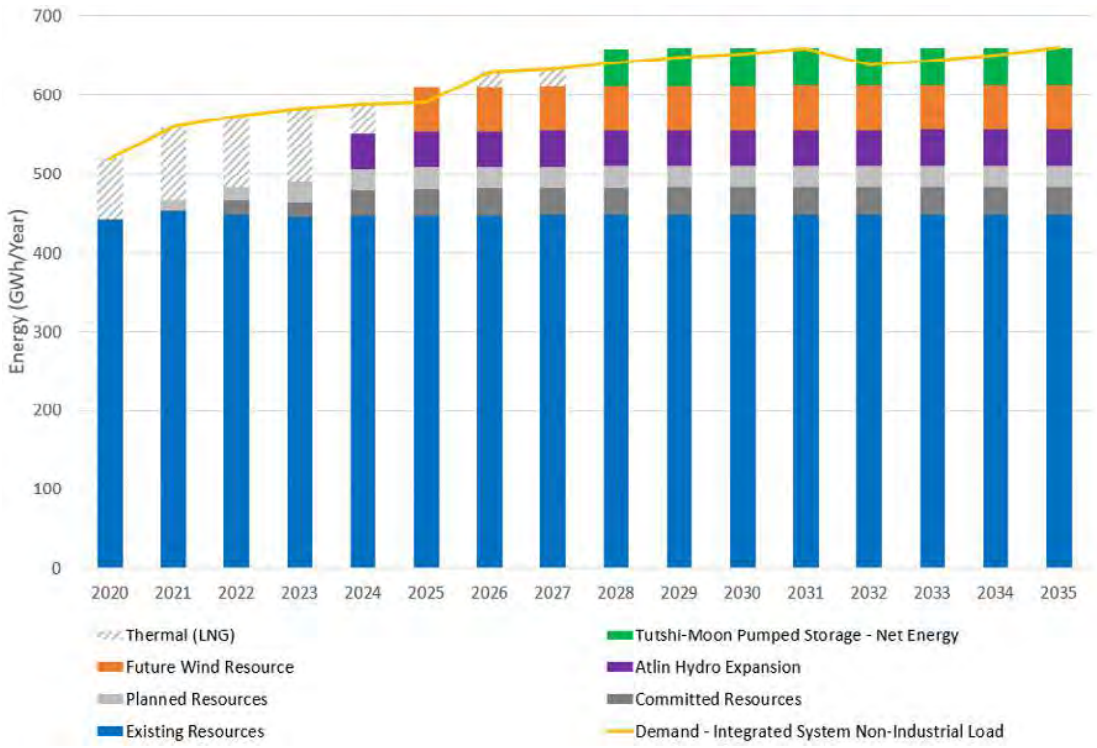


Figure 22: High Case Portfolio, Capacity

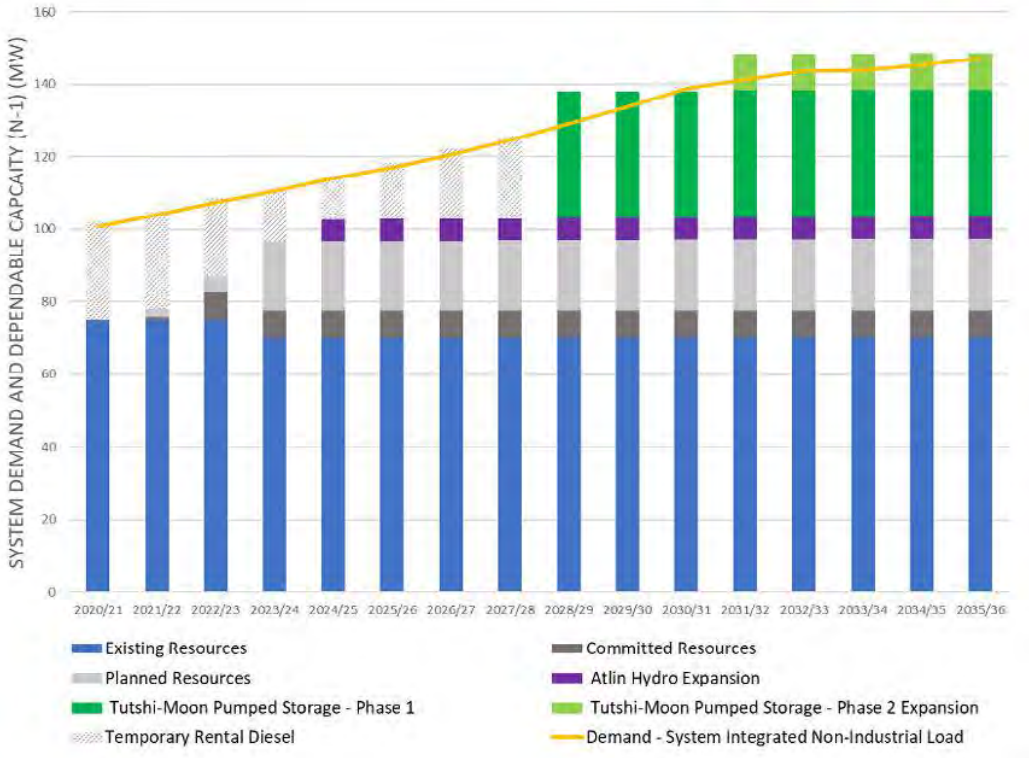


Table 6: High Case Portfolio Summary (2020 – 2030)

	INSTALLED CAPACITY [MW]	DEPENDABLE CAPACITY [MW]
Committed Resources	8.6	7.6
Planned Resources	20.3	19.5
Sub-total (Committed & Planned)	**28.9**	**27.1**
FUTURE RESOURCES:		
2024/25 Atlin Hydro Expansion Project	6	6
2025/26 Wind Resource Project	20	0
2028/29 Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total (Future Projects):	**41**	**41**
GRAND TOTAL:	**89.9**	**68.1**

Table 7: High Case Portfolio Cost Summary (2020 – 2030)

COST COMPONENT	COST [2019$ MILLIONS]
Portfolio Capital Cost without Federal Funding:	$ 651 million
Portfolio Capital Cost with Federal Funding:	$ 163 million

Appendix D: provides a more detailed breakdown of the cost and capacity components for the Base Case.

8.3 Portfolio Summary

As a consequence of the long lead times associated with developing generation and transmission, the portfolios show an energy and dependable capacity shortfall over the planning period, especially in the early years. As a result, residual energy and capacity gaps are assumed to be met with LNG generation and temporary diesel generator rentals over the planning period. Conversely, the Base Case scenario shows an energy surplus after 2030 based on the forecast decrease in industrial load, which indicates that the net energy production from the pumped storage facility would be in surplus. Federal funding will be critical in order to protect ratepayers from the financial cost of this potential surplus.

A summary of the resource options comprising the Base Case and the High Case scenario portfolios is presented in Table 8. Implementation of both the Atlin Hydro Expansion project in year 2024/25 and phase 1 of the Tutshi-Moon Lake Pumped Storage Project in year 2028/29 is required for both portfolios. Finally, the High Case scenario also requires a new 20 MW wind resource in 2025/26 to meet the higher energy requirements over the planning period.

Table 8: Future Resources Selected for Key Scenarios

	BASE CASE	HIGH CASE
2024/25	Atlin Hydro Expansion (6 MW)	Atlin Hydro Expansion (6 MW)
2025/26		Wind Resource (20 MW)
2028/29	Tutshi-Moon Pumped Storage Project – Phase 1 (35 MW)	Tutshi-Moon Pumped Storage Project – Phase 1 (35 MW)
Total Portfolio Capital Cost without Federal Funding ($M)	**$577 Million**	**$651 Million**
Total Portfolio Capital Cost with Federal Funding ($M)	**$144 Million**	**$163 Million**

8.3.1 Southern Lakes Geographic Focus

The 10-Year Renewable Electricity Plan's underlying focus on clean energy and capacity resources led to the development of multiple solutions in the Southern Lakes area, the geographical area shown in Figure 23.

Figure 23: Southern Lakes Transmission Network

With its abundance of lakes and proximity to Whitehorse (Yukon's main population and electrical load centre), the Southern Lakes area is well suited for developing hydroelectric resources. Hydroelectric and pumped storage hydro screening studies were completed as part of the 2016 Integrated Resource Plan. These studies identified several potential project sites in the Southern Lakes area, including the Tutshi-Windy Arm and Surprise Lake hydroelectric project sites, as well as the Moon-Tutshi, Racine-Moon, Lindeman-Fraser, Racine-Mount Brown and Atlin-Black Mountain pumped storage hydro sites. These general findings were confirmed in the study updates discussed in Section 7.1. Prospective Independent Power Producer (IPP) projects have also been identified in the Southern Lakes area, including the Atlin Hydro Expansion project and the Montana Mountain Wind and Solar Projects.

Given the limited existing transmission assets in the Southern Lakes area and the requirement to interconnect new projects, upgrading and expanding the transmission infrastructure is a requirement for enabling the projects in the Southern Lakes area. It may also be possible for YEC to take advantage of a potentially attractive business opportunity to supply electricity to cruise ships docking in Skagway during the summer tourist season. Currently, the Skagway pier has the capability to interconnect up to four (4) cruise ships, which can amount to approximately 35 GWh/year of summer energy demand. Cruise ships visiting Skagway today burn diesel fuel to generate shipboard electricity while at the dock. Electrifying cruise ships using surplus energy available during the summer months could lead to increased revenues for Yukoners to offset Yukon electricity costs, and a reduction in GHG emissions in Skagway. As noted in Section 4.2, this analysis was conducted prior to the COVID-19 pandemic; YEC will assess the timing and extent of the recovery of the cruise ship industry as part of its evaluation of the Skagway business opportunity.

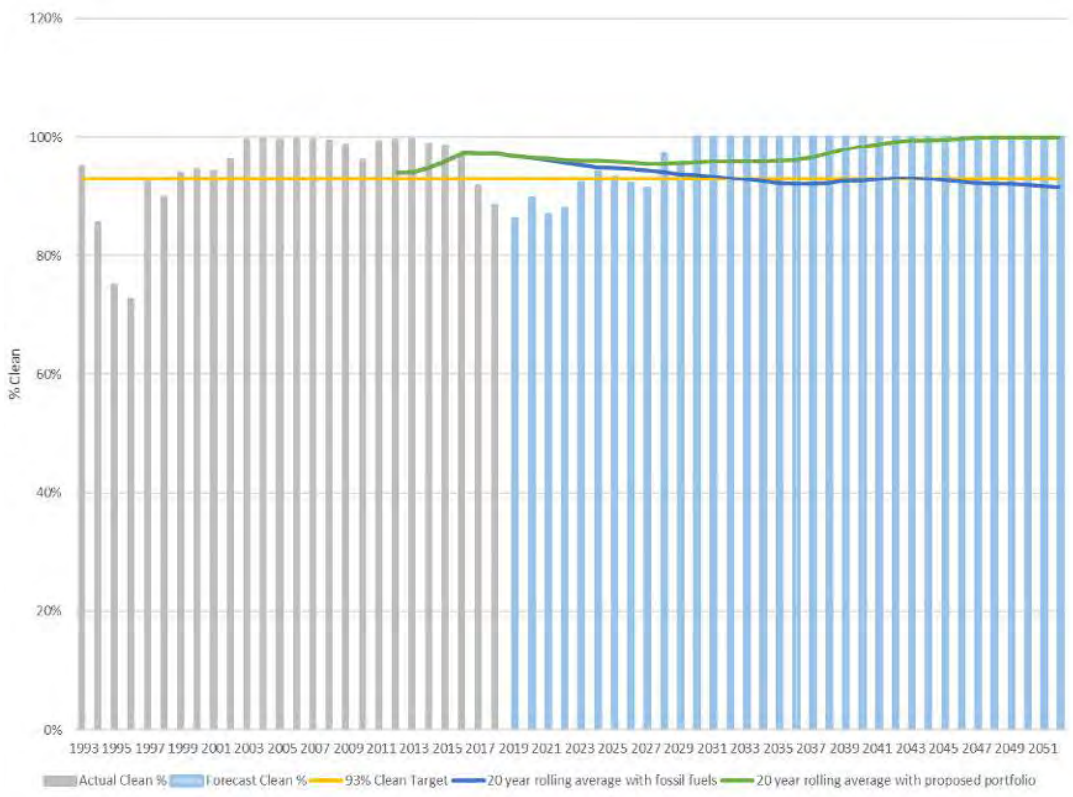
The majority of the new generation in the Plan is located in British Columbia; however, Yukoners will be receiving the benefits of the greenhouse gas emissions reductions and renewable electricity provision. YEC will strive to maximize other benefits to Yukoners via contracting and procurement opportunities and Yukon First Nations benefits agreements. YEC will also continue to work with both the Yukon and BC governments to ensure key stakeholders are engaged appropriately.

8.4 Renewable Portfolio Target

Under the Yukon government's draft Climate Change, Energy and Green Economy strategy, YEC is mandated to meet a renewable portfolio target of 93% on a long-term average basis. This means that at least 93% of the electricity generated on the YIS has to come from renewable sources.

Figure 24 illustrates the forecast percentage renewable generation profile of the electricity mix assuming that the 10-Year Renewable Electricity Plan portfolio is successfully executed. For comparison, the figure also includes a forecast percentage renewable generation profile for an alternate portfolio with a heavy reliance on fossil fuels to meet forecast energy needs (i.e., the portfolio that would be required if the 10-Year Renewable Electricity Plan is not implemented).

Figure 24: Long Term Energy Generation Profile



The bars shown in Figure 24 represent the actual percentage of renewable energy being generated by the system. The gap between the bars and the 100% threshold represents the percentage of energy generated by non-renewable resources (e.g. thermal). The lower percentage of renewable generation observed in recent years (i.e. 2017-2020) was a result of increased thermal generation at the margin given load growth and low hydroelectric resources (drought conditions) in these years.

As new renewable supply projects are developed over the planning period, there is an observed increase in percentage renewables in the energy generation mix. As observed in Figure 24, the 10-Year Renewable Electricity Plan portfolio exceeds the 93% renewable target over the planning period and beyond. The portfolio of projects recommended in the 10-Year Renewable Electricity Plan delivers on Yukon government's commitment for GHG reductions by 2030. It positions YEC favourably to contribute towards achieving the Federal government's "net zero by 2050" target.

9 10-Year Renewable Energy Action Plan

This section presents the key considerations in developing the 10-Year Renewable Electricity Action Plan (Action Plan), and the proposed steps to be undertaken to implement it.

9.1 Project Development Plan

The recommended Action Plan is based on developing the resource portfolio generated for the Base Case scenario, with add-on resources identified for other scenarios. Figure 25 summarizes the Action Plan recommendations.

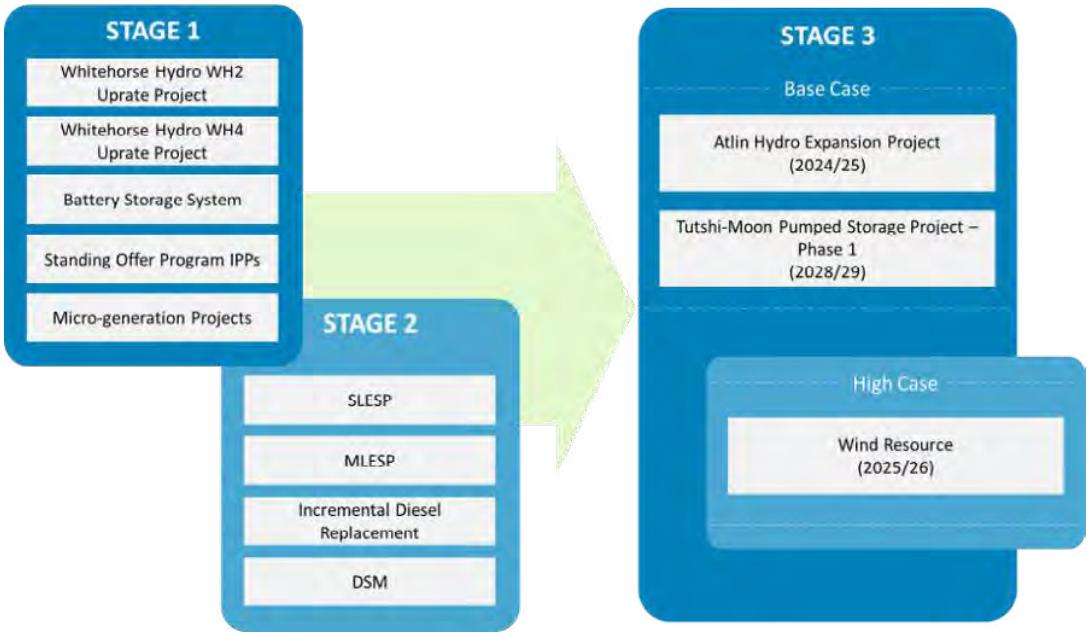
The Action Plan is divided into three stages:

» **Stage 1 – Implementation of the Committed Resources.** These resources are essential in all the portfolios over the planning period. These common resources include the Whitehorse Hydro #2 and #4 (WH2 and WH4) Uprate Projects, Battery Storage System, SOP IPP, and Micro-generation projects.

» **Stage 2 – Completion of Planning Work & Final Decisions to Proceed with Planned Resources.** These common resources include the SLESP, MLESP, the Incremental Diesel Replacement, and DSM.

» **Stage 3 – Development and implementation of the Future Potential Resources.** The options recommended for the expected Base Case scenario are the Atlin Hydro Expansion Project and Phase 1 of the Tutshi-Moon Lake Pumped Storage Project. The additional Future Potential Resource option included in the High Case portfolio (i.e. the Wind Resource) is considered as potential add-on resource to the Action Plan but is ultimately contingent on future growth.

Figure 25: 10-Year Renewable Electricity Action Plan



As with all long-term resource plans, there is the potential for future changes to trigger changes to the path forward. YEC will continue to monitor the key elements that influence the Plan, including the load forecast, progress or obstacles in executing the projects, and developments in emerging or uncertain technologies, and will update the path forward in future long-term resource planning exercises accordingly.

9.2 Key Risks & Uncertainties

The key risks and uncertainties with regard to the 10-year Renewable Electricity Plan are described below. If YEC is unable to move forward with the projects in the Plan, a new plan will be required to address Yukon's load growth and renewable electricity requirements.

- **Federal Funding Uncertainty.** The Action Plan assumes that Federal funding will be secured for the development of the identified generation projects and the supporting Southern Lakes transmission infrastructure. As such, Federal funding is an essential part of the recommended Action Plan as it will help minimize the rate impacts of the plan for Yukoners, and protect ratepayers from contingent risks such as the premature loss of industrial load. However, securing federal funding is not a certainty. To mitigate this risk, options to phase the Federal funding requests, such as focusing on securing funding for project planning first, and only proceeding with project construction once construction funding has been secured, will be explored with Federal funding agencies in order to mitigate risks. YEC will also coordinate closely with Yukon government and potential First Nations project developers and partners in pursuit of this Federal funding. If YEC is unable to secure Federal funding, a new long-term resource plan will need to be developed, as it is a critical requirement for the execution of the 10-Year Renewable Electricity Plan.
- **General Development Risks.** There is always some potential for technical or financial problems during project planning or construction, which could result in abandoning specific lower cost resources in favor of more expensive resources and/or delays. The resulting impacts include higher rates driven by increased portfolio costs and/or insufficient energy and/or capacity supply.
- **Residual Ratepayer Risk (exposure to surplus energy/mismatch).** If the future load projections used to justify capital plans do not materialize, over-building and/or over-production of electricity from the IPP SOP or micro-generation programs could lead to additional surplus energy and a seasonal mismatch between available generation and demand. This poses a financial risk to ratepayers in the form of higher rates.
- **SOP IPP Uncertainty.** The possibility of bankruptcy or failure of contracted generation assets, or the failure of contracted IPPs to reach commercial operation (multiple causes) could result in some IPP projects being delayed or not completed. The resulting risks include the inability to achieve renewable energy targets, increased thermal energy requirements, and/or insufficient energy supply.

» **Regulatory Uncertainties.** These uncertainties could lead to proposed electricity supply projects being disallowed by the regulator or to protracted legal and regulatory processes delaying project approvals or relicensing. If these projects are delayed or canceled, it will result in increased reliance on thermal generation for energy, and ongoing rental of temporary diesel engines for capacity. The resulting risks include the inability to achieve renewable energy targets, and potential rate increases caused by increased portfolio costs due to burning higher cost fossil fuels and introducing more expensive replacement projects.

9.3 First Nations Engagement, Support and Participation

Active First Nations participation in and support for the plan will be vital to the successful execution of the plan. YEC will be actively engaging with those First Nations on whose Traditional Territory the proposed projects are located.

Opportunities exist for First Nations to participate in multiple components of the plan, including the IPP SOP, and by taking an active role as project proponents and/or partners in the 10-Year Renewable Electricity Plan. In addition, First Nations will have contracting and other business opportunities during project planning and construction. These opportunities will be explored in detail during all phases of the project development.

Specific First Nations engagement plans for the two highest priority Future Potential Resources is outlined below:

» **Atlin Hydro Expansion project:** this project is being developed as an Independent Power Producer project by Tlingit Homeland Energy LP (THELP), a corporation owned by the development corporation of the Taku River Tlingit First Nation (TRTFN). As such, THELP will be responsible for all aspects of the project development, including environmental assessment and permitting, engineering design, construction and community and First Nations consultation. Yukon Energy has engaged in negotiations with THELP on a potential Electricity Purchase Agreement (EPA), which will outline the key commercial and operations terms under which YEC would purchase electricity from the Atlin Hydro Expansion project, should the project be approved to proceed. YEC and THELP are actively collaborating on securing government grant funding for the project, which will be critical to supporting the project economics while keeping the price of energy and capacity procured under the EPA affordable to Yukon customers.

» **Moon Lake Pump Storage Project:** this project is located on overlapping Traditional Territory of the Carcross/Tagish First Nation (C/TFN) and the Taku River Tlingit First Nation. As such, YEC plans to actively engage with both First Nations on the development of the Moon Lake Pump Storage project. As of Q4 2020, the project remains in a very early stage of development, and work completed to date has been limited to desk-top engineering and technical studies. YEC plans to engage with both C/TFN and TRTFN to establish a framework agreement covering the initial stages of project assessment and development, with the intent to undertake all field work, environmental assessment and monitoring, engineering design and community engagement in a collaborative, transparent manner. Options for the ultimate ownership structure of the project, including options for either partial of full ownership by First Nations, will also be assessed and negotiated over the initial phase of project planning. YEC will also actively collaborate with C/TFN and TRTFN on securing government grant funding for the project, which will be critical to supporting the project economics while keeping the project affordable for Yukon customers.

Appendix A:
Existing Resources Technical Attributes

Location	Retirement Year	Original Unit #	Current Unit #	Prime Mover Type	Dispatchable	10 Year Renewable Energy Plan		2016 IRP Dependable Capacity (IRP Table 4.2.)
						Installed Capacity [kW]	Dependable Capacity [kW]	[kW]
Aishihik								
Hydro	2050	AH1	AH1	Hydro	Yes	15,600	15,000	15,000
	2050	AH2	AH2	Hydro	Yes	15,600	15,000	15,000
	2050	AH3	AH3	Hydro	Yes	7,000	7,000	7,000
					Subtotal	**38,200**	**37,000**	**37,000**
Faro								
Diesel	2023	FD1	FD1	Diesel	Yes	5,150	3,000	4,000
	2050	FD7	FD7	Diesel	Yes	3,000	2,800	2,800
					Subtotal	**8,150**	**5,800**	**6,800**
Dawson								
Diesel	2050	DD1	DD1	Diesel	Yes	800	650	720
	2023	DD2	DD2	Diesel	Yes	1,000	850	920
	2050	DD3	DD3	Diesel	Yes	1,000	850	920
	2050	DD4	FD5	Diesel	Yes	1,440	1,000	1,000
	2023	DD5	DD5	Diesel	Yes	1,500	1,350	1,400
	2050	YM1	FD6	Diesel	Yes	1,440	850	1,000
					Subtotal	**7,180**	**5,550**	**5,960**
Mayo								
Diesel	2050	MD1	FD2	Diesel	Yes	1,000	850	850
	2050	MD2	FD4	Diesel	Yes	1,000	850	850
	2050	MD3	FD3	Diesel	Yes	1,000	850	850
					Subtotal	**3,000**	**2,550**	**2,550**
Hydro	2050	MH1	MH1	Hydro	Yes	2,550	1,500	1,400
	2050	MH2	MH2	Hydro	Yes	2,550		
	2050	MBH1	MBH1	Hydro	Yes	5,310	2,500	3,800
	2050	MBH2	MBH2	Hydro	Yes	5,310	2,500	3,800
					Subtotal	**15,720**	**6,500**	**9,000**
					Total	**18,720**	**9,050**	**11,550**
Whitehorse								
Hydro	2050	WH1	WH1	Hydro	Yes	5,800	3,500	3,000
	2050	WH2	WH2	Hydro	Yes	5,800	3,500	3,000
	2050	WH3	WH3	Hydro	Yes	8,400		
	2050	WH4	WH4	Hydro	Yes	21,327	20,000	18,500
					Subtotal	**41,327**	**27,000**	**24,500**
Diesel	2015	WD1	WG1	Diesel	Yes	N/A	N/A	N/A
	2015	WD2	WG2	Diesel	Yes	N/A	N/A	N/A
	2019	WD3	WD3	Diesel	Yes	N/A	N/A	4,500
	2050	WD4	WD4	Diesel	Yes	2,500	2,250	2,500
	2050	WD5	WD5	Diesel	Yes	2,500	2,250	2,500
	2050	WD6	WD6	Diesel	Yes	2,500	2,250	2,500
	2050	WD7	WD7	Diesel	Yes	3,300	2,800	3,000
					Subtotal	**10,800**	**9,550**	**15,000**
Natural Gas	2055	WG1	WG1	Natural Gas	Yes	4,400	4,200	4,400
	2055	WG2	WG2	Natural Gas	Yes	4,400	4,200	4,400
	2055	WG3	WG3	Natural Gas	Yes	4,400	4,200	N/A
					Subtotal	**13,200**	**12,600**	**8,800**
					Total	**65,327**	**49,150**	**48,300**

Location	Retirement Year	Original Unit #	Current Unit #	Prime Mover Type	Dispatchable	10 Year Renewable Energy Plan		2016 IRP Dependable Capacity (IRP Table 4.2.)
						Installed Capacity [kW]	Dependable Capacity [kW]	[kW]
Haeckel Hill								
Wind	2019	WW2	WW2	Wind	No	N/A	N/A	0
						0	**0**	**0**
Mobile Diesels								
Diesel	2050	YM2	YM2	Diesel	Yes	150	0	0
	2050	YM3	YM3	Diesel	Yes	125	0	0
	2050	YM4	YM4	Diesel	Yes	35	0	0
	2050	YM5	YM5	Diesel	Yes	125	0	0
					Subtotal	**435**	**0**	**0**
YECL								
Diesel	2050	CD1	CD1	Diesel	Yes	1,600	1,200	1,206
	2050	TD1	TD1	Diesel	Yes	1,500	1,200	1,130
	2050	RD1	RD1	Diesel	Yes	1,000	750	750
	2050	HD1	HD1	Diesel	Yes	1,750	1,500	1,320
	2050	Pelly G1	Pelly G1	Diesel	Yes	275	200	199
	2050	Pelly G2	Pelly G2	Diesel	Yes	600	400	446
	2050	Pelly G3	Pelly G3	Diesel	Yes	300	200	218
	2050	Stewart G1	Stewart G1	Diesel	Yes	150	100	104
					Subtotal	**7,175**	**5,550**	**5,373**
				YEC	**Hydro**	95,247	70,500	70,500
					Diesel	29,565	23,450	30,310
					Natural Gas	13,200	12,600	8,800
					Wind	0	0	0.0
					Total	**138,012**	**106,550**	**109,610**
				YECL	**Diesel**	7,175	5,550	5,373
					Total	**7,175**	**5,550**	**5,373**
				Yukon Power System	**Hydro**	95,247	70,500	70,500
					Diesel	36,740	29,000	35,683
					Natural Gas	13,200	12,600	8,800
					Wind	0	0	0
					Total	**145,187**	**112,100**	**114,983**
				Single Contingency (N-1) Dependable Capacity	**Hydro**	N/A	33,500	33,500
					Diesel	N/A	27,500	34,363
					Natural Gas	N/A	12,600	8,800
					Wind	N/A	0	0
					Total	**0.0**	**73,600**	**76,663**

Notes:

- *Single Contingency (N-1) scenario dependable capacity excludes the dependable capacity for Aishihik (37 MW) and ATCO's Haines junction diesel generator (1.5 MW) as the community would be isolated by the loss of the transmission line between the Aishihik Generating Station and the Takhini substation.*
- *No dependable capcity assumed for Minto Mine diesel generators and YEC wind turbines and mobile generators with the exception of unit YM1.*
- *Excludes ATCO Fish Lake Hydro. The contribution of the ATCO Fish Lake Hydro plant was not included in the inventory of the existing resources as its contribution was deducted from the load forecast modelling.*

Appendix B: Energy & Capacity Gap

Figure B1: Base Case Energy Gap Analysis: Detailed View

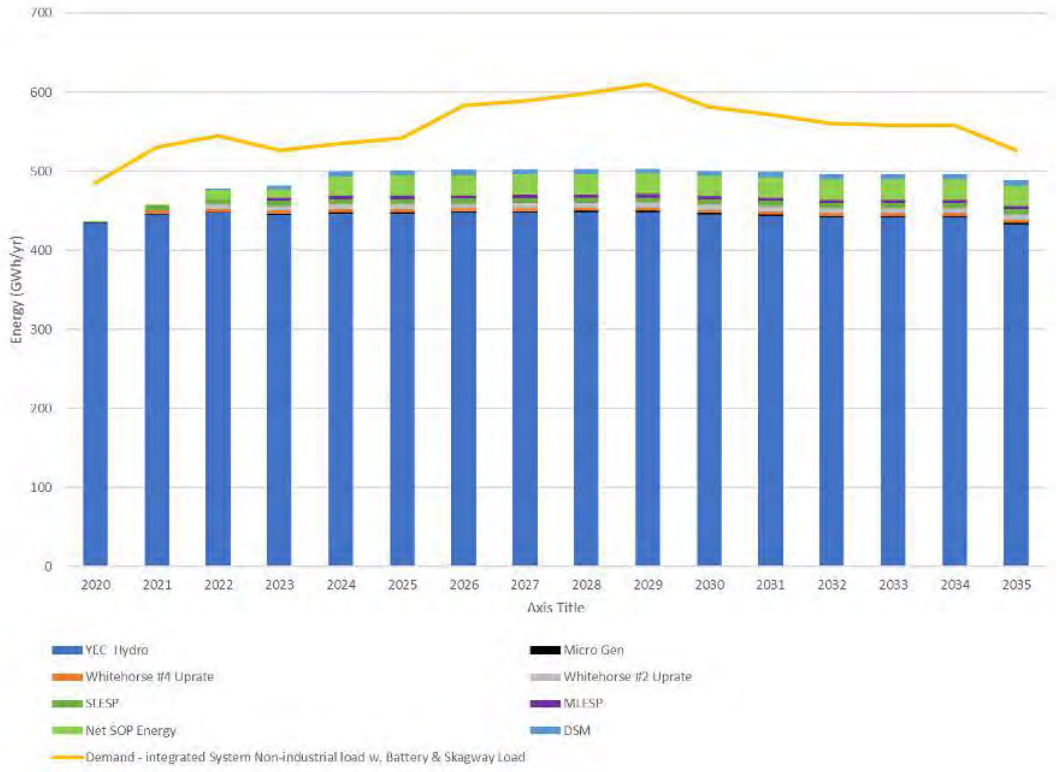


Table B1: Average Annual Energy Surplus/Deficit (Base Case)

YEAR	AVERAGE ENERGY SURPLUS/(DEFICIT) [GWH]	YEAR	AVERAGE ENERGY SURPLUS/(DEFICIT) [GWH]
2020	(49)	2028	(93)
2021	(69)	2029	(103)
2022	(63)	2030	(77)
2023	(42)	2031	(69)
2024	(32)	2032	(60)
2025	(37)	2033	(58)
2026	(78)	2034	(58)
2027	(83)	2035	(35)

Table B2: Average Monthly Energy Gap (Surplus/Deficit)

MONTH	YEAR 2024: AVERAGE ENERGY SURPLUS/ (DEFICIT) [GWH]	YEAR 2030 (BEFORE SKAGWAY LOAD): AVERAGE ENERGY SURPLUS/ (DEFICIT) [GWH]
Jan	(7)	(4)
Feb	(9)	(5)
Mar	(12)	(6)
Apr	(6)	(2)
May	(1)	0
Jun	4	7
Jul	8	10
Aug	10	11
Sep	8	9
Oct	2	3
Nov	(2)	0
Dec	(5)	(3)
Total Surplus [GWh]:	**32**	**40**
Total Deficit [GWh]:	**(42)**	**(20)**

Table B3: Dependable Capacity Surplus/Deficit under N-1 Conditions (Base Case)

YEAR	DEPENDABLE CAPACITY SURPLUS/ (DEFICIT) [MW]	YEAR	DEPENDABLE CAPACITY SURPLUS/ (DEFICIT) [MW]
2020/21	(26)	2028/29	(32)
2021/22	(26)	2029/30	(37)
2022/23	(20)	2030/31	(42)
2023/24	(14)	2031/32	(44)
2024/25	(17)	2032/33	(46)
2025/26	(20)	2033/34	(46)
2026/27	(24)	2034/35	(48)
2027/28	(28)	2035/36	(50)

Appendix C:
Additional Scenario Portfolio Results

C.1 Base Case (Without Skagway) Portfolio

Figure C1: Base Case (Without Skagway), Energy

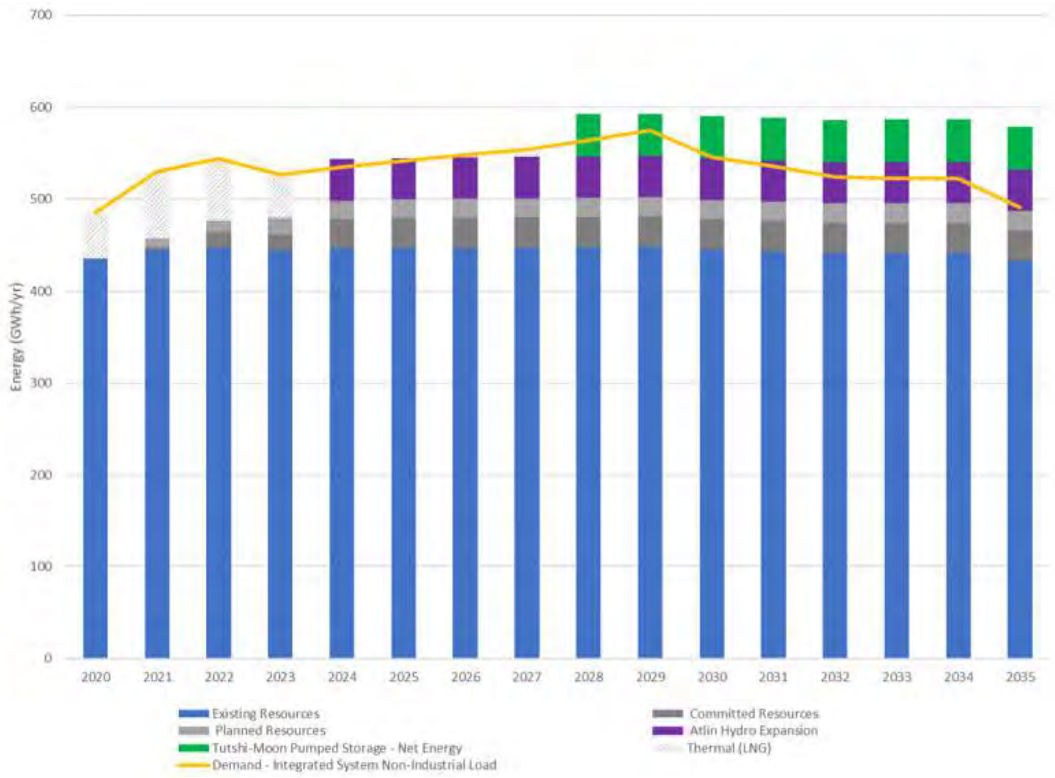


Figure C2: Base Case (Without Skagway), Capacity

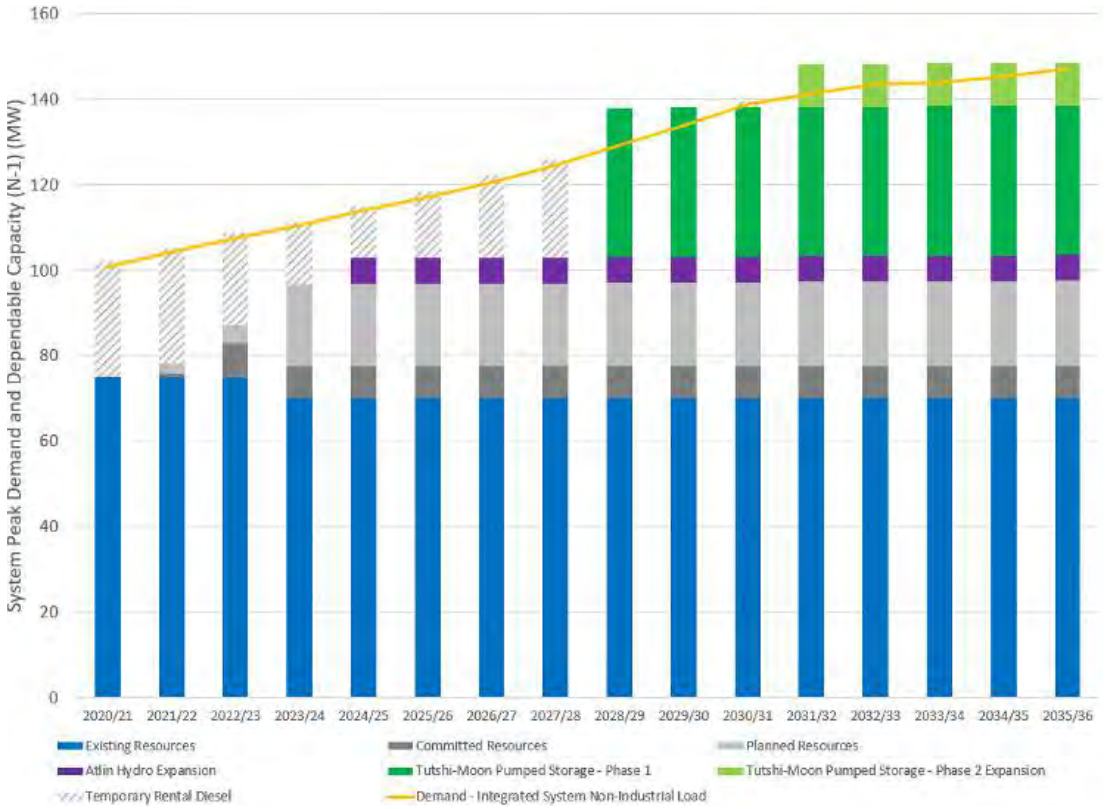


Table C1: Base Case (Without Skagway) Portfolio Summary (2020 - 2030)

	INSTALLED CAPACITY [MW]	DEPENDABLE CAPACITY [MW]
Committed Resources	8.6	7.6
Planned Resources	20.3	19.5
Sub-total (Committed & Planned)	**28.9**	**27.1**
FUTURE RESOURCES:		
2024/25 Atlin Hydro Expansion Project	6	6
2028/29 Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total (Future Projects):	**41**	**41**
GRAND TOTAL:	**69.9**	**68.1**

Table C2: Base Case (Without Skagway) Portfolio Cost Summary (2020 - 2030)

COST COMPONENT	COST [2019$ MILLIONS]
Portfolio Capital Cost without Federal Funding:	$ 519 million
Portfolio Capital Cost with Federal Funding:	$ 130 million

C.2 Low Case Portfolio

Figure C3: Low Case, Energy

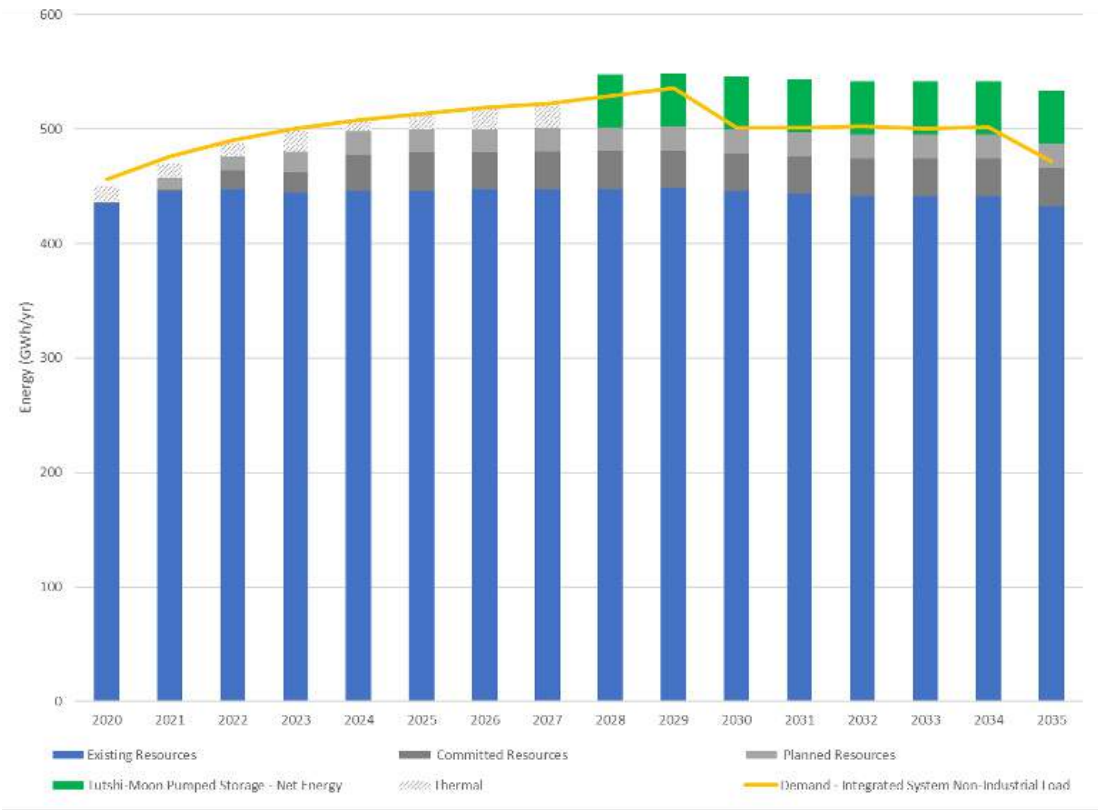


Figure C4: Low Case, Capacity

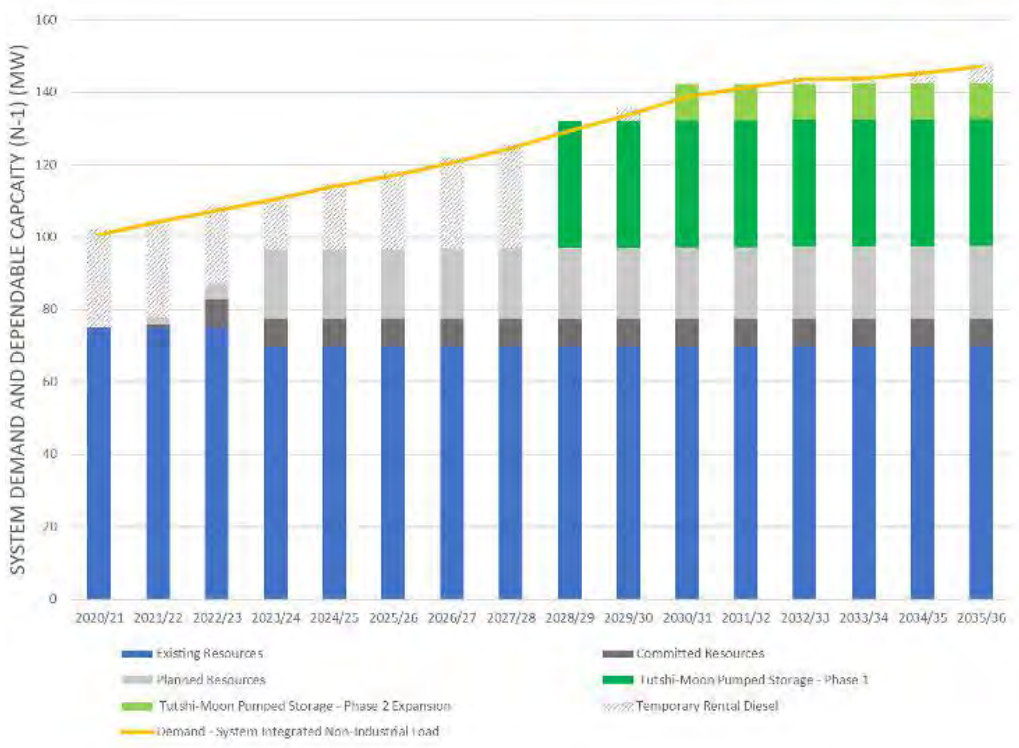


Table C3: Low Case Portfolio Summary (2020 - 2030)

	INSTALLED CAPACITY [MW]	DEPENDABLE CAPACITY [MW]
Committed Resources	8.6	7.6
Planned Resources	20.3	19.5
Sub-total (Committed & Planned)	**28.9**	**27.1**
FUTURE RESOURCES:		
2028/29 Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total (Future Projects):	**35**	**35**
GRAND TOTAL:	**63.9**	**62.1**

Table C4: Low Case Portfolio Cost Summary (2020 - 2030)

COST COMPONENT	COST [2019$ MILLIONS]
Portfolio Capital Cost without Federal Funding:	$ 388 million
Portfolio Capital Cost with Federal Funding:	$ 97 million

Appendix D:
Detailed Scenario Capacity & Capital Costs

D.1 Base Case Portfolio

Table D1: Base Case Capacity Detail 2020-2030

	Installed Capacity [MW]	Dependable Capacity [MW]
Committed Resources		
Whitehorse #2 Uprate	0.6	0.6
Battery Energy Storage System	8	7
Sub-total:	**8.6**	**7.6**
Planned Resources		
Whitehorse #4 Uprate	0.8	0
Southern Lakes Enhanced Storage	N/A	0
Mayo Lake Enhanced Storage	N/A	0
Incremental Diesel Replacement	12.5	12.5
Demand Side Management	7	7
Sub-total:	**20.3**	**19.5**
Future Projects		
2024/25		
Atlin Hydro Expansion Project	6	6
2028/29		
Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total:	**41**	**41**
TOTAL:	**69.9**	**68.1**

Table D2: Base Case Capital Costs[1] Detail 2020-2030

Cost Component	Capital Cost (2019$)	Federal Funding (2019$)	Total Cost with Federal Funding
Atlin Hydro	$ 131,000,000	$ 98,250,000	$ 32,750,000
Moon Lake Pumped Storage	$ 280,000,000	$ 210,000,000	$ 70,000,000
Southern Lakes Transmission Project Phase 1-3 (Whitehorse to Skagway)	$ 166,000,000	$ 124,500,000	$ 41,500,000
TOTAL PORTFOLIO:	**$ 577,000,000**	**$ 432,750,000**	**$ 144,250,000**

[1]The capital costs for the generation projects are from the sources described in Section 7.1.3 and Table 3. The capital costs for the Southern Lakes Transmission Project is based on the 2016 Resource Plan Appendix 5.21: Transmission Options Evaluation study work.

D.2 High Case Portfolio

Table D3: High Case Capacity Detail 2020-2030

	Installed Capacity [MW]	Dependable Capacity [MW]
Committed Resources		
Whitehorse #2 Uprate	0.6	0.6
Battery Energy Storage System	8	7
Sub-total:	**8.6**	**7.6**
Planned Resources		
Whitehorse #4 Uprate	0.8	0
Southern Lakes Enhanced Storage	N/A	0
Mayo Lake Enhanced Storage	N/A	0
Incremental Diesel Replacement	12.5	12.5
Demand Side Management	7	7
Sub-total:	**20.3**	**19.5**
Future Projects		
2024/25		
Atlin Hydro Expansion Project	6	6
2025/26		
Wind Resource Project	20	0
2028/29		
Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total:	61	41
TOTAL:	**89.9**	**68.1**

Table D4: High Case Capital Costs[1] Detail 2020-2030

Cost Component	Capital Cost (2019$)	Federal Funding (2019$)	Total Cost with Federal Funding
Atlin Hydro	$ 131,000,000	$ 98,250,000	$ 32,750,000
Moon Lake Pumped Storage	$ 280,000,000	$ 210,000,000	$ 70,000,000
Wind Resource (20 MW)	$ 73,500,000	$ 55,125,000	$ 18,375,000
Southern Lakes Transmission Project Phase 1-3 (Whitehorse to Skagway)	$ 166,000,000	$ 124,500,000	$ 41,500,000
TOTAL PORTFOLIO:	**$ 650,500,000**	**$ 487,875,000**	**$ 162,625,000**

D.3 Base Case (Without Skagway) Portfolio

Table D5: Base Case (without Skagway) Capacity Detail 2020-2030

	Installed Capacity [MW]	Dependable Capacity [MW]
Committed Resources		
Whitehorse #2 Uprate	0.6	0.6
Battery Energy Storage System	8	7
Sub-total:	**8.6**	**7.6**
Planned Resources		
Whitehorse #4 Uprate	0.8	0
Southern Lakes Enhanced Storage	N/A	0
Mayo Lake Enhanced Storage	N/A	0
Incremental Diesel Replacement	12.5	12.5
Demand Side Management	7	7
Sub-total:	**20.3**	**19.5**
Future Projects		
2024/25		
Atlin Hydro Expansion Project	6	6
2028/29		
Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total:	**41**	**41**
TOTAL:	**69.9**	**68.1**

Table D6: Base Case (without Skagway) Capital Costs[1] Detail 2020-2030

Cost Component	Capital Cost (2019$)	Federal Funding (2019$)	Total Cost with Federal Funding
Atlin Hydro	$ 131,000,000	$ 98,250,000	$ 32,750,000
Moon Lake Pumped Storage	$ 280,000,000	$ 210,000,000	$ 70,000,000
Southern Lakes Transmission Project Phase 1-2 (Whitehorse to Moon Lake)	$ 108,000,000	$ 81,000,000	$ 27,000,000
TOTAL PORTFOLIO:	**$ 519,000,000**	**$ 389,250,000**	**$ 129,750,000**

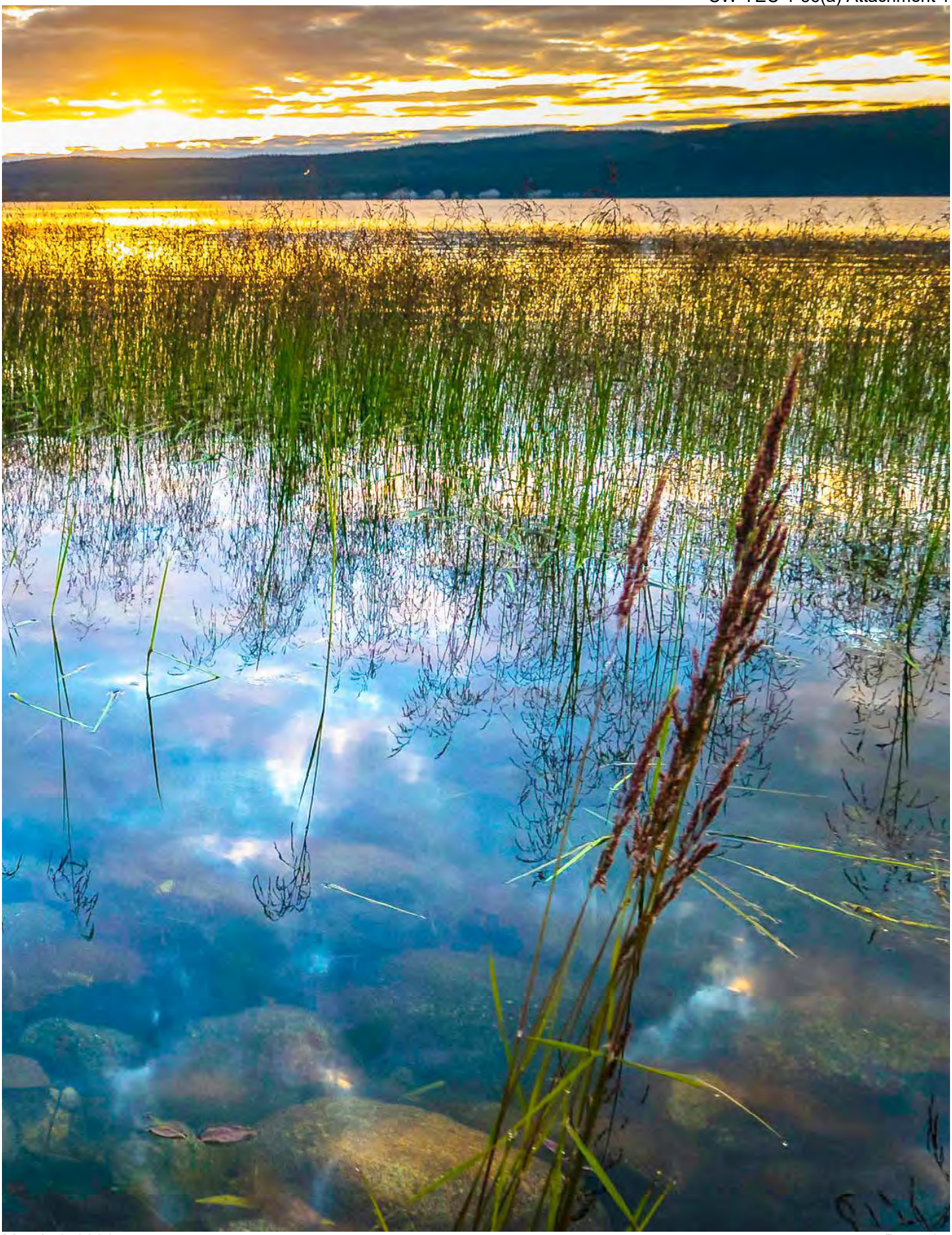
D.4 Low Case Portfolio

Table D7: Low Case Capacity Detail 2020-2030

	Installed Capacity [MW]	Dependable Capacity [MW]
Committed Resources		
Whitehorse #2 Uprate	0.6	0.6
Battery Energy Storage System	8	7
Sub-total:	**8.6**	**7.6**
Planned Resources		
Whitehorse #4 Uprate	0.8	0
Southern Lakes Enhanced Storage	N/A	0
Mayo Lake Enhanced Storage	N/A	0
Incremental Diesel Replacement	12.5	12.5
Demand Side Management	7	7
Sub-total:	**20.3**	**19.5**
Future Projects		
2028/29		
Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total:	**35**	**35**
TOTAL:	**63.9**	**62.1**

Table D8: Low Case Capital Costs[1] Detail 2020-2030

Cost Component	Capital Cost (2019$)	Federal Funding (2019$)	Total Cost with Federal Funding
Moon Lake Pumped Storage	$ 280,000,000	$ 210,000,000	$ 70,000,000
Southern Lakes Transmission Project Phase 1-2 (Whitehorse to Moon Lake)	$ 108,000,000	$ 81,000,000	$ 27,000,000
TOTAL PORTFOLIO:	**$ 388,000,000**	**$ 291,000,000**	**$ 97,000,000**



Appendix E:
Knight Piesold Hydro Options Report

Prepared for
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Prepared by
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VA103-556/6-1

SMALL HYDROELECTRIC PROJECTS
SCREENING ASSESSMENT (10 MW – 30 MW)

Rev	Description	Date
0	Issued in Final	November 25, 2019

Knight Piésold CONSULTING

EXECUTIVE SUMMARY

Yukon Energy Corporation (YEC) engaged Knight Piésold Ltd. (KP) to update and further develop a desktop review of the potential hydroelectric projects in the Yukon and northern British Columbia. This study builds upon KP's 2016 *Small Hydroelectric Projects Screening Assessment,* the Midgard Consulting Inc.'s 2015 *Yukon Next Generation Hydro and Transmission Viability Study - Site Screening Inventory*, and other historic studies. The objectives of the study were to compile a regional assessment of hydropower development sites with installed capacities between 10 MW and 30 MW.

Part I: Screening Assessment

KP completed a screening assessment to progressively eliminate less attractive sites and focus in on the best potential hydroelectric development options. The steps taken in the screening process were:

1. Compilation of a list of 147 sites and alternatives previously considered by Midgard and KP. A handful of additional sites were added for consideration based on proximity to transmission lines and perceived generating potential; however, the review of additional sites should not be considered exhaustive.
2. Screen 1 – Coarse Screening: Projects were grouped by which transmission branch they could be connected to. This included all existing transmission lines in the Yukon as well as a number of proposed lines. With the sites organized, a four-part high-level screen was initiated to eliminate sites that were:
   - Below a 10 MW threshold, or projects not believed to be practical at a 10 MW installed capacity
   - Too distant from transmission (in excess of 50 km from a proposed or existing line)
   - Located in parks (except for Primrose and Tutshi Windy Arm)
   - Affecting the Yukon River or known to flood communities

Sites passing all four of the above criteria, and those sites that were indeterminate on a cursory review, were advanced to Screen 2. A total of 56 sites were advanced.

1. Screen 2 – Quantitative Assessment: KP completed a number of high-level analyses to develop a better understanding of the sites and their hydropower potential. The activities completed in Screen 2 were:
   - Locating sites to best utilize available topographic relief and determining catchment areas
   - Developing conceptual layouts, including intake and powerhouse locations, dam and water conveyance alignments, etc.
   - Reviewing regional hydrological data to establish site-specific estimates for Mean Annual Discharge (MAD) and the seasonal distribution of flow
   - Estimating installed capacity and energy generation profiles
   - Developing indicative capital cost estimates
   - Developing estimates for Levelized Cost of Capacity (LCOC) and Levelized Cost of Energy (LCOE)

Certain sites appeared to have two or more configuration options. KP reviewed these alternatives at a high-level and selected the best option for presentation in this study. In some instances, a run of river and storage option have both been presented.

1. Screen 3 – Final Screening and Selection of Preferred Sites: the results of Screen 2 were presented to YEC for final consideration and selection of the preferred sites. The final screening criteria were applied as follows:
   - Elimination of those sites associated with the proposed Beaver Creek-Hanes Junction and Faro-Watson Lake transmission lines

- Elimination of sites with dams on major rivers due to social risk and high temporary works construction costs
- Elimination of sites with LCOE values exceeding $0.35/kWh

The preferred sites were determined to be Primrose (storage), Drury (storage), Tutshi-Windy Arm (storage), Wolf (as run of river and storage), and Atlin (storage).

Part II: Concept Development for Preferred Sites

KP completed a closer evaluation of the preferred sites to build upon the quantitative results of the screening process and to provide YEC with the basis for planning future studies for these sites. The table below summarizes the key financial and technical attributes for the five preferred sites.

Further evaluations of the preferred sites are recommended to improve the understanding of engineering, economic, environmental, and social factors impacting project development. The first steps would involve discussions with affected First Nations, acquisition of accurate topography to validate elevations, and the initiation of hydrology studies. Should such evaluations indicate that there are no critical barriers to project development, further evaluation of the sites through pre-feasibility and feasibility studies should be pursued to prove economic viability.

Knight Piésold CONSULTING

TABLE 0.1

YUKON ENERGY CORPORATION
HYDROPOWER POTENTIAL ASSESSMENT (10MW-30MW)

PREFERRED SITES
SUMMARY

Print Nov/25/19 08:58:01

DESCRIPTION	Primrose	Drury	Tutshi	Atlin	Wolf	Wolf River & Lake
Installed Capacity (MW)	12.7	10.0	10.0	8.0	11.2	30.0
Dependable Winter Capacity (MW) based on 2 weeks of Winter Production	12.7	10.0	10.0	6.0	4.0	30.0
Average Annual Energy (GWh) x 95% for outages and transmission losses	74.0	30.6	49.3	45.0	79.7	229.5
Average Dec-Mar Energy (GWh) x 95% for outages and transmission losses	33.0	24.9	27.1	20.8	20.1	79.0
Unit Cost of Capacity (M$/MW)	14.0	11.1	16.7	16.4	14.7	15.3
Unit Cost of Energy (M$/GWh)	2.40	3.61	3.39	2.91	2.07	2.00
Levelized Cost of Capacity ($/kW-yr) @4.82%	1,342	673	1,291	1,426	1,780	1,764
Levelized Cost of Energy ($/kWh) @4.82%	0.184	0.277	0.256	0.222	0.160	0.154
Levelized Cost of Winter Energy ($/MWh) @4.82% and 0.19 $/kWh for Non Winter Energy	0.177	0.296	0.311	0.259	0.072	0.086
Project Gross Head (m)	138	100	51	107 and 56	75	100
Design Flow (m^3/s)	11.6	12.7	24.9	7.0	18.8	37.6
MAD (m^3/s)	14.5	4.9	16.2	4.4	75.3	75.3
Design Factor	0.80	2.60	1.55	1.59	0.25	0.50
Dam Height (m)	10	5	5	2.5	-	4
Storable Volume (10^6 m^3)	100	125	265	76	-	350
Water Conveyance Length (m)	4,700	5,200	3,000	4,000	7,400	14,000
Capital Cost Esitmate						
Mod, Demob, Insurance, Bonds, Overheads, Contractor's Profit	$ 29,700,000	$ 18,500,000	$ 27,900,000	$ 1,400,000	$ 27,600,000	$ 57,900,000
Access and Site Preparation	$ 8,000,000	$ 4,600,000	$ 7,900,000	$ 700,000	$ 12,000,000	$ 23,000,000
Intake, Forebay, and Headrace	$ 6,500,000	$ 6,800,000	$ 12,500,000	$ 1,100,000	$ 10,000,000	$ 25,000,000
Water Conveyance System	$ 25,000,000	$ 30,000,000	$ 32,900,000	$ 30,200,000	$ 39,700,000	$ 90,000,000
Powerhouse and Ancilary Services	$ 6,000,000	$ 5,900,000	$ 8,700,000	$ 12,700,000	$ 7,400,000	$ 13,500,000
Power Generation Equipment (Water to Wire)	$ 8,900,000	$ 7,100,000	$ 7,100,000	$ 9,800,000	$ 7,900,000	$ 20,000,000
Switchyward, Transmission and Interconnection	$ 29,500,000	$ 2,700,000	$ 20,200,000	$ 27,100,000	$ 15,000,000	$ 18,000,000
Dams and Reservoirs	$ 15,000,000	$ 4,500,000	$ 3,800,000	$ 1,600,000	$ -	$ 3,500,000
Upgrades to Grid (138 kV 150 km Teslin to Whitehorse)					$ -	$ 82,500,000
SUB-TOTAL	**$ 128,600,000**	**$ 80,100,000**	**$ 121,000,000**	**$ 84,600,000**	**$ 119,600,000**	**$ 333,400,000**
EPCM ENGINEERING COST (8 % of ESTIMATED CONSTRUCTION COST)	$ 10,300,000	$ 6,400,000	$ 9,700,000	$ 20,300,000	$ 9,600,000	$ 26,700,000
CONTINGENCY (30 % of ESTIMATED CONSTRUCTION COST)	$ 38,600,000	$ 24,000,000	$ 36,300,000	$ 26,100,000	$ 35,900,000	$ 100,000,000
TOTAL ESTIMATED CAPITAL COST	**$ 177,500,000**	**$ 110,500,000**	**$ 167,000,000**	**$ 131,000,000**	**$ 165,100,000**	**$ 460,100,000**

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NOTES:
1. DOES NOT INCLUDE UPFRONT ENVIRONMENTAL, PERMITTING AND OWNERS COSTS.
2. DOES NOT INCLUDE APPLICABLE SALES TAXES.
3. EPCM COSTS INCLUDE DETAILED ENGINEERING, TENDERING OF CIVIL AND WATER-TO-WIRE CONTRACTS, SITE SUPERVISION, OVERALL PROJECT MANAGEMENT AND ENVIRONMENTAL MONITORING.
4. COSTS ARE PRELIMINARY AND ARE CONSIDERED EQUIVALENT TO AN AACE CLASS 5 ESTIMATE.
5. ATLIN COSTS ARE BASED COSTS REPORTED BY MORRISON HERSFIELD 2016 ESCALATED AT 2.5%.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
0	25NOV19	ISSUED WITH REPORT VA103-556/6-1	BXF	SDR

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

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APPENDICES

Appendix A Historical Documents and Hydropower Project Sites
Appendix B Site Descriptions

ABBREVIATIONS

C ..... loaded capital cost
CFRD ..... Concrete Faced Rockfill Dam
DFO ..... Fisheries and Oceans Canada
EPCM ..... Engineering, Procurement and Construction Management
GWh ..... gigawatt hour
IFR ..... Instream Flow Requirement
km ..... kilometre
KP ..... Knight Piésold Ltd.
LC ..... levelized capital cost per year
LCOC ..... Levelized Cost of Capacityl=
LCOE ..... Levelized Cost of Energy
m ..... metre
masl ..... metre above sea level
m^3 ..... cubic metre
Mm^3 ..... million cubic metre
m^3/s ..... cubic metre per second
MAD ..... Mean Annual Discharge
MAUD ..... Mean Annual Unit Discharge
MW ..... megawatt
MWh ..... megawatt hour
Q_d ..... design flow
WSC ..... Water Survey of Canada
YDC ..... Yukon Development Corporation
YEC ..... Yukon Energy Corporation
YECL ..... Yukon Electrical Company Ltd.
yr ..... year

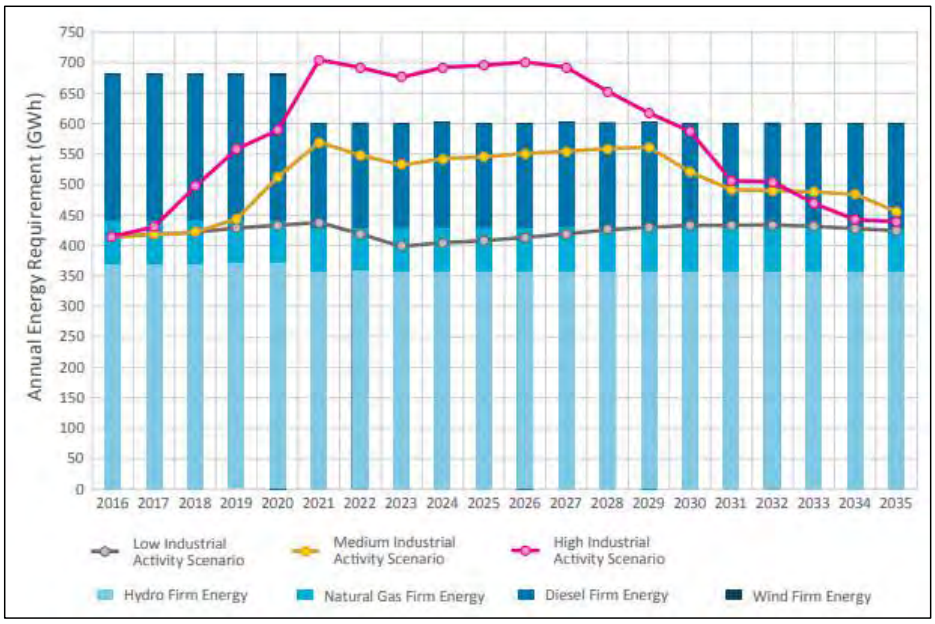
1.0 BACKGROUND

1.1 RESOURCE PLANNING

Yukon Energy Corporation (YEC) and the Yukon government work to ensure that the Yukon's electrical energy needs are met now and in the future, and that future generations can enjoy an energy legacy similar to that provided by the current hydro generation of Whitehorse, Aishihik, Mayo and Fish Lake.

In 2013, the Yukon government issued the Yukon Hydroelectric Power Planning Directive to Yukon Development Corporation (YDC). The directive tasked YDC to plan one or more hydroelectric projects to ensure an adequate and affordable supply of reliable and sustainable electrical power was available in the Yukon.

The 2016 Yukon Energy Resource Plan outlined the energy options that YEC would like to discuss further with the Yukon government, First Nations, stakeholders and the Yukon public. The energy options include small hydro as potential sources of energy to meet future growth. YEC included an investigation of small hydro in its work plan while they monitor how the Yukon load grows over time. Figure 1.1 presents the forecasted energy needs in the Yukon.



NOTES:
1. SOURCE: YUKON ENERGY'S 2016 RESOURCE PLAN (JUNE 2017).

Figure 1.1 Yukon Projected Annual Energy Requirement

The Yukon 2016 Resource Plan states that legally barred and unviable resource options include:

- Generation or transmission options that are located in protected areas or interim protected areas, such as inside a National Park, or projects that would inundate land within a National Park.
- Hydroelectric projects that inundate titled property or a private residence, except for the hydro storage enhancement of existing YEC facilities.
- Projects in remote locations, far from the Yukon transmission grid. The servicing of remote communities is not the focus of the Resource Plan and is covered in specific community planning processes.
- Generation options exceeding 50 MW of installed capacity. Given the YEC demand requirements of the reasonably foreseeable future, and the isolated nature of the Yukon grid, a project beyond this size would exceed domestic requirements, with no ability to sell the surplus.

1.2 ENGAGEMENT

YEC commissioned Knight Piésold Ltd. (KP) in 2019 to update and further develop a desktop review of potential small hydroelectric projects in the Yukon and northern British Columbia. The objectives of the study were to compare technical and economic development criteria and to systematically screen and shortlist development options to provide YEC with the basis to plan future studies on the most attractive sites.

This study is a regional assessment of hydropower development options with capacities between 10 MW and 30 MW, and with estimated transmission line interconnection distances not exceeding 50 km. It builds on KP's 2016 *Small Hydroelectric Projects Screening Assessment*, Midgard Consulting Inc.'s 2015 *Yukon Next Generation Hydro and Transmission Viability Study – Site Screening Inventory*, and other historic studies. It includes a review of all sites previously presented in the 2016 KP study, 2015 Midgard study, and a number of additional sites identified by KP with perceived hydroelectric development potential.

1.3 STUDY LIMITATIONS

The current study is high-level and is based on relatively coarse mapping and hydrology datasets. As such, all results are indicative only and subject to change when better data become available. For example, the publicly available GIS mapping for the Yukon has a contour interval of 20 to 30 metres, and this is restrictive in terms of the identification and evaluation of low-head development sites and low head dams.

The scope of this study is limited to those sites previously identified in the 2016 KP study, the 2015 Midgard study, and a handful of additional sites identified by KP during the current study. There may be other viable sites that have not been considered during previous studies or identified as additional sites in the current study.

The high-level scope and the large number of sites only allowed for limited consideration of alternative configurations at each site. The optimal hydro site will depend on several factors, including capital costs, desired capacity, transmission constraints, environmental impacts, and social conditions.

Finally, the indicative cost estimating performed relies on very generic procedures for estimating quantities (earthworks, concrete, etc.), power equipment types and costs, and transmission line and access road lengths and costs. The values should only be considered as comparative metrics which are used to focus in on the preferred sites. This simplicity is necessary to conduct this type of high-level study, but it may also

lead to oversights in terrain hazards, foundation conditions, or other technical challenges that may affect project costs/viability.

2.0 BACKGROUND INFORMATION

2.1 YUKON POWER GRID

YEC provides the power needs for more than 15,000 customers across the Yukon Territory. The Yukon electricity network is an isolated grid, with no connection to other jurisdictions (i.e. BC, Alaska or Northwest Territory). The Yukon grid currently services all Yukon communities except for Watson Lake, Burwash Landing/Destruction Bay, Beaver Creek, and Old Crow.

2.1.1 CURRENT CAPACITY

YEC currently owns and operates approximately 131 MW of installed capacity, consisting of 92 MW of hydro, 0.8 MW of wind, and 37.8 MW of thermal (diesel and natural gas). Yukon Electrical Company Ltd. (YECL), owned by ATCO, supplies approximately 1.3 MW of hydroelectricity and 6.8 MW of diesel power.

YEC's hydroelectric generating capacity is comprised of:

- 37 MW Aishihik Generating Station, 150 km west of Whitehorse
- 15 MW Mayo Generating Station, 450 km north of Whitehorse
- 40 MW Whitehorse Generating Station, located on the Yukon River at Whitehorse
- 1.3 MW Fish Lake Generating Station (YECL)

2.1.2 EXISTING TRANSMISSION LINES

The Yukon power grid is shown on Figure 2.1 and comprises the following major components:

- 138 kV Whitehorse / Aishihik / Faro (WAF) grid
- 69 kV Mayo / Dawson transmission line
- 138 kV Carmacks / Stewart transmission line, connecting the WAF grid and the Mayo / Dawson transmission line

2.1.3 PROPOSED TRANSMISSION LINES

The following major transmission line extensions have also been considered by YEC:

- Skagway (AK) to Whitehorse through Carcross (YK) and British Columbia
- Atlin (BC) to Whitehorse
- Beaver Creek to Hanes Junction (alternatively Destruction Bay to Hanes Junction)
- Faro to Watson Lake, to connect Watson Lake to the Yukon grid

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

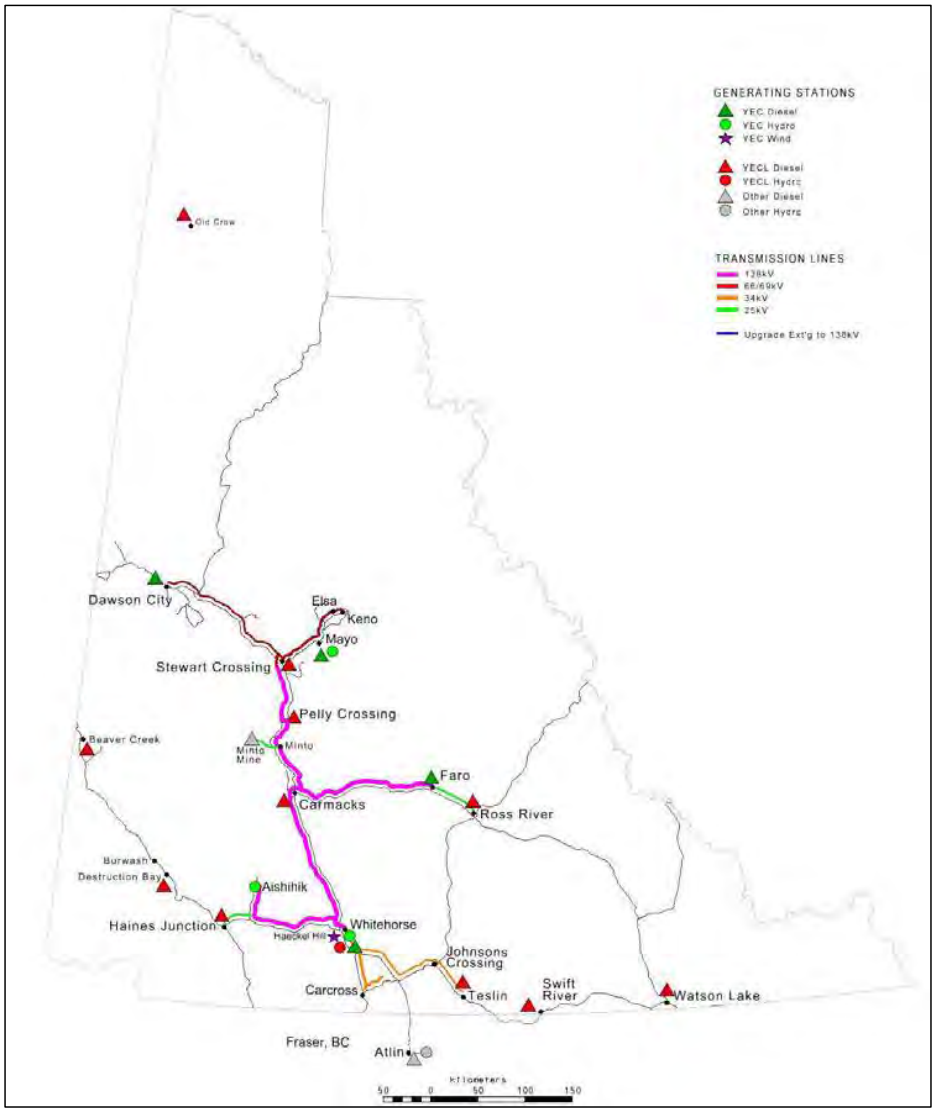


Figure 2.1 Yukon Electricity Network (YEC, 2016)

2.2 OVERVIEW OF HYDROELECTRIC POWER GENERATION

Hydropower is a renewable source of energy with a low carbon footprint. It is a long standing, proven technology that is prevalent worldwide and particularly in regions with high annual precipitation and mountainous terrain.

Conventional hydroelectric power stations can be generally categorized into two types: run of river (RoR) and storage hydro. Storage hydro utilizes water stored behind a dam to generate energy on demand, whereas RoR hydro utilizes the available flows in a river/stream and does not significantly alter natural hydrologic conditions. RoR and Storage hydro are further defined in the sections to follow.

2.2.1 RUN OF RIVER HYDRO

RoR hydroelectric plants utilize the available flow in a river at any given time, with minimal upstream headpond / reservoir live storage. Water is typically diverted at a weir into a water conveyance system (canal, tunnel, and/or penstock), to a powerhouse, and then back into the natural river channel. Very little alteration is made to the natural hydrograph downstream of a run of river project. A conceptual layout of a run of river hydro scheme is provided in Figure 2.2 below.

Electric output is a function of short term (hourly or daily) river discharge, varying daily and seasonally in parallel with the river discharge hydrograph. In the Yukon, run of river generating potential occurs predominantly from May until August, during spring freshet and summer glacial melt.

For the Purpose of this study the run of river projects have been broken down into two categories:

- *"High Head Run of River"* where the projects will divert water away from the main river course, reducing the flow in a portion of the river (i.e. the diversion reach), and then returning the flow to the natural watercourse downstream of the rapids/waterfalls. The project head is generally generated by the natural topographical drop in elevation in the stream over the diversion reach.
- "*Low Head Run of River*" where the project head will principally be generated by the height of the dam/weir in the mainstem of the river. These projects will typically need to handle large flows to generate the required power (i.e. greater than10 MW for the current study). The reservoirs created for these types of dams are not utilized to store the water for electrical generation at select times, but to create the head for power generation. They still operate as run of river facilities utilizing the naturally available flow in the river at any given time.

2.2.2 STORAGE HYDRO

Storage hydroelectric plants utilize an upstream lake or reservoir to store water and to control the outflow and energy output on a daily, monthly, or seasonal basis. This allows for load shaping and winter generation, a times when a run of river hydroelectric facility might not be able to generate a significant amount of energy. A conceptual layout of a storage hydro scheme is provided in Figure 2.2 below.

Storage hydropower configurations vary, from lake/reservoir-controlled High Head RoR style projects, to large dams with built-in generating units where all elevation head is derived from the dam itself, to a combination of both.

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

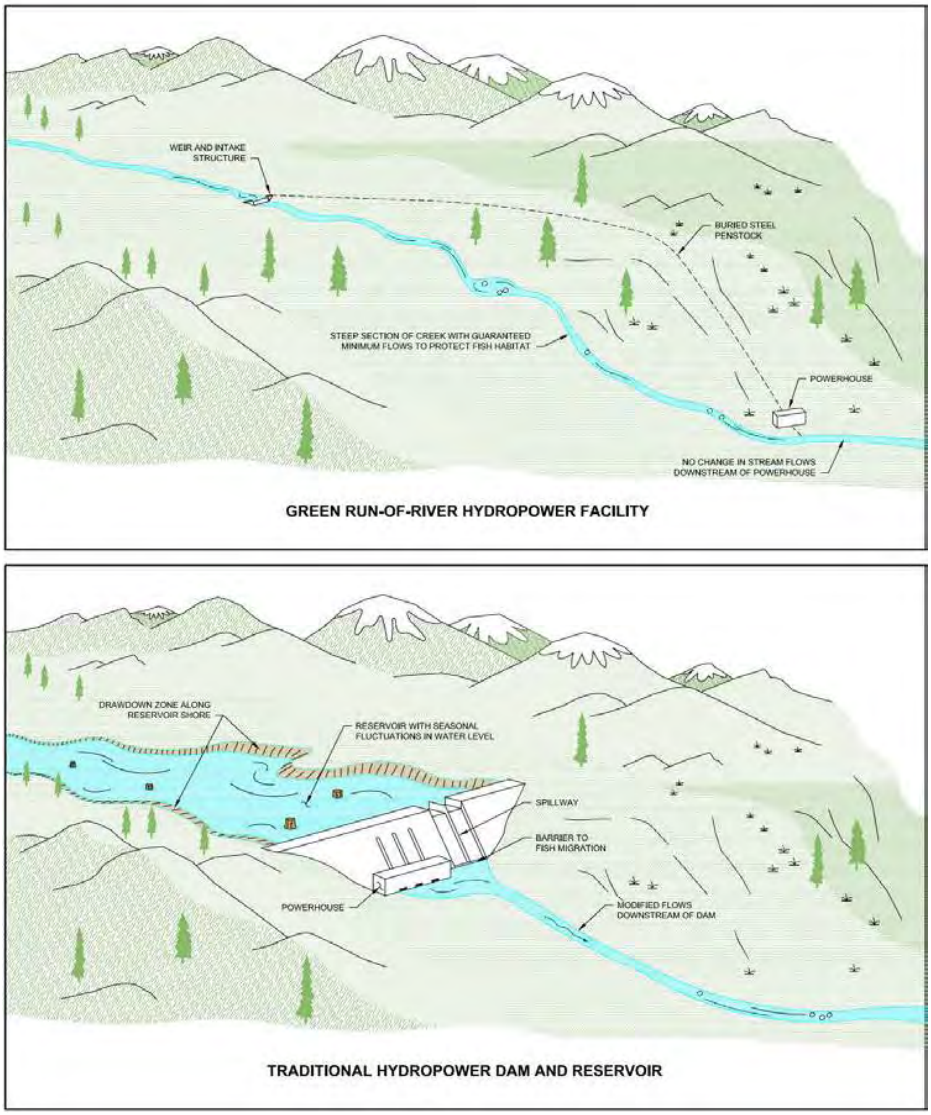


Figure 2.2 Conceptual Hydropower Project Layouts

3.0 SITES AND SCREENING METHODOLOGY

3.1 SITE LIST

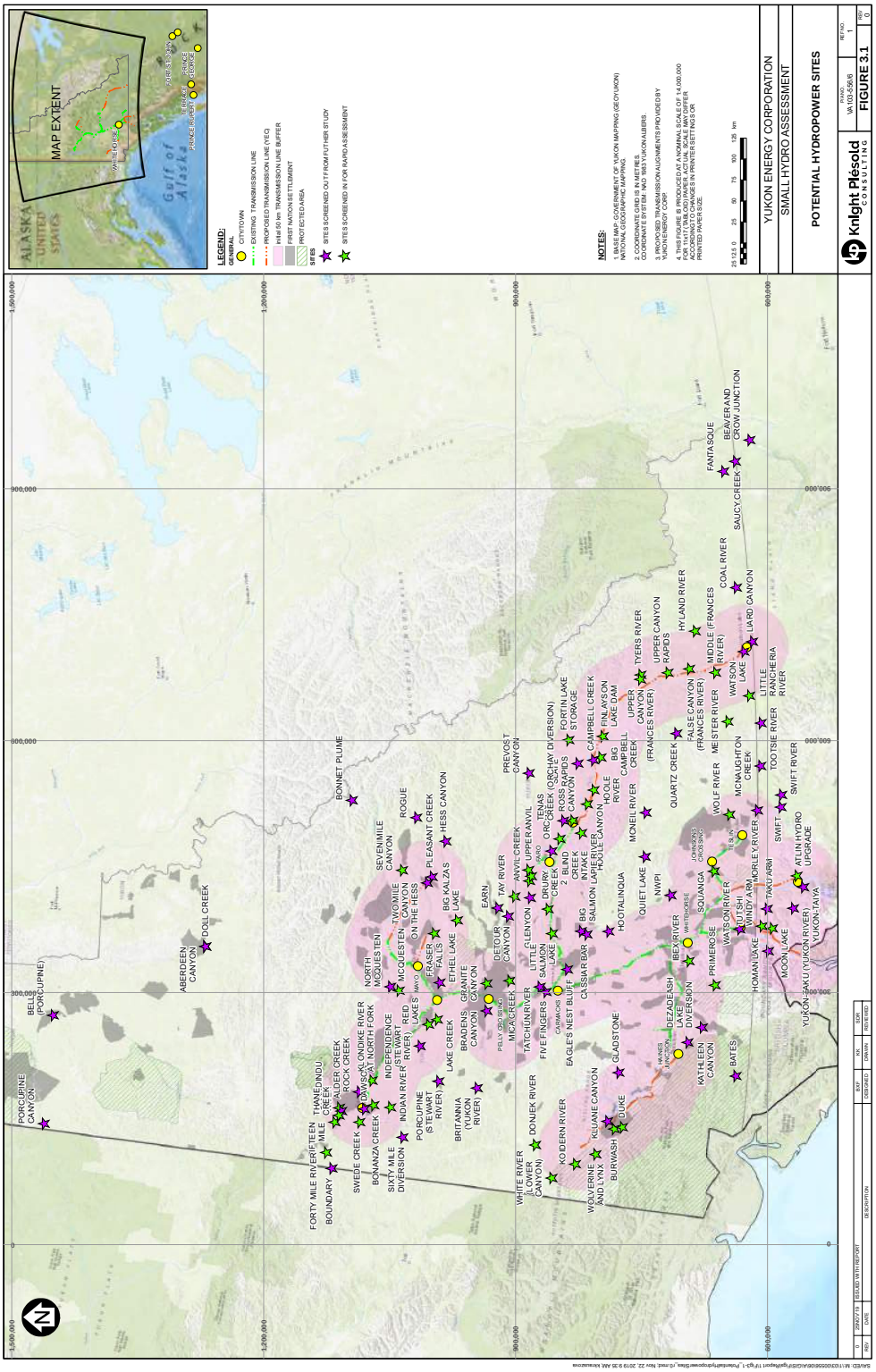
KP compiled a list of 147 sites for preliminary review, comprised of the amalgamated set of sites previously considered in the 2016 KP study and 2015 Midgard study, and a number of additional sites which were identified with perceived hydroelectric development potential in close proximity to transmission lines.

Figure 3.1 shows a map of the Yukon with all sites identified. Table 3.1 provides an alphabetical list of sites.

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

Table 3.1 Site List

Aberdeen Canyon	Fifteen Mile	Lower Canyon on White River	Ross Canyon
Alder Creek	Finlayson	Lynx and Wolverine	Saucy Creek
Anvil Creek	Five Fingers High (150 MW) (Yukon River)	McNaughton Creek	Seven Mile Canyon
Atlin Storage (Yukon River)	Five Fingers High (455 MW) (Yukon River)	McNeil	Site 124
Bates Canyon	Five Fingers Low (75 MW) (Yukon River)	McQuestin	Site 127
Bates Canyon + Dezadeash Diversion	Fortin Lake	Meister River	Sixty Mile River Diversion
Beaver Crow	Forty Mile River	Mica Creek	Slate Rapids (Diversion Scheme)
Bell	Frances River (Lower Canyon)	Middle Canyon (38 MW Version)	Slate Rapids (Powerhouse in Main Dam)
Big Campbell Creek	Frances River (Middle)	Middle Site	Squanga Creek
Big Kalzas Lake	Frances River (Upper Canyon Large)	Moon Lake + Tutshi River Outlet Site A Cluster	Surprise Lake
Big Salmon (Yukon River)	Frances River (Upper Canyon)	Moon Lake + Tutshi Windy Arm Outlet Site B Cluster	Swede Creek
Blind Creek	Frances River (Upper Canyon) - At Rapids or at Francis Lake	Moon Lake A	Swift
Bonanza Creek (Grand Forks)	Fraser Falls (High)	Moon Lake B	Swift River
Bonnet Plume	Fraser Falls (Low)	Moon Lake C	Tatshenshini + Dezadeash / Kusawa Diversion
Boundary	Gladstone Diversion	Morley River	Tatshenshini + Dezadeash Diversion
Bradens Canyon	Glenlyon	North Fork Klondike River	Tay River
Bradens Canyon + Fortin Lake Dam	Granite Canyon (Large)	North McQuesten	Tenas Creek (Orchay Diversion)
Britannia (Yukon River)	Granite Canyon (Small)	NWPI (High)	Thane Creek
Burwash	Hess Canyon	NWPI (Low)	Tootsee River
Campbell Creek	Homan Lake	Ogilvie	Tutshi River Outlet Site A (Lake to Lake)
Cassiar Bar (Yukon River)	Hoole Canyon	Orchay	Tutshi River Outlet Site A (Lake to River)
Chandindu River	Hoole Canyon + Fortin Lake Dam	Pleasant Creek	Tutshi River Outlet Site A (River to Lake)
Coal River	Hoole River	Pleasant Creek with Rogue Diversion	Tutshi River Outlet Site A (River to River)
Dawson	Hootalinqua	Porcupine	Tutshi Windy Arm Outlet Site B (East PH)
Detour Canyon	Hyland River	Porcupine Canyon	Tutshi Windy Arm Outlet Site B (West PH)
Detour Canyon + Fortin Lake Dam	Ibex	Prevost Canyon	Two Mile Canyon
Doll Creek	Independence	Primrose Diversion Scheme (To Takhini Lake)	Tyers River
Donjek to White River Diversion	Indian River	Primrose Lake to Takhini Lake Diversion	Upper & Lower Primrose (2008 Layout)
Drury Creek	Kathleen Canyon	Quartz Creek	Upper Canyon on White River
Duke	Kluane Canyon	Quiet Lake Diversion	Watson Lake
Eagle's Nest Bluff (Yukon River) + Rink Rapids (1 PH)	Koidern	Quiet Lake Diversion + Rose River Diversion	Watson River
Eagle's Nest Bluff (Yukon River) + Rink Rapids (2 PH)	Lake Creek Diversion	Rancheria	Wind
Eagle's Nest Bluff (Alone) (Yukon River)	Lapie	Reid Lakes and Lake Creek	Wolf River
Earn	Liard Canyon	Rock Creek	Wolverine (Yukon River)
Ethel Lake	Little Rancheria River	Rogue	Yukon-Taiya
False Canyon (Frances River)	Little Salmon Dam	Rose Creek	Yukon-Taku (Yukon River)
Fantasque	Little Salmon Diversion	Rose Lake to Kusawa Lake Diversion	


MAP EXTENT
LEGEND:
GENERAL
CITY/TOWN
EXISTING TRANSMISSION LINE
PROPOSED TRANSMISSION LINE (YEC)
FIRST NATION SETTLEMENT
PROTECTED AREA
SITES
SITES SCREENED OUT FROM FURTHER STUDY
SITES SCREENED IN FOR RAPID ASSESSMENT
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON MAPPING (GEOYUKON) NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 YUKON ALBERS.
3. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
4. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:4,000,000 FOR 11"X17" PAPER SIZE. THE SCALE WILL BE SMALLER ACCORDINGLY TO CONFORM TO THE PRINTED PAPER SIZE.
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
POTENTIAL HYDROPOWER SITES
Knight Piésold CONSULTING
FIGURE 3.1

3.2 SCREENING METHODOLOGY

The screening assessment involved several steps to identify, evaluate, and focus in on the preferred hydropower development sites. This process was iterative and included YEC reviews and adjustments to the screening logic throughout the study period. The process was comparable to that used in the 2016 KP study but involved some modifications to the general approach to handle the larger number of sites, modified installed capacity range (between 10 MW and 30 MW), and modified transmission line length restrictions (extended to 50 km).

The process was developed to eliminate sites that are indeterminate, fundamentally flawed, and comparatively expensive or technically unviable, with the overriding objective of providing a focus for future studies on the best development options.

The screening process is described in terms of four main stages:

- Screen 1: Coarse Screening
  - KP applied a coarse screen with four parameters to quickly eliminate many of the less attractive sites which did not warrant an in-depth review. Section 4 describes the coarse screening process.
- Screen 2: Quantitative Assessment
  - KP evaluated a number of quantitative metrics for those sites passing Screen 1 in order to further reduce the site list. Section 5 describes the Screen 2 screening process.
- Screen 3: Final Screening Parameters
  - Those sites passing Screen 2 were presented to YEC for review and feedback, and some final screening criteria were requested by YEC. Section 6 describes the Screen 3 process.
- Assessment of Preferred Options (Top 5 Sites)
  - Screen 3 reduced the site list to the final 5 preferred sites warranting a more detailed assessment. Section 7 describes the final 5 sites.

3.3 DATA COMPILATION

Appendix A summarizes all the previously listed sites and project alternatives in relation to a select number of available reports in which these project sites have been mentioned.

A review of YEC data and a search of publicly available mapping data through the Geomatics Yukon web portal was performed (http://www.geomaticsyukon.ca) to confirm that the data used in the study was as current and comprehensive as possible. In comparison to the 2016 KP study:

- No additional topographical information was available
- Transmission line information was unchanged
- First Nation Settlement Lands were included in the mapping

4.0 SCREEN 1: COARSE SCREENING

4.1 PROJECT GROUPINGS

Projects were first grouped according to the likely transmission line segment (either existing or proposed) that would be used for interconnection. This regional approach helped to streamline the data compilation and review process. The transmission line groupings are:

- Cluster 1: Aishihik-Whitehorse 138 kV (Existing)
- Cluster 2: Carmacks-Whitehorse 138 kV (Existing)
- Cluster 3: Carmacks-Faro 138 kV (Existing)
- Cluster 4: Stewart Crossing-Carmacks 138 kV (Existing)
- Cluster 5: Dawson City-Stewart Crossing 69 kV (Existing)
- Cluster 6: Stewart Crossing-Mayo 69 KV (Existing)
- Cluster 7: Mayo Expansion (Proposed)
- Cluster 8: Faro-Watson Lake (Proposed)
- Cluster 9: Beaver Creek-Hanes Junction (Proposed)
- Cluster 10: Whitehorse-Carcross-Jake's Corner-Johnson's Crossing-Teslin 34 kV (Existing)
- Cluster 11: Carcross-Skagway (Proposed)
- Cluster 12: Jake's Corner-Atlin (Proposed)

4.2 SCREENING ASSESSMENT

With the project sites grouped as discussed above, a coarse screening assessment was undertaken to eliminate undesirable sites and allow the more rigorous Screens 2 and 3 to focus on fewer sites. The coarse screen was implemented with four criteria that could be determined on a cursory review:

- 10 MW minimum installed capacity: sites that were unlikely to meet a minimum installed capacity threshold of 10 MW were eliminated.
- 50 km maximum transmission line length: sites more than 50 km from existing or proposed transmission lines were eliminated.
- Parks and protected areas: sites located in parks or restricted areas were eliminated, except for the Primrose and Tutshi Windy Arm sites (on request by YEC).
- Yukon River and communities: sites affecting the Yukon River or known to flood communities were eliminated.

Table 4.1 presents the full list of sites, grouped according to likely interconnection transmission line. Sites which were not eliminated by any of the four coarse screening parameters are shaded in green and represent the 56 sites that advanced to Screen 2. Figure 4.1 shows a map of the Yukon with the sites that advanced to Screen 2.

Knight Piésold CONSULTING

TABLE 4.1

YUKON ENERGY CORPORATION
REGIONAL HYDROPOWER ASSESSMENT

COARSE SITE SCREENING (56 of 147)

Print: Nov/Mon/19 09:40:30

Site Name	Capacity Screen	T-Line Screen	Park Screen	Flood & Yukon Screen	Include in Rapid Assessment	Notes:
Cluster 1: Aishihik-Whitehorse 138 kV (1 of 10)						
Bates Canyon	Pass	Fail	Fail	Pass	No	
Bates Canyon + Dezadeash Diversion	Pass	Fail	Fail	Pass	No	
Gladstone Diversion	NA	NA	Pass	Pass	No	Diversion to Aishihik, Could be looked at further
Kathleen Canyon	Fail	Pass	Pass	Pass	No	
Rose Lake to Kusawa Lake Diversion	Pass	Pass	Fail	Pass	No	
Tatshenshini + Dezadeash / Kusawa Diversion	Pass	Pass	Fail	Pass	No	
Tatshenshini + Dezadeash Diversion	Pass	Pass	Fail	Pass	No	
Primrose Diversion Scheme (To Takhini Lake)	Pass	Pass	Pass	Pass	No	
Primrose Lake to Takhini Lake Diversion	Pass	Pass	Pass	Pass	No	
Upper & Lower Primrose (2008 Layout)	Pass	Pass	TBD	Pass	Yes	Protected Area
Cluster 2: Carmacks-Whitehorse 138 kV (1 of 5)						
Hootalinqua	Pass	Pass	Pass	Fail	No	
Ibex	TBD	Pass	Pass	Pass	Yes	
NWPI (High)	Pass	Fail	Pass	Pass	No	
NWPI (Low)	Pass	Fail	Pass	Pass	No	
Swift	NA	Fail	Pass	Pass	No	
Cluster 3: Carmacks-Faro 138 kV (5 of 14)						
Big Salmon (Yukon River)	Pass	Pass	Pass	Fail	No	Yukon River
Cassiar Bar (Yukon River)	Pass	Pass	Pass	Fail	No	Assumed location on Yukon River
Detour Canyon	Pass	Fail	Pass	Pass	No	Large System, A Bit far from TL
Detour Canyon + Fortin Lake Dam	Pass	Fail	Pass	Pass	No	TL at 80
Eagle's Nest Bluff (Yukon River) + Rink Rapids (1 PH)	Pass	Pass	Pass	Fail	No	Yukon River
Eagle's Nest Bluff (Yukon River) + Rink Rapids (2 PH)	Pass	Pass	Pass	Fail	No	Yukon River
Eagle's Nest Bluff (Alone) (Yukon River)	Pass	Pass	Pass	Fail	No	Yukon River
Earn	Fail	Fail	Pass	Pass	No	Lake capacity can increase but a bit far from TL
Little Salmon Diversion	TBD	Pass	Pass	Pass	No	
Anvil Creek	TBD	Pass	Pass	Pass	Yes	Change location of diversion.
Drury Creek	TBD	Pass	Pass	Pass	Yes	Capacity could be increased to meet the requirement.
Glenlyon	TBD	Pass	Pass	Pass	Yes	
Little Salmon Dam	TBD	Pass	Pass	Pass	Yes	Impact to Camping, Fish Presence
Tay River	TBD	Pass	Pass	Pass	Yes	Actual TL > 50 km
Cluster 4: Stewart Crossing - Carmacks 138 kV (4 of 13)						
Bradens Canyon	Pass	Pass	Pass	Fail	No	
Bradens Canyon + Fortin Lake Dam	Pass	Pass	Pass	Fail	No	
Britannia (Yukon River)	Pass	Pass	Pass	Fail	No	
Five Fingers High (150 MW) (Yukon River)	Pass	Pass	Pass	Fail	No	
Five Fingers High (455 MW) (Yukon River)	Pass	Pass	Pass	Fail	No	
Five Fingers Low (75 MW) (Yukon River)	Pass	Pass	Pass	Fail	No	
Porcupine	Pass	Pass	Pass	Fail	No	
Wolverine (Yukon River)	Pass	Pass	Pass	Fail	No	
Granite Canyon (Large)	Fail	Pass	Pass	Pass	No	
Granite Canyon (Small)	Pass	Pass	Pass	Pass	Yes	
Lake Creek Diversion	Pass	Pass	Pass	Pass	Yes	
Reid Lakes and Lake Creek	TBD	Pass	Pass	Pass	Yes	
Mica Creek	Pass	Pass	Pass	Pass	Yes	
Cluster 5: Dawson City - Stewart Crossing 69 kV (10 of 16)						
Boundary	Pass	Fail	Pass	Fail	No	
Dawson	Pass	Pass	Pass	Fail	No	
Independence	Pass	Pass	Pass	Fail	No	
Ogilvie	Pass	Fail	Pass	Fail	No	
Rock Creek	Fail	Pass	Pass	Pass	No	
Sixty Mile River Diversion	Pass	Fail	Pass	Pass	No	
Alder Creek	TBD	Pass	Pass	Pass	Yes	ROR TBD
Bonanza Creek (Grand Forks)	TBD	Pass	Pass	Pass	Yes	ROR TBD
Chandindu River	TBD	Pass	Pass	Pass	Yes	Try ROR
Fifteen Mile	TBD	Pass	Pass	Pass	Yes	ROR TBD
Forty Mile River	Pass	Pass	Pass	Pass	Yes	
Indian River	TBD	Pass	Pass	Pass	Yes	
McQuestin	TBD	Pass	Pass	Pass	Yes	Large System, Cascade
North Fork Klondike River	Pass	Pass	Pass	Pass	Yes	
Swede Creek	TBD	Pass	Pass	Pass	Yes	ROR TBD
Thane Creek	TBD	Pass	Pass	Pass	Yes	ROR TBD
Cluster 6: Stewart Crossing - Mayo 69 kV (0 of 2)						
Ethel Lake	Fail	Pass	Pass	Pass	No	
North McQuesten	Fail	Pass	Pass	Pass	No	
Cluster 7: Proposed Mayo Transmission Expansions (3 of 9)						
Fraser Falls (Low)	Pass	Pass	Fail	Pass	No	Only one version to be investigated
Hess Canyon	Pass	Fail	Pass	Pass	No	
Pleasant Creek	Fail	Pass	Pass	Pass	No	
Pleasant Creek with Rogue Diversion	Pass	Fail	Pass	Pass	No	
Rogue	Pass	Fail	Pass	Pass	No	Far and Isolated
Two Mile Canyon	Pass	Fail	Pass	Pass	No	
Big Kalzas Lake	Pass	Pass	Pass	Pass	Yes	
Fraser Falls (High)	Pass	Pass	TBD	Pass	Yes	Need to move out of Horshoe Slough Habitat Protection Area
Seven Mile Canyon	Pass	Pass	Pass	Pass	Yes	
Cluster 8: Proposed Faro to Watson Lake (21 of 31)						
Frances River (Upper Canyon Large)	Fail	Pass	Pass	Pass	No	
Frances River (Upper Canyon)	TBD	Pass	Pass	Pass	No	
Middle Canyon (38 MW Version)	TBD	Pass	Pass	Pass	No	No Info
Prevost Canyon	Pass	Fail	Pass	Pass	No	
Rancheria	TBD	Fail	Pass	Pass	No	
Rose Creek	TBD	Pass	Pass	Pass	No	
Slate Rapids (Diversion Scheme)	TBD	Pass	Pass	Pass	No	
Tenas Creek (Orchay Diversion)	TBD	Pass	Pass	Pass	No	
Tootsee River	Fail	Fail	Pass	Pass	No	100 km TL
Watson Lake	Fail	Pass	Pass	Pass	No	

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TABLE 4.1

YUKON ENERGY CORPORATION
REGIONAL HYDROPOWER ASSESSMENT

COARSE SITE SCREENING (56 of 147)

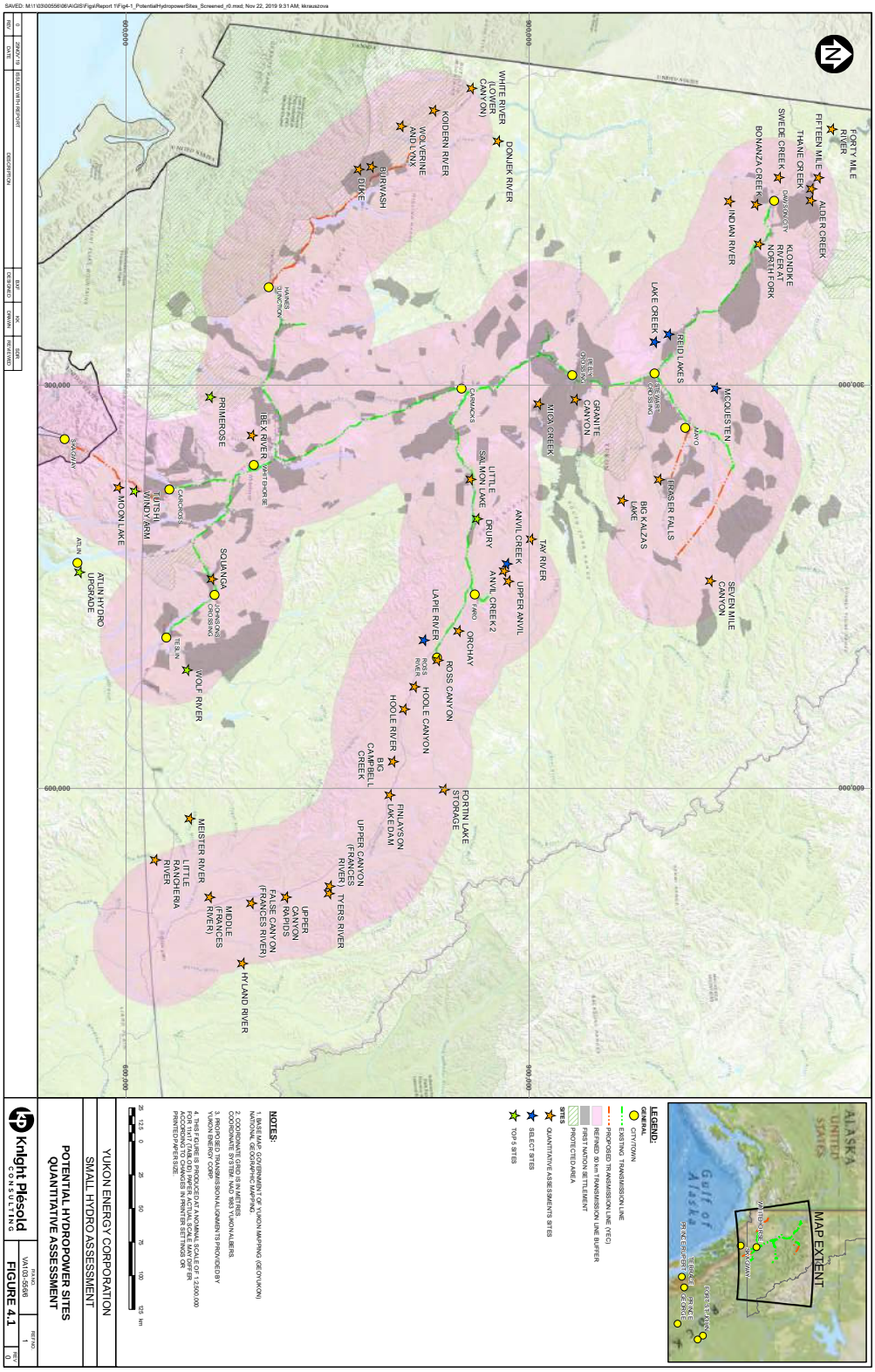
Print: Nov/Mon/19 09:40:30

Site Name	Capacity Screen	T-Line Screen	Park Screen	Flood & Yukon Screen	Include in Rapid Assessment	Notes:
Big Campbell Creek	Pass	Pass	Pass	Pass	Yes	
Blind Creek	TBD	Pass	Pass	Pass	Yes	
Campbell Creek	TBD	Pass	Pass	Pass	Yes	Storage Not Possible, ROR, Mixed with Big Campbell
False Canyon (Frances River)	Pass	Pass	Pass	Pass	Yes	Frances River System
Finlayson	Pass	Pass	Pass	Pass	Yes	
Fortin Lake	TBD	TBD	Pass	Pass	Yes	
Frances River (Lower Canyon)	Pass	Pass	Pass	Pass	Yes	
Frances River (Middle)	Pass	Pass	Pass	Pass	Yes	
Frances River (Upper Canyon)	Pass	Pass	Pass	Pass	Yes	At Rapids or at Francis Lake
Hoole Canyon	Pass	Pass	Pass	Pass	Yes	
Hoole Canyon + Fortin Lake Dam	Pass	Pass	Pass	Pass	Yes	A bit involved, TBD
Hoole River	Pass	Pass	Pass	Pass	Yes	
Hyland River	TBD	TBD	Pass	Pass	Yes	
Lapie	Pass	Pass	Pass	Pass	Yes	Push intake uphill.
Liard Canyon	Pass	Pass	Pass	Pass	Yes	Deemed Urban Flooding - See Note 1.
Little Rancheria River	Pass	Pass	Pass	Pass	Yes	50 km from Watson, 10 MW ROR
Meister River	TBD	Fail	Pass	Pass	Yes	Site of potential but > 50 km TL
Orchay	TBD	Pass	Pass	Pass	Yes	
Ross Canyon	Pass	Pass	Pass	Pass	Yes	
Slate Rapids (Powerhouse in Main Dam)	Pass	Pass	Pass	Pass	Yes	
Tyers River	TBD	Pass	Pass	Pass	Yes	
Cluster 9: Proposed Beaver Creek to Hanes Junction (6 of 8)						
Kluane Canyon	TBD	Pass	Fail	Pass	No	
Upper Canyon on White River	Pass	Pass	Fail	Pass	No	
Burwash	TBD	Pass	TBD	Pass	Yes	
Donjek to White River Diversion	Pass	Pass	Pass	Pass	Yes	
Duke	TBD	Pass	TBD	Pass	Yes	
Koidern	TBD	Pass	TBD	Pass	Yes	
Lower Canyon on White River	Pass	Pass	Pass	Pass	Yes	
Lynx and Wolverine	TBD	Pass	TBD	Pass	Yes	
Cluster 10: Whitehorse-Carcross-Jake's Corner-Johnson's Crossing-Teslin 34kV (2 of 5)						
Morley River	Fail	Pass	Pass	Pass	No	
Swift River	TBD	Fail	Pass	Pass	No	
Watson River	Fail	Pass	Pass	Pass	No	
Squanga Creek	Pass	Pass	Pass	Pass	Yes	Need to Increase Project Head, longer structure (80-100m)
Wolf River	Pass	Pass	Pass	Pass	Yes	
Cluster 11: Proposed Extension from Carcross to Skagway (2 of 13)						
Homan Lake	Fail	Pass	Pass	Pass	No	Increase Project Head, longer structure (80-100m)
Moon Lake A	Fail	Pass	Pass	Pass	No	
Moon Lake C	Fail	Pass	Pass	Pass	No	
Moon Lake B	Fail	Pass	Pass	Pass	No	
Tutshi River Outlet Site A (Lake to Lake)	Fail	Pass	Pass	Pass	No	
Tutshi River Outlet Site A (Lake to River)	Fail	Pass	Pass	Pass	No	
Tutshi River Outlet Site A (River to Lake)	Fail	Pass	Pass	Pass	No	
Tutshi River Outlet Site A (River to River)	Fail	Pass	Pass	Pass	No	
Tutshi Windy Arm Outlet Site B (West PH)	Fail	Pass	Pass	Pass	No	
Yukon-Taiya	Fail	Pass	Pass	Fail	No	
Moon Lake + Tutshi River Outlet Site A Cluster	Pass	Pass	Pass	Pass	Yes	
Moon Lake + Tutshi Windy Arm Outlet Site B Cluster	Pass	Pass	Pass	Pass	Yes	
Tutshi Windy Arm Outlet Site B (East PH)	Pass	Pass	Pass	Pass	No	Will need to increase installed Capacity
Cluster 12: Proposed Extension from Jake's Corner to Atlin (1 of 3)						
Yukon-Taku (Yukon River)	Pass	Pass	Pass	Fail	No	
Surprise Lake	Pass	Pass	Pass	Pass	Yes	
Atlin Storage (Yukon River)	Pass	Pass	Pass	Fail	No	
Projects too far from Transmission (18)						
Aberdeen Canyon		Fail			No	
Beaver Crow		Fail			No	
Bell		Fail			No	
Bonnet Plume		Fail			No	
Coal River		Fail			No	
Doll Creek		Fail			No	
Fantasque		Fail			No	
McNaughton Creek		Fail			No	
McNeil		Fail			No	
Middle Site		Fail			No	
Porcupine Canyon		Fail			No	
Quartz Creek		Fail			No	
Quiet Lake Diversion		Fail			No	
Quiet Lake Diversion + Rose River Diversion		Fail			No	
Saucy Creek		Fail			No	
Site 124		Fail			No	
Site 127		Fail			No	
Wind		Fail			No	

M:\1\03\00556\06\A\Report\1 - Yukon Hydropower Potential Assessment (10-30 MW)\Rev 0\Tables and Figures\[Table 4.1.xlsx]Coarse Screen

NOTES:
1. MAY WARRANT A CLOSER LOOK DUE TO THE PRESENCE OF RAPIDS AND TOPOGRAPHIC INACCURACIES AT THE BOUNDARY BETWEEN THE YUKON AND BC.
2. SITES HIGHLIGHTED GREEN HAVE PASSED THE INITIAL COARSE SITE SCREENING.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
0	25NOV'19	ISSUED FOR REPORT VA103-556/6-1	BXF	SDR


FORTY MILE RIVER
FIFTEEN MILE
THANE CREEK
ALDER CREEK
SWEDE CREEK
KLONDIKE RIVER AT NORTH FORK
BONANZA CREEK
DAWSON CITY
INDIAN RIVER
LAKE CREEK
REID LAKES
MCQUESTEN
MAYO
ERASER FALLS
BIG KALZAS LAKE
SEVEN MILE CANYON
GRANITE CANYON
MICA CREEK
CARMACKS
LITTLE SALMON LAKE
DRURY
ANVIL CREEK
ANVIL CREEK 2
TAY RIVER
UPPER ANVIL
LAPIE RIVER
ORCHAY
ROSS CANYON
HOOLE CANYON
HOOLE RIVER
BIG CAMPBELL CREEK
FINLAYSON LAKE DAM
FORTIN LAKE STORAGE
UPPER CANYON (FRANCES RIVER)
TYERS RIVER
MEISTER RIVER
LITTLE RANCHERIA RIVER
MIDDLE (FRANCES RIVER)
UPPER CANYON RAPIDS
RAPIDS CANYON (FRANCES RIVER)
HYLAND RIVER
WOLF RIVER
TES-SAN
SOUTH CANOL CROSSING
SOUTH CANOL
ATLIN
ATLIN HYDRO
LAKE GRADE
MOON LAKE
WINDY ARM
TUTSHI
CARCROSS
SKAGWAY
PRIMEROSE
BEX RIVER
WHITEHORSE
WHITE RIVER (UPPER CANYON)
DONJEK RIVER
KOIDERN RIVER
WOLVERINE AND L'NUX
SWIFTWASH
DUKE
HANSES JUNCTION
ALASKA
UNITED STATES
Gulf of Alaska
MAP EXTENT
WHITEHORSE
SKAGWAY
PRINCE RUPERT
TERRACE
PRINCE GEORGE
FORT ST. JOHN
LEGEND:
GENERAL
CITY/TOWN
EXISTING TRANSMISSION LINE
PROPOSED 75 kV TRANSMISSION LINE (YEC)
REFINED 30 km TRANSMISSION LINE BUFFER
FIRST NATION SETTLEMENT
PROTECTED AREA
SITES
QUANTITATIVE ASSESSMENTS SITES
SELECT SITES
TOP 5 SITES
NOTES:
1. BASEMAP BY GOVERNMENT OF YUKON MAPPING (GEOYUKON) NATIONAL GEOGRAPHIC MAPPING
2. COORDINATE GRID IS IN METRES
COORDINATE SYSTEM: NAD 1983 YUKON ALBERS
3. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
4. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:2,500,000 AT TABLOID (11" x 17") PAPER SIZE. ACTUAL SCALE MAY DIFFER ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
0 12.5 25 50 75 100 125 km
Knight Piésold CONSULTING
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
POTENTIAL HYDROPOWER SITES
QUANTITATIVE ASSESSMENT
PROJECT NO. VA10-5686
REF. NO. 1
FIGURE 4.1
REV. 0

5.0 SCREEN 2: QUANTITATIVE ASSESSMENT

5.1 OVERVIEW

Screen 1 reduced the site list from 147 to 56 sites. Those sites passing Screen 1 were subjected to the Screen 2 process, referred to as the 'Quantitative Assessment'. Screen 2 involved a number of analyses:

- Review of existing information and development of a high-level conceptualization of the projects, including intake and powerhouse location, project head, and potential for reservoir storage.
- Regional hydrological review to develop estimates for Mean Annual Discharge (MAD) and the seasonal distribution of flows.
- Estimation of installed capacity and energy generation profiles.
- Indicative cost estimating.
- Levelized financial comparison, including Levelized Cost of Capacity (LCOC) and Levelized Cost of Energy (LCOE).

The subsequent sections of this report detail the components of the Screen 2 process. A summary of the results can be found in Table 5.2, and details of the review and concept development are presented in Appendix B.

5.2 HYDROLOGY AND DESIGN FLOW ESTIMATES

5.2.1 PREVIOUS ESTIMATES

During the 2016 KP study, flow records were compiled and reviewed from a total of 46 Water Survey of Canada (WSC) gauges with catchment areas between 10 km^2 and 7,000 km^2. This analysis was undertaken to develop an understanding of regional trends in measured runoff for catchments of varying sizes and regions. Monthly average data was used to develop estimates of Mean Annual Discharge (MAD) and Mean Annual Unit Discharge (MAUD) at each stream gauge location. The data were then used to produce generic monthly hydrographs which were scaled and applied to each project site.

1. GAUGES IN YUKON.

Figure 5.1 illustrates the "generic" Yukon hydrographs that were developed. Figure 5.2 illustrates the location of Yukon stream gauges along with indicative unit runoffs.

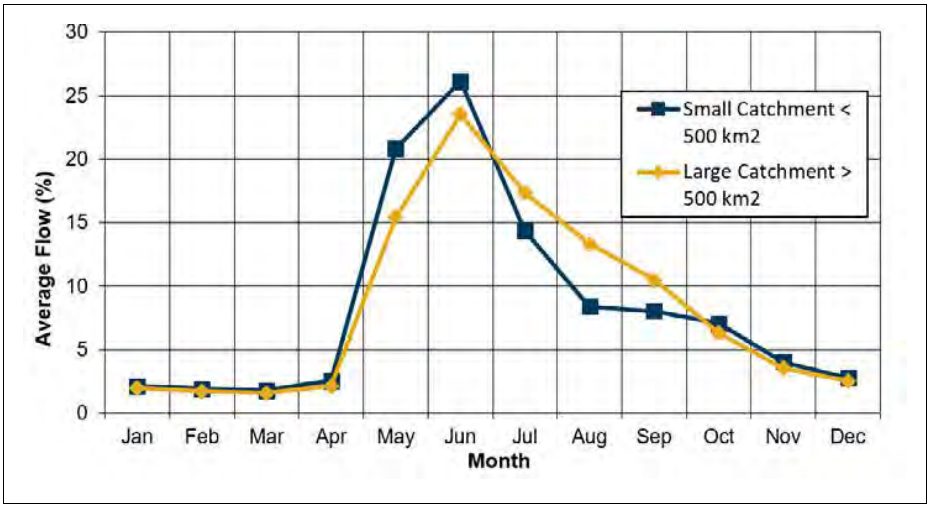
Where no previous hydrology information could be obtained, KP developed estimates based on the MAUD values from the WSC gauges in the region and scaled according to catchment area. These gauges are dispersed across most of the Yukon and provide a reasonable means of assessing hydrologic patterns throughout the region. Some of the basic trends evident in the data are as follows:

- MAUD appears to decrease in a south-westerly direction along the border between the Yukon and the Northwest Territories, with lower unit discharge values evident in the dry, lower relief interior zones versus the mountainous terrain along the eastern provincial border.
- In the south-western corner of the Yukon, MAUD appears to be relatively high due to the onshore movement of moist maritime air from the Pacific Coast. The effects of this moisture influx extend slightly beyond the Coastal Mountain Range, and then drops off markedly due to a 'precipitation shadow' effect that results in a progressive reduction in MAUD moving east.

MAUD values were selected for the project sites based on proximity and similarity of catchment size to the WSC stations. Commonly, there are two to three local gauge stations that provide a basis for estimating unit discharge. Where applicable, consideration was also given to the MAUD values reported for various project sites.

Additional regional considerations when determining a site's MAUD included:

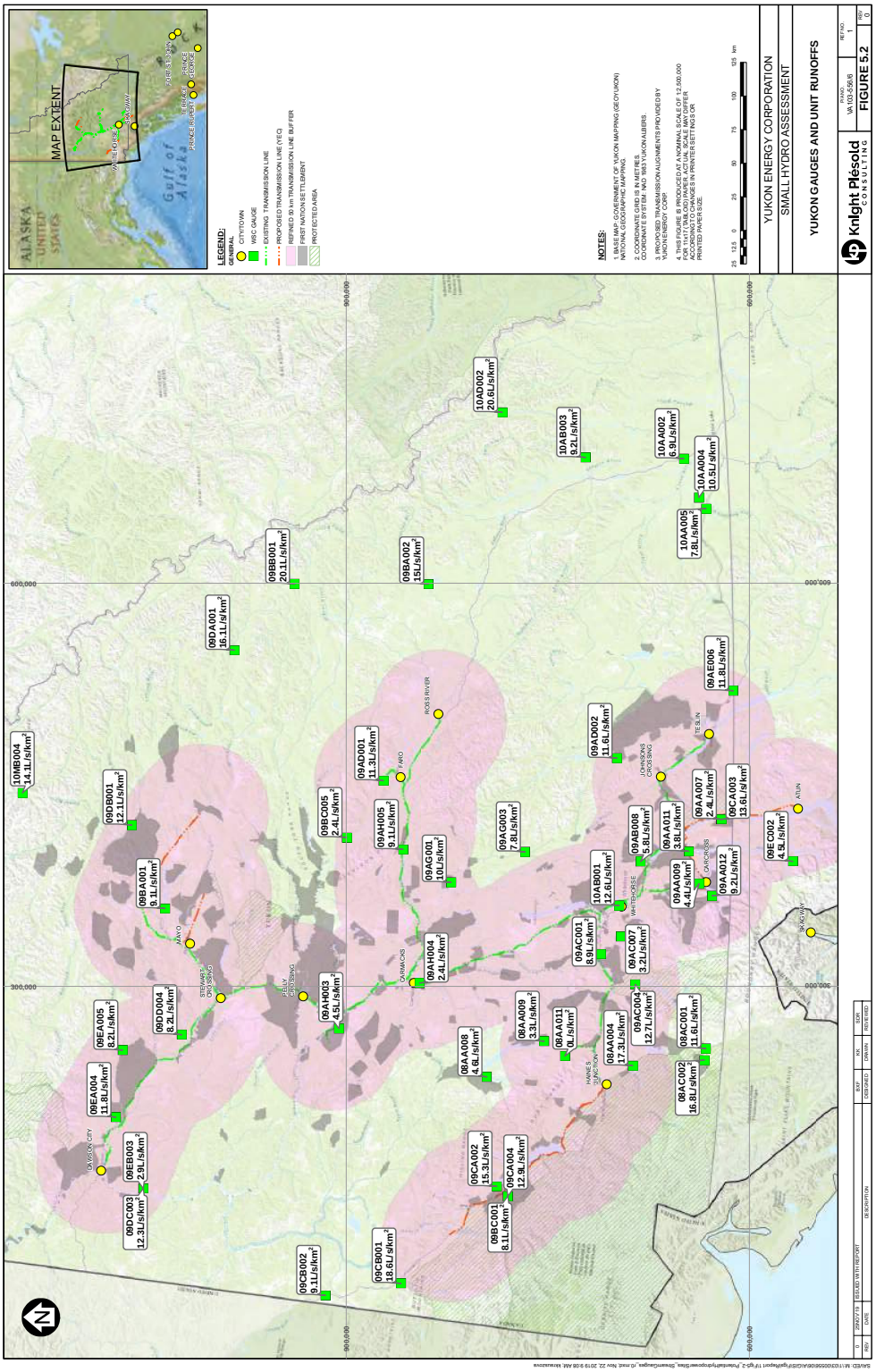
- Glaciers in a watershed, which generally increase MAUD due to melt during the warm summer months
- Lakes in a watershed, which generally decrease MAUD due to greater evaporation
- The local relief, with higher elevation watersheds generally having higher precipitation and correspondingly higher MAUD



NOTES:

2. BASED ON AN EVALUATION OF MONTHLY AVERAGE FLOWS AT 46 WATER SURVEY OF CANADA (WSC) GAUGES IN YUKON.

Figure 5.1 Typical Yukon Hydrograph


MAP EXTENT
ALASKA
UNITED STATES
Gulf of Alaska
WHITEHORSE
DAWSON
HAINES JUNCTION
SKAGWAY
CARCROSS
CARMACKS
PELLY CROSSING
STEWART CROSSING
MAYO
KENO
TAGISH
ROSS RIVER
FARO
JOHNSONS CROSSING
TESLIN
ATLIN
LEGEND:
GENERAL
CITY/TOWN
WSC GAUGE
EXISTING TRANSMISSION LINE
PROPOSED TRANSMISSION LINE YEC
REFINED 50 km TRANSMISSION LINE BUFFER
FIRST NATION SETTLEMENT
PROTECTED AREA
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON MAPPING (GEOYUKON) NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. PROJECTION: NAD83 YUKON ALBERS.
3. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
4. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:2,500,000 FOR 11x17 PAPER SIZE. IT WILL BE PRINTED AT A DIFFERENT SCALE ACCORDING TO CHANGES IN PAPER SIZE BUT MUST BE PRINTED PAPER SIZE.
25 12.5 0 25 50 75 100 125 Km
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
YUKON GAUGES AND UNIT RUNOFFS
Knight Piésold CONSULTING
FIGURE 5.2
10MB004 14.1L/s/km²
09DB001 12.1L/s/km²
09BA001 9.1L/s/km²
09DD004 8.2L/s/km²
09EA005 8.2L/s/km²
09EA004 11.8L/s/km²
09EB003 2.9L/s/km²
09DC003 12.3L/s/km²
09CB002 9.1L/s/km²
09CB001 18.6L/s/km²
09BC001 8.1L/s/km²
09CA002 15.3L/s/km²
09CA004 12.9L/s/km²
09AA008 4.9L/s/km²
09AA009 3.3L/s/km²
09AA011 0L/s/km²
09AA004 17.3L/s/km²
09AC004 12.7L/s/km²
09AC001 11.6L/s/km²
08AC002 16.8L/s/km²
09AH003 4.5L/s/km²
09AH004 2.4L/s/km²
09AH005 9.1L/s/km²
09AD001 11.3L/s/km²
09BC005 2.4L/s/km²
09AG001 10L/s/km²
09AG003 7.8L/s/km²
09AC001 8.9L/s/km²
10AB001 12.8L/s/km²
09AB008 5.8L/s/km²
09AA011 3.8L/s/km²
09AA009 4.4L/s/km²
09AA012 9.2L/s/km²
09AC007 3.2L/s/km²
09AD002 11.6L/s/km²
09AE006 11.8L/s/km²
09AA007 2.4L/s/km²
09CA003 13.6L/s/km²
09EC002 4.5L/s/km²
09BA001 16.1L/s/km²
09BB001 20.1L/s/km²
09BA002 15L/s/km²
10AD002 20.6L/s/km²
10AB003 9.2L/s/km²
10AA002 6.9L/s/km²
10AA004 10.5L/s/km²
10AA005 7.8L/s/km²

5.2.2 RUN OF RIVER PROJECTS DESIGN FLOW FACTORS AND DESIGN FLOWS

RoR hydroelectric plants utilize the available flow in a river at any given time, with unusable headpond/reservoir storage, and electric output is a function of short-term yield (often evaluated on a daily basis). The optimal installed capacity depends on numerous factors, including constructability, environmental requirements, and the need for and ability to sell seasonal power.

In the previous KP evaluation most of the run-of-river projects evaluated were of the “high-head type”. Based on experience evaluating these types of projects KP made the assumption that the optimal design flow for a run of river plant tends to be in the order of 1.5 to 2 times the MAD value. In contrast KP targeted a design factor 0.5 times MAD for “low-head” storage type projects on large river systems.

In the current evaluation the study aims to target a specific range of capacity and needed the ability to evaluate run-of-river projects located on large river systems. To accomplish this, curves were developed based on a set of assumptions that showed the exchange of capacity factor as a function of the design flow factor. The design flow for the plant is equal to the design factor times the average annual flow. To develop these curves, daily stream flow data for various streams were downloaded from the WSC, with years having incomplete daily records removed. An energy model was then built for a single unit meter of head based on the following assumptions:

- In-stream Flow Requirements (IFR) equal to 5 percent of MAD
- A minimum turbinable flow of 5% of the design flow
- 10 percent head losses through intake and conveyance to the turbine, at maximum design flow, and an exponential decrease in head loss with decreasing flow
- Average efficiency of 90 percent from turbine to the point of sale, to account for turbine – generator losses, transformer losses, transmission losses, station usage, and outages

For a given design flow factor and project head, the resulting design flow, power and energy can be calculated (see Figure 5.3).

To further assess the winter capacity a similar set of curves was developed, combining the energy generated in the months of December, January, February, and March (see Figure 5.4).

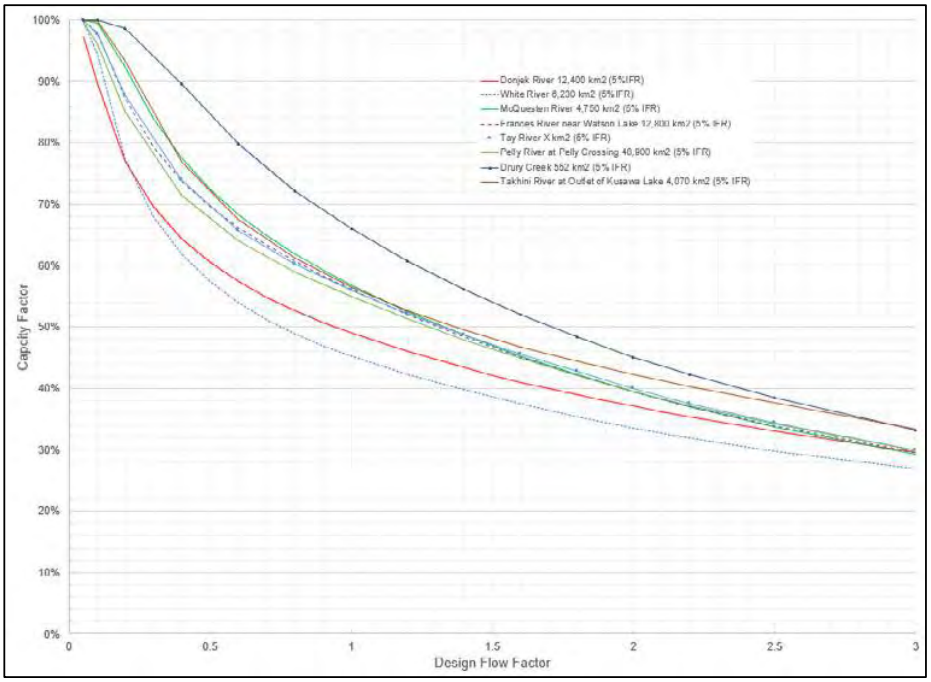


Figure 5.3 **Run of River Based Capacity Factors resulting from Design Flow Factors**

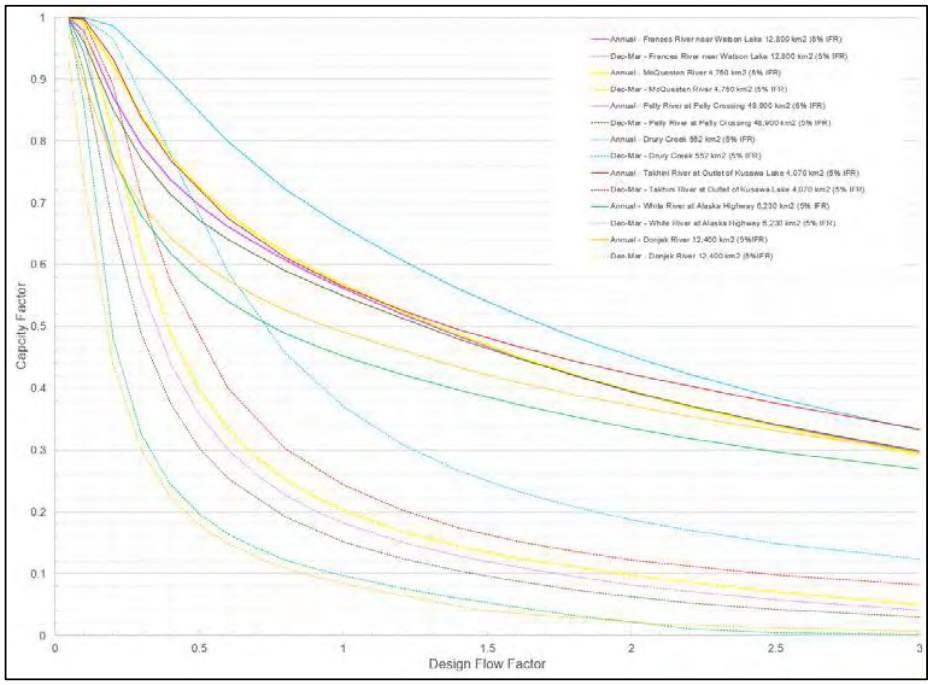


Figure 5.4 **Run of River Based Winter Capacity Factors resulting from Design Flow Factors**

5.2.3 STORAGE PROJECTS DESIGN FLOW FACTORS AND DESIGN FLOWS

Estimating the design flow factor to be applied in energy modeling for a storage hydroelectric project is inherently more complex than for run-of-river analyses. These complexities lie in the regulation of flows due to the ability to store some volume of water for generation. Individual daily storage regulation models were developed for storage sites making the following assumptions:

- Daily inflows were typically prorated from the nearest stream to the proper unit runoff and drainage area (See Table 5.1).
- Depth capacity curves were assumed to be linear between available topographic contours. This was deemed to be acceptable as, in most instances, the reservoir elevation variations were relatively small.
- Release rules assumed a full day release if water was available in the reservoir during the months of December, January, February or March or if the reservoir volume exceeded 90 percent of its capacity.

All other assumptions were identical to the run-of-river model.

Table 5.1 WSC Gauges for Storage Models

Sites	Surrogate Gauge	Complete Record Period
Drury, Big Kalzas, Finlayson, Glenlyon, Reid Lake (Lake Creek)	Drury Creek (09AH005)	1995-2009 and 2016-2017
Fortin	Pelly River at Pelly Crossing (09BC001)	1960-2017
Wolf River	Nisutlin River (09AD001)	1979-1995
Tushi Windy Arm, Primrose	Takhini River (09AC004)	1954,1959-60, 1965-67, 1969-86

5.2.4 DEPENDABLE CAPACITY

YEC requested that all projects shortlisted during this screening process be assessed for Dependable Capacity. Dependable Capacity, expressed in MW, is the maximum generation output that a resource can reliably provide in a specific timeframe, typically during the period of greatest demand. YEC defines dependable capacity as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months (November to February) based on the inflows in the five driest inflow years in history. Dependable Capacity was only evaluated for the five preferred sites which are discussed in Section 7.

5.3 INDICATIVE COSTS

Basic indicative cost estimates in $2019 were developed for each project using KP's in-house experience and cost estimating database for projects with comparable characteristics. Where the level of detail in the existing design was insufficient to permit an accurate assessment of site-specific conditions, facility layouts and sizes, costs were scaled according to head, flow, installed capacity, and other key project costing metrics. Cost estimates included the following major components:

- Mobilization, Demobilization, Insurance, Bonds, Overheads, and Contractor's Profits
- Access and Site Preparation
- Dam(s) and Reservoir(s) (if any)

- Intake, Forebay, and Headrace
- Water Conveyance System
- Powerhouse and Tailrace and Ancillary Services
- Power Generation Equipment (Water to Wire)
- Switchyard, Transmission, and Interconnection
- Engineering, Procurement, and Construction Management (EPCM): 8 %
- Contingency: 30 %

5.4 COST TO BENEFIT ANALYSIS

The fair evaluation of alternative hydropower development options requires an assessment of project costs and benefits. The cost to benefit assessment was based on the comparative values for the following financial metrics:

- Unit Cost of Capacity (UCC)
- Unit Cost of Energy (UCE)
- Levelized Cost of Capacity (LCOC)
- Levelized Cost of Energy (LCOE)
- Levelized Cost of Winter Energy (LCOWE)

5.4.1 UNIT COST OF CAPACITY

Unit Cost of Capacity = Capital Cost ($) / Installed Capacity (MW)

This unit of measurement can be useful for gauging project costs in relation to other proposed or existing power projects in a simplistic manner. For instance, YEC's Mayo B Hydroelectric Project was constructed for a cost of roughly $120 million and added 10 MW of power to the Yukon's energy system (YEC, 2016), equating to a UCC of $12 million/MW. The LCOC of the better options in this study are in this order of magnitude, providing some confidence in the underlying quantities and unit rates that have been assumed.

While UCC does have its usefulness, it is not a good measure of the overall project value since capacity is not directly correlated to energy production and revenues.

5.4.2 UNIT COST OF ENERGY

Unit Cost of Energy = Capital Cost ($) / Average Annual Energy Production (GWh/yr).

UCE is a simple and useful financial metric for the determination of a project's value and relative ranking of sites with different installed capacities and hydrology characteristics. Provided that all energy can be sold, UCE is directly correlated with revenue.

UCE in the order of $2.5 million/GWh/yr or less are considered to have development potential.

5.4.3 LEVELIZED COST OF CAPACITY

The loaded capital cost, or net present cost at Commercial Operation Date (COD) is accounts interest accrued during construction, using the following formula:

$$LCOC = \frac{levelized\ cost\ of\ capital + annual\ expenditure}{installed\ capacity}$$

The levelized capital cost per year is calculated using the capital recovery factor formula:

$$LC = \frac{rC(1+r)^n}{(1+r)^n - 1}$$

Where:

LC	levelized capital cost per year
C	Capital Cost
O	Operating and maintenance cost (estimated at 2.2% of Capital Costs + $0.005/kWh)
r	discount rate (assumed 4.82%)
n	expected lifetime of plan + construction period (assuming 3 years of construction and a 65-year design life.)

5.4.4 LEVELIZED COST OF ENERGY

In the energy sector, LCOE is often used as a metric for evaluating energy projects because it allows for an “apples-to-apples” comparison of the costs associated with the generation of energy between different energy sources. For instance, there is a desire to be able to fairly compare hydropower projects with high upfront capital costs, and comparably low operations and maintenance costs (i.e. no fuel cost) with, for instance, thermal generation projects with lower upfront capital costs but relatively high operating costs that include fuel consumption.

The hydroelectric LCOE can be compared against the LCOE of a Yukon based thermal generation asset. If the hydroelectric project’s LCOE is higher than the thermal generation LCOE, it is deemed uneconomic.

YEC provided the following information to assist in the hydropower screening evaluation:

- Discount rate for net present valuation: 4.82%
- Yukon grid power: $0.19/kWh
- Diesel generation: $0.33/kWh
- Liquified natural gas (LNG): $0.15/kWh

In order to calculate the LCOE an estimate of the capital and operations and maintenance costs is required. The calculation for LCOE is presented below.

$$LCOE = \frac{sum\ of\ costs\ over\ lifetime}{sum\ of\ energy\ produced\ over\ lifetime}$$

$$LCOE = \frac{\sum_{t=0}^{n} \frac{C^t + O^t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{E_t}{(1+r)^t}}$$

Where:

Ct	Capital Cost in year t

Ot	Operating and maintenance cost in year t (estimated at 2.2% of Capital Costs + $0.005/kWh)
Et	Energy Generated in year t (estimated to be the mean annual energy)
r	discount rate (assumed 4.82%)
n	expected lifetime of plan + construction period (assuming 3 years of construction and a 65-year design life.)

5.4.5 LEVELIZED COST OF WINTER ENERGY (LCOWE)

For the purpose of this study the Levelized Cost of Winter Energy (LCOWE) was calculated as follows to compare the winter generation portfolios:

$$LCOWE = \frac{\sum_{t=0}^{n} \frac{C^t + O^t - R^t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{WE_t}{(1+r)^t}}$$

Where:

Ct	Capital Cost in year t
Ot	Operating and maintenance cost in year t (estimated at 2.2% of Capital Costs + $0.005kWh)
Rt	Revenue from non winter energy at the Yukon grid power rate of $0.19/kWh
WEt	Energy Generated in December, January, February and March of year t
r	discount rate (assumed 4.82%)
n	expected lifetime of plan + construction period (assuming 3 years of construction and a 65-year design life.)

5.5 SCREEN 2 RESULTS

The results of the Screen 2 assessment are presented in Table 5.2. Additional information regarding the background review and development of concepts is presented in Appendix B.

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TABLE 5.2

YUKON ENERGY CORPORATION
YUKON REGIONAL POWER ASSESSMENT

HYDROPOWER POTENTIAL ASSESSMENT (10 MW – 30 MW)
QUANTITATIVE ASSESSMENT PROJECT DATA SUMMARY (56 SITES + 5 ALTERNATIVES)

Project Name		Evaluated as	Intake Elev.	Tailrace Elev. (TWL)	Gross Head	Conveyance Length	Transmission Line	Unit Runoff	Drainage Area	MAD	Design Factor	Design Flow	Installed Capacity	Dam Height	Average Annual Capacity Factor	Average Annual Energy	Average Dec Mid Energy	Capital Cost	Capital Cost to Capacity	Capital Cost to Energy	LCOC	LCOE	Screened Out Due to Proximity to Discovered Low Cost Site	Screened Out Due to Location	Screened Out Due to Access and Social Risk	Screened Out Due to Cost	Reinvestment for Final Selection	Comments
			masl	masl	m	m	km	l/s/km²	km²	m³/s		m³/s	MW	m	%	GWh/a	GWh/a	M$	M$/MW	M$/GWh/a	$/kWh - lev	$/kWh @ 4.82%						
Primrose River		HH ROR	878	740	138	4,700	39	12.7	1,138	14.5	2.0	23.1	Cluster 1 Alaska Highway (138 kV (1 of 8) + Alternative)	NA	40%	102.2	10.3	200	7.9	1.89	0.105	0.151					Yes	Barge Access, Protected Area
Primrose River		Storage	878	740	138	4,700	39	12.7	1,138	14.5	2.0	23.1	30	NA	40%	102.2	10.3	200	7.9	1.89	0.105	0.151					Yes	Barge Access, Protected Area
Ibex River		HH ROR	890	825	55	5,000	20	12.5	323	4.0	2	8.1	Cluster 2 Carmacks - Whitehorse (138 kV (1 of 8)	35	40%	37.4	4.6	110	30.8	8.29	2.220	0.950		X			No	
Arrival Creek		HH ROR	905	625	280	8,000	28	6.0	657	5.3	2.0	10.5	Cluster 2 Carmacks - Whitehorse (138 kV (2 of 8)	NA	40%	82.0	4.6	340	14.6	4.15	1.376	0.315					Yes	Tunnel
Clanchatchi River		HH ROR	1,000	625	375	8,000	30	6.0	1,231	7.4	2.00	14.8	Cluster 2 Carmacks - Whitehorse (138 kV (3 of 8)	NA	40%	82.0	0.4	140	22.5	6.09	1.706	0.508		X			No	
Rivers Creek *		Storage	728	620	108	8,200	1	8.1	838	4.9	2.6	12.7	19.1	8.5	38%	31.8	24.2	119	11.1	3.93	0.682	0.248					Yes	
Glenlyon		Storage	740	610	130	6,650	50	8.5	396	3.4	2.6	8.8	50	30	37%	29.3	18.4	230	25.5	7.87	1.927	0.692		X			No	Recreational Areas
Lake Creek		Storage	663	650	13	10,000	50	2.4	11,443	27.5	1.0	27.9	13.6	NA	58%	67.8	6.9	330	23.6	4.82	2.053	0.354					Yes	
Tay River		HH ROR	650	625	25	10,000	30	2.4	2,047	5.0	2.0	5.0	Cluster 4 Stewart Crossing - Carmacks (138 kV (4 of 8)	NA	40%	17.4	1.8	70	13.9	3.82	1.300	0.289					Yes	
Rancheria River		HH ROR	640	540	80	3,700	10	10.2	1,015	10.3	2.00	20.3	10.6	9	40%	41.7	16.3	140	13.5	3.44	1.196	0.261					Yes	
Rancheria River		Storage

6.0 SCREEN 3: FINAL SCREENING

6.1 ADDITIONAL SCREENING CRITERIA

The Screen 2 results were presented to YEC for review and guidance for the final screening and shortlisting of sites. During this phase, YEC requested the removal of the sites associated with two proposed transmission line segments:

- Cluster 8: Faro-Watson Lake
- Cluster 9: Beaver Creek-Hanes Junction

The removal of the sites associated with these transmission lines was based on low probability of these transmission line segments being developed in the foreseeable future.

Additional final screening criteria were implemented as follows:

- Sites below 10 MW except for Atlin;
- Sites consisting of dams on large river systems were removed due to perceived social risk and high temporary works construction costs
- Sites with a LCOE exceeding $0.35/kWh were removed

Table 6.1 presents the sites remaining for the final selection of the top five preferred sites.

Table 6.1 Sites for Final Selection

Project Name	Evaluated as	Cap.	Avg Energy	Winter Energy	Capital Cost	UCC	LCOE
		MW	GWh/a	GWh/a	M$	M$/MW	$/kWh
Primrose River	RoR	25	102	10	200	7.9	0.15
Primrose River	Storage	13	78	35	180	14.0	0.17
Wolf River	RoR	11	84	21	200	17.6	0.18
Tutshi Windy Arm	Storage	10	52	28	138	13.6	0.20
Wolf River with Wolf Lake	Storage	30	242	83	670	22.3	0.21
Atlin Hydro	Storage	8	37	17	121	15.5	0.22
Drury Creek	RoR	10	33	4	100	10.3	0.24
Reid Lakes & Lake Creek	Storage	11	42	16	140	13.5	0.26
Drury Creek	Storage	10	32	26	115	11.1	0.27
Lapie	RoR	13	45	3	170	13.3	0.29
Lake Creek	RoR	13	45	4	170	13.4	0.29
McQuestin	RoR	17	84	10	330	19.1	0.30
Anvil Creek	Storage	23	82	5	340	14.6	0.31

6.2 SELECTION OF TOP 5 SITES

The selection of the top five sites was made on a combination of comparative LCOE results for the sites presented in Table 6.1, and discussions with YEC for site-specific screening criteria. Four of the shortlisted sites were easily selected for their performance on an LCOE basis and their ability to provide winter energy:

- Primrose
- Drury
- Tutshi-Windy Arm
- Wolf

The fifth site for the shortlist was determined to be Atlin following a detailed conversation with YEC. While Atlin did not offer 10MW of capacity, the following additional considerations ultimately led to the decision:

- Lapie is a RoR project which would not offer any reliable winter generation capacity. Winter capacity is of primary importance to YEC, therefore this site was not selected.
- Reid Lakes and Lake Creek: involves two separate generating stations, with a RoR diversion project feeding a lake storage project. Each on its own is uneconomic, and the combined project is complex and requires an inter-basin transfer of water which is anticipated to pose a significant challenge for development.
- Atlin: while this site offers a lower installed capacity (8 MW), it is optimal for its winter generation potential. It is also considered lower risk than many other sites in terms of the available information supporting its design.

7.0 SHORTLIST CONCEPT DEVELOPMENT

7.1 PRIMROSE

The Primrose River and its tributaries form a hanging valley above Kusawa Lake, which make it a potentially very attractive site. Its presence within the boundaries of Kusawa Territorial Park means it was screened out of the 2016 KP study. The neighbouring drainage of Takhini Lake was also considered as part of proposed schemes in the past.

The Primrose site has been investigated on numerous occasions since 1952. The Demers 1989 Report forms the basis for the project configurations listed in the existing project inventories but were assumed to be using large dams. KP evaluated the project as both a RoR project and a storage project with a 10 m high dam and it is attractive in both instances.

A basic arrangement for the proposed project layout is shown on Figure 7.1. Key project parameters for this layout are as follows:

- Design Flow: 11.6 m^3/s.
- Gross Head: 138 m.
- Installed Capacity: 12.7 MW.
- Dependable Capacity: 12.7 MW (during the driest winter of synthetic record 1973-74 the project could generate for 97 continuous days during the winter at 12.7 MW).
- The current access assumes that the project site will require barge access and 20 km of new access roads to reach the proposed dam site from Kusawa Lake. 20 km of additional access road through the Kusawa Territorial Park would be required if the project site is not accessed/accessible by barge.
- A Rose Lake outlet control dam to provide 10 m of lake storage (operating storage of 100 million cubic metres (Mm^3)), equipped with IFR release system and spillway for flood water management.
- A 4,700 m long penstock.
- A Powerhouse (el. 740 masl).
- Substation and a 40 km long transmission line, with a t-tap interconnection to the existing 138 kV line between Aishihik and Whitehorse along Alaska Highway #1.

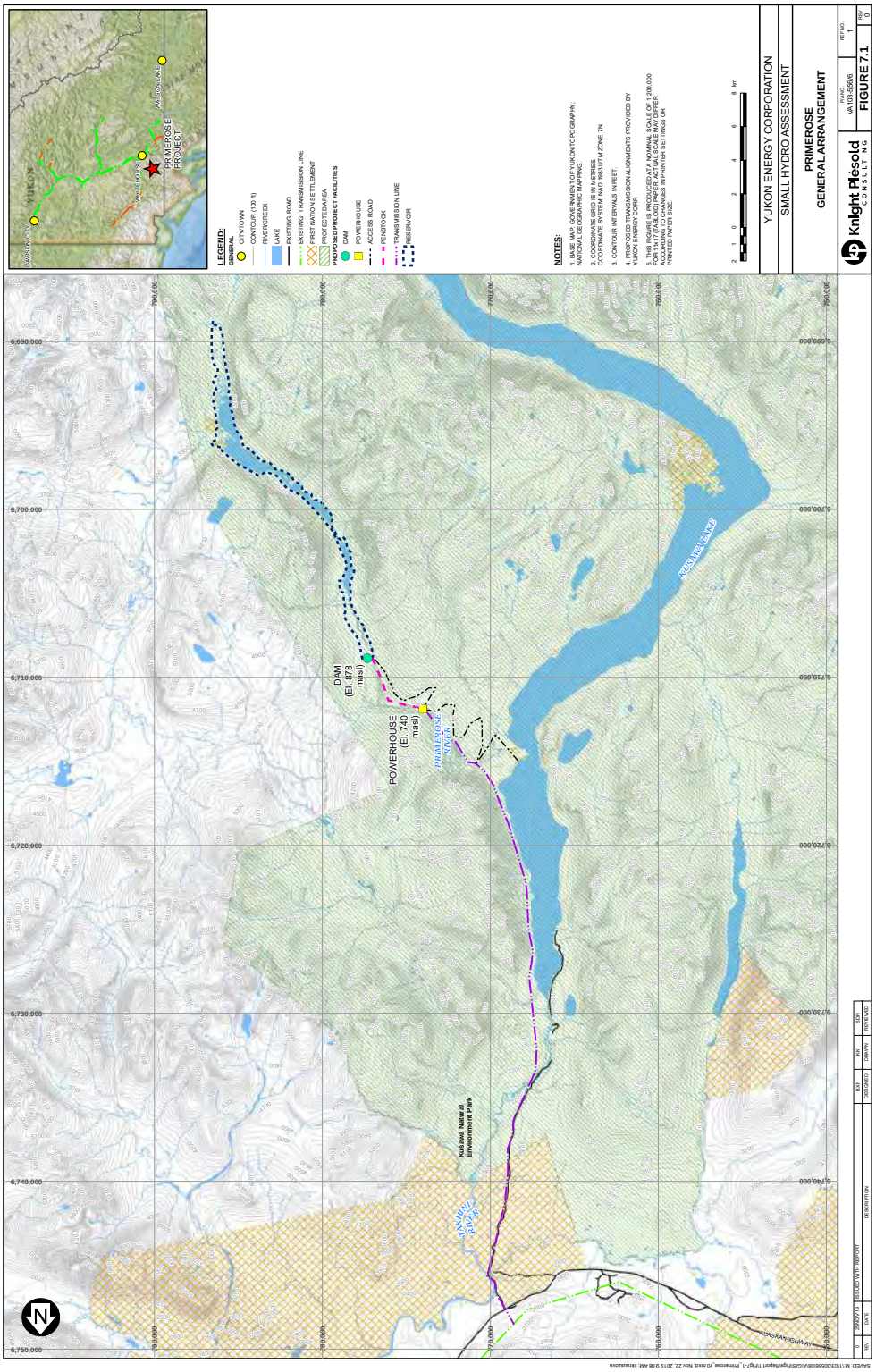
The project site is attractive but its presence in the Kusawa Territorial Park may be a major obstacle. Only one alternative to lower the powerhouse site to increase the project head at the expense of the increased penstock cost was considered. There could be a more optimal project layout once detailed topography for the site is obtained. Physical considerations at the proposed dam site are also unknown.

Table 7.1 presents the estimated average monthly energy output for the Primrose project. The project layout is shown on Figure 7.1.

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

Table 7.1 Primrose Average Monthly Energy (GWh)

	Primrose with Storage
Jan	9.0
Feb	8.1
Mar	7.0
Apr	0.0
May	0.0
Jun	0.1
Jul	6.7
Aug	9.0
Sep	8.7
Oct	9.0
Nov	7.6
Dec	9.0
Annual	74.0


PRIMROSE PROJECT
WHITEHORSE
JAKES CORNER
WATSON LAKE
YUKON
LEGEND:
GENERAL
CITY/TOWN
CONTOUR (100 ft)
RIVER/CREEK
LAKE
EXISTING ROAD
EXISTING TRANSMISSION LINE
FIRST NATION SETTLEMENT
PROTECTED AREA
PROPOSED PROJECT FACILITIES
DAM
POWERHOUSE
ACCESS ROAD
PENSTOCK
TRANSMISSION LINE
RESERVOIR
NOTES:
1. BASEMAP SOURCED FROM GOOGLE YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES.
COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVALS IN FEET.
4. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:200,000 WHEN PLOTTED ON 11x17 PAPER SIZE. ACTUAL SCALE MAY VARY ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
DAM
(El. 878 masl)
POWERHOUSE
(El. 740 masl)
PRIMROSE RIVER
KUSAWA LAKE
Kusawa Natural Environment Park
TAKHINI RIVER
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
PRIMEROSE
GENERAL ARRANGEMENT
Knight Piésold CONSULTING
FIGURE 7.1

7.2 DRURY

The Drury Lake Project is located on Drury Creek between Drury Lake and Little Salmon Lake, in the Yukon River watershed. The site is approximately 170 km north of Whitehorse and is situated within 1 km of the Robert Campbell Highway and the existing transmission line.

The Drury site was evaluated as both a run of river project and a storage project. The available stream gauge information for Drury seems to indicate some natural flow attenuation from Drury lake offering some winter generation even on a RoR basis.

This project was short listed as it has a relatively low LCOE and offers the opportunity to generate winter energy. It was carried forward as a storage project but may also be valuable as a RoR project.

A variety of studies have previously been commissioned for the Drury site, including high level reconnaissance, geotechnical investigations, and design studies, and these have resulted in several alternative design concepts. The most recent study, apart from the 2016 KP study, was completed by KGS in 2008 and provides basic site layouts, design and geotechnical considerations, and cost estimates for different options.

While earlier studies considered a low gradient canal and a short penstock, geotechnical risk and the presence of permafrost were noted by KGS. At this desktop level, the conveyance alignment and specific constructability concerns cannot be addressed in any detail beyond that reported by KGS, and so the selection of a buried low-pressure penstock instead of a canal has been adopted by KP.

A preliminary general arrangement of the project layout is shown on Figure 7.2. Key project parameters and characteristics for this layout are as follows:

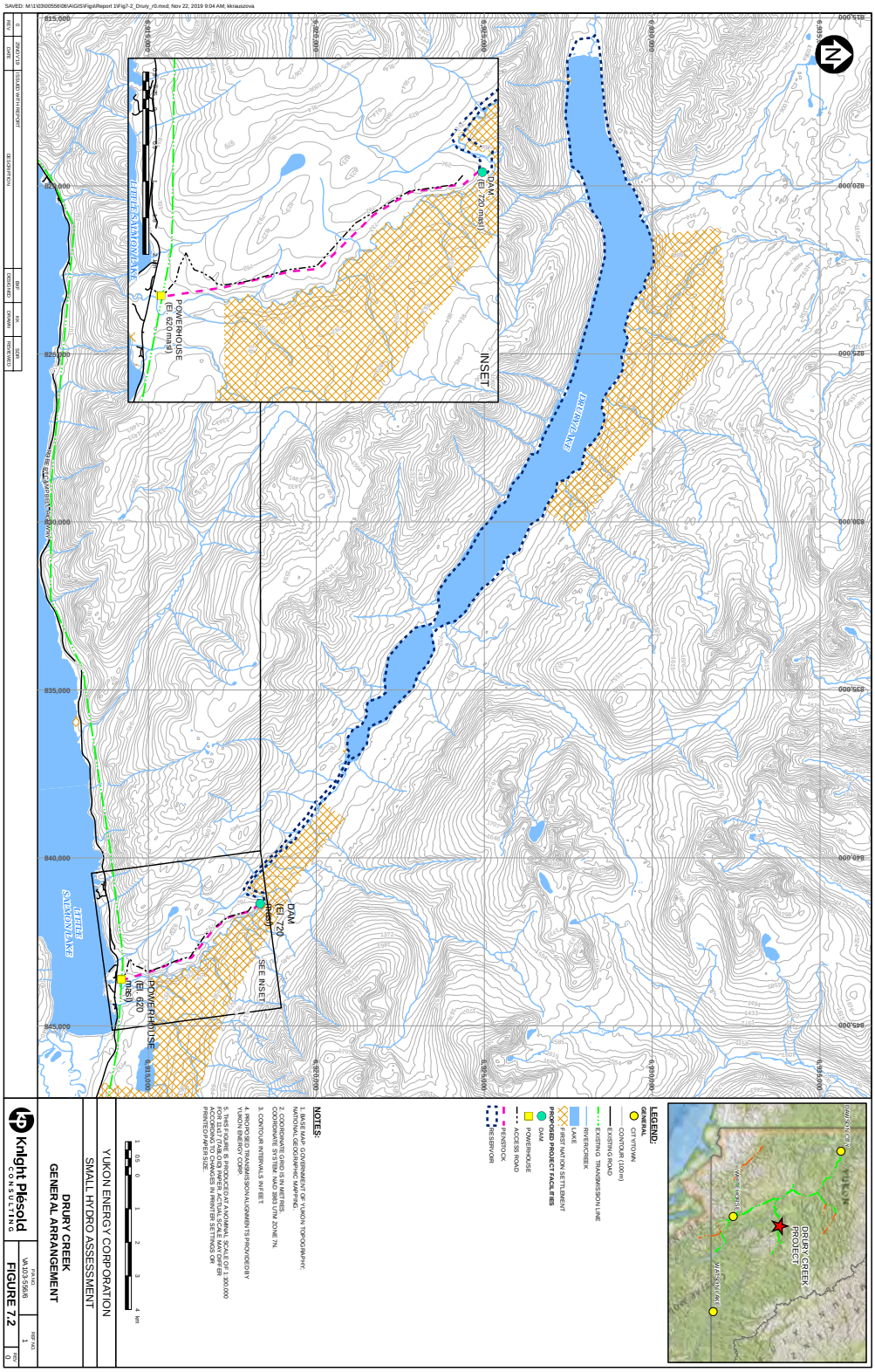
- Design Flow: 12.7 m^3/s.
- Gross Head: 100 m.
- Installed Capacity: 10 MW.
- Dependable Capacity: 10 MW (during the driest winter of synthetic record 1998-99 the project could generate for 63 continuous days during the winter at 10 MW).
- 5.3 km of access roads from the Robert Campbell Highway to the powerhouse, along the water conveyance, and upstream to the outlet of Drury Lake.
- Concrete Faced Rockfill Dam (CFRD) at the outlet of Drury Lake to provide 5 m of storage (operating storage of 130 Mm^3). The dam would be constructed with an IFR discharge system and a spillway to Drury Creek for flood water management.
- An intake structure.
- 4.9 km penstock located on the south side of Drury Creek (alignment as previously indicated by KGS).
- Powerhouse (El. 620 masl) and substation at the edge of Drury Creek, upstream of the Robert Campbell Highway and the river mouth at Little Salmon Lake.
- 0.5 km transmission line, with t-tap interconnection to the existing transmission line.

Note: The lack of detailed topography makes siting the location and configuration of the projects point of diversion difficult. The existing topography shows 5 km of very flat terrain and stream gradient at the outlet of Drury Lake, as such the current option assumes a single structure would be enough to provide impoundment and a penstock offtake.

Table 7.2 presents the average estimated energy output for the Drury project.

Table 7.2 Drury Average Monthly Energy (GWh)

	Drury
Jan	7.2
Feb	6.1
Mar	4.4
Apr	0.0
May	0.0
Jun	0.0
Jul	0.0
Aug	0.2
Sep	1.7
Oct	2.2
Nov	1.6
Dec	7.2
Annual	30.6


LEGEND:
GENERAL
CITY/TOWN
CONTOUR (100m)
EXISTING ROAD
EXISTING TRANSMISSION LINE
RIVER/CREEK
LAKE
FIRST NATION SETTLEMENT
PROPOSED PROJECT FACILITIES
DAM
POWERHOUSE
ACCESS ROAD
PENSTOCK
RESERVOIR
NOTES:
1. BASE MAP GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES.
COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVAL IS 5m.
4. TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:300,000 FOR 11x17 (TABLOID) PAPER ACTUAL SCALE MAY DIFFER PRINTED PAPER SIZE.
DRURY CREEK PROJECT
MAYO
YUKON
WHITEHORSE
DAWSON CITY
DAM (El. 720 masl)
POWERHOUSE (El. 620 masl)
INSET
SEE INSET
LEWIS LAKE
LITTLE SALMON LAKE
RIVER
Knight Piésold CONSULTING
DRURY CREEK
GENERAL ARRANGEMENT
SMALL HYDRO ASSESSMENT
YUKON ENERGY CORPORATION
FIGURE 7.2
PROJECT NO. VA101-156/6
REF. NO. 1
REV. 0

7.3 TUTSHI WINDY ARM

The Tutshi – Windy Arm Project is a proposed storage hydropower development located between Tutshi Lake and Windy Arm of Tagish Lake in northern British Columbia. Tutshi and Tagish Lakes are tributaries to the Yukon River. The project site is approximately 45 km to the south of Carcross, Yukon, and the proposed powerhouse location is within 1 km to the east of the Klondike Highway.

Several studies have previously been completed for this site, including geotechnical investigations, design, and cost estimates, resulting in a number of alternative design concepts. This desktop study is based on the most current concepts, presented in the 2008 KGS report.

The Tutshi Lake/T'ooch' Áayi Conservancy was established in 2012 as a result of the Wóoshtin Wudidaa Atlin Taku Land Use Plan and Taku River Tlingit First Nation Strategic Engagement Agreement. The conservancy, located approximately 65 kilometres northwest of Atlin, encompasses the eastern half of Tutshi Lake. Tutshi Lake is culturally significant to the Carcross/Tagish and Taku River Tlingit First Nations. The lake also has high value lake trout habitat. The Tlingit name (T'ooch' Áayi) means "charcoal lake", after the dark colour of the lake water.

A basic arrangement for the proposed project layout is shown on 3. Key project parameters for this layout are as follows:

- Design Flow: 25 m3/s.
- Gross Head: 51 m.
- Installed Capacity: 10 MW.
- Dependable Capacity: 10 MW (during the driest winter of synthetic record 1973-74 the project could generate for 108 continuous days during the winter at 10 MW).
- 23.5 km of access roads, to reach the powerhouse, surface conveyance, tunnel intake, and outlet control dam on Tutshi Lake.
- Tutshi Lake outlet control dam to provide 5 m of lake storage (operating storage of 267 Mm3), equipped with IFR release system and spillway for flood water management.
- Tunnel intake and 1.7 km tunnel through the hill separating the north end of Tutshi Lake from Windy Arm of Tagish Lake (Intake El. 707 masl).
- 2.7 km long penstock.
- Powerhouse on the south shore of Windy Arm, Tagish Lake (El. 656 masl).
- Substation and a 1 km long transmission line, with t-tap interconnection to a proposed transmission line along the Klondike Highway between Carcross and Skagway (AK).

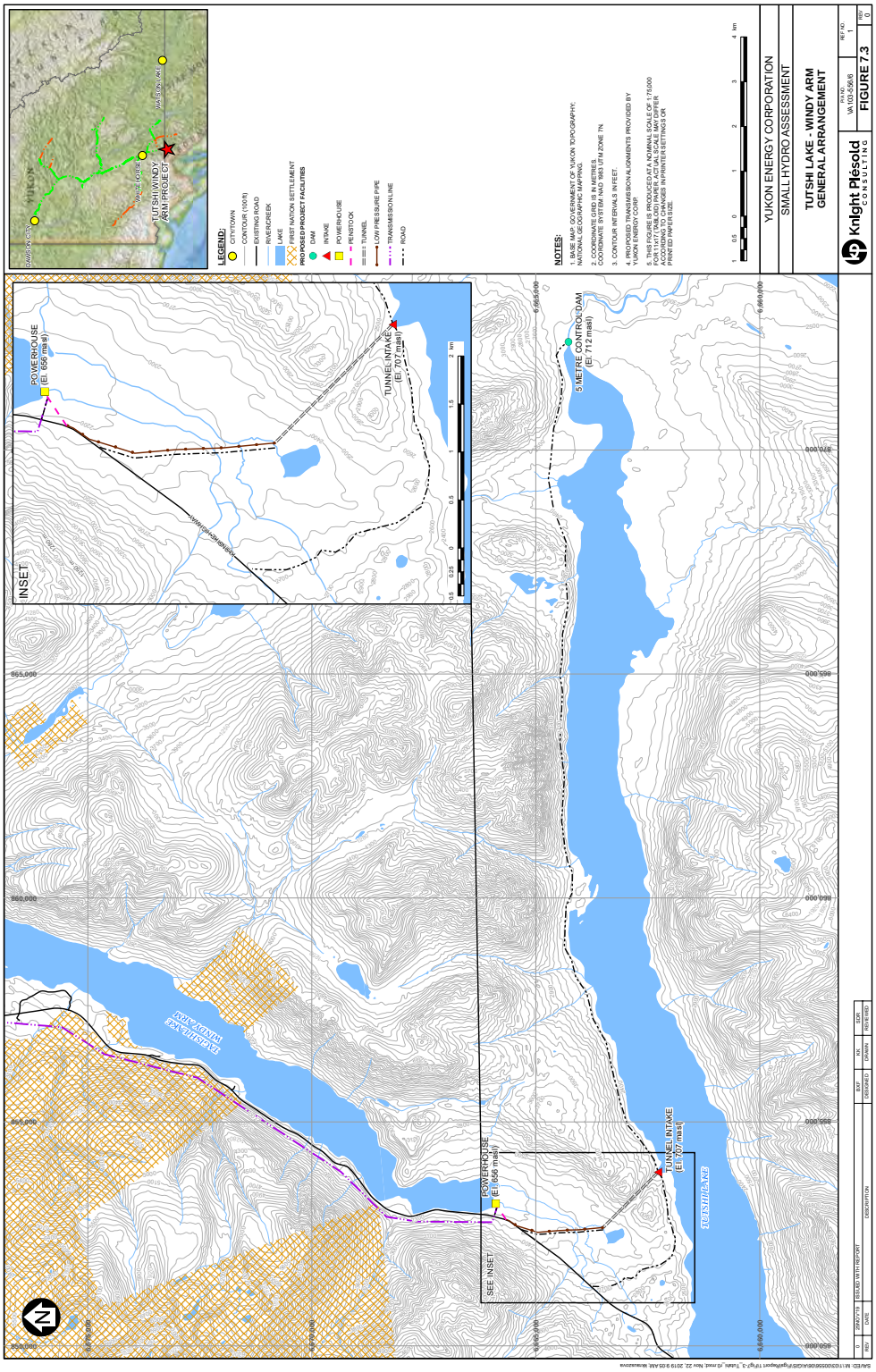
The Taku River Tlingit First Nation and Carcross Tagish First Nation would need to be approached prior to any serious consideration of the project site. Site investigations and a more detailed review of site-specific data would be required to confirm project viability and the optimal project size.

Table 7.3 presents the average monthly energy output for the Tutshi-Windy Arm project. The project arrangement is shown on Figure 7.3.

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

Table 7.3 Tutshi Average Monthly Energy (GWh)

	Tutshi
Jan	7.1
Feb	6.5
Mar	6.2
Apr	0.0
May	0.0
Jun	0.0
Jul	0.4
Aug	5.4
Sep	6.7
Oct	6.4
Nov	3.4
Dec	7.1
Annual	49.3


YUKON
DAWSON CITY
WHITEHORSE
WHITEHORSE
TUTSHI/WINDY ARM PROJECT
LEGEND:
CITY/TOWN
CONTOUR (100 ft)
EXISTING ROAD
RIVER/CREEK
LAKE
FIRST NATION SETTLEMENT
PROPOSED PROJECT FACILITIES
DAM
INTAKE
POWERHOUSE
PENSTOCK
TUNNEL
LOW PRESSURE PIPE
TRANSMISSION LINE
ROAD
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES.
COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVALS IN FEET.
4. PROVISIONAL TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORPORATION.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:75000 FOR 11x17 (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER IF PRINTER SETTINGS CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
TUTSHI LAKE - WINDY ARM
GENERAL ARRANGEMENT
Knight Piésold CONSULTING
FIGURE 7.3
INSET
POWERHOUSE (El. 656 masl)
TUNNEL INTAKE (El. 712 masl)
5 METRE CONTROL DAM (El. 712 masl)
SEE INSET
TUTSHI LAKE
WINDY ARM

7.4 ATLIN HYDRO

Atlin is an isolated community located approximately 50 km south of the Yukon-British Columbia border. Atlin is only road accessible from the Yukon Territory. On April 1, 2009 the 2.1 MW Atlin Hydro Project began commercial power production (Illustrated in Figure 7.4). The hydropower facility is owned by Xeitl Limited Partnership which is 100% owned by Taku River Tlingit First Nation. The project is located on Pine Creek and is approximately 4 km east of the community of Atlin, BC. The facility overlaps with previously conceived layouts of a Surprise Lake hydroelectric project.

NOTES:
1. PHOTO SOURCE: WWW.WATERPOWERMAGAZINE.COM.

Figure 7.4 Atlin Hydro Project Photos

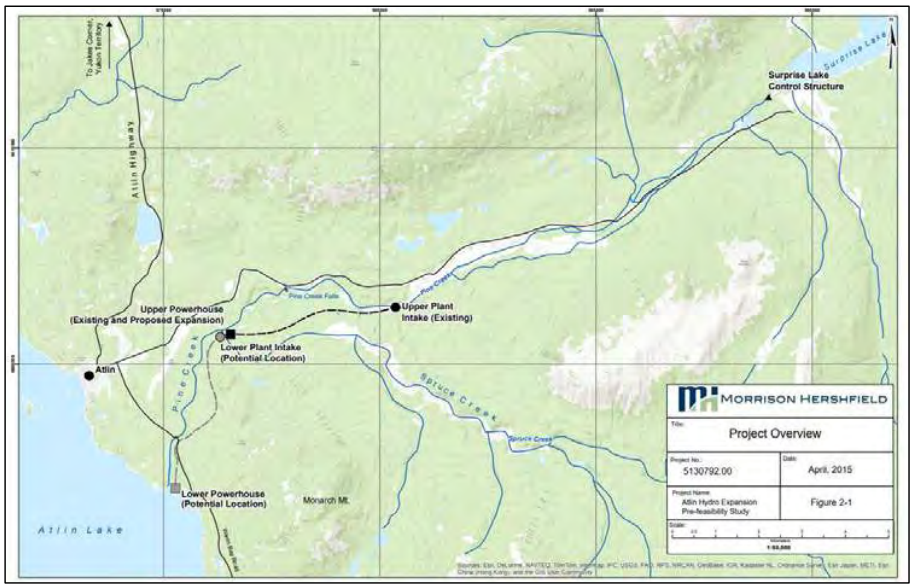
On June 23, 2016 Morrison Hershfield provided YEC with a detailed report on the Atlin Hydro Expansion Project. The report includes a transmission line options assessment for connection to the Yukon electrical system. The detail provided in this report (good quality topography, complete hydrological assessment, detailed drawings and estimates) means this project has less unknowns and risks than the other projects in this short list.

For the purpose of conciseness, the Morrison Hershfield information will only be repeated here in brief summary. They have completed an alternatives assessment, a hydrological assessment and a Pre-Feasibility Assessment. The proposed general arrangement is shown in Figure 7.5. A summary of the estimated energy is shown in Table 7.4 The conclusion is quoted below.

“It is proposed to develop a total of 7.8 MW at Pine Creek, consisting of expanding the existing (upper) 2.1 MW powerhouse with an additional two turbines to bring the total installed capacity to 5 MW plus the addition of a second, or lower, powerhouse near Atlin Lake with an installed capacity of 2.8 MW. The upper power plant operates under a gross head of approximately 107 m and the lower plant has a gross head of approximately 56 m.”

“For the expansion of the upper power plant, a second 4 km long HDPE penstock will be required to convey a maximum flow of 3.55 m³/s from the existing head pond to the powerhouse. The penstock will require the excavation of a trench, mainly through overburden materials except some limited bedrock excavations near the intake structure. The lower power plant requires 4 km of twin HDPE penstocks to convey a maximum

flow of 7 m³/s. A new excavated head pond just downstream of the existing (upper) powerhouse is required to supply the lower penstocks. Spruce Creek would be diverted into the lower head pond such that flows from Spruce Creek can be used to increase electrical generation at the lower power plant.



NOTES:
1. SOURCE: ATLIN HYDRO EXPANSION STUDY.

Figure 7.5 Atlin Hydro Project and Surprise Lake

Increased storage in Surprise Lake to maximize winter electrical generation will be developed by modifying the existing control structure at the lake outlet. It is proposed to increase the storage range from 1.1 m to 2.5 m by increasing both top and bottom storage by approximately 0.7 m. This operating scheme would not require modification of the project's existing Permit Over Crown Land which allows storage of water up to elevation 913.85 masl. The storage of water allows the project to generate approximately 70% of its annual average energy production during winter months (November through April). Winter energy is of highest value to the Yukon's electrical grid.

In consideration of the existing hydropower infrastructure the Atlin Hydro Expansion Project has the potential to produce on average 44.7 GWh/yr of energy, of which at 36 GWh/yr is available for export to the Yukon after the community of Atlin's needs are met. Cost for the hydroelectric development only (without transmission) are estimated at $79.7 million. A total project cost of $120.7 million is estimated, including a 69 kV transmission line to connect with the Yukon's electrical grid at Jakes Corner."

Table 7.4 Atlin Average Monthly Energy (GWh)

	Production	Committed	For Yukon
Jan	5.1	1.0	4.1
Feb	4.9	0.8	4.1
Mar	5.3	0.8	4.5
Apr	4.5	0.8	3.7
May	2.4	0.7	1.7
Jun	3.3	0.6	2.7
Jul	2.2	0.5	1.7
Aug	1.7	0.5	1.2
Sep	2	0.6	1.4
Oct	2.3	0.7	1.6
Nov	5.5	0.7	4.8
Dec	5.5	0.9	4.6
Annual	44.7	8.6	**36.1**

7.5 WOLF RIVER

The Wolf River is a tributary of the Nisutlin River upstream of Teslin Lake, in the headwaters of the Yukon River. The Wolf River Project site is located near the river mouth and approximately 22 km to the northeast of the community of Teslin and the Alaska Highway. First Nation Heritage Routes and First Nation Settlement Lands associated with the Teslin Tlingit Council are visible in the GeoYukon database covering the area adjacent to the north bank of the Wolf River.

The previous KP report and the 1990 and 1991 Hydro Investigations by S. Demers looked at the project site. Little is known of site-specific geotechnical conditions and cannot be confirmed at the desktop level. There are several project configurations possible and the main limitation on the project installed capacity is associated with the capacity of the existing 34 kV transmission line from Teslin. In the current layout the main intake has been placed below the confluence of Caribou Creek and Wolf River (previously the intake was considered a bit higher in the basin missing out on the Caribou Creek catchment.) The 1991 study also noted the potential opportunity for storage in Wolf Lake, which could improve winter generation and the plant capacity factor.

Two project configurations were considered in the first a run-of-river project limited by the existing transmission and capped at 11 MW of installed capacity. A second utilizing the potential of the site at 30 MW with the addition of storage at Wolf Lake to allow for firm winter generation but requiring an additional higher capacity of transmission line to Whitehorse.

A basic general arrangement for the proposed project layout is shown on Figure 7.6.

Key project parameters for this layout are shown below.

Table 7.5 Wolf River Alternatives

Sites	Wolf River	Wolf River and Wolf Lake
Design Flow	18.8	37.6
Gross Head (m)	75	100
Installed Capacity (MW)	11.2	30.0
Dependable Capacity (MW)	4.0	30.0
Canal Length (m)	6,900	11,500
Penstock Length (m)	1,300	900
Transmission Line (km)	20	20+150

Project access should be able to circumvent the Nisutlin River Delta National Wildlife Area. Access to the project site can be done through either or both of the following:

- Upgrades to an existing 34 km trail identified as leaving the Alaska Highway (#1) 20 km east of Teslin.
- A new 23 km access road departing from Teslin, running west of the Nisutlin River Delta National Wildlife Area. This option would require a bridge across the Nisutlin River.
- 73 km of trail upgrades are required to access Wolf Lake from the proposed intake site.

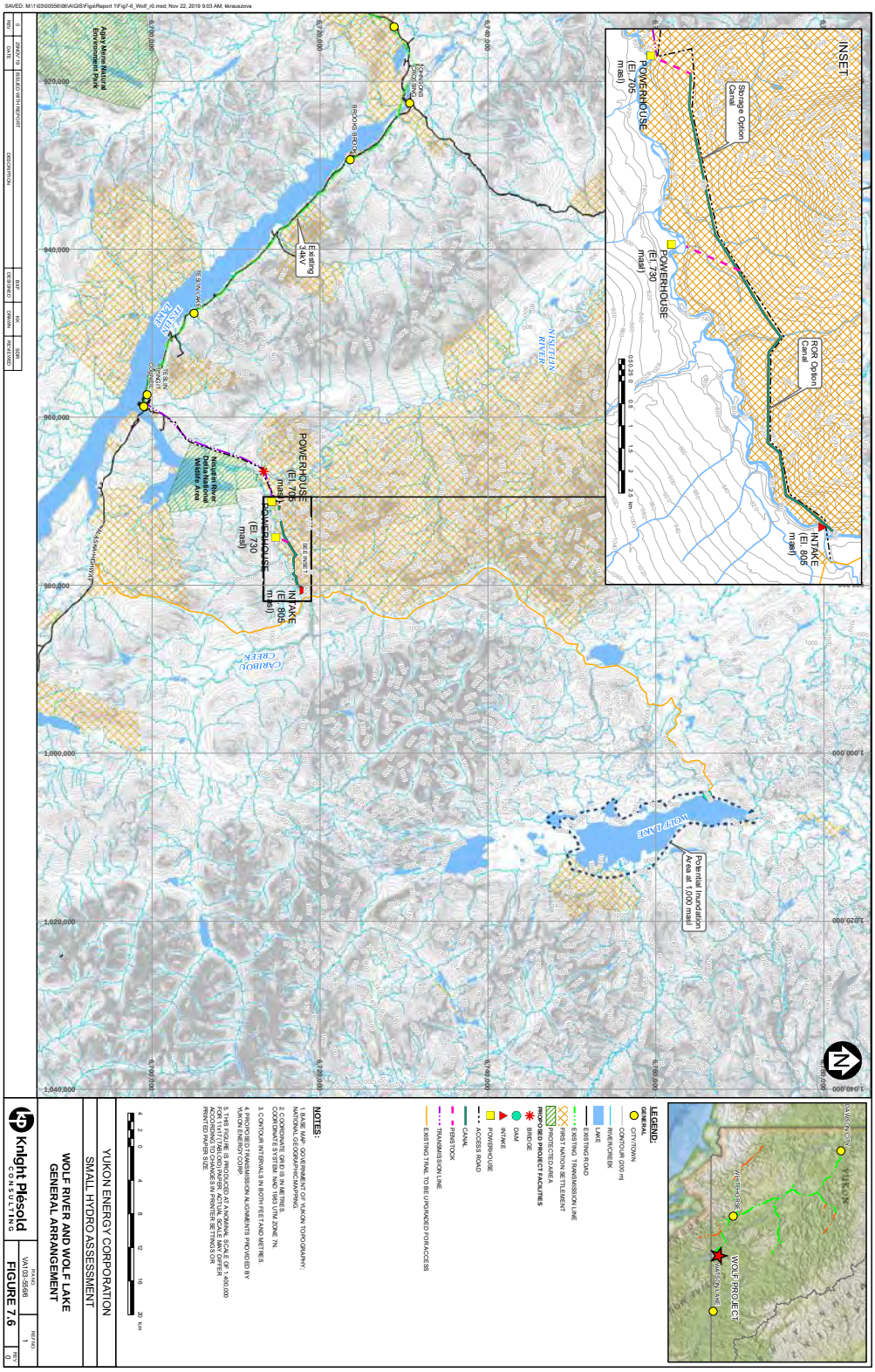
Both project configurations would require a canal diversion and a forebay to the penstock and a powerhouse and a short tailrace channel back to Wolf River.

Both configurations would include a substation and 23 km transmission line to Teslin. Development of a large generating capacity at Wolf River would need a more careful consideration of the transmission line capabilities and energy demand. For the current assessment valuation, it was presumed that 150 km of new line would be needed to connect Teslin to Whitehorse through Jake's Corner to support a 30 MW project site.

Table 7.6 presents the average monthly energy output for the Wolf River project. The project arrangement is shown on Figure 7.6.

Table 7.6 Wolf and Wolf Lake Average Monthly Energy (GWh)

	Wolf	Wolf River and Wolf Lake
Jan	5.7	21.2
Feb	3.9	19.0
Mar	3.9	17.2
Apr	4.8	12.8
May	7.8	19.3
Jun	7.7	20.6
Jul	8.0	21.2
Aug	8.0	21.0
Sep	7.7	20.1
Oct	8.0	20.2
Nov	7.5	15.6
Dec	6.9	21.2
Annual	79.7	229.5


INSET
POWERHOUSE (El. 705 masl)
Storage Option
Canal
POWERHOUSE (El. 730 masl)
ROR Option
Canal
INTAKE (El. 805 masl)
Existing 34kV
TESLIN LAKE
TESLIN RIVER
NISUTLIN RIVER
BROOKS BROOK
Nisutlin River Delta National Wildlife Area
Alaska Marine National Environment Park
CARIBOU CREEK
WOLF LAKE
Potential Inundation Area at 1,000 masl
SEE INSET
LEGEND:
GENERAL
CITY/TOWN
CONTOUR (200 m)
RIVER/CREEK
LAKE
EXISTING ROAD
EXISTING TRANSMISSION LINE
FIRST NATION SETTLEMENT
PROTECTED AREA
PROPOSED PROJECT FACILITIES
BRIDGE
DAM
INTAKE
POWERHOUSE
ACCESS ROAD
CANAL
PENSTOCK
TRANSMISSION LINE
EXISTING TRAIL TO BE UPGRADED FOR ACCESS
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES.
3. CONTOUR INTERVALS IN BOTH FEET AND METRES.
4. PROJECTION/DATUM ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:400,000 FOR 11x17 (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
YUKON
WOLF PROJECT
WATSON LAKE
WHITEHORSE
Knight Piésold CONSULTING
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
WOLF RIVER AND WOLF LAKE GENERAL ARRANGEMENT
FIGURE 7.6
PROJECT NO. VA10-5696
REF NO. 1
REV. 0

8.0 CONCLUSIONS AND RECOMMENDATIONS

8.1 CONCLUSIONS

The objectives of the study were to compile a regional assessment of hydropower development sites with installed capacities between 10 MW and 30 MW and within 50 km of existing or proposed transmission lines. KP developed a list of 147 sites and completed a hydropower screening assessment to progressively eliminate the less attractive sites and focus in on the best potential hydroelectric development options. Following a coarse screening of these 147 sites, 56 Sites were selected for a further quantitative assessment. KP performed a quantitative assessment to determine potential layouts, capacity, average annual and winter energy yield and indicative development costs. During a final screening and selection process, the sites were presented to YEC for final consideration and implementation of additional screening criteria. The final screening was based on capacity, location, expected development costs and perceived social acceptability. This narrowed the 56 sites to nine sites, including:

- Primrose (as both ROR and lake storage projects)
- Wolf River (with and without Wolf Lake)
- Tutshi Windy Arm
- Atlin
- Drury Creek (as both ROR and lake storage projects)
- Lake Creek and Reid Lakes
- Lapie
- McQuestin River
- Anvil Creek

These 9 sites were assessed in more detail, and the final 5 preferred sites were selected as:

- Primrose (as a lake storage project)
- Drury (as a lake storage project)
- Tutshi Windy Arm
- Atlin
- Wolf River (with and without Wolf Lake)

A summary of the Financial and Technical attributes of the preferred sites is presented in Table 8.1.

Knight Piésold CONSULTING

TABLE 8.1

YUKON ENERGY CORPORATION
HYDROPOWER POTENTIAL ASSESSMENT (10MW-30MW)

PREFERRED SITES
SUMMARY

Print Nov/25/19 09:00:03

DESCRIPTION	Primrose	Drury	Tutshi	Atlin	Wolf	Wolf River & Lake
Installed Capacity (MW)	12.7	10.0	10.0	8.0	11.2	30.0
Dependable Winter Capacity (MW) based on 2 weeks of Winter Production	12.7	10.0	10.0	6.0	4.0	30.0
Average Annual Energy (GWh) x 95% for outages and transmission losses	74.0	30.6	49.3	45.0	79.7	229.5
Average Dec-Mar Energy (GWh) x 95% for outages and transmission losses	33.0	24.9	27.1	20.8	20.1	79.0
Unit Cost of Capacity (M$/MW)	14.0	11.1	16.7	16.4	14.7	15.3
Unit Cost of Energy (M$/GWh)	2.40	3.61	3.39	2.91	2.07	2.00
Levelized Cost of Capacity ($/kW-yr) @4.82%	1,342	673	1,291	1,426	1,780	1,764
Levelized Cost of Energy ($/kWh) @4.82%	0.184	0.277	0.256	0.222	0.160	0.154
Levelized Cost of Winter Energy ($/MWh) @4.82% and 0.19 $/kWh for Non Winter Energy	0.177	0.296	0.311	0.259	0.072	0.086
Project Gross Head (m)	138	100	51	107 and 56	75	100
Design Flow (m^3/s)	11.6	12.7	24.9	7.0	18.8	37.6
MAD (m^3/s)	14.5	4.9	16.2	4.4	75.3	75.3
Design Factor	0.80	2.60	1.55	1.59	0.25	0.50
Dam Height (m)	10	5	5	2.5	-	4
Storable Volume (10^6 m^3)	100	125	265	76	-	350
Water Conveyance Length (m)	4,700	5,200	3,000	4,000	7,400	14,000
Capital Cost Esitmate						
Mod, Demob, Insurance, Bonds, Overheads, Contractor's Profit	$ 29,700,000	$ 18,500,000	$ 27,900,000	$ 1,400,000	$ 27,600,000	$ 57,900,000
Access and Site Preparation	$ 8,000,000	$ 4,600,000	$ 7,900,000	$ 700,000	$ 12,000,000	$ 23,000,000
Intake, Forebay, and Headrace	$ 6,500,000	$ 6,800,000	$ 12,500,000	$ 1,100,000	$ 10,000,000	$ 25,000,000
Water Conveyance System	$ 25,000,000	$ 30,000,000	$ 32,900,000	$ 30,200,000	$ 39,700,000	$ 90,000,000
Powerhouse and Ancilary Services	$ 6,000,000	$ 5,900,000	$ 8,700,000	$ 12,700,000	$ 7,400,000	$ 13,500,000
Power Generation Equipment (Water to Wire)	$ 8,900,000	$ 7,100,000	$ 7,100,000	$ 9,800,000	$ 7,900,000	$ 20,000,000
Switchyward, Transmission and Interconnection	$ 29,500,000	$ 2,700,000	$ 20,200,000	$ 27,100,000	$ 15,000,000	$ 18,000,000
Dams and Reservoirs	$ 15,000,000	$ 4,500,000	$ 3,800,000	$ 1,600,000	$ -	$ 3,500,000
Upgrades to Grid (138 kV 150 km Teslin to Whitehorse)					$ -	$ 82,500,000
SUB-TOTAL	**$ 128,600,000**	**$ 80,100,000**	**$ 121,000,000**	**$ 84,600,000**	**$ 119,600,000**	**$ 333,400,000**
EPCM ENGINEERING COST (8 % of ESTIMATED CONSTRUCTION COST)	$ 10,300,000	$ 6,400,000	$ 9,700,000	$ 20,300,000	$ 9,600,000	$ 26,700,000
CONTINGENCY (30 % of ESTIMATED CONSTRUCTION COST)	$ 38,600,000	$ 24,000,000	$ 36,300,000	$ 26,100,000	$ 35,900,000	$ 100,000,000
TOTAL ESTIMATED CAPITAL COST	**$ 177,500,000**	**$ 110,500,000**	**$ 167,000,000**	**$ 131,000,000**	**$ 165,100,000**	**$ 460,100,000**

M:\1\03\00556\06\A\Report\1 - Yukon Hydropower Potential Assessment (10-30 MW)\Rev 0\Tables and Figures\

NOTES:
1. DOES NOT INCLUDE UPFRONT ENVIRONMENTAL, PERMITTING AND OWNERS COSTS.
2. DOES NOT INCLUDE APPLICABLE SALES TAXES.
3. EPCM COSTS INCLUDE DETAILED ENGINEERING, TENDERING OF CIVIL AND WATER-TO-WIRE CONTRACTS, SITE SUPERVISION, OVERALL PROJECT MANAGEMENT AND ENVIRONMENTAL MONITORING.
4. COSTS ARE PRELIMINARY AND ARE CONSIDERED EQUIVALENT TO AN AACE CLASS 5 ESTIMATE.
5. ATLIN COSTS ARE BASED COSTS REPORTED BY MORRISON HERSFIELD 2016 ESCALATED AT 2.5%.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
0	25NOV19	ISSUED WITH REPORT VA103-556/6-1	BXF	SDR

8.2 RECOMMENDATIONS

8.2.1 FIRST NATIONS

All 5 of the sites (Primrose, Drury, Tutshi, Atlin, and Wolf River) short listed for concept development will require the involvement of First Nations and other stakeholders to make them a success. In British Columbia, renewable energy has become an important industry for First Nations and it has been an industry First Nations have embraced because projects can be developed with minimal impacts to their rights, environment, and within their values. It is possible the Yukon may experience a similar situation.

Judith Sayers for the BC First Nations Clean Energy Working Group indicates that First Nations with clear Economic Development Plans, Land Use Plans and Community Energy Policies in place before they start involvement with renewable energy projects have an easier time finding an acceptable community direction regarding such projects. Ensuring that renewable energy development is considered in those plans is of key importance. (Source: https://www.cleanenergybc.org/wp-content/uploads/2016/04/BC-FN-Toolkit.pdf).

8.2.2 TECHNICAL EVALUATION

Further evaluation of the preferred sites is recommended, to improve the design basis, project configurations, and understanding of hydrological and geotechnical conditions. The following activities are recommended:

- Set the projects energy objectives, including the required installed capacity and winter energy generation potential to meet the forecasted energy and power demands in the Yukon
- Undertake a screening assessment of social and environmental permitting constraints at each of the five preferred sites
- Obtain accurate mapping (such as satellite topography) for the proposed project areas to confirm project configurations and details including dam sizes, water conveyance routings, available generation head, powerhouse locations, access roads, and transmission lines
- Implement hydrological data collection programs at the preferred sites or reinforce existing programs
- Conduct preliminary site visits to the preferred sites to further evaluate technical viability
- Update energy estimates based on hydrology data and accurate depth-area-capacity curves for reservoirs
- Update quantity and cost estimates

Should the above assessment indicate that there are no critical technical or environmental barriers to development, detailed evaluation of the sites through pre-feasibility and feasibility studies should be pursued to prove economic viability.

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Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

10.0 CERTIFICATION

This report was prepared and reviewed by the undersigned.

Prepared:

Boris Fichot, P.Eng.
Senior Engineer

Reviewed:

Scott Rees, P.Eng.
Senior Engineer

This report was prepared by Knight Piésold Ltd. for the account of Yukon Energy Corporation. Report content reflects Knight Piésold's best judgement based on the information available at the time of preparation. Any use a third party makes of this report, or any reliance on or decisions made based on it is the responsibility of such third parties. Knight Piésold Ltd. accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions based on this report. Any reproductions of this report are uncontrolled and might not be the most recent revision.

Approval that this document adheres to the Knight Piésold Quality System:

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

APPENDIX A

Historical Documents and Hydropower Project Sites

(Table A.1)

Knight Piésold CONSULTING

VA103-556/6-1 Rev 0
November 25, 2019

Knight Piésold CONSULTING

TABLE A.1

YUKON ENERGY
REGIONAL HYDROPOWER ASSESSMENT

HISTORICAL DOCUMENTS AND HYDROPOWER SITES

Print Nov/25/15

Reports	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Date	Aug-66	Jan-88	Dec-69	Feb-70	Jan-75	1977	Nov-80	Oct-80	Nov-90	Aug-91	Oct-82	Mar-82	Feb-82	Feb-82	Feb-82	Jun-82	Sep-82	Mar-83	Oct-83	Dec 1985	Dec 1990	Jun-05	Feb-08	Jan-10	Jan-11	Sep-14	Jan-15	
Author	Department of Mines and	T. Ingledow & Associates Ltd.	Montreal Engineering	Northern Canada Power Commission + Francis River Power Syndicate	T. Ingledow & Associates Ltd.	Sigma Resource Consultants Ltd.	Montreal Engineering	Morrenco Consultants Pacific	Shawinigan Engineering	Morrenco Consultants Pacific	Shawinigan Consultants Ltd.	Shawinigan Stanley	Acres Consulting Services Ltd.	SNC Constants Ltd.	Crippen Consultants	Crippen Consultants	Morrenco Consultants Pacific	Morrenco Consultants Pacific	Morrenco Consultants Pacific	A.S. Demers	A.S. Demers	(No Stated Author, Stored in	KGS Group Inc.	AECOM Canada Ltd.	AECOM Canada Ltd.	Marc-Andre Lavigne	Midgard Consulting Inc.	Midgard Consulting Inc.
Title	A Preliminary Appraisal of the Yukon-Taiya and Yukon-Taku	Hydro-electric Resources Survey of the Central Yukon Territory	Northern Canada Power Commission + Francis River Power Syndicate Report	Pelly River and Yukon River Basin Yukon and Northwest	The Development of Power in the Yukon (Main Report, Technical	Francis River - Upper Canyon: Preliminary Study of a 25.2 MW	Mid-Yukon Feasibility Study, Year 1, Vol. 1, Summary Report	Teslin River Hydro Power Study	Yukon Mining Hydro Power Study of Small to Mid- Size	False Canyon Hydro Prefeasibility Study, Mid-Yukon Region	Environmental and Socio-Economic Studies of Five Hydro	False Canyon Hydro Prefeasibility Study	Granite Canyon Development Pre-Feasibility Study	Prefeasibility Study of a Hydroelectric Site at Ross	Hoole Canyon Hydroelectric Project 1981 Site Investigation	Hoole Canyon Hydroelectric Project Prefeasibility Study	Yukon Hydro Coordination Conclusions from	Northern Canada Power Commission Slate Rapids	The Inventory of Yukon Hydroelectric Sites: A Review of	Yukon Energy Corporation, 1989 Hydro Investigations	Yukon Energy Corporation 1990 Hydro Investigations	1991 Hydro Investigations	Assessment of Potential Hydroelectric Sites Dossier	2009 Large Hydro Stage 1 Initial Evaluation Draft Report	Preliminary Power Potential Assessment for Homan Lake	EMAL: Next Generation Hydro	Yukon Next Generation Hydro and Transmission Viability Study	Yukon Next Generation Hydro and Transmission Viability Study
Reports	1	2		3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
Project Name																												
Aberdeen Canyon					X														X					X		X	
Alder Creek																												
Anvil Creek		X			X														X	X					X	X		
Atlin Storage																							X	X		X	X	
Bates Canyon					X																					X		
Bates Canyon + Dezadeash Diversion					X														X					X		X		
Beaver Crow				X															X					X		X		
Bell					X														X					X		X		
Big Campbell Creek																												
Big Kalzas Lake		X			X														X							X		
Big Salmon					X														X					X		X		
Blind Creek																												
Bonanza Creek																												
Bonnet Plume																								X		X		
Boundary					X														X					X		X		
Bradens Canyon		X			X														X					X		X		
Bradens Canyon + Fortin Lake Dam		X			X														X					X		X		
Britannia					X														X					X		X		
Burwash																												
Campbell Creek																								X		X		
Cassiar Bar																								X		X		
Chandindu River		X			X																	X				X		
Coal River																								X		X		
Dawson					X														X					X		X		
Detour Canyon		X			X																			X		X	X	
Detour Canyon + Fortin Lake Dam		X			X														X					X		X	X	
Doll Creek																												
Donjek to White River Diversion		X			X														X			X				X		
Drury Creek		X			X															X	X		X			X		
Duke																												
Eagle's Nest Bluff (Alone)							X				X								X					X		X		
Eagle's Nest Bluff + Rink Rapids (1 PH)							X				X								X					X		X		
Eagle's Nest Bluff + Rink Rapids (2 PH)							X				X								X					X		X		
Earn		X			X														X	X						X		
Ethel Lake		X			X														X							X		
False Canyon				X	X				X	X	X	X					X							X		X	X	
Fantasque				X															X					X		X		
Fifteen Mile Diversion		X			X														X			X				X		
Finlayson																					X			X		X		
Five Fingers High (150 MW)					X														X					X		X		
Five Fingers High (455 MW)					X														X					X		X		
Five Fingers Low (75 MW)					X														X					X		X		
Forty Mile River		X			X														X			X				X		
Frances River (Lower Canyon)				X	X																			X		X	X	
Fraser Falls (High)		X			X														X					X		X	X	
Fraser Falls (Low)		X			X																			X		X	X	
Gladstone Diversion																							X			X		
Glenlyon																												
Granite Canyon (Large)		X			X						X		X						X		X			X		X	X	
Granite Canyon (Small)		X			X						X		X						X		X			X		X	X	
Hess Canyon		X			X														X					X		X		
Homan Lake																						X		X	X	X		
Hoole Canyon		X									X									X				X		X		
Hoole Canyon + Fortin Lake Dam		X			X				X		X				X	X	X			X				X		X	X	
Hoole River																								X		X		
Hootalinqua					X														X							X		
Hyland Diversion				X															X		X			X		X		
Ibex																												
Independence		X			X														X					X		X		
Indian River		X			X														X			X				X		
Kathleen Canyon																								X		X		
Kluane Canyon		X			X														X	X					X	X		
Koidern																												
Lake Creek Diversion		X			X														X							X		
Lapie																						X				X		
Liard Canyon				X	X														X		X			X		X		
Little Rancheria River																								X		X		
Little Salmon Dam									X										X							X		
Little Salmon Diversion		X			X															X						X		
Lower Canyon on White River		X			X														X							X		
Lynx and Wolverine																												
McNaughton Creek																					X		X			X		
McNeil		X			X														X							X		
McQuestin																												
Meister River																								X		X		
Mica Creek		X			X														X							X		
Middle (or Lower) Canyon (Large)					X														X					X		X	X	
Middle Canyon (38 MW Version)																								X		X		
Middle Site										X														X		X		
Moon Lake + Tutshi River Outlet Site A Cluster																					X		X	X		X		
Moon Lake + Tutshi Windy Arm Outlet Site B Cluster																					X		X	X		X		
Moon Lake A																					X		X	X		X		

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Reports	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Date	Aug-68	Jan-68	Dec-69	Feb-70	Jan-75	1977	Nov-80	Oct-80	Nov-80	Aug-81	Oct-82	Mar-82	Feb-82	Feb-82	Feb-82	Jun-82	Sep-82	Mar-83	Oct-83	Dec 1988	Dec 1990	Jun-05	Feb-08	Jan-10	Jan-11	Sep-14	Jan-15		Oct-16
Author	Department of Mines and	T. Ingledow & Associates Ltd.	Montreal Engineering	T. Ingledow & Associates Ltd.	Sigma Resource Consultants Ltd.	Montreal Engineering	Monenco Consultants Pacific	Shawinigan Engineering	Monenco Consultants Pacific	Shawinigan Stanley	Northwest Hydraulic Consultants Ltd.	Shawinigan Stanley	Acres Consulting Services Ltd.	SNC Consultants Ltd.	Crippen Consultants	Crippen Consultants	Monenco Consultants Pacific	Monenco Consultants Pacific	Monenco Consultants Pacific	A.S. Demers	A.S. Demers	(No Stated Author, Solved in	KGS Group Inc.	AECOM Canada Ltd.	AECOM Canada Ltd.	Marc-Andre Lavigne	Midgard Consulting Inc.	Midgard Consulting Inc.	Knight Piesold Ltd.
Title	A Preliminary Appraisal of the Yukon-Taiya and Yukon-Taku Hydro-electric Resources Survey of the Pelly River Basin	Hydro-electric Resources Survey of the Pelly River Basin	Northern Canada Power Commission - Francis River Power Survey of the Laird River Basin Yukon and Northwest	The Development of Power in the Yukon Mayo-Dawson District	Francis River - Upper Canyon Preliminary Study of a 26.2 M.W.	Mid-Yukon Feasibility Study, Year 1; Vol 1; Summary Report	Teslin River Hydro Power Study	Yukon Mining Hydro Power Study of Small to Mid- Size	False Canyon Hydro Prefeasibility Study: Mid-Study Report	Evaluation and Economic Studies of Five Hydro	False Canyon Hydro Prefeasibility Study	Granite Canyon Development Pre Feasibility Study	Preliminary Study of a Hydroelectric Site at Ross	Hoole Canyon Hydroelectric Project 1981 Site Investigation	Hoole Canyon Hydroelectric Project Investigations	Yukon Hydro Investigations Coordination Conclusions from	Northern Canada Power Commission Slate Rapids	The Inventory of Yukon Hydroelectric Sites - Review of	Yukon Energy Corporation: 1989 Hydro Investigations	Yukon Energy Corporation: 1990 Hydro Investigations	1991 Hydro Investigations	Assessment of Potential Hydroelectric Sites: Concept	2009 Large Hydro Stage 1: Initial Evaluation Draft Report	Preliminary Power Potential Assessment Tributaries Lake	EMAIL: Next Generation Hydro	Yukon Next Generation Hydro and Transmission Viability Study	Yukon Next Generation Hydro and Transmission Viability Study	YEC Small Hydroelectric Projects - Screening Assessment
Reports	1	2		3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Project Name																													
Moon Lake C																					X		X	X		X	X		
MoonLake B																							X	X			X		
Morley River																					X	X	X			X	X		X
North Fork Klondike River																					X						X		X
North McQuesten		X			X														X								X		X
NWPI (High)																							X				X		
NWPI (Low)		X			X			X											X				X				X	X	
Ogilvie					X														X				X				X		
Orchay																					X						X		X
Pleasant Creek		X			X														X		X						X		X
Pleasant Creek with Rogue Diversion		X			X																X						X		X
Porcupine		X			X														X				X				X		
Porcupine Canyon					X														X				X				X		
Prevost Canyon		X			X														X	X							X		X
Primrose Diversion Scheme (To Takhini Lake)																				X							X		
Primrose Lake to Takhini Lake Diversion		X																	X								X		
Quartz Creek				X															X				X				X		
Quiet Lake Diversion		X			X														X								X		X
Quiet Lake Diversion + Rose River Diversion		X																	X								X		X
Rancheria																							X						
Reid Lakes and Lake Creek																													X
Rock Creek																													X
Rogue		X			X														X								X		X
Rose Creek																													
Rose Lake to Kusawa Lake Diversion		X			X														X							X	X		X
Ross Canyon		X			X			X		X				X			X		X	X			X				X		
Saucy Creek				X															X				X				X		
Seven Mile Canyon		X			X														X								X		X
Site 124																							X				X		
Site 127																							X				X		
Sixty Mile River Diversion		X			X														X			X					X		X
Slate Rapids (Diversion Scheme)																		X		X			X			X	X	X	
Slate Rapids (Powerhouse in Main Dam)																		X		X			X			X	X		
Squanga Creek																				X		X				X	X		X
Surprise Lake																													
Swede Creek																													
Swift																							X				X		
Swift River																							X				X		
Tatshenshini + Dezadeash / Kusawa Diversion					X														X								X		
Tatshenshini + Dezadeash Diversion					X																		X				X		
Tay River		X			X														X				X				X		
Tenas Creek (Orchay Diversion)																													
Thane Creek																													
Tootsee River																													X
Tutshi River Outlet Site A (Lake to Lake)																					X		X				X		
Tutshi River Outlet Site A (Lake to River)																					X		X				X		
Tutshi River Outlet Site A (River to Lake)																					X		X				X		
Tutshi River Outlet Site A (River to River)																					X		X				X		
Tutshi Windy Arm Outlet Site B (East PH)																							X				X		X
Tutshi Windy Arm Outlet Site B (West PH)																							X				X		
Two Mile Canyon		X			X														X								X	X	
Upper & Lower Primrose (2008 Layout)																				X	X		X				X		X
Upper Canyon (Large) -Francis River				X	X	X	X												X							X	X	X	
Upper Canyon (Medium) -Francis River				X	X	X	X												X							X	X	X	
Upper Canyon (Small) -Francis River				X	X	X	X												X							X	X	X	
Upper Canyon on White River		X			X														X								X		
Watson Lake																										X	X		X
Watson River		X			X																						X		X
Wind																											X		
Wolf River					X														X		X	X					X		X
Wolverine					X														X								X		
Yukon-Taiya	X				X														X								X		
Yukon-Taku	X				X														X								X		

M:\1\03\00558\08\A\Report\1 - Yukon Hydropower Potential Assessment (10-30 MW)\Rev 0\Appendix A\[Appendix A.xlsm]Table A.1

0	29NOV19	ISSUED WITH REPORT YUK-ENGR-1	BJF	SGS
REV	DATE	DESCRIPTION	PREP'D	ROV'D

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

APPENDIX B

Site Descriptions

(Pages B-1 to B-9)

APPENDIX B
SITE DESCRIPTIONS

The projects passing the coarse screen have been reviewed below and numeric details about each site can be found in **Error! Reference source not found.** of the main report. On occasion sites previously lacking information have been added to the Table for completeness or a further site-specific review revealed the site should be dismissed from consideration or added for consideration.

1.0 CLUSTER 1 – AISHIHIK-WHITEHORSE 138 KV

1.1 PRIMROSE

This site was short listed. See Section 7.1.

2.0 CLUSTER 2 – CARMACKS-WHITEHORSE 138 KV

2.1 IBEX RIVER

A concept for a 3.5 MW run-of-river on the Ibex River was investigated and dismissed based on size and cost. The site is a bit too far removed from transmission and access to be viable. It does benefit from a nearby stream gauge that could help in refining the energy generation assessment.

3.0 CLUSTER 3 – CARMACKS-FARO 138 KV

3.1 ANVIL

A few run-of-river configurations were considered up and down Anvil Creek. The project location has been previously been associated with Anvil Lake, a site that does not offer the same generating opportunities. The most attractive options for Anvil Creek assume long tunnels, resulting in average to higher LCOE returns, as such the project was not shortlisted. It was only possible to fully regulate the river for winter generation with a very tall dam structure, which proved to be cost prohibitive (i.e. $1 billion for 30 MW of firm winter generation).

3.2 DRURY

This site was short listed. See Section 7.2.

3.3 GLENLYON

Glenlyon offers the opportunity for a lake storage project or a run-of-river project but falls short of the desired installed capacity and is a bit too isolated and costly.

3.4 LITTLE SALMON

The Little Salmon Lake outlet offers little in the way of elevation differential given the current available topography. It is also not believed that it would be an environmentally acceptable site given its use for recreational angling and the name of the lake. It was elected not to consider the site for a high dam.

3.5 TAY RIVER

The Tay River forms a large watershed but it's existing WSC stream gauge indicates (perhaps inaccurately) a very low unit runoff (2.4 l/s/km^2). The gauge information also reveals the site offers a poor winter generation profile even at a low design factor. The site is also a bit too distant from transmission and access increasing its cost.

4.0 CLUSTER 4 - STEWART CROSSING - CARMACKS 138 KV

4.1 LAKE CREEK AND REID LAKES

Lake Creek offered the opportunity for an average run of river project. A Reid Lakes storage project could only be built with a diversion from Lake Creek (through the run of river project). Reid Lakes is a flat system of lakes that appear difficult to keep contained based on the available topographical observations; as a result, it is not able to provide full impoundment for winter generation limiting the concepts value.

Reid Lake was nevertheless a relatively interesting winter energy option, but when averaged with the inclusion of the Lake Creek cost and energy it fell off the project short list, particularly given the requirement for an interbasin transfer.

4.2 GRANITE CANYON

The Granite Canyon project site is located on the Pelly River, approximately 20 km east of Pelly Crossing. It is considered as a small run-over river project on a very large system, the total drainage area is estimated to be 46,200 km^2. The site proved one of the more difficult to evaluate at a very high level as the temporary works costs could outweigh the costs of the permanent works, but this is difficult to evaluate without a detailed assessment.

The Granite Canyon site was previously designed as a potential 254 MW hydroelectric project. The project first appeared in T. Ingledow & Associates Limited's report entitled "Hydroelectric Resources Survey of the Central Yukon Territory" in 1968 and subsequently revisited in Sigma Resource Consultants Limited's 1975 "The Development of Power in the Yukon" report.

KP has not had the opportunity to review the Acres Consulting Services Limited's (Acres) 1982 "Granite Canyon Development Prefeasibility Study" or the AECOM Canada Limited's 2010 "Large Hydro Stage 1" report. The Acres 1982 preliminary project layout included a large facility with a 100 m high concrete arch dam and a smaller 50 m high arch dam configuration with a crest gate spillway structure built into the dam. The water intake, conveyance, powerhouse, and tailrace structures were located on the west abutment of the river. Diversion tunnels were located under the east abutment of the river to facilitate de-watering of the dam site during construction.

KP's rapid assessment assumes a 25 m, concrete faced rockfill dam and a low design flow factor (0.25 x MAD). The initial cost estimate indicates that the project site had a low LCOE and a decent winter energy profile but was not short listed due to perceived social acceptability and permitting risks.

4.3 MICA CREEK

Taltmain Lake offers the ability to regulate the Mica Creek flows however we assume a low unit runoff for the area and there appears to be insufficient drop in elevation to justify a 10 MW project size.

5.0 CLUSTER 5: DAWSON CITY - STEWART CROSSING 69 KV

5.1 ALDER CREEK, BONANZA CREEK, FIFTEEN MILE DIVERSION, FORTY MILE RIVER AND INDIAN RIVER, SWEDE CREEK, AND THANE CREEK

These projects were evaluated on a run-of-river basis as they offered decent drainages or elevation drops but their assumed poor unit runoffs and a lack of winter generating potential make them unsuitable based on current assumptions.

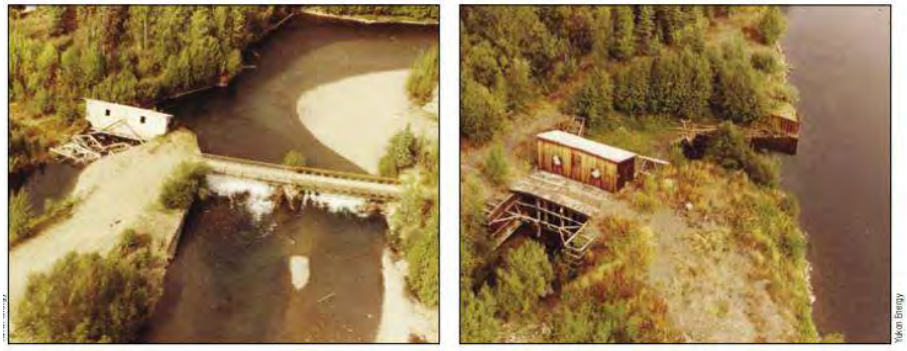
5.2 MCQUESTIN

McQuestin is a sizable river basin (3,769 km^2) and offered some promise as a small section of the river appears on the mapping to show a 60 m drop over a 9 km distance. The existing stream gauge on the river offered some certainty around the unit runoff. The cost estimate puts the project in a high but viable range for further consideration.

5.3 NORTH FORK KLONDIKE RIVER

A plant used to exist on the Klondike River at North Fork. YEC information reveals:

“The North Fork plant operated until 1966, when the last Yukon Consolidated Gold Company dredge shut down. A number of studies have been undertaken over the years to explore the feasibility of re-activating the North Fork plant. All have recommended against it, largely because of the difficulty of maintaining power production through the winter months when demand is the highest.”



NOTE:
1. SOURCE: HTTP:/ /WWW.ENERGY.GOV.YK.CA/PDF/POWER_OF_WATER.PDF

Figure 5.1 North Fork Plant (Photos)

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

Powerhouse at North Fork, (left) 1922 and (right) interior, 1913. In 1935, the building was extended to house a third unit.

NOTE:
2. SOURCE: HTTP:/ /WWW.ENERGY.GOV.YK.CA/PDF/POWER_OF_WATER.PDF

Figure 5.2 North Fork Plant (Photos)

For this review KP considered a 10 MW project with a 10 m dam on the Klondike River at North Fork, elevation was limited due to the presence of bridges and the Klondike Highway.

6.0 CLUSTER 6 - STEWART CROSSING - MAYO 69 KV

No sites investigated.

7.0 CLUSTER 7: PROPOSED MAYO TRANSMISSION EXPANSIONS

7.1 BIG KALZAS LAKE

Big Kalsas Lake offers the opportunity of a 10 MW project with storage and regulation on the lake for winter generation. The cost estimate reveals it is on the higher end of the LCOE.

7.2 FRASER FALLS

A project at Fraser Falls would likely backwater the Horseshoe Slough Habitat Protection Area.

The available topography does not currently allow the identification of any specific drop in elevation at the fall's location. As a result, the project configuration assumed a dam would be the only means of providing any elevation drop. Fraser Falls drain an area in excess of 30,000 km^2. The assumed project costs end up being very high due to the very large temporary work costs.

7.3 PLEASANT CREEK WITH ROGUE DIVERSION

A further look into the access and transmission distances gave reason to remove this site from consideration due to the very high access and temporary works costs.

7.4 SEVEN MILE CANYON

Seven Mile Canyon offer the opportunity for a low head run of river project with a 20 m high structure, but the remoteness and configuration of the project resulted in a higher LCOE.

8.0 CLUSTER 8: PROPOSED FARO TO WATSON LAKE

During the second stage of screening, it was elected not to short list projects along the proposed Faro to Watson route. Lapie and Ross Canyon were still considered due to there proximity to the existing YEC transmission line at Faro.

8.1 BIG CAMPBELL CREEK

The Campbell Creek site was listed in the 2010 AECOM report as “no defined scheme” with a report reference from a 1980 Moneco report. Midgard reviewed the two 1980 Moneco reports available, but neither mentioned the site. The Campbell Creek site was listed in the 1983 Moneco summary report with the statement “not yet studied”. Due to the lack of available site information, it was previously discarded by Midgard. KP had also considered Campbell Creek but Big Campbell Creek is the name of the actual location considered. The site offers the possibility of a 10 MW run of river, but with a high LCOE.

8.2 BLIND CREEK

Small sub 10 MW run of river project that benefits from Anvil Lake.

8.3 CAMPBELL CREEK

In adequate site, possibly confused with Big Campbell Creek in previous studies.

8.4 FALSE CANYON OR FRANCES RIVER (LOWER CANYON)

The site may have been referred to previously as Frances River (Lower Canyon).

False Canyon on the Frances River offers the opportunity for a low head run of river project in a relatively restrained canyon, near the Robert Campbell Highway and the proposed transmission. A 15 m structure would allow for a 15 MW facility.

8.5 FINLAYSON

The Finlayson River is a major tributary to Frances Lake and the Frances River, in the Liard River watershed. The Finlayson River Project is located adjacent to the Robert Campbell Highway and just upstream of Frances Lake, approximately 300 km to the northeast of Whitehorse. The project site was previously short listed by KP.

The current design concept involves a run of river diversion on Finlayson River downstream of the Wolverine River confluence with possible lake storage and flow regulation on Finlayson Lake and Wolverine Lake. The Finlayson site could function as a run of river project on its own merits due to the relatively large drop in elevation. The project could easily be staged as the added controls at Finlayson Lake and Wolverine Lake are distinct sites that simply add value to the run-of-river project.

The site was relatively attractive but was removed from consideration with the removal of the Faro to Watson Lake proposed line.

8.6 FORTIN LAKE DAM

The Fortin Lake site was evaluated as a 6 MW and 10 MW storage site. Its value lies in regulating the Pelly River Flows for the benefit of downstream generation sites. Based on available topography a 25 m structure should offer a large amount of storage without needing to construct multiple saddle dams.

8.7 FRANCIS RIVER (MIDDLE)

On the Frances River, near the Frances River bridge on HWY 4 a narrow portion of the river offers the opportunity for a low head run of river project. A 20 m structure would allow for a 15 MW facility.

8.8 HOOLE CANYON

Hoole Canyon on the Pelly River offers the opportunity for a low head run of river project in a relatively restrained canyon, near the Robert Campbell Highway and the proposed transmission. A 25 m structure would allow for a 12 MW facility.

8.9 HOOLE CANYON + FORTIN LAKE DAM

If the two projects are combined, they offer a firmer winter generation profile for smaller individual installed capacities.

8.10 HOOLE RIVER

The Hoole River site was listed in the 2010 AECOM report but was cut due to having “no defined scheme”. Midgard’s review of all available previous studies revealed no other mention of the Hoole River Project. Due to the lack of available information on the site, it was previously discarded. For the purpose of this study a 12 MW project resulting from a low head 20 m structure is proposed.

8.11 HYLAND RIVER

Hyland River at the Hyland Canyon offer the opportunity for a dam and some drop river elevation. The project site is a bit removed from other infrastructure increasing the potential project cost.

8.12 LAPIE

Lapie is an attractive run of river site and is located close to exiting transmission at Ross River. This study did not evaluate the large number of design permutations that are possible to optimize this site, as the drainage area varies greatly as the potential intake is pushed upstream for greater project head.

8.13 LIARD CANYON

The proper evaluation of Liard Canyon suffers from some topographical and mapping uncertainty at the border between British Columbia and the Yukon. A more detailed look at the site revealed that it is likely that a dam structure would impact the community of Watson Lake, as such the project was removed from further consideration.

8.14 LITTLE RANCHERIA RIVER

The 2010 AECOM report references the 1990 Demers report as a source for the Little Rancheria River site. The Little Rancheria site was listed in the 2010 AECOM report (with no stated capacity or energy) but was cut due to being a "very distant site". Midgard's review reveals the Little Rancheria River site was subject to reconnaissance study only in 1990, and no sites were identified. Due to the lack of available site information, it was previously discarded.

The current evaluation assumes a run-of-river project could be developed at the site with a long penstock, but the project is rather distant from the proposed transmission.

8.15 ROSS CANYON

Ross Canyon on the Ross River offers the opportunity for a low head run of river project in a relatively restrained canyon, near the community of Ross River. A 40 m structure would allow for a 15 MW facility. The site was looked at with a long conveyance system in lieu of a large dam but the capital cost would have increased. The site was removed from further consideration to a perceived lack of social licence. The project would also affect Canol Road #6.

8.16 SLATE RAPIDS

Slate Rapids as previously designed, is a potential 42 MW hydroelectric project on the Pelly River, located in the Pelly River Basin approximately 75 km east of the community of Ross River. The project first appeared in Moneco Consultants Pacific Limited's report entitled "Slate Rapids Hydropower Development" in 1983. It was subsequently revisited in A.S. Demers' 1989 "Yukon Energy Corporation: 1989 Hydro Investigations", and in AECOM Canada Limited's 2010 "Large Hydro Stage 1" report.

Given the range of projects considered 10-30 MW and the fact the Slate Rapids site was difficult to contain requiring multiple saddle dams, the use of Fortin Lake with a smaller structure seemed to be a better option for consideration.

8.17 TYERS RIVER

Tyers River is large drainage tributary of Frances Lake and offers the opportunity for a run of river project, but it is a bit removed from major infrastructure.

9.0 CLUSTER 9 - PROPOSED BEAVER CREEK TO HANES JUNCTION

9.1 LOWER CANYON ON WHITE RIVER

The Lower Canyon on White River is located immediately upstream of the Alaska Highway #1 White River Bridge. The area offers a narrowing of the glacier fed river, creating the potential for a 25 m structure and a 15 MW project.

9.2 DONJEK RIVER

KP Considered a low head run of river project on the Donjek River, it has very similar characteristics to the White River project but with the added costs of being more distant from the proposed transmission line and existing roads. It does drain a slightly larger area.

9.3 KOIDERN

The Koidern Project is a proposed glacier fed run-of-river hydropower development located between Haines Junction and Beaver Creek in southwestern Yukon. The Koidern River is a tributary of the Kluane River. The proposed powerhouse location is within 5 km of the Alaska Highway. It was selected as it is indicative of a more compact and cost-effective type of run-of-river project. It offers lower LCOE despite not offering any dependable capacity.

The project location is outside the bounds of the Asi Keyi Territorial Park, but the intake structure is proposed within the bounds of the Kluane Wildlife Sanctuary. The powerhouse is located outside the area bounds. It is not believed that this particular type of run-of-river development would be in conflict with the objectives of these protected areas, chiefly:

- To provide economic opportunities for Kluane and White River First Nation people.
- To recognize and protect the traditional and current use of the area by Kluane and White River First Nation people.
- To encourage public awareness, appreciation and enjoyment of the natural, historical and cultural resources of the park in a manner that will ensure it is protected for the benefit of future generations.
- To protect, for all time, a natural area of territorial significance, which includes a portion of the Kluane Wildlife Sanctuary, containing physical and biological features of international significance as well as sites of archaeological, historical and cultural value.

It is understood that the management planning for these areas began in April 2015 and is ongoing and that the Government of Yukon and the two affected First Nations will jointly review the plan before it is approved by Yukon's Minister of Environment.

A basic arrangement for the proposed project layout is shown on **Error! Reference source not found.**. Key project parameters for this layout are as follows:

- Design Flow: 16.4 m^3/s
- Gross Head: 140 m
- Installed Capacity: 16 MW
- Dependable Capacity: 0 MW (This project is a glacier fed run-of-river project and does not offer much in the way of winter generation)
- 10 km of access roads, to reach the powerhouse, penstock, and intake
- A run-of-river intake with a small headpond (El. 930 masl.)
- A 7 km long penstock.
- A Powerhouse and tailrace (El. 790 masl)
- A Substation and 20 km long transmission line to a potential transmission line along the Alaskan Highway

9.4 LYNX AND WOLVERINE

Like Koidern, the site offers the opportunity for a high head freshet driven run of river project.

9.5 BURWASH

Like Koidern, the site offers the opportunity for a high head freshet driven run of river project.

9.6 DUKE

Like Koidern, the site offers the opportunity for a high head freshet driven run of river project.

10.0 CLUSTER 10: WHITEHORSE-CARCROSS-JAKE'S CORNER-JOHNSON'S CROSSING-TESLIN 34KV

10.1 SQUANGA CREEK

A development at Squanga Creek would not meet the 10 MW criteria threshold.

10.2 WOLF RIVER

This site was short listed. See Section 7.5.

11.0 CLUSTER 11: PROPOSED EXTENSION FROM CARCROSS TO SKAGWAY

11.1 MOON LAKE

Moon Lake is located roughly 100 km south-southeast from Whitehorse, and 18 km south of the BC Yukon border, and it drains into Tutshi Lake from the south and is ultimately a tributary to the Yukon River, above Whitehorse. While the site was attractive site that had been previously reported in some detail and offered storage capability but was below 10 MW in capacity at a design flow of 2.2 x MAD. The project would also be too small to support a transmission line to Carcross on its own merit.

11.2 TUTSHI LAKE

This site was short listed. See Section 7.3.

12.0 CLUSTER 12 - PROPOSED EXTENSION FROM JAKE'S CORNER TO ATLIN

12.1 SURPRISE LAKE AND THE ATLIN HYDRO PROJECT

This site was short listed. See Section 7.4.

Appendix F:
Knight Piesold Pumped Storage Report

Knight Piésold CONSULTING

November 27, 2019

Mr. Hector Campbell
Chair, NNDDC Board
Campbell's North Consulting
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Dear Hector,

RE: Moon–Tutshi Pumped Storage Options

1.0 INTRODUCTION

1.1 REQUEST FOR INFORMATION

YEC (Yukon Energy Corporation) has requested Knight Piésold (KP) to add the Moon-Tutshi pumped storage project to the short-listed sites for its report "Hydropower Potential Assessment (10 MW – 30 MW)". This letter report has been prepared to provide the relevant information for the Moon-Tutshi pumped storage project separately, as the assessment parameters and characteristics of the proposed pumped storage development are not easily comparable to a traditional hydropower project and are best presented in a separate report.

As requested, KP modeled the proposed Moon-Tutshi Pumped Storage Project, assuming the following development options:

- 15 MW installed capacity and 25 GWh/yr of continuous winter generating capability
- 15 MW installed capacity and 50 GWh/yr of continuous winter generating capability
- 25 MW installed capacity and 50 GWh/yr of continuous winter generating capability
- 35 MW installed capacity and 50 GWh/yr of continuous winter generating capability

1.2 PURPOSE

The proposed purpose of the Moon-Tutshi Pumped Storage Project would be as follows: a pump storage project between Tutshi Lake and Moon Lake designed to seasonally store freshet energy from other Yukon hydropower assets and provide additional winter generation potential to YEC. A pumped storage project would also provide greater flexibility within the YEC grid to allow for easier integration of solar and wind renewables.

1.3 PROJECT SITE AND BASIC CONCEPT

Moon Lake is located in British Columbia (BC) approximately 100km south of Whitehorse, and 20 km south of the BC-Yukon border. Moon Lake drains into Tutshi Lake through Moon Creek at a steep gradient. Existing mapping shows an approximate 390 m drop in elevation between the two lakes. Tutsh Lake drains into Tagish Lake and onwards to the Yukon River.

The Klondike Highway linking Carcross Yukon and Skagway Alaska runs along the western shore of Tutshi Lake. Accessing the Moon Lake site will require either a barge or a new road. If a barge is used, new barge

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landings will need to be constructed at a point along the Klondike Highway and at the foot of Moon Creek. If a new access road is constructed, the shortest and most practical route would be along the southern shoreline of Tutshi Lake.

The 2015 study by Midgard of a proposed pumped storage project at Moon-Tutshi Lakes assumes that flows from Tutshi Lake are pumped into the Moon Lake storage reservoir during high flow - low energy demand periods. The Midgard study had not accounted for a new structure at the outlet of Tutshi Lake, which has now been included. Access to the outlet of Tutshi Lake would require either a new 20 km access road from the Klondike Highway or a new barge landing and access road from Tagish Lake. (See Figure 1.1.)

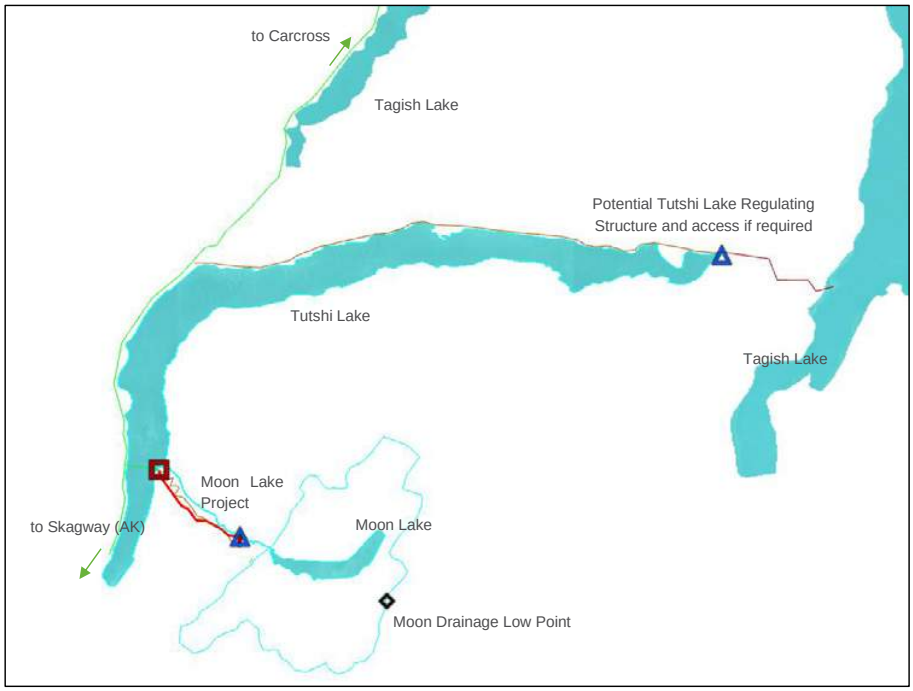

Figure 1.1 Tutshi-Moon Project

The proposed pumped storage project will create a large reservoir for storage on the existing Moon Lake and draw flows as need for generation from this new Moon Lake Reservoir. Water stored in the Moon Lake reservoir will come for two sources, including:

- Natural inflows into the reservoir from the Moon Creek catchment
- Pumped water from the lower Tutshi Lake

The Tutshi Lake/T'ooch' Áayi Conservancy was established in 2012 as a result of the Wóoshtin Wudidaa Atlin Taku Land Use Plan and Taku River Tlingit First Nation Strategic Engagement Agreement. The

conservancy, located approximately 65 kilometres northwest of Atlin, encompasses the eastern half of Tutshi Lake. Tutshi Lake is culturally significant to the Carcross/Tagish and Taku River Tlingit First Nations. The lake also has high value lake trout habitat. The Tlingit name (T'ooch' Áayi) means "charcoal lake", after the dark colour of the lake water. Moon Lake is not located within the conservancy, but the outlet of Tushi Lake is.

2.0 CONFIGURATIONS

2.1 PREVIOUS

The 2015 Midgard report proposed a project arrangement comprising the following key components:

- a 31 m high, 700 m long earthfill dam on Moon Lake with a spillway on the south abutment of the dam.
- a low level outlet/intake in both Moon Lake and Tutshi Lake.
- a 5.24 km long, 1.6 m diameter buried steel penstock.
- a powerhouse, with concrete substructure and steel superstructure, containing a 20.2 MW vertical axis Pelton turbine and synchronous generator as well as two 9.4 MW peak power, variable speed drive vertical axis pumps. Flows would be discharged to or drawn from a 7 m deep sump connected to Tutshi Lake.

2.2 PROPOSED

For the purpose of this assessment the layout of the proposed Moon-Tutshi Project has been assumed to be comparable to the Midgard layout, but with differing storage capacities and generation capacities. The Moon Lake dam location and powerhouse location were assumed to be identical; the penstock was assumed to be run on the left bank. The penstock alignment was changed slightly for a more manageable access gradient shortening it by 250m for a total 5km length. These concepts should be further refined if the project is advanced.

The project characteristics for the different development options are presented in Table 2.2 below. The pumping durations presented below were determined based on preliminary modeling of the hydrological system and could be increased in size if desired (i.e. to provide additional flexibility for YEC's Grid for the addition of more renewables such as wind and solar).

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Table 2.1 Moon-Tutshi Project Attributes

	Moon-Tutshi Pumped Storage			
	15 MW	15MW	25MW	35MW
	25 GWh	50 GWh	50 GWh	50 GWh
Moon Lake Minimum Operating Level (masl)	1,114	1,114	1,114	1,114
Moon Full Supply Level (masl)	1,121.5	1,124	1,124	1,124
Tutshi Lake Tail Water Level (masl)	714	714	714	714
Active Storage Variation (m)	7.5	10	10	10
Total Dam Height (m) (assuming 3 m of overburden and 4 m of dead storage and 1 m freeboard)	15.5	18	18	18
Active Storage Volume ($x10^6$ m^3)	40	59	59	59
Design Flow - Generation (m^3/s)	4.4	4.4	7.35	10.25
Design Flow - Pumping (m^3/s)	1.0	3.0	3.0	3.5
Installed Capacity (MW)	15	15	25	35
Full to Empty Energy Storage (GWh)	38	56	56	56
Generation Duration to Empty Reservoir (Days)	106	156	93	67
Pumping Duration to Fill Reservoir (Days)	460	228	228	196
Average Annual Generating Energy (GWh)	33.4	51.8	54.7	59.1
Minimum Annual Generating Energy (GWh)	25.2	47.6	46.2	51.2
Average Annual Pumping Energy (GWh)	14.8	39.5	44.6	51.2
Average Annual Net Energy (GWh)	18.5	12.2	10.1	7.9
Average Whitehorse Hydro Plant Bonus Winter Yield (GWh) based on 140 kW per m3/s	1.4	1.8	1.9	2.1
Average Total Net Energy (GWh)	19.9	14.0	12.0	9.0

3.0 HYDROLOGY AND ENERGY ASSESSMENT

KP assessed the hydrology of both the Moon Lake and Tutshi Lake catchment areas and then developed a daily energy model using the parameters presented in the sections below (Sections 3.1. through 3.6).

3.1 HYDROLOGY

For the purpose of this study, more effort was placed on the assessment of the Moon Lake catchment area, as it is small when compared to the Tutshi Lake catchment area and would therefore be the more critical water resource in terms of the pumped storage hydro assessment. The natural inflows into Moon Lake would also contribute to the energy generation potential of the project, and therefore have a direct impact on the financial viability of the project.

Moon Creek has a drainage area of 57.4 km^2 at the proposed dam on Moon Lake. The existing WSC data shown in Table 3.1 was utilised to determine long-term daily inflows into Moon Lake averaging out to 0.8 m^3/s.

Table 3.1 Stream Gauges

Gauge	WSC	Period	Drainage Area (km^2)	Unit Runoff (l/s/km^2)	Complete Years
Moon Creek near the outlet of Moon Lake	09AA018	2012-2017	53	13.5	4
Tutshi River at outlet of Tutshi Lake	09AA013	1956-2017	989	16.2	50

3.2 TUTSHI LAKE STAGE DISCHARGE RELATIONSHIP

For the purpose of this evaluation is was assumed that the Tutshi Lake elevation is naturally maintained at 1,114 masl. This is not an unreasonable assumption given the relative size of Tutshi Lake compared to Moon Lake.

If this project is advanced to the next stage, it is recommended that existing WSC data be utilized to develop a Tutshi Lake stage discharge curve to simulate the natural control of the lake outlet and then perform the appropriate water balance to determine if there is any significant fluctuation in the Tutshi Lake levels that might impact the energy and power generation potential of the proposed project.

3.3 CYCLE EFFICIENCY

A traditional pumped storage hydroelectric project has a roundtrip efficiency of about 70% (i.e. consumes 30% more energy than it generates). As per the previous studies by KP and Midgard, the same 30% losses have been assumed for the Moon-Tutshi Project. This equates to a combined hydraulic, electrical and mechanical efficiency of 87% while generating and 81 % while pumping for the 15 MW, 25 GWh option.

3.4 YEC SYSTEM BENEFIT

YEC has advised KP that the average winter water to kW conversion at the Whitehorse Hydro Plant is 140 kW per m^3/s. The expected additional annual winter energy yield is shown in Table 2.2.

3.5 STORAGE

For the purpose of this assessment the depth area capacity relationship (DAC) provided by the Midgard has been used in the assessment. The corresponding active storage volumes are shown in Table 2.2.

3.6 OPERATING RULES

The Moon Lake Reservoir is operated on a continual generation basis to the extent possible during the months of November-February or if the reservoir is over 95% full. Pumping is triggered in the months of June-September until the reservoir is 95% full. An instream flow release (IFR or ecological flow) of 5% of the Mean Annual Discharge (MAD) is continually released from the Moon Lake Reservoir to sustain the aquatic habitat in Moon Creek.

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3.7 ENERGY ASSESSMENT

A daily flow energy model was developed for the system that accounted for both the pumped flow into Moon Lake plus the natural inflow into Moon Lake. This makes the Moon-Tutshi Pumped Storage Project somewhat unique, as for all four options for the project are net energy generators (i.e. not consumers like traditional closed loop pumped storage hydro facilities). Table 2.2 presents the results of the study, including:

- Energy required for pumping
- Energy generated from a combination of the pumped flows and natural inflows
- Energy generated through benefits to the YEC grid
- Total Net Energy (GWh/year)

4.0 COST ESTIMATE

The capital cost estimates shown in Table 4.1 are based on the project configurations described in Table 2.2 above. These basic project characteristics were used to establish the sizes of the project components and associated quantities. These technical attributes were used to estimate approximate material volumes for excavation, backfill, embankment material and reinforced concrete. Electrical and mechanical equipment requirements were estimated based on empirical data from KP's prior projects and published reports. The capital cost estimate includes an allowance for the Contractor's preliminary and general costs (overheads, insurance, bonus and profit etc.), an allowance for EPCM costs, and a variable contingency.

Unit rates for material production, equipment procurement and installation costs relied on KP's internal costing database including recent, relevant experience with similar sized hydroelectric projects in Western Canada and the Yukon Territory. KP's hydro project cost database also offered an "order of magnitude check of total estimated costs for individual facility components and complete facilities, based on projects with comparable characteristics such as, design flow, penstock pipe characteristics (length, diameter, etc.), gross head, generating capacity, powerhouse area, excavation quantities, reinforced concrete volumes, backfill quantities, switchyard capacity and transmission line capacity and length. Generating equipment costs are based on installed capacity, head and flow, while switchyard costs are interpolated based on installed capacity.

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Table 4.1 Cost Estimate

	Tutshi-Moon			
	15 MW	**15MW**	**25MW**	**35MW**
	25 GWh	**50 GWh**	**50 GWh**	**50 GWh**
Mod, Demob, Insurance, Bonds, Overheads, Contractor's Profit	$30,500,000	$32,500,000	$41,000,000	$46,800,000
Access and Site Preparation	$6,000,000	$6,000,000	$6,000,000	$6,000,000
Intake, Forebay, and Headrace	$3,200,000	$3,200,000	$4,500,000	$5,700,000
Water Conveyance System	$25,000,000	$25,000,000	$37,500,000	$43,400,000
Powerhouse and Ancillary Services	$11,000,000	$11,000,000	$15,500,000	$18,000,000
Power Generation Equipment (Water to Wire)	$15,000,000	$15,000,000	$25,000,000	$35,000,000
Switchyard, Transmission and Interconnection	$4,000,000	$4,000,000	$4,000,000	$4,000,000
Dams and Reservoirs	$22,500,000	$29,000,000	$29,000,000	$29,000,000
Access and Dam on Tutshi	$15,000,000	$15,000,000	$15,000,000	$15,000,000
Sub-Total	$132,200,000	$140,700,000	$177,500,000	$202,900,000
EPCM	$10,600,000	$11,300,000	$14,200,000	$16,200,000
Contingency	$39,700,000	$42,200,000	$53,300,000	$60,900,000
Total Estimated Capital Cost	**$182,500,000**	**$194,200,000**	**$245,000,000**	**$280,000,000**

NOTES:

1. 2019 CANADIAN DOLLARS (CAD)
2. DOES NOT INCLUDE UPFRONT ENVIRONMENTAL, PERMITTING AND OWNERS COSTS.
3. DOES NOT INCLUDE APPLICABLE SALES TAXES.
4. EPCM COSTS INCLUDE DETAILED ENGINEERING, TENDERING OF CIVIL AND WATER-TO-WIRE CONTRACTS, SITE SUPERVISION, OVERALL PROJECT MANAGEMENT AND ENVIRONMENTAL MONITORING.
5. COSTS ARE PRELIMINARY AND ARE CONSIDERED EQUIVALENT TO AN AACE CLASS 5 ESTIMATE.

5.0 RECOMMENDATIONS

It is recommended that the Taku River Tlingit First Nation and Carcross Tagish First Nation be consulted prior to any serious consideration of the project development. There may be traditional use and cultural values associated with the site that this study does not take into consideration. A more detailed review of site-specific data would be required to confirm project viability and the optimal project size.

Further evaluation of the site is recommended, to improve the design basis, the project configuration, and the understanding of hydrological, topographical and geotechnical conditions. The following activities are recommended:

- Set the project's energy objectives, including the required installed capacity and winter energy generation requirement with a clear purpose for how the plant is envisaged to be utilised.
- Perform a more detailed review of the existing hydrological information.

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- Obtain accurate topographical mapping for the proposed project area to confirm project configurations and details including dam sizes, water conveyance routings, available generation head, powerhouse locations, access roads, and transmission lines. For this project site a LIDAR survey is highly recommended. KP can aide in solicitating contractors to this effect.
- Several existing rights have been previously been identified at the project site and its vicinity. These should be investigated further in order to make sure all potential development barriers have been mitigated.
- Submit a water licence application to Front Counter BC so as to secure the first-in-line water rights to the project ahead of other potential claimants. British Columbia recognizes the rights to water on a first come, first serve basis.
- Complete a feasibility level assessment of the project, including environmental screening.

6.0 CLOSING

Should you require any additional information or clarification on the content of this report, please do not hesitate to contact either of the undersigned.

Yours truly,
Knight Piésold Ltd.

PROFESSIONAL ENGINEER PROVINCE OF BRITISH COLUMBIA B. S. FICHOT # 30575

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Approval that this document adheres to the Knight Piésold Quality System: SRM

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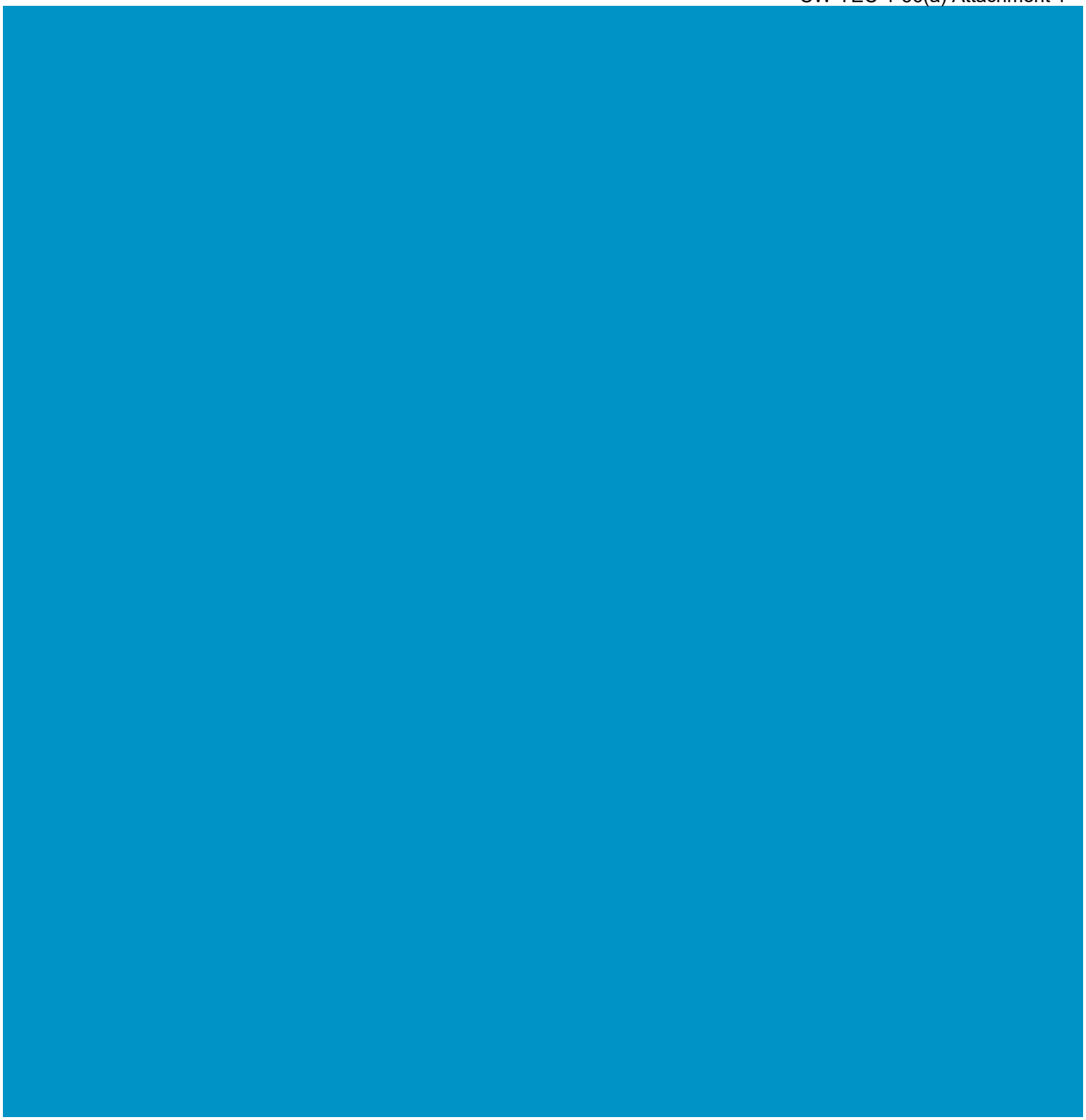

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TOPIC: **Diesel Retirement Replacement**

REFERENCE: **2021 General Rate Application, Appendix 5-3, Section 5.3-1**

PREAMBLE: On page 5.3-3 (PDF page 181), YEC discusses diesel replacement.

QUESTION:

a) Please provide the business case that identifies all the options or alternatives considered and a detailed analysis of the costs of replacement compared to each of the options considered. In the response, please provide the costs of each unit included in the proposal, and the total cost or the project.

b) Please fully discuss how YEC considers total life cycle cost of the alternatives in its business case.

c) Please provide the expected life of each unit.

ANSWER:

(a)

The project is currently in the planning phase, and will remain in WIP in 2021 and therefore not affect the 2021 GRA forecast revenue requirement. Please see response to YUB - YEC-1-92(c) for an update on planning assessments to date.

(b)

When assessing thermal generation capacity development options focused on addressing the N-1 dependable capacity shortfall, business case assessments examine the levelized cost of capacity (LCOC) for each option over the expected life of the facility.

(c)

The expected life of the planed diesel retirements are:

- Faro Diesel 1 (FD1) is March 2022;

- Dawson Diesel 2 (DD2) is March 2023; and

- Dawson Diesel 5 (DD5) is March 2023.

The remaining diesel plant retirements are beyond the 10 year period.

TOPIC: **Southern Lakes Enhanced Storage**

REFERENCE: **2021 General Rate Application, Appendix 5-3, Section 5.3-1**

PREAMBLE: On page 5.3-4 (PDF page 182), YEC discusses Southern Lakes Enhanced Storage.

QUESTION:

a) Please provide a detailed analysis that clearly demonstrates how the Southern Lakes Enhanced Storage project was considered in determining the need for each capital project that results in increased capacity of the asset or system.

ANSWER:

(a)

The Southern Lakes Enhanced Storage Project was selected in all scenarios of YEC's 2016 Resource Plan, and was also included in YEC's 10-Year Renewable Electricity Plan. Accordingly, the project has been inherently included in the analysis of all YEC projects needed for the future.

TOPIC: **EV Infrastructure Project**

REFERENCE: **2021 General Rate Application, Appendix 5-5**

PREAMBLE: On PDF page 194, YEC discusses an EV Infrastructure Project.

QUESTION:

a) Please fully discuss and explain who (shareholder or customer) would bear the risk if there is not sufficient EV usage to warrant EV stations.

b) Please fully explain YEC's position as to whether EV stations should be owned and operated by independent competitive entities or by regulated utilities.

ANSWER:

(a) and **(b)**

Please see response to YUB-YEC-1-101. Subsequent to the submission of the Application, YEC has chosen to defer this project to a future year, as it is expected to take several years for the rollout of electric vehicles to take place at a larger scale in Yukon. This change has no impact on the forecast revenue requirement for the 2021 test year, i.e., Appendix 5.5 includes only projects forecast to remain in WIP.

The potential impact of electric vehicles on the Yukon electrical system will need to be assessed along with any requirements for YEC to meet these challenges. As noted in the Application, not addressing this could result in unforeseen costs and reactionary programs.

TOPIC: **Board Directions**

REFERENCE: **2021 General Rate Application, Tab 6.0**

PREAMBLE: On PDF page 198, YEC discusses Cost of Service (COS) studies and rate design. On lines 15-19, YEC states:

> The latest Order in Council (OIC) direction provided in December 2018 (OIC 2018/220) provides that material rate design changes that would result in rebalancing of rates between different customer classes cannot be undertaken at this time. The remaining outstanding directives in Order 2010-13 will be addressed in the next joint cost of service and rate design application. This includes directives #1 to #12 and #19 (as summarized in Tab 6 of the 2012/13 GRA filing).

QUESTION:

a) Please fully discuss and explain all conversations, communications, and correspondence YEC has had with its Shareholder, about why a COS proceeding and rate rebalancing may in fact be appropriate.

ANSWER:

(a)

This question is outside the scope of the current proceeding.

TOPIC: **Directive #463 – Battery Project**

REFERENCE: **2021 General Rate Application, Tab 6.1.5**

PREAMBLE: On PDF page 207, YEC notes that the Board did not approve a battery project, yet YEC proceeded with a project, based on receiving grants for the project.

QUESTION:

a) Please fully explain YEC's position on who bears the risk if the project does not produce benefits or proves to be unviable. Would that be written off to the shareholder or included in future rates?

ANSWER:

(a)

It is noted that the Battery Energy Storage System project has been designated by OIC 2020/180 as a "regulated project" under Part 3 of *the Public Utilities Act*. Based on this requirement, on January 20, 2021 Yukon Energy filed an application for an energy project certificate and an energy operation certificate with the Minister of Justice of Yukon; and the need and justification for the project will be subject to a review by the YUB prior to the issuance of a project energy certification and operation certification by the Yukon Government. This process will include a review of the project business case and risks.

The project will also be subject to a prudence review by the YUB prior to it being included in rates. Costs determined to be prudently incurred by the YUB would be included in rates.

TOPIC: **Depreciation Study**

REFERENCE: **2021 General Rate Application, Tab 9 Depreciation Study**

PREAMBLE: On PDF page 246, The Alliance Consulting Group states:

> At the request of Yukon Energy, this study continues to use the ALG depreciation procedure to group the assets within each account. In its last depreciation study, Yukon Energy was authorized to use the average life group, whole life ("ALG-WL") depreciation procedure. This study continues to use the ALG depreciation procedure to group the assets within each account.

QUESTION:

a) Please fully explain all methods that are accepted by depreciation experts, including the ELG method. In the response, please provide the advantages and disadvantages of each.

b) Please fully explain the impact on depreciation rates if the ELG were used. Would lives tend to lengthen or shorten?

c) Please provide a full discussion of The Alliance Consulting Group's experience as to which depreciation method is most commonly used.

d) Does The Alliance Consulting Group support the ALG method or would it prefer some other method like the ELG method?

e) Please fully explain whether The Alliance Consulting Group recommended a different method to YEC. Please fully explain the process for the selection of the ALG.

f) Please provide the retainer letter or other engagement documents that govern the relationship between YEC and The Alliance Consulting Group.

g) Please fully explain any ways that The Alliance Consulting Group could support that would lengthen lives and reduce customer rates.

ANSWER:

(a)

ALG or ELG are depreciation procedures. See Attachment 1 to this response which is an extract from Depreciation Systems, an authoritative treatise on the subject. ALG and ELG are defined by how assets are grouped.

As stated in the attachment:

> "Both procedures are "systematic and rational" as required by the definition of depreciation accounting. Use of the average life procedure matches the depreciation charges to the service provided by the average lived unit. That is, the shorter-lived units contribute fewer units of service than the longer-lived units, and therefore, the total accrual associated with a short-lived unit is less than that associated with a long-lived unit. The ALG procedure treats each unit as though its life is equal to the average life of the group. The ELG procedure treats each unit in the group as though its life was known. This is the basis for the argument that the equal life group procedure better matches depreciation charges with the life of the units in the group."

(b)

Alliance Consulting Group has not made the computation to quantify impact of using ELG to determine depreciation rates. In general, with growing plant (such as the case with YEC), ELG will produce higher depreciation accrual rates than ALG. The life choices would remain the same, but the deprecation accrual rates would change and increase if ELG was adopted. If lives are lengthened, both ALG and ELG depreciation rates decrease. If lives are shortened, both ALG and ELG depreciation rates increase.

(c)

Alliance Consulting Group supports the uses of the ALG method, which has been used in the majority of our cases. We have also recommended ELG in certain jurisdictions where ELG is the precedent accepted by the regulatory body.

(d)

Yes, although ELG will provide a more precise pattern for recovering the cost of varying-live assets within a group, both ALG and ELG are accepted in various jurisdictions. YEC's existing depreciation rates are derived using the ALG procedure. Therefore, Alliance Consulting Group supports the uses of the ALG method for YEC.

(e)

Alliance Consulting Group did not recommend any other method to YEC. ALG is the procedure used in YEC's currently approved depreciation rates and ALG is used by many companies across the utility industry.

(f)

See Attachment 1 to this response.

(g)

Alliance Consulting Group does not agree with the concept propounded in the question. Depreciation provides cost recovery of the investment in capital equipment. Regulatory principles incorporate the matching principle where customers utilizing assets should be charged for the recovery of those costs over the assets' lives, rather than shift the burden to ratepayers who do not have use of the assets. The proposed depreciation rates by Alliance Consulting Group achieve that objective.

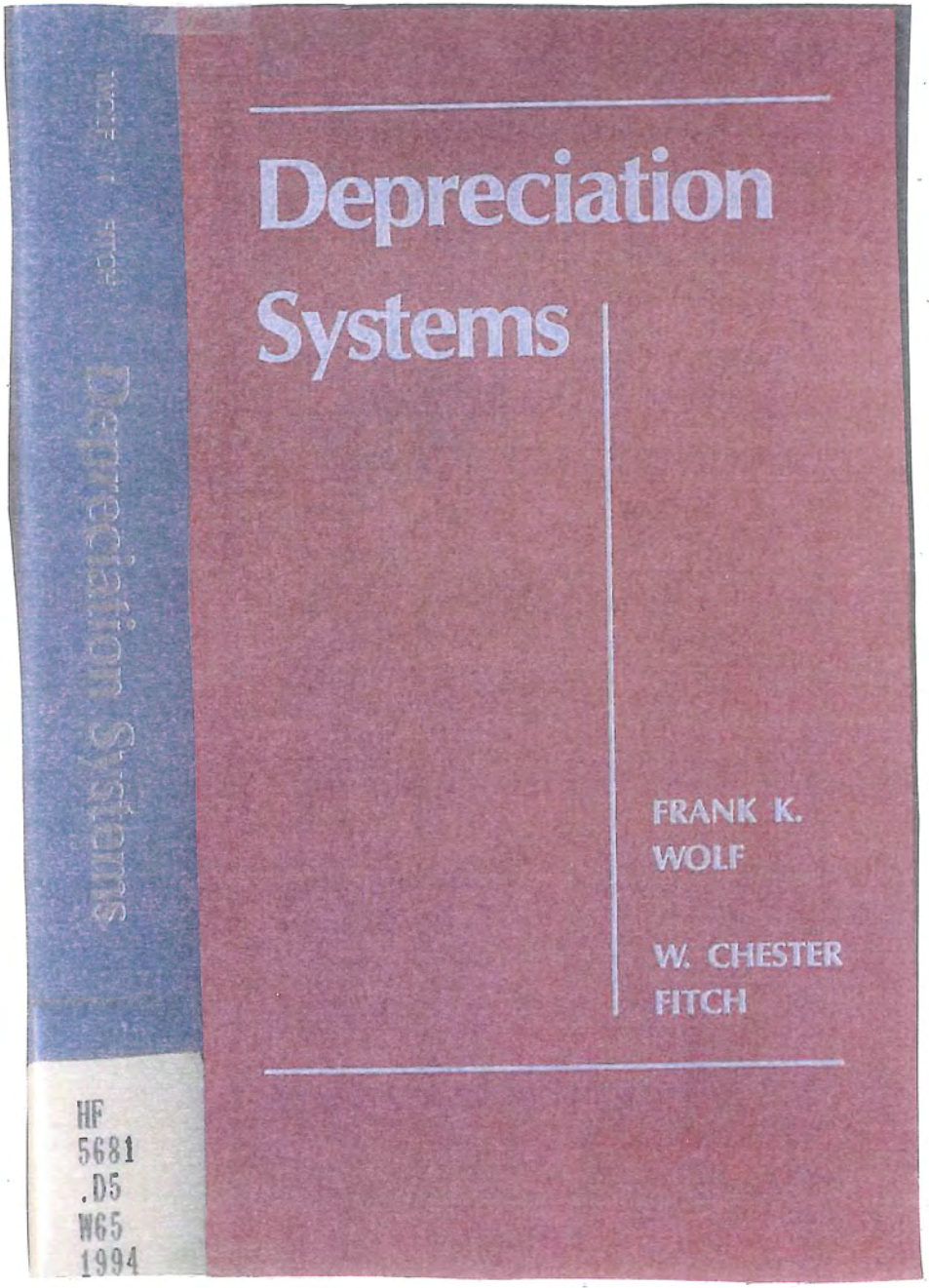
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Table 4.10. Conversion of salvage in Table 4.9 to 1982 dollars.

	Experience year						
	82	83	84	85	86	87	88
Gross salvage	94	337	418	645	834	890	720
Cost of retiring	27	106	163	276	437	539	553
Annual retirements	157	627	941	1568	2508	3135	3292
Gross salvage ratio	.60	.54	.44	.41	.33	.28	.22
Cost of retiring ratio	.17	.17	.17	.18	.17	.17	.17
Net salvage ratio	.43	.37	.27	.23	.16	.11	.05

5 Depreciation Systems

THE recovery of capital through depreciation accruals may be thought of as a dynamic system. A system is an arrangement of things that are connected to form a complete organization of integrated parts. The state of the system at any time is defined by current values of the characteristics that define the system. A dynamic system is one where the state of the system depends on the history of the input variables. To define and study a system is to better understand the system so that more efficient methods of control can be designed to accomplish the desired ends.

There are two methods of controlling a system. One is to select an input and wait for the result or final output. If a different output is desired, the input is changed and the new output is obtained. The other method of control is to select an initial input, monitor the process, and when necessary, alter the input to achieve the desired goal. The first method is called an open control loop and the second a closed control loop. A necessary feature of the closed control loop is the feedback resulting from the monitoring of the system. A home heating system is a common and simple example of a dynamic system with a closed feedback loop. The parts of the system are a furnace and a thermostat. The thermostat monitors the room temperature and creates feedback, in the form of electrical signals, when the room temperature rises above or falls below the desired temperature. The electrical signals turn the furnace off or on to achieve the desired goal, a constant, predetermined room temperature.

Think of a depreciation accounting system as a dynamic system controlled with a closed feedback loop. Estimates of life and salvage and the

amount of plant in service are inputs to the system, and the accumulated provision for depreciation is a measure of the state of the system at any time. The process of calculating the accumulated provision for depreciation is determined by the factors needed to define the system. The initial input to the system is estimates of the life and salvage, which are combined in an accrual rate. Dynamic forces affect the life and salvage, and revision of the original life and salvage estimates are the result of the monitoring process. These revisions to the initial input initiate feedback in the form of adjustments to the accumulated provision for depreciation. The goal of the system is recovery of capital in a timely manner.

One consideration that complicates this discussion is that many options can be combined to form many different depreciation systems. Whether the depreciation is for book, tax, valuation, or other purposes, each of these factors must be considered when discussing and defining a depreciation system.

DEFINING A DEPRECIATION SYSTEM

Below is a list of the factors needed to define a depreciation system. Each factor contains two or three options, and the complete definition of a system requires the selection of one option from each factor. The order of the list is arbitrary, but the last four factors are those whose options are varied when discussing depreciation systems commonly used to calculate book depreciation.

1. The depreciation concept, including (a) physical condition, (b) decrease in value, or (c) cost of operation
2. Depreciation over (a) time or (b) units of production
3. Depreciation of (a) a unit of property or (b) a group of property
4. Methods of allocation, including (a) the straight line method, (b) an accelerated method, or (c) a decelerated method
5. Procedures for applying the method of allocation including (a) the average life procedure, (b) the equal life group procedure, or (c) the probable life procedure
6. Adjustment using (a) the amortization method or (b) the remaining life method
7. Use of (a) the broad group model or (b) the vintage group model

The mathematically astute reader who multiplies the number of options in each factor will find that there are 432 combinations of options, each of which is a potential depreciation system. However, not all of these combinations are feasible, and some are unimportant. Only a few of these

combinations are of major interest when considering systems of book depreciation currently being used.

Concepts of Depreciation

Three options are available when defining the concept of depreciation. These include (a) physical condition, (b) decrease in value, or (c) cost of operation. Though all have been used by utilities to determine book value, the cost of operation is, with few exceptions, the concept in current use.

Physical condition is, perhaps, the first option a lay person would think of if asked to define depreciation. An early reference to the relationship between depreciation and physical condition is from the 1588 textbook by John Mellis who referred to a debit to the profit and loss account because "implements of householde I doe find at this day to be consumed and worn." A later reference is in the 1833 annual report of the Baltimore and Ohio Railroad, which reported that an annuity was established "to provide for the replacement of oak sills and sleepers and yellow pine stringpieces."

Two problems arise when using the concept of physical condition as a measure of depreciation. First, wear and tear do not account for all retirements; in fact, they are often a minor reason for the retirement of property. Second, physical condition can be difficult to measure. Though it is possible to measure directly the wear of railroad track and the corrosion of cast iron pipe, easily measurable wear is not characteristic of most industrial property.

The concept of loss of value is also a common depreciation concept, and the lay person often uses it to explain the difference between the purchase price and the current market value of an automobile or major household appliance. The definition from the Supreme Court case *Lindheimer v. Illinois Bell Telephone* (1934) is often quoted: "Broadly speaking, depreciation is the loss, not restored by current maintenance, which is due to all the factors causing the ultimate retirement of the property. These factors embrace wear and tear, decay, inadequacy, and obsolescence."

In contrast to the concept of physical depreciation, the Lindheimer definition recognizes that factors other than wear and tear cause or contribute to the retirement of property. The definition refers to the "loss" but does not clearly state what is "lost" or how the "loss" should be measured. A 1935 definition by the Federal Communications Commission was similar to the Lindheimer definition but referred to "loss in service value," where service value is equated to the original cost less salvage.

Use of the concept of loss of value to determine annual depreciation charges might imply the need for an annual valuation of the property owned by the organization, particularly if the rate of loss in value was not

uniform or readily defined. The process of determining a value is complex, depending on the purpose of the valuation and type of property. Thus, an annual valuation of a utility could be such an expensive and time-consuming process that it would not be a practical approach to use in determining annual depreciation.

Many types of property provide a constant level of service until they are retired. The intrinsic physical value of this type of property is only that it functions. A gas meter is a common example of a type of property that may provide a constant level of service throughout its life. If value is measured by the level of service provided, the meter would retain full value until retirement because its value to the utility would depend on its function rather than its age. This concept ignores the consumption of future service and would result in an annual depreciation charge that would be zero until the final year of service. Then the charge would equal the full value and would result in deferring all depreciation charges until the final year of service. A concept that better matches depreciation to service rendered and weighs it in relation to the total service potential might be preferable for purposes of both book and valuation depreciation. That is, a quantitative measure of value, such as service-years, is generally preferable to a functional measure.

The third concept is that depreciation represents an allocated cost of capital to operation. This concept recognizes that depreciation is a cost of providing service and that an organization should recover the capital invested in equipment and other property needed to provide the required service. In fact, the term *capital recovery* is often used in connection with depreciation. An early reference to depreciation is by the Roman Marcus Vitrurius Pollio, who in 27 B.C. wrote of "walls which are built of soft and smooth-looking stone, that will not last long." He calculated that the walls would not last more than eighty years and suggested that, for purposes of valuation, one-eightieth part of their original cost be deducted each year. Pollio not only raised several issues concerning depreciation but seemed to be equating depreciation to a cost of operation.

The definition of *depreciation accounting* by the American Institute of Certified Public Accountants (1961, par. 56) reflects the concept of depreciation as a cost: "Depreciation accounting is a system of accounting that aims to distribute cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation." This definition does not use the term *loss of service value* because it is defining depreciation accounting rather than depreciation itself. The definition emphasizes that the purpose of depreciation accounting is a means of distributing cost in a rational manner during the service life, in turn providing for the systematic recovery of capital. By use of the term *useful life,* the definition encompasses all causes of retirement. By referring to the distribution of cost less salvage, this definition recognizes that salvage should be considered when developing depreciation charges.

Historically, all three concepts of depreciation have been used by utilities to determine the book value of industrial property. Of these, the concept of depreciation as the allocation of cost has proven to be the most useful and most widely used concept.

Time versus Unit of Production

Useful life can be measured in units of time or units of production (also called units of service). Measurement of life in years is a common and familiar concept. Measurement of life in units of production can be applied to some types of property such as a truck, whose life can be measured in miles (e.g., a useful life of 100,000 miles). A feeder pipeline connecting an oil field to a transmission line will be in service until the field is no longer productive. If the only function of the feeder line is to transport oil from the field to the transmission line, the life of the feeder line is determined by the reserves of the oil field that must eventually pass through the pipeline. Annual depreciation could be measured in units of production, such as barrels of oil. A railroad might depreciate rail as a function of the accumulated weight that the rail has carried.

Suppose a truck is to be depreciated over its life as measured in miles. First, the life must be estimated, say 100,000 miles. Second, the number of miles the truck will be driven during the next year, say 27,000 miles, must be forecast to have sufficient information to budget the annual depreciation charge. Third, at the end of the year when the budgeted annual depreciation becomes an accounting entry, the amount would be calculated to reflect the actual miles driven.

The most common measure of life is in units of time rather than units of production. Most types of property (e.g., poles, buildings, wire) do not have a measure of production associated with them. If the life can be measured in some unit of production and the rate of production is constant from year to year, measurement of life in either units of time or production will result in the same annual accruals. The unit of production has strong appeal in situations where use varies significantly over time and the life can be measured in units of production. But these two conditions are not often met, and usually life is measured over time.

Depreciation of an Individual Unit versus a Group

Accounting records of transactions relating to depreciable property can be kept on either a unit or a group basis. An individual unit of property has a single life, while the units in a group of property display a range, or

dispersion, of lives. Grouping many units of property into a single account simplifies the accounting system but also creates a complexity not encountered in the depreciation of an individual unit. The resulting complications provide a major challenge to the depreciation analyst.

A vintage group refers to a group of property placed in service during the same year. The plant in service decreases until all units are retired from service. The individual unit and the vintage group are similar because each has well-defined life characteristics. The life of an individual unit is described by a single number and the life of a vintage group is described by a survivor curve, which is a statistical description of the lives of the units of property in the group.

Methods of Allocation

To fully recover capital invested in plant and equipment, the total depreciation charge must equal the depreciation base. When using the allocation of cost concept, the depreciation base is the initial, or original, cost less net salvage. The annual depreciation accrual rate for a unit of property can be (a) constant over life (straight line), (b) high during early years and low in later years (accelerated), or (c) low in early years and high in later years (decelerated). Most methods of allocation fall into one of these three classifications, although it would be possible to develop a method that is a combination of them. The straight line method of allocation is the method of allocation most often used when calculating book depreciation. Accelerated methods of allocation are commonly used for tax purposes. Decelerated methods of allocation are not in common use for book or tax purposes, but they are of historical interest and are used in valuation problems.

Average Life, Equal Life Group, or Probable Life Procedures

The average life and equal life group procedures are two ways of applying a method of allocation to determine the annual accrual. The probable life procedure is similar to the average life procedure, but is not appropriate for depreciation accounting.

A group of property displays a wide range of lives, and the life characteristics of the group must be described statistically. This is in contrast to a unit of property, whose life can be described as a single number. When depreciating a group of property, rather than a unit of property, a major decision must be made whether to base the depreciation accrual rate on the average life of the group (the average life procedure) or whether to divide the group into subgroups of equal life (the equal life group procedure).

In the average life procedure, a constant annual accrual rate based on the average life of all property in the group is applied to the surviving

property. Most retirements occur either before or after, rather than at, the average life, but both short- and long-lived property are depreciated at the same rate. Property having a shorter life than the average will not be fully depreciated by the time of its retirement. Because the accrual rate is based on the average life of the group, the difference between accruals for early retirements and the full cost of the early retirements will be balanced during the life of the property having lives longer than the average. The result is that the group will be fully depreciated by the time of the final retirement.

In the equal life group procedure the property is divided into subgroups that each have a common life. Each subgroup is then depreciated as a unit using an accrual rate based on the common life of the group. Each unit is fully depreciated by the time it is retired. Application of the equal life group procedure is generally considered to better match the consumption of capital with service provided than does application of the average life procedure.

Any of the three methods of allocation (i.e., straight line, accelerated, or decelerated) can be applied to an individual unit or to group property. When the average life procedure is applied, the straight line method of allocation is easily used; application of either an accelerated or a decelerated method becomes more complicated. When the equal life group procedure is used, any of the three methods of allocation can be easily used.

The probable life procedure is a variation of the average life procedure. It is not valid for depreciation accounting or capital recovery because it does not fully depreciate the group. The depreciation charges are allocated over the average life of the property remaining in service (i.e., over the probable life), so that the continually decreasing rate is inadequate to fully recover the depreciable base. Use of this procedure should be restricted to those special situations where it is applicable; for example, it may used in the valuation process.

Methods of Adjustment

Depreciation accrual rates are calculated using estimates of the service life and salvage. Over time, new events that provide additional information occur, and the existing estimates are revised. A revision of the estimates of life and salvage results in the recognition that the accumulated provision for depreciation may now be either higher or lower than necessary, depending upon the magnitude and direction of the revised estimates. This recognition may justify an adjustment to the accumulated provision for depreciation, an adjustment to the annual depreciation rate, or both.

Adjustments to the accumulated provision for depreciation[1] can be made using either a fixed amortization period or the remaining life basis. The term *amortization method of adjustment* is used to describe a general

approach in which the first step is the estimation of the required adjustment to the accumulated provision for depreciation and the second step is the determination of the timing and amount of the adjustment. In the remaining life method of adjustment, adjustments to the accumulated provision for depreciation are amortized over the remaining life of the property and are automatically included in the annual accrual.

The amortization method of adjustment uses the revised estimates of life and salvage characteristics to compute the calculated accumulated depreciation (CAD) to serve as a guide when determining the appropriate adjustment. The CAD is compared to the accumulated provision for depreciation; a significant difference between the two shows that an adjustment to the accumulated provision for depreciation may be advisable. The adjustment can be allocated in several ways, which might include (1) a lump sum equal to the adjustment made immediately, (2) amortization of the adjustment over a fixed period (e.g., over 5 years), or (3) amortization of the adjustment over the remaining life of the property. A lump sum adjustment is not an amortization but will be considered an option in the amortization method of adjustment (i.e., the amortization method could be more accurately called the amortization or lump sum method of adjustment). The difference between the CAD and the accumulated provision for depreciation is only an estimate of the required adjustment. The need for, the magnitude of, and the timing of the actual adjustment should be based upon the recommendation of the depreciation professional. This recommendation requires professional judgment and should consider several factors: the characteristics of the account; the cause of the difference; estimates of future events that will affect the property; the year-to-year volatility of the accumulated provision for depreciation; and the depreciation policies of the organization. A revised forecast of life or salvage normally leads to a revised depreciation rate even when an adjustment to the accumulated provision for depreciation is not considered necessary.

When using the remaining life method of adjustment, emphasis is placed upon forecasting the remaining life of the property in service. A change in the estimate of either life or salvage characteristics automatically triggers an adjustment to the accumulated provision for depreciation, and the adjustment will be spread over the remaining life of the property.

Broad Group or Vintage Group Model

Typically, property depreciated as a group provides a service to the organization over a long period of time. Each year property in the group is retired from service, but new property is added to the group to replace that retired or to increase the capacity of the group. Thus, over time vintage groups are continually being retired from and added to the group. A group

such as this is called a *continuous property group,* though the term *open-ended group* is also used. The life and salvage characteristics of the vintages in the continuous property group must be specified in some systematic manner. The broad group model views each vintage in the continuous group as having identical life and salvage characteristics. The vintage group model views each vintage as having different life and salvage characteristics.

UNIT DEPRECIATION

Depreciation of a unit of property is a concept more readily understood than depreciation of a group of property. This section will present a brief discussion of the three methods of allocating the depreciable cost of a unit of property among accounting periods. An understanding of unit depreciation, particularly the straight line method of allocation, is necessary when considering depreciation for a group of property. In all examples, the cost of operation depreciation concept will be used, and depreciation will be over time (i.e., years). The depreciation base will equal the original cost less net salvage. This base represents the amount of capital to be consumed and, therefore, the amount of capital to be recovered through depreciation accruals.

Methods of Allocation

The three general methods of allocation are straight line, accelerated, and decelerated. An example of each will be applied to a unit of property that has an initial cost of $4000, a life of 4 years, and a net salvage value of $800 at retirement. The net salvage is commonly expressed in terms of the *salvage ratio* (SR), $800/$4000 or 0.20 or 20%.

Straight Line Method of Allocation

The straight line method of allocation is used almost exclusively by regulated, capital-intensive companies when calculating depreciation accruals for book accounting purposes. The straight line method applies a constant annual accrual rate to the cost of the unit, thus yielding a constant annual depreciation charge. The net book value (i.e., the original cost less the accumulated provision for depreciation) plotted versus time is a straight line.

The straight line rate is (1 – SR)/life. The factor (1 – SR) = (1 – 0.20) = 0.80, or 80%, represents the fraction of the original investment consumed during the life of the property, or the depreciable base. In this example that amount is 0.80 × $4000, or $3200. The accrual rate is 0.80/4

or 20%. The equal annual accruals are obtained by multiplying the original cost by the accrual rate. The figures in Table 5.1 (see end of chapter) are based on the assumption that this property was installed on January 1, 1974, and show the resulting accumulated provision for depreciation by year for this system. In the final year, the credit to the accumulated provision for depreciation equals the annual depreciation charge of $800 plus the net salvage of $800 for a total credit of $1600.

A major reason for the popularity of the straight line method is its simplicity. In addition, it occupies a middle ground between the accelerated and decelerated methods. Implicit in the use of the straight line method is the suggestion that the level of service provided by industrial property is independent of its age, and therefore the annual depreciation rate also should be independent of age (i.e., constant). Examples can be given where property such as poles, pipelines, cable, and meters provides a constant level of service throughout its life, but examples where the service provided by these types of property varies with age also can be given.

Accelerated Methods of Allocation

Any method that results in annual accruals that are higher early in life than late in life is called an accelerated method of allocation. Accelerated methods are allowed for calculating depreciation for tax purposes and are often used because of the rapid recovery of capital that they provide. Sometimes industrial property provides more service during early years than later years. An electrical generating unit begins its life as a base load generator operating continuously except for scheduled maintenance. As more efficient generators are installed, the base load generator becomes a peak load generator and operates only several hours each day. Eventually the generator is not used regularly but is used on a standby basis. Thus the service it provides changes significantly with age.

One accelerated method is the sum-of-years–digits method. Applying it to the $4000, 4 years, 20% salvage ratio example leaves the depreciable base unaffected at $3200, but the annual accruals vary with age rather than staying constant. To calculate the annual rate during year i, first sum the digits from 1 through the maximum life. In the example the sum is $1 + 2 + 3 + 4 = 10$. (A useful equation is that the sum of digits from 1 to n is $[(n)(n + 1)/2]$ or in the example $[(4) \times (5)/2] = 10$.) The rate during year i is $(1 - SR)(\text{life} - i + 1)/(\text{sum-of-years–digits})$. Applied to the example, the annual accrual rates are calculated as follows:

			Annual Rate	
Year	Sum	Life − Year + 1	No Salvage	With Salvage
1	10	4 − 1 + 1 = 4	40%	32%
2	10	4 − 2 + 1 = 3	30%	24%
3	10	4 − 3 + 1 = 2	20%	16%
4	10	4 − 4 + 1 = 1	10%	8%
			100%	80%

Note that with no salvage the accrual rates sum to 100% and that with salvage the accrual rates sum to 100%(1 − SR) or 80%, so that the depreciable base is recovered. Table 5.2 (see end of chapter) shows the application of the sum-of-years–digits method to the example.

The annual accruals of $1280 and $960 during the first two years are larger than the $800 annual accrual when using the straight line method of allocation, but the $640 and $320 for the final two years are less. When matching depreciation to service, an accelerated method of allocation would be appropriate if the property yields significantly more service early in life than it does later in life.

The declining balance method is another example of an accelerated method of allocation and it is widely used for tax depreciation. This method applies a constant rate to the declining balance of the book value, so that the annual accruals decrease even though the rate is constant. The rate is equal to a constant/life; if the constant is two, the rate is double the straight line rate and results in the double declining balance method. Rather than double declining balance, we will use 1.5 declining balance, so that the rate is 1.5/4 or 37.5%. Table 5.3 (see end of chapter) shows the calculations using the 1.5 declining balance method and illustrates a complexity inherent in the method. Because salvage was not included in the rate, it is necessary to switch to a straight line rate late in life so that the final value of the accumulated provision for depreciation is zero. In this example, the book value is $976 at the beginning of the fourth year; continuation of the 37.5% rate will result in a fourth-year accrual of $366 and total accruals of $3390, which is $190 more than the $3200 capital that has been consumed. We will switch to a straight line rate that will yield a final accrual of $976 − $800 or $176 during the final year as shown in Table 5.3. Details on switching rules should be obtained from the IRS if using this method for tax depreciation.

The equation $1 - (SR)^{1/N}$ calculates the declining balance rate that will yield a final book value equal to a nonzero salvage. In our example that rate is $1 - 0.2^{1/4}$ or 1 − 0.67 or 33%. Applying that rate to the book balance yields total annual accruals of $3200 without resorting to switching rules at the end of the life.

Decelerated Methods of Allocation

Any method that results in annual accruals that are lower early in life than later in life is called a decelerated method of allocation. The sinking fund method is an example of a decelerated method. To apply it to our example, the sinking fund factor (also called the A/F factor) must be calculated; the sinking fund factor is $\{r/[(1 + r)^n - 1]\}$, where r is an interest rate and n is the life. Tables of this factor as a function of r and n are included in most books on business finance and engineering economics. If r = 10% and n = 4, the sinking fund factor is $\{0.10/[(1.10)^4 - 1]\}$ or 0.2155. This means that if \$100 × 0.2155 or \$21.55 is invested at the end of each year for four years and returns an annual effective return of 10% compounded annually, the value of the sinking fund at the end of the fourth year will be \$100. But in order for the four annual payments of \$21.55 to total \$100, each payment must be compounded by (1 + r), or 1.10 in the example, each year. The accrual rate without salvage is 21.55% the first year, 1.1 × 21.55% or 23.70% the second year, 1.1 × 23.70% or 26.07% the third year, and 1.1 × 26.07% or 28.68% the fourth year. The annual accrual rates without and with 20% salvage are summarized as follows:

	Annual Rate	
Year	No Salvage	With Salvage
1	21.55%	17.24%
2	23.70%	18.96%
3	26.07%	20.85%
4	28.68%	22.95%
	100.00%	80.00%

The accrual rates with salvage are used in Table 5.4 (see end of chapter).

The annual accruals of \$690 and \$758 during the first two years are less than the \$800 annual accrual resulting from the straight line method of allocation, and the \$834 and \$918 during the final two years are more. A larger rate of interest results in a larger difference between annual accruals. A negative interest rate will result in accelerated depreciation. A zero interest rate results in a straight line rate.

Another decelerated method of allocation is the present worth method. It results in annual accruals that are identical with the sinking fund method, although the rationale leading to the calculation of the annual accruals is different. The present worth method is often used in the economic valuation and comparison of capital investments.

GROUP DEPRECIATION SYSTEMS WITH NO SALVAGE

The remainder of this chapter is devoted to the depreciation of a vintage group of property. First, the systems described and examples presented will assume zero salvage. Then the modifications to these systems when salvage is not zero will be introduced and discussed.

Four of the seven factors of depreciation listed at the beginning of the chapter will be limited to one option during the following discussion. Only the cost of operation concept of depreciation will be considered. Depreciation will be over time. Depreciation will be of a group, not a unit. Only the straight line method of allocation will be used. Both the average life and equal life group procedures, and the amortization and remaining life methods of adjustments will be examined. A discussion of the broad group and vintage group models will be deferred to a following chapter.

The Average Life Procedure Applied to a Vintage Group

Calculation of the Annual Accrual

One system of calculating the annual accrual incorporates the straight line method of allocation (SL) and applies the average life procedure (AL) to a vintage group. It is denoted by the initials SL-AL. As defined, this system lacks a feedback loop to control the system. A method of adjustment must be added to design a controlled, closed loop depreciation system.

The average life procedure applies the constant rate of 1/AL to the average plant in service during the year. Note that because the balance is averaged over a year, the AL must be measured in years. If the estimate of the average life is accurate, the vintage will be fully depreciated (i.e., the accumulated provision for depreciation will equal zero) after the final retirement.

It may not be immediately clear that this system will work (i.e., that the sum of the accruals will equal the original cost of the initial installations). The left side of the equation below equals the sum of the annual accruals when a rate of 1/AL is used and is set equal to the amount to be recovered (i.e., the original cost or initial balance).

$$\Sigma \text{ (average plant in service during age interval j)/AL} = \text{original cost}$$
$$\text{summed for j} = 0, 1, 2, \ldots, \text{ML (the maximum life)}$$

The average plant in service during the age interval times the one-year width of the age interval equals the dollar-years service provided during the year. The sum of the values (average plant in service during age interval j) is

equal to the area under the survivor curve and may be written (area under the survivor curve)/AL = original cost, or by rearranging this equation, AL = (the area under the survivor curve)/(original cost). The average life has been shown to equal the area under the survivor curve divided by the original cost (true whether the survivor curve is measured in dollars or units), so the original equality is true. We can conclude that this system will fully recover the initial investment regardless of the shape of the survivor curve.

This equation also shows that if the AL used in the accrual rate is not equal to the actual average life, the sum of the accruals will not equal the original cost. Suppose that the actual life was 8 years, but a life of 6 years was forecast and used in the depreciation rate. The total accruals would equal 8/6 or 133% of the original cost, and the accumulated provision for depreciation would show an overaccrual equal to 133% − 100% or 33% of the original cost at the time of the final retirement. Similarly, a forecast of a life of 10 years would result in total accruals of 8/10 or 80% of the original cost. At the time of the final retirement the accumulated provision for depreciation would show an underaccrual equal to 100% − 80% or 20% of the original cost.

Consider a property group having the survivor curve shown in Figure 5.1. This curve could result from the grouping of two units, one with a cost of $4000 and a 4-year life and the second with a cost of $6000 and an 8-year life. The average life (AL) is the area under the survivor curve divided by the original cost or the AL = [(4000 × 4) + (6000 × 8)]/10000 or 6.4 years. The straight line, average life annual accrual rate is 1/6.4 or 15.625%.

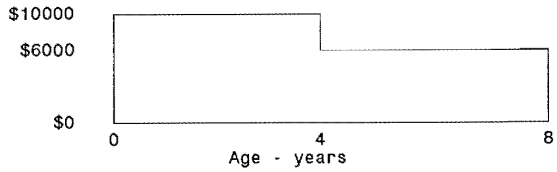


Figure 5.1. A survivor curve with an average life of 6.4 years.

NOTE: To simplify calculations in this section, age intervals will be 0–1, 1–2, 2–3, etc., installations will be assumed to occur at the start of the age interval, and retirements will be assumed to occur at the end of the age interval. The average plant in service during the age interval will then equal the balance at the start of the interval, so that applying the annual accrual rate to the plant in service at the start of the interval is equivalent to applying it to the average balance. In all tables in this section, the balance, accumulated provision for depreciation, and calculated accumulated depreciation are calculated at the beginning of the year. Note that the accumulated provision for depreciation is zero at the beginning of the initial year. Examples using the half-year convention will be shown later.

Table 5.5 (see end of chapter) shows the annual accruals and accumulated provision for depreciation that result from the SL-AL system. Column (b) shows beginning of year balances of $10,000 for the four years 1974 to 1977, and balances of $6000 for the next four years, 1978 to 1981. This follows the survivor curve shown in Figure 5.1. Column (c) shows a $4000 retirement at the end of 1977 and a $6000 retirement at the end of 1981. The annual accrual, column (e), is the product of the rate, column (d), and the plant balance at the start of the year, column (b). As described in the preceding note, retirements are assumed to take place at the end of the year, so that the plant balance at the start of the year is also the average balance during the year. The accumulated provision for depreciation, column (f), is zero at the start of the first year and is then increased by the annual accruals and reduced by the annual retirements. At the time of the final retirement, the accumulated provision for depreciation is zero, showing that the sum of the annual accruals and the annual retirements equals zero and that the property is fully depreciated.

Suppose that at the time of the initial installation of the property, the estimate of the average life was 7.4 years. If the rate 1/7.4 is used throughout the life of the property but the actual life is 6.4 years, then only (6.4/7.4)($10000) or $8649 will be depreciated and $10000 − $8649 or $1351 of invested capital will not be recovered. This is verified by the calculations shown in Table 5.6 (see end of chapter).

An Adjustment Problem—AL Procedure

Now suppose that in January 1977, because of events and activities occurring since 1974, the original forecast of 7.4 years average life is revised to 6.4 years. Table 5.7 (see end of chapter) shows the accumulated provision for depreciation at the start of 1977 is $4054. Unless some corrective action is taken, the annual accruals will not equal the $10,000 original cost, and at the time of the final retirement a total of $1351 will remain unrecovered. The SL-AL system of calculating the annual accruals must be augmented to include a method of adjustment to define a depreciation system that will adapt to the almost certain circumstance that forecasts are revised from time to time.

When there is a revision of the original forecast of service life, it

becomes necessary to consider a method of augmenting the SL-AL system of calculating annual accruals. Either of two methods of adjustment, the amortization method (AM) or the remaining life method (RL), can be added to the system of calculating annual accruals to construct a depreciation system with a closed feedback loop.

Amortization Method of Adjustment (SL-AL-AM)

Use of the amortization method of adjustment does not result in the prescription of an adjustment, but places the responsibility of recommending the magnitude and timing of the adjustment in the hands of the depreciation professional. Control focuses on the calculated accumulated depreciation (CAD). The CAD is normally a reasonable and valid estimate of an adequate level of the accumulated provision for depreciation. The depreciation professional will examine the variation between the CAD and the accumulated provision for depreciation to determine if adjustments to the annual accrual are necessary.

DEVELOPMENT OF THE CALCULATED ACCUMULATED DEPRECIATION. Two approaches can be used to develop the calculated accumulated depreciation. One, a retrospective approach, is to reconstruct the past accruals and retirements to determine what the accumulated provision for depreciation would have been given the current estimate of the life characteristics. The other, a prospective approach, is to estimate the sum of the future additions to and subtractions from the accumulated provision for depreciation. The sum of these additions and subtractions also is an estimate of the accumulated provision for depreciation that would be desirable to have on the books.

The retrospective approach appears to be straightforward. In fact, Table 5.5 shows that if property had the service life characteristics shown in Figure 5.1, the accumulated provision for depreciation at the start of the fourth year would be $4688. Comparison of this figure to the accumulated provision for depreciation of $4054 shown in Table 5.7 shows that an adjustment of $634 is necessary. In practice, however, the retrospective approach has a major shortcoming. The history of the account may go back many years and include accounting transactions, such as transfers, sales, acquisitions, and adjustments, which have been recorded in the accumulated provision for depreciation account. Use of the retrospective approach requires complete knowledge of these transactions as they must be considered for inclusion in the construction of the CAD. Because of the difficulties likely to be encountered in reconstructing the accumulated provision for depreciation, the retrospective approach is usually discarded in favor of the prospective approach.

The prospective approach to the CAD is based on estimates of the

future accruals and retirements. Estimates of future accruals and retirements can be made if the survivor characteristics of the property have been estimated. The following relationship states that the calculated accumulated depreciation plus all future accruals, less all future retirements, equals zero. If this relationship holds, the cost of the property will be fully allocated at the time of the final retirement.

$$\text{CAD(i)} + \text{future accruals} - \text{future retirements} = 0$$

or

$$\text{CAD(i)} = \text{future retirements} - \text{future accruals}$$

The future retirements equal the current balance of the plant in service, because all property currently in service must eventually be retired. The future accruals is the sum of the annual future accruals when the SL-AL system of calculating the annual accruals is used. Thus, CAD(i) = current balance $-$ Σ (average balance during year j)(1/AL) = current balance $-$ (1/AL)Σ (average balance during year j) summed for j from year i to year of final retirement, where CAD(i) = calculated accumulated depreciation at the start of year i.

The average balance during each year is determined by the survivor curve used to describe the life characteristics of the vintage. The sum of the average balances during the year, starting with the current year and continuing through all years until the year of the final retirement, is equal to the area under the survivor curve and to the right of the current age. This area represents the remaining service and is measured, in this case, in dollar-years. The remaining service divided by the plant in service is defined as the average remaining life (also called the expectancy). Dividing both sides of the equation above by the current balance yields the following definition and equation for the calculated accumulated depreciation ratio, which will be abbreviated as CADR[2]:

CAD(i)/current balance = current balance/current balance $-$ (area under the survivor curve/current balance)/AL

CAD(i)/current balance = CADR(i) = 1 $-$ RL(i)/AL, where CADR(i) = calculated accumulated depreciation ratio at age i and RL(i) = remaining life at age i

Tables of the Iowa survivor curves contain values of the calculated accumulated depreciation ratios.

Table 5.8 (see end of chapter) shows the calculation of the RL, the

CADR, and the CAD for the survivor curve shown in Figure 5.1. The 64,000 dollar-years of remaining service at age zero, column (d), is equal to the sum of the annual balances shown in column (c) and also equal to the area under the survivor curve. (Remember that the width of each interval is one year, so that the balance at the start of the year multiplied by the width of the interval, one year, is the area under the survivor curve attributable to that year.) The amount in column (d) represents the remaining service contained in the existing plant. Each year the amount in column (d) is reduced by the average plant balance during that year times the one-year period (i.e., the service provided during the year) to calculate the service, measured in dollar-years, remaining at the beginning of the next year. The remaining life, column (e), is the remaining service divided by the balance or column (d)/column (c). The CADR, column (f), is 1 – remaining life/average life. The CAD, column (g), equals the CADR multiplied by the plant in service. This calculation shows that the CADR is sensitive to both the average life *and* the shape of the survivor curve.

AN AMORTIZATION SOLUTION TO THE AL ADJUSTMENT PROBLEM. Now return to the problem raised in the scenario shown in Table 5.7. Table 5.8 shows that if the estimate of a 6.4-year average life is accurate, the current value of the accumulated provision for depreciation would be $4688 rather than the recorded $4054, and this results in an apparent deficit of $634. If the depreciation professional believes this variation is significant, then an adjustment to the accumulated provision for depreciation should be made.

The adjustment to the accumulated provision for depreciation can be made in several ways, ranging from a lump sum adjustment of $634 to amortizing the $634 over a period less than the remaining life, equal the remaining life, or longer than the remaining life. For example, suppose it is decided to amortize the $634 over two years; then the accumulated provision for depreciation would be credited an additional $317 in 1978 and 1979. In addition, the annual rate would be changed to 1/6.4 to reflect the revised forecast. Table 5.9 (see end of chapter) shows that these adjustments will result in a recovery of the $10,000 initial investment as reflected by the final zero balance of the accumulated provision for depreciation.

The CAD is not a precise measurement. It is based on a model that only approximates the complex chain of events that occur in an actual property group and depends upon forecasts of future life and salvage. Thus, it serves as a guide to, not a prescription for, adjustments to the accumulated provision for depreciation.

Remaining Life Method of Adjustment (SL-AL-RL)

In 1953 the California Public Utilities Commission issued *Determination of Straight-line Remaining Life Depreciation Accruals,* also called *Standard Practice U-4.* This document, which was revised in 1961, presents the steps required in determining the annual accrual when using the straight line method of allocation, the average life procedure, and the remaining life method of adjustment.

Though the term *remaining life* is often thought of as a basis for calculating the annual accrual, it is more appropriately considered a method of adjustment used with a system of calculating annual accruals. As discussed in the preceding paragraphs, a revision of the forecast of average life may lead to an adjustment to the accumulated provision for depreciation. When the remaining life method of adjustment is used, the variation between the CAD and the accumulated provision for depreciation is amortized over the remaining life of the plant in service. This adjustment is automatic in the sense that it is built into the remaining life calculations.

Table 5.5 shows the calculation of annual accruals using the SL-AL system applied to property described by the survivor curve of Figure 5.1. Remember that the annual accrual is the average balance during the year times the straight line rate 1/AL. Use of the remaining life method of adjustment requires different calculations even though the same annual accruals will result. Before calculating the accruals, the remaining life rates for the survivor curve used to estimate the life characteristics must be determined, and these calculations are shown in Table 5.10 (see end of chapter).

The remaining life calculations can be viewed in two ways. One is that the rate 1/RL is applied to the future accrual, which is the current plant in service less the accumulated provision for depreciation. The future accrual (i.e., the amount remaining to be accrued) is allocated over the remaining life of the vintage group using the straight line method. The procedure used to apply the straight line method assumes each unit in service has a remaining life equal to the average remaining life. Thus the AL procedure is used. Table 5.11 (see end of chapter) shows the remaining life calculations using the survivor curve in Figure 5.1. Column (d), the future accruals, is the balance less the accumulated provision for depreciation, column (b) – column (g). The remaining life rates, taken from Table 5.10, are shown in column (e). The annual accruals, the product of columns (d) and column (e), are in column (f). Note that the annual accruals resulting from the remaining life calculations are identical with those obtained by applying the rate 1/AL to the average plant in service and shown in Table 5.5.

A second way of viewing the remaining life calculation is to consider the annual accrual as the SL-AL accrual plus an adjustment to reduce the variation between the CAD and the accumulated provision for depreciation. The following calculations show that the amortization method, SL-AL-AM, and the remaining life method, SL-AL-RL, yield identical annual accruals when the variation between the CAD and the accumulated provi-

sion for depreciation is either (a) zero or (b) amortized over the remaining life.[3]

Let:[4] B = plant balance
AL = average life
RL = remaining life
APD = the accumulated provision for depreciation
APDR = the ratio APD/B
CAD = the calculated accumulated depreciation
CADR = the ratio CAD/B
AARL = the annual accrual using the RL method of adjustment
AAAM = the annual accrual using the AM method of adjustment

The annual accrual will be calculated for both methods of adjustment, and the two annual accruals will then be compared. First, the annual accrual using the remaining life method of adjustment (the AARL) is the total amount remaining to be depreciated (i.e., the future accrual) divided by the remaining life or AARL = (B − APD)/RL = B[(1 − APDR)/RL].

Next, the annual accrual using the amortization method of adjustment (the AAAM) will be written as the sum of the straight line, average life accrual plus the annual adjustment of the variation between the CAD and the accumulated provision for depreciation. The following calculations assume the variation is amortized over the remaining life and make use of the fact that the CADR = 1 − RL/AL.

$$\begin{aligned} \text{AAAM} &= \text{annual accrual} + \text{adjustment} \\ &= \text{annual accrual} + \text{variation/remaining life} \\ &= B/AL + (CAD - APD)/RL \\ &= B/AL + [B(CADR) - B(APDR)]/RL \\ &= B[1/AL + CADR/RL - APDR/RL] \\ &= B[1/AL + (1 - RL/AL)/RL - APDR/RL] \\ &= B[1/AL + 1/RL - 1/AL - APDR/RL] \\ \text{AAAM} &= B[(1 - APDR)/RL] \end{aligned}$$

but this is the same as the annual accrual using the RL method of adjustment so AARL = B[(1 − APDR)/RL] = AAAM.

If the variation is zero, then the accumulated provision for depreciation (APDR) equals the CAD. Because the CAD equals 1 − RL/AL, the annual accruals using the remaining life method of adjustment can be written

$$\begin{aligned} \text{AARL} &= B[(1 - APDR)/RL] \\ &= B[(1 - CADR)/RL] \\ &= B[(1 - 1 + RL/AL)/RL] \\ &= B[1/AL] \\ &= \text{AAAM} \end{aligned}$$

Thus, when the variation is zero, the remaining life accrual can be expressed as the balance divided by the AL.

EFFECTS OF USING AN IMPROPER REMAINING LIFE. Calculation of the remaining life requires knowledge of the survivor curve; survivor curves with the same average life but different shapes will have different remaining lives. This raises the question of the result of applying the remaining life method of adjustment when the average life is correct but the shape of the survivor curve used to calculate the remaining lives differs from the actual retirement pattern. To examine this question, suppose the survivor curve shown in Table 5.12 (see end of chapter) is used to estimate the life characteristics of the property to be depreciated. Though the average life of this curve is 6.4 years, the same as the survivor curve shown in Figure 5.1, its retirement pattern is significantly different from the pattern shown in Figure 5.1.

Note that, as shown during 1981 in Table 5.12, calculation of the remaining life can be puzzling. Confusion arises because the final retirement takes place not at the end of the year, but 1/3 of the way through the year. At the start of the year, the remaining life is 2000/6000 or 1/3 year. However, a remaining life of 1 is needed to obtain a final rate of 100%. An explanation is the choice of one-year intervals to calculate accruals. Suppose that accruals were calculated every 1/3 year, so that a unit of time is 1/3 year rather than 1 year. The average life would then be 6.4 × 3 or 19.2 units (i.e., 19.2 one/third years). These calculations would show the sum of the three 1/3-year accruals equal the annual accruals shown in Table 5.12. However, at the start of 1981, the remaining life is 1 unit, and the corresponding rate is 100%.

Table 5.13 (see end of chapter) shows the result of applying the accrual rates from Table 5.12 to property whose survivor curve is described in Figure 5.1. That is, we will use the correct average life but the incorrect remaining lives. Though the total accruals equal the $10,000 original cost, the annual accruals are not identical with those of Table 5.11. In this example, the maximum life of the survivor curve used to calculate the remaining life rates (7.33 years) is less than the maximum life of the property (8 years), so the final, 100% accrual rate of Table 5.12 assures the accruals will total $10,000.

Now suppose that the survivor curve used to describe the life characteristics of the property being depreciated still has an average life of 6.4 years but the maximum life is greater than 8 years, as shown in Table 5.14

(see end of chapter). When the accrual rates shown in Table 5.14 are applied to property whose life characteristics are shown in Figure 5.1, an underaccrual of $1875 results, because the final retirement was forecast to occur in 1983 but actually occurred in 1981. This emphasizes the fact that when using the remaining life method of adjustment, estimates of the shape of the survivor curve may need to be revised, even though estimates of the average life are unchanged. See Table 5.15 at the end of this chapter.

How does the remaining life adjustment behave when life estimates are revised? Again, the scenario shown in Table 5.7 can be used to observe the results of applying the remaining life method of adjustment. Let the initial forecast of service life be the survivor curve shown in Table 5.16 (see end of chapter); it has an average life of 7.4 years, the same life used to generate the accrual rate shown in Table 5.6.

The remaining life rates of Table 5.16 are used to calculate annual accruals and the accumulated provision for depreciation shown in Table 5.17 (see end of chapter). Because the actual average life is 6.4 years but the forecast life is 7.4 years, the total accruals are $1351 less than the required $10,000.

A REMAINING LIFE SOLUTION TO THE AL ADJUSTMENT PROBLEM. Table 5.7 presented a scenario where accrual rates based on a forecast life of 7.4 years were used for the years 1974, 1975, and 1976. Then in January 1977, the forecast was revised to an average life of 6.4 years. From our discussion of the amortization method of adjustment, we know that in 1977 the accumulated provision for depreciation is $634 less than it would be had the revised forecast been used during 1974, 1975, and 1976. Unless some adjustment is made, that difference will grow to $1351.

The remaining life method of adjustment shown in Table 5.18 (see end of chapter) will amortize the $634 in the following manner. At the start of 1977 the remaining life is 3.4 years, so the adjustment during that year is $634/3.4 or $186. This amount is the difference between the $1749 accrual shown in Table 5.18 and the $1563 accrual (i.e., the average life accrual $10000/6.4) shown in Table 5.5. It reduces the adjustment to $643 − $186 or $448 at the start of 1978. Then the remaining life is 4 years, so the adjustment during 1978 is $448/4 or $112, which is again the difference between the accruals for 1978 as shown in Tables 5.17 and 5.5. In this manner the adjustments for 1979, 1980, and 1981 can be shown to be $112, $112, and $112. Thus, the $1634 variation is amortized over the remaining life. The adjustments are "automatic"; that is, they result automatically when the remaining life calculations are used to determine the annual accruals.

Summary

When comparing the amortization and remaining life methods of adjustment, remember that the magnitude and timing of the annual accruals depend upon the method of allocation and the procedure for applying the method of allocation. The difference between the two methods of adjustment only becomes apparent when the forecast is revised. The remaining life method amortizes the variation between the CAD and the accumulated provision for depreciation over the remaining life and the adjustment is included in the annual accrual. The amortization method allows the variation to be amortized over any period, but requires that the annual amount to be amortized be calculated separately and then added to the calculated accrual. If the depreciation professional chooses to amortize the variation over the remaining life, the two methods result in equal annual accruals.

Neither method of adjustment will properly recover the depreciable base unless accurate forecasts are made. It could be argued that the remaining life method requires only an estimate of the remaining life, while the amortization method requires an estimate of the average life. Remember that at age zero the remaining life is also the average life, and that at any time, the average life can be partitioned into the realized life and the remaining life. The realized life can be obtained from historical records while the remaining life must be forecast. From that point of view, there is no difference between the difficulty of forecasting the remaining life and the average life, because the average life depends on the realized life (which is known) and the remaining life (which must be forecast).

Both methods of adjustment require a forecast of the survivor curve describing the property. The amortization method requires only the average life when calculating the annual accruals, but requires the shape of the survivor curve to calculate the CAD. The remaining life method requires the average life and the shape of the curve to calculate the remaining life and the annual accruals.

The Equal Life Group Procedure Applied to a Vintage Group

The next system of calculating the annual accrual uses the straight line method of allocation and applies the equal life group procedure to a vintage group (SL-ELG). Both the AM and RL methods of adjustment are combined with the ELG procedure.

History of the Equal Life Group Procedure

Allocation using the equal life group procedure was discussed as early as March, 1928, during an ICC hearing (*Telephone Engineer and Management,* 1967, p. 55). Robley Winfrey studied it during the 1930s and in 1942

published a detailed discussion of the procedure in *Depreciation of Group Properties, Bulletin 155.* Winfrey considered it "the only mathematically correct procedure" (p. 71) and called it the unit summation procedure. The procedure was primarily of academic interest until the 1970s.

The major objection to the everyday use of the equal life group procedure was the large number of computations necessary to calculate the annual depreciation. When done manually, these calculations consumed enough time to make the equal life group procedure impractical. As computers became more common and computer time less expensive, this objection gradually disappeared. Another objection focused on the fact that in a growing account, the change from the average life to the equal life group procedure typically was accompanied by a significant increase in annual accruals. Though this increase was coupled with a similar decrease as the account matured, the increase created a bias against the procedure. In the early 1970s, the Bell System began to espouse the equal life group procedure in both the United States and Canada. Bell's informational campaign speeded acceptance first by regulators in Canada and then in the United States. The major argument for equal life group procedure is that it more closely matches depreciation charges with the service rendered during the life of the property than does the average life procedure.

The ELG Procedure

To find the accrual rate when using the equal life group procedure, the life characteristics (the average service life and the shape of the survivor curve) must be estimated. Then the original cost is subdivided into equal life groups. Typically, the equal life groups are formed by specifying the life of each group in one-year increments, and the survivor curve is used to find the proportion of the original cost assigned to each equal life group. Though it is not possible to physically identify the individual units in each ELG, it is possible to statistically identify the fraction of the plant in service in each ELG. Each equal life group is treated as a unit of property and is depreciated using the straight line method of allocation. Note that any method of allocation that can be applied to an individual unit can be applied in the same manner to an equal life group. The total annual accrual for the vintage is found by summing the annual accruals for each equal life group remaining in service. The ELG accrual rate is the total annual accrual divided by the average plant in service during the year.

The $10,000 original cost of the survivor curve shown in Figure 5.1 can be divided into two groups. The first group has a life of 4 years and contains $4000 of the original cost. The second group has a life of 8 years and contains $6000 of the original cost. These will be identified as group A and group B respectively. Note that each dollar in group A has a life of 4 years, therefore the name *equal life group.* Each group will be depreciated using the straight line method of allocation, so that the first group will be depreciated at a rate of 1/4 for 4 years and the second group at a rate of 1/8 for 8 years. Table 5.19 (see end of chapter) shows the calculation of the annual accruals for each equal life group and then sums them to obtain the total accruals and accrual rates. For the year 1974, the annual accruals of $1000 and $750 total $1750, which results in a composite annual rate of $1750/$10000 or 17.50%. For this survivor curve, the ELG rates are constant during the first 4 years (17.50%) and during the last 4 years (12.50%).

The annual accrual rates developed in Table 5.19 are used in Table 5.20 (see end of chapter), which shows the SL-ELG method of calculating the annual accruals and accumulated provision for depreciation for property described by the survivor curve shown in Figure 5.1.

Comparison of the AL and ELG Procedure

Compare the annual accruals and the accumulated provision for depreciation resulting from the use of the SL-ELG system, which are shown in Table 5.20, with the annual accruals and accumulated provision for depreciation resulting from the use of the SL-AL system, which are shown in Table 5.5. When contrasted with the average life procedure, the equal life group procedure results in annual accruals that are higher during the early years and lower in the later years. After the first retirement, which reduces the 1977 balance by $4000, the accumulated provision for depreciation using the average life procedure is $2250 as contrasted with $3000 using the equal life group procedure. With the equal life group procedure, the first unit has been fully depreciated and retired, and $3000 has been accumulated against the eventual (in 4 years) retirement of the $6000 life group, which has a life of 8 years. The $6000 life group is halfway through its life and is half depreciated. The accumulated provision for depreciation with the average life procedure is only $2250, so the $4000 unit was not fully depreciated at the time of its retirement. The $750 difference in the accumulated provision for depreciation between the two procedures will be made up over the life of the longer-lived unit. This is not to imply that the average life procedure is incorrect, only that it is different.

Both procedures are "systematic and rational" as required by the definition of depreciation accounting. Use of the average life procedure matches the depreciation charges to the service provided by the average-lived unit. That is, the shorter-lived units contribute fewer units of service than the longer-lived units, and therefore, the total accrual associated with a short-lived unit is less than that associated with a long-lived unit.

The AL procedure treats each unit as though its life is equal to the average life of the group. The ELG procedure treats each unit in the group as though its life was known. This is the basis for the argument that the equal life group procedure better matches depreciation charges with the life of the units in the group.

Effect of Improper Forecast of Curve Shape

What happens if the shape of the curve used to calculate the equal life group rates differs from the shape of the curve describing the property, even though the estimate of the average service life is correct? Table 5.14 shows a survivor curve with an average life of 6.4 years and with units of $4000 and $6000 but with a different shape than the survivor curve shown in Figure 5.1. Table 5.21 (see end of chapter) shows the application of the ELG rates (see Table 5.19) for the survivor curve shown in Figure 5.1 to property whose survivor curve is shown in Table 5.14. The accruals total only $9400, leaving $600 of the original cost unrecovered. This shows that the shape of the survivor curve affects the capital recovery when using the ELG procedure.

Effect of Improper Average Life Forecast

Now recall the survivor curve with an average life of 7.4 years that was used to show the result of overestimating the service life when using the SL-AL system. The annual accrual rates for this curve when using the SL-ELG system are shown in Table 5.22 and these accrual rates are applied to property with an average life of 6.4 years to obtain the annual accruals shown in Table 5.23. (See end of chapter for both tables.) The results are similar to those shown in Table 5.6. The property lacks $1034 of being fully recovered; this is a smaller deficit than if the average life procedure had been used because of the higher early accrual rates resulting from the use of the equal life group procedure.

An Adjustment Problem—The ELG Procedure

As before, suppose that during 1974, 1975, and 1976 annual accruals were obtained from rates based on a 7.4 year life and shown in Table 5.22. In January 1977, the original forecast is revised to the survivor curve shown in Figure 5.1. Table 5.24 (see end of chapter) shows the accumulated depreciation at the time of the revised forecast to be $4863. The SL-ELG system must be augmented to include a method of adjusting the accumulated provision for depreciation to correct for the accruals made during 1974, 1975, and 1976.

Either the amortization or the remaining life method of adjustment can be used to add a feedback loop to the SL-ELG system of calculating annual accruals. Much of the previous discussion of adjustments to the SL-AL system is applicable to the SL-ELG system, and this section will address only the additional information needed when the equal life group procedure is substituted for the average life procedure.

Amortization Method of Adjustment (SL-ELG-AM)

The discussion of the purpose of, approach to, and estimation of the accumulated provision for depreciation in a preceding section is germane to the CAD calculation when using the SL-ELG-AM system. The calculation of the calculated accumulated depreciation ratio at age i using the equation CADR(i) = 1 − RL(i)/AL is still correct, but the terms RL(i) and the AL now apply to each equal life group rather than the total vintage group. As such, the RL and the AL are no longer averages but are simply the remaining life and the life of a single ELG. The CADR is calculated for each equal life group and is then multiplied by the number of dollars in that equal life group to find the CAD for that equal life group. The CAD for the vintage group is then obtained by summing the CAD for each equal life group remaining in service.

Calculation of the CADR(i) is simplified because the remaining life of an equal life group is the life of the equal life group minus its age. This is true because the survivor curve of a unit is the square survivor curve. If the life of an equal life group is 8 years and its age is 3 years, the remaining life is 5 years, and the calculated accumulated depreciation ratio is CADR(3) = 1 − 5/8 or 3/8, which simplifies to the age/AL.

Table 5.25 (see end of chapter) shows the CAD calculations for the survivor curve shown in Figure 5.1. At the end of the third year, both equal life groups remain in service and their age is 3 years. The $4000 equal life group has an age of 3 years, a CADR of 3/4 or 0.75, and the CAD for this unit is $4000 × 0.75, or $3000. The $6000 equal life group has an age of 3 years, a calculated accumulated depreciation ratio of 3/8 or 0.375, and the CAD for this unit is $6000 × 0.375 or $2250. The CAD of the vintage is $3000 + $2250 or $5250. Because the balance at that time is $10,000, the calculated accumulated depreciation ratio for the vintage is 0.525.

AN AMORTIZATION SOLUTION TO THE ELG ADJUSTMENT PROBLEM. Now return to the scenario summarized in Table 5.24. The accumulated provision for depreciation is $4863 and it is now the start of 1977; the original forecast has been revised and the CAD, based on the revised forecast, calculated. Had the revised forecast been used starting in 1974, the current amount of the accumulated provision for depreciation would be $5250. An adjustment of $5250 − $4863 or $387 is needed to fully recover the initial $10,000 investment.

The amortization method of adjustment allows the $387 to be amortized over a period recommended by the depreciation professional. Suppose that it is decided to make the entire adjustment as a lump sum during 1977. An argument for an immediate adjustment of $387 is that this timing places the increase in the cost of service nearest to the customers who benefitted

by the under-accruals during 1974, 1975, and 1976. Deferral of this adjustment until later in the life of the property may be more likely to assess customers who had not benefitted by the service provided by the property during 1974, 1975, and 1976.

Table 5.26 (see end of chapter) shows the resulting accruals if an immediate, lump sum adjustment is made and the revised rates adopted. As anticipated, the accumulated provision for depreciation is zero at the time of the final retirement.

Remaining Life Method of Adjustment (SL-ELG-RL)

The remaining life method of adjustment can be used with the ELG procedure to form the SL-ELG-RL system of depreciation. The general comments concerning the SL-AL-RL system of depreciation apply when using the ELG procedure, rather than the AL procedure. This section will discuss the differences between the two systems and will focus on the equal life groups formed from the vintage group.

When using the SL-ELG-RL system of depreciation, the annual accruals, as shown in Table 5.20, are determined by the SL-ELG system. But the remaining life method of adjustment requires that the annual accruals be calculated by dividing the future accrual by the remaining life. Application of the remaining life method of adjustment to the ELG procedure requires calculations be made for each ELG. The accruals for each ELG are obtained by dividing the future accrual of the ELG by the remaining life of the ELG and summing over all ELGs to obtain the annual accrual for the vintage. These calculations are shown in Table 5.27 (see end of chapter), where the first section of the table shows the calculations for the $4000 and the $6000 units, and the second portion of the table totals the accruals from each ELG to obtain the vintage accrual. As expected, the annual accruals and the accumulated provision for depreciation are equal to those shown in Table 5.20.

Note that column (e) of the final section of Table 5.27, labeled 1/RL and equaling the composite rate, was calculated by dividing the annual accruals by the future accrual (i.e., the vintage accrual rate was calculated after the annual accrual was calculated).

These accrual rates also can be viewed as a weighted average, where the remaining life for an ELG is weighted by the balance/life of the ELG. In 1976 both unit A and B are in service and their remaining lives are 2 and 6 years respectively. The weight for A is $4000/4 (the balance/life of the ELG) or $1000; for B it is $6000/8 or $750. The remaining life using the average service life weighting is then [$1000(2) + $750(6)]/$1750 or 3.71 years. Note that the numerator ($6500) equals the future accrual and the denominator equals the annual accrual, so that these calculations are equivalent to those shown in Table 5.27.

ALLOCATION OF THE ACCUMULATED PROVISION FOR DEPRECIATION. The calculation of the annual accruals when there is a variation between the CAD and the accumulated provision for depreciation raises the question of how the accumulated provision for depreciation should be allocated among the equal life groups. Any accrual rate used to calculate the annual accrual either explicitly or implicitly allocates the accumulated provision for depreciation (and the variation) among the ELGs. Suppose that at the start of 1976 the accumulated provision for depreciation is $2500, resulting in a variation between the CAD and the accumulated provision for depreciation of $3500 − $2500 or $1000, so that future accrual must include adjustments that will total $1000.

Any method that allocates the accumulated provision for depreciation to each ELG could be used (e.g., the accumulated provision for depreciation could be spread equally among the ELGs, or $1250 to unit A and $1250 to unit B). Logically, the method used should be based on a rational scheme that is consistent with the goals of the depreciation system.

Two methods of allocation will be considered: (a) allocation proportional to the CAD and (b) allocation proportional to the balance less the CAD, which will be called the calculated future accrual (CFA). In either case, we must divide the $2500 accumulated provision for depreciation into two parts and assign one part to unit A and the other to unit B.

The first method considered will be an allocation proportional to the CAD. The calculations are shown below, with columns (b) and (c) taken from Table 5.27. Column (d) shows that ratio of the CAD associated with unit A to the total CAD is 2000/3500 or 57.14%, so that portion of the accumulated provision for depreciation will be allocated to unit A and the remaining 1500/3500 or 42.86% to unit B. Column (e) shows the results of using these percentages to allocate the $2500 accumulated provision for depreciation to the two units. Column (f) is obtained by subtracting the accumulated provision for depreciation allocated to the unit, column (e), from the balance, column (b), and is divided by the remaining life to obtain the annual accrual, column (h), for the ELG. These calculations are equivalent to allocating the $1000 variation proportionally to the CAD; note that 57.14% of $1000 is $571 and that the CAD for unit A, $2000 less $571 is $1429. The total annual accrual is $2107, the resulting composite rate is 2107/7500 or 28.09%, and the composite remaining life is 1/0.2809 or 3.56 years.

Unit (a)	Bal (b)	CAD (c)	% CAD (d)	Accum depr (e)	Future accrual (f)	RL (g)	Accrual (h)
A	4000	2000	57.14	1429	2571	2	1286
B	6000	1500	42.86	1071	4929	6	821
		3500		2500	7500		2107

The preceding example assumed a variation of +$1000. Now suppose the accumulated provision for depreciation is $4500 as shown below. The resulting variation is $3500 − $4500 or −$1000; the future accrual will be reduced by $1000. The calculations below show allocation of this variation proportional to the CAD. The annual accrual is now only $1393, the composite rate is 25.32%, and the composite remaining life is 1/0.2532 or 3.95 years. Note that when using this method of allocation, the composite rate varies with the variation. The larger the variation the larger the rate (and the smaller the composite remaining life), while the smaller the variation the smaller the rate (and the larger the composite remaining life).

Unit (a)	Bal (b)	CAD (c)	% CAD (d)	Accum depr (e)	Future accrual (f)	RL (g)	Accrual (h)
A	4000	2000	57.14	2571	1429	2	714
B	6000	1500	42.86	1929	4071	6	679
		3500		4500	5500		1393

The second method allocates the variation proportional to the CFA. The calculations are shown below. Column (d) shows the balance less the CAD and column (e) shows these figures as a percentage of the total. The $7500 actual future accrual is then allocated to each unit using these percentages and the results are shown in column (f). This is equivalent to allocating the $1000 variation by assigning 30.77% to unit A and 69.23% to unit B. The total accrual is $2019, the composite rate is 2019/7500 or 26.92%, and the composite remaining life is 3.71 years. Note that the composite rate is the same as that used when there was a zero variation and is shown in Table 5.27. If this example was carried out assuming an accumulated provision for depreciation of $4500 resulting in a variation of −$1000, the composite rate would remain at 26.92% and the composite remaining life would remain at 3.71 years.

Unit (a)	Bal (b)	CAD (c)	CFA (d)	% CFA (e)	Future Accrual (f)	RL (g)	Accrual (h)
A	4000	2000	2000	30.77	2308	2	1154
B	6000	1500	4500	69.23	5192	6	865
			6500		7500		2019

An important insight into the difference between the two methods is gained by observing the contribution of each ELG to the total annual accrual. The variation can be expressed as $1000/6500 or 15.38% of the CFA; the future accrual is 15.38% more than it should be if the most recent forecast is correct. Had the accumulated provision for depreciation been $6500, the annual accrual would have been $1750. If the accumulated provision for depreciation is allocated proportionally to the CAD (i.e., the first method), the total annual accrual is increased by (2107 − 1750)/1750 or 20.40%; also, the accrual due to unit A is increased by (1286 − 1000)/1000 or 28.60%, and the accrual due to unit B is increased by (821 − 750)/750 or 9.5%. In contrast, allocation proportional to the CFA (i.e., the second method) yields an increase in the annual accrual of (2019 − 1750)/1750 or 15.38%; also, the accrual due to unit A and unit B are both increased by 15.38%. Allocation proportional to the CAD results in accruals associated with units with a smaller remaining life receiving a proportionally larger share of the variation. Allocation proportional to the CFA yields accruals that are uniformly proportional to the variation.

Use of the method of allocation in which the variance is proportional to the CAD is supported by these arguments.

1. Each ELG will be fully depreciated by the end of its service life.
2. Adjustments (either positive or negative) to past accruals are more rapid, thus placing the added costs or savings on the rate payers closest to the past.
3. The composite rate will increase or decrease as the size of the variation increases or decreases. The larger the variation, the more rapid the rate of adjustment.
4. Typically the allocation of the accumulated provision for depreciation among accounts is proportional to the CAD, and this method extends that concept to the vintage group.

Arguments for allocation proportional to the CFA are listed below:

1. The accrual for each ELG is increased (or decreased) by the same proportion.
2. Adjustments to past accruals are spread over a longer period, thus the magnitude of change in the annual accrual is minimized.
3. The composite rate remains constant despite the size of the variation, thus simplifying both the concept and the calculations.
4. This method is currently widely used when allocating the accumulated provision for depreciation among ELGs within a vintage group.

Strong arguments exist for both methods of allocation. In all future examples, the variation within a vintage group will be allocated proportionally to the CFA, thus allowing use of a constant composite rate despite the

magnitude of the variation. This does not imply that this method is better, only that in this case it is more convenient because the composite rate can be calculated without knowledge of the variation.

Again, return to the problem raised in the scenario shown in Table 5.24. First, duplicate the results of Table 5.23 using the remaining life calculations. This requires calculation of the composite remaining life of the survivor curve shown in Table 5.16, which had an average life of 7.4 years; these calculations are shown in Table 5.28 (see end of chapter).

A REMAINING LIFE SOLUTION TO THE ELG ADJUSTMENT PROBLEM. Next, apply these accrual rates to the example problem, as shown in Table 5.29 (see end of chapter). Note that the annual accruals and accumulated provision for depreciation are the same as in Table 5.23 because both use the same forecast. If the forecast is not revised, $1034 of the initial investment will not be recovered.

Now apply the remaining life method of adjustment to the problem presented in Table 5.24. Starting in 1977, use the accrual rates shown in Table 5.27. The results, shown in Table 5.30 (see end of chapter), are that the −$387 difference between the accumulated provision for depreciation and the CAD at the start of 1977 is amortized over the remaining life of the property, and the accumulated provision for depreciation, after the final retirement, is $0.

How does the remaining life method of adjustment allocate the $387 deficit? Table 5.27 shows that the CFA, at the start of 1977, is $1000 for unit A and $3750 for unit B, for a total of $4750, and that the remaining lives are 1 and 5 years respectively. Unit A accounts for 1000/4750 or 21% of the total while unit B accounts for 3750/4750 or 79%. The method of calculating the composite rate shown in Table 5.27 prorates the $387 deficit so that 21% or 0.21 × $387 or $82 is added to the future accrual of unit A and 79% or 0.79 × $387 or $305 is added to the future accrual of unit B. The $82 is amortized over the remaining life of 1 year, so that the 1977 accrual includes ($1000 + $82)/1 or $1082 for unit A. The $305 is amortized over the remaining life of 5 years, so that the 1977 accrual includes 750 + $305/5 or $811 for unit B. The total 1977 accrual is then $1082 + $811 or $1893. The annual accruals from 1978 through 1981 include the $750 and a $305/5 or $61 adjustment.

GROUP DEPRECIATION SYSTEMS WITH SALVAGE

The preceding discussion of systems of depreciation of a vintage group of property assumed there was no salvage (i.e., the net salvage was zero). These systems can be modified to include salvage so that the annual accruals are a function of the estimates of both life and salvage. In this section the term *salvage* will always refer to salvage used in the accrual rate, which is the net salvage (i.e., the gross salvage less the cost of retiring). An important concept is that a depreciation system should consider the change in salvage as the property ages.

Aged Salvage

Examine the salvage schedule shown in Table 5.31 (see end of chapter) as it will be used in the examples that follow. The salvage ratios of units A and B are 30% and 10% respectively so the salvage is 0.30 × $4000 or $1200 for unit A and 0.10 × $6000 or $600 for unit B. The average salvage ratio (ASR) is (1200 + 600)/10000 or 18%. Column (b) shows the age at the start of the year and reminds us that the salvage ratio changes with age. The term *aged salvage* is used to express this concept. Column (c) is the survivor curve and column (e) shows the salvage ratio for each year in which the plant is retired. Column (f) is the salvage ratio times the retirement frequency. The salvage ratio during the fourth year is 30% and the retirement frequency is 4000/10000 or 0.40, yielding a weighted ratio of 30% × 0.40 or 12% to show that salvage during that year equals 12% of the original investment. The sum of column (f), 18%, is the total salvage expressed as a percentage of the initial cost and is called the average salvage ratio (ASR). The product of the average salvage ratio and the original cost equals the total salvage dollars for the vintage group. Column (g) is the total salvage to that time divided by the total retirements to that time and equals the (average) realized salvage ratio[5] at that age. At age 4, the total salvage realized thus far is $1200 and retirements have totaled $4000; the ratio 1200/4000 yields the realized salvage ratio of 30%. Column (h) is the total salvage remaining to be collected divided by plant remaining to be retired and equals the (average) future salvage ratio. At age 4, the remaining salvage is $600 and the plant remaining to be retired is the $6000 plant in service; the ratio 600/6000 yields the future salvage ratio of 10%. Column (i) is the average salvage ratio. It is the sum of the product of the realized salvage ratio, column (g), times the percent of the plant that has been retired, plus the product of the future salvage ratio, column (h), times the percent of the plant in service. At age 5, 40% of the plant has been retired with a realized salvage ratio of 30%, while 60% remains in service with a future salvage ratio of 10%; the average salvage ratio is 30% × 0.4 + 10% × 0.6 or 18%. Though the realized and future salvage ratios vary with time, the average salvage ratio for the salvage schedule is constant.

It is important to remember that the future salvage ratio changes with the age of the plant. At the time of the initial installation, the future salvage ratio and the average salvage ratio are both 18%. But after unit A is retired,

the future salvage depends only on the remaining plant in service, unit B, and that salvage ratio is 10%. A positive salvage was used in the example, but negative salvage could have been selected just as easily. This schedule also reflects salvage that decreases with age, but an example where salvage increases with age could have been used.

The Average Life Procedure Applied to a Vintage Group

Calculation of the Annual Accrual

When applying the SL-AL system of calculating annual accruals, the rate 1/AL is applied to the plant in service to recover the initial investment. Only the original cost less salvage, or 1 − ASR, may be recovered through annual accruals. In our example the original cost is $10,000 and the ASR is 18%, so $10000 × 1.00 − 0.18 or $8200 is recovered through annual accruals and the remaining 18% or $1800 is recovered as salvage at the time of the retirement.

In the section that assumed no salvage, it was shown that original cost = Σ (average plant in service during age interval j)/AL, when summed over j = 0,1,2, . . ., ML. The equation below shows both sides multiplied by the fraction of the original cost to be recovered, (1 − ASR), so that the rate, on the righthand side, will now be (1 − ASR)/AL. The total accruals, the lefthand side, will be the original cost times (1 − ASR), which equals the capital consumed. This shows that application of the rate (1 − ASR)/AL will fully recover the original cost less the salvage.

(original cost)(1 − ASR) = Σ (average plant in service during age interval j)(1 − ASR)/AL when summed over j = 0,1,2, . . ., ML

Table 5.32 (see end of chapter) shows the result of applying this rate to the example used in the previous section to obtain the annual accruals.

The accumulated provision for depreciation is $2325 after the first retirement. The accumulated provision for depreciation at the start of the previous year, $3844, is increased by the annual accrual of $1281, decreased by the $4000 original cost, and increased by the $1200 salvage to yield the accumulated provision for depreciation of $2325 at the start of 1978.

Note that any other salvage schedule with an average salvage ratio of 18% will yield the same annual rate and result in the same annual accruals shown in Table 5.32. However, the accumulated provision for depreciation will vary from Table 5.32 because the timing of the salvage between the two schedules will differ. If, for example, the salvage ratio is 18% for *both* units (so that the average salvage remains at 18%), the annual accruals will remain at $1281 for the first 4 years and $769 for the last 4 years. But, the accumulated provision for depreciation at the start of 1978 will equal $3844 + $1281 − $4000 × (1.00 − 0.18) or $1845 rather than $2325. This difference would continue until the final retirement, when the accumulated provision for depreciation becomes zero.

Modifying the annual accrual rate (1/AL) by the factor (1 − ASR) is an extension of the average life procedure to include salvage. The factor (1 − ASR) in the accrual rate is a constant used throughout the life of the property regardless of the actual salvage ratio at each age. All units are treated as though their salvage ratio was equal to the average salvage ratio even though the actual salvage for that year is, depending on the salvage schedule, above or below the average.

Effect of Error in the Estimate of Average Salvage

If the estimate of average salvage is wrong, then the total accruals will not equal the capital consumed. Suppose the estimate of average salvage is $0; then $10,000 rather than $8200 is recovered and the accumulated provision for depreciation will equal $1800 after the final retirement. Or suppose the original estimate is a salvage ratio of 40% for unit A and 15% for unit B, resulting in an average salvage ratio of [(40% × 4000) + (15% × 6000)]/10000 or 25%, as shown in Table 5.33 (see end of chapter).

If a correct life estimate of 6.4 years is assumed, the resulting rate using this schedule is (100% − 25%)/6.4 or 11.719%. Table 5.34 (see end of chapter) shows that the total accruals will equal only $7500, leaving $7500 − $8200 or −$700 in the accumulated provision for depreciation after the final retirement because an ASR of 25% rather than 18% was used.

An Adjustment Problem—The AL Procedure

Assume that our initial estimate of the salvage schedule is that shown in Table 5.33 and that the annual accruals for 1974 through 1977 were based on the 11.719% rate. Now suppose that in January 1978, because of events and activities occurring since 1974, the original salvage forecast of 25% average salvage is revised to 18% as shown in the salvage schedule in Table 5.31, which will turn out to be a correct estimate. Table 5.35 (see end of chapter) shows the accumulated provision for depreciation at the start of 1978 is $1888 and presents the problem of adjusting the future accruals in light of the revised forecast.

When you use either the amortization (AM) or remaining life (RL) method of adjustment, the distinction between the average salvage and future salvage plays an important role in the calculation of the adjustment to the accumulated provision for depreciation. Since both the CAD and remaining life calculations are based on future events, they require estimates of future, rather than average, salvage. Though at age zero the average and future salvage ratios are equal, the difference between these two

averages typically increases as the property ages.

Amortization Method of Adjustment **(SL-AL-AM)**

The underlying relationship used to develop the CAD when there was no salvage was CAD = future retirements − future accruals. Future salvage will affect the future value of the accumulated provision for depreciation. The relationship should be modified to read CAD = future retirements − future gross salvage + future cost of retiring − future accrual, or CAD = future retirements − future net salvage − future accrual. This shows that positive future salvage reduces the required accumulated provision for depreciation, because a portion of the original cost is recovered through salvage. Future retirements equal the current balance, the future salvage can be expressed as the future salvage ratio times the current balance, and the straight line rate (1 − ASR)/AL is used to calculate future accruals so that

CAD(i) = B(i) − B(i)[(FSR(i)] − [(1 − ASR)/AL] Σ (average balance during year j) when summed over j from year i to final year of retirement

where B(i) = balance at age i (i.e., the current balance)
CAD(i) = calculated accumulated depreciation at age i
CADR(i) = calculated accumulated depreciation ratio at age i, CAD(i)/B(i)
FSR(i) = future salvage ratio at age i
RL(i) = remaining life at age i
AL = average life

The term Σ (average balance during year j)/B(i) has been shown to equal the remaining life, RL(i), so RL(i) × B(i) = Σ (average balance during year i). Making this substitution and dividing both sides of the equation by B(i) yields the equation CADR(i) = [1 − FSR(i)] − (1 − ASR)[RL(i)/AL]. The first term is the fraction of the plant in service to be recovered and the second is the future accruals expressed as a fraction of the plant in service. Another form of this equation is CADR(i) = (1 − ASR)[1 − RL(i)/AL] + ASR − FSR(i). This form emphasizes the sensitivity of the CADR(i) to the difference between the average and future salvage. If the average and future salvages are equal, or if they are assumed to be equal, the above equation reduces to CADR(i) = (1 − ASR) − (1 − ASR)[RL(i)/AL] = (1 − ASR)[1 − RL(i)/AL].

Table 5.36 (see end of chapter) shows the CAD for the example problem when the salvage schedule shown in Table 5.31 is used. Column (e) is 1 − FSR(i), which represents the percentage of the current plant in service that must be recovered through annual accruals. Initially this is 82%, but

after the first retirement it changes to reflect the fact that 90% of plant now in service must be recovered via depreciation. Column (f) is the straight line rate (100% − 18%)/6.4 or 12.81%. Column (g) is the remaining life, which was obtained from Table 5.8. These factors are combined using the equation [1 − FSR(i)] − (1 − ASR)[RL(i)/AL] to compute the calculated accumulated depreciation ratios shown in column (h). At the end of 1978, the remaining life is 4 years and the future salvage ratio is 10%. If the first form of the equation for the CADR(4)—note that at this time both the age and the remaining life happen to be 4 years—is used, the calculation is (1 − 0.10) − (1 − 0.18)(4/6.4) or 38.75%. If the second form is used, the calculation is (1 − 0.18)(1 − 4/6.4) + (0.18 − 0.10), which also equals 38.75%. Finally, the CADR(4) is multiplied by the current balance, B(4), to obtain the CAD(4), which is shown in column (i).

AN AMORTIZATION SOLUTION TO THE AL ADJUSTMENT PROBLEM. A comparison of the CAD shown in Table 5.36 with the accumulated provision for depreciation shown in Table 5.35 shows that at the start of 1978 the plant is underaccrued by $2325 − $1888 or $437. With the amortization method of adjustment, this deficit is amortized over a period recommended by the depreciation professional. Suppose it was decided to amortize the deficit over the remaining 4 years of life, or $437/4 or $109 each year. The results are shown in Table 5.37 (see end of chapter).

Remaining Life Method of Adjustment **(SL-AL-RL)**

The remaining life method of adjustment requires an estimate of future salvage to calculate the future accrual. When the salvage is not zero, the future accrual (i.e., the total amount remaining to be recovered) equals the current balance less the *future* salvage less the accumulated provision for depreciation. As before, the annual accrual is the future accrual divided by the remaining life or

AARL(i) = [B(i) − FS(i) − APD(i)]/RL(i)
= B(i)[1 − FSR(i) − APDR(i)]/RL(i)

where: B(i) = balance at age i
FS(i) = future salvage at age i
FSR(i) = future salvage ratio at age i
APD(i) = the accumulated provision for depreciation at age i
APDR(i) = the ratio APD(i)/B(i)
RL(i) = remaining life at age i
AARL(i) = the annual accrual at age i using the RL method of adjustment

When there is no salvage, the annual accrual resulting from use of the RL method of adjustment equals the annual accrual resulting from use of the AM method of adjustment if the variation between the CAD and the accumulated provision for depreciation is zero or if the variation is amortized over the remaining life. This is also true when the salvage is not zero and can be proven using the arguments presented in the preceding section. Remember both methods of adjustment require use of the future salvage; the RL method requires it to calculate the future accrual and the amortization method requires it to calculate the CAD.

Table 5.38 (see end of chapter) shows the remaining life calculations for the example problem; the future accrual, column (d), is calculated by subtracting the future salvage and the accumulated provision for depreciation from the balance. At the start of 1978 this calculation is \$6000 − \$600 − \$2325 or \$3075. Because the variation between the CAD and the accumulated provision for depreciation is zero, the annual accruals equal those calculated using the SL-AL method and shown in Table 5.32.

Table 5.39 (see end of chapter) shows the remaining life calculations when the salvage schedule shown in Table 5.33 is used as a forecast. Because the salvage forecast is incorrect, the original cost is not fully recovered. When using the remaining life method of adjustment, the actual salvage for unit A, \$1200, was reflected in the accumulated provision for depreciation at the start of 1978. The difference between the actual and forecast salvage for unit A, (0.40 − 0.30) × \$4000 or \$400, was amortized over the remaining four years, accounting for the \$100 a year difference between annual accruals shown in Table 5.34 and those shown in Table 5.39 during the years 1978 to 1981. Because the final salvage is misestimated by \$300, total accruals in Table 5.39 are \$300 less than the required \$8200.

A REMAINING LIFE SOLUTION TO THE AL ADJUSTMENT PROBLEM. Now return to the problem presented in Table 5.35 and use the revised forecast of future salvage to calculate annual accruals starting in 1978. The remaining life calculations will amortize the \$437 deficit over the remaining 4 years. The 1978 annual accrual of \$878 shown in Table 5.40 (see end of chapter) is composed of a \$769 accrual and a \$437/4 or \$109 adjustment. The annual adjustment for the next year is the variation, which is now \$437 − \$109, divided by the remaining life of 3 years, which again yields an adjustment of (\$437 − \$109)/3 or \$109. In the same manner the adjustments for the next 2 years can each be shown to be \$109. Table 5.37 shows the results of using the amortization method of adjustment to distribute the \$437 variation over 4 years. The annual accruals for both methods of adjustment are the same (see Tables 5.37 and 5.40) because the 4-year amortization period chosen for the AM method of adjustment equals the remaining life (4 years).

The Equal Life Group Procedure Applied to a Vintage Group

Calculation of the Annual Accrual

A previous section illustrated the division of the survivor curve shown in Figure 5.1 into ELGs, each of which had zero salvage and were depreciated as a unit using the annual rate of 1/AL. When salvage is not zero, the annual rate (1 − ASR)/AL is applied to each ELG. The average salvage ratio (ASR) and the average life (AL) both refer to a specific ELG rather than to the average of the vintage group. Table 5.41 (see end of chapter) shows the calculation of annual accrual rates using the SL-ELG system of calculating annual accruals. The rate of (100% − 30%)/4 or 17.5% is applied to unit A and results in annual accruals of \$700 for 4 years; the rate of (100% − 10%)/8 or 11.25% applied to unit B results in annual accruals of \$625 for 8 years. The ELG rate for the vintage group is 13.75% for the first 4 years and 11.25% for the final 4 years.

Table 5.42 (see end of chapter) shows the application of the rates developed in Table 5.41 to obtain the annual accruals and the accumulated provision for depreciation.

Now compare the accruals using the ELG procedure with those obtained using the AL procedure and shown in Table 5.32. The ELG procedure again results in higher annual accruals early in life and lower accruals later in life. The ELG procedure with zero salvage was shown to yield the same accruals that would result if each equal life group was depreciated as an individual unit, so that each unit is fully depreciated at the time of its retirement. The same principle applies with nonzero salvage; each equal life group is assigned the salvage ratio associated with that particular group, thus assuring that the dollars in each ELG will be fully depreciated at retirement. In contrast, the AL procedure uses the average salvage ratio in the accrual rate. The salvage ratio during any year may be above or below the average ratio used in the accrual rate. Retirements with a large salvage ratio are averaged with those with a small ratio so that the depreciation for a particular retirement is averaged over the life of the vintage group.

Table 5.33 is a schedule with an average salvage ratio of 25% and was used to show the results of misestimating salvage when using the AL procedure. Table 5.43 (see end of chapter) shows the ELG rates that result from using that same salvage schedule.

The higher average salvage ratio yields lower accrual rates. When these rates are applied, as shown in Table 5.44, the original cost is not fully recovered. After the final retirement the accumulated provision for depreciation is −\$700, which is the difference between the actual salvage of \$1600 and forecast salvage of \$2500. This is the same deficit that resulted when using the AL procedure (see Table 5.34). In both procedures, the depreciable base was underestimated by \$700, so the total annual accruals were \$700

less than required to fully recover the original cost.

An Adjustment Problem—ELG Procedure

Again suppose that the rates shown in Table 5.43 are used from 1974 through 1977. Then in January 1978, the original salvage ratio estimate of 40% for unit A and 15% for unit B is revised to 30% for unit A and 10% for unit B. Table 5.45 (see end of chapter) shows the current accumulated provision for depreciation at the start of 1978 is $2150. The future accrual must be adjusted to ensure recovery of the $8200 of capital used to provide service during the years 1974 to 1982.

Both the amortization (AM) and remaining life (RL) methods of adjustment used with the ELG procedure and with no salvage were discussed in a previous section. That discussion will now be extended to include salvage.

Amortization Method of Adjustment (SL-ELG-AM)

The first step when using the amortization method of adjustment is to calculate the current value of the CAD as shown in Table 5.46 (see end of chapter). Unit A has a life of 4 years and a salvage of 30% so that (1.00 − 0.30) × $4000 or $2800 must be recovered through the annual accruals. The first row shows the accumulated provision for depreciation for unit A at the start of years 1, 2, 3, and 4. At the start of year 5, the sum of the previous accruals equals the original cost less salvage ($2800), so the retirement of unit A reduces the CAD to zero. In a similar manner, the (1.00 − 0.10) × $6000 or $5400 depreciable cost associated with unit B is recovered over 8 years as shown in the second row. The annual CAD is the sum of the CAD over all ELGs, 2 in this case, and the calculated accumulated depreciation ratio is, by definition, the CAD/plant in service.

The CAD at age 4 is $2700, but the accumulated provision for depreciation at the start of 1977 and shown in Table 5.45 is $2150, which results in a variation of $550. The depreciation professional must decide if this is a significant variation and, if so, how an adjustment should be made.

Note that at the start of 1978 unit A has been retired and is no longer an element in the calculation of the CAD. Any estimates relating to the age or salvage of unit A do not affect the calculation of the CAD from 1978 on. In general, equal life groups that have been retired do not affect the CAD. When calculating the CAD for a system using the ELG procedure, future, rather than past or average, estimates of life and salvage are needed.

AN AMORTIZATION SOLUTION TO THE ELG ADJUSTMENT PROBLEM. At the start of 1978 only unit B remains in service and the estimate of its life remains at 8 years, while its salvage ratio is now estimated to be 10% rather than 15%. Even if the annual accrual rate is immediately revised to 11.25% (see Table 5.41) to reflect this change in the salvage forecast, the existing deficit of $550 will remain in the accumulated provision for depreciation. By amortizing this variation over 3 years, $550/3 or $183 per year will be added to the annual accruals during the next 3 years, as shown in Table 5.47 (see end of chapter).

Remaining Life Method of Adjustment (SL-ELG-RL)

The remaining life method of adjustment requires the future salvage and the life of each ELG to calculate the annual accrual. Each ELG has a single life and a single salvage, so the average and future salvage for each ELG are the same. Table 5.48 (see end of chapter) shows the calculation of the annual accruals for each ELG using the salvage schedule shown in Table 5.31. The future accrual equals the plant in service less the future salvage less the accumulated provision for depreciation and must be calculated for each ELG remaining in service. The initial value of the future accrual for unit A is (1.00 − 0.30) × $4000 or $2800, the remaining life is 4 years, and the annual accrual is $700. For unit B the future accrual is (1.00 − 0.10) × $6000 or $5400, the remaining life is 8 years, and the annual accrual is $675.

The future accrual and the annual accrual for each ELG are combined in the bottom portion of the table to obtain the totals shown in columns (d) and (f). The annual accrual rate shown in column (e) of Table 5.48 was obtained by dividing the annual accrual shown in column (f) by the future accrual shown in column (d) (i.e., the annual accruals were calculated first and then divided by the future accrual to find the annual rate). As mentioned previously, the reciprocal of the rate is called the composite remaining life.

The annual rate also can be calculated using the weighted average referred to in the discussion of depreciation systems with no salvage. Calculation of this average when there is salvage requires calculating the weighted average of the remaining life times (1 − ASR). In 1976, both units A and B are in service and their remaining lives are 2 and 6 years respectively, while their salvage ratios are 30% and 10% respectively. The numerator of the weight for A is the balance over the average life, $4000/4 years, and this weight is independent of salvage. The numerator of the weight for B is $6000/8. The composite remaining life is {[$4000 × (1 − 0.30)/4] × 2 + [$6000 × (1 − 0.10)/8] × 6} divided by the sum of the weights, [$4000 × (1 − 0.30)/4 + $6000 × (1 − 0.10)/8] or [($700 × 2) + ($675 × 6)]/$1375 or 3.964 or 25.229%, which agrees with the rate shown in Table 5.48.

ALLOCATION OF THE VARIATION. In the section on depreciation systems with no salvage, we discussed the calculation of annual accruals when there is a variation between the CAD and the accumulated provision for

depreciation. That discussion will now be expanded to include salvage.

In the section with no salvage we assumed a $1000 variation and then calculated the 1976 accrual. We will now repeat that calculation with salvage. Assume the accumulated provision for depreciation at start of 1976 is $1750 (i.e., from Table 5.46 we see the CAD at the start of 1976 is $2750, the variation is $2750 − $1750 or $1000). First allocate the variation in proportion to the CAD as shown below. Column (e) uses the percentages in column (d) to allocate the $1750 accumulated provision for depreciation to units A and B. The future accrual, column (f), is obtained by subtracting the accumulated provision for depreciation and the salvage ($1200 and $600 for units A and B respectively) from the balance, column (b). Dividing the future accrual by the remaining life yields the annual accrual for each ELG, column (h). The accruals total $1712. This results in a composite rate of $1712/$6450 or 26.54% and a composite remaining life of 3.77 years.

Unit (a)	Bal (b)	CAD (c)	% CAD (d)	Accum depr (e)	Future accrual (f)	RL (g)	Accrual (h)
A	4000	1400	50.91	891	1909	2	955
B	6000	1350	49.09	859	4541	6	757
		2750		1750	6450		1712

Now consider the same circumstances but make the allocation in proportion to the calculated future accrual, as shown in the following calculations. For unit A the calculated future accrual (CFA), column (d), is the balance less the CAD less the salvage or $4000 − $1400 − $1200 or $1400. Column (f) is obtained by first calculating the total future accrual, which is $10000 − ($1200 + $600) − $1750 or $6450; this amount is then prorated to units A and B using the percentages shown in column (e). Totaling the accruals for each ELG yields $1627 and a composite rate of $1627/$6450 or 25.229% and a composite remaining life of 3.96 years. This is the same as the composite rate when the variation is zero (see Table 5.48).

Unit (a)	Bal (b)	CAD (c)	CFA (d)	% CFA (e)	Future accrual (f)	RL (g)	Accrual (h)
A	4000	1400	1400	25.69	1657	2	829
B	6000	1350	4050	74.31	4793	6	798
			5450		6450		1627

Now the composite rates shown in Table 5.48 are applied to the example problem and the results are shown in Table 5.49 (see end of chapter). At

the start of 1979, the estimated future salvage is $600, so the future accrual is $6000 − $600 − $3375 or $2025, and applying the composite annual remaining life rate of 33.33% results in an annual accrual of $675. Because the life and salvage estimates used in Table 5.48 were correct, no adjustments are required and the remaining life accruals are equal those obtained using the SL-ELG system of calculating annual accruals and shown in Table 5.42.

Table 5.50 (see end of chapter) shows the calculation of the composite annual rates when the estimated salvage ratios are 40% and 15% for units A and B respectively. The balance to be depreciated for unit A is (1.00 − 0.40) × $4000 or $2400; the balance for unit B is (1.00 − 0.15) × $6000 or $5100. Composite rates are shown in the bottom portion of the table. Note that the rates during ages 5 through 8 are identical with those in Table 5.48 although the salvage ratios differ. To explain this, remember that the composite rate is the sum of the balance less salvage divided by the annual accrual. During the final 4 years of the example problem, only one ELG survives. The numerator and the denominator of the composite rate both contain the factor (1 − ASR); these cancel, so in this example the composite rates for the final 4 years are independent of the salvage ratios.

Table 5.51 (see end of chapter) shows application of these rates to the example problem. Future salvage ratio estimates of 25% from 1974 to 1977 and 15% from 1978 to 1981 are used to calculate the future accrual. As with the SL-AL-RL system (see Table 5.39), the misestimation of future salvage results in an under-accrual of $300.

A REMAINING LIFE SOLUTION TO THE ADJUSTMENT PROBLEM. Return to the ELG adjustment problem presented in Table 5.45. When the 1978 forecast of future salvage is changed from 15% to 10% and the depreciation process is carried forward, the entire $8200 is, as shown in Table 5.52 (see end of chapter), fully recovered.

A COMMENT. Hypothetical examples of survivor curves and salvage schedules have been used to show basic concepts of depreciation. Be careful when making generalizations based on these examples. The only generalization that can be drawn from the preceding examples is that incorrect forecasts can result in improper capital recovery. The magnitude and direction of the error depends on the particular example. Estimates of life can be too short or too long and the shape of the curve can vary while keeping the average life constant. The shape of the curve determines the remaining life and therefore affects the CAD calculations and the remaining life rates. The salvage ratio can be positive or negative, though only positive salvage was used in the preceding examples. When considering aged salvage, the ratios can increase or decrease with age, and the consequences of using average

rather than aged salvage depend on the pattern of the salvage. Any generalizations concerning the variation between the calculated accumulated depreciation and the accumulated provision for depreciation because of errors in estimation of parameters should carefully state the assumptions made.

Use of Average, Rather than Aged, Salvage

Salvage is sometimes viewed as though it remains constant as the property ages, as opposed to the more realistic view that the salvage varies with age. The former view equates average and future salvage, while the latter view recognizes that the salvage ratio may change each year and that it is necessary to estimate the salvage schedule. This section will examine the results of not recognizing that salvage varies with age by illustrating the use of the average salvage ratio rather than a salvage schedule.

The Average Life Procedure

The average life procedure requires estimates of future salvage to assure proper adjustments. When using the amortization method of adjustment, the future salvage enters the CAD calculation; when using the remaining life method of adjustment, the future salvage is needed to calculate the future accrual.

First consider the amortization method of adjustment. The CAD equation CADR(i) = (1 − ASR)[1 − RL(i)/AL] + ASR − FSR(i) reduces to CADR(i) = (1 − ASR)[1 − RL(i)/AL] when the future salvage ratio, FSR(i), is set equal to the average salvage ratio, ASR. The annual values of the CAD using the second equation are shown in Table 5.53 (see end of chapter), and these values should be compared to those in Table 5.36, which were calculated using the correct future salvage. Though the CAD starts and ends at zero in both tables, there is a significant difference between the two after the first retirement. In Table 5.53 the calculations for the CAD at the start of year 5 anticipate a salvage ratio of 18%, which is \$4000 × 0.18 or \$720 for unit A, rather than the actual salvage of \$1200. This difference of \$1200 − \$720 or \$480 equals the difference between the CAD at the start of year 5 in the two tables.

If the CAD shown in Table 5.53 is used as a guide in analyzing the problem posed in Table 5.35, the variation between the calculated accumulated depreciation and the accumulated provision for depreciation is \$1845 − \$1888 or −\$43. This suggests that the future accrual should be *reduced* by a total of \$43. The potential \$437 deficit is concealed by the failure of the depreciation professional to forecast the salvage schedule. The salvage of the final retirement is estimated to be \$6000 × 0.18 or \$1080 rather than the actual \$600, and this difference of \$480 is the difference between the CAD calculated using the salvage schedule and the CAD calculated using

the average salvage during the final 4 years.

The net impact of not distinguishing between average and future salvage depends on the amount of the change in salvage ratios as the account matures. Forecasters may tend to associate realized salvage with average salvage, thus presupposing that future salvage ratios will be close to those observed early in the life of the vintage. The result may be a poor forecast of the average salvage ratio used in the accrual rate.

Results of using the average salvage rather than the future salvage with the remaining life method of adjustment are shown in Table 5.54 (see end of chapter). The annual accruals during the first 4 years are the same as in Table 5.38 (which uses the correct value of future salvage), because the future and average salvage are equal until the time of the first retirement. During the remaining 4 years, the system assumes that only 82% of the plant in service must be recovered. Actually 90% is needed, so a deficit of (82% − 90%) × \$6000 or −\$480 results.

When using the AL procedure and either method of adjustment, accurate estimates of the salvage schedule are needed to fully recover invested capital in a timely manner. Use of the average, rather than aged salvage, will result in incorrect estimates of the CAD and may result in accruals that do not equal the capital consumed.

The Equal Life Group Procedure

The equal life group procedure requires the salvage ratio for each life group in order to calculate the annual accrual. The future salvage is the weighted average of all ELGs remaining in service. Table 5.55 (see end of chapter) shows the calculation of annual accrual rates using the 18% average salvage ratio for both ELGs. Unit A is assigned a rate of (100% − 18%)/4 or 20.5% and unit B a rate of (100% − 18%)/8 or 10.25%.

Table 5.56 (see end of chapter) shows the application of these rates. Note that the accruals total \$8200, as they should, but the timing of the accruals differs from those shown in Table 5.42, which use the correct aged salvage. Because the first retirement had a higher than average salvage ratio, the total annual accruals generated by unit A, 4 × \$820 or \$3280, are \$480 greater than the \$4000 − \$1200 or \$2800 to be depreciated, while the total annual accruals for unit B, 8 × \$615 or \$4920, are \$480 less than the \$6000 − \$600 or \$5400 to be depreciated. The fact that the two differences cancel each other is not coincidence, but the result of using the average salvage ratio.

In this example, use of the average salvage resulted in higher early rates than would have resulted if the salvage schedule had been used. If the salvage schedule had reflected salvage ratios that increased with age, the early rates would have been lower than those resulting from using the average.

Use of the average salvage rather than the aged salvage associated with

each ELG results in the use of the AL procedure for the salvage portion of the annual accrual rate. This combination of the ELG procedure for life and the AL procedure for salvage fully recovers the initial investment less salvage, but it partially negates the major attribute of the ELG procedure. Use of the average salvage in the ELG accrual rate will not match the annual depreciation charges with the consumption of capital. When the ELG procedure is used with a salvage schedule, the units comprising the ELG are fully accrued at the time of their retirement. This is not true if the average salvage is used. The magnitude of the difference in timing resulting from using the average salvage rather than the salvage schedule depends on two factors. First, if the salvage ratio is zero or near zero, then the difference is also zero or near zero. Second, if the salvage ratio is constant, or nearly constant, the annual retirement ratios will be close to the average salvage ratio and the difference will be small. These two factors interact to determine the magnitude of the difference.

Suppose the average salvage ratio of 18%, rather than the aged salvage, had been applied to each ELG when calculating the CAD. The resulting CADs and CADRs are shown in Table 5.57 (see end of chapter).

The CAD at the start of 1978 calculated using the average salvage is $2460 as compared to the CAD of $2700 obtained using the salvage schedule. If the average salvage is used, the variation between the CAD and the accumulated provision for depreciation of $2150 shown in Table 5.45 would be $310 rather than the correct value of $550. If the adjustment was based on the CAD calculated using the average salvage, a deficit of $240 would result. This shows that when the salvage varies with age, use of the average salvage with the ELG procedure will affect the accuracy of the CAD.

Now examine the effects of using the average salvage rather than the aged salvage when the remaining life method of adjustment is used. Table 5.58 at the end of the chapter (which is constructed in the same manner as Table 5.48) shows the calculation of the composite rates using average salvage. The balances for both units A and B are calculated by multiplying the initial cost by (100% − 18%) or 82%, yielding balances of $3280 and $4920 respectively.

Table 5.59 (see end of chapter) shows the results of using average rather than aged salvage with the remaining life method of adjustment. Note that the total accruals were $480 less than necessary to recover the $8200 of capital consumed. After the first retirement, the system expected a future salvage of 0.18 × $6000 or $1080 and accruals were based on that assumption. When only $600 was received, a deficit in accumulated provision for depreciation of $480 resulted.

SUMMARY

The two preceding sections discussed depreciation systems for group property. All the systems discussed applied the straight line method of allocation to a vintage group. First it was assumed that there was no salvage, and then the consideration of salvage was added.

Two procedures for applying the straight line method of depreciation were used. The average life procedure treats each member of the group as though it will have a life and salvage equal to the group average. Though we know that each member of the group will not behave as the average member, our assumption works because the variation between members brings us back to the average. The equal life group procedure statistically divides the vintage group into smaller, equal life groups so that each member of the equal life group will have the same life and salvage. Each equal life group is then depreciated as a unit using the life and salvage associated with the ELG. This yields two systems of calculating annual accruals, the SL-AL system and the SL-ELG system.

These systems are incomplete until a method of control is included in the system. There are two methods of creating a closed loop feedback system. One method is labeled the amortization (AM) method of adjustment. This term describes a system in which the calculated accumulated depreciation (CAD) is used as a measure against which the (book) accumulated provision for depreciation is compared. The depreciation analyst uses this feedback as a guide in determining the necessary adjustment to the annual accruals or, if necessary, to the accumulated provision for depreciation. The remaining life (RL) method of adjustment automatically amortizes the variation between the CAD and the accumulated provision for depreciation over the remaining life of the property.

Combining both methods of allocation with both methods of adjustment yields four depreciation systems. Two use the average life procedure, SL-AL-AM and SL-AL-RL, and two use the equal life group procedure, SL-ELG-AM and SL-ELG-RL. Because the methods of allocation for purpose of book depreciation are almost exclusively limited to the straight line method, these four choices represent the systems available for the depreciation of a vintage group.

Table 5.1. Calculation of the annual accruals and the accumulated provision for depreciation for a unit of property using the straight line method of allocation. The unit has a life of 4 years and a 20% salvage ratio.

Year	Balance Jan 1	Retired	Rate%	Annual accrual	* Accumulated depreciation * Net Jan 1	Debit	Credit
1974	$4000		20.0	$800	$0	$0	$800
1975	4000		20.0	800	800	0	800
1976	4000		20.0	800	1600	0	800
1977	4000	$4000	20.0	800	2400	4000	1600
1978	0				0		
				$3200		$4000	$4000

Table 5.2. Calculation of the annual accruals and the accumulated provision for depreciation for a unit of property using the sum-of-years-digits (accelerated) method of allocation. The unit has a life of 4 years and a 20% salvage ratio.

Year	Balance Jan 1	Retired	Rate%	Annual accrual	* Accumulated depreciation * Net Jan 1	Debit	Credit
1974	$4000		32.0	$1280	$0	$0	$1280
1975	4000		24.0	960	1280	0	960
1976	4000		16.0	640	2240	0	640
1977	4000	$4000	8.0	320	2880	$4000	1120
1978	0				0		
				$3200		$4000	$4000

Table 5.3. Calculation of the annual accruals and the accumulated provision for depreciation for a unit of property using the declining balanbe (accelerated) method of allocation. The unit has a life of 4 years and a 20% salvage ratio. The rate is 1.5/4 or 37.5%.

Year	Declining balance Jan 1	Retired	Rate%	Annual accrual	* Accumulated depreciation * Net Jan 1	Debit	Credit
1974	$4000		37.5	$1500	$0	$0	$1500
1975	2500		37.5	938	1500	0	938
1976	1562		37.5	586	2438	0	586
1977	976	$4000	*	176	3024	4000	976
1978	0				0		
				$3200		4000	$4000

* Switch to straight line rate. This yields a final accrual of $176.

Table 5.4. Calculation of the annual accruals and the accumulated provision for depreciation for a unit of property using the sinking fund (decelerated) method of allocation with i=10%. The unit has a life of 4 years and a 20% salvage ratio.

Year	Balance Jan 1	Retired	Rate%	Annual accrual	* Accumulated depreciation * Net Jan 1	Debit	Credit
1974	$4000		17.24	$690	$0	$0	$690
1975	4000		18.96	758	690	0	758
1976	4000		20.86	834	1448	0	834
1977	4000	$4000	22.95	918	2282	4000	1718
1978	0				0		
				$3200		4000	$4000

Table 5.5. Calculation of annual accruals and accumulated provision for depreciation using the SL-AL system and a rate of 1/6.4 or 15.625%.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		15.625	$1563	$0
1975	10000		15.625	1563	1563
1976	10000		15.625	1563	3125
1977	10000	$4000	15.625	1563	4688
1978	6000		15.625	938	2250
1979	6000		15.625	938	3188
1980	6000		15.625	938	4125
1981	6000	6000	15.625	938	5063
1982	0				0

Table 5.6. Calculation of annual accruals and accumulated provision for depreciation using the SL-AL system and a rate of 1/7.4 or 13.514%.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		13.514	$1351	$0
1975	10000		13.514	1351	1351
1976	10000		13.514	1351	2703
1977	10000	$4000	13.514	1351	4054
1978	6000		13.514	811	1405
1979	6000		13.514	811	2216
1980	6000		13.514	811	3027
1981	6000	6000	13.514	811	3838
1982	0				-1351

Table 5.7. Calculation of annual accruals and accumulated provision for depreciation using the SL-AL system. A rate of 1/7.4 or 13.514% was used during the first three years.

	Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
P	1974	$10000		13.514	$1351	$0
A	1975	10000		13.514	1351	1351
S	1976	10000		13.514	1351	2703
T						4054
F	1977	0000	$4000			
U	1978	6000				
T	1979	6000				
U	1980	6000				
R	1981	6000	6000			
E	1982	0				

Table 5.8. Calculation of the CAD for the survivor curve shown in Figure 5.1.

Year (a)	Age (b)	Balance (c)	Service in $-yrs (d)	Remaining life (e)	CADR (f)	CAD (g)
1974	0	$10000	64000	6.40	.0000	$0
1975	1	10000	54000	5.40	.1563	1563
1976	2	10000	44000	4.40	.3125	3125
1977	3	10000	34000	3.40	.4688	4688
1978	4	6000	24000	4.00	.3750	2250
1979	5	6000	18000	3.00	.5313	3188
1980	6	6000	12000	2.00	.6875	4125
1981	7	6000	6000	1.00	.8438	5063
1982	8	0	0		1.0000	0

Table 5.9. Application of the amortization method of adjustment to the problem presented in Table 5.7. The $634 deficit is amortized over two years and the rate is increased to 15.63%.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		13.51	$1351	$0
1975	10000		13.51	1351	1351
1976	10000		13.51	1351	2702
1977	10000	$4000	15.63	1880*	4054
1978	6000		15.63	1255**	1933
1979	6000		15.63	938	3187
1980	6000		15.63	938	4125
1981	6000	6000	15.63	938	5062
1982	0				0

* Includes a $1563 annual accrual plus a $317 adjustment.

** Includes a $938 annual accrual plus a $317 adjustment.

Table 5.10. Calculation of the remaining life and the rate for the survivor curve shown in Figure 5.1.

Year (a)	Age (b)	Balance (c)	Retired (d)	Remaining service $-yrs (e)	Remaining life (f)	Rate % 1/RL (g)
1974	0	$10000		$64000	6.40	15.63
1975	1	10000		54000	5.40	18.52
1976	2	10000		44000	4.40	22.73
1977	3	10000	$4000	34000	3.40	29.41
1978	4	6000		24000	4.00	25.00
1979	5	6000		18000	3.00	33.33
1980	6	6000		12000	2.00	50.00
1981	7	6000	6000	6000	1.00	100.00
1982	8	0				

Table 5.11. Calculation of the annual accrual and the accumulated provision for depreciation using the SL-AL-RL system of depreciation and the accrual rates shown in Table 5.10.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	15.625	$1563	$0
1975	10000		8438	18.519	1563	1563
1976	10000		6875	22.727	1563	3125
1977	10000	$4000	5313	29.412	1563	4688
1978	6000		3750	25.000	938	2250
1979	6000		2813	33.333	938	3188
1980	6000		1875	50.000	938	4125
1981	6000	6000	938	100.000	938	5063
1982	0					0

Table 5.12. Remaining life of a survivor curve in which $4000 is retired after 5 years and $6000 after 7.33 years, resulting in an average life of 6.4 years.

Year (a)	Age (b)	Balance (b)	Retired (c)	Remaining service $-yrs (e)	Remaining life (f)	Rate % (g)
1974	0	$10000		$64000	6.40	15.63
1975	1	10000		54000	5.40	18.52
1976	2	10000		44000	4.40	22.73
1977	3	10000		34000	3.40	29.41
1978	4	10000	$4000	24000	2.40	41.67
1979	5	6000		14000	2.33	42.86
1980	6	6000		8000	1.33	75.00
1981	7	6000	6000	2000*	1.00*	100.00
1982	8	0				

* $6000 is retired 1/3 of the way through the final year so the average balance during 1981 is $2000 and the remaining life at the start of the year is 1.00 year.

Table 5.13. Calculation of the annual accrual and the accumulated provision for depreciation using the SL-AL-RL system and accrual rates developed in Table 5.12.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	15.625	$1563	$0
1975	10000		8438	18.519	1563	1563
1976	10000		6875	22.727	1563	3125
1977	10000	$4000	5313	29.412	1563	4688
1978	6000		3750	41.667	1563	2250
1979	6000		2188	42.857	938	3813
1980	6000		1250	75.000	938	4750
1981	6000	6000	313	100.000	313	5688
1982	0					0

Table 5.14. Remaining life for a survivor curve in which $4000 is retired after 1 year and $6000 after 10 years, resulting in an average life of 6.4 years.

Year (a)	Age (b)	Balance (c)	Retired (d)	Remaining service $-yrs (e)	Remaining life (f)	Rate % (g)
1974	0	$10000	$4000	$64000	6.40	15.63
1975	1	6000		54000	9.00	11.11
1976	2	6000		48000	8.00	12.50
1977	3	6000		42000	7.00	14.29
1978	4	6000		36000	6.00	16.67
1979	5	6000		30000	5.00	20.00
1980	6	6000		24000	4.00	25.00
1981	7	6000		18000	3.00	33.33
1982	8	6000		12000	2.00	50.00
1983	9	6000	6000	6000	1.00	100.00
1984	10	0				

Table 5.15. Calculation of the annual accrual and the accumulated provision for depreciation using the SL-AL-RL system and accrual rates developed in Table 5.14.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	15.625	$1563	$0
1975	10000		8438	11.111	938	1563
1976	10000		7500	12.500	938	2500
1977	10000	$4000	6563	14.286	938	3438
1978	6000		5625	16.667	938	375
1979	6000		4688	20.000	938	1313
1980	6000		3750	25.000	938	2250
1981	6000	6000	2813	33.333	938	3188
1982	0			50.000		-1875
1983				100.000		

Table 5.16. Remaining life for a survivor curve in which $4000 is retired after 4 years, $6000 after 9.67 years, with an average life of 7.4 years.

Year (a)	Age (b)	Balance (b)	Retired (c)	Remaining service $-yrs (e)	Remaining life (f)	Rate % (g)
1974	0	$10000		$74000	7.40	13.51
1975	1	10000		64000	6.40	15.63
1976	2	10000		54000	5.40	18.52
1977	3	10000	$4000	44000	4.40	22.73
1978	4	6000		34000	5.67	17.65
1979	5	6000		28000	4.67	21.43
1980	6	6000		22000	3.67	27.27
1981	7	6000		16000	2.67	37.50
1982	8	6000		10000	1.67	60.00
1983	9	6000*	6000	$4000*	1.00*	100.00
1984	10	0				

* $6000 is retired two-thirds of the way through the final year, so the average balance during 1983 is $4000 and the remaining life is 1.00 year.

Table 5.17. Calculation of the annual accrual and the accumulated provision for depreciation using the SL-AL-RL system and accrual rates developed in Table 5.16.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	13.514	$1351	$0
1975	10000		8649	15.625	1351	1351
1976	10000		7297	18.519	1351	2703
1977	10000	$4000	5946	22.727	1351	4054
1978	6000		4595	17.647	811	1405
1979	6000		3784	21.429	811	2216
1980	6000		2973	27.273	811	3027
1981	6000	6000	2162	37.500	811	3838
1982	0			60.000		-1351
1983				100.000		

Table 5.18. Application of the remaining life method of adjustment to the problem presented in Table 5.7.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate% 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	13.514	$1351	$0
1975	10000		8649	15.625	1351	1351
1976	10000		7297	18.519	1351	2703
1977	10000	$4000	5946	29.410*	1749	4054
1978	6000		4197	25.000*	1049	1803
1979	6000		3148	33.333*	1049	2852
1980	6000		2099	50.000*	1049	3901
1981	6000	6000	1049	100.000*	1049	4951
1982	0					0

* Accrual rates from Table 5.10.

Table 5.19. Calculation of the annual accrual rates for the survivor curve shown in Figure 5.1 using the SL-ELG system.

Group (a)	Group amount (b)	Group life (c)	Group rate % (d)	Annual accrual 1974-77 (e)	Annual accrual 1978-81 (f)
A	$4000	4	25.00	$1000.00	
B	6000	8	12.50	$750.00	$750.00
Annual accruals				$1750.00	$750.00
Balance during interval				$10000	$6000
Annual accrual rate %				17.50	12.50

Table 5.20. Calculation of annual accruals and accumulated provision for depreciation using the SL-ELG system using the rates calculated in Table 5.19.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		17.50	$1750	$0
1975	10000		17.50	1750	1750
1976	10000		17.50	1750	3500
1977	10000	$4000	17.50	1750	5250
1978	6000		12.50	750	3000
1979	6000		12.50	750	3750
1980	6000		12.50	750	4500
1981	6000	6000	12.50	750	5250
1982	0				0

Table 5.21. Calculation of annual accruals and accumulated provision for depreciation using the SL-ELG system and the accrual rates calculated in Table 5.19. The survivor curve for the property is shown in Table 5.14.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000	$4000	17.50	$1750	$0
1975	6000		17.50	1050	-2250
1976	6000		17.50	1050	-1200
1977	6000		17.50	1050	-150
1978	6000		12.50	750	900
1979	6000		12.50	750	1650
1980	6000		12.50	750	2400
1981	6000		12.50	750	3150
1982	6000		12.50	750	3900
1983	6000	6000	12.50	750	4650
1984	0				-600

Table 5.22. Calculation of the annual accrual rates for the survivor curve shown in Table 5.16 using the SL-ELG system.

Group (a)	Group amount (b)	Group life (c)	Group rate % (d)	Annual accrual 1974-78 (e)	Annual accrual 1979-81 (f)
A	$4000	4	25.00	$1000.00	
B	6000	9.67	10.34	620.69	$620.69
Annual accruals				$1621.00	$621.00
Balance during interval				$10000	$6000
Annual accrual rate %				16.21	10.34

Table 5.23. Calculation of annual accruals and accumulated depreciation using the SL-ELG system and the accrual rates calculated in Table 5.22.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		16.21	$1621	$0
1975	10000		16.21	1621	1621
1976	10000		16.21	1621	3242
1977	10000	$4000	16.21	1621	4863
1978	6000		10.34	620	2484
1979	6000		10.34	620	3104
1980	6000		10.34	620	3725
1981	6000	6000	10.34	620	4345
1982	0				-1034

Table 5.24. Calculation of annual accruals and accumcumulated depreciation using the SL-ELG system. The accrual rates shown in Table 5.22 are used for the first three years.

	Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
P	1974	$10000		16.21	$1621	$0
A	1975	10000		16.21	1621	1621
S	1976	10000		16.21	1621	3242
T						4863
F	1977	10000	$4000			
U	1978	6000				
T	1979	6000				
U	1980	6000				
R	1981	6000	6000			
E	1982	0				

Table 5.25. Calculation of the calculated accumulated depreciation and the calculated accumulated depreciation ratios for the survivor curve shown in Figure 5.1.

		CAD At Start of Year								
Life	Amount	1	2	3	4	5	6	7	8	9
4	4000	0	1000	2000	3000	0				
8	6000	0	750	1500	2250	3000	3750	4500	5250	0
Annual CAD		0	1750	3500	5250	3000	3750	4500	5250	0
Start of year balance		10000	10000	10000	10000	6000	6000	6000	6000	0
CADR		.000	.1750	.3500	.5250	.5000	.6250	.7500	.8750	1.000

Table 5.26. Application of the amortization method of adjustment to the problem presented in Table 5.24. The $387 deficit is amortized over a 1-year period and the accrual rates are changed to those shown in Table 5.19.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		16.21	$1621	$0
1975	10000		16.21	1621	1621
1976	10000		16.21	1621	3242
1977	10000	$4000	17.50	2137*	4863
1978	6000		12.50	750	3000
1979	6000		12.50	750	3750
1980	6000		12.50	750	4500
1981	6000	6000	12.50	750	5250
1982	0				0

* Includes a $1750 accrual and a $387 adjustment.

Table 5.27. Calculation of the annual accruals and accumulated provision for depreciation using the SL-ELG-RL system of depreciation and the survivor curve shown in Figure 5.1.

Accruals by ELG

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
Unit A						
1974	$4000		$4000	25.000	$1000	$0
1975	4000		3000	33.333	1000	1000
1976	4000		2000	50.000	1000	2000
1977	4000	$4000	1000	100.000	1000	3000
						0
Unit B						
1974	$6000		$6000	12.500	$750	$0
1975	6000		5250	14.286	750	750
1976	6000		4500	16.667	750	1500
1977	6000		3750	20.000	750	2250
1978	6000		3000	25.000	750	3000
1979	6000		2250	33.333	750	3750
1980	6000		1500	50.000	750	4500
1981	6000	$6000	750	100.000	750	5250
						0

Total accruals

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Composite rate % (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	17.50	$1750	$0
1975	10000		8250	21.21	1750	1750
1976	10000		6500	26.92	1750	3500
1977	10000	$4000	4750	36.84	1750	5250
1978	6000		3000	25.00	750	3000
1979	6000		2250	33.33	750	3750
1980	6000		1500	50.00	750	4500
1981	6000	6000	750	100.00	750	5250
1982	0					0

Table 5.28. Calculation of the composite annual accrual rates using the SL-ELG-RL system of depreciation and the survivor curve shown in Table 5.16.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
Unit A						
1974	$4000		$4000	25.000	$1000	$0
1975	4000		3000	33.333	1000	1000
1976	4000		2000	50.000	1000	2000
1977	4000	$4000	1000	100.000	1000	3000
						0
Unit B						
1974	$6000		$6000	10.341	$620	$0
1975	6000		5380	11.534	620	620
1976	6000		4759	13.037	620	1240
1977	6000		4139	14.992	620	1860
1978	6000		3518	17.637	620	2480
1979	6000		2898	21.413	620	3100
1980	6000		2277	27.248	620	3720
1981	6000		1657	37.453	620	4340
1982	6000		1036	59.880	620	4960
1982	6000	$6000	416	100.000	416	5580
1983	0					0

Total accruals

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Composite rate % (e)	Annual accrual (f)
1974	$10000		$10000	16.205	$1621
1975	10000		8379	19.339	1621
1976	10000		6758	23.975	1621
1977	10000	$4000	5137	31.536	1621
1978	6000		3516	17.637	620
1979	6000		2816	21.413	620
1980	6000		2276	27.248	620
1981	6000		1656	37.453	620
1982	6000	6000	1036	59.880	620
1983	0		416	100.000	416

Table 5.29. Calculation of the annual accrual and the accumulated provision for depreciation using the SL-ELG-RL system of depreciation and the accrual rates shown in Table 5.28.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	16.205	$1621	$0
1975	10000		8379	19.339	1621	1621
1976	10000		6758	23.975	1621	3242
1977	10000	$4000	5137	31.536	1621	4863
1978	6000		3516	17.637	620	2484
1979	6000		2896	21.413	620	3104
1980	6000		2276	27.248	620	3724
1981	6000	6000	1656	37.453	620	4344
1982	0			59.880		-1034
1983				100.000		

Table 5.30. Application of the remaining life method of adjustment to the problem presented in Table 5.24.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	16.205	$1621	$0
1975	10000		8379	19.339	1621	1621
1976	10000		6758	23.975	1621	3242
1977	10000	$4000	5137	36.842*	1893	4863
1978	6000		3244	25.000*	811	2756
1979	6000		2433	33.333*	811	3567
1980	6000		1622	50.000*	811	4378
1981	6000	6000	811	100.000*	811	5189
1982	0					0

* Accrual rates from Table 5.27.

Table 5.31. The salvage schedule for the survivor curve shown in Figure 5.1 and having an average salvage ratio of 18%.

Year (a)	Age (b)	Balance (c)	Retired (d)	SR % (e)	% of orig cost (f)	Realized salvage ratio % (g)	Future salvage ratio % (h)	Average salvage ratio % (i)
1974	0	$10000				.00	18.00	18.00
1975	1	10000				.00	18.00	18.00
1976	2	10000				.00	18.00	18.00
1977	3	10000	$4000*	30.00	12.00	.00	18.00	18.00
1978	4	6000				30.00	10.00	18.00
1979	5	6000				30.00	10.00	18.00
1980	6	6000				30.00	10.00	18.00
1981	7	6000	6000*	10.00	6.00	30.00	10.00	18.00
1982	8	0				18.00		18.00
					18.00			

* Salvage for these units is $1200 and $600 respectively.

Table 5.32. Calculation of annual accruals and accumulated provision for depreciation using the SL-AL system and a rate of (100%-18%)/6.4 or 12.813%.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		12.813	$1281	$0
1975	10000		12.813	1281	1281
1976	10000		12.813	1281	2563
1977	10000	$4000*	12.813	1281	3844
1978	6000		12.813	769	**2325
1979	6000		12.813	769	3094
1980	6000		12.813	769	3863
1981	6000	6000*	12.813	769	4631
1982	0				***0

* Salvage for these units is $1200 and $600 respectively.

** 2325 = 3844 + 1281 - 4000 + 1200

*** 0 = 4631 + 769 - 6000 + 600

Table 5.33. Salvage schedule for survivor curve shown in Figure 5.1 and having an average salvage ratio of 25%.

Year (a)	Age (b)	Balance (c)	Retired (d)	SR % (e)	% of orig cost (f)	Realized salvage ratio % (g)	Future salvage ratio % (h)	Average salvage ratio % (i)
1974	1	$10000				.00	25.00	25.00
1975	2	10000				.00	25.00	25.00
1976	3	10000				.00	25.00	25.00
1977	4	10000	$4000*	40.00	16.00	.00	25.00	25.00
1978	5	6000				40.00	15.00	25.00
1979	6	6000				40.00	15.00	25.00
1980	7	6000				40.00	15.00	25.00
1981	8	6000	6000*	15.00	9.00	40.00	15.00	25.00
1982	9	0				25.00		25.00
					25.00			

* Salvage for these units is $1600 and $900 respectively.

Table 5.34. Calculation of annual accruals and accumulated provision for depreciation using the SL-AL system using a rate of (100%-25%)/6.4 or 11.719%.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		11.719	$1172	$0
1975	10000		11.719	1172	1172
1976	10000		11.719	1172	2344
1977	10000	$4000*	11.719	1172	3516
1978	6000		11.719	703	1888
1979	6000		11.719	703	2591
1980	6000		11.719	703	3294
1981	6000	6000*	11.719	703	3997
1982	0				-700

* Salvage for these units is $1200 and $600 respectively.

Table 5.35. Calculation of annual accruals and accumulated provision for depreciation using the SL-AL system. A rate of (100%-25%)/6.4 or 11.719% was used during the first four years.

	Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
P	1974	$10000		11.719	$1172	$0
A	1975	10000		11.719	1172	1172
S	1976	10000		11.719	1172	2344
T	1977	10000	$4000*	11.719	1172	3516
						1888
F	1978	6000				
U	1979	6000				
T	1980	6000				
U	1981	6000	6000			
R	1982	0				
E						

* Salvage for this unit is $1200.

Table 5.36. Calculation of the CAD for the SL-AL system using the survivor curve shown in Figure 5.1 and the salvage schedule shown in Table 5.31.

Year (a)	Age (b)	Balance (c)	Retired (d)	1-FSR (e)	Rate % (f)	RL (g)	CADR (h)	CAD (i)
1974	0	$10000		82.00	12.81	6.40	.00	$0
1975	1	10000		82.00	12.81	5.40	12.81	1281
1976	2	10000		82.00	12.81	4.40	25.63	2563
1977	3	10000	$4000*	82.00	12.81	3.40	38.44	3844
1978	4	6000		90.00	12.81	4.00	38.75	2325
1979	5	6000		90.00	12.81	3.00	51.56	3094
1980	6	6000		90.00	12.81	2.00	64.38	3863
1981	7	6000	6000*	90.00	12.81	1.00	77.19	4631
1982	8	0						0

* Salvage for these units is $1200 and $600 respectively.

Table 5.37. Application of the amortization method of adjustment to the problem presented in Table 5.35. The $437 deficit is amortized over 4 years and the rate is increased to 12.813%.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		11.719	$1172	$0
1975	10000		11.719	1172	1172
1976	10000		11.719	1172	2344
1977	10000	$4000*	11.719	1172	3516
1978	6000		12.813	878**	1888
1979	6000		12.813	878**	2766
1980	6000		12.813	878**	3644
1981	6000	6000*	12.813	878**	4522
1982	0				0

* Salvage for these units is $1200 and $600 respectively.

** Includes a $769 accrual and a $109 adjustment.

Table 5.38. Calculation of the annual accruals and the accumulated provision for depreciation using the SL-AL-RL system of depreciation. The rates are shown in Table 5.10 and the future salvage is shown in Table 5.31.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$8200	15.625	$1281	$0
1975	10000		6919	18.519	1281	1281
1976	10000		5638	22.727	1281	2563
1977	10000	$4000*	4356	29.412	1281	3844
1978	6000		3075	25.000	769	2325
1979	6000		2306	33.333	769	3094
1980	6000		1538	50.000	769	3863
1981	6000	6000*	769	100.000	769	4631
1982	0					0

* Salvage for these units is $1200 and $600 respectively.

Table 5.39. Calculation of the annual accrual and the accumulated provision for depreciation using the SL-AL-RL system of depreciation with the rates shown in Table 5.10 and the salvage schedule shown in Table 5.33.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$7500	15.625	$1172	$0
1975	10000		6328	18.519	1172	1172
1976	10000		5156	22.727	1172	2344
1977	10000	$4000*	3984	29.412	1172	3516
1978	6000		3213	25.000	803	1888
1979	6000		2409	33.333	803	2691
1980	6000		1606	50.000	803	3494
1981	6000	6000*	803	100.000	803	4297
1982	0					-300

* Salvage for these units is $1200 and $600 respectively.

Table 5.40. Application of the SL-AL-RL system of depreciation to the problem presented in Table 5.35.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$7500	15.625	$1172	$0
1975	10000		6328	18.519	1172	1172
1976	10000		5156	22.727	1172	2344
1977	10000	$4000*	3984	29.412	1172	3516
1978	6000		3513**	25.000	878	1888
1979	6000		2634**	33.333	878	2766
1980	6000		1756**	50.000	878	3644
1981	6000	6000*	878**	100.000	878	4522
1982	0					0

* Salvage for these units is $1200 and $600 respectively.

** A future salvage of 10% ratio is used.

Table 5.41. Calculation of the annual rates for the survivor curve shown in Figure 5.1 and the salvage schedule shown in Table 5.31 using the SL-ELG system of calculating annual accruals.

Group (a)	Group amount (b)	Group life (c)	Group salvage % (d)	Group rate % (e)	Annual accrual 1974-77 (f)	Annual accrual 1978-81 (g)
A	$4000	4	30.00	17.50	$700.00	
B	6000	8	10.00	11.25	675.00	$675.00
Annual accruals					$1375.00	$675.00
Balance during interval					$10000	$6000
Annual accrual rate %					13.75	11.25

Table 5.42. Calculation of annual accruals and accumulated provision for depreciation using the SL-ELG system of calculating annual accruals and the rates shown in Table 5.41.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		13.750	$1375	$0
1975	10000		13.750	1375	1375
1976	10000		13.750	1375	2750
1977	10000	$4000*	13.750	1375	4125
1978	6000		11.250	675	2700
1979	6000		11.250	675	3375
1980	6000		11.250	675	4050
1981	6000	6000*	11.250	675	4725
1982	0				0

* Salvage for these units is $1200 and $600 respectively.

Table 5.43. Calculation of the annual rates for the survivor curve shown in Figure 5.1 and the salvage schedule shown in Table 5.33 using the SL-ELG system.

Group (a)	Group amount (b)	Group life (c)	Group salvage % (d)	Group rate % (e)	Annual accrual 1974-77 (f)	Annual accrual 1978-81 (g)
A	$4000	4	40.00	15.00	$600.00	
B	6000	8	15.00	10.63	638.00	$638.00
Annual accruals					$1238.00	$638.00
Balance during interval					$10000	$6000
Annual accrual rate %					12.38	10.63

Table 5.44. Calculation of annual accruals and accumulated provision for depreciation using the SL-ELG system and the rates shown in Table 5.43.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		12.375	$1238	$0
1975	10000		12.375	1238	1238
1976	10000		12.375	1238	2475
1977	10000	$4000*	12.375	1238	3713
1978	6000		10.625	638	2150
1979	6000		10.625	638	2788
1980	6000		10.625	638	3425
1981	6000	6000*	10.625	638	4063
1982	0				-700

* Salvage for these units is $1200 and $600 respectively.

Table 5.45. Calculation of annual accruals and accumulated provision for depreciation using the SL-ELG system. Rates shown in Table 5.43 were used during the first 4 years.

	Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
P	1974	$10000		12.375	$1238	$0
A	1975	10000		12.375	1238	1238
S	1976	10000		12.375	1238	2475
T	1977	10000	$4000*	12.375	1238	3713
						2150
F	1978	6000				
U	1979	6000				
T	1980	6000				
U	1981	6000	6000			
R	1982	0				
E						

* Salvage for this unit is $1200.

Table 5.46. Calculation of the calculated accumulated depreciation and the calculated accumulated depreciation ratios for the survivor curve shown in Figure 5.1 and the salvage schedule shown in Table 5.31.

		CAD at start of year								
Life	Amount	1	2	3	4	5	6	7	8	9
4	2800	0	700	1400	2100	0				
8	5400	0	675	1350	2025	2700	3375	4050	4725	0
Annual CAD		0	1375	2750	4125	2700	3375	4050	4725	0
Start of year balance		10000	10000	10000	10000	6000	6000	6000	6000	0
CADR		.000	.1375	.2750	.4125	.4500	.5625	.6750	.7875	1.000

Table 5.47. Application of the amortization method of adjustment to the problem presented in Table 5.45. The $550 variation is amortized over a 3-year period and rates are changed to those shown in Table 5.41.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		12.375	$1238	$0
1975	10000		12.375	1238	1238
1976	10000		12.375	1238	2475
1977	10000	$4000*	12.375	1238	3713
1978	6000		11.250	858**	2150
1979	6000		11.250	858**	3008
1980	6000		11.250	858**	3867
1981	6000	6000*	11.250	675	4725
1982	0				0

* Salvage for these units is $1200 and $600 respectively.

** Includes $675 annual accrual and $183 adjustment.

Table 5.48. Calculation of the composite annual accrual rates using the SL-ELG-RL system of depreciation, the survivor curve shown in Figure 5.1, and the future salvage shown in Table 5.31.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
Unit A						
1974	$4000		$2800	25.000	$700	$0
1975	4000		2100	33.333	700	700
1976	4000		1400	50.000	700	1400
1977	4000	$4000	700	100.000	700	2100
						0
Unit B						
1974	$6000		$5400	12.500	$675	$0
1975	6000		4725	14.286	675	675
1976	6000		4050	16.667	675	1350
1977	6000		3375	20.000	675	2025
1978	6000		2700	25.000	675	2700
1979	6000		2025	33.333	675	3375
1980	6000		1350	50.000	675	4050
1981	6000	$6000	675	100.000	675	4725
						0

Total accruals

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Composite rate % (e)	Annual accrual (f)
1974	$10000		$8200	16.768	$1375
1975	10000		6825	20.147	1375
1976	10000		5450	25.229	1375
1977	10000	$4000*	4075	33.742	1375
1978	6000		2700	25.000	675
1979	6000		2025	33.333	675
1980	6000		1350	50.000	675
1981	6000	6000*	675	100.000	675
1982	0				

* Salvage for these units is $1200 and $600 respectively.

Table 5.49. Calculation of the annual accruals and accumulated provision for depreciation using the SL-ELG-RL system of depreciation and the rates shown in Table 5.48 and the future salvage shown in Table 5.31.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$8200	16.768	$1375	$0
1975	10000		6825	20.147	1375	1375
1976	10000		5450	25.229	1375	2750
1977	10000	$4000*	4075	33.742	1375	4125
1978	6000		2700	25.000	675	2700
1979	6000		2025	33.333	675	3375
1980	6000		1350	50.000	675	4050
1981	6000	6000*	675	100.000	675	4725
1982	0					0

* Salvage for these units is $1200 and $600 respectively.

Table 5.50. Calculation of the composite rates for the survivor curve shown in Figure 5.1 and the salvage schedule shown in Table 5.33.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
Unit A						
1974	$4000		$2400	25.000	$600	$0
1975	4000		1800	33.333	600	600
1976	4000		1200	50.000	600	1200
1977	4000	$4000	600	100.000	600	1800
						0
Unit B						
1974	$6000		$5100	12.500	$638	$0
1975	6000		4463	14.286	638	638
1976	6000		3825	16.667	638	1275
1977	6000		3188	20.000	638	1913
1978	6000		2550	25.000	638	2550
1979	6000		1913	33.333	638	3188
1980	6000		1275	50.000	638	3825
1981	6000	$6000	638	100.000	638	4463
						0

Total accruals

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Composite rate % (e)	Annual accrual (f)
1974	$10000		$7500	16.500	$1238
1975	10000		6263	19.760	1238
1976	10000		5025	24.627	1238
1977	10000	$4000	3788	32.673	1238
1978	6000		2550	25.000	638
1979	6000		1913	33.333	638
1980	6000		1275	50.000	638
1981	6000	6000	638	100.000	638
1982	0				

Table 5.51. Calculation of annual accruals and accumulated provision for depreciation using the SL-AL-RL system of depreciation with the rates shown in Table 5.50 and future salvage shown in Table 5.33.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$7500	16.500	$1238	$0
1975	10000		6263	19.760	1238	1238
1976	10000		5025	24.627	1238	2475
1977	10000	$4000*	3788	32.673	1238	3713
1978	6000		2950	25.000	738	2150
1979	6000		2213	33.333	738	2888
1980	6000		1475	50.000	738	3625
1981	6000	6000*	738	100.000	738	4363
1982	0					-300

* Salvage for these units is $1200 and $600 respectively.

Table 5.52. Application of the SL-ELG-RL depreciation system to the problem presented in Table 5.45.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$7500	16.500	$1238	$0
1975	10000		6263	19.760	1238	1238
1976	10000		5025	24.627	1238	2475
1977	10000	$4000*	3788	32.673	1238	3713
1978	6000		3250**	25.000***	813	2150
1979	6000		2438**	33.333***	813	2963
1980	6000		1625**	50.000***	813	3775
1981	6000	6000*	813**	100.000***	813	4588
1982	0					0

* Salvage for these units is $1200 and $600 respectively.

** A future salvage of 10% is used.

*** Accrual rates from Table 5.48.

Table 5.53. Calculation of CAD for the SL-AL system using the survivor curve shown in Figure 5.1 and a future and average salvage ratio of 18%.

Year (a)	Age (b)	Balance (c)	Retired (d)	1-ASR (e)	RL (f)	CADR (g)	CAD (h)
1974	0	$10000		82.00	6.40	00.00	$0
1975	1	10000		82.00	5.40	12.81	1281
1976	2	10000		82.00	4.40	25.63	2563
1977	3	10000	$4000*	82.00	3.40	38.44	3844
1978	4	6000		82.00	4.00	30.75	1845
1979	5	6000		82.00	3.00	43.56	2614
1980	6	6000		82.00	2.00	56.38	3383
1981	7	6000	6000*	82.00	1.00	69.19	4151
1982	8	0					0

* Salvage for these units is $1200 and $600 respectively.

Table 5.54. Application of the SL-AL-RL system of depreciation using the average salvage ratio of 18% rather than the future salvage ratio.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$8200	15.625	$1281	$0
1975	10000		6919	18.519	1281	1281
1976	10000		5638	22.727	1281	2563
1977	10000	$4000*	4356	29.412	1281	3844
1978	6000		2595	25.000	649	2325
1979	6000		1946	33.333	649	2974
1980	6000		1298	50.000	649	3623
1981	6000	6000*	649	100.000	649	4271
1982	0					-480

* Salvage for these units is $1200 and $600 respectively.

Table 5.55. Calculation of the annual accrual rates for the survivor curve shown in Figure 5.1 and an average salvage ratio of 18% using the SL-ELG system of calculating annual accruals.

Group (a)	Group amount (b)	Group life (c)	Group salvage % (d)	Group rate % (e)	Annual accrual 1974-77 (f)	Annual accrual 1978-81 (g)
A	$4000	4	18.00	20.50	$820.00	
B	6000	8	18.00	10.25	$615.00	$615.00
Annual accruals					$1435.00	$615.00
Balance during interval					$10000	$6000
Annual accrual rate %					14.35	10.25

Table 5.56. Calculation of annual accrual rates and accumulated provision for depreciation using the SL-ELG system with rates based on average salvage and shown in Table 5.55.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		14.350	$1435	$0
1975	10000		14.350	1435	1435
1976	10000		14.350	1435	2870
1977	10000	$4000*	14.350	1435	4305
1978	6000		10.250	615	2940
1979	6000		10.250	615	3555
1980	6000		10.250	615	4170
1981	6000	6000*	10.250	615	4785
1982	0				0

* Salvage for these units is $1200 and $600 respectively.

Table 5.57. Calculation of the calculated accumulated depreciation and calculated accumulated depreciation ratios using the SL-ELG-AM depreciation and an average salvage ratio of 18% for all ELGs.

		CAD at start of year								
Life	Amount	1	2	3	4	5	6	7	8	9
4	3280	0	820	1640	2460	0				
8	4920	0	615	1230	1845	2460	3075	3690	4305	0
Annual CAD		0	1435	2870	4305	2460	3075	3690	4305	0
Start of year balance		10000	10000	10000	10000	6000	6000	6000	6000	0
CADR		.000	.1445	.2870	.4305	.4100	.5125	.6150	.7175	1.000

Table 5.58. Calculation of composite rates using the survivor curve shown in Figure 5.1 and letting the salvage ratio for all retirements equal the average salvage ratio of 18%.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
Unit A						
1974	$4000		$3280	25.000	$820	$0
1975	4000		2460	33.333	820	820
1976	4000		1640	50.000	820	1640
1977	4000	$4000	820	100.000	820	2460
						0
Unit B						
1974	$6000		$4920	12.500	$615	$0
1975	6000		4305	14.286	615	615
1976	6000		3690	16.667	615	1230
1977	6000		3075	20.000	615	1845
1978	6000		2460	25.000	615	2460
1979	6000		1845	33.333	615	3075
1980	6000		1230	50.000	615	3690
1981	6000	$6000	615	100.000	615	4305
						0

Total accruals

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Composite rate % (e)	Annual accrual (f)
1974	$10000		$8200	17.500	$1435
1975	10000		6765	21.212	1435
1976	10000		5330	26.923	1435
1977	10000	$4000	3895	36.842	1435
1978	6000		2460	25.000	615
1979	6000		1845	33.333	615
1980	6000		1230	50.000	615
1981	6000	6000	615	100.000	615
1982	0				

Table 5.59. Application of the SL-AL-ELG-RL system of depreciation using the rates shown in Table 5.58 and a future salvage ratio of 18% rather than the future salvage shown in Table 5.31.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$8200	17.500	$1435	$0
1975	10000		6765	21.212	1435	1435
1976	10000		5330	26.923	1435	2870
1977	10000	$4000*	3895	36.842	1435	4305
1978	6000		1980	25.000	495	2940
1979	6000		1485	33.333	495	3435
1980	6000		990	50.000	495	3930
1981	6000	6000*	495	100.000	315	4425
1982	0					-480

* Salvage for these units is $1200 and $600 respectively.

NOTES

1. Gas (FERC), electric (FERC), and water companies (NARUC) use the title Accumulated Provision for Depreciation, while telecommunications (FCC) and railroads (ICC) use the title Accumulated Depreciation. Telecommunications used the title Depreciation Reserve until 1986. We will use the term *Accumulated Provision for Depreciation*. It refers to the net balance of either of these accounts.

2. The CADR is also called reserve ratio or the accrued ratio.

3. The balance, usually shown in column (b) of the tables at the end of this chapter, can be defined as the balance at the start of the year or the average balance during the year. The convention used in this chapter results in the start-of-year balance equaling the average balance. When other conventions are used, a small difference between the two annual accruals may result because the remaining life calculation typically applies the rate to the beginning-year balance while the amortization calculation typically applies the rate to the average balance during the year.

4. All of these variables except AL are a function of the age of the property, and a complete notation would include an index for the age. For example, rather than RL, use RL(i) = the remaining life at age i. The following calculations all refer to the same year so the index i is dropped.

5. Remember that both the realized and future salvage ratios are averages. Both the survivor curve and the salvage ratio at each age from zero to the maximum life are required to calculate these average ratios. For convenience, we will use the terms realized or future salvage ratio rather than *average* realized or *average* future salvage ratio.

6 Continuous Property Groups

CHAPTER 5 used elementary survivor curves, a single vintage group, and a simplified format to illustrate the calculation of the annual accrual for depreciation for several systems of depreciation. This chapter will use Iowa survivor curves and formats characteristic of those found in industrial practice to illustrate the application of these systems of depreciation to continuous property groups. The illustrations will include the use of both average salvage and salvage that varies with age.

A continuous property group[1] is created when vintage groups are combined to form a common group. Each year property is removed from service for many reasons and, at the same time, property may be added either to replace property that was retired or to increase service capacity. Over time the operating and physical characteristics of the property change, but the continuous property group continues as long as the service it provides is needed. If new vintages are no longer added, the continuous property group becomes closed, or bounded, and over time becomes smaller and finally vanishes. The continuous property group, which is usually recorded as a plant account or subaccount, is of interest because it represents the most common method of grouping assets for depreciation.

The method of allocation, the procedure for applying the method of allocation, and the method of adjustment (e.g., SL-AL-AM) specify the factors that define a depreciation system for a vintage group. The terms broad group and vintage group describe two ways of viewing the life and salvage characteristics of the vintage groups that have been combined to form a continuous property group for purposes of depreciation. One approach is to view the continuous property group as a collection of vintage

CONSULTING CONTRACT NO. 19013

This Consulting Contract (the **"Contract"**) is made effective as of **March 5, 2019** (the "**Effective Date**") and is entered into

BETWEEN

YUKON ENERGY CORPORATION, having its place of business at 2 Miles Canyon Road, P.O. Box 5920, Whitehorse YT Y1A 6S7 (hereinafter referred to as the **"Corporation"**)

AND

ALLIANCE CONSULTING GROUP a company duly incorporated under the laws of the United States of America and Texas, having an office at Suite 220, 101 E. Park Blvd, in the city of Plano, State of Texas 75074 (hereinafter referred to as the **"Consultant"**)

WHEREAS:

The Corporation wishes to engage the Services of the Consultant on the terms and conditions and understandings hereinafter set forth.

NOW THEREFORE THIS CONTRACT WITNESSES THAT in consideration of the terms set out in this Contract and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Corporation and Consultant hereto agree as follows:

1. TERMS OF ENGAGEMENT

1.1 The Term of this Contract shall begin on the Effective Date and terminate on **June 30, 2019** unless terminated earlier in accordance with this Contract.

1.2 The Corporation and the Consultant may elect to extend the term of this Contract by mutual consent by the parties.

1.3 In consideration for the remuneration hereinafter set out, the Consultant agrees to make available Services as described in Schedule B, Scope of Work, "**Depreciation Study"** (the "Services") to the Corporation, provide advice with respect to the provision of Services as required, and other Services as may be requested by the Corporation.

1.4 This Contract represents the entire Contract between the Corporation and the Consultant.

1.5 The Services provided by the Consultant under the terms of this Contract will be authorized by the Corporation. The Consultant will not, without the prior written authorization from the Corporation, cause the Corporation to commit any funds or to incur any liability.

1.6 The Consultant agrees to act in the best interest of the Corporation and will devote time, effort, skill, attention and energies to carrying out the duties and responsibilities. As part of those responsibilities, the Consultant will provide any and all information requested in a timely fashion and the Consultant will conduct its business in a professional and reputable manner. Failure to comply with these requirements may be cause for termination of this Contract as provided for herein.

1.7 References herein to this "Contract" means the main text of this Contract and the schedules, being:

Schedule A - FEES AND DISBURSEMENTS

Schedule B - RFP SCOPE OF WORK

Schedule C - TESTIMONY LIST AS OF JANUARY 24, 2019

Schedule D - RESUMES

2. STATUS OF THE CONSULTANT

The Consultant is an independent Consultant and is not the servant, employee or agent of the Corporation. The Consultant agrees to indemnify and hold harmless the Corporation from any and all claims or demands for taxes, premiums or other statutory payments or assessments that may be made against the Corporation on behalf of the Consultant.

2.1 The Consultant may provide the Services at the Consultant's place of business or at the Corporation's place of business in Whitehorse, Yukon or at such other place or places as may be required from time to time by the Corporation.

3. SUBCONTRACTORS/SUBCONSULTANTS

3.1 The Consultant may hire or engage one or more subcontractor(s)/subconsultant(s) to perform any or all of its obligations under this Contract; provided, that:

3.1.1 that the Consultant shall use the same degree of care in selecting any such subcontractor(s)/subconsultant(s) as it would if such subcontractor(s)/subconsultant(s) was being retained to provide similar services to the Consultant; and

3.1.2 that the Consultant shall in all cases remain responsible for all of its obligations under this Contract with respect to the scope of the Services.

3.2 The Consultant shall require each subcontractor/subconsultant, to the extent of the Work to be performed by the subcontractor/subconsultant, to be bound to the Consultant by the terms of any Contract, and to assume toward the Consultant all the obligations and responsibilities which the Consultant, by this Contract, assumes toward the Corporation. Said Contract shall preserve and protect the rights of the Corporation under the Contract with respect to the Work to be performed by the subcontractor/subconsultant so that the subcontracting thereof will not prejudice such rights.

4. GENERAL PROVISIONS

4.1 Unless otherwise specified, this Contract shall be governed by the laws of the Yukon and the Consultant will hereby attorn to the jurisdiction of the Yukon Courts.

4.2 The Corporation and the Consultant respectively bind themselves, their partners, successors, assigns and legal representatives to the other party to this Contract to the partners, successors, assigns and legal representatives of all such other parties with respect to all terms and conditions of this Contract.

4.3 Neither party to this Contract may assign any of its rights or obligations under this Contract without the prior written consent of the other party, which consent may be unreasonably withheld, except that either party may assign this Contract or any of its rights or obligations to any of its subsidiaries and/or affiliated companies without consent of the other party.

4.4 This Contract and any Schedules hereto, constitute the entire Contract between the Corporation and the Consultant and no other representations or Contracts, oral or otherwise, exist between the parties with respect to the subject matter of this Contract unless referred to in the Contract.

4.5 This Contract may be amended only by written instrument signed by both the Corporation and the Consultant.

4.6 The Consultant has no authority to make any statements, representations or commitments of any kind or take any action that will bind the Corporation.

4.7 No condoning, excusing or waiver by any party of any default, breach of non-observance by any other party at any time or times in respect of any covenant or condition contained in this Contract will operate as a waiver of that party's rights in respect of any continuing or subsequent default, breach of non-observance, or so as to defeat or affect in any way the rights of that party in respect of any such continuing or subsequent defaults, breach of non-observance, and no waiver will be inferred from or implied by anything done or omitted to be done by the party having those rights.

4.8 If any provision of this Contract or the application thereof to any person or circumstance to any extent is invalid or unenforceable, the remainder of this Contract or the application of that provision to any other person or circumstance other than those in respect of which it is held invalid or unenforceable will not be affected thereby and each provision of this Contract is separately valid and enforceable to the fullest extent permitted by law.

5. FEES AND REIMBURSABLE EXPENSES

5.1 The Corporation agrees to pay the Consultant for Services performed in accordance with the terms of this Contract, and in accordance with the rates set out in Schedule "A" attached to this Contract. The Consultant will accept such payment as full payment and full reimbursement for the Services performed under this Contract.

5.2 The Consultant agrees that any and all engineering changes that are deemed minor by both parties and necessary in the completion of the Services covered under the Contract will be included within the price and rates quoted in the Contract, unless otherwise mutually agreed by the Change Order.

5.3 If the Corporation considers it appropriate, the Consultant may be required to submit monthly progress/milestone reports with payment invoices.

5.4 The Corporation may require that invoices are allocated into multiple cost codes, which will be provided to the Consultant.

5.5 Changes to the Services shall only be made on receipt of written instructions from the Corporation. Any resulting adjustment to the agreed price shall be agreed upon by the Corporation and the Consultant and will represent the reasonable and proper costs incurred by or savings accruing to the Consultant using the rates submitted in the proposal.

5. TERMINATION, SUSPENSION OR ABANDONMENT

5.1 The Corporation, at its sole discretion, may by providing written notice to the Consultant suspend the Services in whole or part or suspend this Contract. Upon receipt of such notice, the Consultant shall immediately discontinue its work on the suspended Services and continue to perform all other Services that have not been suspended. The Corporation may, by written notice, require the Consultant to resume some or all of the suspended Services in accordance with the notice.

5.2 The Corporation, at its sole discretion, may by providing a minimum of thirty (30) days written notice to the Consultant terminate all or any part of this Contract or the Service. Such notice may specify the scope of the termination and will specify the effective date of such termination. Upon receipt of such notice, the Consultant shall immediately discontinue the Services in accordance with the notice.

5.3 If the Services or this Contract are suspended or terminated in whole or in part pursuant to this section, the Consultant shall take all steps necessary to minimize the costs associated with such termination or suspension.

5.4 In the event of termination of this Contract, the Consultant shall be compensated within thirty (30) days of the date that an invoice is rendered for all Services performed to the date of termination, together with reimbursable expenses then due to the Consultant provided such Services and expenses have been properly documented and justified to the Corporation's satisfaction.

6. INDEMNIFICATION

6.1 The Consultant will indemnify and save harmless the Corporation, its successors, assigns, directors, officers, agents, employees, and authorized representatives and each of them from and against any and all claims, demands, losses, costs, damages, actions, suits, or proceedings whether directly or indirectly caused or incurred, related to or occasioned by, arising or resulting from and to the extent of any negligent error omission or act of the Consultant, any sub-consultant and their respective servants, agents and employees in the performance of the Contract, excepting liability arising out of any error, omission or negligent act of the Corporation, its successors, assigns, agents, employees and authorized representatives. Notwithstanding and superseding anything to the contrary on this Contract.

6.1.1 The aggregate liability of the Consultant arising out of the performance or non-performance of the Services or otherwise in connection with this Contract is limited to the sum of the amount of the professional fees paid to the Consultant pursuant to this Agreement up to [redacted] USD and 10% of such fees paid in excess of [redacted] USD;

6.1.2 Provided that in no event will the Consultant's aggregate liability exceed $1,000,000; Consultants liability for claims or losses covered by the insurance policies referred to in Clause 7. (a) (b) and (c) shall not be subject to Clause 6.1 and shall instead be limited to the proceeds of insurance up to the amounts specified in Clause 7. (a) (b) and (c).

6.2 The Corporation shall indemnify and save harmless the Consultant, its successors, assigns, agents, employees and authorized representatives and each of them from and against any and all claims, demands, losses, costs, damages, actions, suits or proceedings whether directly or indirectly caused or incurred, related to or occasioned by, arising or resulting from any error, omission or negligent act of the Corporation or its servants, agents and employees in the performance of this Contract, excepting liability arising out of any negligent error, omission or negligent act of the Consultant, its successors, assigns, agents, employees and authorized representatives.

6.3 The indemnity provided by the Consultant in this Section 6 will survive the expiration or termination of this Contract for a period of one year.

6.4 The Consultant shall perform the Services (a) with due care and skill in accordance with the standard of care and skill normally exercised by professional engineers providing similar services on projects of similar scope and complexity and in comparable locations, and (b) re-perform any Services that fail to comply with this standard of care if the Corporation gives the Consultant notice of such failure within twelve months of performance of such Services.

6.5 The Corporation or any person authorized by the Corporation will have the right, at all reasonable times, to inspect or otherwise review the Services performed, or being performed, and the premises and locations where the Services are being performed. No review or approval by or on behalf of the Corporation will have the effect of relieving the Consultant of its responsibilities and obligations under this Contract. No review or approval by the Corporation will be deemed to be a waiver or release of any rights that the Corporation may have against the Consultant; save to the extent that the Corporation expressly waives such rights or releases the Consultant in writing.

7. INSURANCE

7.1 Before commencing the Work, Consultant shall obtain and maintain the following insurance policies during the term of the Contract:

7.1.1 A commercial general liability policy, in an amount for each and every occurrence of $2 million for each and every occurrence and in the aggregate, with a standard form cross liability clause and a broad form property damage endorsement, the latter in an amount equal to the full policy limit. The policy will name Yukon Energy Corporation as an additional insured with respect to liabilities that arise out of Consultant's operations, and shall contain cross liability and severability of interest clauses or equivalent wording;

7.1.2 Automobile insurance covering liability for bodily injury, including death, or property damage to third parties arising out of ownership, use or operation of Consultant owned or leased licensed motor vehicles of $2 million inclusive;

7.1.3 Property insurance covering loss or damage to tools, property and equipment of Consultant or for which Consultant is legally liable or responsible of an amount equal to the full replacement value of such tools, property and equipment with a waiver of the insurer's rights of subrogation against the Corporation.

7.1.4 A Professional Liability Insurance policy in an amount of $1 million per claim and in the aggregate, to cover damages because of any error, omission or negligent act in professional services rendered by the Consultant. Coverage will be maintained for at least twenty four (24) months after completion of the Work or earlier termination of the Contract.

7.2 Consultant shall within fourteen (14) days following a request by Corporation's Designate, provide a completed Certificate of Insurance evidencing Consultant's compliance with this clause, except that no evidence of automobile insurance is required unless evidence of such insurance is specifically requested.

7.3 Consultant shall be solely responsible for determining the appropriate type and amount of insurance that Consultant should have in place from time to time, but must maintain during the term of the Contract at least the amount and type of insurance it is required to maintain under this clause.

7.4 Consultant shall be responsible for the full amount of all deductibles of all insurance policies required. Failure to furnish proof of insurance shall be considered a breach of the Contract, allowing the Corporation to obtain such insurance and charge the cost to the Consultant, or to terminate the Contract at the Corporation's absolution discretion.

8. WORKER'S COMPENSATION

8.1 Requirements for Consultants Registered Outside the Yukon

If the Consultant is to perform any work on the Corporation's site including but not limited to delivery, assembly, installation and/or unloading of deliverables, Consultant shall within ten (10) days of the award of a Contract and before commencing work on site, provide a Letter of Compliance issued by the Yukon Workers' Compensation Health and Safety Board ("YWCHSB"), including but not limited to:

- an account number and/or Letter of Compliance from YWCHSB to confirm registration in Yukon;
- a statement from WCB that the Consultant and any sub-contractors are registered and in good standing in their home province;
- confirmation that all persons performing the Work who are not covered by the Workers Compensation Act are covered under personal optional protection coverage available through WCB.

8.2 Requirements for Consultants Performing Work in the Yukon

If the Consultant is to perform any work on the Corporation's site including but not limited to delivery, assembly, installation and/or unloading of deliverables, Consultant shall within ten (10) days of the award of a Contract and before commencing work on site, and at any time on the request of the Corporation, provide evidence of certification by the Yukon Workers' Compensation Health and Safety Board ("YWCHSB"), including but not limited to:

- if the Consultant will be performing work on the Corporation's site that does not exceed ten (10) days per year, a statement from the YWCHSB that the Consultant is registered with the YWCHSB;
- if the Consultant will be performing work on the Corporation's site that exceeds ten (10) days per year, a statement and/or certificate from the YWCHSB that the Consultant and all sub-contractors are registered and in good standing, and that all workers performing the Work are covered by the Consultant's or sub-'s workers compensation through the YWCHSB;
- confirmation that all persons performing the Work who are not covered by the YWCHSB are covered under personal optional protection coverage available through YWCHSB.

8.3 **Responsibility**

The Consultant shall be responsible for the safe performance of all the Work and the safety of all persons engaged in the Work and shall comply with all applicable safety provisions of the applicable Workers' Compensation Board(s) and safety regulations issued by the Corporation for the Work site.

8.4 **On-Line Safety Orientation**

Consultant is required to complete the Corporation on-line safety orientation prior to commencing any work on the Corporation's premises. The orientation may be found at the following link. YEC On-Line Safety Orientation

9. COMPLIANCE WITH THE OCCUPATIONAL HEALTH AND SAFETY ACT

9.1 The Consultant shall confirm it will comply with all the provisions of the Yukon Occupational Health and Safety Act, regulations and codes, and all amendments thereto, now or hereafter, made there under the said act and shall confirm it will indemnify the Corporation in respect to all matters arising out of or in connection with failure of the Consultant to comply in all respects with applicable provisions of the said act, regulations and codes.

9.2 If the Consultant is to perform any work on the Corporation's site, the Consultant shall comply with all applicable safety regulations issued by the Corporation. For the purpose of this general condition, the term "safety regulations" includes any and all operating order, work protection practices, lockout procedures, and any other safety requirements that may be required or regulated whether municipally, provincially, federally, or otherwise. The Consultant shall be solely responsible for the safe performance of all the work and the safety of all persons engaged in the work and shall ensure all safety laws, regulations and requirements are implemented and adhered to through the performance of the Contract.

9.3 Prior to commencing any work on the Corporation's site, the Consultant shall ensure that all on-site personnel and sub-consultant personnel shall participate in the Corporation's contractor safety orientation (available on-line or in person), or have previously participated in a Corporation contractor safety orientation within the past three years. The contractor safety orientation is specific to the Corporation's properties, sites, equipment, hazards, precautionary measures, emergency protocols, job safety analysis requirements, tailboard requirements and security requirements and can be accessed the Corporation Project Manager.

9.4 The Consultant shall immediately notify the Corporation in writing of any incidents or circumstances described herein, and about any claims made, and the Consultant shall obtain a release in the names of the Corporation and the Consultant.

10. CONFIDENTIALITY

10.1 In the course of this Contract, the Consultant may acquire confidential information with respect to the work or the Corporation's business operations, including without restriction, costing information, strategic plans and product services. Any information given to or reviewed by the Consultant for the purposes of this Contract shall be considered as confidential and privileged by the Consultant and Sub-consultant(s) and shall include all information relating to the work and any process, technology or system relating thereto, the design, construction, operation, maintenance or any other aspect of the Services or the work or relating to the nature of the Corporation's business and affairs that the Consultant, either directly or indirectly, receives or acquires from the Corporation or from anyone on behalf of the Corporation either in writing or verbally or through observation of the Corporation facilities or rights of way, except information falling into any one of the following categories:

10.1.1 Information that the Consultant demonstrates was in its possession on a non-confidential basis prior to receipt or acquisition of such information from the Corporation;

10.1.2 Information that is lawfully in the public domain at the time of receipt by the Consultant of such information from the Corporation;

10.1.3 Information that upon the Consultant's receipt or acquisition from the Corporation, becomes part of the public domain through no act of the Consultant or of any third party under an obligation or confidence with respect to such information, but only after such information becomes part of the public domain;

10.1.4 Information that upon the Consultant's receipt or acquisition from the Corporation, is lawfully obtained by the Consultant from a third party, provided that such third party is under no obligation of confidence with respect to such information;

10.1.5 Information that the Corporation is required to disclose pursuant to the Personal *Information Protection and Electronic Documents Act* ("PIPEDA") *or* other legislation.

10.2 The Consultant shall keep all confidential information in confidence and shall not disclose it to others without the prior written consent of the Corporation and the Consultant shall not use the confidential information except in the performance of the Services.

10.3 The Consultant may disclose the confidential information to those of its employees, Sub-consultant(s) or suppliers and their respective employees to whom disclosure is required for the Consultant to perform the Services provided that the Consultant shall ensure that its employees, Sub-consultant(s) and suppliers keep confidential information in confidence and shall not disclose it to others without prior written consent of the Corporation.

10.4 The Consultant shall not use the Corporation's name, registered or unregistered trademarks or any of the Corporation's slogans or logos in any advertising or promotional

materials or publicity releases, and shall not take, permit to be taken or use any photographs of the Corporation facilities without the prior written approval of the Corporation.

10.5 Any documentation relating to the work that is in the custody or under the control of the Corporation is subject to the *Access to Information and Protection of Privacy Act* ("ATIPP"). Except as stated above in this section, all information submitted by the Consultant to the Corporation will be considered confidential during the term of this Contract.

11. AUTHORSHIP AND USE OF DOCUMENTS

11.1 Reports, plans, sketches, drawings, graphic representations and specifications as instruments of Service prepared by the Consultant pursuant to this Contract (the "Documents") are and shall belong to the Corporation. The copyright in such Documents shall belong to the Corporation and such copyright shall continue for fifty (50) years from the date of their first publication. The Consultant may retain one copy of such Documents for its records.

11.2 The Corporation may use the Documents for any other purposes and the Corporation and Consultant shall agree on the fees for any Services necessary to properly revise the Documents for such use. If the Corporation and Consultant are unable to reach such an agreement, the Corporation may retain another Consultant for the purpose of revising the Documents for such alteration, addition or deletion, as it deems fit.

11.3 The Documents referred to above include Documents prepared by Sub-consultant(s) as well.

11.4 The Corporation shall indemnify and save harmless the Consultant and Sub-consultant(s) from and against any costs, damages, actions, suits or proceedings arising out of any modification or revision of the plans, sketches, drawings, graphic representations and specifications made pursuant to this section made by the Corporation other than by the Consultant or the Sub-consultant(s).

11.5 Submission or distribution of the Documents to meet official regulatory requirements or for other purposes in connection with the Corporation's requirements in accordance with this Contract will not be construed as publication in disparagement of the Corporation's rights.

12. INTELLECTUAL PROPERTY

12.1 All information and data, in any form, prepared by the Consultant pursuant to this Contract, together with all designs or materials capable of intellectual property protection, prepared, developed or created by the Consultant, its employees or agents during the performance of and/or pursuant to this Contract shall automatically become the property of the Corporation unless specifically noted otherwise in this Contract.

13. DISPUTES

13.1 **Amicable Negotiation**. Each party will make bona fide efforts to resolve any disputes arising among them by amicable negotiations and provide frank, candid and timely disclosure of all relevant facts, information and documents to facilitate those negotiations.

The parties will use their best efforts to conduct any dispute resolution procedures under this Contract as efficiently and cost effectively as possible. If there is a dispute among the parties under this Contract, a party will provide written notice (the "Dispute Notice") to the other party to the dispute of the nature of the dispute.

13.2 **Reference to Senior Officials**. If a dispute cannot be resolved between the parties within 5 working days after the date of receipt of the Dispute Notice, the parties will attempt to resolve the dispute with the assistance of one senior official from each party to the dispute. The place of discussion will be Whitehorse, Yukon, unless the senior officials otherwise agree. Each party will bear its own costs of the discussion. The results of the discussion will be non-binding and will be reported to the parties forthwith.

13.3 **Mediation**. If a dispute cannot be resolved under above section within 10 working days of receipt of the Dispute Notice, either party may give notice to the other party of a desire to commence mediation and the parties will jointly appoint a mutually acceptable mediator within 5 working days after such notice is given.

13.4 **Arbitration**. If a dispute cannot be resolved under above section within 20 working days of a mediation under above section, either party may, by written notice to the other party, commence arbitration. Arbitration will be administered under the Arbitration Act (Yukon). The place of arbitration will be Whitehorse, Yukon. Each party will bear its own costs of the arbitration and any additional costs of the arbitrator(s) will be borne equally by each of the parties. Arbitration will be final and binding on the parties. Notwithstanding the foregoing, either party may at any time, prior to the first face to face meeting of the Parties and the arbitrator, under this section 13 refer the dispute being arbitrated to the courts for resolution.

13.5 **Confidentiality**. All negotiations and/or matters relating to the arbitration under this Contract will be kept confidential and will not be disclosed to any other persons except those persons authorized in writing by the parties.

13.6 **Continued Performance**. For greater certainty the parties will continue to perform their respective obligations under this Contract while a dispute under this Contract is being resolved.

14. FORCE MAJEURE

14.1 Neither party shall be responsible for any delay or failure to perform its obligations under this Contract where such delay is due to fire, flood, explosion, war, embargo, government action, act of public authority, act of god, or to any other cause beyond its control, except labour disruption.

14.2 In the event Force Majeure occurs, the party who is delayed or fails to perform shall give prompt notice to the other party and shall take all reasonable steps to eliminate the cause.

14.3 Should the Force Majeure event last longer than thirty (30) days, the Corporation may terminate this Contract by notice to the Consultant without further liability, expense or cost of any kind except for the fees and expenses incurred to the date of termination and demobilization costs.

15. NOTICE

15.1 For the purpose of this Contract, any notices required to be given to the Corporation may be sent by email to Project Authority who for this Contract is Jason Epp, Controller, with an email address of jason.epp@yec.yk.ca, along with a copy to procurement@yec.yk.ca or personally delivered, sent by prepaid registered post addressed to the Corporation at the address indicated on Page 1 of this Contract.

16. GOVERNING LAW

16.1 This Agreement shall be governed by, subject to and interpreted in accordance with the laws of the Yukon and the federal laws of Canada applicable therein.

17. COUNTERPARTS

17.1 This Contract may be executed in multiple copies, each of which will be deemed an original, and all of which taken together will constitute one single agreement.

[End of Document]

In witness whereof the parties hereto have executed this Contract as of the dates listed below:

YUKON ENERGY CORPORATION	ALLIANCE CONSULTING GROUP
E Mollard	Dane A. Watson
Signature	*Signature*
Ed Mollard	Dane Watson
Please Print Name	*Please Print Name*
CFO	Partner
Title	*Title*
May 1/19	5/1/19
Date	*Date*

SCHEDULE "A"

FEES AND DISBURSEMENTS
TIMING OF PAYMENT

A.1 The Corporation shall pay the Consultant for Services completed and invoiced as outlined below when approved by the Project Manager. Please quote the Contract number on all invoices and all correspondence submitted to the Corporation.

A.2 Total Lump Sum Fixed Pricing

The total lump sum fixed price is [redacted] **DOLLARS USD,** detailed in A.3.

A.3 Detailed Pricing Breakdown

Activity	Partner Hrs.	Senior Consultant Hrs.	Consultant/ Admin Hrs.
Request initial data feed	0	1	0
Planning and discussions with Company	1	0	0
Reconciliation, analysis and load data.	4	24	12
Conduct life analysis and salvage and removal analysis	4	36	8
Conduct interviews and field visits	20	0	0
Conduct Evaluations	16	8	0
Calculate preliminary rates	2	24	8
Review preliminary rates with the Company	2	0	0
Prepare Report	2	8	8
Re-run analysis and update as needed.	1	4	0
Preparation of workpapers and relied upon data. Complete and submit final report and Initial Testimony	8	8	16
	60	113	52
Total Partner Hours ([redacted] hr rate USD)	60		$ [redacted]
Total Sr. Consultant Hours ([redacted] hr rate USD)	113		$ [redacted]
Total Consultant/Admin Hours ([redacted] /hr rate USD)	52		$ [redacted]
Total Project Hours	225		
Total Professional Fees			$ [redacted]
Misc expenses (5% of Professional Fees)			$ [redacted]
Estimated Travel for Site Visit			$ [redacted]
Power Plan Royalty Fee (Pass thru)			$ [redacted]
Estimated Travel to Hearings			$ -
Total Project Cost (USD)			[redacted]

A.4 Personnel Rates

Personnel rates are to be all inclusive including benefits, overhead, mark-up and all other employee and/or subcontractor related costs.

Personnel By Occupation	Hourly Rate (USD)	Overtime
Partner	[redacted]	N/A
Senior Consultant	[redacted]	N/A
Consultant / Admin	[redacted]	N/A

A.5 Expenses

All reimbursable expenses (if applicable) are subject to prior approval by the corporation.

A.6 Payment Terms

Net 30 / USD

A.7 Invoices can be mailed to: **Yukon Energy Corporation, P.O. Box 5920, Whitehorse, Yukon Y1A6S7** or emailed to **ap@yec.yk.ca**

SCHEDULE "B"

SCOPE OF WORK

Assess and recommend appropriate depreciation rates for Yukon Energy property plant and equipment at a level appropriate for review by the regulator, Yukon Utilities Board.

Specific activities to include:

- Review of historical data including review of previous depreciation study results and corporate accounting records sufficient to understand the nature of the assets, historical acquisition/construction timing, current rates and planned usage;
- a review of the average service lives of a peer group of Canadian electric utilities;
- operation and management interviews to confirm nature and use of assets;
- assessment and recommendation of appropriateness of current method and procedure of depreciation rate calculation;
- determination of the adequacy of the current accumulated depreciation accounts to reflect the consumption of the consumed service value of the assets under review;
- interviews with management and internal subject matter experts to the extent necessary;
- Prepare report that makes recommendations on:
    - Expected service life of assets;
    - Depreciation requirements by asset
    - Adequacy of the accumulated depreciation by class
    - Average remaining life of assets by class.
- support for study findings with Yukon Utilities Board as appropriate (support may include drafting of application sections, response to interrogatories and/or appearance before the Board]; and
- Completion and delivery of the final Depreciation Studies report.

Note asset classifications are based on OEB/FERC definitions.

Dane Watson Testimony Appearances
2019-05-01

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Alaska	Regulatory Commission of Alaska	U-18-121	Municipal Power and Light City of Anchorage	2018	Electric Depreciation Study
Various	FERC	RP19-352-000	Sea Robin	2018	Gas Depreciation Study
Texas New Mexico	Federal Energy Regulatory Commission	ER19-404-000	Southwestern Public Service Company	2018	Electric Transmission Depreciation Study
California	Federal Energy Regulatory Commission	ER19-221-000	San Diego Gas and Electric	2018	Electric Transmission Depreciation Study
Kentucky	Kentucky Public Service Commission	2018-00281	Atmos Kentucky	2018	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-054	Matanuska Electric Coop	2018	Electric Generation Depreciation Study
California	California Public Utilities Commission	A17-10-007	San Diego Gas and Electric	2018	Electric and Gas Depreciation Study
Texas	Public Utility Commission of Texas	48401	Texas New Mexico Power	2018	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	18-05031	Southwest Gas	2018	Gas Depreciation Study
Texas	Public Utility Commission of Texas	48231	Oncor Electric Delivery	2018	Depreciation Rates
Texas	Public Utility Commission of Texas	48371	Entergy Texas	2018	Electric Depreciation Study
Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power and Light	2018	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	18-027-U	Liberty Pine Bluff Water	2018	Water Depreciation Study

Dane Watson Testimony Appearances
2019-05-01

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Kentucky	Kentucky Public Service Commission	2017-00349	Atmos KY	2018	Gas Depreciation Rates
Tennessee	Tennessee Public Utility Commission	18-00017	Chattanooga Gas	2018	Gas Depreciation Study
Texas	Railroad Commission of Texas	10679	Si Energy	2018	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-104	Anchorage Water and Wastewater	2017	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-18488	Michigan Gas Utilities Corporation	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	10669	CemterPoint South Texas	2017	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	17-061-U	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Kansas	Kansas Corporation Commission	18-EPDE-184-PRE	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Oklahoma	Oklahoma Corporation Commission	PUD 201700471	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Missouri	Missouri Public Service Commission	EO-2018-0092	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Michigan	Michigan Public Service Commission	U-18457	Upper Peninsula Power Company	2017	Electric Depreciation Study
Florida	Florida Public Service Commission	20170179-GU	Florida City Gas	2017	Gas Depreciation Study
Michigan	FERC	ER18-56-000	Consumers Energy	2017	Electric Depreciation Study

Dane Watson Testimony Appearances
2019-05-01

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Missouri	Missouri Public Service Commission	GR-2018-0013	Liberty Utilites	2017	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18452	SEMCO	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	47527	Southwestern Public Service Company	2017	Electric Production Depreciation Study
MultiState	FERC	ER17-1664	American Transmission Company	2017	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-008	Municipal Power and Light City of Anchorage	2017	Generating Unit Depreciation Study
Mississippi	Mississippi Public Service Commission	2017-UN-041	Atmos Energy	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	46957	Oncor Electric Delivery	2017	Electric Depreciation Study
Oklahoma	Oklahoma Corporation Commission	PUD 201700078	CenterPoint Oklahoma	2017	Gas Depreciation Study
New York	FERC	ER17-1010-000	New York Power Authority	2017	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10580	Atmos Pipeline Texas	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10567	CenterPoint Texas	2016	Gas Depreciation Study
MultiState	FERC	ER17-191-000	American Transmission Company	2016	Electric Depreciation Study
New Jersey	New Jersey Public Utilities Board	GR16090826	Elizabethtown Natural Gas	2016	Gas Depreciation Study

Dane Watson Testimony Appearances
2019-05-01

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
North Carolina	North Carolina Utilities Commission	Docket G-9 Sub 77H	Piedmont Natural Gas	2016	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18195	Consumers Energy/DTE Electric	2016	Ludington Pumped Storage Depreciation Study
Alabama	FERC	ER16-2313-000	SEGCO	2016	Electric Depreciation Study
Alabama	FERC	ER16-2312-000	Alabama Power Company	2016	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-18127	Consumers Energy	2016	Natural Gas Depreciation Study
Mississippi	Mississippi Public Service Commission	2016 UN 267	Willmut Natural Gas	2016	Natural Gas Depreciation Study
Iowa	Iowa Utilities Board	RPU-2016-0003	Liberty-Iowa	2016	Natural Gas Depreciation Study
Illinois	Illinois Commerce Commission	GRM #16-208	Liberty-Illinois	2016	Natural Gas Depreciation Study
Kentucky	FERC	RP16-097-000	KOT	2016	Natural Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-16-067	Alaska Electric Light and Power	2016	Generating Unit Depreciation Study
Florida	Florida Public Service Commission	160170-EI	Gulf Power	2016	Electric Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-16-0107	Southwest Gas	2016	Gas Depreciation Study
Texas	Public Utility Commission of Texas	45414	Sharyland	2016	Electric Depreciation Study

Dane Watson Testimony Appearances
2019-05-01

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Colorado	Colorado Public Utilities Commission	16A-0231E	Public Service Company of Colorado	2016	Electric Depreciation Study
Multi-State NE US	FERC	16-453-000	Northeast Transmission Development, LLC	2015	Electric Depreciaiton Study
Arkansas	Arkansas Public Service Commission	15-098-U	CenterPoint Arkansas	2015	Gas Depreciation Study and Cost of Removal Study
New Mexico	New Mexico Public Regulation Commission	15-00296-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Atmos Energy Corporation	Tennessee Regulatory Authority	14-00146	Atmos Tennessee	2015	Natural Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00261-UT	Public Service Company of New Mexico	2015	Electric Depreciation Study
Hawaii	NA	NA	Hawaii American Water	2015	Water/Wastewater Depreciation Study
Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Atmos Kansas	2015	Gas Depreciation Study
Texas	Public Utility Commission of Texas	44704	Entergy Texas	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-15-089	Fairbanks Water and Wastewater	2015	Water and Waste Water Depreciation Study
Arkansas	Arkansas Public Service Commission	15-031-U	Source Gas Arkansas	2015	Underground Storage Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00139-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	44746	Wind Energy Transmission Texas	2015	Electric Depreciation Study

Dane Watson Testimony Appearances
2019-05-01

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Colorado	Colorado Public Utilities Commission	15-AL-0299G	Atmos Colorado	2015	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	15-011-U	Source Gas Arkansas	2015	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10432	CenterPoint- Texas Coast Division	2015	Gas Depreciation Study
Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power and Light	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-120	Alaska Electric Light and Power	2014-2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43950	Cross Texas Transmission	2014	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	14-00332-UT	Public Service of New Mexico	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43695	Xcel Energy	2014	Electric Depreciation Study
Multi State – SE US	FERC	RP15-101	Florida Gas Transmission	2014	Gas Transmission Depreciation Study
California	California Public Utilities Commission	A.14-07-006	Golden State Water	2014	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-17653	Consumers Energy Company	2014	Electric and Common Depreciation Study
Colorado	Public Utilities Commission of Colorado	14AL-0660E	Public Service of Colorado	2014	Electric Depreciation Study

Dane Watson Testimony Appearances
2019-05-01

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Wisconsin	Wisconsin	05-DU-102	WE Energies	2014	Electric, Gas, Steam and Common Depreciation Studies
Texas	Public Utility Commission of Texas	42469	Lone Star Transmission	2014	Electric Depreciation Study
Nebraska	Nebraska Public Service Commission	NG-0079	Source Gas Nebraska	2014	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-055	TDX North Slope Generating	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-054	Sand Point Generating LLC	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-045	Matanuska Electric Coop	2014	Electric Generation Depreciation Study
Texas, New Mexico	Public Utility Commission of Texas	42004	Southwestern Public Service Company	2013-2014	Electric Production, Transmission, Distribution and General Plant Depreciation Study
New Jersey	Board of Public Utilities	GR13111137	South Jersey Gas	2013	Gas Depreciation Study
Various	FERC	RP14-247-000	Sea Robin	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-078-U	Arkansas Oklahoma Gas	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-079-U	Source Gas Arkansas	2013	Gas Depreciation Study
California	California Public Utilities Commission	Proceeding No.: A.13-11-003	Southern California Edison	2013	Electric Depreciation Study

Dane Watson Testimony Appearances
2019-05-01

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
North Carolina/South Carolina	FERC	ER13-1313	Progress Energy Carolina	2013	Electric Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	4220-DU-108	Northern States Power Company - Wisconsin	2013	Electric, Gas and Common Transmission, Distribution and General
Texas	Public Utility Commission of Texas	41474	Sharyland	2013	Electric Depreciation Study
Kentucky	Kentucky Public Service Commission	2013-00148	Atmos Energy Corporation	2013	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	13-252	Allete Minnesota Power	2013	Electric Depreciation Study
New Hampshire	New Hampshire Public Service Commission	DE 13-063	Liberty Utilities	2013	Electric Distribution and General
Texas	Railroad Commission of Texas	10235	West Texas Gas	2013	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-154	Alaska Telephone Company	2012	Telecommunications Utility
New Mexico	New Mexico Public Regulation Commission	12-00350-UT	Southwestern Public Service Company	2012	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1269ST	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1268G	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-149	Municipal Power and Light City of Anchorage	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40824	Xcel Energy	2012	Electric Depreciation Study

Dane Watson Testimony Appearances
2019-05-01

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
South Carolina	Public Service Commission of South Carolina	Docket 2012-384-E	Progress Energy Carolina	2012	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-141	Interior Telephone Company	2012	Telecommunications Utility
Michigan	Michigan Public Service Commission	U-17104	Michigan Gas Utilities Corporation	2012	Gas Depreciation Study
North Carolina	North Carolina Utilities Commission	E-2 Sub 1025	Progress Energy Carolina	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40606	Wind Energy Transmission Texas	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40604	Cross Texas Transmission	2012	Electric Depreciation Study
Minnesota	Minnesota Public Utilities Commission	12-858	Northern States Power Company - Minnesota	2012	Electric, Gas and Common Transmission, Distribution and General
Texas	Railroad Commission of Texas	10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10174	Atmos West Texas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10182	CenterPoint Beaumont/ East Texas	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-KCPE-764-RTS	Kansas City Power and Light	2012	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	12-04005	Southwest Gas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10147, 10170	Atmos Mid-Tex	2012	Gas Depreciation Study

Dane Watson Testimony Appearances
2019-05-01

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Kansas	Kansas Corporation Commission	12-ATMG-564-RTS	Atmos Kansas	2012	Gas Depreciation Study
Texas	Texas Public Utility Commission	40020	Lone Star Transmission	2012	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16938	Consumers Energy Company	2011	Gas Depreciation Study
Colorado	Public Utilities Commission of Colorado	11AL-947E	Public Service of Colorado	2011	Electric Depreciation Study
Texas	Texas Public Utility Commission	39896	Entergy Texas	2011	Electric Depreciation Study
MultiState	FERC	ER12-212	American Transmission Company	2011	Electric Depreciation Study
California	California Public Utilities Commission	A1011015	Southern California Edison	2011	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16536	Consumers Energy Company	2011	Wind Depreciation Rate Study
Texas	Public Utility Commission of Texas	38929	Oncor	2011	Electric Depreciation Study
Texas	Railroad Commission of Texas	10038	CenterPoint South TX	2010	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-070	Inside Passage Electric Cooperative	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	36633	City Public Service of San Antonio	2010	Electric Depreciation Study
Texas	Texas Railroad Commission	10000	Atmos Pipeline Texas	2010	Gas Depreciation Study
Multi State – SE US	FERC	RP10-21-000	Florida Gas Transmission	2010	Gas Depreciation Study
Maine/ New Hampshire	FERC	10-896	Granite State Gas Transmission	2010	Gas Depreciation Study

Dane Watson Testimony Appearances
2019-05-01

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Public Utility Commission of Texas	38480	Texas New Mexico Power	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38339	CenterPoint Electric	2010	Electric Depreciation Study
Texas	Texas Railroad Commission	10041	Atmos Amarillo	2010	Gas Depreciation Study
Georgia	Georgia Public Service Commission	31647	Atlanta Gas Light	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	38147	Southwestern Public Service	2010	Electric Technical Update
Alaska	Regulatory Commission of Alaska	U-09-015	Alaska Electric Light and Power	2009-2010	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-043	Utility Services of Alaska	2009-2010	Water Depreciation Study
Michigan	Michigan Public Service Commission	U-16055	Consumers Energy/DTE Energy	2009-2010	Ludington Pumped Storage Depreciation Study
Michigan	Michigan Public Service Commission	U-16054	Consumers Energy	2009-2010	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15963	Michigan Gas Utilities Corporation	2009	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-15989	Upper Peninsula Power Company	2009	Electric Depreciation Study
Texas	Railroad Commission of Texas	9869	Atmos Energy	2009	Shared Services Depreciation Study
Mississippi	Mississippi Public Service Commission	09-UN-334	CenterPoint Energy Mississippi	2009	Gas Depreciation Study
Texas	Railroad Commission of Texas	9902	CenterPoint Energy Houston	2009	Gas Depreciation Study

Dane Watson Testimony Appearances
2019-05-01

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Colorado	Colorado Public Utilities Commission	09AL-299E	Public Service Company of Colorado	2009	Electric Depreciation Study
Louisiana	Louisiana Public Service Commission	U-30689	Cleco	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35763	Southwestern Public Service Company	2008	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Wisconsin	Wisconsin	05-DU-101	WE Energies	2008	Electric, Gas, Steam and Common Depreciation Studies
North Dakota	North Dakota Public Service Commission	PU-07-776	Northern States Power Company - Minnesota	2008	Net Salvage
New Mexico	New Mexico Public Regulation Commission	07-00319-UT	Southwestern Public Service Company	2008	Testimony – Depreciation
Multiple States	Railroad Commission of Texas	9762	Atmos Energy	2007-2008	Shared Services Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015/D-08-422	Minnesota Power	2007-2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35717	Oncor	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	34040	Oncor	2007	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15629	Consumers Energy	2006-2009	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	06-234-EG	Public Service Company of Colorado	2006	Electric Depreciation Study

Dane Watson Testimony Appearances
2019-05-01

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Arkansas	Arkansas Public Service Commission	06-161-U	CenterPoint Energy – Arkla Gas	2006	Gas Distribution Depreciation Study and Removal Cost Study
Texas, New Mexico	Public Utility Commission of Texas	32766	Southwestern Public Service Company	2005-2006	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Texas	Railroad Commission of Texas	9670/9676	Atmos Energy Corp	2005-2006	Gas Distribution Depreciation Study

REBECCA RICHARDS

SENIOR CONSULTANT, ALLIANCE CONSULTING GROUP

Profile

- 13 years of experience in utility property accounting, depreciation, and corporate finance.
- Coordinated several depreciation studies for all types of utilities including electric, gas, water, and steam heating

Professional Experience

- 2015-present
    - Senior Consultant - Alliance Consulting Group, Plano, TX

      Senior Consultant involved in all aspects of depreciation studies. Perform depreciation studies for electric, gas, communication, water and wastewater utility clients. Provide support during rate case litigation including drafting study narratives and responding to interrogatories.

- 2006-2015
    - Team Lead Property Accounting - We Energies, Milwaukee, WI

      Managed all fixed asset internal and external reporting and property accounting functions in compliance with state and federal regulatory requirements. Established and maintained the Company's capitalization and depreciation policies. Initiated and oversaw all process improvement initiatives related to fixed asset finance systems and processes. Coordinated depreciation studies and supported rate case and regulatory proceedings. Vast working knowledge of fixed asset and finance systems including SAP, UI, and PowerPlant.

- 1995-2006
    - Operations Manager - Courtyard by Marriott, Brookfield, WI

      Hired, trained, and developed all front desk associates and maintained Marriott's high quality customer service standards.

Education

- Bachelor of Science in Accounting, Marquette University, Milwaukee, WI
- Associates Degree in Accounting, Milwaukee Area Technical College, Milwaukee, WI

Memberships

- EEI/AGA Property Accounting and Valuation Committee
- Society of Depreciation Professionals

DANE A. WATSON, PE, MBA, CDP

MANAGING PARTNER, ALLIANCE CONSULTING GROUP

Profile

- 34 years of experience in utility depreciation, valuation and property accounting.
- Industry wide reputation with significant experience as Expert Witness, in depreciation, valuation, and rate base areas.
- Proven experience in effectively managing property systems and reengineering processes/ systems to achieve significant cost savings.
- Goal-Oriented, "outside the box" thinker with demonstrated strong leadership and communication capabilities.
- Organized, highly-motivated, and focused problem solver.

Relevant Experience and Accomplishments

- Depreciation and Asset Accounting
  - Conducted over 200 depreciation studies for electric (generation, transmission, and distribution), gas (transmission, distribution, LNG and storage), water/wastewater, telecom and mining companies (regulated and non-regulated) and supported over 35 state regulatory bodies and FERC.
  - Ongoing teaching of depreciation (basic and advanced) in many industry venues (EEI/AGA, SDP, Michigan State, State Commissions).
  - Lead or served in numerous national industry roles related to depreciation and property accounting including twice chairing the Plant Accounting and Valuation Committee of the Edison Electric Institute and twice chairing the Society of Depreciation Professionals.
  - Served as gas and electric industry Project Manager for the implementation of SFAS 143.
  - Served as general editor for "Introduction to Depreciation and Net Salvage".
  - Managed fixed asset accounting, depreciation accounting and analysis, lease accounting, inventory accounting, transportation accounting and records management for one of the largest electric and gas utilities in the US.
- System/Process Reengineering
  - Reengineered fixed asset process and managed redesign of a Fixed Asset system to create a $1.5-$2.0 million savings per year.
  - Designed and implemented a new leased asset tracking and payment system that enabled reduction of errors in lease payments by $3-$4 million per year.
  - Designed and implemented an internal shared asset tracking and allocation system to meet stringent affiliate transaction rules.
  - Championed, designed and implemented imaging system to replace paper and microfilm document storage system saving over $1 million per year.

Employment History:

- 2004-present
  - Partner Alliance Consulting Group, Plano, TX

- 1996-2004
  - Manager of Property Accounting Services TXU Business Services, Dallas, TX
    Testified in 15 rate or restructuring proceedings before various Commissions including the Texas Railroad Commission, the Texas Public Utilities Commission and the FERC. Lead Sarbanes-Oxley implementation for property processes. During tenure, increased scope to managing all fixed asset and construction accounting, inventory accounting, transportation accounting, and fixed asset accounting systems. Lead efforts to convert 14 companies to a new fixed asset system. Restructured valuation system to provide a 90% faster response time. Implemented new construction/fixed asset systems that facilitated a 12 FTE reduction in staff. Built state-of-the-art lease accounting system to handle reporting and payment of all TXU leases. Built highly automated imaging system to replace microfilm and paper document storage and retrieval system reducing costs and shortening response time.

- 1992-1996
  - Technical Support Manager Texas Utilities Generating Company, Dallas, TX
    Managed group responsible for depreciation and valuation analysis for TXU as well as special projects. Responsible for teaching and running engineering economics analysis for large capital projects. Managed nuclear plant decommissioning studies and electrical line loss allocation studies.

- 1985-1992
  - Associate Engineer to Senior Engineer Texas Utilities Generating Company, Dallas, TX
    Given increasing responsibility related to depreciation and valuation program creation, valuation analysis, depreciation analysis, training TXU employees in engineering economics, report preparation, writing and supporting depreciation testimony before the Texas Public Utilities Commission.

Education:

- M.B.A., General Business, Amberton University, Garland, TX
- B.S., Electrical Engineering, University of Arkansas

Honors and Awards

- Professional Engineer (TX)
- Certified Depreciation Professional (“CDP”)
- Senior Member of the Institute of Electronics and Electrical Engineers (“IEEE”)
- IEEE 3rd Millennium Medal
- IEEE Region 5 Treasurer, Audit Committee Chair, IEEE-USA Secretary Treasurer, IEEE MGA Treasurer, IEEE Finance Committee Member
- American Association of Engineering Societies (AESS) Treasurer
- Twice Chair of the Edison Electric Institute (“EEI”) Property Accounting and Valuation Committee
- Former Board member and twice President of the Society of Depreciation Professionals

KAREN HALLAMAN PONDER, PH.D.

SENIOR CONSULTANT, ALLIANCE CONSULTING GROUP

Profile

- Recognized expert in the field, particularly with regard to historical analyses of life and net salvage.
- More than 40 years of experience in utility property accounting, depreciation, and valuation.
- Involved in dozens of depreciation studies through all facets of the process including regulatory support through information discovery and rate proceedings.
- Prepared depreciation studies for all types of utilities including electric, gas water and wastewater.
- Taught courses on depreciation models and theory, actuarial analysis, and simulated plant record analysis for 30 plus years in nationally recognized training venues.

Professional Experience:

- 2004-present
    - Senior Consultant - Alliance Consulting Group, Plano, TX

      Involved in all aspects of conducting depreciation studies from data gathering to analysis and supporting recommendations through testimony. Participated in more than 200 depreciation studies. Subject matter expert on depreciation theory. Performed depreciation studies for various entities ranging from electric, gas, mining, water and wastewater.
- 1993-2004
    - Capital Recovery Specialist - Texas Utilities, Dallas, TX.

      Responsible for studies and analysis of asset data in a variety of assignments ranging from the engineering department to property accounting.
- 1985-1997
    - Faculty Member - Depreciation Programs of Kalamazoo, Michigan

      Taught classes on Depreciation Models, Simulated Plant Record Method Analysis, and Actuarial Analysis. Participants included company representatives, staff of various state commissions and consultants from the United States and Canada.
- 1978-1984
    - Senior Engineer - Texas Utilities, Dallas, TX.

      Held positions of increasing responsibility in various utility departments including general office engineering, economic research and budgets. Responsibilities included preparing depreciation studies and rate case support.

Education

- Ph.D., Industrial Engineering with specialty in Engineering Valuation, Iowa State University
- M.S., Statistics, Iowa State University
- B.S., Mathematical Statistics *summa cum laude*, McNeese State University, Lake Charles, LA

Memberships

- Society of Depreciation Professionals
- Society of Depreciation Professionals, Training Faculty, 2007 to present
- Society of Depreciation Professionals, Secretary, 2014 to 2015
- Society of Depreciation Professionals, Training Deputy Chair, 2018 to present

RHONDA WATTS

SENIOR CONSULTANT, ALLIANCE CONSULTING GROUP

Profile

- 29 years of experience in utility accounting, property accounting, depreciation, and regulatory processes. Participated in over 100 depreciation studies.
- Industry reputation with experience as Expert Witness in depreciation.
- Performed numerous depreciation studies through all facets of the process including regulatory support and testimony. Experience focus on historical analyses of life and net salvage.
- Prepares depreciation studies for all types of utilities including electric, gas, telecommunication, water and wastewater.

Professional Experience

- 2009-present
    - Senior Consultant - Alliance Consulting Group, Plano, TX

      Senior Consultant involved in all aspects of depreciation studies. Performs depreciation studies for electric, gas, communication, water and wastewater utility clients. Provides support during rate case litigation including drafting study narratives and testimony and responding to interrogatories. Provides testimony before state regulatory bodies.
- 1996-2009
    - Senior Manager - Deloitte & Touche LLP

      Senior Manager in the Energy and Resources Group with concentration in the areas of depreciation and fixed asset accounting systems. Areas of expertise include the principles and procedures of capital recovery, utility organization, accounting and information systems and regulatory practices.
- 1990-1996
    - Accountant - Nevada Power Company

      Accountant and analyst positions of increasing responsibility. Areas of responsibility include plant and receivables accounting, depreciation study updating, rate case schedule preparation and support, regulatory compliance reporting, financial report preparation, and budget variance analysis.
- 1986-1990
    - Primary Accountant - UNLV Foundation

      Primary Accountant responsible for the proper processing and accounting for donations to the UNLV Foundation in support of academic excellence. Also compiled financial reports for the Board of Directors and Trustees.

Major Projects

- Conducted numerous depreciation studies and assisted in regulatory support through testimony, information discovery and rate proceedings for various electric, gas, water and wastewater utility companies.
- Assisted various audit teams in the review of client's implementation of FASB 143 and Interpretation No. 47 (Asset Retirement Obligations). The review encompasses the Company's processes, assessments, calculations and supporting documentation.
- Managed teams in the conduct of Sarbanes Oxley Section 404 readiness testing for international advertising, marketing and communication services companies in 2004 and 2005.

Education

- Bachelor of Science in Business Administration, Accounting and Finance emphasis, University of Nevada, Las Vegas

Certifications and Memberships

- Member of EEI/AGA Property Accounting and Valuation Committee and Society of Depreciation Professionals
- Past President and other leadership positions for the Society of Depreciation Professionals

Other Professional Activities

- Review and content contributor for Hahne-Aliff "Accounting for Public Utilities", Chapter 6 Public Utility Depreciation during tenure at Deloitte
- Former Board member as well as Treasurer, Secretary, Vice President and President of the Society of Depreciation Professionals
- Presenter at AGA/EEI Accounting Committee Meetings
- Taught client requested Depreciation Basics

TOPIC: **Secondary Sales**

REFERENCE: **2021 General Rate Application, Table 2.1, 2.2 and Section 2.2.4 and Section 2.3.1**

PREAMBLE: In Tables 2.1 and 2.2, YEC forecasts 0 for secondary sales related to Generation for 2021. On page 2-8 (PDF page 33 of 441), lines 9-14, YEC states:

> Due to the lack of surplus hydro generation available resulting from below average water conditions and growth of firm load, secondary sales ceased in September 2018. Secondary sales were 258 MW.h in 2018 (compared with 2,059 MW.h forecast in the 2018 Compliance Filing) and 0 MW.h in 2019. Secondary sales were forecast at 0 MW.h sales in 2020 and 2021 when the 2021 GRA load forecast was prepared. YEC will update 2021 test year forecasts in the compliance filing if any secondary sales are expected to occur in 2021 as a result of surplus water availability.

On page 2-9 (PDF page 34 of 441) at line 19, YEC states "[a]ctual hydro generation is currently forecast to reflect water availability at about LTA in 2020, and water availability above LTA in 2021."

CW would like to understand the correlation between surplus water and secondary sales.

QUESTION:

a) Please provide an analysis that compares water levels and secondary sales for each of the last 10 years.

b) Please fully explain the relationship between water levels and secondary sales.

c) Please explain what YEC means by stating that 2021 water levels will be above LTA.

ANSWER:

(a)

Table 1 below provides a comparison of Whitehorse yearly inflows (percent of average) to secondary sales from 2011 to 2020.

Table 1: Summary of Secondary Sales vs Whitehorse Yearly Inflow

	Secondary Sales (KWh)	Whitehorse Yearly Inflow %
2011	552,300	93%
2012	1,992,620	103%
2013	3,959,400	114%
2014	5,414,580	110%
2015	7,030,020	110%
2016	4,835,100	105%
2017	8,385,030	99%
2018	257,955	97%
2019	480	94%
2020	173,841	97%

(b)

Secondary sales typically occur when Yukon Energy is spilling water at one of the hydro facilities and the facility is not operating at a 100% capacity factor. The relationship of secondary sales to water condition is that during higher water (inflows) periods there is a higher potential for spill, and therefore a higher potential for secondary sales. However, secondary sales also relate to the timing and volume of potential secondary sales loads – which tend to focus on winter heating time periods when the potential for spill is reduced.

(c)

Table 2.2 in the Application shows forecast ST 2021 hydro generation at 506.5 GWh, and shows LTA hydro generation for 2021 at the lower level of 452.4 GWh. The ST forecast reflects conditions in the fall of 2020, following high inflows to Aishihik and Mayo during the preceding summer that reversed the prior year's low water conditions.

As shown in prior years, water availability forecasts provided in the fall for the following year are subject to review in following spring and again during the following summer – and can display material changes as actual conditions unfold.

Nathaniel YEE
(NY)

REFERENCE: **Page 1-8, "Diesel rental unit costs of approximately $3.8 million are forecast for the diesel rental units expected to be required for the 2021 GRA test year,5 and [5] 15 units at 1.8 MW for each unit to total 27 MW for 2021 plus two spare units to total of 17 units."**

QUESTION:

a) Please provide a breakdown of all rental and installation infrastructure costs, also noting those attributable to the "spare units."

b) Please explain the decision to rent and install "spare units."

c) As they are rented to increase "reliable capacity," what is the reliability/failure history of rental diesels?

d) How is service and maintenance handled with the supplier?

e) What are the terms of the rental? Monthly, yearly or?

ANSWER:

(a)

Diesel rental unit costs of approximately $3.8 million are broken out in Table 1. Costs for spare units are included in the categories of Generators and Transformers. Each unit whether initially designated as spare or not has the same cost. See YUB-YEC-1-49 for a breakdown of capital costs for N-1 Capacity Shortage Faro Thermal Rental Site; and N-1 Capacity Shortage Whitehorse Thermal Rental Site. See also discussion in NY-YEC-1-3.

Table 1: Diesel Rental Cost Summary

Rental	**Cost ($millions)**
Generators	$ 2.1
Transformers	$ 0.7
Fuel Tanks	$ 0.2
Total Rental	$ 3.0
Other	
Delivery fees	$ 0.4
Stand-down fees	$ 0.2
Start-up and Commissioning	$ 0.2
Total	$ 3.8

(b)

Based on the 2019/2020 rental season, the availability of the units averaged 85.7%, effectively reducing the dependable capacity of the rental fleet from 16.2 MW to 13 MW. The rental fleet provides the N-1 scenario generation capacity. To ensure YEC has the capability to meet the N-1 capacity requirement YEC rented two additional units.

(c)

The following is noted regarding the units:

- 2019/2020 – Availability 82.4%; and
- 2020/2021 – YTD availability 86.6% (Whse), 78.6% (Faro).

(d)

Twice daily reports are issued to the vendor in a group email identifying unit unavailability for service. The vendor dispatches service technicians to the sites and reports back on resolutions or delays to equipment issues. YEC has a comprehensive report provided to the vendor upon request that provides current status and historical availability statistics (see below).

S150 YM Running Hours & Availability Report

2019-2020	YM10	YM11	YM12	YM13	YM14	YM15	YM16	YM17	YM18	Row Total
Availability	75.9%	97.9%	60.0%	87.6%	90.1%	59.3%	90.9%	93.8%	86.0%	82.4%
Current Status	Avail	Avail	Off Rent	Avail	Avail	Avail	Unavail	Unavail	Unavail	
Dec 13 - Jan 9	148.8	131.3	113.6	124.2	136.6	26.6	128.7	114.9	62.5	987.0
Jan 10 - Feb 6	201.1	196.7	91.1	182.9	171.5	0.4	155.5	166.1	124.2	1289.4
Feb 7 - Mar 5	145.5	138.2	138.7	96.8	140.4	127.1	103.0	79.6	71.6	1040.9
Mar 6 - Apr 2	74.2	180.7	44.5	163.7	172.1	132.3	87.2	90.8	90.4	1035.9
Apr 3 - May 1	22.3	13.9	0.0	17.4	25.1	26.3	9.0	10.6	5.6	130.2
Unused Hours (To Date)	-91.7	-160.8	112.2	-85.0	-145.6	187.4	16.6	38.0	145.6	16.7
Total Used Hours	591.8	660.8	387.8	585.0	645.6	312.6	483.5	462.1	354.4	4483.3
									Contract Hours Used	99.6%
									Contract Duration Completed	85.7%

Report Date: 11/04/2020

S140 & S150 YM Running Hours & Availability Report

2020-2021	YM10	YM11	YM12	YM13	YM14	YM15	YM16	YM17	YM18	YM19	Row Total
Availability	81.7%	86.4%	94.8%	81.7%	93.9%	62.1%	89.5%	88.2%	93.8%	94.1%	86.6%
Current Status	Avail	Avail	Avail	Avail	Avail	Unavail	Avail	Unavail	Avail	Unavail	
Used Hours Dec 01 - Apr 19	331.5	506.7	510.9	477.9	511.9	182.6	512.3	491.7	514.0	494.2	4533.6
Unused Hours (To Date)	268.6	93.3	89.1	122.1	88.1	417.4	87.7	108.3	86.0	105.8	1466.4
Accepted Meter Start	2,202.7	4,159.2	3,703.2	16,097.4	6,124.9	11,232.4	25,929.1	14,453.1	3,029.8	16,183.2	6000 Total
Breaker Cycles	28.5	30.5	32.0	29.5	38.0	22.5	33.0	32.5	24.0	34.5	
Engine Cycles	32.0	34.0	34.0	33.0	42.5	23.5	34.5	39.5	30.5	37.5	
Issues	5	4	4	4	7	6	6	8	5	3	

2020-2021	YM20	YM21	YM22	YM23	YM24	YM25	YM26	Row Total
Availability	73.5%	73.0%	64.5%	95.1%	62.6%	87.3%	93.9%	78.6%
Current Status	Avail	Avail	Avail	Avail	Avail	Avail	Avail	
Used Hours Dec 01 - Apr 19	21.0	43.0	5.0	136.0	5.0	44.0	117.0	371.0
Unused Hours (To Date)	336.1	314.1	352.1	221.1	352.1	313.1	240.1	2128.9
Accepted Meter Start	5279.1	2120.3	3124.2	916.1	17704	6,810.0	18,446.0	2500 Total
Breaker Cycles	7.5	5.5	3.0	11.0	8.0	4.5	13.5	
Engine Cycles	10.0	5.5	2.5	11.5	15.0	7.0	28.0	
Issues	3	2	4	1	2	3	3	
							Contract Hours Used	57.7%
							Contract Duration Completed	65.7%

Report Date: 3/3/2021

(e)

The existing rental agreements have a term from December 1, 2020 to April 20, 2021.

REFERENCE: **Page 1-8, "Non-industrial peak load has increased from 86.4 MW in the approved 2018 GRA forecast to 100.7 MW (or 100.6 on page 2-4?) forecast for 2021 (14 MW increase), accounting for most of the 17 MW growth in the N-1 dependable capacity shortfall."**

and

Page 2-12 Item 2.4 "As indicated in Table 2.2, the peak demand for the integrated system is forecast to be 112.7 MW in 2021. The actual peak demand was 93.0 MW in 2018, 90.0 MW in 2019 and 103.8 MW in 2020."

and

QUESTION:

a) 103.8MW is indicated as "Forecast" in Table 2.2 and "Actual" on page 2-12. Which is correct? Is this forecast or actual?

b) Please explain the inputs and forecasting methodology that resulted in 100.7 MW (or 100.6 MW) non-industrial peak load, and 112.7 MW integrated system peak.

c) Please also provide peak loads by month (Non-industrial and integrated system separately), approved, actual and forecast for 2017 to 2021 inclusive.

ANSWER:

(a)

2020 columns in the 2021 GRA reflect preliminary actuals for January through June, and forecasts for July through December. Therefore, the 2020 columns are shown as forecasts. The peak demand of 103.8 MW shown in Table 2.2 was realized in January 2020. Therefore, on page 2-12 it is noted as actual peak.

(b)

As part of the development of YEC's 10-year Renewable Electricity Plan, the non-industrial peak forecast was updated using the Itron model (as described in the 2016 Resource Plan) and calibrated to consider the updated recorded actual 2019/20 peak. The integrated system peak includes the non-industrial and industrial peaks. The industrial peaks were added based on data provided by the industrial customers.

(c)

The YEC peak forecast model only models a winter peak (maximum load expected in coldest period) – this data is not forecast by month. Peak loads are recorded as the maximum load experienced in each winter. Please see response to CW-YEC-1-1 (a).

REFERENCE:

QUESTION:

a) What is the actual rental cost of the 17 diesels? The GRA has rental cost of 3.834 (or 3.8) million, while according to the Hansard, Andrew Hall cited 4.1 million on 15-Dec, 2020. Should the GRA reflect 4.1 million rather than 3.8 million for the rental diesels? Please provide documentation.

ANSWER:

(a)

The diesel rental costs of $3.834 million included in the operating and maintenance costs reflect forecast rental payments required for 17 rental units.

In addition to the rental costs, there are capital costs required to accommodate and connect rental diesel units to the Yukon Integrated System. As reviewed in section 5.2.1.2 of the Application the capital cost for N-1 Capacity Shortage Thermal Rental Site Infrastructures in Whitehorse and Faro at $3.335 million which has annual capital related costs of about $0.243 million [annual depreciation and return on rate base]. With the annual capital related costs, the total annual cost for 2021 for diesel rentals at about $4.1 million.

Please also see response to YUB-YEC-1 (a).

REFERENCE: **Page 5-7 "N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure[7] ($2.037 million forecast in 2020). The project involves the design and installation of temporary rental site electrical infrastructure at Faro (870S) to ensure Yukon Energy can continue to meet its N-1 capacity planning requirements."**

QUESTION:

a) As the project has been completed, is/was the $2.037 million accurate? Are actuals available?

b) Please provide a breakdown of all costs of this infrastructure.

ANSWER:

(a) and **(b)**

The actual cost was $2.446 million. Please see response to YUB-YEC-1-49 and CW-YEC-1-26 (a) and (b).

REFERENCE: **Page 2-14, "Installed YEC and AEY dependable grid capacity for the winter peak in 2021, based on existing capacity today and any planned additions/retirements and excluding Fish Lake hydro, is 139.1 MW in 2021 (70.5 MW of YEC hydro, 12.6 MW YEC LNG, 23.5 MW of YEC diesel, 5.6 MW of AEY diesel and plus 27 MW20 diesel from rented diesel units in order to meet the N-1 criterion assessment).21"**

and

"21 Yukon Energy's 2016 Resource Plan provides details on YEC's updated generation inventory and dependable winter capacity of 114,983 kW (see Chapter 4, Table 4.1). The updates since 2016 Resource Plan include reduced Mayo GS dependable capacity to 6.5 MW due to restricted winter outflows, increased WH GS dependable capacity to 27 MW, retired WH diesel #3, added LNG 3rd engine and other changes to the dependable capacity of the existing diesel units."

I believe that the note is actually referencing Table 4.2 of the 2016 Resource Plan, as Table 4.1 is comparisons with BC Hydro and Hydro-Québec – and not generation inventory.

QUESTION:

a) Please provide an updated Yukon Integrated System Generation Inventory, incorporating the changes in note 21. This would be an update of Table 4.2 from the 2016 resource plan.

b) While referencing the 2016 Resource Plan, noted discrepancies between Table 4.2 and Figure 4-7, Yukon's Transmission and Generation Facilities. Please also provide an update/correction of Figure 4-7 from the 2016 Resource Plan.

ANSWER:

(a) and **(b)**

Please see Appendix A to YEC's 10-Year Renewable Electricity Plan that provides updated version of Table 4.2 from the 2016 Resource Plan. Figure 1 of 10-Year Renewable Electricity Plan illustrates Yukon Electrical System in similar way as Figure 4-7 from 2016 Resource Plan, but without a list of generation capacities. As noted, the generation capacity list is provided in Appendix A of the 10-Year Renewable Electricity Plan.

The copy of the 10-Year Renewable Electricity Plan is provided in response to CW-YEC-1-36 (a).

It is also confirmed that the correct reference to the 2016 Resource Plan is Table 4.2, not Table 4.1.

REFERENCE:

QUESTION:

a) Please provide the stacking order for all thermal generation, YEC owned and rentals – for each site and for the integrated system.

ANSWER:

(a)

The stacking order for all thermal generation is as follows:

	Type/ Location	Units	Comment
1	YEC LNG	WG1, WG2 and WG3	
2	Whse rentals	YM-10, YM-11, YM-12, YM-13, YM-14, YM-15, YM-16, YM-17, YM-18, YM-19.	There is no particular stacking order for these units
3	Faro rentals	YM-20, YM-21, YM-22, YM-23, YM-24, YM-25 and YM26	There is no particular stacking order for these units
4	YEC Whse	WD4, WD5, WD6, WD7	
5	YEC Dawson	DD5, DD4, DD3, DD2, DD1	
6	YEC Faro	FD7, FD1	
7	YEC Mayo	MD1, MD2, MD3	

REFERENCE:

QUESTION:

a) What modifications have been made to the Faro diesel plant since the 2014 YESAB assessment? Please provide details and dates of any and all changes/modifications to the Faro plant.

ANSWER:

(a)

Please see the summary provided below – which provides the modification to the plant and the date of the modification since 2014.

S/N	Modification	Date
1	Moved FD5 Dawson	2014
2	FD0 plant RTU replacement	2017
3	Heating system UG leak replacement (FD7 to FD1)	2017
4	Faro plant repairs	2016

REFERENCE:

QUESTION:

Please provide all documents relating to permits for the addition of the rental generators. If any of these are not available or steps were not taken, please explain.

a) Any and all applications and correspondence with regulator(s) regarding rental diesels.

b) Community consultation and feedback results.

c) YESAB assessment documentation relating to the rental generators.

d) Compliance documents, decision documents and permits.

ANSWER:

(a)

Please see Attachment 1 and Attachment 2 to this response which provide correspondence related to rental diesels at the WRGS and FGS.

(b)

Yukon Energy has undertaken the following effort to inform governments, residents and Citizens in the Faro area of the Corporation's requirement to install temporary rentals diesels at the existing Faro diesel plant:

- **Ross River Dena Council:**

    - Between April 2020 and January 2020, Yukon Energy contacted representatives of the Dena Nezzidi Limited Partnership (DNLP) (designate for the Ross River Dena Council) at least nine times by email and phone to share information about the Faro rental diesel project and procurement opportunities, and to request a meeting with Ross River Dena Council to discuss the project.

- The Dena Nezzidi Limited Partnership representative attended Yukon Energy's December 2, 2020 public information meeting. Copies of the presentation and a summary of the discussion were provided following the meeting.

- As of February 9, 2021, representatives of the Dena Nezzidi Limited Partnership have not provided Yukon Energy with a date and time for the requested meeting with Ross River Dena Council to discuss the specific Faro rental diesel project and YESAA project proposal.

- **Town of Faro:**
  - On April 14, 2020, Yukon Energy emailed the Town of Faro advising of its plans to add rental diesels in Faro in 2020. The email included a request for a follow-up discussion.

  - On July 27, 2020, Yukon Energy met with the Town of Faro Council to discuss the 10-Year Renewable Electricity Plan. As part of this meeting, Yukon Energy shared information about the rental diesel project with Council and garnered feedback on the project.

  - Additional information about the project and public consultation efforts were shared with Town staff and Council members in follow-up emails and conversations.

- **Residents and Citizens:**
  - An information piece about the Faro rental project was mailed to all residents and citizens in Faro in September 2020. Information about the project, along with a copy of the mailer, was added to Yukon Energy's website at the same time. See Attachment 1 to this response.

  - Yukon Energy hosted a public information meeting about the project on December 2, 2020. The session was hosted online due to COVID-19 concerns. Six members of the public attended. The meeting was advertised with community posters, radio and print ads, and social media. A copy of the presentation was made available after the meeting on Yukon Energy's website. See Attachment 2 to this response.

- Yukon Energy responded to questions received by phone, email and social media about the project as received.

- Key themes of questions and comments raised by public members were:
  - Noise levels from rentals
  - Air quality
  - Consultation with local residents
  - Consultation with Ross River Dena Council
  - Faro Air Permits (allowances, changes and subsequent consultation)

(c)

The rental diesels at the Whitehorse Rapids Generating Station (WRGS) have been installed and operated under Air Emission Permit amendments that were made under existing YESAA Decision Documents. No YESAA assessments have been required to date for the use of rental diesels as the activities represented by their use are sufficiently similar to those generating activities that have been previously assessed under YESAA and the YG regulatory authority determined that the existing decision documents for previous assessments of these activities are sufficient for the purposes of amending YEC's air emissions permit.

The rental diesels at the Faro Generating Station (FGS) can be operated up to an operating cap of 10.6 MW and no YESAA assessment is required for that purpose as the previous YESAA assessments of the facility and the associated Decision Documents allow for this operational cap at the site under YEC's existing air emissions permit.

(d)

Per the response to NY-YEC-1-8 (c), the rentals have not required specific assessment under YESAA to be authorized for use under YEC's air emissions permit, therefore there are no compliance documents, decision documents, or permits issued pursuant to a specific YESAA assessment for the rentals, other than the existing air emissions permit, which authorizes the use of temporary diesel generators beyond those permanently installed at the facility within a generating capacity limit.

From: Elizabeth.Barker@gov.yk.ca
To: Travis Ritchie
Subject: RE: AEP 60-010 Amendment
Date: October 13, 2020 4:05:52 PM

Good Afternoon Travis,
We have determined that the information provided in YEC's previous Faro station YESAA assessments (2008-0230 and 2011-0246) is still valid for the proposed 2020 amendment of reinstalling capacity of approximately 5.65MW at the Faro generating station. YEC has authorization to reinstall previously relocated/de-rated capacity of up to 10.6MW, cumulative station capacity, without proceeding through the YESAA assessment process. As discussed, any additional capacity increase that will bring the Faro station's cumulative capacity above 10.6MW will need to proceed through the YESAA assessment process before being considered.
As this amendment doesn't change the content of your current Air Emissions Permit 60-010, we will not be issuing an amended permit and you may continue to use permit 60-010 as is .
Cheers,
Liz

Elizabeth Barker
Environmental Protection Analyst
Department of Environment
Government of Yukon
(867) 667-5456

From: Travis Ritchie
Sent: September 28, 2020 1:30 PM
To: Elizabeth.Barker
Subject: RE: AEP 60-010 Amendment

***** External E-mail: Do not click on links or attachments except from trusted senders. *****
*****

pursuant to the 2008/2011 assessment findings and related decision documents.
If you need, I can resubmit the amendment application for reinstallation of only the previously assessed capacity, removing reference to the 3 additional units (YM23-YM25). YEC can then work on getting a YESAA assessment completed for the additional capacity, which could be permitted afterward.
Does that sound reasonable? If it's helpful to speak on the phone please let me know and I will call you at a convenient time.
Thanks again.
Regards,
Travis

From: Elizabeth.Barker@gov.yk.ca [mailto:Elizabeth.Barker@gov.yk.ca]
Sent: September 23, 2020 5:03 PM
To: Travis Ritchie <Travis.Ritchie@yec.yk.ca>
Subject: AEP 60-010 Amendment
Good Afternoon Travis,
According to the Assessable Activities Regulation under YESAA, Part 4, Item 2 (b) applies to your AEP 60-010 amendment application.

PART 4

Energy and Telecommunications

	Column 1	Column 2
Item	Activity	Specific Exception
1	Construction, installation, operation, modification, decommissioning or abandonment of, or other activity in relation to, a power line or a telecommunications line	
2	Construction, operation, modification, decommissioning or abandonment of, or other activity in relation to, • **(a)** a hydroelectric generating station; • **(b)** a fossil fuel-fired electrical generating station; • **(c)** a wind-powered electrical generating station; • **(d)** a wood-fired electrical generating station; or • **(e)** a wood-fuelled heating facility for the commercial sale of heat	Construction, operation, modification, decommissioning or abandonment of, or other activity in relation to, a wind-powered electrical generating station if its production capacity is, and in the case of a modification remains, 50 kW or less

Specifically, the Faro generating station underwent a YESAA assessment in 2014. In the assessment, FD1 and FD7 were assessed with production capacities of 5.15MW and 3MW for a total of 8.15MW.
Currently, FD1 and FD7 have been derated to 2.4MW and 2.8MW however, with the addition of YM20-22 (5.4MW) and the addition of the YM23-25(5.4MW) as emergency backup, this brings the station capacity to a total of 16MW. This is 7.85MW greater than the capacity that was previously assessed in 2014. As the modification of production capacity is greater than 50kW, this project will need to proceed through YESAB before we can issue any permit amendments.
Please let me know if you would like to discuss this further.
Have a great day,
Liz

Yukon Energy Corporation
P.O. Box 5920
Whitehorse
Yukon Y1A 6S7
Ph: (867) 393-5300
Fax: (867) 393-5322

September 28, 2020 File: 2515.03.01

Elizabeth Barker, Environmental Protection Analyst
Department of Environment, Standards & Approvals Section
Yukon Government
Box 2703
Whitehorse, Yukon Y1A 2C6

(Via email)

Dear Ms. Barker,

RE: AIR EMISSIONS PERMIT NO. 60-010 – APPLICATION FOR APPROVAL TO INSTALL PREVIOUSLY REPLOCATED AND DERATED GENERATING CAPACITY - FARO GENERATING STATION

Please find an application and supporting documentation regarding the above referenced permit amendment request. Pursuant to permit Part 2, Item 5, we are seeking approval to reinstall site capacity that was relocated to other generating stations in recent years, as well derated site capacity with existing units.

Please contact me by telephone at 867.393.5350 or by email: travis.ritchie@yec.yk.ca if you have any questions, comments, or concerns with this submission.

Thank you for your time and consideration in this matter.

Yours Sincerely,

Travis Ritchie, P.Biol.

Manager – Environment, Assessment, & Licensing

Attachment:
Air Emissions Permit Application and Supporting Attachments A-C

Yukon
Environment

APPLICATION FOR RENEWAL, AMENDMENT OR CANCELLATION OF *ENVIRONMENT ACT* PERMITS

Please complete the following and ensure that all information is legibly printed or typed:

Permittee: Yukon Energy Corporation
(Business or individual name)

Permit type: Air Emissions Permit
(e.g. pesticide, special waste, air emissions, solid waste, land treatment facility, relocation, ODS/OH)

Permit number: 60-010
(e.g. 4201-XX-XXX)

Please check (✓) appropriate box:

Renewal

☐ I have fully reviewed my permit and the information on my current permit is correct and complete and my business is operating as described therein.

Amendment

☑ I have fully reviewed my permit and the following changes or additions have occurred and should be taken into account when renewing my permit (attach additional information if necessary):

Ownership: Yukon Energy Corporation (no change)
Mailing Address: Box 5920
Whitehorse Yukon Y1A 6S7
Site Location(s): Faro Generating Station (XX, Faro, YT

Telephone #: 867.393.5350 Fax #:
Email: travis.ritchie@yec.yk.ca
Products/Activities: Reinstall previoulsy relocated/derated capacity (aprx. 5.65 MW)
Transport special wastes: yes: ☐ no: ☑
Other: See attached supporting documents.
Note: additional information may be required depending on the nature of the change.

Cancellation

☐ I am no longer undertaking the activities authorized by the above permit. I understand that I will be contacted by enforcement officials to confirm that a permit is no longer required, at the following coordinates:

Mailing Address:
Site Location(s):
Telephone #: Fax #:
Email:
Permitted Activities:

I, Travis Ritchie *[print name clearly]*, certify that I am an authorized representative of Yukon Energy Corporation *[business name]*, and hereby make application for the renewal, amendment or cancellation of the above-noted permit, as indicated, and certify that the information provided on this form is correct.

Signature of applicant	Date	# of attachments
	Sepetmber 28, 2020	3 (Attachments A-C)

This information is being collected under the authority of s.90 of the *Environment Act*. For further information contact the Environmental Programs Branch at (867) 667-5683.

YG(5694E)E1 Rev. 04/2010

AIR EMISSIONS PERMIT (NO. 60-010)
AMENDMENT APPLICATION
SUPPORTING DOCUMENT

ATTACHMENT A

FIGURE 1

INSTALLATION SITE LAYOUT

September 2020

NOTES:
1. EXHAUST STACK HEIGHTS:
   FD1 - 8.3m
   FD5 - 3.7m
   FD7 - 8.9m

FD7 BUILDING
BUILDING
11m x 12.3m BERMED AREA
DIESEL FUEL TANK 3.55m x 10.1m
BERMED AREA 36m x 36m
BUILDING
6.3m HIGH 14.5m dia. DIESEL FUEL TANK
RENTAL FUEL TANKS
COOLERS
FD1 PLANT
OFFICE
CONTROL BUILDING
STORAGE BUILDING
ROAD
138kV
70T
5021
25kV
4160V
50T
670S SUBSTATION
YM20
YM21
YM22
YM23
YM24
YM25
YM26
S146
MITCHELL ROAD
LOT 413, QUAD 105 K/03
PLAN 75828 CLSR
METERS
50 25 0

REFERENCE DRAWINGS

DWG. NO.	DRAWING TITLE

REV.	DATE	DESCRIPTION	BY	DES.	APP.
C	APR 20 2020	UPDATED TX LOCATION	CM	LP	
B	APRIL 14 2020	REVISED TX LOCATION	CM	LP	
A	MAR 19 2020	REVIEW	CM	LP	

COMPANY PERMIT

ENGINEERS STAMP

YUKON ENERGY CORPORATION

C20028 - RENTAL DIESELS

CHECKED BY -
DATE -
DRAWN BY -

FARO DIESEL & SUBSTATION
SITE PLAN
LOT 413, FARO - YUKON

SCALE A1

farositeplan.dgn

REV. C

THIS DRAWING IS THE PROPERTY OF YUKON ENERGY CORPORATION AND CONTAINS PROPRIETARY AND CONFIDENTIAL INFORMATION WHICH MUST NOT BE DUPLICATED, USED OR DISCLOSED OTHER THAN AS EXPRESSLY AUTHORIZED BY YUKON ENERGY CORPORATION.

AIR EMISSIONS PERMIT (NO. 60-010)
AMENDMENT APPLICATION
SUPPORTING DOCUMENT

ATTACHMENT B

EPA APPROVED TIER 2
3516C CATERPILLAR ENGINE
GENERATOR SPECIFICATIONS

September 2020

SCHEDULE "B"

XQ2000 RENTAL

CATERPILLAR®

Image shown may not reflect actual package

STANDBY 2000 kW
PRIME 1825 kW
POWER MODULE
50/60 Hz

Frequency	Voltage	Standby kW (kVA)	Prime kW (kVA)
60	480/277V	2000 (2500)	1825 (2281)
50	400V	1440 (1800)	1310 (1638)

FEATURES

EPA TIER 2 and CARB certified for non-road mobile applications. Factory designed, certified prototype tested with torsional analysis. Production tested and delivered in a package that is ready to be connected to your fuel and power lines. Supported 100% by your Caterpillar® dealer with warranty on parts and labor. Extended warranty available in some areas. The generator set is designed and manufactured in an ISO 9001:2000 compliant facility. Generator set and components meet or exceed the following specifications: AS1359, AS2789, ABGSM TM3, BS4999, DIN6271, DIN6280, EGSA101P, JEM1359, IEC 34/1, ISO3046/1, ISO8528, NEMA MG1-22

CATERPILLAR SR4B GENERATOR

Single bearing, wye-connected, static regulated, brushless permanent magnet excited generator designed to match the performance and output characteristics of the Caterpillar diesel engine driving it.

RELIABLE, FUEL EFFICIENT DIESEL ENGINE

The compact, four-stroke-cycle diesel engine combines durability with minimum weight while providing dependability and economy. The fuel system operates on a variety of fuels.

CATERPILLAR COOLING SYSTEM

Sized compatible to rating with energy efficient fan and core.

CATERPILLAR SWITCHGEAR

Provides single unit and/or multi-unit/utility paralleling components. Standby, load sense/load demand, import, export, and base load modes. Comes standard with Basler Utility Multi-function Relay IPS-100.

EXCLUSIVE CATERPILLAR DIGITAL VOLTAGE REGULATOR (CDVR)

Three-phase sensing and adjustable Volts-per-Hertz regulation give precise control, excellent block loading, and constant voltage in the normal operating range.

ENVIRONMENTALLY FRIENDLY

110% spill containment of onboard engine fluids.

SOUND ATTENUATED CONTAINER

For ease of transportation and protection. Meets 75 dB(A) at 50 ft or below per SAE J1074 measurement procedure at 110% prime load.

XQ2000 RENTAL

CATERPILLAR®

FACTORY INSTALLED STANDARD EQUIPMENT

SYSTEM	STANDARD EQUIPMENT
Engine	EPA approved Tier 2 3516C Caterpillar engine Heavy duty air cleaner with service indicator 60-Amp charging alternator Fuel filters – primary and duplex secondary with integral water separator and change-over valve Lubricating oil system with spin-on, full flow oil filters and water cooled oil cooler Oil drain lines routed to engine rail Jacket water heater Fuel cooler and priming pump Electronic ADEM™ A3 controls 24V electric starting motors with battery rack and cables
Generator	SR-4B brushless, permanent magnet excited, three-phase with Caterpillar digital voltage regulator (CDVR), space heater, 6-lead design, Class H insulation operating at Class F temperature for extended life, winding temperature detectors and anti-condensation space heaters (120/240V 1.2 kW)
Containerized Module	40' ISO high cube container, CSC certified 3-axle, 40' ISO container chassis Seven (7) sound attenuated air intake louvers and 4 lockable personnel doors with panic release Side bus bar access door, external access load connection bus bars Shore power connection via distribution block connections for jacket water heater, battery charger, space heaters, and generator condensate heaters Standard lighting 3 AC/4 DC, one (1) single duplex service receptacle, 2 external break-glass emergency stop push buttons 1,250 gal fuel tank, UL listed, double wall, 9 hr runtime @ prime rating Sound attenuated 75 dB(A) @ 50 ft Spill containment 110% of all engine fluids Four (4) oversized maintenance-free batteries, battery rack and 20-Amp battery charger Hospital grade, internally insulated, rectangular exhaust silencer with vertical discharge Vibration isolators, corrosion resistant hardware and hinges External drain access to standard fluids Fire extinguishers (Qty 2) Standard Cat rental decals and painted standard Cat power module white Interior walls and ceilings insulated with 100 mm of acoustic paneling Floor of container insulated with acoustic glass and covered with galvanized steel
Cooling	Standard cooling provides 43° C ambient capability (60 Hz) at prime +10% rating Vertically mounted, separate ATAAC and JW cores with vertical air discharge
Generator Paralleling Control	Custom switchgear control with EMCP 3.3 genset mounted controller and wall mounted paralleling controls Automatic start/stop with cool down timer Protections: 25, 27/59, 40, 32, 81 O/U Utility multi-function relay protections: 25,27/59, 32, 47, 50/51, 62, 67, 81 O/U UMR is IEEE1547-2003 compliant in most applications Reverse compatibility module provided for interface to legacy power modules Touch screen controls with event log Multi-mode operation (island, multi-island and utility parallel), load sharing (multi-unit only) Import & export control (utility parallel only), manual and automatic paralleling capability Touch screen display (status and alarms) Metering display: voltage, current, frequency, power factor, kW, WHM, kVAR, and synchroscope
Quality	Standard genset and package factory tested UL, NEMA, ISO and IEEE standards O&M manuals

XQ2000 RENTAL

CATERPILLAR®

SPECIFICATIONS

CAT SR4B GENERATOR

Frame Size 825
Pitch 0.6667
No. of poles 4
Excitation . . . . . Static regulated brushless PM excited
Constructions . . . . . Single bearing, close coupled
Insulation . . . . . Class H
Enclosure . . . . . Drip proof IP22
Alignment . . . . . Pilot shaft
Overspeed capability – % of rated . . . . . 125% of rated
Voltage regulator . . . . . 3 phase sensing with Volts-per-Hertz
Voltage regulation . . . . . Less than ± ½% voltage gain
Adjustable to compensate for engine speed droop and line loss
Wave form deviation . . . . . Less than 5% deviation
Telephone Influence Factor (TIF) . . . . . Less than 50
Harmonic Distortion (THD) . . . . . Less than 5%

CAT 3516C DIESEL ENGINE

3516C, 4-Stroke diesel
Bore – mm (in) 170 (6.7)
Stroke – mm (in) 190 (7.5)
Displacement – L (cu in) 69 (4,210)
Compression ratio 15:1
Aspiration . . . . . ATAAC
Fuel system . . . . . EUI
Governor type . . . . . Caterpillar ADEM™ A3 Control System

TECHNICAL DATA

Materials and specifications are subject to change without notice.

Generator Set Technical Data		50 Hz		60 Hz	
	Units	Prime	Standby	Prime	Standby
Performance Specification		DM8754		DM8264	
Power Rating	kW (kVA)	1310 (1637)	1440 (1800)	1825 (2281)	2000 (2500)
Lubricating System					
Oil pan capacity	L (gal)	401.3 (106)		401.3 (106)	
Fuel System					
Fuel Consumption					
100% load	L (gal)	350.1 (92.5)	372.9 (98.5)	483.2 (127.6)	525.7 (138.9)
75% load	L (gal)	281.9 (74.5)	302.8 (80)	380 (100.4)	408.2 (107.8)
50% load	L (gal)	205.5 (54.3)	350.1 (92.4)	270.5 (71.5)	294.2 (77.7)
Fuel tank capacity	L (gal)	4731 (1,250)		4731 (1,250)	
Running time @ 75% rating	Hours	16.7	15.6	12.5	11.5
Cooling System					
Radiator coolant capacity including engine	L (gal)	630 (166)		630 (166)	
Air Requirements					
Combustion air flow	m^3/min (cfm)	114.8 (4052)	118.1 (4173)	174.7 (6169)	180.3 (6367)
Maximum air cleaner restriction	kPa (in H_2O)	6.2 (24.9)		6.2 (24.9)	
Generator cooling air	m^3/min (cfm)	140 (5,933)		168 (4,995)	
Exhaust System					
Exhaust flow at rated kW	m^3/min (cfm)	311.3 (10,993)	320.8 (11,335)	404 (14,260)	428.6 (15,137)
Exhaust stack temperature at rated kW – dry exhaust	°C (°F)	502.1 (935.8)	513.1 (955.6)	387 (728)	405 (762)
Noise Rating (with enclosure)					
@ 7 meters (23 feet)	dB(A)	77	78	78	79
@15 meters (50 feet)	dB(A)	73	74	74	75

Model	Length mm (in)	Width mm (in)	Height mm (in)	Weight	
				With Lube Oil and Coolant kg (lb)	With Fuel, Lube Oil and Coolant kg (lb)
XQ2000 w/o Chassis	12 192 (480)	2438 (96)	2896 (114)	34 019 (75,000)	38 102 (84,000)
XQ2000 w/Chassis	12 192 (480)	2438 (96)	4267 (168)	38 102 (84,000)	42 184 (93,000)

RATING DEFINITIONS

Standby – Applicable for supplying continuous electrical power (at variable load) in the event of a utility power failure. No overload is permitted on these ratings. The generator on the generator set is peak prime rated (as defined in ISO8528-3) at 30° C (86° F).

Prime – Applicable for supplying continuous electrical power (at variable load) in lieu of commercially purchased power. There is no limitation to the annual hours of operation and the generator set can supply 10% overload power for 1 hour in 12 hours.

XQ2000 RENTAL

CATERPILLAR®

STANDARD FEATURES

GENERATOR SET EMCP 3.3 LOCAL CONTROL PANEL

- Generator mounted EMCP 3.3 provides power metering, protective relaying and engine and generator control and monitoring.
- Provides MODBUS datalink to paralleling control for monitoring of engine parameters.
- Convenient service access for Caterpillar service tools (not included).
- Integration with the CDVR provides enhanced system monitoring.
- Ability to view and reset diagnostics of all controls networked on J1939 datalink.
- Network modules via the control panel removes the need for a separate service tool for troubleshooting.
- Real-time clock allows for date and time stamping of diagnostics and events.

EMCP 3.3 ENGINE OPERATOR INTERFACE

- Graphical display with positive image, transflective LCD, adjustable white backlight/ contrast.
- Two LED status indicators (1 red, 1 amber).
- Three engine control keys and status indicators (Run/Auto/Stop).
- Lamp test key.
- Alarm acknowledgement key.
- Display navigation keys.
- Two shortcut keys: Engine Operating Parameters and Generator Operating Parameters.
- Fuel level monitoring and control.

CIRCUIT BREAKER

- 3000A fixed type, 3 poles, genset mounted, electrically operated, insulated case circuit breaker.
- Solid state trip unit for overload (time overcurrent) and fault (instantaneous) overcurrent protection.
- Includes DC shunt trip coil activated on any monitored engine or electrical fault, 100 KA-interrupting capacity at 480 VAC.

VOLTAGE REGULATION AND POWER FACTOR CONTROL CIRCUITRY

- Generator mounted automatic voltage regulator, microprocessor based.
- Manual raise/lower voltage adjust capability and VAR/power factor control circuitry for maintaining constant generator power factor while paralleled with the utility.
- Includes RFI suppression, exciter limiter and exciter diode monitoring.
- Voltage and power factor adjustments are performed on the setting screen of the HMI touch screen.

FUEL TANK

- UL Listed 1250 gallon double walled.
- Fuel transfer system

CURRENT TRANSFORMERS

- CT's rated 3000:5 with secondaries wired to shorting terminal strips.

POTENTIAL TRANSFORMERS

- 4:1 ratio with primary and secondary fuse protection.

BUS BARS

- Three phase, plus full rated neutral, bus bars are tin-plated copper with NEMA standard hole pattern for connection of customer load cables and generator cables.
- Bus bars are sized for full load capacity of the generator set at 0.8 power factor.
- Includes ground bus, tin-plated copper, for connection to the generator frame ground and field ground cable.

AC DISTRIBUTION

- Provides 240 VAC for all module accessories.
- Includes controls to de-energize jacket water heaters and generator space heater when the engine is running.

SHORE POWER TWO (2)

- One (1) shore power connection distribution block for jacket water heaters.
- One (1) for generator space, battery charger, and fuel pump.

INTERNAL LIGHTING

- Four (4) internal DC lights with one (1) timer and two switches installed at each side of the container door.
- Three (3) internal AC lights.
- One (1) single duplex service receptacle.

BATTERY CHARGER AND BATTERIES

- 24 VDC/20A battery charger with float/equalize modes and charging ammeter.
- Maintenance free batteries.

EMERGENCY STOP PUSHBUTTON

- Two external ESPs located near each access door.

MODES OF OPERATION

Caterpillar utility paralleling controls are intended for automatic or manual paralleling with a utility power source as a load management system, with provisions for standby operation feeding an isolated load network. Load management operation involves microprocessor-based automatic loading controls with soft loading, base load, Import/Export control and soft unloading. For Standby operation, the generator operates as an isochronous machine isolated from the utility supply. The controls allow for automatic operation, initiated locally or remotely by the customer's SCADA system. Detailed modes of operation are listed below:

SINGLE UNIT ISLAND AND MULTI-UNIT ISLAND OPERATION

1. Utility Standby Mode (Normal)
   a. The utility is providing power for the plant loads.
   b. The Power Module Generator breaker is open.
   c. The pm is in automatic standby mode to respond to a utility failure.
2. Emergency Mode (Emergency)
   a. Utility Failure
      1) The customer protective relaying senses a utility abnormal condition.
      2) A run request is sent to the Power Module Generator plant.
      3) The first Power Module Generator reach rated to voltage and frequency is closed to the bus.
      4) In Multi-Unit Island Mode, the remaining Power Module Generators are paralleled to the bus as they reach rated voltage and frequency. This function is performed via the ModBus Plus data link connected between the Power Modules.
      5) Plant load is transferred to the Power Modules, which share load equally via ModBus Plus data link.
      6) The system is now in Emergency Mode.

GENERATOR DEMAND PRIORITY CONTROL

The System Controls include a Generator Demand Priority Control function to automatically match the on-line Power Module Generator capacity to the loads in order to avoid unnecessary operation of all the Power Module Generators when the plant loads are low.

The following controls are provided for each Power Module Generator:

a. User-settable Generator Priority Selector
b. Status indicator for the Generator Priority selected
c. Status indicator for Power Module Generator on-line or off-line
d. Generator Demand Priority Control Switch (On/Off)
e. User-settable Generator Remove Level (% as a function of single generator capacity)
f. User-settable Generator Remove Time Delay
g. User-settable Generator Add Level (% as a function of single generator capacity)
h. User-settable Generator Add Time Delay

Upon entrance into Emergency Mode, all generators will be started and paralleled to the bus. After the Remove Time Delay, Power Module Generators will be removed from the bus as a function of the generator percentage loading. Generators will be removed from the bus in descending priority order.

Should the generator percentage loading increase to the user-selected Generator Add Level after the user-selected Generator Add Time Delay, the next priority generator will be started, synchronized and paralleled to the bus. Should the Power Module Generator plant ever reach 100% loading, the next priority generator will be started and added to the bus, bypassing the Generator Add Time Delay.

MODES OF OPERATION (continued)

SINGLE UNIT IMPORT, EXPORT OR BASE LOAD OPERATION

During periods of peak demand the system may be placed in operation using the operator interface panel on the front of the switchgear.

1. Entry – Local
   a. The operator places the System Control Switch into Load Management.
   b. The operator selects Import, Export or Base Load Operation.
   c. The Load Management Setpoint is the amount of power Imported, Exported or Base-Loaded. A 4-12-20mA signal is provided by the customer and is linearly proportional to the utility load, with 12mA equaling 0 kW. The 4-12-20mA utility load signal is wired to one and only one Power Module. If the Power Module selected for Load Management is not available, the 4-12-20mA signal will be routed to a different Power Module.
   d. The operator sets the Load Management Setpoint and Power Factor Setpoint.
   e. A Run request signal is received by the Single Unit Power Module.
   f. The Power Module Generator is started and will run for a predetermined warm-up time before it is synchronized and paralleled to the utility.
   g. When the generator is on the bus, it is soft-ramp-loaded until the generator output reaches the Load Management Setpoint.
   h. The generator output is dynamically adjusted to maintain the Load Management Setpoint.
   i. Should the utility fail during Load Management Operation, the Protective Relay will cause the Paralleling Circuit Breaker 52G to open and be locked out until the Lockout Relay is manually reset by an operator on site. The generator is allowed to run for the duration of the cooldown time.
2. Exit – Local
   a. The Run Request signal is removed from the power module.
   b. The generator is soft-ramp-unloaded until the plant load is fully supported by the utility.
   c. The Paralleling Circuit Breaker 52G is opened.
   d. The generator is allowed to run for the duration of the cooldown time.

STANDARD PARALLELING CONTROL

GENERATOR PARALLELING CONTROLS

The switchgear includes:

- Single unit island mode.
- Multiple unit island mode.
  - Includes Load Sense/Load Demand control.
  - Load sharing capability is provided via network communication.
- Single unit utility parallel mode.
  Selectable for Import/Export control.
  If import or export control is selected a 4-12-20mA signal is required (provided by others) scalable to the utility contribution.
- 6 inch black and white HMI touch screen.
- Reverse compatibility module provided for interface to legacy designed Power Module Switchgear. Includes PLC, load share and voltage droop.

Incoming Utility Breaker Status Circuit – Circuit to accept customers contact from remote utility disconnect device. Customer to provide a normally open form 'a' contact to indicate when the local load network is connected to the utility grid.

Utility Transfer Trip Circuit – Circuit accepts input (normally open dry contact) from customer's system protective relay(s) or other controlling device. Operation of contacts causes tripping of the generator circuit breaker via the generator (software) 86 lock-out function and places the engine in cooldown mode. Circuit is disabled when operating in single unit or multiple unit island.

GENERATOR PARALLELING CONTROLS OPERATOR INTERFACE

Graphical mimic one line diagram that shows generator with its respective circuit breaker in a one-line representation of the system. The graphics utilize black and white indicators and bar graphs while actively displaying the following information:

- Utility CB Open/Closed. Input contacts provided by others.
- Utility kW 4-12-20mA signal required and provided by customer that is scalable to the utility contribution.
- Generator CB Open/Closed/Tripped.
- Generator Volts/Amps/kW/Frequency.
- Engine Stopped/Running/Cooldown/Pre-Alarm/Shutdown.
- Engine ECS Position Stop/Auto/Run.
- Utility Output kW.
- System Summary Alarm.

Event logging is also included with up to 500 stored events.

GENERATOR METERING AND PROTECTION

Generator metering that will graphically display 3Ø Voltage, 3Ø Current, Frequency, Power Factor, kW, kVAR and a Synchroscope Display of EMCP 3.3 faults, CDVR or ADEM 3 will be provided via Modbus RTU interface to EMCP 3.3.

Generator/Intertie Protective Relaying including:

- Device 27/59 – Under/Over Voltage.
- Device 81O/U – Under/Over Frequency.
- Device 40 – Loss of Excitation.
- Device 32 – Reverse Power.
- Device 25 – Synchronizing Check.
- Device 15 – Auto Synchronizer.
- Device 65 – Governor Load Sharing, Soft Loading Control.
- Device 90 – VAR/PF and Cross Current Compensation Controller.

PROGRAMMING AND DIAGNOSTICS

Includes field programmable set points for engine control and monitoring variables and self-diagnosis of the EMCP 3.3 system component and wiring failures.

ENGINE CONTROL SWITCH

Keypad selectable, four (4) positions – Off, Auto, Man, Cool:

- Off for engine shutdown and resetting faults.
- Auto for local or remote automatic operation when initiated by switch operation or contact closure.
- Man for local starting and manual paralleling.
- Cool for normal engine shutdown with timed cool-down cycle.

CIRCUIT BREAKER CONTROL SWITCH

Heavy duty, three- (3) position spring return to center with momentary trip and close position and slip contacts for automatic closing. Includes circuit breaker position indicating lamps.

EMERGENCY STOP PUSHBUTTON

- Mushroom head, twist to reset, causes engine shutdown and tripping of the generator circuit breaker. Prevents engine starting when depressed.

XQ2000 RENTAL

CATERPILLAR®

STANDARD PARALLELING CONTROL (continued)

ELECTRONIC LOAD SHARING GOVERNOR

- Includes speed adjustment, and auto load share capability when in parallel with legacy power modules.

ALARM MODULE

- Dedicates annunciator screens for warning and shutdown faults. Includes external mounted horn and acknowledge push-button.

AUTOMATIC/MANUAL PARALLELING

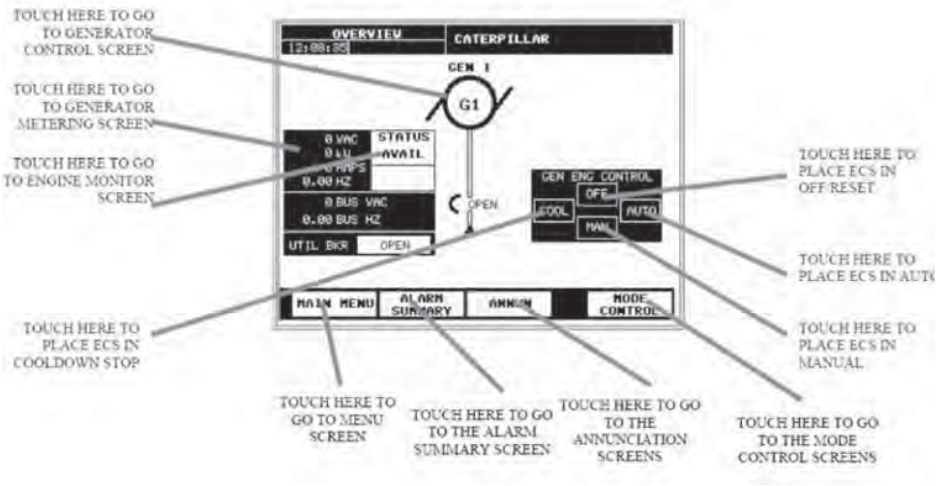
- Automatically synchronizes and parallels the generator with another power source.
- Includes provisions for manual permissive paralleling.

HUMAN MACHINE INTERFACE (HMI) HIGHLIGHTS

- Engine/Generator function is performed thru the 6" HMI touch screen interface.

Overview Screen (Typical)

Shows the generator status, generator metering data, bus metering data, ECS position, and generator/utility breaker status.

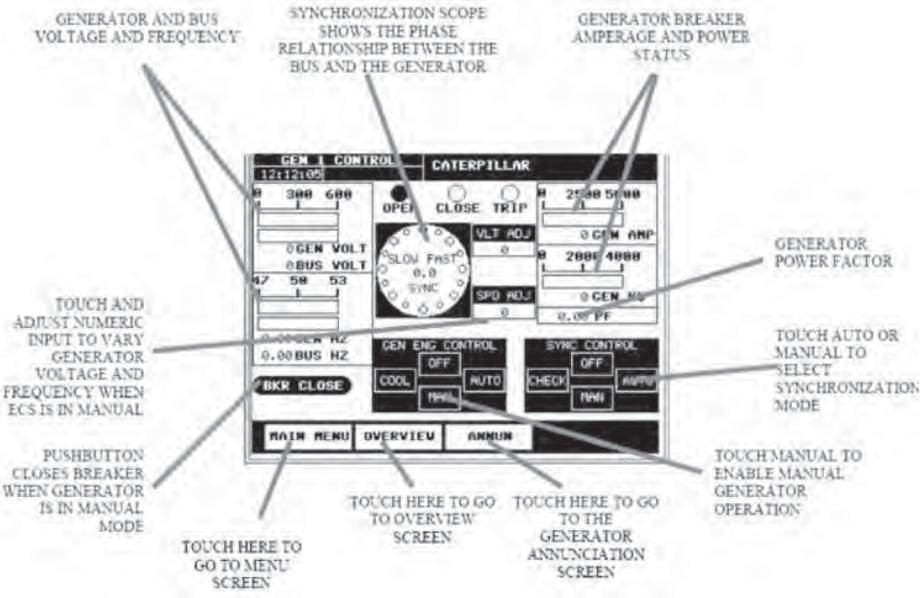


XQ2000 RENTAL

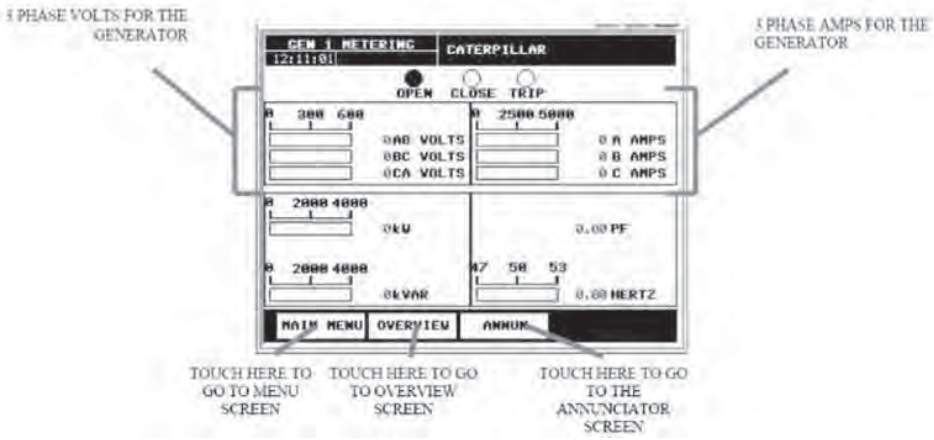
CATERPILLAR®

STANDARD PARALLELING CONTROL (continued)

Generator Control Screen (Typical)
It allows the operator to observe the automatic synchronization and transfer of the load to and from the generator. Engine control allows the operator to run the engine in manual, or switch to automatic modes. Voltage and frequency offset adjustment allows the operator to control generator frequency and voltage.



Generator Metering Screen (Typical)
Allows the operator to view three phases of voltage and amperage for the bus and the generator.

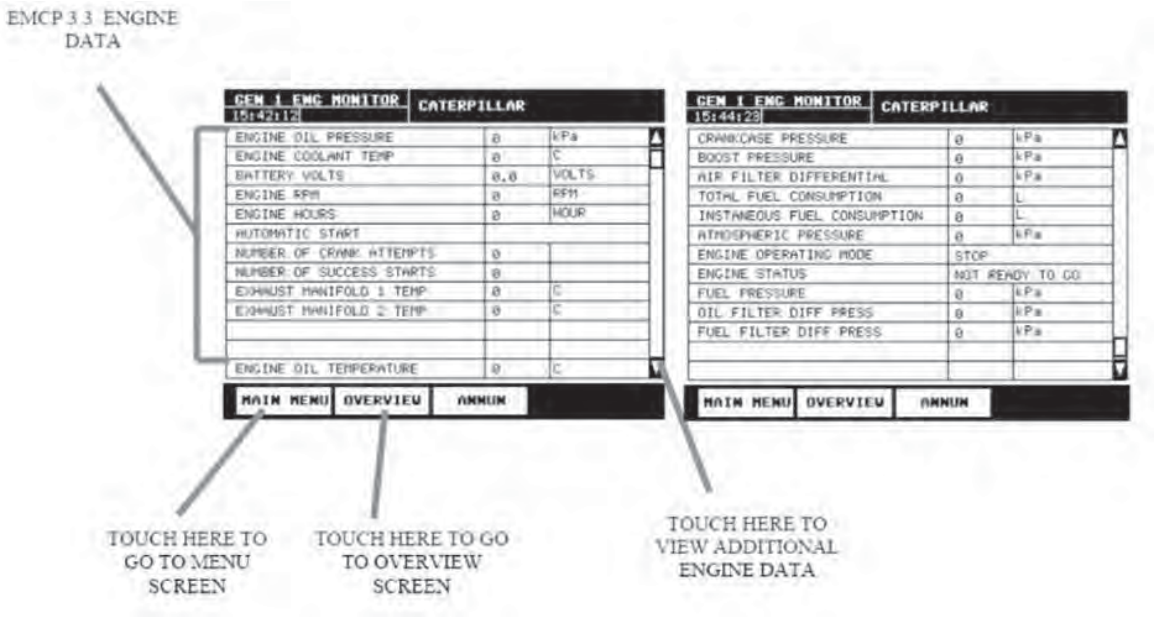


XQ2000 RENTAL

CATERPILLAR®

STANDARD PARALLELING CONTROL (continued)

Engine Monitoring Screen (Typical)
Engine status is obtained directly from the EMCP 3. Engine starts and total hours can be used by the operator to determine when regular preventive maintenance is required. Other metering includes engine battery and oil filter health.



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AIR EMISSIONS PERMIT (NO. 60-010)
AMENDMENT APPLICATION
SUPPORTING DOCUMENT

ATTACHMENT C

EMS

ENVIRONMENTAL WORK PRACTICES

September 2020

ENVIRONMENTAL WORK PRACTICE

An Environmental Work Practice is a set of positive guidelines or "Do's and Don'ts" on how to control an aspect of the services, activities, or products of Yukon Energy that may have a negative effect on the environment.

DIESEL GENERATOR EMISSIONS

EMS-EWP-002

1.0 Introduction

1.1 Purpose

Provide steps to use Yukon Energy Diesel generators efficiently and with the fewest air emissions and least pollution emitted into the environment, as well as to minimize the impact of such air emissions where they are unavoidable.

1.2 Requirements

- A copy of the Air Emissions Permit, from Environment Yukon, is kept at each site.

1.2.1 Operation and Maintenance

- Except for maintenance purposes (e.g., exercise, run after repair) SCC and Plant Operators must use the generators at each site **in order of highest efficiency** under the circumstances. In the rare event that is not possible the operator and SCC must keep a record of why this was done.
- Whenever possible schedule maintenance with surplus hydroelectricity availability so diesel generation is not needed to meet electrical demand.
- Follow manufacturers maintenance presciptions and conduct all necessasary maintenance for generators and environmental emissions controls so the units are as efficient as possible. Monthly run-ups are currently done as scheduled maintenance.
- All particulates collected by emissions control equipment shall be contained such that they are not released to the environment.
- All inspections carried out on the diesel generators shall be documented and retained and will include the name of inspector, date, observations, and actions taken and date of actionsand the date each action was taken.

2.0 Monitoring, Reporting and Record Keeping

1. Keep all records for a minimum of three years and make them available upon request for inspection by a Yukon GovernmentEnvironmental Protection Officer.
2. Records will be kept at Records Management
3. The unit operating authority (i.e., SCC, by way of YEC Environment Department) must obtain approval from an Environmental Protection Officer with YG prior to:
   a. any addition, modification, removal or replacement of any equipment or components related to the release, abatement, control or treatment of air emissions; or
   b. any change in the location of the source(s) (i.e., if there is a plan to move a generator).

3.0 Applicable Legislation and Other Requirments

4. *Yukon Environment Act Yukon Air Emissions Regulations*
5. *Yukon Air Emissions Permit No. 60-010*

4.0 Other Related Information

Yukon Energy Safe Work Practices
SWP's can be found on the Health and Safety Sharepoint site.

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ENVIRONMENTAL WORK PRACTICE

An Environmental Work Practice is a set of positive guidelines or "Do's and Don'ts" on how to control an aspect of the services, activities, or products of Yukon Energy that may have a negative effect on the environment.

FUELS, LUBRICANTS AND COOLANTS

EMS-EWP-005

1.1 Purpose

The purpose of the **Environmental Work Practice** for **Fuels, Lubricants and Coolants** is to provide the steps required to purchase, store, use, products in compliance with applicable laws and otherwise in an environmentally responsible manner.

2.0 Fuels, Lubricants and Coolants

Spills and leaks of oils, coolants, liquids and fuels can harm soil and water and human health. Spills need to be documented, reported, and cleaned up immediately.

2.1 Requirements

- All fuel storage containers should have secondary containment and ideally include integral leak detection and recovery capabilities.
- In addition to absorbent material required to cleanup drips, leaks and minor spills, a fully stocked spill kit shall be available where substances are stored and/or where oil filled equipment will be working.
- Once a spill kit is used, any materials taken out shall be replaced as soon as possible.
- Replacement materials can be obtained through the supplier.
- Lead hands will be responsible for storing spill response equipment in their areas of responsibility.
- All service vehicles transporting hazardous materials and all heavy equipment, must maintain suitable spill response equipment with the vehicle/equipment at all times.
- Staff and contractors on site will be familiar with the contents of onsite spill kits and will be trained in the proper use of spill kits.
- Use external secondary containment for single-walled tanks, for double-walled tanks with capacities more than 4,000 litres, or when storing more than twenty-four 45-gallon drums in one group.
- For 45-gallon drums, use drip pans or similar containers.
- For single walled tanks or double walled tanks over 4,000L, use an approved liner or a curbed concrete pad surrounding the tank, and a spill containment device attached to the intake valve.

The liner or pad and spill containment device must be made of materials that are compatible with the stored materials.

Records Maintenance

- Spill Contingency Plans will be located at each facility. Project managers, lead hands and the site supervisors shall have a copy of the spill contingency plan available on site at a central location.
- Spill contingency plans will also be located in T&D service vehicles.
- Monthly summaries of fuel inventories must be maintained on site as well as records of anytime fuel is added to the system

Reporting

- If a fuel system fails a leak test, it must be reported to the Yukon Energy Department of Environment
- Reporting to the Yukon Spill Report line by the YEC Dept of Environment is necessary if;
    - There is a shortage of 1.0% on monthly tank capacity or tank thouroughput,
    - if there are 4 shortages of 50 litres or more;
    - or consecutive losses totaling 200 litres or more
    - Any loss to water

Fuelling

- Ensure personel is present during fuelling
- Do not refuel equipment within 30m of a watercourse or waterbody. Exceptions to this requirement include equipment refueled within secondary containment (e.g., water pump contained within spill tray).
- Ensure written standard operating procedures, work practices or guidleines (this EWP) are in place during fuelling activities.
- Keep adequate quantities of spill response equipment near fuelling areas
- Use secondary containment at all times when refueling.

Transportation

- All fuels, lubricants, coolants and other hazardous substances must be transported under applicable Transportation of Dangerous Goods Act and Regulation. When transporting any hazardous materials, refer to TDG regulations and the MSDS sheet for the product.
- Contractors hauling hazardous goods for YEC must have Transporation of Dangerous Goods training and certification as well as MSDS sheets for the product in the vehicle.

Waste Handling

WHITEHORSE PLANTS: PUT OILY WASTE INTO RED METAL CONTAINERS.

- Put all contaminated absorbent pads, spent oil filters and contaminated rags into the red oily waste bins in the Whitehorse Hydro and Diesel plants. Oily waste bins will get emptied into a larger dumpster for oily waste outside the WH Diesel plant.
- Do not line red bins with plastic bags as it could cause a fire.
- Waste oil/fuel/solvents/coolants must be stored in clearly labeled and sealed containers, located upright and out of the elements (i.e., not exposed to precipitation or excessive ultraviolet light), and ideally will be stored in outdoor shelters, or indoors on pallets, with integral leak containment
- Keep storage sites secure
- Keep containers at least 30m away from surface waters, catch basins (stormwater), private and public water supply wells.

Waste Records Collection & Retention

- Leadhands are responsible for storing this material and coordinating with waste collection contractor for regular pick-ups.
- Properly completed and signed records and waste manifests must be completed for all waste disposal events and must be retained and regularly provided to Yukon Energy Records Management for filing.

3.0 Applicable Legislation

- Yukon Environment Act, *Spills Regulations*, Yukon Territorial Government
- The storage of hazardous substances is regulated under the *Yukon's Storage Tank Regulations*
- Oil and Gas Act, *Gas Processing Plant Regulations*, Yukon Territorial Government

4.0 Additional Information

YEC Spill Contingency Plans
Can be found on the EMS SharePoint site under Environmental Documents.

ENVIRONMENTAL WORK PRACTICE

An Environmental Work Practice is a set of positive guidelines or "Do's and Don'ts" on how to control an aspect of the services, activities, or products of Yukon Energy that may have a negative effect on the environment.

SPECIAL WASTES

EMS-EWP-008

1.0 Introduction

*1.1 **Purpose***

The purpose of this **Work Practice** for **Special Wastes** (commonly known as hazardous wastes) is to provide the steps required to purchase, store, use and dispose of hazardous wastes in an environmentally responsible manner and according to the YEC Special Waste Permit **41-120.**

2.0 Special Wastes

Yukon Energy is permitted to generate and store the following:

- Waste oil
- Waste solvent
- Waste anti-freeze
- Waste lead based paint chips

Other examples of special wastes include waste batteries, SF6 and asbestos. In addition, any waste dangerous goods are considered special wastes.

2.1 Requirements

If the contractor or employee works with special waste in any way, they need to understand the YEC Special Waste Permit. The following are requirements under the permit:

Documentation

- Keep the Special Waste Permit posted at each site
- Keep a waste manifest everytime you transport or get rid of special wastes, send to YEC Environment Department
- Maintain records of the types of special wastes in and out of your storage areas, volume, origin and storage location. File with YEC Records Management on a yearly basis.

- Submit inspection reports of weekly, monthly and annual inspections (see below requirements) to YEC Environment Department

Storage

- Prevent contamination and leaks by ensuring containers are:
    - properly labelled,
    - sealed, covered and
    - stored within secondary containment.
- Never mix or dilute special wastes.
- Routinely remove special wastes from site to an approved facility

Inspection

- Weekly - inspect for leaks of special waste storage weekly
- Monthly - Inspect storage containers for change in volume
- Annually – check container integrity, check for cracks or other issues

The Yukon *Special Waste Regulations* and the *Gas Processing Plant Regulations* state that a person who possesses or controls a special waste at the time of a release (spill), or who causes a release, **must report the incident** to the Yukon Spill Report Line (667-7244) and the Chief Operating Officer of the Oil and Gas Branch (334-3112, if LNG). The Manager of Environment or Environmental Analyst will make this report.

Containment and clean-up action should begin as soon as possible to protect human health and the environment.

Note that for all but very small quantities of special waste, most placarding, shipping documentation, and transporter certification requirements consistent with the *Transportation of Dangerous Goods Regulations* apply to the transport of special waste.

3.0 Other Special Wastes not included in the Special Waste Permit 41-120

3.1 Pest Control Products

3.1.1 Requirements

Pest control products include herbicides (e.g., weeds, other undesirable vegetation) and pesticides (e.g., insects, rodents). One must ensure that the certified applicator or his/her assistant performs the work as specified in the permit.

The applicator must have a **Pesticide Service Permit** (see separate Fact Sheet) to apply commercial or restricted pesticides. A **Pesticide Applicator Certificate** is required to purchase any commercial or restricted pesticides.

3.2 Mercaptan

Mercaptan is used to add smell to natural gas and has the ability to leach through soil or the sediment at a moderate rate. Accumulates very little in the bodies of living organisms. Highly volatile from water.

3.2.1 Requirements

- Store and handle in accordance with federal and territorial regulations. Grounding and bonding required. Keep separated from incompatible substances.

3.3 Used Batteries and Aerosol Cans

- Batteries contain sulfuric acid and lead. Both of these materials can damage the environment and pose a safety hazard if handled improperly.
- Under the *Yukon Special Waste Regulations*, you must have a Special Waste Permit if you handle more than five kilograms of lead-acid batteries per month.
- Keep used batteries in a bin and call KBL environmental when the bin is full for disposal.

3.3.1 Requirements

When storing batteries, or preparing them for shipment, follow the steps outlined below to help prevent leaks and spills and to avoid contamination of the storage site:

- Batteries and aerosol cans should be collected and stored in a leak-proof container out of direct sunlight and exposure to precipitation (rain/snow).
- Leadhands shall ensure the proper storage and disposal of such materials. They are also responsible for coordinating the collection and disposal of the material in cooperation with the Environmental Coordinator on an annual or more frequent basis, as required.
- Larger batteries can be placed on wooden pallets. Do not make stacks of batteries more than **three layers thick**. Separate each layer with a sheet of plywood or other suitable material.
- **Layers of pallets** should not be stacked more than **two** high.
- Enclose batteries on the pallet with thick plastic to prevent leaks. All sides must be wrapped to protect the batteries from the weather and to prevent any acid from being discharged into the environment.
- After wrapping the batteries in plastic, strap the stack of batteries to the pallet to prevent the batteries from shifting.

4.0 Disposal methods

- **Collection by a Permitted Facility**
  There are several facilities in Yukon that have permits in place for treating and/or disposing of special waste.

- Liquid natural gas, natural gas
  In the event of a spill, allow to vapourize and disperse to the atmosphere

- Mercaptan: Contain in leak proof container and dispose at permited special waste handling facility.

5.0 Applicable Legislation

- Environment Act, *Pesticides Regulation,* Yukon Territorial Government
- Environment Act , *Spills Regulations*, Yukon Territorial Government
- Environment Act, *Solid Waste Regulations*, Yukon Territorial Government
- Environment Act, *Special Waste Regulations*, Yukon Territorial Government
- Canadian Environmental Protection Act. *Ozone Depleting Substances Regulations*, Environment Canada
- Oil and Gas Act, *Gas Processing Plant Regulations*, Yukon Territorial Government
- Transportation of Dangerous Goods Act, Government of Canada

6.0 Additional Information

YEC Safe Work Practices (SWP)
SWP's can be found on the Health and Safety Departments SharePoint site.

YEC Spill Contingency Plans
Can be found on the Environmental Management System (EMS) Sharepoint site under the Environment Department.

From:	Jacquie.VanMarck@gov.yk.ca
To:	Travis Ritchie
Cc:	Lindsay.Dehart@gov.yk.ca; Tim.Smith@yesab.ca; John.Ryder@gov.yk.ca; EMO.Yukon@gov.yk.ca; Joyia.Chakungal@gov.yk.ca; patrick.ross@whitehorse.ca; Andrew.Smith@gov.yk.ca; Janine.Kostelnik@gov.yk.ca; Todd.Powell@gov.yk.ca; Chioma.Izugbokwe@gov.yk.ca
Subject:	Requirement for Assessment under the YESAA for Renewal of Permit #60-010
Date:	December 15, 2017 2:45:14 PM
Attachments:	Record of Determination dec 2017.pdf Air Emissions Permit 60-010 dec 2017.pdf TRitchie letter dec 2017.pdf

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Please find attached a letter from Todd Powell, A/Director of Environmental Programs regarding the requirement for assessment under the Yukon Environmental and Socio-economic Assessment Act for Renewal of Permit #60-010.
Also attached is Air Emissions Permit #60-010 and the Record of Determination of Significant Change for Proponent Yukon Energy Corporation.

Jacquie Van Marck
Administrative Assistant
Environmental Programs Branch
Yukon Government
(PH) 867-667-5683
(Fax) 867-393-6213

Yukon
Environment
Box 2703, Whitehorse, Yukon Y1A 2C6

December 12, 2017

Travis Ritchie
Manager, Environment, Assessment & Licensing
Yukon Energy Corporation
Email: Travis.Ritchie@yec.yk.ca

Dear Mr. Ritchie:

Re: Requirement for Assessment under the *Yukon Environmental and Socio-economic Assessment Act* for Renewal of Permit #60-010

As you are aware, s.49.1(1) of the *Yukon Environmental and Socio-economic Assessment Act* (*YESAA*) as amended in 2015 placed the responsibility for determining whether an assessment is required prior to renewal or amendment of an authorization on the Decision Body for the project. Assessment of an existing project is required when an authorization is renewed or amended, if, in the opinion of a Decision Body for the project, there is a significant change to the original project that would otherwise be subject to an assessment.

As the Decision Body on *YESAA* project 2011-0241 (YEC AEP renewal – Whitehorse Rapids Generating Station), and a regulator on project 2013-0115 (YEC Whitehorse Natural Gas Conversion), the Department of Environment has determined that there have been no significant changes to the air emissions components of the projects since these two previous assessments. Therefore, the amendment of Air Emissions Permit #60-010 does not require a *YESAA* assessment at this time.

We are in receipt of your amendment form and will proceed in issuing the permit to complete the renewal process.

Your project may require a new *YESAA* assessment in the future if there are significant changes to the site or activities. You are required to notify an environmental protection analyst if there are any changes to the air emissions components of your project as compared to the scope of the most recent *YESAA* assessment, so that the significance of the change can be determined. Inspections and/or enforcement officials may also conduct permit inspections to assess whether any changes have occurred.

.../2

Please do not hesitate to contact either myself (867-667-8177; Todd.Powell@gov.yk.ca) or Janine Kostelnik (667-5456; Janine.Kostelnik@gov.yk.ca) if you have any questions about this determination.

Sincerely,

Todd Powell
A/Director, Environmental Programs

Enclosure: Record of Determination for Yukon Energy Corporation

cc: Lindsay DeHart, Development Assessment Branch (Lindsay.DeHart@gov.yk.ca)
Tim Smith, Yukon Environmental and Socioeconomic Assessment Board
John Ryder, Department of Environment (john.ryder@gov.yk.ca)
Yukon Oil & Gas Branch (Chioma.izugbokwe@gov.yk.ca)
EMO, Yukon (EMO.Yukon@gov.yk.ca)
Fire Marshal's Office (Joyia.Chakungal@gov.yk.ca)
City of Whitehorse (pat.ross@city.whitehorse.yk.ca)
Andrew Smith, Major Project Yukon (andrew.smith@gov.yk.ca)

RECORD OF DETERMINATION OF SIGNIFICANT CHANGE

DATE: December 11, 2017

NAME OF DECISION BODY: Department of Environment

PROJECT NAME: Yukon Energy Corporation

YESAB File #: 2011-0241, 2013-0115

PROPONENT NAME: Yukon Energy Corporation

REGULATORY AUTHORIZATION(S), LEGISLATION AND PERMIT #:

1. **Air Emissions Permit**
   Air Emissions Regulations, Permit #60-010

YESAA subsection 49.1(1) states: "A new assessment of a project or existing project is not required when an authorization is renewed or amended unless, in the opinion of a decision body for the project, there is a significant change to the original project that would otherwise be subject to an assessment."

Following are the criteria, factors and analysis that have been taken into consideration by the Decision Body:

Criteria/Factors Considered	Analysis
1. Is the activity listed in the Assessable Activities, Exceptions and Executive Committee Regulations? Identify the section of the regulations and how the exemptions do not apply.	**Schedule 1, Part 4.2** Activity: Construction, operation, modification, decommissioning or abandonment of, or other activity in relation to a fossil fuel-fired electrical generating station. Specific Exemption: Construction, operation, modification, decommissioning or abandonment of, or other activity in relation to, a wind-powered electrical generating station if its production capacity is, and in the case of a modification remains, 50 kW or less. The exemption does not apply because the modification is specific to fossil fuel-fired electrical generation.

Criteria/Factors Considered	Analysis
2. How has the project changed since the previous assessment?	Yukon Energy Corporation (YEC) have requested an amendment to their Air Emissions permit to include the use of four (with a potential 5th unit in 2018/2019) Tier 2 diesel engines to the Whitehorse facility for N-1 emergency use only, to address potential capacity gaps over the winter months on an interim basis.
3. Were the subject, scale and scope of the changes to the project identified in #2 above discussed in the previous Evaluation Report or Decision Document? If the changes were discussed in the Evaluation Report or Decision Document, did YESAB provide any comment on how these changes would affect the environment?	The installed thermal capacity that was assessed in 2011-0241 was 25.2 MW of diesel. In 2013-0115 two of the diesel engines identified in 2011-0241 were taken out and replaced by LNG units. The two diesel generators decommissioned were rated at 3.92 MW and 5.15 MW (9.1 MW total). They were replaced by 2 modern natural gas units rated at 4.4 MW each (8.8 MW total). The proposed additional temporary engines were not directly discussed in either of the past two assessments, however the overall capacity of the facility remains within the 25MW. The air quality impact assessments conducted for each WRGS plant configuration (25MW diesel in 2008 and 2011 and 16.1 MW diesel + 8.8 MW natural gas in 2013) indicated that no significant adverse human health effects would result even under the worst case operating scenario for either facility configuration (all units operating under the most adverse meteorological conditions). The potential for temporary use of up to five units with 10 MW of diesel generation, using more modern and cleaner operating EPA Tier 2 rated engines, is not anticipated to result in significant changes to the overall facility emissions and the conclusions of previous air quality impact assessments for the station.
4. Do any of the changes identified in #2 conflict with any of the terms and conditions of the Decision Document in the previous	N/A

Criteria/Factors Considered	Analysis
assessment?	
5. During the previous assessment, did First Nations, organizations, other stakeholders, or the public indicate concerns about the project that could be intensified as a result of the proposed changes?	2011-0241: residents of Riverdale raised some concerns about the cumulative short and long term health impact of diesel emissions on the already poor air quality in their neighbourhood. Concerns were also raised about a potential increase to noise levels, and about industrial customers being required to supply their own power. These concerns were raised by residents, Riverdale Community Association, and Yukon Conservation Society. 2013- 0115: Many concerns were raised about the use and transportation of LNG to Whitehorse. These comments were specific to impacts about use of LNG, rather than the removal of the two diesel engines and therefore falls outside of the scope of this determination of significant change.
6. Do you consider the changes to the project to be "significant"? Why?	Yukon Environment has deemed that there are no significant changes to the project proposed.

RATIONALE FOR DETERMINATION

Two previous YESAA assessments are relevant to this determination:

1. 2011-0241: renewal of Air Emissions Permit in order to maintain the ability to operate its diesel generating facilities.
2. 2013-0115: construction and operation of natural gas powered, reciprocating engine driven generation station and associated liquefied natural gas transfer, storage and vapourization facilities on the site adjacent to YECs hydroelectric facility. The two LNG generators replaced two existing diesel generators which were at the end of their life cycle with a total capacity of 8MW (9.1 MW nameplate rating).

An N-1 emergency event is a very unlikely incident where an extended winter power outage occurs due to loss of their largest source of electricity (Aishihik hydro plant or Aishihik to Whitehorse transmission line). YEC's 2016 Resource Plan identified that should they find themselves in an N-1 event situation, they may not be able to produce enough electricity to meet demand at peak times. Without emergency

back-up, rolling black-outs would be initiated, which is not a preferable solution.

YEC will be renting four diesel engines as back up this winter (2017/18), which if all ran at the same time, would generate less emissions than the two which were taken out of service in 2013, due to higher efficiency. The units are Tier 2 engines that meet current US Environmental Protection Agency guidelines for diesel generators, and would be the cleanest in their diesel fleet at the Whitehorse facility. The applicant is requesting this emergency use be approved during the winter seasons until 2021, which is when they plan on having a more permanent solution to addressing the longer term capacity gap.

The potential need for a 5th unit is based on a load forecast and the consideration of historic winter temperatures. Should ongoing load monitoring and any updating of the load forecast suggest that an additional 2 MW is needed to protect against an N-1 event, then an additional unit would be temporarily installed during the winter period in 2018/2019 and in future winters until such time as a permanent solution can be brought into service to address the current capacity gap.

The potential significance of this change may be considered both in light of the capacity but also of the air emissions resulting from the activity. Notwithstanding the contribution of the natural gas generators, the temporary use of up to 10 MW of Tier 2 diesel engines, the air quality impact assessment from previous assessments that indicated that there would be no significant adverse human health effects would result even under the worst case operating scenario for either facility configuration (all units operating under the most adverse meteorological conditions.

The amended air emissions permit will include appropriate operational, reporting and record keeping requirements.

The Decision Body has:

Consulted with other decision bodies on the determination (if there are multiple decision bodies).	☒ N/A-there are no other decision bodies for this project.
Discussed determination with other regulator(s) on the determination (if applicable)	☒ The Department of Environment provided Yukon departments of EMR (O&G) and EMO, and the City of Whitehorse, with an opportunity to provide comments. No comments were received.
Ensured that First Nation consultation obligations are being met for this renewal or amendment	☒ The Department of Environment initiated written consultation with Ta'an Kwächän Council and Kwanlin Dün First Nations on November 28, 2017. No comments were received from either of these First Nations.

In the opinion of the Decision Body for this project, as noted in the reasons mentioned above, it has been determined that the renewal or amendment to the regulatory authorization:

☐ **Requires a *YESAA* assessment**
☒ **Does not require a *YESAA* assessment**

Todd Powell
A/Director, Environmental Programs
Department of Environment

THERMAL ENERGY PART OF OUR
Future-Focused Portfolio

yukon energy

planning for cold weather, emergencies and increased demand

THE INSTALLATION OF RENTAL DIESEL GENERATORS AT THE EXISTING FARO DIESEL PLANT

next steps

Over the next few months, we'll be working to get our Faro diesel plant site ready for the arrival of the rental generators. During that time you can expect to see the following.

Yukon Energy crews and contractors at the Faro diesel plant doing groundwork and installing additional electrical equipment in the yard

The arrival of the seven generators

The delivery of additional shipments of fuel now and throughout the winter

staying safe during COVID-19

Yukon is our home too. Like you, we are committed to the health and safety of our employees, families and customers. We have developed a strict COVID-19 safety plan that makes the Faro diesel generator project COVID-safe. We will:

Maintain two metres of separation between workers

Use Personal Protective Equipment at all times

Disinfect equipment regularly

Stagger work breaks to help enforce social distancing

For more information, visit **yukonenergy.ca** or contact **communications@yec.yk.ca.**

yukon energy

At Yukon Energy, it's our job to supply the electricity Yukoners need when and where they need it. Our ability to keep the lights on is especially important during Yukon's cold and dark winters when demand for electricity is the highest.

This means we're always planning for cold weather, emergencies and increased demands for electricity. That's why we rent diesel generators each year as our insurance policy against prolonged power outages until we can build more dependable renewable resources.

This winter, we're renting 17 portable diesel generators; seven more than last year. If the cold snap in January 2020 reinforced anything for us, it's that, collectively, Yukoners are using more electricity than ever before, and that more sources of dependable electricity are needed at the flip of a switch during the winter.

Ten of the rental diesel generators will be installed in our Whitehorse parking lot like last year. The other seven will be installed at our diesel power plant in Faro.

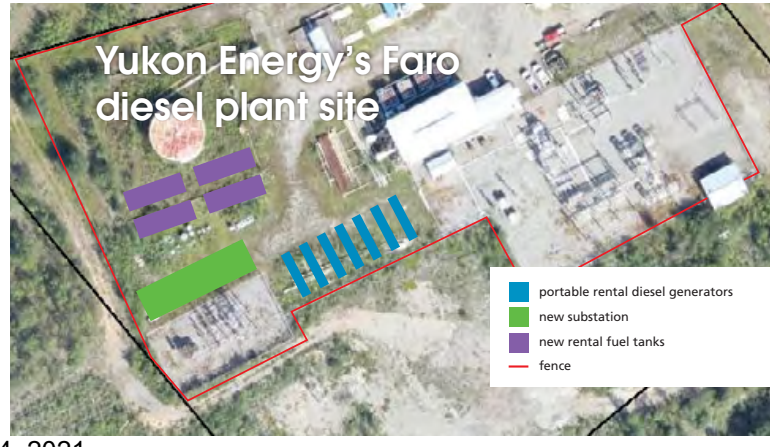
why Faro?

Our diesel plant in Faro is the ideal second location for these portable rental diesel generators because:

- There's enough room to install the generators within our property's fenceline.
- There's room in our yard to build the new substation we need to connect the generators to the Yukon grid.
- There's an existing fuel storage tank on site and room to add the extra temporary fuel tanks we'll need.

When researching this project, we also looked at the option of adding rental generators at our existing diesel plants in Dawson and Mayo. We ruled out those options because:

1. There isn't enough room at the Dawson and Mayo plants to add the extra rental units, fuel and electrical equipment we would need.
2. Our studies showed that by having all seven of the extra rentals located in Faro, they could more efficiently meet peak demands for electricity across the entire Yukon grid.
3. Setting up the seven extra rentals in Faro is less expensive than having to set them up in three separate locations.



how often will they be used?

We rent portable diesel generators each winter to protect Yukoners from prolonged power outages during emergencies and periods of high demand.

The rental diesel generators in Faro won't run all of the time. They'll be used:

- On extremely cold winter days when Yukoners need more electricity (usually around breakfast and dinner time).
- In case of a breakdown at one of our major hydro power plants.
- Each month, for a few hours, to test the engines.

how loud will they be?

We know that diesel generators can be loud.

This winter, we will monitor noise levels emitted by the rental diesel units at the Faro plant. If sound levels are found to be higher than permissible levels, we'll look at ways to help muffle the noise in future years.

Rental Diesels in Faro

December 2, 2020

With thanks and gratitude

Yukon Energy recognizes that we live and work on the Traditional Territories of Yukon First Nations.

We give thanks to the Ross River Dena Council for allowing our facilities and this project to take place on their Traditional Territory.

2

Today's discussion

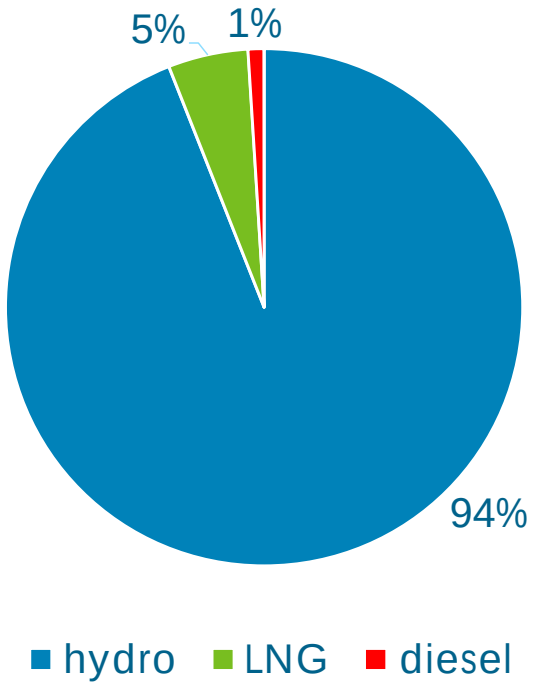
- Why diesel?
- Why more now?
- Why Faro?
- When will they be used?
- What does it mean?
- What does the future hold?
- Discussion

3

Why diesel?

It’s a key part of our electricity mix

Generation Sources, 2015-2019 average

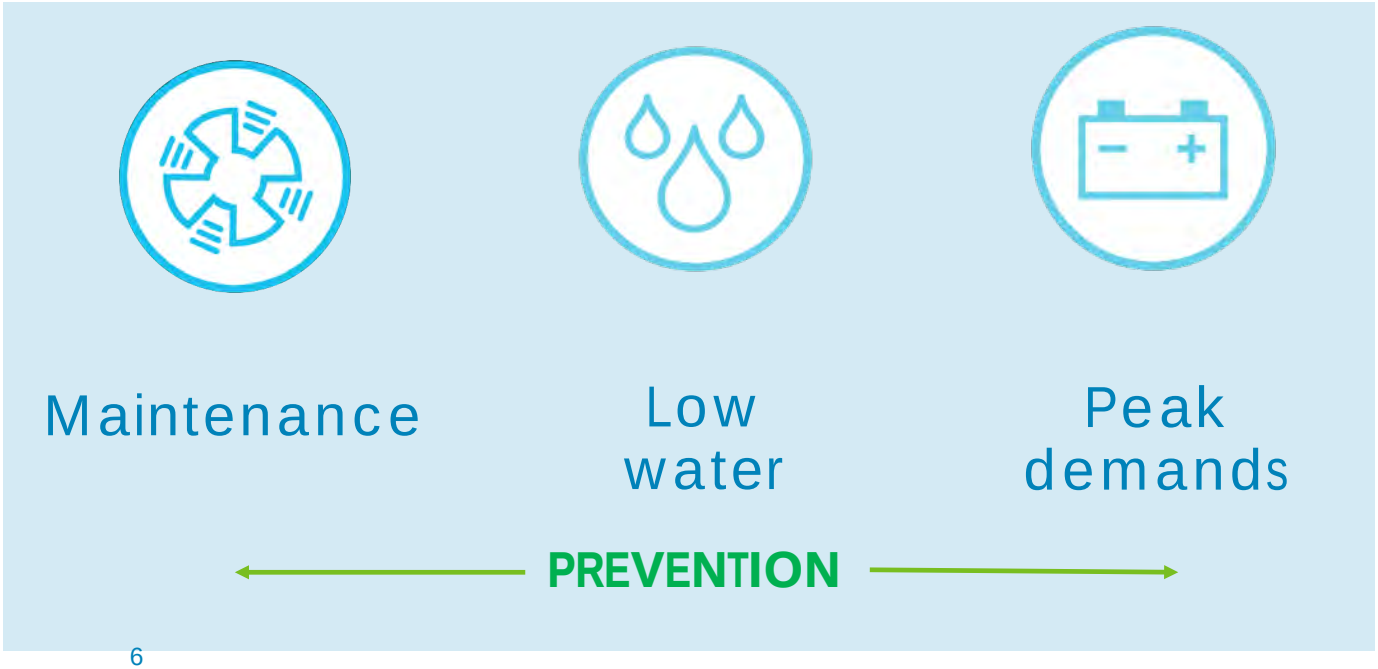


5

Yukon's electricity system is one of the greenest in Canada, using mostly hydro.

We're an isolated grid, not connected to any other province or territory. We need to be self-sufficient.

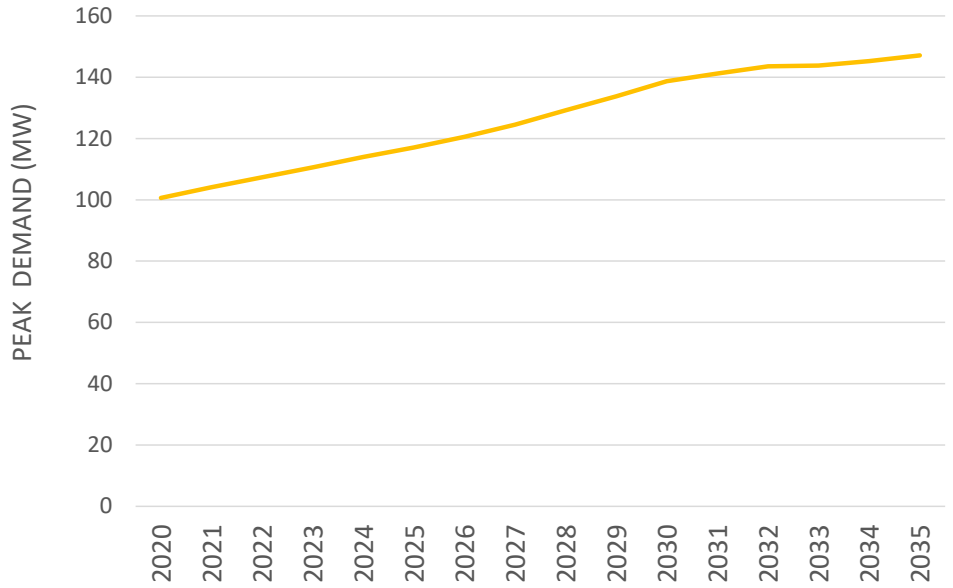
Diesel is used during:



Why more now?

Peak demand for electricity is growing

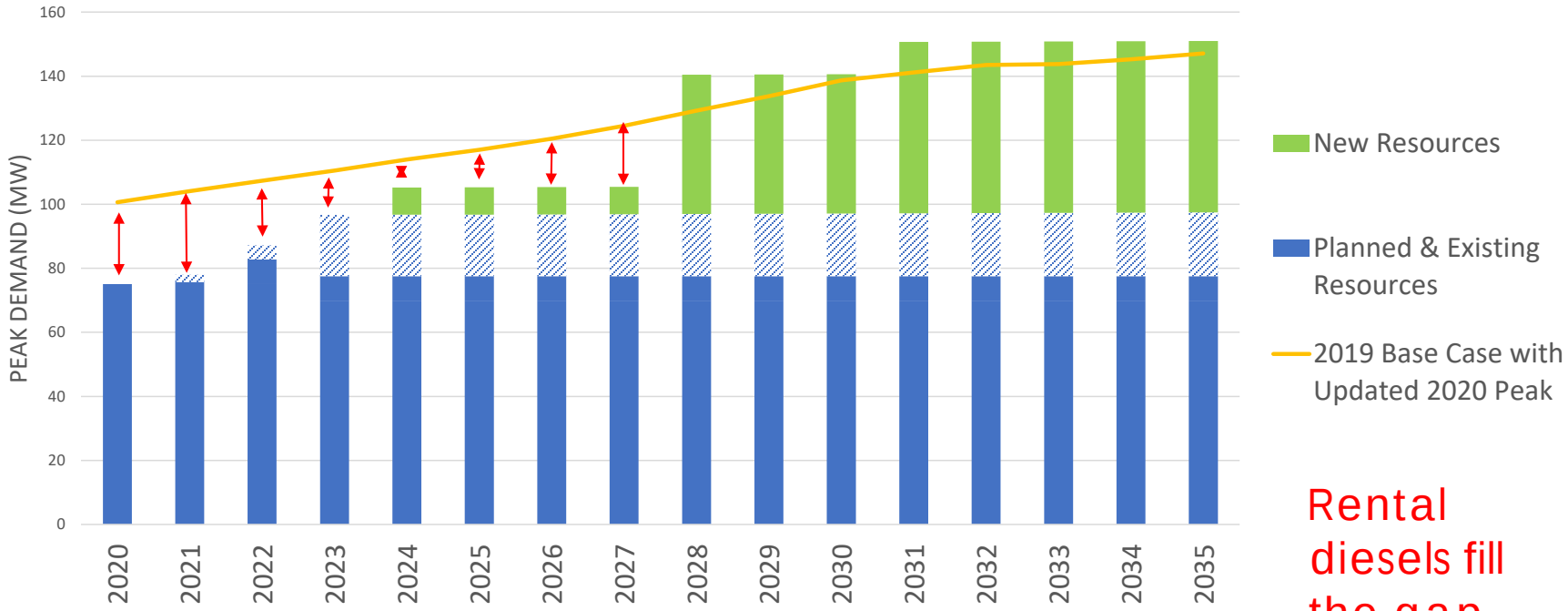
We expect peak demand for electricity to grow by 40% in the next 10 years



- Continued growth in population & electricity use
- Policy actions to address the climate change emergency

8

Rental diesels are needed to fill the gap until new projects are built



Rental diesels fill the gap

9

Why Faro?

The ideal second site for rentals

Whitehorse is full

11

Project location considerations

Site specific:

- Existing diesel sites only
- Allowances in existing air permit
- Space for units, fuel and substation

General:

- Whitehorse is maxed out
- Operating efficiencies (output and resources)
- Cost efficiencies

12

Faro as the preferred site

Site layout

14

Space in our yard

Equipment and fuel tanks

New substation

Rental units

18

Commissioning

19

When will they be used?

To keep the lights on

Running the rentals

During cold weather for peaking

In case of an emergency

21

What does it mean?

Environment, sound and air assessments

Environmental & socio-economic assessments

Sound assessment

Existing Site	With Rentals
58 dB	<1 dB change

Note: nearest point of reception is barracks bldg. on Ketza Ave.

Rental units are more efficient and have lower emissions than the existing permanent units.

Annual facility emissions are well under those permitted by the Yukon Ambient Air Quality Standards.

An irritant (NOx) may be present under extreme conditions, very infrequently and for short periods of time.

What does the future hold?

Upgrades and improvements on site

Immediate: Diesel will be used to keep the lights on.

Next year: A proposal to YESAB for an expanded air permit.

2-3 years: Replacing an old diesel unit with newer model.

8-10 years: Rentals used each winter until renewables built.

Long-term: Diesel used to prevent & restore outages and during emergencies.

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Discussion

Thank you for your time

REFERENCE:

QUESTION:

a) As the Faro diesel site is on RRDC Traditional Territory, does YEC have have [sic] the support of Ross River Dena Council for the modifications to the plant? Please provide documentation of any consultation and interaction with RRDC concerning the Faro plant.

ANSWER:

(a)

Between April 2020 and January 2020, Yukon Energy has contacted representatives of the Dena Nezzidi Limited Partnership (designate for the Ross River Dena Council) at least nine times by email and phone to share information about the Faro rental diesel project and procurement opportunities, and to request a meeting with Ross River Dena Council to discuss the project.

The Dena Nezzidi Limited Partnership representative attended Yukon Energy's December 2, 2020 public information meeting. Copies of the presentation and a summary of the discussion was provided to them following the meeting.

As of February 9, 2021, representatives of the Dena Nezzidi Limited Partnership have not provided Yukon Energy with a date and time for the requested meeting with Ross River Dena Council to discuss the specific Faro rental diesel project and YESAA project proposal.

REFERENCE:

QUESTION:

At the (virtual) meeting that YEC held with the community about the rental diesels on 2-Dec, 2020, one slide had the text: “Next Year: A proposal to YESAB for an expanded air permit.”

a) Please explain what is covered by the current 2014-2024 air permit.

b) Please explain what YEC is seeking with the “expanded air permit,” and why it is needed.

c) Please provide the “Project Description” that will be used for the upcoming YESAB assessment for the Faro site.

d) Please explain the business case for applying for the air permit after the installation of infrastructure and the renting of generators.

e) Please discuss the risks and potential financial impacts of building a project before applying for a required YESAB assessment.

f) Please discuss how this approach relates to social license for stakeholders (RRDC and Faro residents)

ANSWER:

(a)

The current air emissions permit authorizes the use of diesel fuel to operate compression ignition engines to generate electricity at the Whitehorse Rapids Generating Station (WRGS), Mayo Generation Station (MGS), Dawson City Generating Station (DCGS), and Faro Generating Station (FGS) generating stations, with WRGS also having authorization to operate three (3) natural gas fired generators.

(b)

Yukon Energy is seeking authorization to operate up to an additional 4.9 MW of diesel generation at the FGS, in addition to its existing generation limit of 10.6 MW (for a total of 15.5 MW).

(c)

The Yukon Energy Corporation (Yukon Energy) is applying under Parts 6 and 9 of the *Environment Act* and Part V of the *Air Emissions Regulations* for an amendment of Air Emissions Permit No. 60-010 authorizing Yukon Energy to modify the thermal generating component (the Project) of its Faro Diesel Facility (the Site).

Yukon Energy is seeking an amendment of the Permit to allow for the addition of up to 4.9 MW of additional (to a maximum total of 15.5 MW) operational capacity for the diesel electricity generators. The Site is currently permitted to operate at a capacity of 10.6 MW. These generators will act as insurance against the very unlikely event that Yukon Energy experiences an extended winter power outage with loss of generation or transmission from the Aishihik Generating Station,[1] if hydroelectricity cannot meet energy demands and for maintenance purposes. An extended power outage has a very low probability, but the likely consequences require Yukon Energy to be prepared to immediately restore supply to customers on the grid to avoid rolling blackouts. Having access to portable diesel generators ensures that Yukon Energy can continue to provide reliable service during the winter in an emergency.

The need for this contingency measure came as a result of analysis of information prepared as part of Yukon Energy's 2016 Resource Plan (2017). The 2016 plan and the 2017-18 GRA identified that there was a capacity gap in 2017-18 of approximately 8 MW between maximum probable (winter) load and the installed capacity of the system under an N-1 event. Yukon Energy's updated 10-Year Renewable Electricity Plan, updated in December 2020, identifies an even greater gap (> 20 MW) between existing resources

[1] **Emergency (or "N-1") Whitehorse-Aishihik-Faro (WAF) and Mayo-Dawson (MD) system capacity planning criteria:** Each grid system (WAF and MD) will be planned to be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency (known as "N-1"). The N-1 criterion determines system capacity assuming the loss of the system's single largest generating or transmission-related generation source. In the case of WAF, this is presently the Aishihik transmission line, without which the WAF grid loses ability to access approximately 37 MW of generation.

and forecasted peak energy demand (Yukon Energy 2020). This Project is expected to be required until more permanent solutions to address the current N-1 capacity gap are implemented. Yukon Government's document Our Clean Future: A Yukon strategy for climate change, energy and a green economy (Government of Yukon 2020) identifies a renewable energy target of 97% by 2030. Yukon Energy's 10-Year Renewable Electricity Plan outlines key projects and partnerships that will help to address the energy and peak capacity shortfalls over the 10-year planning horizon. A number of projects have been identified in the Future-Focused Portfolio (such as Whitehorse Hydro uprates, the battery energy storage system, the Southern and Mayo Lakes Enhanced Storage Projects) but these projects will take time to plan, design, permit, and construct, and Yukon Energy requires a temporary solution be put in place until new capacity can be added to the system. These back-up units would be at the bottom of stacking order and would only be operated in the case of an emergency, when hydroelectricity cannot meet demands, and for short durations for monthly exercise to confirm operational readiness.

The permit amendment request to modify the existing thermal is subject to a Designated Office level environmental and socio-economic effects assessment by the Yukon Environmental and Socio-economic Assessment Board (YESAB) under the *Yukon Environmental and Socio-economic Assessment Act* (YESAA).

Pursuant to that assessment, Yukon Energy requests a recommendation from the Designated Office to allow the Permit amendment to proceed, on the basis that the Project (i.e., the modifications to Yukon Energy's diesel generating facilities described in this proposal and operated in accordance with the terms and conditions of an air emissions Permit and the applicable provisions of the *Environment Act* and *Air Emissions Regulations*) will not have a significant adverse environmental or socio-economic effect within the meaning of section 56(1)(a) of YESAA.

In contrast to the diesel generation facilities operated by ATCO in communities such as Watson Lake and Old Crow, which are isolated from the transmission grid and must therefore operate continuously (24 hours per day, 365 days per year), Yukon Energy only uses its fossil fuel-fired generators:

- As back up during renewable energy system outages (planned and unplanned);

- To supplement energy demand during colder periods of the year; and

- To exercise the units for very short durations on a monthly basis to ensure operational readiness.

This is because most of the needs of customers on the system are satisfied by Yukon Energy's three hydro generating stations. For the vast majority of the time, the thermal generators do not operate. However, Yukon Energy's thermal generation facilities are essential to its ability to provide a reliable supply of electricity to customers whenever demand exceeds hydro supply (e.g., as a result of planned maintenance, emergency repair, or peaking demand during cold temperatures).[2]

Yukon Energy is regulated principally under the Yukon *Business Corporations Act*, *Public Utilities Act*, and *Waters Act*, and the federal *Fisheries Act.* In particular, under the *Public Utilities Act*, Yukon Energy has an obligation to supply electricity service to its customers, and its rates and operations are subject to regulation by the Yukon Utilities Board. Yukon Energy's thermal generation facilities are also subject to regulation under the Yukon *Environment Act* and *Air Emissions Regulations*, as well as *YESAA*.

Yukon Energy's diesel (thermal) electric generating plants are installed and operated to ensure the ongoing operation of the integrated power system and so all customers on these systems can receive reliable power consistent with Yukon Energy's corporate and regulatory obligations.

Given the current generation mix (hydro, wind, and thermal) and system design, Yukon Energy's ability to operate the installed thermal plants, particularly during conditions where demand for electricity cannot be adequately met by hydro (e.g., planned maintenance, emergency repair, demand during cold winter temperatures), is essential to avoid scenarios where there would be a requirement to impose blackout conditions to various customers. This is particularly relevant during times where the lack of such ability would at best be very inconvenient, and at worst dangerous to infrastructure and human health and safety, such as would be the case during cold winter temperatures.

[2] For example, Yukon Energy's reliance on the thermal generation facilities was essential when a major power outage occurred on the WAF grid in January 2006 due to a failure on the connection to the Aishihik hydro generating facility. If Yukon Energy had not had the ability to operate its diesel units in those circumstances, customers would have been left without power in the middle of the winter.

The current need for thermal generation is related to several factors including:

1. The need to meet demand for electricity during those times when hydro-electric facilities are offline as a result of an emergency condition;

2. The need to meet demand for electricity during those times when hydro-electric facilities are taken offline for routine maintenance;

3. The need to meet demand for electricity during those times when there is a grid separation (i.e., transmission outage) and electricity from hydro-electric facilities is not available;

4. The need to exercise a particular diesel unit as a part of routine maintenance; and

5. The need to meet demand for electricity during those times when hydro-electric facilities are otherwise unable to meet current demand for energy.

This Project includes an amendment to the existing Air Emissions Permit (Permit No. 60-010) to operate additional temporary rental diesel units up to a total site operational capacity of 15.5 MW, as required. The reason these units have been added to the Faro Diesel Facility is add additional capacity to reduce the gap in dependable energy required versus available.

Yukon Energy requires an amendment of its existing Air Emissions Permit No. 60-010 to have the ability to operate additional thermal generation resources and ensure the continuity of a reliable supply of power to Yukoners as described earlier in this proposal. A Permit can be issued by the Minister responsible for the Department of the Environment pursuant to Section 12 of the *Air Emissions Regulations* under the *Environment Act*. It is expected that the existing permit would be amended to allow the requested modification to the Faro Diesel Facility.

To amend the Permit, the Yukon Government regulatory authorities may require a decision document based on the environmental and socio-economic assessment of the amendment application under *YESAA*. An environmental and socio-economic assessment is understood to be required under Schedule 1, Part 4, Item 2(b) of the *Assessable Activities, Exceptions and Executive Committee Projects Regulations* under

YESAA, because the Permit is for the "operation … of … a fossil fuel-fired electrical generating station".

While the amendment request will be to authorize changes to the Faro Diesel Facility to have up to 15.5 MW of standby/back-up diesel generating capacity, the activity is a modification to an existing facility and does not involve the construction, decommissioning, or abandonment of a fossil-fuel fired electrical generating station, as such the proposed activity is not immediately assessable at the Executive Committee level.

Yukon Energy is requesting a recommendation by the Designated Office to allow the Permit amendment to proceed, on the basis that the Project (i.e., the continuing operation of the Yukon Energy's Faro Diesel Facility with the addition of 4.9 MW of additional diesel generating capacity (total of 15.5 MW of generating capacity) in accordance with the terms and conditions of the amended Permit and the applicable provisions of the *Environment Act* and *Air Emissions Regulations*) will not have a significant adverse environmental or socio-economic effect within the meaning of section 56(1)(a) of *YESAA*.

(d)

The Corporation deemed it prudent to advance the project activities in order to ensure it was positioned to meet the grid demand for energy as soon as the assessment and permitting could be completed for the additional capacity beyond the existing facility generating capacity limit. The prudency of sequencing activities in this manner was based on several factors that balanced the very real risks of not being ready to meet demand under an emergency condition with the risks of being denied a recommendation to proceed with the expanded generation capabilities as a consequence of the YESAA assessment and/or the permitting process that would follow under the *Environment Act*, *Air Emission Regulations*. The risk of proceeding with installation of the additional generators was mitigated by the following factors:

- Previous standardized modelling, stack testing, and assessments (including 3 assessments under YESAA) of air emissions at the Whitehorse Rapids Generating Station up to a maximum of 22 MW, with the nearest human receptor being within 250 m of the facility, have repeatedly demonstrated that there is a low likelihood of significant adverse effects arising from the operation of the facility.

- With the nearest receptor in the case of the FGS being more than 300 m from the facility, and the fact that operations would be capped at 15.5 MW, it was concluded that the potential for significant adverse effects associated with the increased generating complement proposed for the FGS was low.

- The FGS has previously been assessed under YESAA and authorized under the Environment Act, Air Emission Regulation for a total generating capacity of 10.6 MW. Through changing operational requirements the installed capacity at the facility has changed periodically, with installed units being moved to other generating stations that required such relocation to optimize operations. The FGS currently has generators with rated capacity lower than the permitted site limit or cap and as such the installation of at least some of the rental diesels could be used at the facility up to the existing permitted cap without further YESAA assessment. The availability capacity room within the permitted cap is another factor in proceeding with making provisions for additional unit installation at site before undertaking the assessment for the additional capacity which is only proposed for use beyond the existing air permit capacity limits once the required assessment and permitting is successfully completed.

(e)

Given the risk assessment and conclusions made under the circumstances described in the response to NY-YEC-1-10(d), the potential financial implications of proceeding with the project installation before applying for YESAA assessment required to add to the site capacity were deemed to be minimal and tolerable when compared to the very serious health, safety, and numerous other relevant implications of not being able to meet customer demand for electricity in the case of an emergency in the cold and darkness of winter in the Yukon.

(f)

Yukon Energy takes its responsibility to provide safe, reliable, affordable, and environmentally responsible electricity very seriously. In the context of the operational requirements driving the emerging need for the Project and the consequences of not being in a position to meet that need in an emergency it was determined that interested and potentially affected governments, organizations, and communities would best served by YEC advancing project planning. This would ensure timely ability to avoid the potential

need for service disruptions up to the current generating capacity limits it was lawfully permitted to operate, and has been for decades, while undertaking the appropriate activities to assess and permit the additional capacity it was proposing only to operate once an amended permit could be issued. On balance, it was assessed that reasonable societal expectations of the Corporation would be met by such an approach given the circumstances and the low likelihood of potentially significant adverse effects of such actions.

REFERENCE:

QUESTION:

Diesel Timeline: Please provide a timeline documenting the decisions and implementations of rental diesel in Faro. Please include the following points:

a) When was the decision made to add more rental diesel?

b) When was the decision made to put the additional rentals in Faro?

c) When did YEC inform Faro residents of the installation of the new diesels?

d) When did work begin on the installation of the rental diesels and related infrastructure?

e) When did YEC seek regulatory approval for the additional rentals?

f) When did YEC receive compliance documentation from the Department of Environment?

g) When was it realized that a YESAB assessment will be required to use the installed capacity?

h) When will the YESAB process for the additional diesels begin?

i) What is the projected date of YESAB completion?

j) How long are rental diesels expected to be part of the system?

k) When will other projects be completed or brought on-line to retire rental diesels? (Faro and Whitehorse) Please include specific projects and estimated completion dates and corresponding reduction in rental diesel.

ANSWER:

(a)

The decision to add more temporary diesel was made in January 2020 following an update of the peak forecast based on the record 2020 peak event recorded January 16, 2020.

(b)

The decision to add additional rental diesels at Faro was made in February 2020.

(c)

An information piece about the Faro rental project was mailed to all residents and citizens in Faro in September 2020. Information about the project, along with a copy of the mailer, was added to Yukon Energy's website at the same time. See response to NY-YEC-1-8 (a) Attachment 1 for referenced materials.

Yukon Energy hosted a public information meeting about the project on December 2, 2020. The session was hosted online due to COVID-19 concerns. Six members of the public attended. The meeting was advertised with community posters, radio and print ads, and social media. A copy of the presentation was made available after the meeting on Yukon Energy's website. See response to NY-YEC-1-8 (b) Attachment 2 for referenced materials.

Yukon Energy responded to questions received by phone, email and social media about the project as received.

(d)

Work began on February 26, 2020.

(e)

Yukon Energy has not yet sought regulatory approval for the additional capacity beyond the capacity limits of the existing air emissions permit. Only once an assessment is completed under YESAA and a Decision Document is issued will Yukon Energy make

application for the additional capacity beyond its existing permit capacity limits for the FGS. Regarding the installation of new units at the site to bring the operating complement of generators on site up the existing permitted capacity limit of 10.6 MW, that formal approval, which is provided for under the permit, was sought in August 2020.

(f)

As outlined in NY-YEC-1-10, “compliance documentation” has not been required for the activities Yukon Energy has undertaken to date.

(g)

It was understood that an assessment under YESAA would be required as soon as it was determined that the project proposed to install operating capacity beyond the existing permit limits of 10.6 MW. That conclusion was reached in summer 2020.

(h)

The YESAB process is tentatively planned for Q1 2021, following additional planned engagement with the RRDC.

(i)

While beyond Yukon Energy’s control, an assessment under YESAA for a project of this nature has historically taken 3-6 months.

(j)

Rental diesels are expected to be required on the system for the next 8 to 10 years.

(k)

The expected annual capacity additions, and forecast rental diesel requirements, are shown in the Table 1 below.

Table 1: Expected Capacity Additions: 2020/21 to 2028/29

	2020/ 2021	2021/ 2022	2022/ 2023	2023/ 2024	2024/ 2025	2025/ 2026	2026/ 2027	2027/ 2028	2028/ 2029
Rental Requirements (# of Units)									
Whitehorse	9	9	9	8	6	8	9	9	0
Faro	6	6	3	0	0	0	1	3	0
New Capacity Resources (MW)									
DSM Programs	-	2.2	4.4	6.6	6.7	6.7	6.8	6.8	7.0
Battery Energy Storage System	-	-	7	7	7	7	7	7	7
Whitehorse #2 Uprate	-	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Diesel Replacement[1]	-	-	-	7.3	7.3	7.3	7.3	7.3	7.3
Atlin Hydro Expansion	-	-	-	-	8.5	8.5	8.5	8.5	8.5
Moon Lake Pumped Storage	-	-	-	-	-	-	-	-	35

[1] While the diesel replacement project replaces retired capacity with like-for-like nameplate capacity, some older units currently have de-rated dependable capacity, and the Whitehorse units being replaced have already been retired from the system. Replacement of these units with like-for-like nameplate capacity results in an increase in 7.3 MW of dependable capacity for the system.

REFERENCE:

QUESTION:

Rental diesel alternatives

a) What alternatives to rental diesel were considered?

b) Please provide cost/benefit analysis on alternatives to rental diesel.

c) What sites/locations were considered?

d) What criteria was used in selection / elimination of sites?

ANSWER:

(a) and **(b)**

YEC experienced a record peak in January 2020, which informed the forecast of required N-1 dependable capacity. This capacity was required for the winter of 2020/2021. No alternative to rental diesels would be available in this timeline. YEC's 10-Year Renewable Electricity Plan (see CW-YEC-1-36(a) Attachment 1) outlines several alternatives which will replace the rental diesels as they are brought online over the next ten years.

(c)

The following sites/locations were considered:

1. New site in Whitehorse
2. Faro
3. Mayo
4. Dawson

(d)

Given the tight timeline for deployment, the main criteria for site section was the existing permitting at each site, in order to maximize how much additional capacity of thermal could

be added under YEC's current air emissions permits. Consideration was also given to whether a YESAB Designated Office review and amended permit would be required (timeline of several months) versus a full YESAB Executive Committee Assessment, as that process would take more than a year to complete.

REFERENCE: **Impacts of rental generators on Faro which may affect future YESAB**

QUESTION:

a) Please provide a copy of the sound modeling study for the Faro generators.

(This study was cited by Travis Ritchie of YEC in a (virtual) meeting that YEC held with the community about the rental diesels on 2-Dec, 2020 – from the YEC meeting summary: "Travis noted that the findings of Yukon Energy's sound modelling study showed that if all rentals were to be running that predicted sound levels from the site at the nearest point of reception (occupied building) would be less than 1 dB more than what is emitted by the permanent generators.")

b) Please provide an updated spill plan and map of the site.

c) Please provide the most recent air quality assessment and dispersion study for the Faro site, and explain how this will be affected by the addition of the rentals.

ANSWER:

(a)

Please see Attachment 1 to this response.

(b)

Please see Attachment 1 to this response for the Faro Spill Contingency Plan. The site plan can be found on page 18 of the Spill Contingency Plan.

(c)

Please see Attachment 1 to this response.

YUKON ENERGY CORPORATION

NOISE IMPACT ASSESSMENT
FARO FACILITY

FEBRUARY 12, 2021

wsp

NOISE IMPACT ASSESSMENT

FARO FACILITY

YUKON ENERGY CORPORATION

FINAL

PROJECT NO.: 191-02438-01
DATE: FEBRUARY 12, 2021

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VERSION HISTORY

VERSION	DATE	TITLE	COMMENTS	PREPARED BY
1.0	February 12, 2021	Noise Impact Assessment – Generator Additions	Upgrade facility from approved 10.6 MW to 15.5 MW.	WSP Canada Inc

EXECUTIVE SUMMARY

WSP Canada Inc., (WSP) was retained by Yukon Energy Corporation (YEC) to prepare a Noise Impact Assessment (NIA) report for its diesel-fuelled electricity generating facility in Faro, Yukon. The Facility is located in south-central Yukon, within the asserted traditional territory of the Kaska Nation and upstream from the territory of the Selkirk First Nation. The Facility is located just northwest of the Town of Faro, Yukon and approximately 15 km south of Faro Mine.

The Facility has an existing Air Emissions Permit which allows the Facility to operate up to a capacity of 10.6 MW. The Facility has been, and is currently operating much below the permitted facility capacity of 10.6 MW with only two existing diesel generators on-site. WSP conducted a NIA to evaluate the potential noise impacts of increasing the Facility's capacity from the existing permitted capacity at 10.6 MW to 15.5 MW in the future. As a conservative approach the assessment of noise impact is based on 16.0 MW capacity. However, it is understood that the YEC will only be applying for a permit amendment with the Yukon Environmental and Socio-economic Assessment Board (YESAB), to allow up to 15.5 MW of capacity at the Faro Facility.

Compliance was established using the manufacturer's sound level data for the existing and proposed generators as noted below:

1. The existing generator, Model: Mirrlees KV16 with rated capacity of 5.15 MW, located within FD1 building shall be operated at or below the capacity of 2.4 MW
2. The existing generator, Model: Caterpillar (CAT) 3612 with rated capacity of 3.3 MW, located within FD7 building shall be operated at or below the capacity of 2.8 MW
3. Seven new generators are proposed (6 will be used for regular operation and 1 standby generator); each generator will be with rated capacity of 1.8 MW. Each of these generators will be with enclosures, silencers or mufflers providing an overall maximum sound level of 78 dBA at 7 metres (23 feet);

The assessment presented in this report are based on the guidelines provided British Columbia Oil and Gas Commission's (BC OGC) "British Columbia Noise Control Best Practices Guideline" (2009) and the principles provided in the Health Canada's (HC) "Guidance for Evaluating Human Health Impacts in Environmental Assessments: Noise" (2017). The assessment indicated that the changes in sound level due to the upgrade is minimal (less than 1 dB). Therefore, it is concluded that the operation of Facility with the proposed expansion complies with the PSL.

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B TABLES
C MANUFACTURER SPECIFICATION

1 INTRODUCTION

WSP Canada Inc. (WSP) was retained by Yukon Energy Corporation (YEC) to prepare a Noise Impact Assessment (NIA) report for its facility located in Faro, Yukon (the Facility). The Facility currently includes diesel generators with a permitted generating capacity of 10.6 MW. YEC is planning to expand the Facility's generation capacity to 15.5 MW. This report is required in support of a permit amendment pursuit with the Yukon Environmental and Socio-economic Assessment Board (YESAB) to increase capacity at the diesel-fuelled electric generating facility from the permitted capacity of 10.6 MW to 15.5 MW. Although the application of the Faro Facility is for 15.5 MW capacity, as a conservative approach, the NIA considered a capacity of 16 MW. However, it is understood that the YEC will only be applying for a permit amendment to allow up to 15.5 MW of capacity at the Faro Facility.

The purpose of this assessment is to evaluate the overall changes in noise impact due to the proposed changes at the nearby sensitive receptors. The analysis is based on manufacturer's sound level data and conservative estimates of the source sound levels. The findings of the assessment are discussed further within this report.

1.1 STUDY AREA

The study area surrounding the Facility can be classified as a rural area. The existing acoustic environment in the study area is expected to be dominated by natural environmental sounds during the day and night time.

The Facility is located in south-central Yukon, within the asserted traditional territory of the Kaska Nation and upstream from the territory of the Selkirk First Nation. The Facility is located just northwest of the Town of Faro, Yukon and approximately 15 km south of Faro Mine. The 25-sq. km Faro Mine was once the largest open pit lead-zinc mine in the world. The mine has been closed since 1998 and in the process of reclamation. The town is home to approximately 348 residences (Statistics Canada, 2016).

The Facility is in an area classified as 'Industrial/Commercial' surrounded by 'Industrial/Commercial' to the north; 'Parks & Open Space' to the west, and south; and 'Unsurvey Interim Protected First Nation Lands' to the east. The 'residential' lands located to the south and southeast is known as the Town of Faro. A scaled area map showing the Facility and its surrounding area is shown in **Figure 1** and a zoning map is included in **Figure 2**.

1.2 FACILITY DESCRIPTION

The Facility provides reliable energy supply to supplement renewable energy sources. The Facility provides electricity during loss of hydro generation, peak hours of consumption, low water periods, extreme low temperatures and emergencies. The Facility has the potential to operate 24 hours a day.

The Facility is comprised of the following existing buildings; a site plan showing the Facility buildings is provided in **Figure 3**:

- Generator Building (ID: FD1);
- Generator Building (ID: FD7)
- Office Building;
- Control Building;
- Storage Building and
- Diesel Storage Tanks.

The expansion includes operation of 7 rental units at the Facility; the make and mode of these units are Caterpillar (CAT) model 3516C. During the period of this permit the make and model of these units will remain the same.

1.2.1 *OPERATING CAPACITY*

The following generator operations makes up the proposed operating capacity (**Table 1.1**):

Table 1.1 Generator Capacities

GENSET ID	DESCRIPTION	RATED CAPACITY	OPERATING CAPACITY	REMARKS
FD1 (within building)	Mirrlees KV16 Model	5.15 MW	2.4 MW	Existing Operation
FD7 (within building)	Caterpillar (CAT) 3612	3.3 MW	2.8 MW	Existing Operation
YM20 to YM26[1]	Caterpillar (CAT) 3516C	1.8 MW each	6 units to provide 10.3 MW	New Turbines
Total Operating Capacity			15.5 MW	Total future capacity

[1] One of the rental units (i.e. YM26) will be a standby generator and will be used in case of power failure of another generator.

Other than the generator building, other buildings do not have a source with significant noise generation. The noise sources associated with generator building includes, air intake louvres and dampers, exhaust fans, noise breakout through the façade and combustion exhaust. In addition, there are remote radiators for the existing generators located outside the buildings on the north and southwest side at ground level, respectively. The 1.8 MW units (YM20 to YM26) comes with enclosures, silencers and mufflers designed to control noise emissions.

1.3 STUDY OBJECTIVES

The Facility has an existing Air Emissions Permit which allows the Facility to operate up to a capacity of 10.6 MW. The Facility has been, and is currently operating much below the permitted facility capacity of 10.6 MW with only two existing diesel generators on-site. These generators are housed in separate buildings on-site (FD1 and FD7). The study investigates if the future operation with 15.5 MW capacity has the potential to change the existing conditions.

2 NOISE SOURCE SUMMARY

WSP used drawings and site photographs to identify and establish the source of sound for the existing Facility operation and future Facility upgrade. Drawings from the site are included in **Appendix A**. The sources of noise are primarily air intakes and exhausts, radiators and the generators.

2.1 NOISE SOURCES

A total of thirty-four (34) non-negligible noise sources were identified and included in the assessments. These noise sources considered in the assessment are summarized in **Table 2.1;** the sound power of these sources were estimated based on the manufacturer's data. A detailed summary of the sources is provided in **Appendix B.** Manufacturer specification sheets are provided in **Appendix C**.

A site layout plan showing the source locations within the Facility is provided in **Figure 3**.

Table 2.1 Noise Source Summary Table

SOURCE ID	SOURCE DESCRIPTION	SOUND POWER LEVEL (dBA)	SOURCE LOCATION[1]	NOISE CONTROL MEASURES[2]
FD1_GEN_EXH1	FD1 2.4 MW Generator Combustion Exhaust	139	O	S
FD1_GEN_EXH2	FD1 2.4 MW Generator Combustion Exhaust	139	O	S
FD1_GEN_INT1	FD1 2.4 MW Generator Intake	118	O	S
FD1_GEN_INT2	FD1 2.4 MW Generator Intake	118	O	S
FD1_BLD_DIS1	FD1 2.4 MW Building Discharge	111	O	S
FD1_BLD_INT1	FD1 2.4 MW Building Intake	111	O	S
FD1_GEN_RAD1	FD1 2.4 MW Generator Radiator	114	O	U
FD1_GEN_RAD2	FD1 2.4 MW Generator Radiator	114	O	U
FD1_GEN_RAD3	FD1 2.4 MW Generator Radiator	114	O	U
FD1_GEN_RAD4	FD1 2.4 MW Generator Radiator	114	O	U
FD1_BLD_OUT1	FD1 2.4 MW Building Breakout Noise	116	O	U
FD1_BLD_OUT2	FD1 2.4 MW Building Breakout Noise	116	O	U
FD7_GEN_EXH1	FD7 2.8 MW Generator Combustion Exhaust	140	O	U
FD7_BLD_INT1	FD7 2.8 MW Building Intake	121	O	U
FD7_BLD_INT2	FD7 2.8 MW Building Intake	121	O	U
FD7_BLD_INT3	FD7 2.8 MW Building Intake	121	O	U
FD7_BLD_INT4	FD7 2.8 MW Building Intake	121	O	U
FD7_GEN_INT1	FD7 2.8 MW Generator Intake	112	O	U
FD7_GEN_INT2	FD7 2.8 MW Generator Intake	112	O	U
FD7_BLD_DIS1	FD7 2.8 MW Building Discharge Fan	120	O	U
FD7_BLD_DIS2	FD7 2.8 MW Building Discharge Fan	120	O	U
FD7_BLD_DIS3	FD7 2.8 MW Building Discharge Fan	120	O	U

SOURCE ID	SOURCE DESCRIPTION	SOUND POWER LEVEL (dBA)	SOURCE LOCATION[1]	NOISE CONTROL MEASURES[2]
FD7_BLD_DIS4	FD7 2.8 MW Building Discharge Fan	120	O	U
FD7_GEN_RAD1	FD7 2.8 MW Generator Radiator	112	O	U
FD7_GEN_RAD2	FD7 2.8 MW Generator Radiator	112	O	U
FD7_BLD_OUT1	FD7 2.8 MW Building Breakout Noise	115	O	U
FD7_BLD_OUT2	FD7 2.8 MW Building Breakout Noise	115	O	U
YM20_GEN_CAS	YM20 1.8 MW Generator Casing	103	O	E
YM21_GEN_CAS	YM21 1.8 MW Generator Casing	103	O	E
YM22_GEN_CAS	YM22 1.8 MW Generator Casing	103	O	E
YM23_GEN_CAS	YM23 1.8 MW Generator Casing	103	O	E
YM24_GEN_CAS	YM24 1.8 MW Generator Casing	103	O	E
YM25_GEN_CAS	YM25 1.8 MW Generator Casing	103	O	E
YM26_GEN_CAS	YM26 1.8 MW Generator Casing (Backup)	n/a	O	E

Notes:
[1] Source Location: O = outside of a building, I = inside of a building
[2] Noise Control Measures: S = Silencer/Muffler, A = Acoustic Lining, E = Acoustic Enclosure, U = Uncontrolled.

2.2 SOURCES WITH NEGIGIBLE EFFECTS

Some sources are expected to produce sound levels that are not significant compared to other loud sources. These noise sources are considered negligible and are not included in the assessment as these sources are not expected to contribute to the overall noise effect of the Facility at the nearby noise sensitive receptors. The sources with a negligible contribution (or source with insignificant contribution) at the receptors are listed below.

- Small exhaust fans and HVAC units;
- Small compressor or pumps;
- Indoor equipment with small or no motors;
- Breakout noise through façade of building that do not house generators;
- Small transformers (if any); and
- Worker vehicles (moving and idling).

3 NOISE RECEPTOR SUMMARY

Noise receptors are those locations where sound from noise sources at a facility is received and assessed against applicable limits. Sound may be assessed at the plane of a window (PoW) of a noise receptor such as a dwelling. For the purpose of this assessment, the selected PoWs represent the predictable worst-case noise impacts; it represents the closest PoW to the Facility (i.e., the window of the receptor facing the Facility). Receptors are summarized in **Table 3.1** and locations are shown in **Figure 1**.

Table 3.1 Point of Reception Summary

POR ID	DESCRIPTION	RECEPTOR HEIGHT[1] (M)	DISTANCE FROM FACILITY (M)[2]
R1	One Storey Residence on Dawson Drive	1.5	359
R2	Two Storey Residence on Dawson Drive	4.5	406
R3	Three Storey Residence on Dawson Drive	7.5	415
R4	One Storey Army Barracks on Kitza Avenue	1.5	359
R5	One Storey Del Van Gorder School on 100 Bell Avenue	4.5	792
R6	One Storey Faro Health Centre on 447 Campbell Street	1.5	915

Notes:
[1] The height represents the upper story window, which is most exposed to the site.
[2] Distance are provided from the Facility's closest noise source to the receptor.

4 ASSESSMENT CRITERIA

This section reviews the available criteria and establishes acceptable criteria for the Facility upgrade.

In the absence of any specific regulatory noise guidance or criteria in the Yukon, this assessment takes into account best practices and the following guidelines:

- British Columbia Oil and Gas Commission's (BC OGC) "British Columbia Noise Control Best Practices Guideline" (2009); and
- Health Canada's (HC) "Guidance for Evaluating Human Health Impacts in Environmental Assessments: Noise" (2017).

4.1 BRITISH COLUMBIA NOISE CONTROL BEST PRACTICES GUIDELINE

The BC OCG guidelines (BC Guide) are widely accepted in western Canada and commonly used in the Yukon. The guideline provides guidance regarding noise management from noise emission from energy-industry activities. The guideline requires a noise impact assessment for modifications to existing facilities, if there is a reasonable expectation of changes in noise source or sound level, and if there is a receptor located within 1.5 km distance. There is reasonable expectation of source sound levels as well, as there are receptors nearby for the Yukon Energy Facility. Therefore, a noise assessment is required.

The BC Guide is a receptor-based guideline (not property line-based guideline); it defines Permissible Sound Levels (PSLs) at the receptor locations. A PSL at the nearest residence or nearby receptors can be determined based on the methods discussed in the BC Guide. The BC Guide provides methods to estimate daytime (07:00 to 22:00) PSL and nighttime (22:00 to 07:00) PSL.

In accordance with the BC Guide, facilities constructed in and in operation prior to October 1998 are considered "deferred facilities". Such facilities, without outstanding noise complaints are considered to meet the community noise tolerance levels. It is understood that the Faro Facility was constructed prior to 1998 and does not have outstanding noise complaints. Therefore, the sound level from the existing operation is considered to be the PSL for this assessment.

Accordingly, a baseline model with existing operation was completed and the sound levels at the receptors were estimated. The estimated sound level from existing operation at receptors R1 to R6 are shown in **Table 4.1**.

Table 4.1 Permissible Sound Level Limits from BC OCG

POR ID	EXISTING NOISE LEVEL DAYTIME/NIGHTIME PSL (dBA)[1]
R1	58
R2	59
R3	59
R4	59
R5	48
R6	46

Notes:
[1] Refer Section 5 for modelling and results.

4.2 ACCEPTABLE SOUND LEVEL

As discussed previously, the sound levels in this assessment are expressed in terms of energy equivalent sound level over a one-hour period (Leq (1 hour)). Since the generator upgrade is proposed to an existing facility, the assessment considers changes to the acoustical environment before and after the upgrade.

Table 4.2 below, from published literatures, outlines the noise impact rating in relation to the change in sound levels from the baseline condition (or condition prior to the proposed upgrades). When a "significant" or greater impact is predicted (5 dB or greater), noise mitigation measures and their feasibility should be investigated.

Table 4.2 Noise Impact Rating

CHANGES IN SOUND LEVEL	IMPACT RATING
0 to 2.99 dB	Insignificant
3 to 4.99 dB	Noticeable
5 to 9.99 dB	Significant
Over 10 dB	Very Significant

Therefore, a change of up to 3 dB is considered insignificant and was used to assess the impact.

5 IMPACT ASSESSMENT

The objective of this acoustic assessment is to determine the changes in sound level due to proposed changes at Yukon Energy's Faro generator station upgrades during a predictable worst-case operation. A predictable worst-case operation is considered as an hour of operation during which the facility operates at its capacity (i.e. operates at 16 MW capacity).

Since the generator upgrade is being designed, this assessment is completed using an acoustic modelling approach for Faro Facility's current and future operations. This section discusses the assessment methodology, modelling scenarios, the results of the assessment as well as discusses the compliance of the Faro Facility.

5.1 ASSESSMENT METHODS

The predictive analysis of the Faro Facility's noise impact at the POR was completed using commercially available software package CADNA/A (Ver. 2020), a computerized implementation of the algorithms contained in the ISO 9613 "Acoustics – Attenuation of Sound during Propagation Outdoors". CadnaA modelling takes into account the following:

- Source sound power levels;
- Distance attenuation;
- Source-receptor geometry;
- Ground and air (atmospheric) attenuation; and
- Temperature and humidity effects on noise propagation.

The lands between the Facility and receptors are a mixture of sound abortive (e.g. grass) with some reflective (e.g. paved road) and modelled accordingly. Road pavements were modelled with a ground absorption of 0.4 and remaining surfaces were modelled with a ground absorption of one (1). Typical Yukon meteorological values were used to initialize several parameters in the model. These included a temperature of 10 degrees Centigrade and a relative humidity of 80%.

5.2 OPERATING SCENARIOS

The assessment was done assuming a predictable worst-case operation. Since the Facility has the potential to operate at full capacity 24 hours per day to meet power demands, no differences between daytime, evening, or nighttime operations were considered. Two scenarios were evaluated to determine the changes in sound level as previously discussed:

- Existing/Current Operation; and
- Future Expanded Capacity

5.3 MODELLING RESULTS

Table 5.1 shows the predicted sound level results between existing and future scenarios and compares the change in sound levels. Equivalent sound level contours (isopleths of equal sound level) are presented in **Figure 4** and **Figure 5** at heights of 1.5 m above the ground for existing and future scenarios, respectively.

Table 5.1 Summary of Changes in Sound Levels between Existing and Future Scenarios

POR ID	PREDICTED SOUND PRESSURE LEVELS (SPL), dBA			
	EXISTING SPL /PSL [dBA]	FUTURE SPL [dBA]	CHANGE in SPL[1] [dBA]	IMPACT RATING
R1	58	58	< 1	Insignificant
R2	59	60	< 1	Insignificant
R3	59	59	< 1	Insignificant
R4	59	60	< 1	Insignificant
R5	48	48	< 1	Insignificant
R6	46	46	< 1	Insignificant

Notes:
[1] No changes are also considered less than 1 decibel change for simplicity.

As indicated in **Table 5.1**, the changes in the sound levels produced by addition of generators to reach a capacity of 15.5 MW are predicted to be less than 1 dBA. The change in sound level caused by the proposed changes to the Yukon Energy Facility are therefore not considered a significant change. **Figure 6** shows the equivalent sound level contours for the existing and future operation side by side for comparison purposes; these figures show minimal change in sound level contours near the receptor area.

Since the change in sound level due to proposed modification (i.e. capacity increase) is predicted to be less than 1 dB, no additional mitigation other than those included with the proposed 1.8 MW rental units as identified are required.

6 RECOMMENDATIONS AND CLOSURE

6.1 RECOMMENDATIONS

Compliance was established using the manufacturer's sound level data; therefore, when selecting the new generators to reach operational capacity of 15.5 MW the following shall be implemented:

1. The existing generator, Model: Mirrlees KV16 with rated capacity of 5.15 MW, located within FD1 building shall be operated at or below the capacity of 2.4 MW
2. The existing generator, Model: Caterpillar (CAT) 3612 with rated capacity of 3.3 MW, located within FD7 building shall be operated at or below the capacity of 2.8 MW
3. The proposed new generators (YM20 to YM26) shall be 6 regulars plus 1 standby generator each with rated capacity of 1.8 MW and each with enclosures providing an overall maximum sound level of 78 dBA at 7 metres (23 feet);
4. Prior to installation, a shop drawing can be requested from supplier confirming the sound data to be less than 78 dBA at 7 metres (23 feet);
5. If a complaint is received after installation, an acoustic audit shall be performed consisting of onsite measurements.

6.2 CLOSURE

WSP Canada Inc., was retained by Yukon Energy Corporation (YEC) to conduct a Noise Impact Noise Impact Assessment (NIA) report in support of a permit amendment pursuit with the Yukon Environmental and Socio-economic Assessment Board (YESAB) to increase capacity at the diesel-fuelled electric generating facility in Faro, Yukon (the Facility) from the existing permitted capacity of 10.6 MW to 15.5 MW in the future.

Based on WSP's assessment and available information at the time of this report, the assessment indicated that the changes in sound level due to the upgrade is minimal. Therefore, it is concluded that the operation of Facility with the proposed expansion complies with the PSL.

FIGURES

126 DON HILLOCK DRIVE, UNIT 2
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LEGEND

SITE LOCATION

REPRESENTATIVE RECEPTORS

N
W E
S

POR ID	Description	Receptor Height[1] (m)
R1	One Storey Residence on Dawson Drive	1.5
R2	Two Storey Residence on Dawson Drive	4.5
R3	Three Storey Residence on Dawson Drive	7.5
R4	One Storey Army Barracks on Kitza Avenue	1.5
R5	One Storey Del Van Gorder School on 100 Bell Avenue	4.5
R6	One Storey Faro Health Centre on 447 Campbell Street	1.5

150 75 0 150 Metres

CLIENT:
YUKON ENERGY CORPORATION

PROJECT:
NOISE ASSESSMENT
FARO POWER STATION
FARO, YUKON

PROJECT NO:	DATE:
191-02438-01	NOVEMBER 2020

DESIGNED BY: -

DRAWN BY: TP

CHECKED BY: -

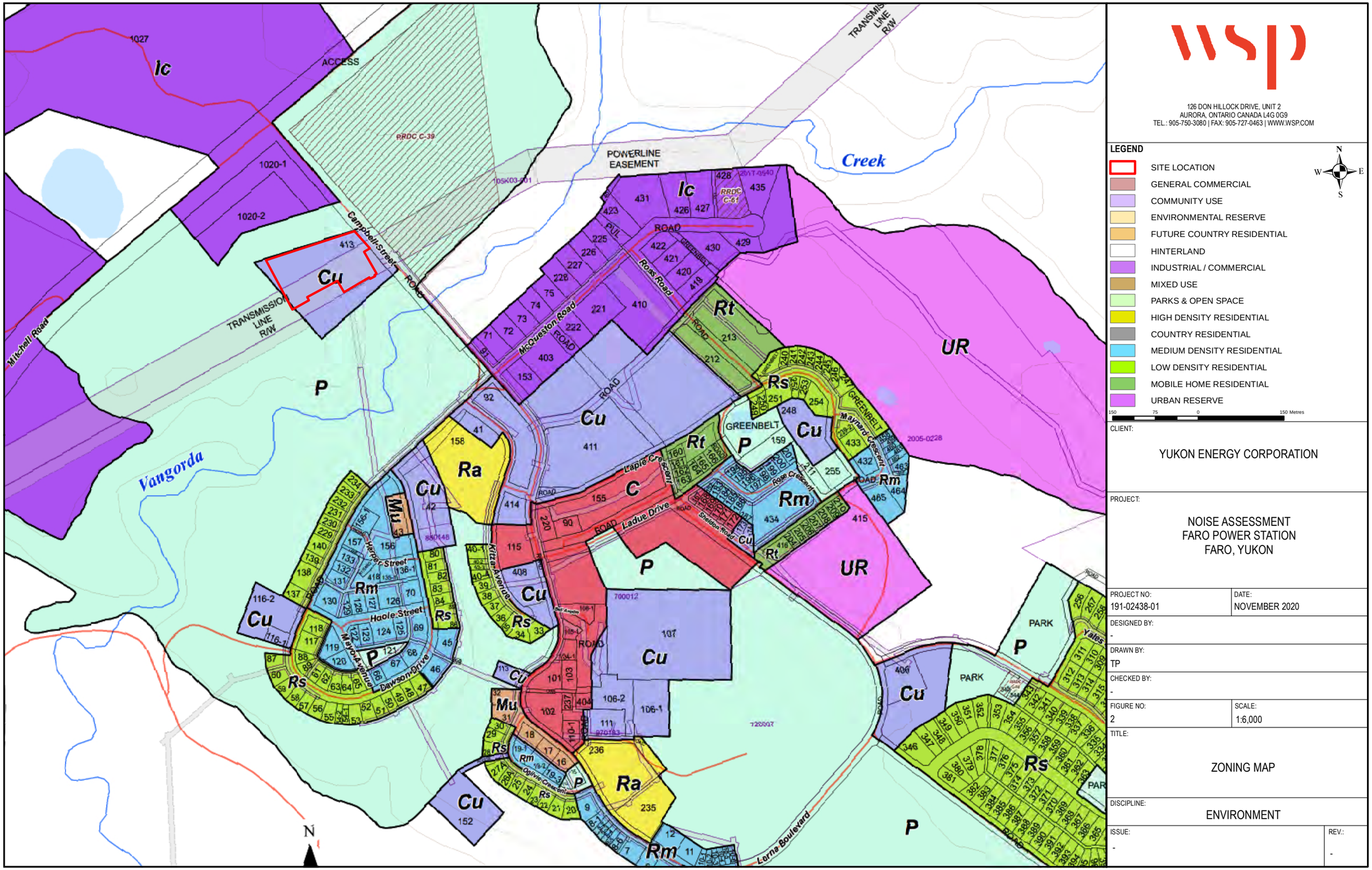
FIGURE NO:	SCALE:
1	1:6,000

TITLE:
AREA MAP SHOWING SITE LOCATION

DISCIPLINE:
ENVIRONMENT

ISSUE:	REV.:
-	-

Document Path: D:\aProjects\191-02438-01\MXD\191-02438-01 Figure 1 Area Map.mxd



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LEGEND

- SITE LOCATION
- GENERAL COMMERCIAL
- COMMUNITY USE
- ENVIRONMENTAL RESERVE
- FUTURE COUNTRY RESIDENTIAL
- HINTERLAND
- INDUSTRIAL / COMMERCIAL
- MIXED USE
- PARKS & OPEN SPACE
- HIGH DENSITY RESIDENTIAL
- COUNTRY RESIDENTIAL
- MEDIUM DENSITY RESIDENTIAL
- LOW DENSITY RESIDENTIAL
- MOBILE HOME RESIDENTIAL
- URBAN RESERVE

150 75 0 150 Metres

CLIENT:
YUKON ENERGY CORPORATION

PROJECT:
NOISE ASSESSMENT
FARO POWER STATION
FARO, YUKON

PROJECT NO:	DATE:
191-02438-01	NOVEMBER 2020

DESIGNED BY: -

DRAWN BY: TP

CHECKED BY: -

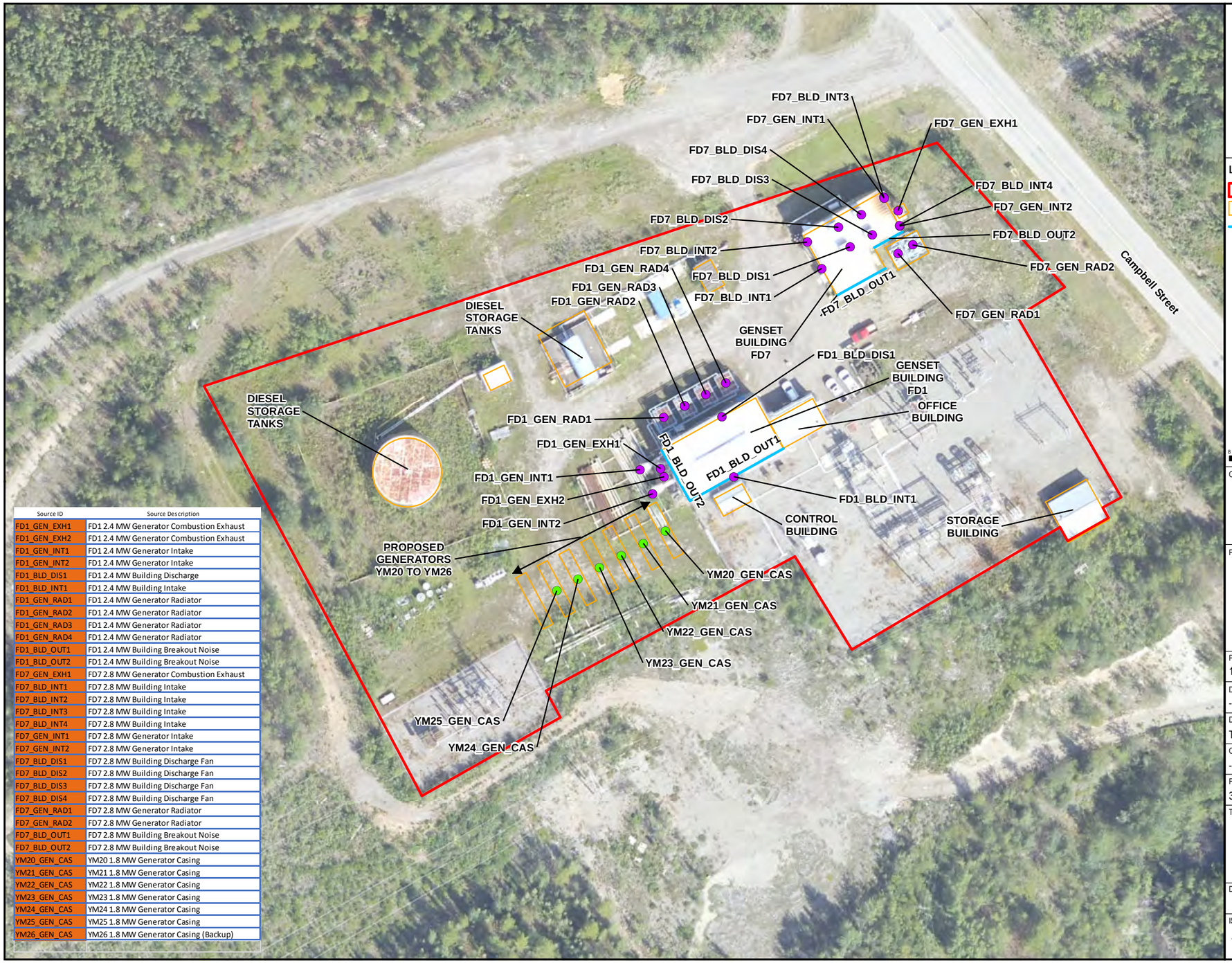
FIGURE NO:	SCALE:
2	1:6,000

TITLE:
ZONING MAP

DISCIPLINE:
ENVIRONMENT

ISSUE:	REV.:
-	-

Document Path: D:\aProjects\191-02438-01\MXD\191-02438-01 Figure 2 Zoning.mxd



Source ID	Source Description
FD1_GEN_EXH1	FD1 2.4 MW Generator Combustion Exhaust
FD1_GEN_EXH2	FD1 2.4 MW Generator Combustion Exhaust
FD1_GEN_INT1	FD1 2.4 MW Generator Intake
FD1_GEN_INT2	FD1 2.4 MW Generator Intake
FD1_BLD_DIS1	FD1 2.4 MW Building Discharge
FD1_BLD_INT1	FD1 2.4 MW Building Intake
FD1_GEN_RAD1	FD1 2.4 MW Generator Radiator
FD1_GEN_RAD2	FD1 2.4 MW Generator Radiator
FD1_GEN_RAD3	FD1 2.4 MW Generator Radiator
FD1_GEN_RAD4	FD1 2.4 MW Generator Radiator
FD1_BLD_OUT1	FD1 2.4 MW Building Breakout Noise
FD1_BLD_OUT2	FD1 2.4 MW Building Breakout Noise
FD7_GEN_EXH1	FD7 2.8 MW Generator Combustion Exhaust
FD7_BLD_INT1	FD7 2.8 MW Building Intake
FD7_BLD_INT2	FD7 2.8 MW Building Intake
FD7_BLD_INT3	FD7 2.8 MW Building Intake
FD7_BLD_INT4	FD7 2.8 MW Building Intake
FD7_GEN_INT1	FD7 2.8 MW Generator Intake
FD7_GEN_INT2	FD7 2.8 MW Generator Intake
FD7_BLD_DIS1	FD7 2.8 MW Building Discharge Fan
FD7_BLD_DIS2	FD7 2.8 MW Building Discharge Fan
FD7_BLD_DIS3	FD7 2.8 MW Building Discharge Fan
FD7_BLD_DIS4	FD7 2.8 MW Building Discharge Fan
FD7_GEN_RAD1	FD7 2.8 MW Generator Radiator
FD7_GEN_RAD2	FD7 2.8 MW Generator Radiator
FD7_BLD_OUT1	FD7 2.8 MW Building Breakout Noise
FD7_BLD_OUT2	FD7 2.8 MW Building Breakout Noise
YM20_GEN_CAS	YM20 1.8 MW Generator Casing
YM21_GEN_CAS	YM21 1.8 MW Generator Casing
YM22_GEN_CAS	YM22 1.8 MW Generator Casing
YM23_GEN_CAS	YM23 1.8 MW Generator Casing
YM24_GEN_CAS	YM24 1.8 MW Generator Casing
YM25_GEN_CAS	YM25 1.8 MW Generator Casing
YM26_GEN_CAS	YM26 1.8 MW Generator Casing (Backup)

Document Path: D:\aProjects\191-02438-01\MXD\191-02438-01 Figure 3 Sources.mxd

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LEGEND

- SITE LOCATION
- BUILDING AND GENERATOR LOCATIONS
- BREAKOUT NOISE SOURCE LOCATION
- EXISTING NOISE SOURCE LOCATION
- FUTURE SOURCES DUE TO ADDITION

N W E S

8 4 0 8 Metres

CLIENT:

YUKON ENERGY CORPORATION

PROJECT:

NOISE ASSESSMENT
FARO POWER STATION
FARO, YUKON

PROJECT NO:	DATE:
191-02438-01	NOVEMBER 2020

DESIGNED BY: -

DRAWN BY: TP

CHECKED BY: -

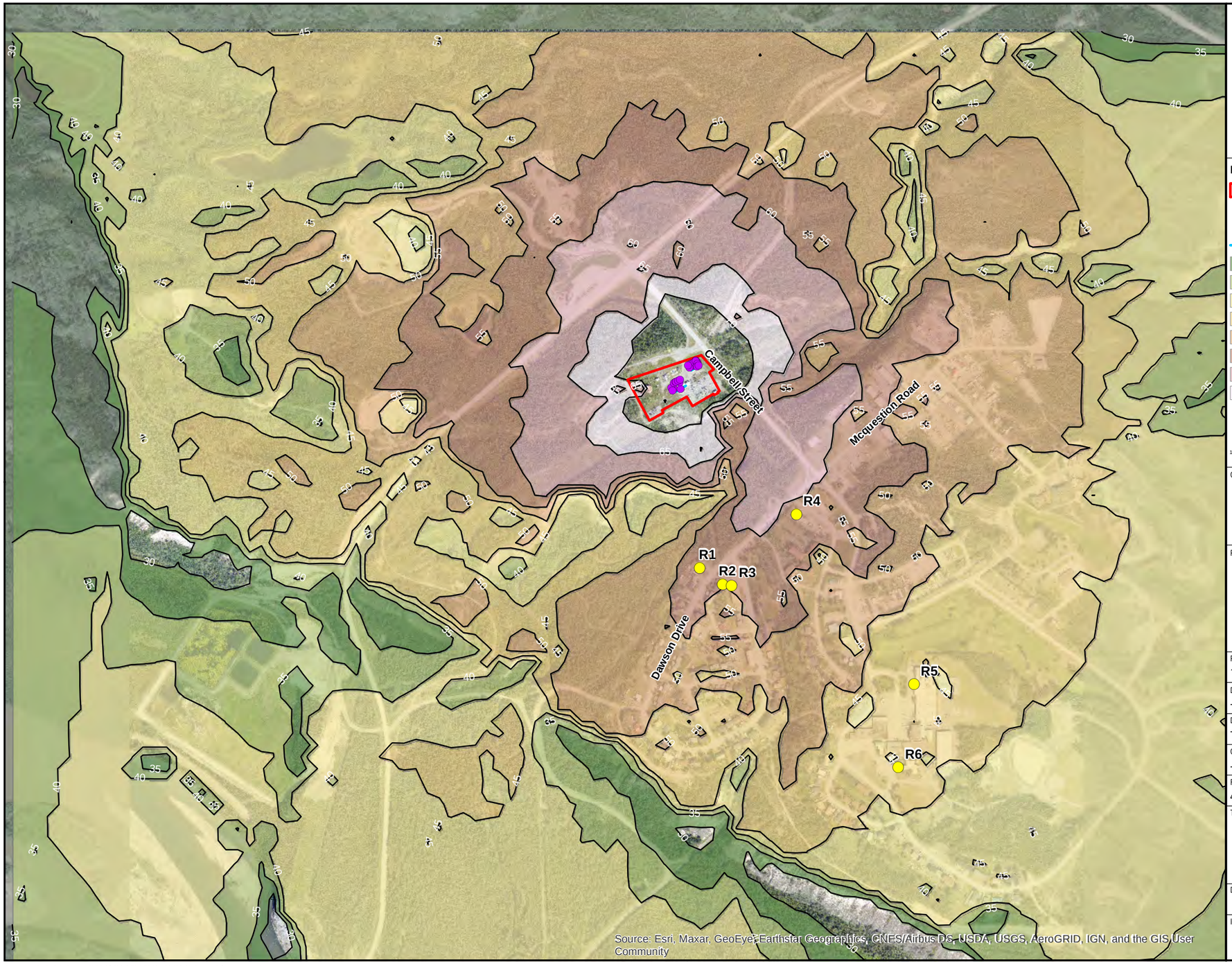
FIGURE NO:	SCALE:
3	1:800

TITLE:

SITE MAP SHOWING EXISTING
FARO FACILITY SOURCES
WITH PROPOSED ADDITIONS

DISCIPLINE: ENVIRONMENT

ISSUE:	REV.:
-	-



126 DON HILLOCK DRIVE, UNIT 2
AURORA, ONTARIO CANADA L4G 0G9
TEL.: 905-750-3080 | FAX: 905-727-0463 | WWW.WSP.COM

LEGEND

- SITE LOCATION
- REPRESENTATIVE RECEPTORS
- EXISTING NOISE SOURCE LOCATION
- BREAKOUT NOISE SOURCE LOCATION
- 30 dB
- 35 dB
- 40 dB
- 45 dB
- 50 dB
- 55 dB
- 60 dB
- 65 dB

N W E S

150 75 0 150 Metres

CLIENT:
YUKON ENERGY CORPORATION

PROJECT:
NOISE ASSESSMENT
FARO POWER STATION
FARO, YUKON

PROJECT NO:	DATE:
191-02438-01	NOVEMBER 2020

DESIGNED BY: -

DRAWN BY: TP

CHECKED BY: -

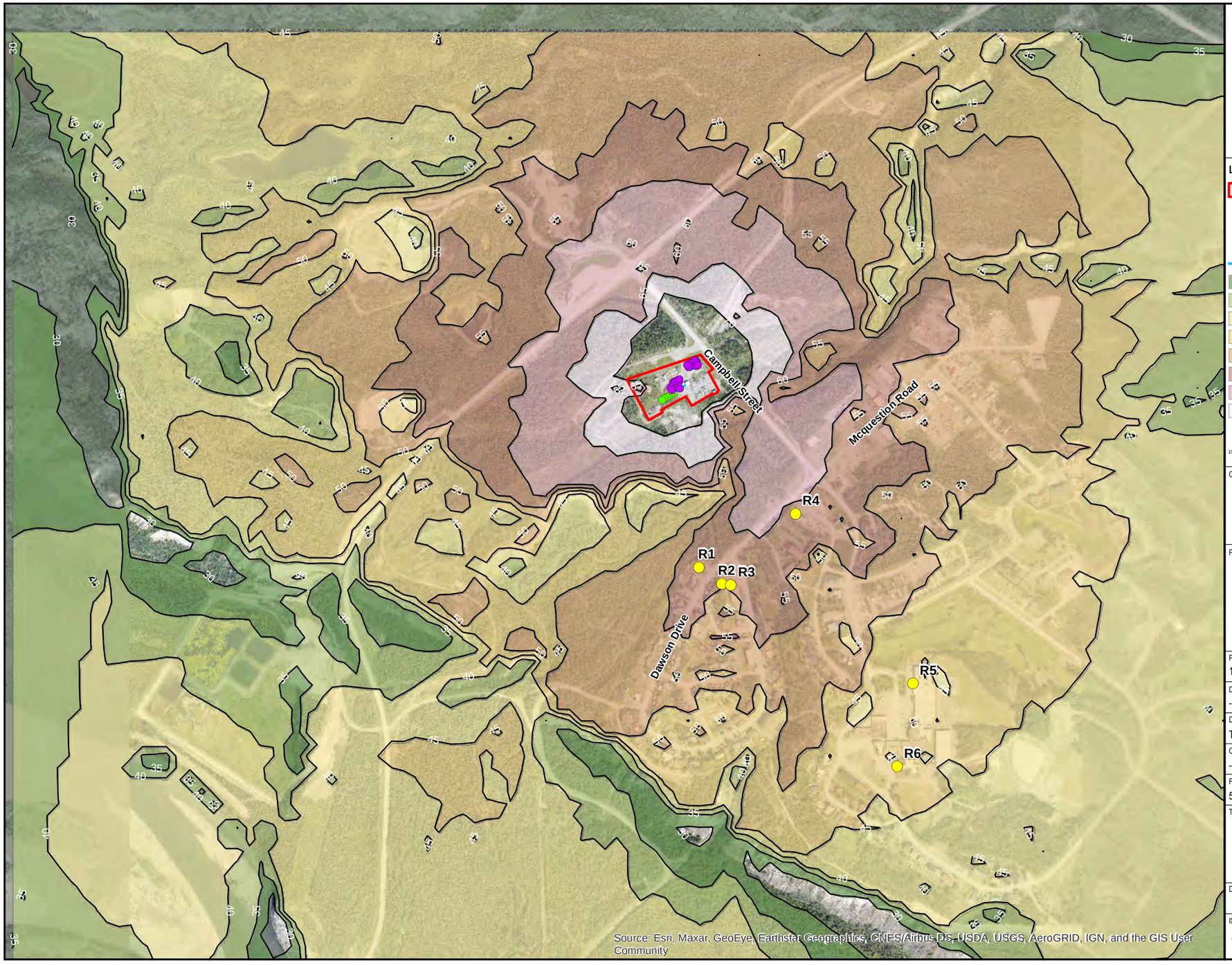
FIGURE NO:	SCALE:
4	1:8,000

TITLE:
EQUVALENT SOUND LEVEL CONTOURS
FOR EXISTING FARO FACILITY

DISCIPLINE:
ENVIRONMENT

ISSUE:	REV.:
-	-

Document Path: D:\aProjects\191-02438-01\MXD\191-02438-01 Figure 4 Contours.mxd



126 DON HILLOCK DRIVE, UNIT 2
AURORA, ONTARIO CANADA L4G 0G9
TEL.: 905-750-3080 | FAX: 905-727-0463 | WWW.WSP.COM

LEGEND

- SITE LOCATION
- REPRESENTATIVE RECEPTORS
- EXISTING NOISE SOURCE LOCATION
- FUTURE SOURCES DUE TO ADDITION
- BREAKOUT NOISE SOURCE LOCATION
- 30 dB
- 35 dB
- 40 dB
- 45 dB
- 50 dB
- 55 dB
- 60 dB
- 65 dB

N W E S

150 75 0 150 Metres

CLIENT:
YUKON ENERGY CORPORATION

PROJECT:
NOISE ASSESSMENT
FARO POWER STATION
FARO, YUKON

PROJECT NO:	DATE:
191-02438-01	NOVEMBER 2020

DESIGNED BY: -

DRAWN BY: TP

CHECKED BY: -

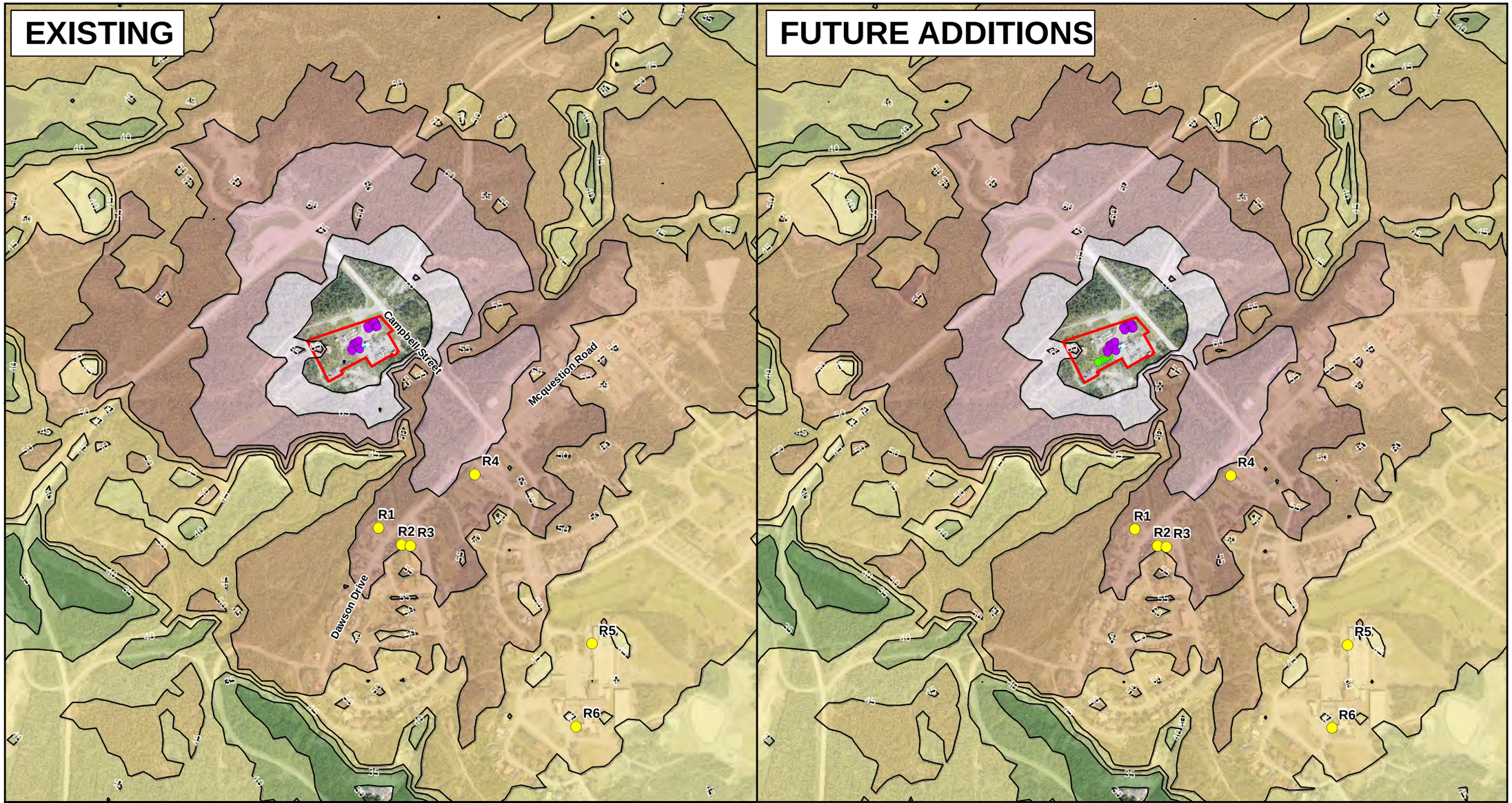
FIGURE NO:	SCALE:
5	1:8,000

TITLE:
EQUVALENT SOUND LEVEL CONTOURS
FOR EXISTING FARO FACILITY
AND FUTURE ADDITIONS

DISCIPLINE:
ENVIRONMENT

ISSUE:	REV.:
-	-

Document Path: D:\aProjects\191-02438-01\MXD\191-02438-01 Figure 5 Contours.mxd



126 DON HILLOCK DRIVE, UNIT 2
AURORA, ONTARIO CANADA L4G 0G9
TEL.: 905-750-3080 | FAX: 905-727-0463 | WWW.WSP.COM

LEGEND

- SITE LOCATION
- REPRESENTATIVE RECEPTORS
- EXISTING NOISE SOURCE LOCATION
- FUTURE SOURCES DUE TO ADDITION
- BREAKOUT NOISE SOURCE LOCATION
- 30 dB
- 35 dB
- 40 dB
- 45 dB
- 50 dB
- 55 dB
- 60 dB
- 65 dB

160 80 0 160 Metres

CLIENT: YUKON ENERGY CORPORATION

PROJECT: NOISE ASSESSMENT
FARO POWER STATION
FARO, YUKON

PROJECT NO: 191-02438-01	DATE: NOVEMBER 2020
DESIGNED BY: -	
DRAWN BY: TP	
CHECKED BY: -	
SCALE: AS SHOWN	

TITLE: EQUVALENT SOUND LEVEL CONTOURS FOR EXISTING FARO FACILITY AND FUTURE ADDITIONS

DISCIPLINE: ENVIRONMENT

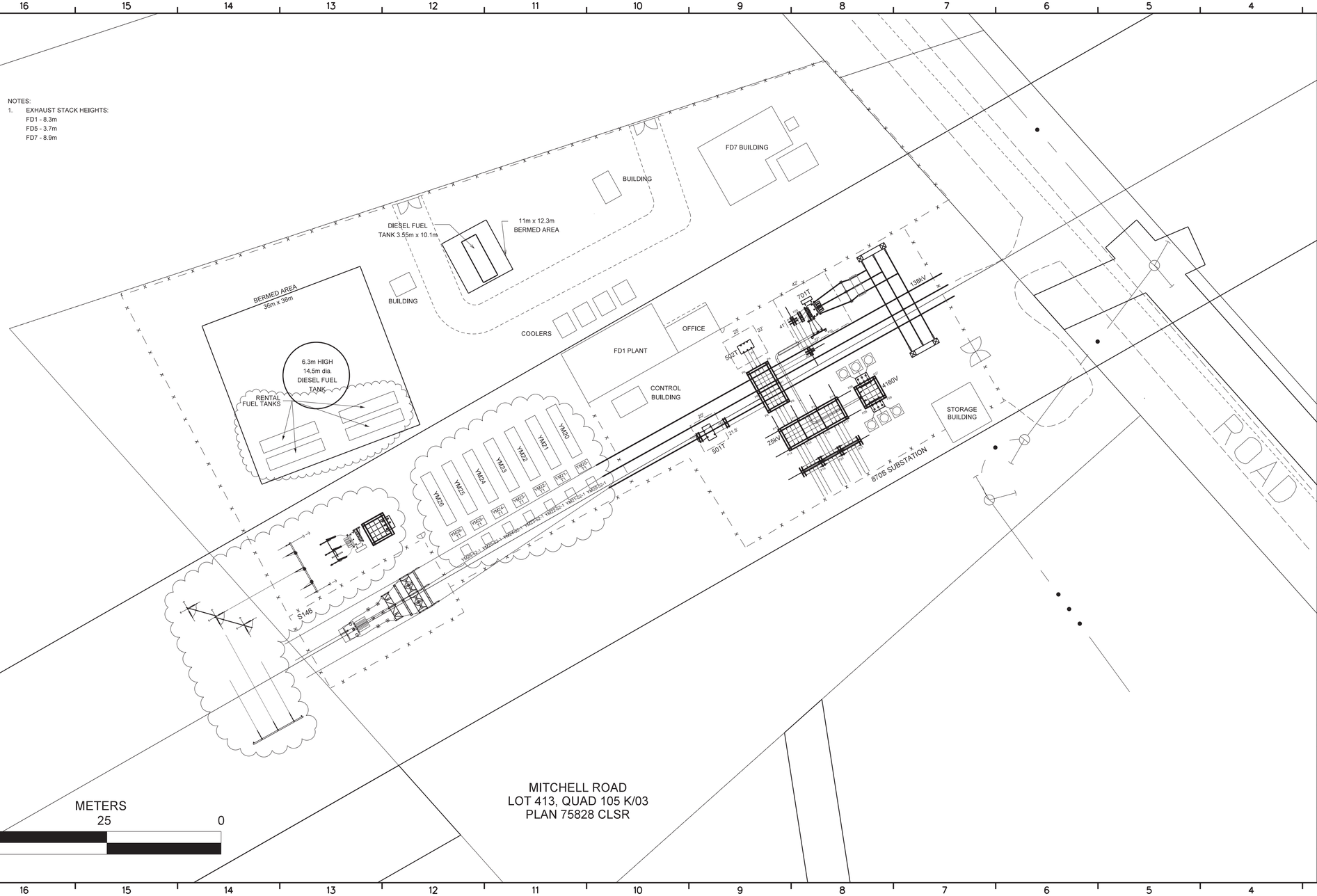
ISSUE: -	FIGURE NO: 6

Document Path: D:\aProjects\191-02438-01\MXD\191-02438-01 Figure 6 Contours.mxd

APPENDIX

A DRAWINGS

NOTES:
1. EXHAUST STACK HEIGHTS:
   FD1 - 8.3m
   FD5 - 3.7m
   FD7 - 8.9m



REFERENCE DRAWINGS

DWG. NO.	DRAWING TITLE

REV.	DATE	DESCRIPTION	BY	DES.	APP.
C	APR 20 2020	UPDATED TX LOCATION	CM	LP	
B	APRIL 14 2020	REVISED TX LOCATION	CM	LP	
A	MAR 19 2020	REVIEW	CM	LP	

COMPANY PERMIT

ENGINEERS STAMP

YUKON ENERGY CORPORATION

C20028 - RENTAL DIESELS

CHECKED BY -
DATE -
DRAWN BY -

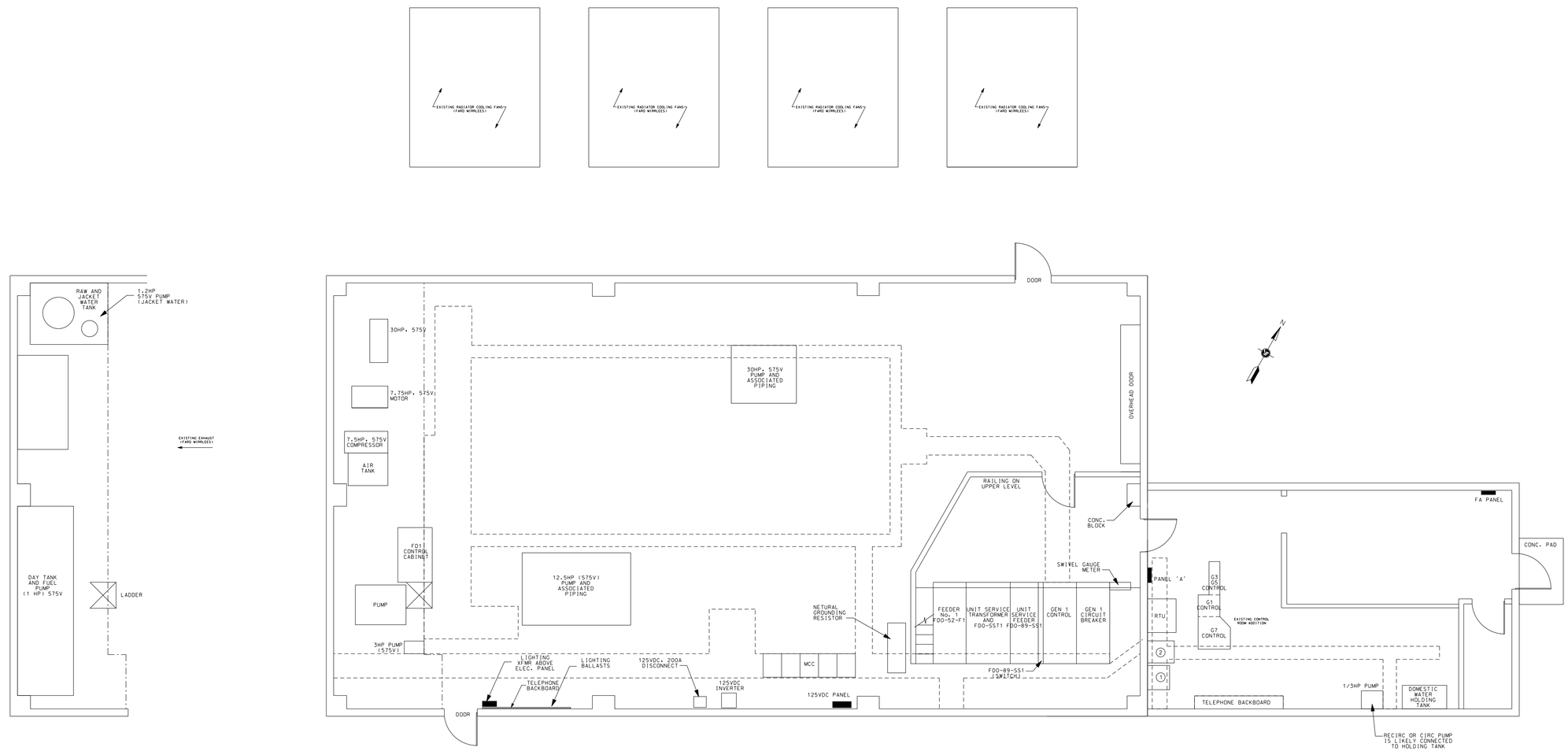
FARO DIESEL & SUBSTATION
SITE PLAN
LOT 413, FARO - YUKON

SCALE A1

farositeplan.dgn

REV. C

THIS DRAWING IS THE PROPERTY OF YUKON ENERGY CORPORATION AND CONTAINS PROPRIETARY AND CONFIDENTIAL INFORMATION WHICH MUST NOT BE DUPLICATED, USED OR DISCLOSED OTHER THAN AS EXPRESSLY AUTHORIZED BY YUKON ENERGY CORPORATION.



MEZZANINE LAYOUT

MAIN FLOOR LAYOUT

(1) POWERLINE CARRIER FARO-TAKHINI

(2) OLD PLC/MARSHALLING CABINET

FARO FD1 PLANT

COMPILED FROM P131-1003, P131-608

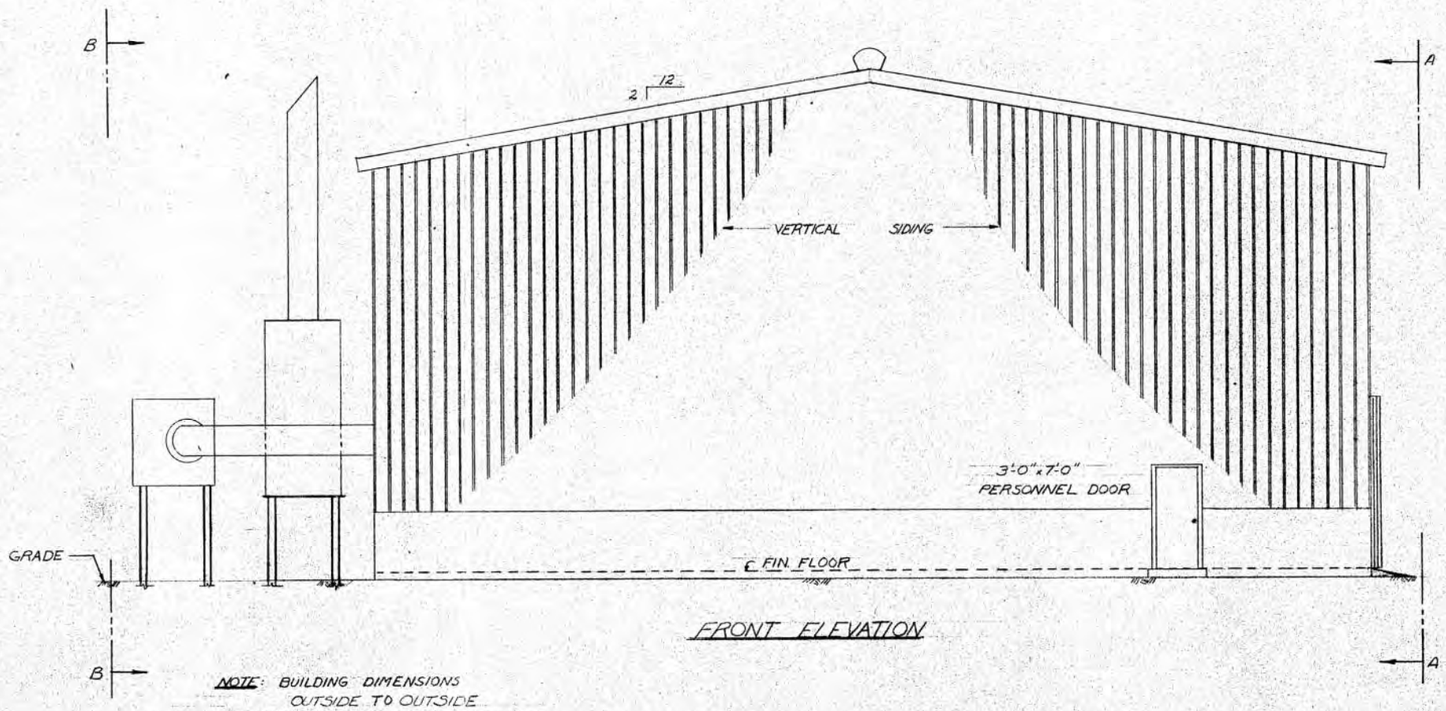
FOR REFERNCE ONLY

CADD

YUKON ENERGY CORPORATION

| | | |

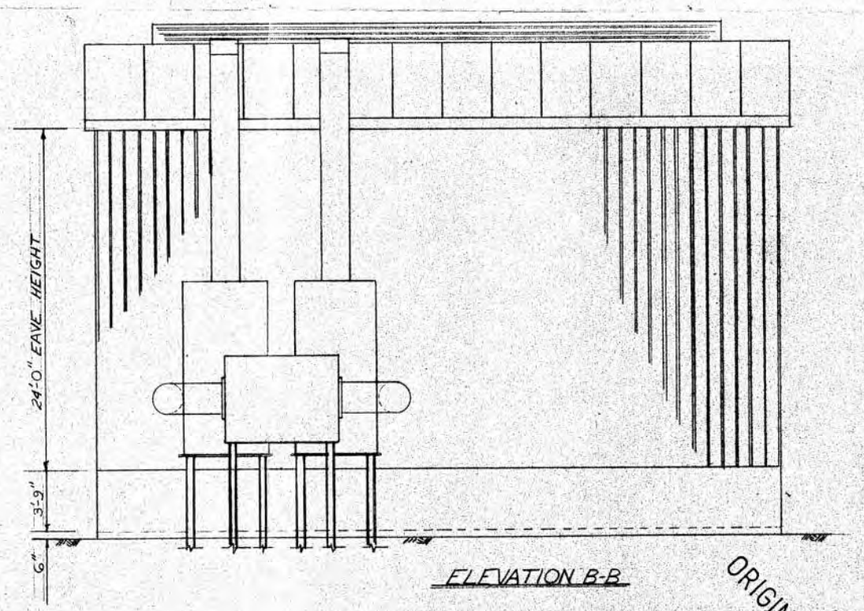
REAR ELEVATION



FRONT ELEVATION

NOTE: BUILDING DIMENSIONS
OUTSIDE TO OUTSIDE
70'-0" (ENDWALL) x 48'-0" (SIDEWALL)
BAY SPACING TO BE 24'-0"

ELEVATION A-A



ELEVATION B-B

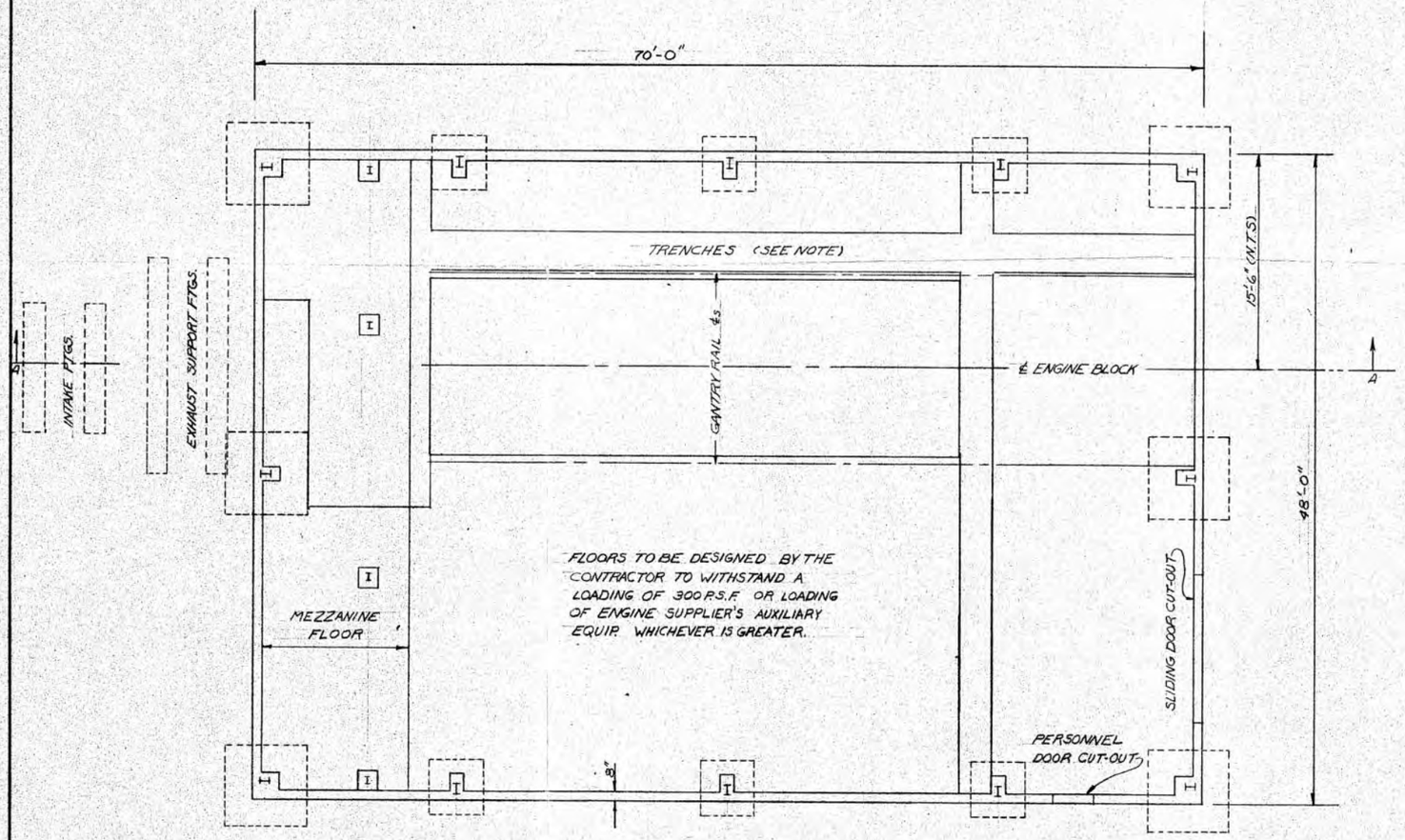
ORIGINAL

PRELIMINARY ONLY
NOT FOR CONSTRUCTION

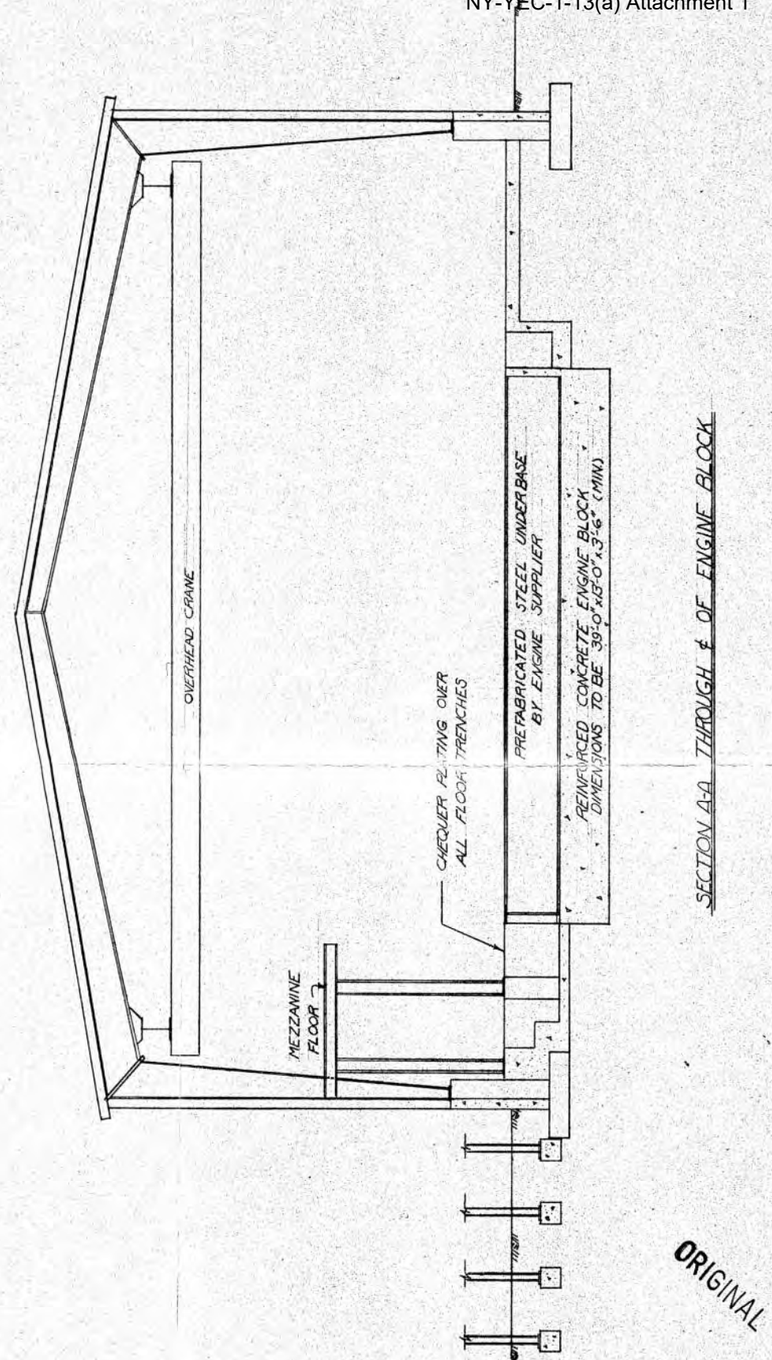
NORTHERN CANADA POWER COMMISSION
FARO, Y.T.
1970 DIESEL STAND-BY PLANT
ELEVATIONS

DCP	ETM&K	FEB 13,70	
D.C.P.		3/32"=1'-0"	

NOTES: 1) FTGS. & COLUMNS SHOWN ARE APPROX. ONLY. CONTRACTOR TO DESIGN SAME IN CO-ORDINATION WITH BUILDING SUPPLIER. ALLOWABLE SOIL BEARING = 2000 P.S.F.
2) FTGS. FOR INTAKE & EXHAUST SUPPORTS AS WELL AS ALL FLOOR TRENCHING SHALL BE DESIGNED BY THE CONTRACTOR IN CO-ORDINATION WITH THE ENGINE SUPPLIER.



FOUNDATION PLAN



SECTION A-A THROUGH ℄ OF ENGINE BLOCK

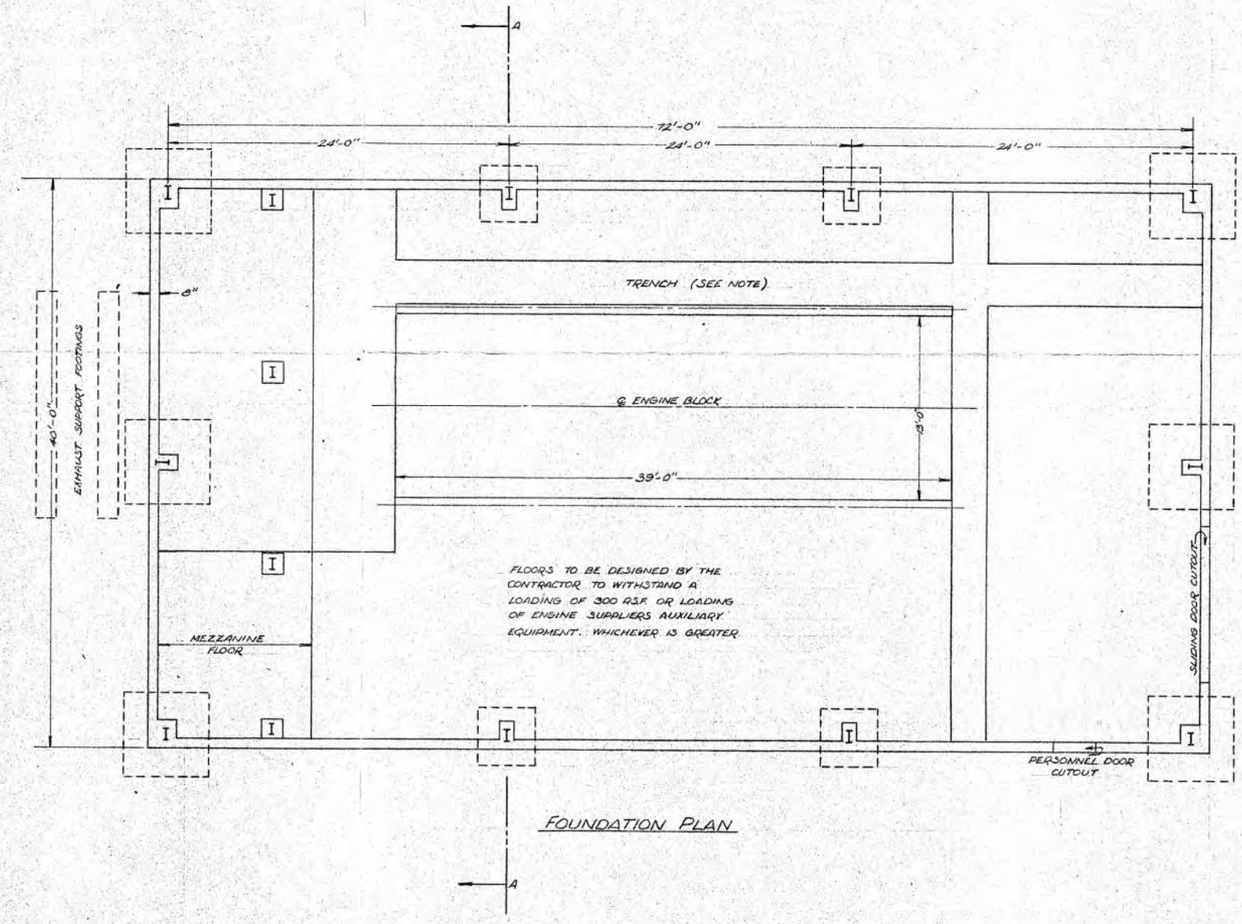
ORIGINAL

PRELIMINARY ONLY
NOT FOR CONSTRUCTION

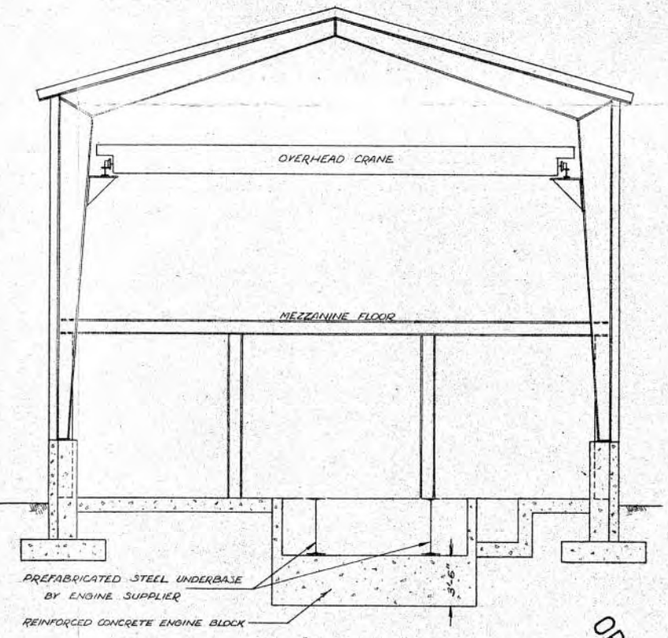
NORTHERN CANADA POWER COMMISSION			
FARO, Y.T.			
1970 DIESEL STANDBY PLANT FOUNDATION PLAN & SECTION			
DRAWN D.C.P	CHECKED K.N.C	DATE FEB 15, 1970	DRAWING WH-1678
REVISED	APPROVED	SCALE 3/16"=1'-0"	SHEET 1 OF 1

NOTE: (1) FTGS. & COLUMNS SHOWN ARE APPROX. ONLY. CONTRACTOR TO DESIGN SAME IN CO-ORDINATION WITH BUILDING SUPPLIER. ALLOWABLE SOIL BEARING = 2000 P.S.F.

(2) FTGS. FOR INTAKE & EXHAUST SUPPORTS AS WELL AS ALL FLOOR TRENCHING SHALL BE DESIGNED BY THE CONTRACTOR IN CO-ORDINATION WITH THE ENGINE SUPPLIER.



FOUNDATION PLAN



SECTION A-A

ORIGINAL

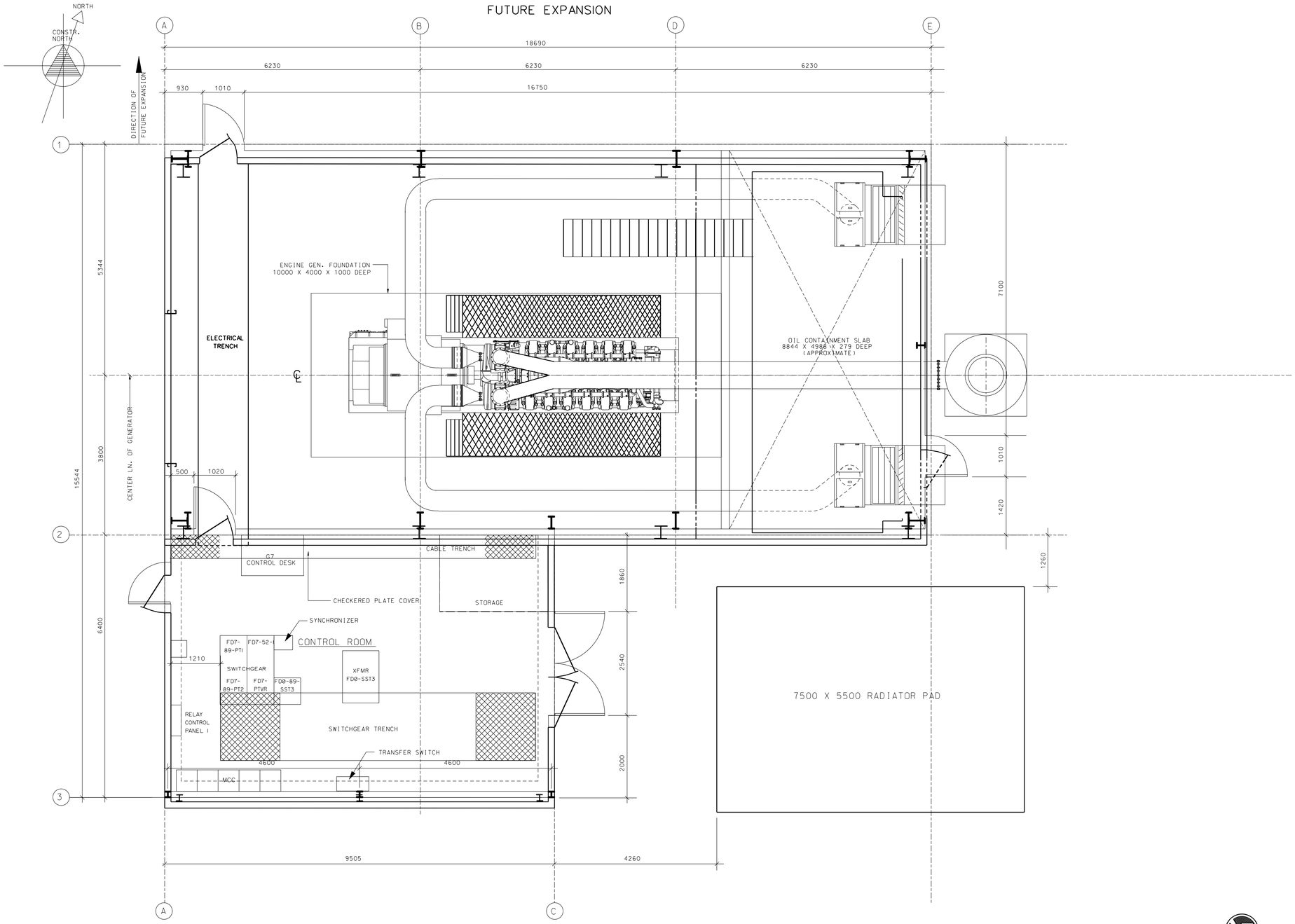
PRELIMINARY ONLY
NOT FOR CONSTRUCTION

NORTHERN CANADA POWER COMMISSION

FARO, Y.T.

1970 DIESEL STAND-BY PLANT
FOUNDATION
PLAN & SECTION (ALTERNATIVE 2)

DRAWN	CHECKED	DATE	DRAWING No.
DR	E. MACK	28 FEB, '70	114-1702
DESIGNED	APPROVED	SCALE 3/16" = 1'-0"	



CADD

MAIN FLOOR LAYOUT

YUKON ENERGY CORPORATION

NO.	DATE	REVISIONS	BY	CIVIL	DESIGN	E.LEC	MECH	PROT	STND	P.ENG	E.MAN
Ø	15-DEC-06	AS BUILT EXISTING EQUIPMENT - M06Ø1Ø	TARA		CC/AL						
C	29-JUL-92	REVISED	S.C.		PGG						
B	11-JUN-92	REVISED	LGP		WDV						
A	19-MAY-92	PRELIMINARY	S.C.		WDV						

NO.	DATE	REVISIONS	BY	CIVIL	DESIGN	E.LEC	MECH	PROT	STND	P.ENG	E.MAN

REF. DWG. NO.	REF. DWG. TITLE
YE03-20200, Rev. C	APL DRAWING - FROM CONSTRUCTION

APPROVALS		DATE	APPROVALS		DATE
PROTECTION			MECHANICAL		
STANDARD			CIVIL		
PROJECT ENG.			DESIGN		
ENG. MANAGER			ELECTRICAL		

FARO - FD7 BUILDING
EQUIPMENT LAYOUT
PLAN VIEW
SHEET 1 OF 2

DRAWN	DESIGN BY	SCALE
S. CLARK	D. VERVEDA	NTS

AI DWG. NO. YE03-20200 REV. Ø

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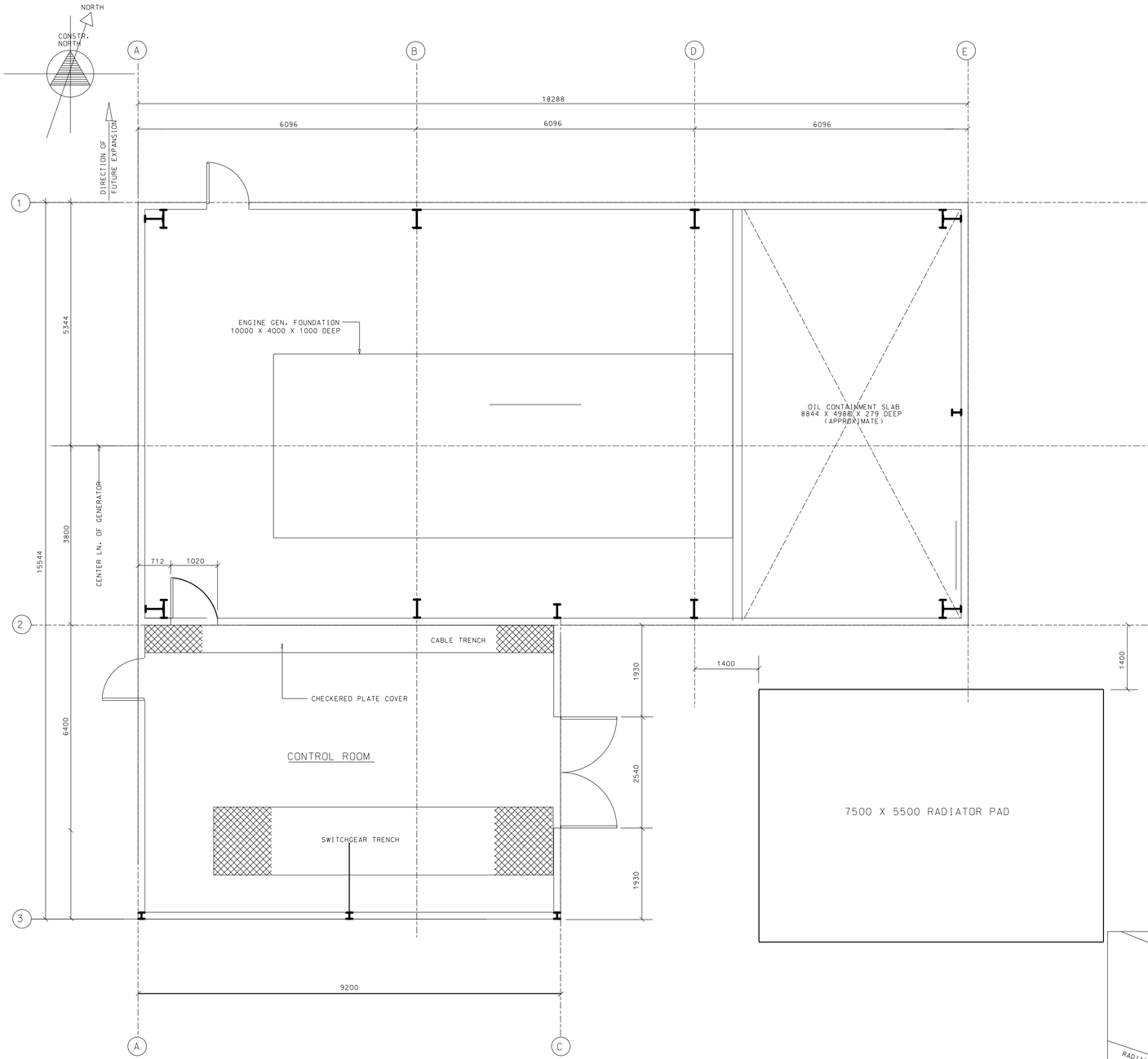
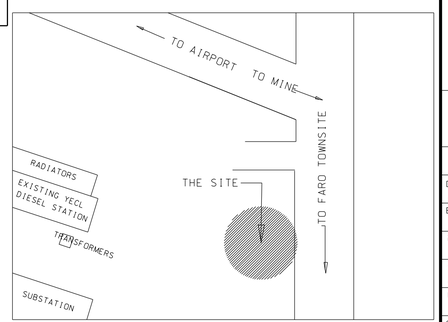


MAIN FLOOR LAYOUT
SCALE 1 : 50 M.



SITE MAP
NOT TO SCALE

REFERENCE DRAWINGS

DWG NO.	DRAWING TITLE
YE03 - 20151	BUILDING PLAN VIEW
YE03 - 20102	PRELIMINARY BUILDING LAYOUT
YE03 - 20608	UNDER SLAB CONDUIT LAYOUT
YE03 - 20700	UNDER SLAB LAYOUT DETAILS

NOTES:

1. FOR PVC PIPES LOCATION SEE ELECTRICAL DWG. NO'S. YE03-50608 & YE03-50700.
2. TOP OF CONCRETE (ASSUMED ELEVATION = 100.00) SHOULD BE AT LEAST 200 MM ABOVE GRADE.

REV.	DATE	DESCRIPTION	BY	DES.	APP.
0	APR 16/93	AS BUILT	LGP	AMV	
6	MAR 08/93	REMOVED ENGINE OUTLINE	LGP	AMV	AMV
5	AUG 17/92	MOVED RADIATOR PAD	S.C.	AMV	AMV
4	AUG 11/92	ADDED MANUAL CHANGES	S.C.	AMV	AMV
3	JULY 20/92	REVISED NOTE 2	CEU	AMV	AMV
2	JULY 09/92	PVC PIPES LOCATION REMOVED. NOTES ADDED. ENGINE GEN. ANCHOR BOLTS REMOVED	CEU	AMV	AMV
1	JUNE 24/92	RADIATOR PAD. SWITCH GEAR PAD CHANGED.	CEU	AMV	AMV

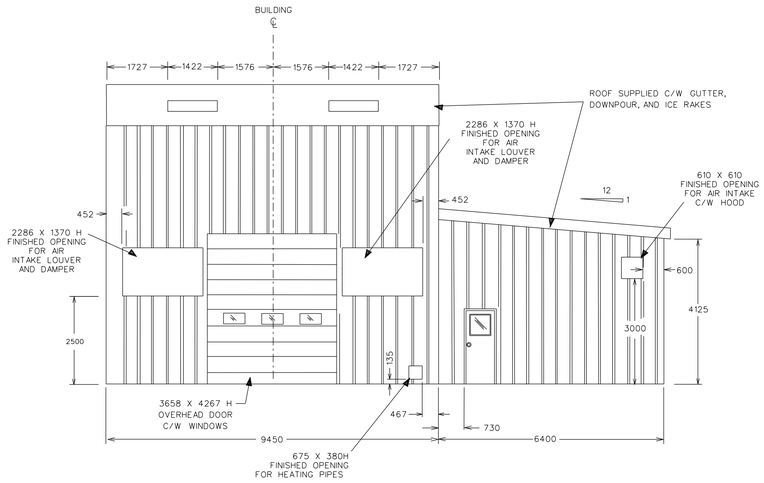
COMPANY PERMIT

ENGINEERS STAMP

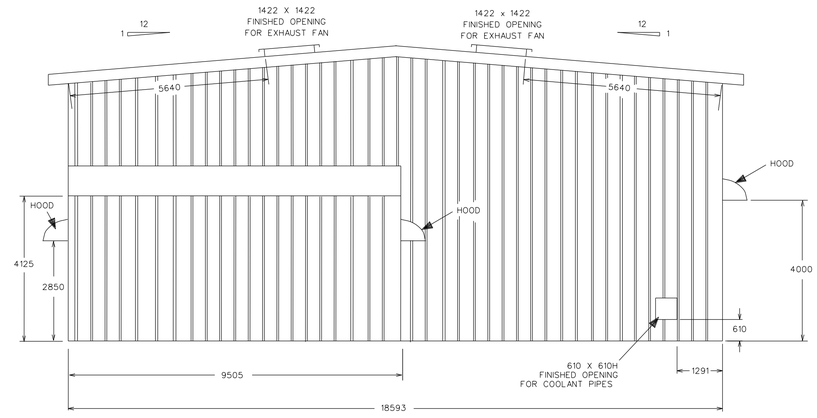
ALBERTA POWER LIMITED

THE YUKON ELECTRICAL CO. LTD.

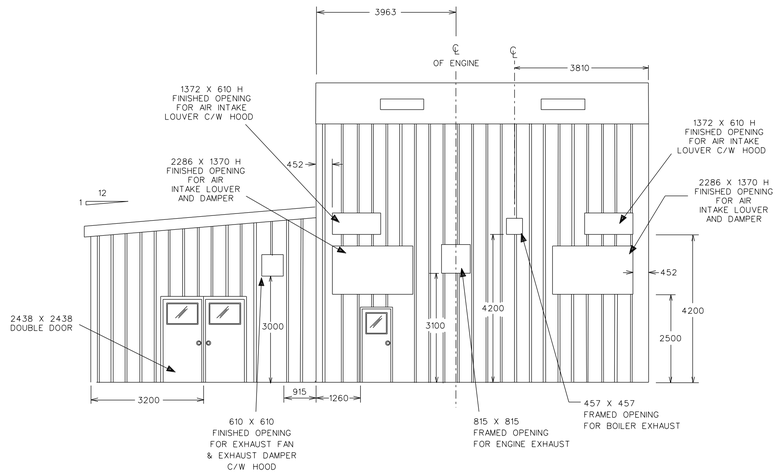
DESIGN A.M.VILLARAZA	1992 FARO ADDITION
ELECTRICAL	
MECHANICAL	
STRUCTURAL A.M.VILLARAZA	MAIN FLOOR LAYOUT SITE MAP
DRAWN C.E.USON	
SCALE AS NOTED	S1 DWG. NO: YE03-20100 RØ
CAD-Y0320100	



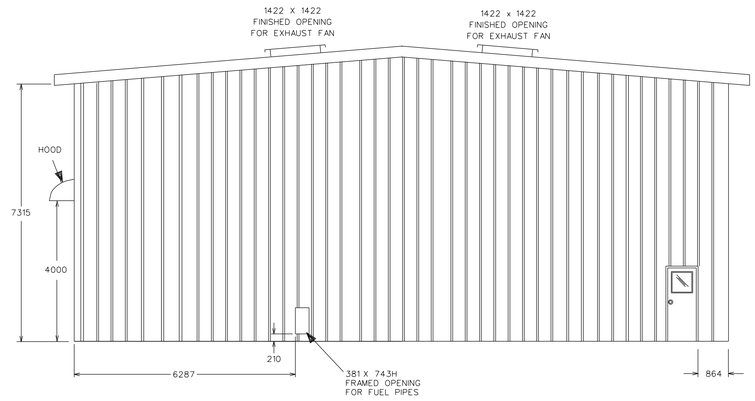
FRONT VIEW



RIGHT SIDE VIEW



REAR VIEW



LEFT SIDE VIEW

REFERENCE DRAWINGS

DWG. NO.	DRAWING TITLE

NOTES:

1. CONTRACTOR SHALL SUPPLY ALL FLASHING AND INSULATION REQUIRED TO COMPLETE ANY PIPE OPENINGS ONCE THE PIPES HAVE BEEN INSTALLED.
2. ALL EXHAUST FANS, LOUVERS, AND DAMPERS SHALL BE PROVIDED BY OTHERS; BUT INSTALLED BY THE BULDING CONTRACTOR. HOODS SUPPLIED BY CONTRACTOR.

REV.	DATE	DESCRIPTION	BY	DES.	APP.
0	APR 19/93	AS BUILT	LGP	PGG	
C	MAR 08/93	REVISED	LGP	PGG	PGG
B	JULY 15/92	REVISED	S.C.	PGG	PGG
A	JUNE 04/92	PRELIMINARY	S.C.	PGG	PGG

COMPANY PERMIT

ENGINEERS STAMP

YUKON ENERGY CORPORATION

YUKON ELECTRICAL CO. LTD.

P. GOGUEN

CHECKED BY P. GOGUEN

DATE

DRAWN BY S.CLARK

SCALE 1 TO 80 | A1

CAD-Y0320150

FARO 1992 ADDITION BUILDING EXTERIOR VIEWS

DWG. NO: YE03-20150

REV. 0

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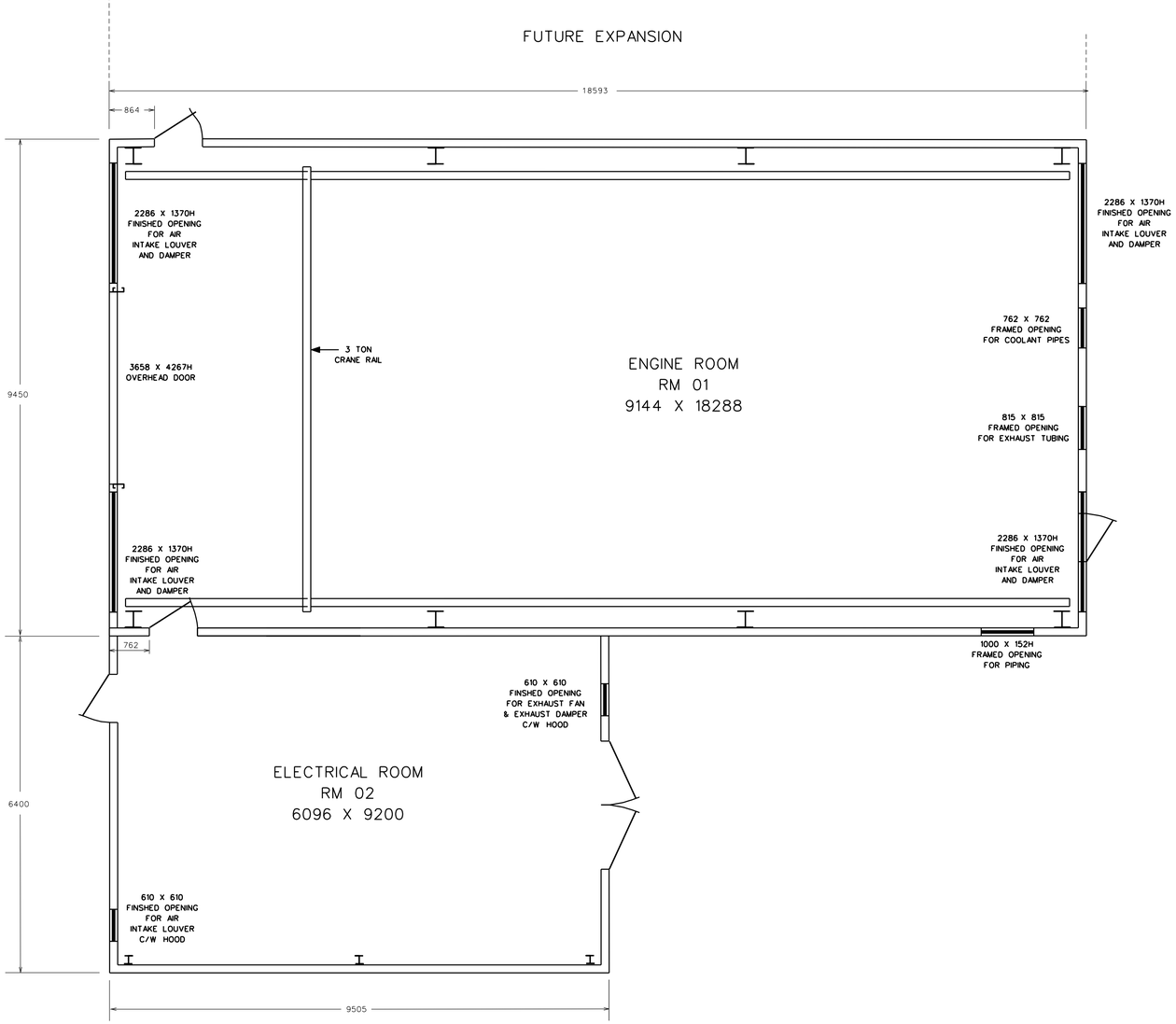
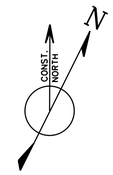
ROOM NAME	ROOM NO.	FLOOR FINISH	WALL FINISHES	CEILING FINISH	EXITS			FRAMED OPENING		FRAMED OPENING APPLICATION	
ENGINE ROOM	01	FINISHED CONCRETE	PREPAINTED WHITE SHEET STEEL	PREPAINTED WHITE SHEET STEEL	2 - 915 X 2135 MANDOOR EXITS TO EXTERIOR	1 - 915 X 2135 MANDOOR EXITS TO ROOM 02	1 - 3658 X 4267H OVERHEAD DOOR EXITS TO EXTERIOR	4 - 2286 X 1370H 2 - 1372 X 610H 1 - 457 X 457 1 - 381 X 743H	1 - 815 X 815 1 - 610 x 610 4 - 1232 X 1232 1 - 675 X 380H	4 - AIR INTAKES 2 - AIR INTAKES 1 - BOILER EXHAUST 1 - FUEL PIPING	1 - ENGINE EXHAUST 1 - COOLANT PIPE OPENING 1 - ROOF TOP FAN 1 - HEATING PIPES
ELECTRICAL ROOM	02	FINISHED CONCRETE	PREPAINTED WHITE SHEET STEEL	PREPAINTED WHITE SHEET STEEL	1 - 2438 X 2438 DOUBLE MANDOOR EXITS TO EXTERIOR	1 - 915 X 2135 MANDOOR EXITS TO EXTERIOR	1 - 915 X 2135 MANDOOR EXITS TO ROOM 02	2 - 610 X 610		1 - AIR INTAKE 1 - AIR EXHAUST	





REFERENCE DRAWINGS

DWG. NO.	DRAWING TITLE

LEGEND

FINISHED OPENING

NOTES:

1. SOME FRAMED OPENINGS ARE NOT SHOWN FOR CLARITY PURPOSES.
2. THE CONTRACTOR SHALL SUPPLY ALL FLASHING AND INSULATION REQUIRED TO COMPLETE ANY PIPE OPENINGS ONCE THE PIPES HAVE BEEN INSTALLED.
3. ALL EXHAUST FANS, LOUVERS, AND DAMPERS SHALL BE PROVIDED BY OTHERS; BUT INSTALLED BY THE BUILDING CONTRACTOR.
4. BUILDING STRUCTURAL SHALL BE DESIGNED TO ACCOMMODATE FUTURE EXPANSION.

REV.	DATE	DESCRIPTION	BY	DES.	APP.
Ø	APR 16/93	AS BUILT	LGP	PGG	
C	MAR 09/93	REVISED	LGP	PGG	PGG
B	JULY 15/92	REVISED	S.C.	PGG	PGG
A	JUNE 04/92	PRELIMINARY	S.C.	PGG	PGG

COMPANY PERMIT

APPROVED FOR CONSTRUCTION

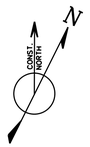
DATE — BRANCH HEAD CIVIL
DATE — BRANCH HEAD ELECTRICAL
DATE — BRANCH HEAD MECHANICAL
DATE — BRANCH HEAD CONSTRUCTION

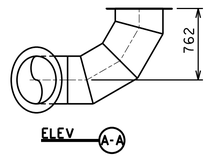
ENGINEERS STAMP

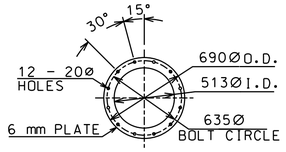
ALBERTA POWER LIMITED

YUKON ELECTRICAL CO. LTD.

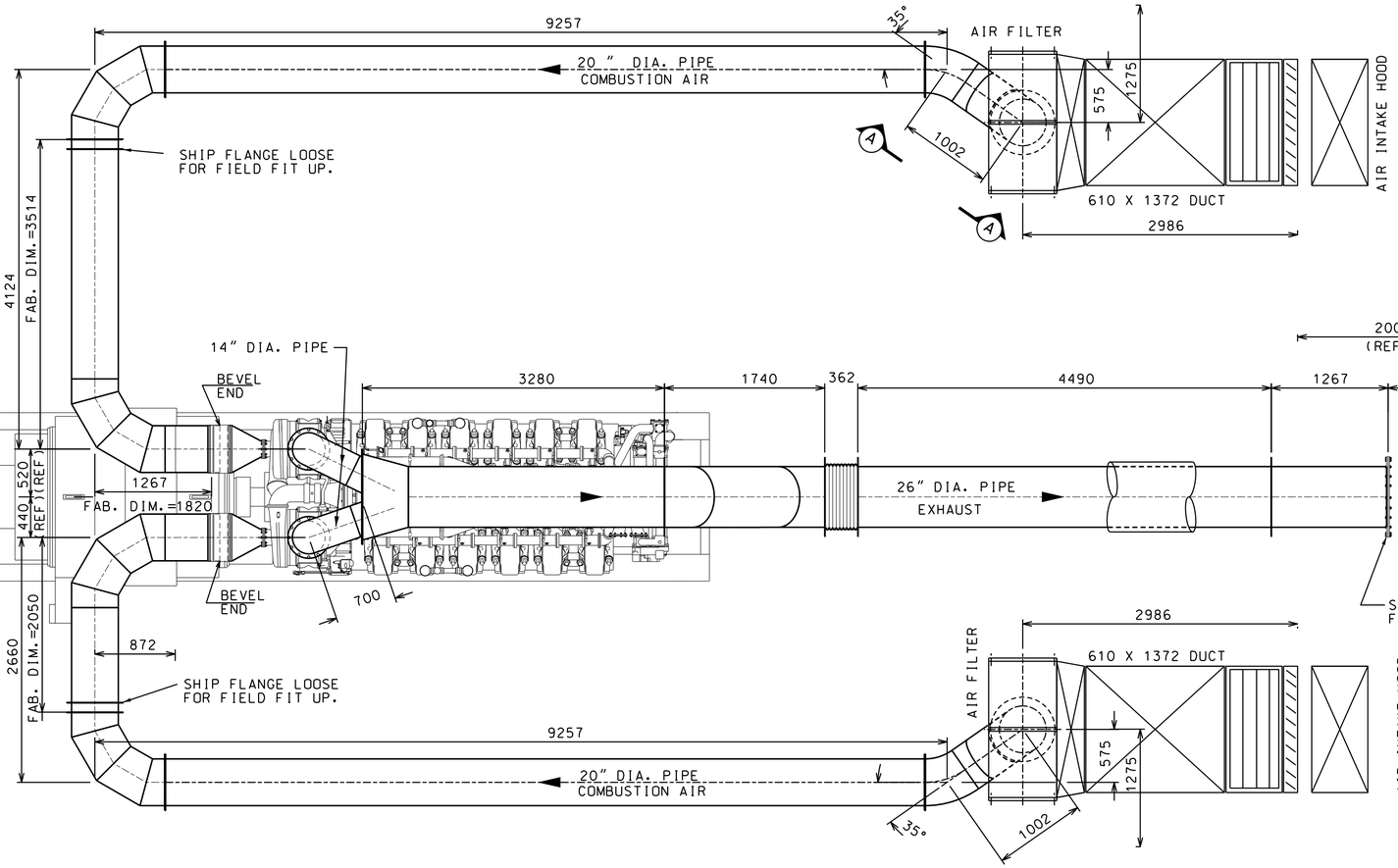
DESIGN P. GOGUEN	FARO 1992 ADDITION BUILDING PLAN VIEW
ELECTRICAL	
MECHANICAL P. GOGUEN	
OTHER	
DRAWN S.CLARK	
SCALE 1 TO 50 A1	DWG. NO: YE03-20151 REV. 0
CAD-Y0320151	







FLANGE DETAIL
SCALE= 1 : 20
QUAN.: 16 REQ'D



REFERENCE DRAWINGS

DWG. NO.	DRAWING TITLE
YE03 - 20502	ENGINE COMBUSTION AIR AND EXHAUST SYSTEM ELEVATION VIEW

REV.	DATE	DESCRIPTION	BY	DES.	APP.
1	MAY 26/93	AS BUILT REVISED	LGP	PGG	
0	APR 19/93	AS BUILT	LGP	PGG	PGG
D	MAR 10/93	PRELIMINARY	LGP	PGG	PGG
C	SEPT. 15/92	ISSUED FOR CONSTRUCTION	GR	E.H.	E.H.
B	SEPT. 01/92	ISSUED FOR BID	GR	I.C.	I.C.
A	JULY 16/92	PRELIMINARY	LGP	WDV	WDV

COMPANY PERMIT

ENGINEERS STAMP

YUKON ENERGY CORPORATION

THE YUKON ELECTRICAL CO. LTD.

D. VERVEDA

CHECKED BY
D. VERVEDA

DATE

DRAWN BY
S. CLARK

FARO 1992 ADDITION ENGINE COMBUSTION AIR AND EXHAUST SYSTEM PLAN VIEW

SCALE
1 : 30
A1

CAD-Y0320501

DWG. NO.:YE03-20501

REV.
1

YE03-20501

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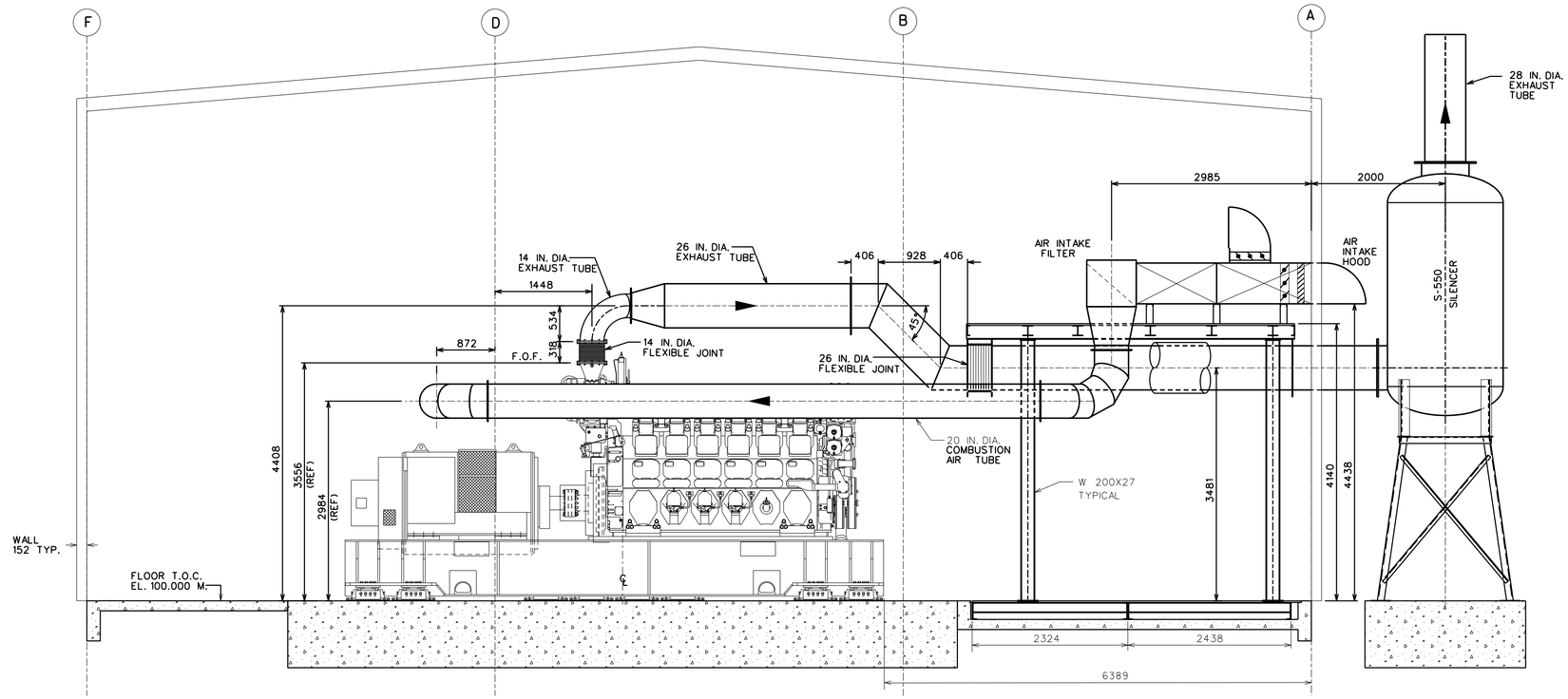
REFERENCE DRAWINGS	
DWG. NO.	DRAWING TITLE
YE03 -20501	ENGINE COMBUSTION AIR & EXHAUST SYSTEM PLAN VIEW
YE03 -20556	SILENCER SUPPORT STAND



ELEVATION LOOKING NORTH
@ COLUMN LINE 2

REV.	DATE	DESCRIPTION	BY	DES.	APP.
1	MAY 26/93	AS BUILT REVISED	LGP	PGG	
0	APR 19/93	AS BUILT	SC	PGG	PGG
B	NOV. 12/92	ISSUED FOR CONSTRUCTION	GR	PGG	PGG
A	JULY 21/92	PRELIMINARY	LGP	WDV	WDV

COMPANY PERMIT

ENGINEERS STAMP

YUKON ENERGY CORPORATION

THE YUKON ELECTRICAL CO. LTD

D.VERVEDA

CHECKED BY D.VERVEDA

DATE

DRAWN BY S.CLARK

SCALE 1 TO 40 A1

CAD-Y0320502

FARO 1992 ADDITION ENGINE COMBUSTION AIR AND EXHAUST SYSTEM ELEVATION VIEW

DWG. NO: YE03-20502

REV. 1

YE03-20502

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APPENDIX

B TABLES

Project Name: Noise Assessment
Site Name: FARO Power Station
WSP Job #: 191-02438-01

Table 1: Noise Source Summary Table

Noise Source ID	Source Description	Sound Power Level [1] (dBA)	Source Location [2] (I or O)	Sound Characteristics [3] (S,Q,I,B,T,C)	Noise Control Measures [4] (S,A,B,L,E,O,U)
Existing Sources					
FD1_GEN_EXH1	FD1 2.4 MW Generator Combustion Exhaust	136	O	S	S
FD1_GEN_EXH2	FD1 2.4 MW Generator Combustion Exhaust	136	O	S	S
FD1_GEN_INT1	FD1 2.4 MW Generator Intake	118	O	S	S
FD1_GEN_INT2	FD1 2.4 MW Generator Intake	118	O	S	S
FD1_BLD_DIS1	FD1 2.4 MW Building Discharge	111	O	S	S
FD1_BLD_INT1	FD1 2.4 MW Building Intake	111	O	S	S
FD1_GEN_RAD1	FD1 2.4 MW Generator Radiator	114	O	S	U
FD1_GEN_RAD2	FD1 2.4 MW Generator Radiator	114	O	S	U
FD1_GEN_RAD3	FD1 2.4 MW Generator Radiator	114	O	S	U
FD1_GEN_RAD4	FD1 2.4 MW Generator Radiator	114	O	S	U
FD1_BLD_OUT1	FD1 2.4 MW Building Breakout Noise	116	O	S	U
FD1_BLD_OUT2	FD1 2.4 MW Building Breakout Noise	116	O	S	U
FD7_GEN_EXH1	FD7 2.8 MW Generator Combustion Exhaust	140	O	S	U
FD7_BLD_INT1	FD7 2.8 MW Building Intake	115	O	S	U
FD7_BLD_INT2	FD7 2.8 MW Building Intake	115	O	S	U
FD7_BLD_INT3	FD7 2.8 MW Building Intake	115	O	S	U
FD7_BLD_INT4	FD7 2.8 MW Building Intake	115	O	S	U
FD7_GEN_INT1	FD1 2.8 MW Generator Intake	109	O	S	U
FD7_GEN_INT2	FD1 2.8 MW Generator Intake	109	O	S	U
FD7_BLD_DIS1	FD1 2.8 MW Building Discharge Fan	114	O	S	U
FD7_BLD_DIS2	FD1 2.8 MW Building Discharge Fan	114	O	S	U
FD7_BLD_DIS3	FD1 2.8 MW Building Discharge Fan	114	O	S	U
FD7_BLD_DIS4	FD1 2.8 MW Building Discharge Fan	114	O	S	U
FD7_GEN_RAD1	FD7 2.8 MW Generator Radiator	112	O	S	U
FD7_GEN_RAD2	FD7 2.8 MW Generator Radiator	112	O	S	U
FD7_BLD_OUT1	FD7 2.8 MW Building Breakout Noise	115	O	S	U
FD7_BLD_OUT2	FD7 2.8 MW Building Breakout Noise	115	O	S	U
Future Sourcs due to Addition					
YM20_GEN_CAS	YM20 1.8 MW Generator Casing	103	O	S	E
YM21_GEN_CAS	YM21 1.8 MW Generator Casing	103	O	S	E
YM22_GEN_CAS	YM22 1.8 MW Generator Casing	103	O	S	E
YM23_GEN_CAS	YM23 1.8 MW Generator Casing	103	O	S	E
YM24_GEN_CAS	YM24 1.8 MW Generator Casing	103	O	S	E
YM25_GEN_CAS	YM25 1.8 MW Generator Casing	103	O	S	E
YM26_GEN_CAS	YM26 1.8 MW Generator Casing (Backup)	n/a	O	S	E

Notes:

[1] Sound Power Level of Source, in dBA

[2] Source Location:

O	located/installed outside the building
I	located/installed inside the building

[3] Sound Characteristics:

S	Steady
Q	Quasi Steady Impulsive
I	Impulsive
B	Buzzing
T	Tonal
C	Cyclic
O	Occasional
W	Time Weighted (factor applied)

[4] Noise Control Measures:

S:	silencer, acoustic louver
A:	acoustic lining, plenum
B:	barrier, berm, screening
L:	lagging
E:	acoustic enclosure
O:	other
U:	uncontrolled

Project Name: Environmental Compliance Approval - Air and Noise
Site Name: FARO Power Station
WSP Job #: 191-02438-01

Table 2: Significant Noise Source Summary

Noise Source ID	Noise Source Description	Source Type	Cadna Sound Library ID	Height Above Grade	Source Coordinates		Octave band sound power spectra (dB)								Overall dB	Overall dBA
				(m)	(x)	(y)	63	125	250	500	1K	2K	4K	8K		
Existing Sources																
FD1_GEN_EXH1	FD1 2.4 MW Generator Combustion Exhaust	Point	FD1_GEN_EXH	8.7	585143	6901251	139	145	141	133	127	120	109	102	147	136
FD1_GEN_EXH2	FD1 2.4 MW Generator Combustion Exhaust	Point	FD1_GEN_EXH	8.7	585143	6901249	139	145	141	133	127	120	109	102	147	136
FD1_GEN_INT1	FD1 2.4 MW Generator Intake	Point	FD1_GEN_INT	5.0	585138	6901251	113	116	116	114	113	112	106	100	122	118
FD1_GEN_INT2	FD1 2.4 MW Generator Intake	Point	FD1_GEN_INT	9.4	585141	6901246	113	116	116	114	113	112	106	100	122	118
FD1_BLD_DIS1	FD1 2.4 MW Building Discharge	Point	FD1_BLD_DIS	9.4	585155	6901262	104	108	108	106	106	105	99	92	114	111
FD1_BLD_INT1	FD1 2.4 MW Building Intake	Point	FD1_BLD_INT	9.4	585158	6901249	106	109	109	107	106	105	99	94	115	111
FD1_GEN_RAD1	FD1 2.4 MW Generator Radiator	Point	FD1_GEN_RAD6	2.0	585143	6901262	96.0	122.0	114.0	109.0	108.0	104.0	100.0	95.0	123	114
FD1_GEN_RAD2	FD1 2.4 MW Generator Radiator	Point	FD1_GEN_RAD6	2.0	585148	6901264	96.0	122.0	114.0	109.0	108.0	104.0	100.0	95.0	123	114
FD1_GEN_RAD3	FD1 2.4 MW Generator Radiator	Point	FD1_GEN_RAD6	2.0	585152	6901267	96.0	122.0	114.0	109.0	108.0	104.0	100.0	95.0	123	114
FD1_GEN_RAD4	FD1 2.4 MW Generator Radiator	Point	FD1_GEN_RAD6	2.0	585156	6901269	96.0	122.0	114.0	109.0	108.0	104.0	100.0	95.0	123	114
FD1_BLD_OUT1	FD1 2.4 MW Building Breakout Noise	V.Area	FD1_BLD_OUT	8.9	Varies	Varies	112.0	115.0	115.0	112.0	111.0	110.0	104.0	99.0	121	116
FD1_BLD_OUT2	FD1 2.4 MW Building Breakout Noise	V.Area	FD1_BLD_OUT	8.9	Varies	Varies	112.0	115.0	115.0	112.0	111.0	110.0	104.0	99.0	121	116
FD7_GEN_EXH1	FD7 2.8 MW Generator Combustion Exhaust	Point	FD7_GEN_EXH	7.5	585193	6901305	143.0	149.0	145.0	137.0	132.0	126.0	116.0	109.0	151	140
FD7_BLD_INT1	FD7 2.8 MW Building Intake	Point	FD7_BLD_INT	3.9	585177	6901293	108.0	112.0	112.0	110.0	110.0	109.0	103.0	96.0	118	115
FD7_BLD_INT2	FD7 2.8 MW Building Intake	Point	FD7_BLD_INT	3.9	585173	6901299	108.0	112.0	112.0	110.0	110.0	109.0	103.0	96.0	118	115
FD7_BLD_INT3	FD7 2.8 MW Building Intake	Point	FD7_BLD_INT	3.9	585190	6901308	108.0	112.0	112.0	110.0	110.0	109.0	103.0	96.0	118	115
FD7_BLD_INT4	FD7 2.8 MW Building Intake	Point	FD7_BLD_INT	3.9	585193	6901302	108.0	112.0	112.0	110.0	110.0	109.0	103.0	96.0	118	115
FD7_GEN_INT1	FD1 2.8 MW Generator Intake	Point	FD7_GEN_INT	4.8	585190	6901308	102.0	106.0	106.0	104.0	104.0	103.0	97.0	91.0	112	109
FD7_GEN_INT2	FD1 2.8 MW Generator Intake	Point	FD7_GEN_INT	4.8	585193	6901302	102.0	106.0	106.0	104.0	104.0	103.0	97.0	91.0	112	109
FD7_BLD_DIS1	FD1 2.8 MW Building Discharge Fan	Point	FD7_BLD_DIS	0.5	585182	6901298	107.0	110.0	110.0	109.0	109.0	108.0	102.0	95.0	117	114
FD7_BLD_DIS2	FD1 2.8 MW Building Discharge Fan	Point	FD7_BLD_DIS	0.5	585180	6901302	107.0	110.0	110.0	109.0	109.0	108.0	102.0	95.0	117	114
FD7_BLD_DIS3	FD1 2.8 MW Building Discharge Fan	Point	FD7_BLD_DIS	0.5	585187	6901300	107.0	110.0	110.0	109.0	109.0	108.0	102.0	95.0	117	114
FD7_BLD_DIS4	FD1 2.8 MW Building Discharge Fan	Point	FD7_BLD_DIS	0.5	585185	6901305	107.0	110.0	110.0	109.0	109.0	108.0	102.0	95.0	117	114
FD7_GEN_RAD1	FD7 2.8 MW Generator Radiator	Point	FD7_GEN_RAD4	2.0	585193	6901296	94.0	120.0	112.0	107.0	106.0	102.0	98.0	93.0	121	112
FD7_GEN_RAD2	FD7 2.8 MW Generator Radiator	Point	FD7_GEN_RAD4	2.0	585196	6901298	94.0	120.0	112.0	107.0	106.0	102.0	98.0	93.0	121	112
FD7_BLD_OUT1	FD7 2.8 MW Building Breakout Noise	V.Area	FD7_BLD_OUT	7.3	Varies	Varies	109.0	112.0	112.0	110.0	110.0	109.0	103.0	97.0	118	115
FD7_BLD_OUT2	FD7 2.8 MW Building Breakout Noise	V.Area	FD7_BLD_OUT	7.3	Varies	Varies	109.0	112.0	112.0	110.0	110.0	109.0	103.0	97.0	118	115
Future Sourcs due to Addition																
YM20_GEN_CAS	YM20 1.8 MW Generator Casing	Point	NEW_CAS	4.0	585144	6901238	106	115	106	97	90	89	87	91	116	103
YM21_GEN_CAS	YM21 1.8 MW Generator Casing	Point	NEW_CAS	4.0	585139	6901235	106	115	106	97	90	89	87	91	116	103
YM22_GEN_CAS	YM22 1.8 MW Generator Casing	Point	NEW_CAS	4.0	585134	6901233	106	115	106	97	90	89	87	91	116	103
YM23_GEN_CAS	YM23 1.8 MW Generator Casing	Point	NEW_CAS	4.0	585130	6901230	106	115	106	97	90	89	87	91	116	103
YM24_GEN_CAS	YM24 1.8 MW Generator Casing	Point	NEW_CAS	4.0	585125	6901228	106	115	106	97	90	89	87	91	116	103
YM25_GEN_CAS	YM25 1.8 MW Generator Casing	Point	NEW_CAS	4.0	585121	6901225	106	115	106	97	90	89	87	91	116	103
YM26_GEN_CAS	YM26 1.8 MW Generator Casing (Backup)	Point	NEW_CAS	4.0	585116	6901223	106	115	106	97	90	89	87	91	116	103

Project Name: Environmental Compliance Approval - Air and Noise
Site Name: FARO Power Station
WSP Job #: 191-02438-01

Table 3: Summary of Changes in Sound Levels between Existing and Future Sources due to Addition

Point of Reception ID	Point of Reception Description	Receptor Coordinates			Sound Impact at POR [1], dBA			
		X	Y	Z	Existing	Future	Change	Impact
R1	One Storey Army Barracks on Kitza Avenue	585198	6900873	1.5	58	58	<1	Insignificant
R2	One Storey Residence on Dawson Drive	585246	6900838	4.5	59	60	<1	Insignificant
R3	Three Storey Residence on Dawson Drive	585266	6900836	7.5	59	59	<1	Insignificant
R4	One Storey Army Barracks on Kitza Avenue	585402	6900986	1.5	59	60	<1	Insignificant
R5	One Storey Del Van Gorder School on 100 Bell Avenue	585650	6900629	1.5	48	48	<1	Insignificant
R6	One Storey Faro Health Centre on 447 Campbell Street	585616	6900454	1.5	46	46	<1	Insignificant

Notes:

[1] Worst-case one hour equivalent sound level from all applicable sources operating in dBA as per scenarios listed in noise report.

APPENDIX

C MANUFACTURER SPECIFICATION

AIR EMISSIONS PERMIT (NO. 60-010)
AMENDMENT APPLICATION
SUPPORTING DOCUMENT

ATTACHMENT B

EPA APPROVED TIER 2
3516C CATERPILLAR ENGINE
GENERATOR SPECIFICATIONS

September 2020

Image shown may not reflect actual package

STANDBY 2000 kW
PRIME 1825 kW
POWER MODULE
50/60 Hz

Frequency	Voltage	Standby kW (kVA)	Prime kW (kVA)
60	480/277V	2000 (2500)	1825 (2281)
50	400V	1440 (1800)	1310 (1638)

FEATURES

EPA TIER 2 and CARB certified for non-road mobile applications. Factory designed, certified prototype tested with torsional analysis. Production tested and delivered in a package that is ready to be connected to your fuel and power lines. Supported 100% by your Caterpillar® dealer with warranty on parts and labor. Extended warranty available in some areas. The generator set is designed and manufactured in an ISO 9001:2000 compliant facility. Generator set and components meet or exceed the following specifications: AS1359, AS2789, ABGSM TM3, BS4999, DIN6271, DIN6280, EGSA101P, JEM1359, IEC 34/1, ISO3046/1, ISO8528, NEMA MG1-22

CATERPILLAR SR4B GENERATOR

Single bearing, wye-connected, static regulated, brushless permanent magnet excited generator designed to match the performance and output characteristics of the Caterpillar diesel engine driving it.

RELIABLE, FUEL EFFICIENT DIESEL ENGINE

The compact, four-stroke-cycle diesel engine combines durability with minimum weight while providing dependability and economy. The fuel system operates on a variety of fuels.

CATERPILLAR COOLING SYSTEM

Sized compatible to rating with energy efficient fan and core.

CATERPILLAR SWITCHGEAR

Provides single unit and/or multi-unit/utility paralleling components. Standby, load sense/load demand, import, export, and base load modes. Comes standard with Basler Utility Multi-function Relay IPS-100.

EXCLUSIVE CATERPILLAR DIGITAL VOLTAGE REGULATOR (CDVR)

Three-phase sensing and adjustable Volts-per-Hertz regulation give precise control, excellent block loading, and constant voltage in the normal operating range.

ENVIRONMENTALLY FRIENDLY

110% spill containment of onboard engine fluids.

SOUND ATTENUATED CONTAINER

For ease of transportation and protection. Meets 75 dB(A) at 50 ft or below per SAE J1074 measurement procedure at 110% prime load.

FACTORY INSTALLED STANDARD EQUIPMENT

SYSTEM	STANDARD EQUIPMENT
Engine	EPA approved Tier 2 3516C Caterpillar engine Heavy duty air cleaner with service indicator 60-Amp charging alternator Fuel filters – primary and duplex secondary with integral water separator and change-over valve Lubricating oil system with spin-on, full flow oil filters and water cooled oil cooler Oil drain lines routed to engine rail Jacket water heater Fuel cooler and priming pump Electronic ADEM™ A3 controls 24V electric starting motors with battery rack and cables
Generator	SR-4B brushless, permanent magnet excited, three-phase with Caterpillar digital voltage regulator (CDVR), space heater, 6-lead design, Class H insulation operating at Class F temperature for extended life, winding temperature detectors and anti-condensation space heaters (120/240V 1.2 kW)
Containerized Module	40' ISO high cube container, CSC certified 3-axle, 40' ISO container chassis Seven (7) sound attenuated air intake louvers and 4 lockable personnel doors with panic release Side bus bar access door, external access load connection bus bars Shore power connection via distribution block connections for jacket water heater, battery charger, space heaters, and generator condensate heaters Standard lighting 3 AC/4 DC, one (1) single duplex service receptacle, 2 external break-glass emergency stop push buttons 1,250 gal fuel tank, UL listed, double wall, 9 hr runtime @ prime rating Sound attenuated 75 dB(A) @ 50 ft Spill containment 110% of all engine fluids Four (4) oversized maintenance-free batteries, battery rack and 20-Amp battery charger Hospital grade, internally insulated, rectangular exhaust silencer with vertical discharge Vibration isolators, corrosion resistant hardware and hinges External drain access to standard fluids Fire extinguishers (Qty 2) Standard Cat rental decals and painted standard Cat power module white Interior walls and ceilings insulated with 100 mm of acoustic paneling Floor of container insulated with acoustic glass and covered with galvanized steel
Cooling	Standard cooling provides 43° C ambient capability (60 Hz) at prime +10% rating Vertically mounted, separate ATAAC and JW cores with vertical air discharge
Generator Paralleling Control	Custom switchgear control with EMCP 3.3 genset mounted controller and wall mounted paralleling controls Automatic start/stop with cool down timer Protections: 25, 27/59, 40, 32, 81 O/U Utility multi-function relay protections: 25,27/59, 32, 47, 50/51, 62, 67, 81 O/U UMR is IEEE1547-2003 compliant in most applications Reverse compatibility module provided for interface to legacy power modules Touch screen controls with event log Multi-mode operation (island, multi-island and utility parallel), load sharing (multi-unit only) Import & export control (utility parallel only), manual and automatic paralleling capability Touch screen display (status and alarms) Metering display: voltage, current, frequency, power factor, kW, WHM, kVAR, and synchroscope
Quality	Standard genset and package factory tested UL, NEMA, ISO and IEEE standards O&M manuals

XQ2000 RENTAL

SPECIFICATIONS

CAT SR4B GENERATOR

Frame Size 825
Pitch 0.6667
No. of poles 4
Excitation . . . . . Static regulated brushless PM excited
Constructions . . . . . Single bearing, close coupled
Insulation . . . . . Class H
Enclosure . . . . . Drip proof IP22
Alignment . . . . . Pilot shaft
Overspeed capability – % of rated . . . . . 125% of rated
Voltage regulator . . . . . 3 phase sensing with Volts-per-Hertz
Voltage regulation . . . . . Less than ± ½% voltage gain
Adjustable to compensate for engine speed droop and line loss
Wave form deviation . . . . . Less than 5% deviation
Telephone Influence Factor (TIF) . . . . . Less than 50
Harmonic Distortion (THD) . . . . . Less than 5%

CAT 3516C DIESEL ENGINE

3516C, 4-Stroke diesel
Bore – mm (in) 170 (6.7)
Stroke – mm (in) 190 (7.5)
Displacement – L (cu in) 69 (4,210)
Compression ratio 15:1
Aspiration . . . . . ATAAC
Fuel system . . . . . EUI
Governor type . . . . . Caterpillar ADEM™ A3 Control System

TECHNICAL DATA

Materials and specifications are subject to change without notice.

Generator Set Technical Data		50 Hz		60 Hz	
	Units	**Prime**	**Standby**	**Prime**	**Standby**
Performance Specification		DM8754		DM8264	
Power Rating	kW (kVA)	1310 (1637)	1440 (1800)	1825 (2281)	2000 (2500)
Lubricating System					
Oil pan capacity	L (gal)	401.3 (106)		401.3 (106)	
Fuel System					
Fuel Consumption					
100% load	L (gal)	350.1 (92.5)	372.9 (98.5)	483.2 (127.6)	525.7 (138.9)
75% load	L (gal)	281.9 (74.5)	302.8 (80)	380 (100.4)	408.2 (107.8)
50% load	L (gal)	205.5 (54.3)	350.1 (92.4)	270.5 (71.5)	294.2 (77.7)
Fuel tank capacity	L (gal)	4731 (1,250)		4731 (1,250)	
Running time @ 75% rating	Hours	16.7	15.6	12.5	11.5
Cooling System					
Radiator coolant capacity including engine	L (gal)	630 (166)		630 (166)	
Air Requirements					
Combustion air flow	m^3/min (cfm)	114.8 (4052)	118.1 (4173)	174.7 (6169)	180.3 (6367)
Maximum air cleaner restriction	kPa (in H_2O)	6.2 (24.9)		6.2 (24.9)	
Generator cooling air	m^3/min (cfm)	140 (5,933)		168 (4,995)	
Exhaust System					
Exhaust flow at rated kW	m^3/min (cfm)	311.3 (10,993)	320.8 (11,335)	404 (14,260)	428.6 (15,137)
Exhaust stack temperature at rated kW – dry exhaust	°C (°F)	502.1 (935.8)	513.1 (955.6)	387 (728)	405 (762)
Noise Rating (with enclosure)					
@ 7 meters (23 feet)	dB(A)	77	78	78	79
@15 meters (50 feet)	dB(A)	73	74	74	75

Model	Length mm (in)	Width mm (in)	Height mm (in)	Weight	
				With Lube Oil and Coolant kg (lb)	With Fuel, Lube Oil and Coolant kg (lb)
XQ2000 w/o Chassis	12 192 (480)	2438 (96)	2896 (114)	34 019 (75,000)	38 102 (84,000)
XQ2000 w/Chassis	12 192 (480)	2438 (96)	4267 (168)	38 102 (84,000)	42 184 (93,000)

RATING DEFINITIONS

Standby – Applicable for supplying continuous electrical power (at variable load) in the event of a utility power failure. No overload is permitted on these ratings. The generator on the generator set is peak prime rated (as defined in ISO8528-3) at 30° C (86° F).

Prime – Applicable for supplying continuous electrical power (at variable load) in lieu of commercially purchased power. There is no limitation to the annual hours of operation and the generator set can supply 10% overload power for 1 hour in 12 hours.

STANDARD FEATURES

GENERATOR SET EMCP 3.3 LOCAL CONTROL PANEL

- Generator mounted EMCP 3.3 provides power metering, protective relaying and engine and generator control and monitoring.
- Provides MODBUS datalink to paralleling control for monitoring of engine parameters.
- Convenient service access for Caterpillar service tools (not included).
- Integration with the CDVR provides enhanced system monitoring.
- Ability to view and reset diagnostics of all controls networked on J1939 datalink.
- Network modules via the control panel removes the need for a separate service tool for troubleshooting.
- Real-time clock allows for date and time stamping of diagnostics and events.

EMCP 3.3 ENGINE OPERATOR INTERFACE

- Graphical display with positive image, transflective LCD, adjustable white backlight/ contrast.
- Two LED status indicators (1 red, 1 amber).
- Three engine control keys and status indicators (Run/Auto/Stop).
- Lamp test key.
- Alarm acknowledgement key.
- Display navigation keys.
- Two shortcut keys: Engine Operating Parameters and Generator Operating Parameters.
- Fuel level monitoring and control.

CIRCUIT BREAKER

- 3000A fixed type, 3 poles, genset mounted, electrically operated, insulated case circuit breaker.
- Solid state trip unit for overload (time overcurrent) and fault (instantaneous) overcurrent protection.
- Includes DC shunt trip coil activated on any monitored engine or electrical fault, 100 KA-interrupting capacity at 480 VAC.

VOLTAGE REGULATION AND POWER FACTOR CONTROL CIRCUITRY

- Generator mounted automatic voltage regulator, microprocessor based.
- Manual raise/lower voltage adjust capability and VAR/power factor control circuitry for maintaining constant generator power factor while paralleled with the utility.
- Includes RFI suppression, exciter limiter and exciter diode monitoring.
- Voltage and power factor adjustments are performed on the setting screen of the HMI touch screen.

FUEL TANK

- UL Listed 1250 gallon double walled.
- Fuel transfer system

CURRENT TRANSFORMERS

- CT's rated 3000:5 with secondaries wired to shorting terminal strips.

POTENTIAL TRANSFORMERS

- 4:1 ratio with primary and secondary fuse protection.

BUS BARS

- Three phase, plus full rated neutral, bus bars are tin-plated copper with NEMA standard hole pattern for connection of customer load cables and generator cables.
- Bus bars are sized for full load capacity of the generator set at 0.8 power factor.
- Includes ground bus, tin-plated copper, for connection to the generator frame ground and field ground cable.

AC DISTRIBUTION

- Provides 240 VAC for all module accessories.
- Includes controls to de-energize jacket water heaters and generator space heater when the engine is running.

SHORE POWER TWO (2)

- One (1) shore power connection distribution block for jacket water heaters.
- One (1) for generator space, battery charger, and fuel pump.

INTERNAL LIGHTING

- Four (4) internal DC lights with one (1) timer and two switches installed at each side of the container door.
- Three (3) internal AC lights.
- One (1) single duplex service receptacle.

BATTERY CHARGER AND BATTERIES

- 24 VDC/20A battery charger with float/equalize modes and charging ammeter.
- Maintenance free batteries.

EMERGENCY STOP PUSHBUTTON

- Two external ESPs located near each access door.

MODES OF OPERATION

Caterpillar utility paralleling controls are intended for automatic or manual paralleling with a utility power source as a load management system, with provisions for standby operation feeding an isolated load network. Load management operation involves microprocessor-based automatic loading controls with soft loading, base load, Import/Export control and soft unloading. For Standby operation, the generator operates as an isochronous machine isolated from the utility supply. The controls allow for automatic operation, initiated locally or remotely by the customer's SCADA system. Detailed modes of operation are listed below:

SINGLE UNIT ISLAND AND MULTI-UNIT ISLAND OPERATION

1. Utility Standby Mode (Normal)
   a. The utility is providing power for the plant loads.
   b. The Power Module Generator breaker is open.
   c. The pm is in automatic standby mode to respond to a utility failure.
2. Emergency Mode (Emergency)
   a. Utility Failure
      1) The customer protective relaying senses a utility abnormal condition.
      2) A run request is sent to the Power Module Generator plant.
      3) The first Power Module Generator reach rated to voltage and frequency is closed to the bus.
      4) In Multi-Unit Island Mode, the remaining Power Module Generators are paralleled to the bus as they reach rated voltage and frequency. This function is performed via the ModBus Plus data link connected between the Power Modules.
      5) Plant load is transferred to the Power Modules, which share load equally via ModBus Plus data link.
      6) The system is now in Emergency Mode.

GENERATOR DEMAND PRIORITY CONTROL

The System Controls include a Generator Demand Priority Control function to automatically match the on-line Power Module Generator capacity to the loads in order to avoid unnecessary operation of all the Power Module Generators when the plant loads are low.

The following controls are provided for each Power Module Generator:

a. User-settable Generator Priority Selector
b. Status indicator for the Generator Priority selected
c. Status indicator for Power Module Generator on-line or off-line
d. Generator Demand Priority Control Switch (On/Off)
e. User-settable Generator Remove Level (% as a function of single generator capacity)
f. User-settable Generator Remove Time Delay
g. User-settable Generator Add Level (% as a function of single generator capacity)
h. User-settable Generator Add Time Delay

Upon entrance into Emergency Mode, all generators will be started and paralleled to the bus. After the Remove Time Delay, Power Module Generators will be removed from the bus as a function of the generator percentage loading. Generators will be removed from the bus in descending priority order.

Should the generator percentage loading increase to the user-selected Generator Add Level after the user-selected Generator Add Time Delay, the next priority generator will be started, synchronized and paralleled to the bus. Should the Power Module Generator plant ever reach 100% loading, the next priority generator will be started and added to the bus, bypassing the Generator Add Time Delay.

MODES OF OPERATION (continued)

SINGLE UNIT IMPORT, EXPORT OR BASE LOAD OPERATION

During periods of peak demand the system may be placed in operation using the operator interface panel on the front of the switchgear.

1. Entry – Local
   a. The operator places the System Control Switch into Load Management.
   b. The operator selects Import, Export or Base Load Operation.
   c. The Load Management Setpoint is the amount of power Imported, Exported or Base-Loaded. A 4-12-20mA signal is provided by the customer and is linearly proportional to the utility load, with 12mA equaling 0 kW. The 4-12-20mA utility load signal is wired to one and only one Power Module. If the Power Module selected for Load Management is not available, the 4-12-20mA signal will be routed to a different Power Module.
   d. The operator sets the Load Management Setpoint and Power Factor Setpoint.
   e. A Run request signal is received by the Single Unit Power Module.
   f. The Power Module Generator is started and will run for a predetermined warm-up time before it is synchronized and paralleled to the utility.
   g. When the generator is on the bus, it is soft-ramp-loaded until the generator output reaches the Load Management Setpoint.
   h. The generator output is dynamically adjusted to maintain the Load Management Setpoint.
   i. Should the utility fail during Load Management Operation, the Protective Relay will cause the Paralleling Circuit Breaker 52G to open and be locked out until the Lockout Relay is manually reset by an operator on site. The generator is allowed to run for the duration of the cooldown time.
2. Exit – Local
   a. The Run Request signal is removed from the power module.
   b. The generator is soft-ramp-unloaded until the plant load is fully supported by the utility.
   c. The Paralleling Circuit Breaker 52G is opened.
   d. The generator is allowed to run for the duration of the cooldown time.

STANDARD PARALLELING CONTROL

GENERATOR PARALLELING CONTROLS

The switchgear includes:

- Single unit island mode.
- Multiple unit island mode.
  - Includes Load Sense/Load Demand control.
  - Load sharing capability is provided via network communication.
- Single unit utility parallel mode.
  Selectable for Import/Export control.
  If import or export control is selected a 4-12-20mA signal is required (provided by others) scalable to the utility contribution.
- 6 inch black and white HMI touch screen.
- Reverse compatibility module provided for interface to legacy designed Power Module Switchgear. Includes PLC, load share and voltage droop.

Incoming Utility Breaker Status Circuit – Circuit to accept customers contact from remote utility disconnect device. Customer to provide a normally open form 'a' contact to indicate when the local load network is connected to the utility grid.

Utility Transfer Trip Circuit – Circuit accepts input (normally open dry contact) from customer's system protective relay(s) or other controlling device. Operation of contacts causes tripping of the generator circuit breaker via the generator (software) 86 lock-out function and places the engine in cooldown mode. Circuit is disabled when operating in single unit or multiple unit island.

GENERATOR PARALLELING CONTROLS OPERATOR INTERFACE

Graphical mimic one line diagram that shows generator with its respective circuit breaker in a one-line representation of the system. The graphics utilize black and white indicators and bar graphs while actively displaying the following information:

- Utility CB Open/Closed. Input contacts provided by others.
- Utility kW 4-12-20mA signal required and provided by customer that is scalable to the utility contribution.
- Generator CB Open/Closed/Tripped.
- Generator Volts/Amps/kW/Frequency.
- Engine Stopped/Running/Cooldown/Pre-Alarm/Shutdown.
- Engine ECS Position Stop/Auto/Run.
- Utility Output kW.
- System Summary Alarm.

Event logging is also included with up to 500 stored events.

GENERATOR METERING AND PROTECTION

Generator metering that will graphically display 3Ø Voltage, 3Ø Current, Frequency, Power Factor, kW, kVAR and a Synchroscope Display of EMCP 3.3 faults, CDVR or ADEM 3 will be provided via Modbus RTU interface to EMCP 3.3.

Generator/Intertie Protective Relaying including:

- Device 27/59 – Under/Over Voltage.
- Device 81O/U – Under/Over Frequency.
- Device 40 – Loss of Excitation.
- Device 32 – Reverse Power.
- Device 25 – Synchronizing Check.
- Device 15 – Auto Synchronizer.
- Device 65 – Governor Load Sharing, Soft Loading Control.
- Device 90 – VAR/PF and Cross Current Compensation Controller.

PROGRAMMING AND DIAGNOSTICS

Includes field programmable set points for engine control and monitoring variables and self-diagnosis of the EMCP 3.3 system component and wiring failures.

ENGINE CONTROL SWITCH

Keypad selectable, four (4) positions – Off, Auto, Man, Cool:

- Off for engine shutdown and resetting faults.
- Auto for local or remote automatic operation when initiated by switch operation or contact closure.
- Man for local starting and manual paralleling.
- Cool for normal engine shutdown with timed cool-down cycle.

CIRCUIT BREAKER CONTROL SWITCH

Heavy duty, three- (3) position spring return to center with momentary trip and close position and slip contacts for automatic closing. Includes circuit breaker position indicating lamps.

EMERGENCY STOP PUSHBUTTON

- Mushroom head, twist to reset, causes engine shutdown and tripping of the generator circuit breaker. Prevents engine starting when depressed.

STANDARD PARALLELING CONTROL (continued)

ELECTRONIC LOAD SHARING GOVERNOR

- Includes speed adjustment, and auto load share capability when in parallel with legacy power modules.

ALARM MODULE

- Dedicates annunciator screens for warning and shutdown faults. Includes external mounted horn and acknowledge push-button.

AUTOMATIC/MANUAL PARALLELING

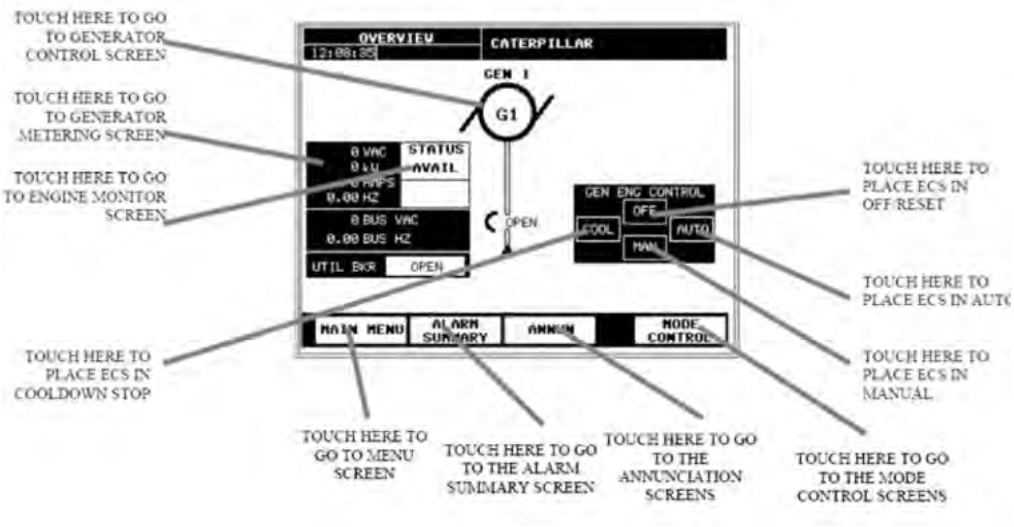
- Automatically synchronizes and parallels the generator with another power source.
- Includes provisions for manual permissive paralleling.

HUMAN MACHINE INTERFACE (HMI) HIGHLIGHTS

- Engine/Generator function is performed thru the 6" HMI touch screen interface.

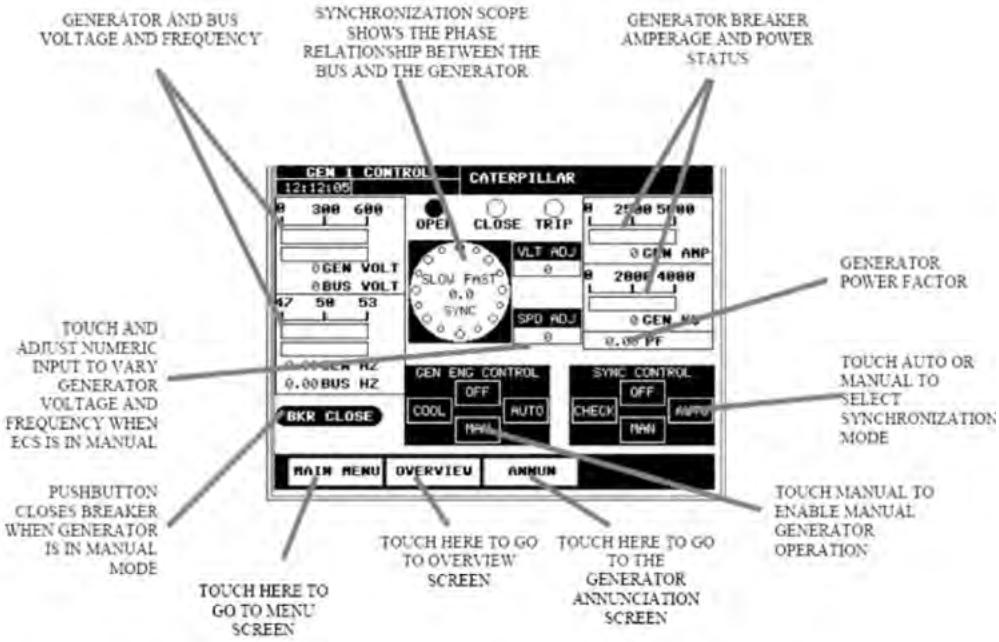
Overview Screen (Typical)

Shows the generator status, generator metering data, bus metering data, ECS position, and generator/utility breaker status.

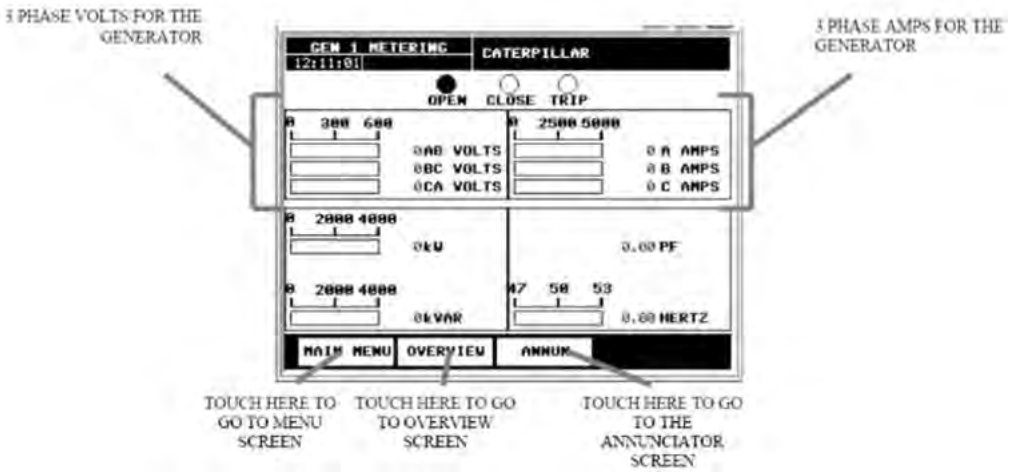


STANDARD PARALLELING CONTROL (continued)

Generator Control Screen (Typical)
It allows the operator to observe the automatic synchronization and transfer of the load to and from the generator. Engine control allows the operator to run the engine in manual, or switch to automatic modes. Voltage and frequency offset adjustment allows the operator to control generator frequency and voltage.



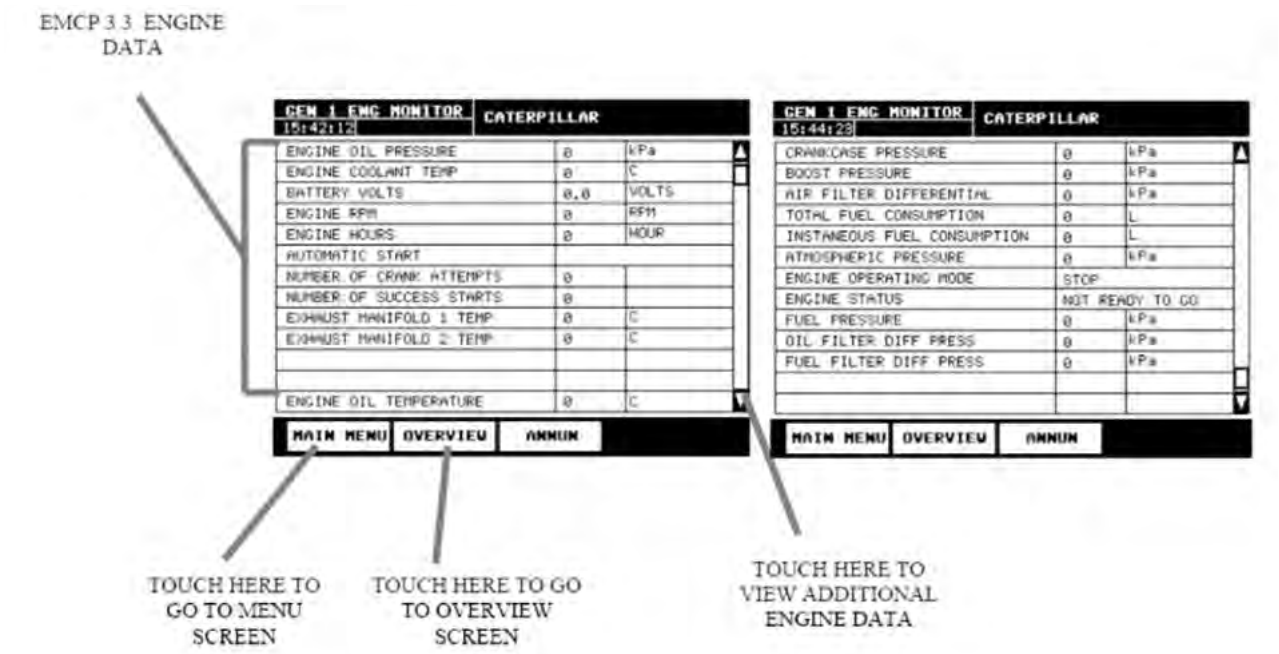
Generator Metering Screen (Typical)
Allows the operator to view three phases of voltage and amperage for the bus and the generator.



STANDARD PARALLELING CONTROL (continued)

Engine Monitoring Screen (Typical)

Engine status is obtained directly from the EMCP 3. Engine starts and total hours can be used by the operator to determine when regular preventive maintenance is required. Other metering includes engine battery and oil filter health.



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GEN SET PACKAGE PERFORMANCE DATA [DM8266]

Performance Number: DM8266

Sales Model: 3516CDITA	**Combustion:** DI	**Aspr:** TA
Engine Power: 2500 W/F EKW 2593 W/O F EKW 3,622 HP	**Speed:** 1,800 RPM	**After Cooler:** ATAAC
Manifold Type: DRY	**Governor Type:** ADEM3	**After Cooler Temp(F):** 122
Turbo Quantity: 4	**Engine App:** GP	**Turbo Arrangement:** Parallel
Hertz: 60	**Engine Rating:** PGS	**Strategy:**
Rating Type: STANDBY	**Certification:** EPA TIER-2 2006 -	

General Performance Data

GEN W/F EKW	PERCENT LOAD	ENGINE POWER BHP	ENGINE BMEP PSI	FUEL RATE LB/BHP-HR	FUEL RATE GPH	INTAKE MFLD TEMP DEG F	INTAKE MFLD P IN-HG	INTAKE AIR FLOW CFM	EXH MFLD TEMP DEG F	EXH STACK TEMP DEG F	EXH GAS FLOW CFM
2,500.0	100	3604	333	0.337	173.3	122.0	78.2	6,992.3	1,236.7	921.9	19,048.8
2,250.0	90	3256	301	0.337	156.7	119.3	71.3	6,600.3	1,190.3	889.0	17,516.1
2,000.0	80	2911	269	0.341	141.9	117.0	64.3	6,183.6	1,159.0	871.0	16,167.1
1,875.0	75	2738	253	0.344	134.6	115.9	60.8	5,961.1	1,145.8	864.7	15,506.7
1,750.0	70	2566	237	0.347	127.3	114.6	57.1	5,731.6	1,133.6	859.6	14,846.3
1,500.0	60	2223	205	0.355	112.8	112.8	49.6	5,254.8	1,112.0	853.0	13,522.0
1,250.0	50	1880	174	0.366	98.4	111.0	41.5	4,739.2	1,091.7	848.5	12,144.7
1,000.0	40	1545	143	0.375	82.8	109.4	31.8	4,075.3	1,062.9	848.1	10,439.0
750.0	30	1203	111	0.387	66.5	108.0	22.0	3,404.3	1,012.8	837.9	8,627.4
625.0	25	1029	95	0.396	58.2	107.2	17.4	3,086.5	970.9	818.2	7,702.1
500.0	20	854	79	0.406	49.5	106.3	12.9	2,772.2	905.7	782.2	6,723.9
250.0	10	496	46	0.443	31.4	104.2	4.8	2,193.0	702.9	643.5	4,693.3

Heat Rejection Data

GEN W/F EKW	PERCENT LOAD	REJ TO JW BTU/MN	REJ TO ATMOS BTU/MN	REJ TO EXHAUST BTU/MN	EXH RCOV TO 350F BTU/MN	FROM OIL CLR BTU/MN	FROM AFT CLR BTU/MN	WORK ENERGY BTU/MN	LHV ENERGY BTU/MN	HHV ENERGY BTU/MN
2,500.0	100	47,202	9,156	140,924	75,921	18,596	43,392	152,866	371,872	396,156
2,250.0	90	44,245	8,587	127,047	67,163	16,833	38,046	138,080	336,328	358,280
2,000.0	80	41,458	8,303	115,901	60,566	15,241	33,155	123,408	304,481	324,386
1,875.0	75	40,093	8,189	110,555	57,609	14,445	30,767	116,128	288,899	307,780
1,750.0	70	38,672	8,076	105,266	54,766	13,649	28,321	108,792	273,260	291,117
1,500.0	60	35,885	7,791	94,916	49,420	12,113	23,601	94,233	242,152	257,962
1,250.0	50	32,871	7,564	84,566	44,074	10,578	18,824	79,732	211,101	224,864
1,000.0	40	29,515	7,336	72,566	37,762	8,872	13,478	65,514	177,718	189,320
750.0	30	25,648	6,881	59,258	30,823	7,109	8,474	51,012	142,743	152,070
625.0	25	23,544	6,597	52,150	26,729	6,256	6,426	43,676	124,886	133,019
500.0	20	21,156	6,142	44,245	22,009	5,289	4,550	36,169	106,119	113,057
250.0	10	15,867	5,118	27,525	11,601	3,355	1,763	21,042	67,277	71,656

MECHANICAL Sound Data: 23.0 FEET

GEN W/F EKW	PERCENT LOAD	OVERALL SOUND DB(A)	OBCF 63HZ DB	OBCF 125HZ DB	OBCF 250HZ DB	OBCF 500HZ DB	OBCF 1000HZ DB	OBCF 2000HZ DB	OBCF 4000HZ DB	OBCJ 8000HZ DB
2,500.0	100	103	107	116	107	98	91	90	88	92
2,250.0	90	103	107	116	107	98	91	90	88	92
2,000.0	80	103	107	116	107	98	91	90	88	92
1,875.0	75	103	107	116	107	98	91	90	88	92
1,750.0	70	103	107	116	107	98	91	90	88	92
1,500.0	60	103	107	116	107	98	91	90	88	92
1,250.0	50	103	107	116	107	98	91	90	88	92
1,000.0	40	103	107	116	107	98	91	90	88	92
750.0	30	103	107	116	107	98	91	90	88	92
625.0	25	103	107	116	107	98	91	90	88	92
500.0	20	103	107	116	107	98	91	90	88	92
250.0	10	103	107	116	107	98	91	90	88	92

MECHANICAL Sound Data: 49.2 FEET

GEN W/F EKW	PERCENT LOAD	OVERALL SOUND DB(A)	OBCF 63HZ DB	OBCF 125HZ DB	OBCF 250HZ DB	OBCF 500HZ DB	OBCF 1000HZ DB	OBCF 2000HZ DB	OBCF 4000HZ DB	OBCF 8000HZ DB
2,500.0	100	97	100	110	100	91	85	85	82	86
2,250.0	90	97	100	110	100	91	85	85	82	86
2,000.0	80	97	100	110	100	91	85	85	82	86
1,875.0	75	97	100	110	100	91	85	85	82	86
1,750.0	70	97	100	110	100	91	85	85	82	86
1,500.0	60	97	100	110	100	91	85	85	82	86
1,250.0	50	97	100	110	100	91	85	85	82	86
1,000.0	40	97	100	110	100	91	85	85	82	86
750.0	30	97	100	110	100	91	85	85	82	86
625.0	25	97	100	110	100	91	85	85	82	86
500.0	20	97	100	110	100	91	85	85	82	86
250.0	10	97	100	110	100	91	85	85	82	86

File # 2500-00-01

SPILL RESPONSE PLAN-FARO	DEPARTMENT:	INQUIRIES TO:	TOPIC:	Last Review Date
	Operations	VP, Operations	Spill Response/Hazardous Material Location Page 1 of 67	Aug 18, 2020
	ISSUED:	REVIEW DATE:	APPROVED BY:	Revision #
	May 2000	Annually	VP, Operations	8

FARO DIESEL/SUB-STATION

SPILL RESPONSE PLAN

Yukon Energy Corporation
Box 220
Faro, YT
Y0B 1K0

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1.0 EMERGENCY CONTACT INFORMATION

SCC **(Available 24/7)**

Phone: **867-393-5324, 867-393-5355**

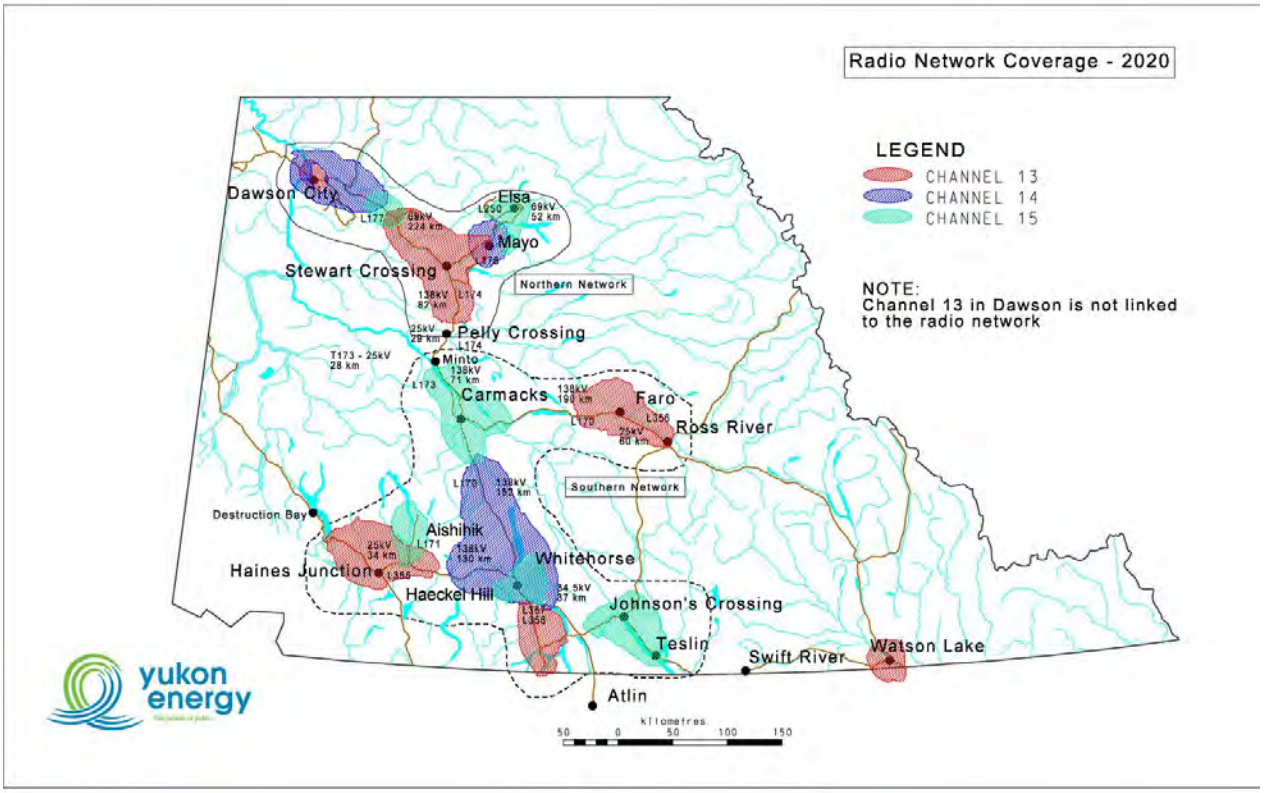
YEC Radio:

1. Ensure your radio is on the correct channel for your area.
2. Press and hold the "push to talk (PTT)" button (large button on left hand side of the mic)
3. While pressing the PTT button dial 1111 on the mic.
4. Voicecall your party.

If you are in the Faro Area, use channel 13

YEC Radio Notes:

- The link can be enabled/disabled from the northern or the southern radio network.
- The link will automatically be disabled after five minutes of inactivity.
- When in the Carmacks area you will hear a beep-beep after enabling the link and a beep-beep-beep after disabling the link. Unfortunately these acknowledgment tones are not transmitted in other areas of the radio network.
- The radio link between the southern and northern networks is very long and heavy snow or ice fog between Carmacks and Stewart Crossing may render the link inoperable at times.


Radio Network Coverage - 2020
LEGEND
CHANNEL 13
CHANNEL 14
CHANNEL 15
NOTE:
Channel 13 in Dawson is not linked to the radio network
Dawson City
Elsa
Mayo
Stewart Crossing
Northern Network
Pelly Crossing
Minto
Carmacks
Faro
Ross River
Southern Network
Destruction Bay
Aishihik
Haines Junction
Whitehorse
Haeckel Hill
Johnson's Crossing
Teslin
Swift River
Watson Lake
Atlin
yukon energy
Kilometres
50 0 50 100 150

2.0 INITIAL ACTION/SAFE APPROACH GUIDELINES

The following are intended as guidelines. Consider the circumstances of each event and act accordingly.

NOTIFY SSC and SUPERVISOR IF AVAILABLE **SCC Phone# 867-393-5324, 867-393-5355**

- Arrange Call-Back time, if appropriate.

ALERT OTHER EMPLOYEES/PERSONS IN AREA

- Approach spill site from up-wind or, if indoors, ensure you have a clear escape route
- Establish Perimeter Security
- Evacuate, if necessary
- Eliminate Ignition Sources
- Commence documentation

USE THE BUDDY SYSTEM

IDENTIFY MATERIAL, SPILL SOURCE, ESTIMATE QUANTITY SPILLED AND POTENTIAL FATE

- Block Potential Escape Routes, if appropriate

IF SPILL CONTINUING, CONTROL SOURCE, IF SAFE TO DO SO

- **SUBSTATION SPILLS. DO NOT ENTER UNLESS AUTHORIZED. HIGH VOLTAGE: CONTACT SCC then LEADHAND ELECTRICAL MAINTENANCE 334-5868**
- Develop Spill Site Safety Plan located on page 9 and 10 of this document.

Refer to product MSDS. Wear appropriate PPE.

- (See "Fast Fact Sheets" at the back pages of this plan for spills of specific products.)

SUMMON RESPONSE RESOURCES, AS APPROPRIATE

UPDATE SCC and SUPERVISOR ON PROGRESS

Note: In some instances, initial on-scene personnel will only be able to monitor and/or contain the spill with resources at hand until assistance arrives.

DO NOT PUT YOURSELF at RISK

3.0 PURPOSE AND SCOPE

At this time this Spill Contingency Plan covers situations related to a spill or other unintended release of a liquid, solid and/or gas that may present a threat to those in a YEC facility or to the environment.
This spill contingency plan applies to all spills that occur at Yukon Energy's diesel facilities located in Faro, Yukon. The VP of Operations will approve the plan yearly and the Environment and Resource Analyst with Leadhands of Mechanical and Electrical Maintenance will review the plan yearly to ensure the information is current.

Purpose

The purpose of Yukon Energy's Spill Contingency Plan is to provide a plan of action for every foreseeable hazardous material spill event at the Faro Generating Facility. It defines the responsibilities of key response personnel and outlines the procedures for responding to spills in a way that will minimize potential health and safety hazards, environmental damage, and clean-up costs. The plan has been prepared to provide easy access to all the information needed in dealing with a spill.

It is the policy of Yukon Energy to initiate clean up activity when, in the opinion of its management, Yukon Energy is clearly associated, or likely to be associated with the spilled material. As well it is our company policy:

- To meet or surpass regulatory requirements;
- To provide protection of the environment using all of YEC's resources; when practicable
- To cooperate with other groups working on protection of the environment;
- To minimize the adverse effects of our activities on the natural and social environment;
- To keep employees, government officials and the public informed.

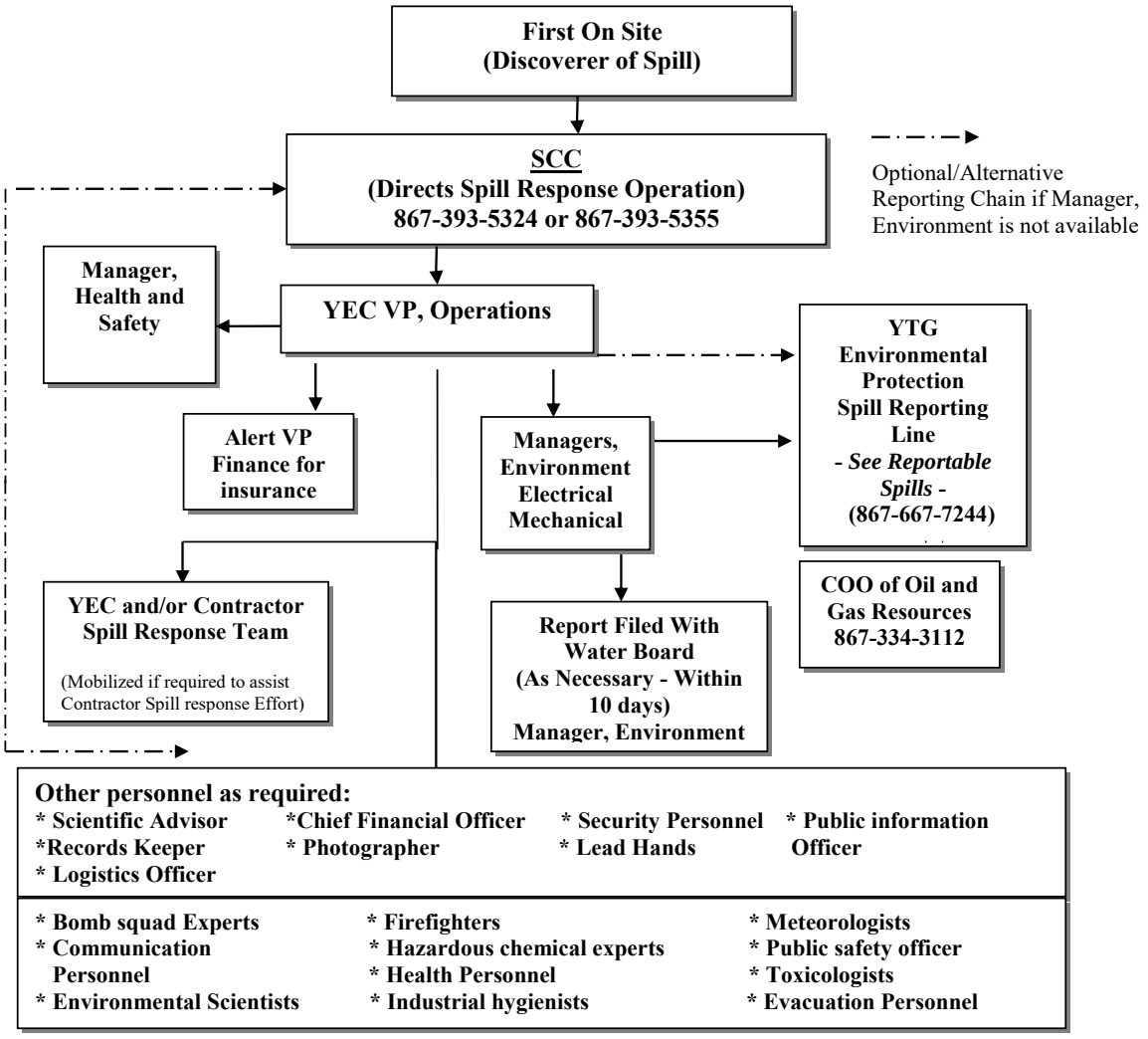
Scope

The Faro Diesel/Substation Spill Contingency Plan, Reporting Procedures and Hazardous Materials Locations document covers all hazardous materials stored and used at the Faro Diesel Generating Station and Substation sites. This document covers both spills on land as well as in adjacent watercourses (e.g., Rose Creek). The plan is approved yearly by the VP of Operations following a yearly review by and the Leadhands of Electrical and Mechanical Maintenance will review the plan yearly to ensure the information is current and accurate.

4.0 NOTIFICATIONS

Figure 1. Contact/Reporting Flow Chart
Contact flow chart in the event of a fuel, oil or other hazardous material spill. Qualified alternates will be contacted in the event someone is unavailable.

All spills of petroleum products of **5 litres** or more of fresh, or **0.5 L** of used waste oil or other hazardous materials to permeable surface and any amount to water must be reported to the 24 Hour Spill Report Line by the Manager, Environment to insure that an investigation may be undertaken by the appropriate government authority. In the event of a LNG or natural gas release, the Chief Operating Officer of the Oil and Gas Branch must be informed.



The specific information requested when a spill is reported to government is outlined in Yukon Energy's Incident Reporting Safe Work Practice SWP-006 and Environmental Work Practice EWP-006 found on the Health and Safety and Environment EMS Sharepoint Site

5.0 RESPONSE ORGANIZATION

Response organization Structure (s) by Classification Level of Response

MINOR: Level 1 INCIDENT COMMANDER: **RESPONDER/SUPERVISOR**

Is a spill of a minor nature that presents no significant threat to employees, property or the environment and absolutely no risk to the public. It can be cleaned up and remediated using workers and equipment available at the facility or site.

Example: A litre of varsol was spilled on the impermeable shop floor. The spiller alerts those around him of the occurrence, that the incident has occurred and cleans the product up using a small spill kit. Waste is disposed of in an appropriately labelled hazardous material waste container manner. No need to report externally or internally unless an equipment deficiency is raised. In this example if the solvent had been in use (i.e., was not fresh) and/or had been spilled to a dirt floor, or other permeable surface, internal and external reporting would be required.

MODERATE: Level 2 INCIDENT COMMANDER: **LEAD HAND** or delegate

A medium spill event where there is potential risk to employees, property or the environment but no risk to the public. This level may require external assistance to contain, recover or remediate.

Example: A vehicle entering the Whitehorse facility has impacted and punctured several barrels of waste oil stored directly on the ground with no spill tray to catch any release.

MAJOR: Level 3 INCIDENT COMMANDER: **VP, OPERATIONS** or delegate

A major spill event where there is a significant risk to employees, property, the environment and/or the public. Considerable internal and possibly external resources may be required to effectively respond.

Example: The 160,000L fuel tank in the yard of the Whitehorse facility has leaked and the product is escaping through a previously unidentified crack low on the secondary containment wall. The spill is spreading around the yard and entering the unpaved area adjacent to the property fence.

Responsibility to summon/manage external resources:

First Responders: SCC or personnel at the scene

External Emergency Responders/Regulators: Manager, Environment or Delegate. VP of Operations
Spill Response Contractors: SCC, Manager of Environment, VP of Operations, Lead hands

6.0 SPILL SITE SAFETY PLAN

Incident Name _____ ***Operational Period*** From _____ To _____

1. DESCRIBE THE INCIDENT AND SPECIFY THE SITE ENTRY OBJECTIVES

Description _____

Location _____

Incident Type

- ☐ Spill
- ☐ Gas release
- ☐ Explosion
- ☐ Fire
- ☐ Other _____
- ☐ Unknown

Site Entry Objectives under this Site Safety Plan

- ☐ Initial assessment or reconnaissance
- ☐ Account for personnel and/or rescue victims
- ☐ Source control
- ☐ Fire suppression
- ☐ Spill containment
- ☐ Spill recovery and/or cleanup

2. IDENTIFY PRODUCT HAZARDS

Consult MSDS; if no MSDS call CANUTEC at 613-996-6666 or "*666" (in Canada only)

Product Properties

Name _____
Estimated Amount _____
MSDS on Hand? _____
Gas / Liquid / Solid (circle)
Water soluble? _____
Specific gravity or vapor density _____

Product Hazards *(check all that apply)*

- ☐ Flammable (flash point _____ °C)
- ☐ Explosive (LEL range _____ to _____ %)
- ☐ Corrosive (corrodes _____)
- ☐ Reactive (reacts with _____)
- ☐ Toxic (IDLH _____; TLV _____)
- ☐ Carcinogenic

Potential Routes of Exposure to the Product *(check all that apply)*

☐ Inhalation ☐ Ingestion ☐ Eye contact ☐ Skin contact

3. IDENTIFY PHYSICAL SITE HAZARDS AND CONDITIONS

Physical Site Hazards

- ☐ Confined space
- ☐ Elevated area
- ☐ Pit or trench
- ☐ On or near water
- ☐ Unstable structure
- ☐ Electrocution
- ☐ Wildlife encounter
- ☐ Noise/vibration
- ☐ Extreme temperatures
- ☐ Low visibility
- ☐ Slip or trip hazards

Site Conditions *(as applicable)*

Air temperature _____
Wind chill temperature _____
Water temperature _____
Wind speed & direction _____
Precipitation _____
Humidity _____
Visiblity _____
Wave ht. (avg & max) _____
Speed of current _____
Direction of current _____
High/low tide times _____
High/low tide heights _____
Forecast _____
_____
_____
_____

Wind Chill Temperature Chart

Wind Speed (km/hr)

Effective temperature (°C)	0	10	15	20	25	30	35	40	45	50	55	60
10	8.6	7.9	7.4	6.9	6.6	6.3	6	5.7	5.5	5.3	5.1	
5	2.7	1.7	1.1	0.5	0.1	-0	-1	-1	-1	-2	-2	
0	-3	-4	-5	-6	-7	-7	-7	-8	-8	-9	-9	
-5	-9	-11	-12	-12	-13	-14	-14	-15	-15	-15	-16	
-10	-15	-17	-18	-19	-20	-20	-21	-21	-22	-22	-23	
-15	-21	-23	-24	-25	-26	-27	-27	-28	-29	-29	-30	
-20	-27	-29	-31	-32	-33	-33	-34	-35	-35	-36	-37	
-25	-33	-35	-37	-38	-39	-40	-41	-42	-42	-43	-43	
-30	-39	-41	-43	-45	-46	-47	-48	-48	-49	-50	-50	
-35	-45	-48	-49	-51	-52	-53	-54	-55	-56	-57	-57	
-40	-51	-54	-56	-57	-59	-60	-61	-62	-63	-63	-64	
-45	-57	-60	-62	-64	-65	-66	-68	-69	-70	-70	-71	
-50	-63	-66	-68	-70	-72	-73	-74	-75	-76	-77	-78	

4. CHOOSE CORRECT LEVEL OF PPE (personal protective equipment)

Responders

- ☐ LEVEL A
- ☐ LEVEL B
- ☐ LEVEL C
- ☐ LEVEL D

Decon Team

- ☐ LEVEL A
- ☐ LEVEL B
- ☐ LEVEL C
- ☐ LEVEL D

A	B	C	D	*Equipment Requirement (*depends on situation)*
x	x			SCBA (self-contained breathing apparatus) or positive pressure supplied air respirator with escape SCBA
		x		Full-face or half-face respirator with appropriate cartridges
		x	x	Escape mask*
x				Encapsulating suit (chemical protective with vapor barrier)
x	x	x		Outer gloves (chemically resistant)
x	x	x		Inner gloves (chemically resistant)
x	x	x	x	Boots (chemically resistant, steel-toe and shank)
x				Disposable protective suit worn over entire ensemble
x	x	x	x	Disposable outer boot covers, chemically-resistant*
x	x	x	x	Hard hat
	x	x	x	Face shield*
		x	x	Safety glasses or chemical splash goggles
x	x	x	x	Coveralls*
x	x	x	x	Hearing protection*
x	x	x	x	Personal flotation device*
x	x	x	x	Cold weather gear*

5. SPECIFY MONITORING REQUIREMENTS

Site Safety Officer or designee is responsible for monitoring the following parameters (indicated by checked boxes) at the appropriate frequency and for immediately communicating levels requiring action to the On-Scene Commander. Action levels based on TLVs published by ACGIH.

Parameter	*Frequency*	*Action Level*	*Required Action*
☐ Oxygen		<19.5%	Wear SCBA
		>23.5%	Fire potential; stop monitoring, leave area
☐ Flammable gas		≥10% LEL	Explosion hazard; leave area
☐ Benzene		>25 ppm	Wear SCBA
		0.5 - 25 ppm	Use full-face air purifying respirator with organic vapor cartridges
☐ Carbon dioxide		>50,000 ppm	Wear SCBA
		5,000 - 50,000 ppm	Use half-face air purifying respirator with appropriate cartridge
☐ Hydrocarbons		50 to 500 ppm	Use half-face air purifying respirator with appropriate cartridge
		>500 - 2,500 ppm	Use full-face air purifying respirator with appropriate cartridge

6. BRIEF ALL PERSONNEL

Site Diagram attached? ☐ Yes ☐ No

Reviewed with all team members *(check all applicable items)*

- ☐ Buddy system
- ☐ Hazards / conditions on site
- ☐ Emergency hand signals
- ☐ Evacuation alarm
- ☐ Evacuation / escape route
- ☐ Criteria for immediate evacuation
- ☐ Radio communications
- ☐ Location of first aid/rescue gear
- ☐ Required PPE
- ☐ Safe access route to site

Prepared by Site Safety Officer

Signature Date/Time

Approved by On-Scene Commander

Signature Date/Time

7.0 MATERIAL/EQUIPMENT

MSDS

Refer to the SDS binder that is available in all control rooms at each plant location and is updated every 3 years by the Health and Safety Department. In the diesel plant for Aishihik, Faro, Whitehorse and Dawson, the SDS binder is located in the Operators office.

PPE

Use/wear the appropriate PPE as recommended by the SDS sheet. The appropriate PPE is mandatory.

Location: Faro

Glycol	5,100L
Diesel Fuel	112,250L
Oil	6,000L
Oil – Voltesso	12,900L

Location: Faro FD1
Container: Spill Response Kit - Rocky Mountain Small, wheeled

Quantity	Description	Size	To Purchase	Date needed
1	White Oil/Gas sheets (bag of 100)	17"x19" ea		
6	White Oil/Gas Small pillows	8"x18"		
2	White Oil/Gas Large pillows	18"x18"		
5	Grey universal Socks	3"x8'		
2	Grey universal Socks	3"x4'		
1	Plug n' Dike (Leak Repair Putty)	1 lbs Jar		
1	Multi-Zorb Granular Sorbent	25lb bag		
2	Drain covers: Neoprene			
1 box	Gloves Nitrile	Pairs XL		
2	Splash Goggles	One fits all		
2	Disposable poly coated overalls	One fits all		
1	Disposal bags (6mil plastic) industrial waste	6mil plastic, box of 50		
1	Shovel, small foldable			
1	Meter tag on spill kit after restocked			
100	Grey sheets -full bag			
5	Grey pillows 18x18			

Location: **Faro FD7**
Container: Spill Response Kit - Large box Outside FD7 plant

Quantity	Description	Size	To Purchase	Date needed
1	White Oil/Gas sheets (bag of 100)	17"x19" ea		
4	White Oil/Gas small pillows	8”x18”		
5	White Oil/Gas Large pillows	18"x18"		
6	White Oil/Gas only socks	3”x4”		
6	White Oil/Gas only socks	3”x3”		
5	Grey universal Socks	3"x8'		
2	Grey universal Socks	3"x4'		
1	Plug n’ Dike (Leak Repair Putty)	10 lbs bag		
1	Multi-Zorb Granular Sorbent	25lb bag		
1	Drain covers: Neoprene			
1	Gloves Nitrile	Pairs XL		
2	Splash Goggles	One fits all		
2	Disposable poly coated overalls	One fits all		
2	Disposal bags (6mil plastic) industrial waste	6mil plastic		
1	Shovel			
1	Grey sheets -full bag	100 sheet bag		
5	Grey pillows 8x8			
1	Tarp			
1	Meter tag on spill kit after restocked			

Location: **Whitehorse Spill trailer**

Quantity	Description	
Box 1 - PPE		**To Purchase**
1	Rain suit	
1	Organics respirator	
3	Protective Goggles	
1	Gloves, Nitrile, box of 100	
4	Rubber gloves, Latex 12"	
4	High visibility safety vests	
6	Pairs Rubber Boots	
12	Disposable Coveralls	
1	Emergency Response guide	
Box 2 - Emergency equipment		
2	Headlamps	
3	Hand lanterns battery operated	
2	Paint orange aerosol	
2	Blankets	
1	Polyester 100’ rope	

Shelving - Spill equipment		
1	Oil Skimmer	
1	White, Oily only Absorbent rolls (new)	
1	150 Gallon pop-up pool	
1	20 gallon pop up pool	
1	3' by 3" absorbent sock	
1	33lb bag granular "floor dry"	
2	25lb bags granular oil absorbent	
3	Soild waste barrels, poly over packs	
1	ft 10'x8" boom (new)	
1	Putty, jar for drum and tank leaks	
100	Garbage bags, industrial waste	
1	Plastic sheeting	
1	Rubbermaid bins for dirty equipment	
2	Wire flags, bundles	
Other Tools/Equipment		
1	Camera (disposable)	
1	Pick-axe	
1	Rake	
1	Shovel	
1	Push Broom	
1	Nylon hand broom	
1	4L container of solvent	
1	Plastic dust pan	
2	Spades	
4	Pylons	
1	Air Horn	
1	Fire extinguisher	

***Edits of this inventory will be catalogued and sent to the Environmental coordinator.**

8.0 EQUIPMENT/SERVICES

Table 1. Inventories/services supplied by contractor/consultant in the Faro area

NAME	PHONE/ADDRESS	EQUIPMENT/SERVICES AVAILABLE	SERVICE AREA
Town of Faro Public Works Department	(867)-689-0679 (867) 994-2762	Spill clean up services, excavator and skidsteer services, dump truck/trailer	Faro, Yukon
Pilgrims	(867) 994-3101 (250) 279 3101	Bobcat service Transport materials Snow removal	Faro, Yukon
Boreal Engineering	(867) 335-0211	Equipment Services, dump truck/trailer, engineering services, Vac and Water Truck	Faro, Yukon
Van Gorda Enterprises	(867) 689-0679, (867) 994-2762	Spill clean up services, excavation and skidsteer services, dump truck/trailer	Faro, Yukon

9.0 CONTACT DIRECTORY

Yukon Energy SCC **867-393-5324**
867-393-5355

Emergency Services	**Fire**	**Ambulance**	**Police**
Dawson City	993-2222	993-4444	993-5555
Faro	994-2222	994-4444	994-5555
Mayo	996-2222	996-4444	996-5555
Whitehorse	911	911	911
Aishihik (Haines Junction)	634-2222	634-4444	634-5555

Yukon Energy Contacts

Yukon Energy VP of Engineering and Capital Projects	867-393-5317 (w) 867-336-0317 (cell)
Yukon Energy VP of Operations	867-393-5366 (w) 867-334-6904 (cell)
Yukon Energy Manager, Operations	867-393-5383(w) 867-334-6586 (cell)
Yukon Energy Lead Hand, System Control Operations	867-393-5399(w) 867-334-6759 (cell)
Yukon Energy Lead Hand, Transmission & Distribution	867-667-6213 (w) 867-336-4050 (cell)
Yukon Energy Lead Hand, Mechanical Maintenance	867-393-5384 (w) 867-335-2863(cell)
Yukon Energy Lead Hand, Electrical Maintenance	867-393-5311 (w) 867-334-5868 (cell)
Yukon Energy Manager, Environment	867-393-5350 (w) 867-333-0300 (cell)
Yukon Energy Manager, Health and Safety	867-393-5353 (w) 867-334-2073(cell)

External Agency Contacts

Department of Environment, YTG, Whitehorse. Yukon	Phone: (867) 667-7244 (24 Hour Spill Report Line) Fax: (867) 667-7962
Oil and Gas Resources	Toll Free: 1-800-661-0408 ext 5087
Oil and Gas Resources Chief Operations Officer	Phone: (867) 667-3565 Cell: 867-334-3112
CANUTEC National Advisory Centre offering advice On dangerous goods emergencies	Phone (613) 996-6666
Fire Marshall National Fire Code (fuel storage)	Phone: (867) 667-5417 (work)
Faro Fire Department (24 hr emergency line)	Phone: (867) 994-2704
Environmental Protection Spill Regulations	Phone: (867) 667-3436 (work)
Water Inspections Section Yukon Government Yukon Waters Act	Phone (867) 667-3227 (work)
Canadian Environmental Protection Agency Fisheries Act PCB Regulations	Phone (867) 667-3470 (work)
Department of Fisheries and Oceans	Phone (867)-393-6722

10.0 SITE SPECIFIC INFORMATION: FARO

The Facility

The Faro Diesel/Substation site is located in the town of Faro. The Faro Diesel/Substation facility includes the following structures:

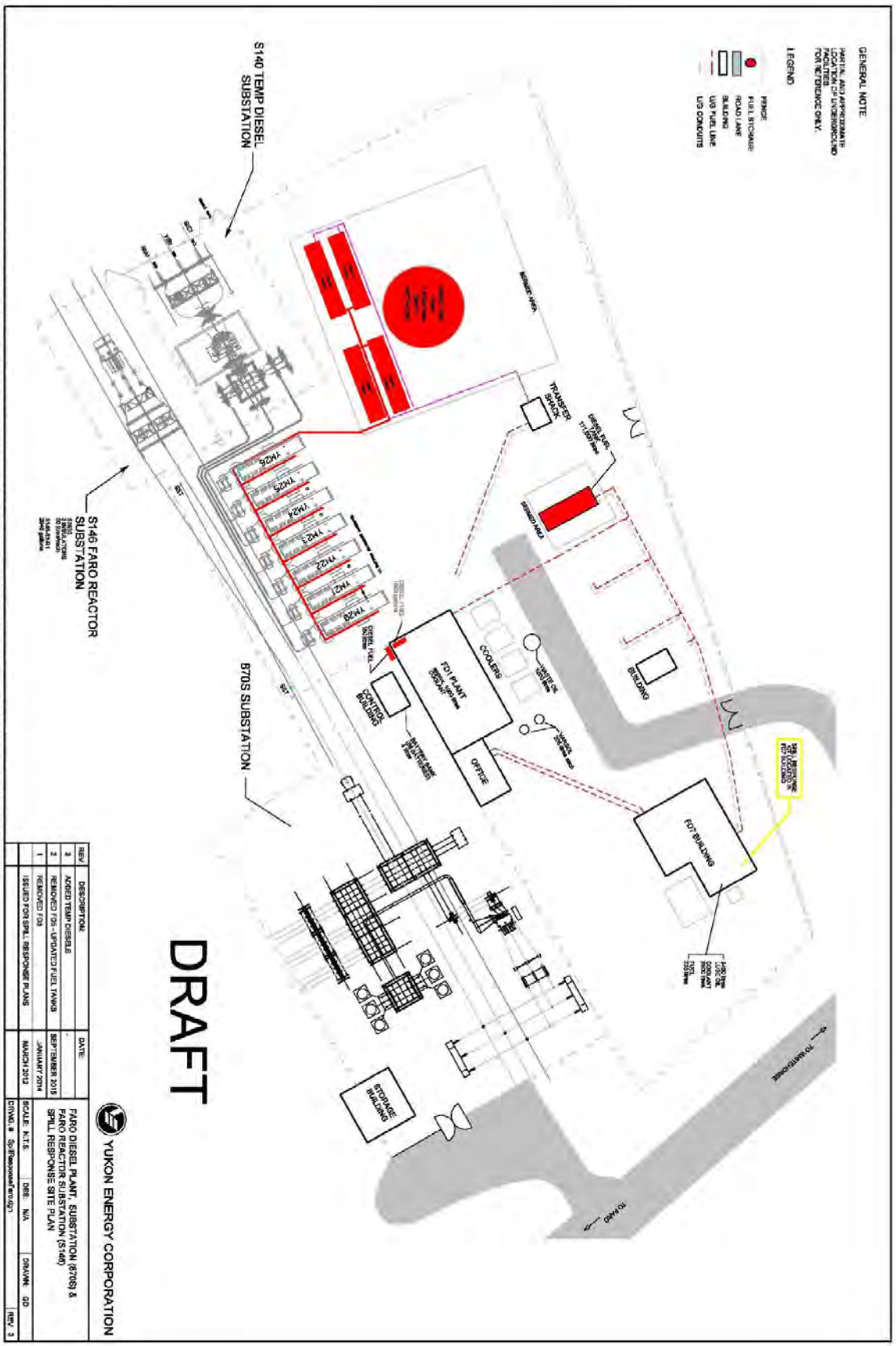
- Diesel generating plant buildings (2) and mobile diesel gensets (6)
- Diesel fuel storage tanks (4)
- Substation

The map on the following page shows the existing layout of the Yukon Energy's area at the Faro Generating Facility.

- YEC and its contractors shall maintain reports of all spill or unauthorized discharge occurrences, including spills that are less than the reportable quantities under the Yukon *Spills Regulations.* The log book shall be made available at the request of the inspector. The reports shall include, but not necessarily be limited to:

    - Date and time of the spill;
    - Substance spilt or discharged;
    - Approximate amount spilled or discharged;
    - Distance between the spill or discharge and the nearest watercourse; and
    - Remedial measures taken to contain and clean-up the spill area or to cease the discharge

These are written in the reports by the first responder, Lead Hand or VP of Operations depending on the severity of the spill. See page 6 for response organization structure.


GENERAL NOTE
LEGEND
FENCE
FUEL STORAGE
ROAD / LANE
BUILDING
U/G FUEL LINE
U/G CONDUITS
S140 TEMP DIESEL SUBSTATION
S146 FARO REACTOR SUBSTATION
870S SUBSTATION
TRANSFER SHACK
FDT BUILDING
FDT PLANT BUILDING
OFFICE
COOLERS
CONTROL BUILDING
BUILDING
STORAGE BUILDING
TO WATERHOUSE
TO FARO
DRAFT
YUKON ENERGY CORPORATION
FARO DIESEL PLANT, SUBSTATION (870S) & FARO REACTOR SUBSTATION (S146)
SPILL RESPONSE SITE PLAN
REV 3
ADDED TEMP DIESEL
REMOVED FSS - UPDATED FUEL TANKS
REMOVED F2H
ISSUED FOR SPILL RESPONSE PLANS
SEPTEMBER 2015
JANUARY 2014
MARCH 2013

Location of temporary storage tanks and temporary diesel generators.

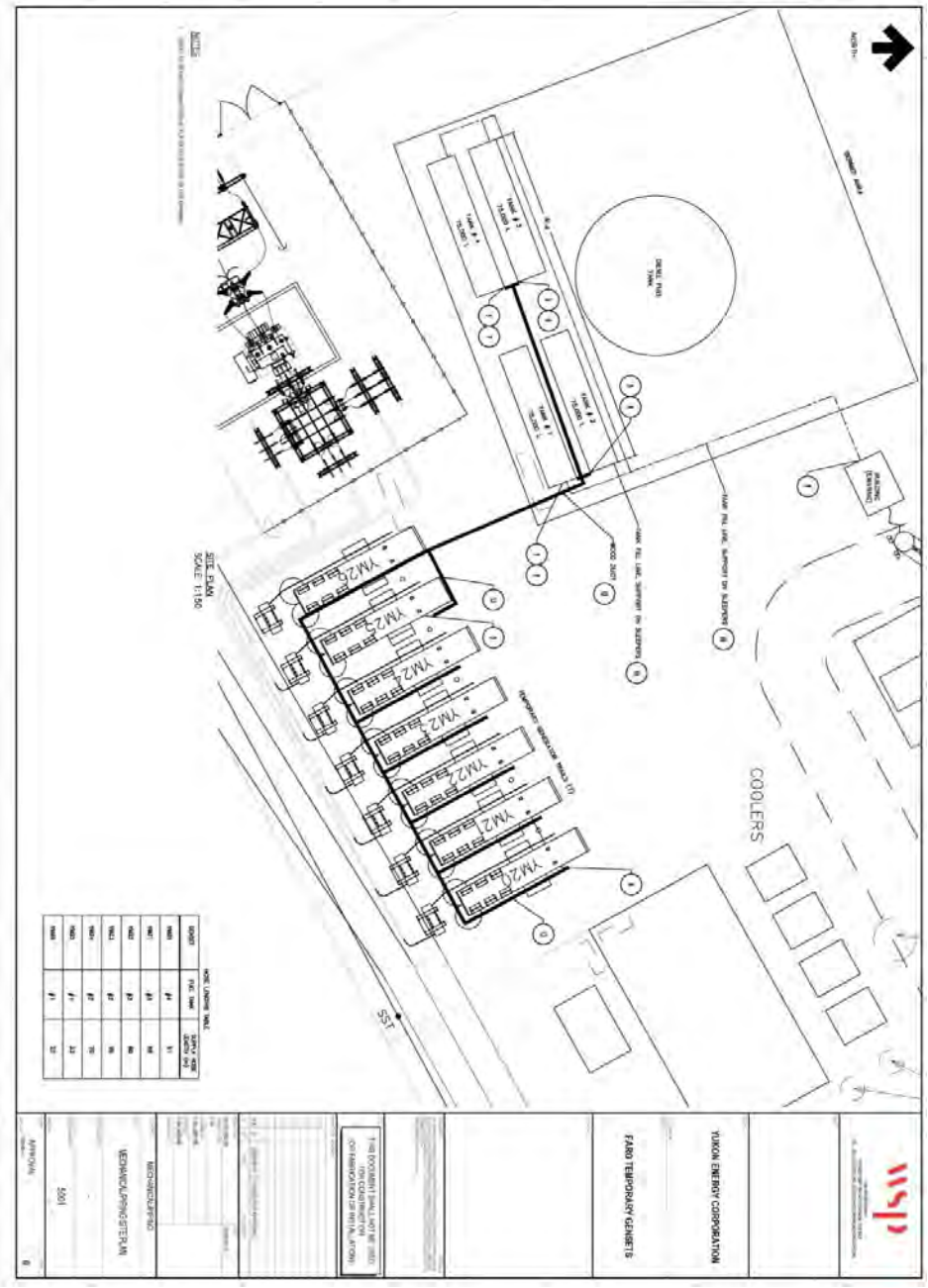
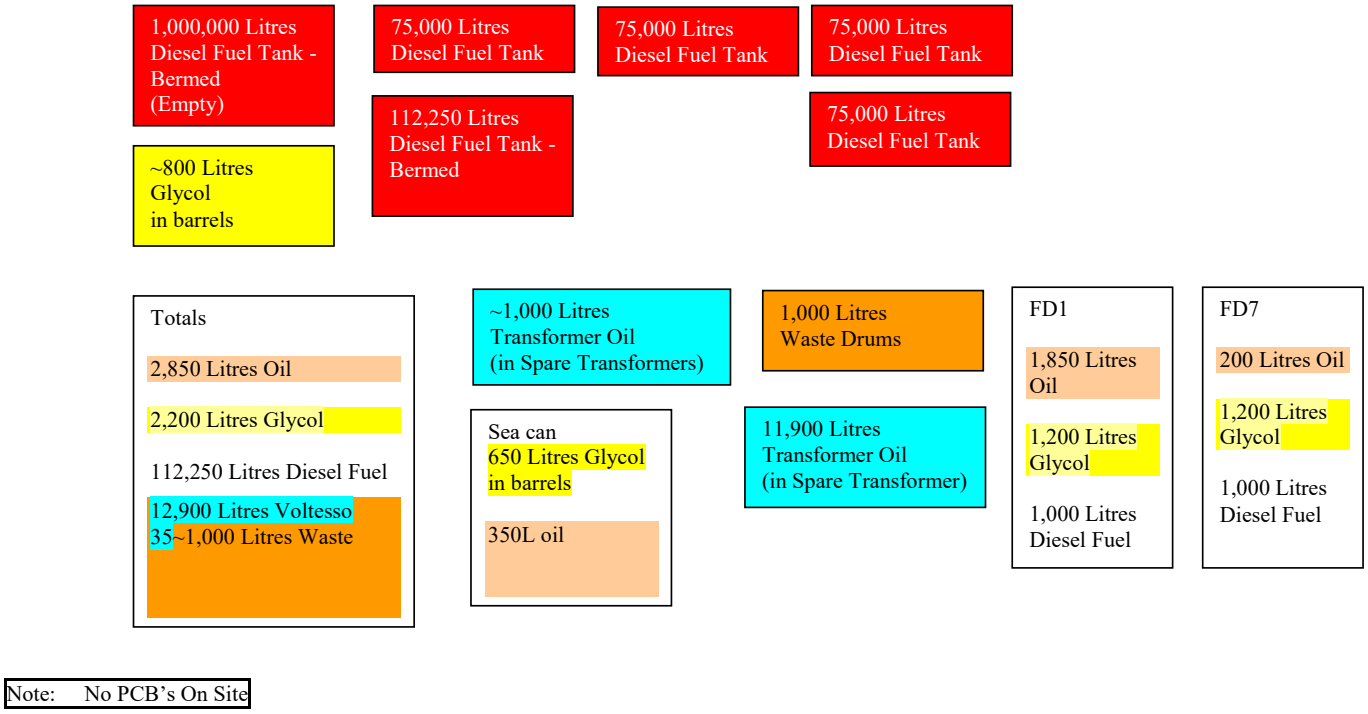


Table 2. Fuel, Petroleum Product and other Hazardous Materials Brought On-Site or Generated On-Site

Hazardous Material Name	Est. Max. Amount of Material On-Site at Any One Time	Material Staging, Use, and Storage Location(s), & Material Storage and Secondary Containment Practices and Structures[1]	Distance of Material Staging, Use, and Storage Locations from Nearby Waterways[2] and Sensitive Areas[3]
Glycol	6,050L		~400m
Diesel Fuel	412,250L	A 4 ft high concrete secondary containment berm was constructed around the main fuel tank, with a plastic liner. Sand covers the liner	~400m
Oil	5,250 L	Operators walk through the building once every 24 hours during plant operation and visually check for spills in process.	~400m
Oil – Voltesso 35 Diesel plant	25,835L	Operators walk through the building once every 24 hours during plant operation and visually check for spills in process.	~400m
Oil – Voltesso 35 Faro substation S146	40,286L	Operators walk through the building once every 24 hours during plant operation and visually check for spills in process.	~400m
Oil – Voltesso 35 Faro substation S162	30,600L	Operators walk through the building once every 24 hours during plant operation and visually check for spills in process.	~400m
Waste Oil	2,000L	Operators walk through the building once every 24 hours during plant operation and visually check for spills in process.	~400m

Figure 2. Total Volumes of Hazardous Materials at the Faro Generating Station



Note: No PCB's On Site

Figure 3. Sub-station 870S/S146

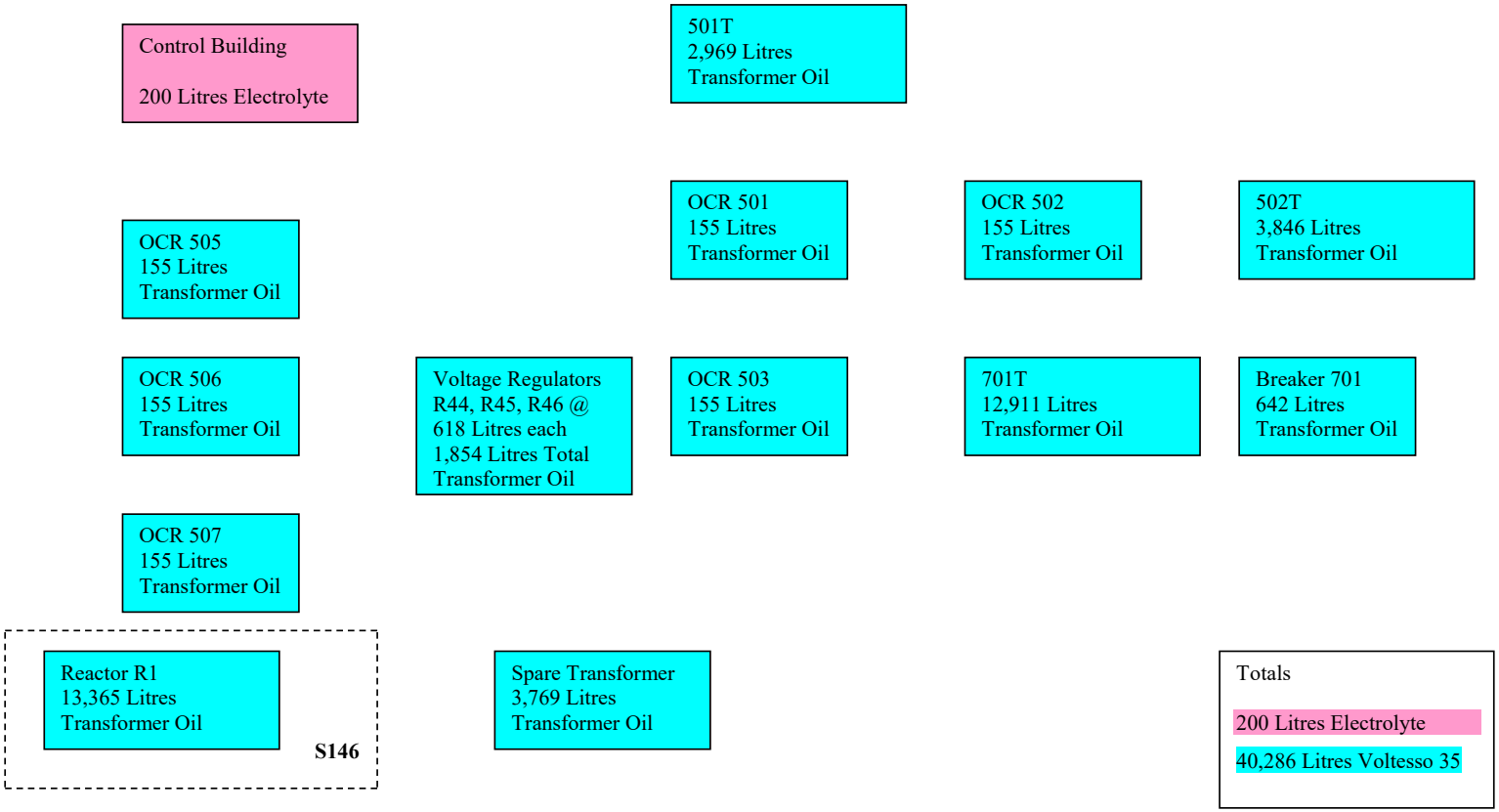
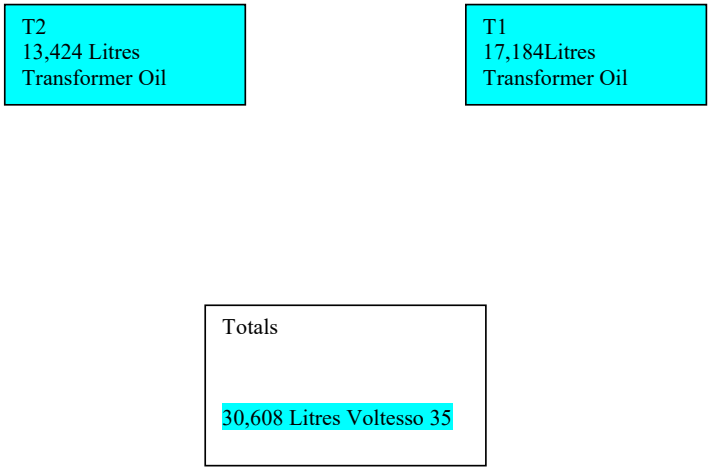


Figure 4. Faro Sub-station S162



11.0 RESOURCES AT RISK

Table 3. Site Description

A.	**Site Locations**	Running of Diesels to produce Electricity.
B.	**The site location and boundaries:**	Faro, Yukon, Canada. Yukon Energy Diesel Generating site
C.	**The drainage pathways from the site:**	Rose Creek, Pelly River
D.	**Nearby waterways and sensitive areas:**	Rose Creek, Pelly River, Town of Faro Residents

Table 4. Nearby Waterways[1] and Sensitive Areas[2]

Waterway[1] or Sensitive Area[2]	Distance from Project Site	Direction of Flow from Project Site
Rose Creek	70m from waterway	South, into the Pelly River

It is very unlikely that Yukon Energy would affect any water resources as diesel fuel tanks are located inside berms and the facility is not located adjacent to a waterway. As well sumps are located under the plant floors to intercept oils from going to ground.

12.0 SITE SPECIFIC SCENARIOS

SCENARIO 1

During a short break, employees were in the parking lot at the Faro Diesel Generating Station.
They observed a tank truck enter the main gate, hit what they took to be a patch of ice and hit the main diesel storage tank and create a crack in the wall of the main diesel tank.
The students saw the driver stumble from the tank truck cab and collapse against the perimeter fence adjacent to the tank.
The PLT onsite took command of the incident.

1. **NOTIFY SUPERVISOR OR SSC**

    - Call SCC and VP of Operations
    - Arrange Call-Back time, if appropriate.
    - Incident commander will call all emergency response teams

2. **ALERT OTHER EMPLOYEES/PERSONS IN AREA**

    - Approach spill site from up-wind or, if indoors, ensure you have a clear escape route
        - Check to see if tanker truck is intact and not spilling onto ground
        - Check on the person that stumbled from the truck and remove him from the scene
        - Check cab of truck for any other passengers
        - Call YEC advanced first aiders to tend to the driver
        - Check inside berm for any YEC employees

    - Establish Perimeter Security. Stop people from going in and out of the YEC gate. Call police to do this or other YEC group. Use danger tape around the area, restricting access. Keep everyone inside buildings until clean-up is complete

    - Evacuate main corporate building and diesel plants, if necessary

    - Eliminate Ignition Sources. Shut off power going to tank fed from inside. SCC will call contractor with a vacuum truck to pump the diesel out of the tanker truck. Pads and absorbents are thrown down where liquid has spilled.

    - Commence documentation

USE BUDDY SYSTEM

3. **IDENTIFY MATERIAL, SPILL SOURCE, ESTIMATE QUANTITY SPILLED AND POTENTIAL FATE**

    - Block Potential Escape Routes, if appropriate

4. **IF SPILL CONTINUING, CONTROL SOURCE, IF SAFE TO DO SO**

    - Develop Initial Incident Response Plans (Defensive, Offensive or Non-Intervention)

    - Refer to product SDS. Wear appropriate PPE.

(See "Fast Fact Sheets" in this Plan for spills of specific products.)

5. **SUMMON RESPONSE RESOURCES, AS APPROPRIATE**

6. **UPDATE SUPERVISOR AND/OR SCC ON PROGRESS**

7. **COMPLETE DETAILED INCIDENT REPORT**

Table 5. Other Possible Scenarios

Hazardous Materials and Location	Spill Response Task			
	Assess the Spill	**Secure the Area**	**Contain and Eliminate the Spill Source**	**Clean Up Spilled Material Decontaminate Equipment Dispose of Spilled & Contaminated Material[1]**
Diesel Plant Storage – Mobilgard 312, Delvac 1340, Diesel, Varasol, Anti-Freeze	• Any considerable losses in the dip readings from one check to the next • Any fuel/lubricants smells or any pools on the floor	Inside the diesel plant	• Cover drains with the drain covers from the spill kit. • Use leak filler if leak is accessible and if it is safe to do so	• Use granular sorbents and sorbent sheets to mop up the spill • Hydrocarbon soiled materials will be disposed of in barrels and sealed. Barrels are located in the spill trailer. • Special waste is picked up is once a year by Environment Yukon
Waste oil	• Oil smells or any pools outside the waste oil containment	Outside the diesel plant in waste oil containment	• Use the spill kit located next to WD3 • Use oilwik boom around the spill site	• Use granular sorbents and sorbent sheets • Dig up the area to assess the extent of the spill • Place the contaminated soil in a poly lined temporary containment or a metal bin. • Attain a contaminated soil removal permit and transport to a land treatment facility
Any hazardous material	• See material flowing in the Whitehorse YEC yard	Cover the man holes immediately and contain the spill	• Use the Spill response trailer. Use man hole covers and a sorbent boom	• Clean up material with sorbents and discard appropriately

13.0 APPENDIX A: FORMS

ICS 201 –BREIFING DOCUMENT
ICS 214A – INDIVIDUAL LOG
Safe action/Initial Action Checklists by Substance

- **Diesel Fuel**
- **Delvac 1340**
- **Coolant- CAT EC-1 (238-8650)**
- **Mobilgard 312**
- **Teresso 46**
- **Varsol**
- **Waste Oil**
- **Voltesso 35**
- **SF6**

Appendix A1: **ICS 201-BRIEFING DOCUMENT**

Purpose. The Incident Briefing form provides the Incident Commander (YEC Site Supervisor) with basic information regarding the incident situation and the resources allocated to the incident. It also serves as a permanent record of the initial response to the incident.

Preparation. The briefing form is prepared by the Incident Commander (YEC Site Supervisor) for presentation to the incoming Incident Commander along with a more detailed oral briefing. Proper symbology should be used when preparing a map of the incident.

Distribution. After the initial briefing of the Incident Commander (YEC Site Supervisor) and General Staff members, the Incident Briefing is duplicated and distributed to the Command Staff, Section Chiefs, Branch Directors, Division/Group Supervisors, and appropriate Planning and Logistics Section Unit Leaders. The sketch map and summary of current action portions of the briefing form are given to the Situation Unit while the Current Organization and Resources Summary portion are given to the Resources Unit.

1. Incident Name:	2. Prepared by: Date: Time:	INCIDENT BRIEFING ICS 201-OS (pg 1 of 4)

3. Map/Sketch (include maps drawn here or attached, showing the total area of operations, the incident site/area, overflight results, trajectories, impacted shorelines, or other graphics depicting situational and response status)

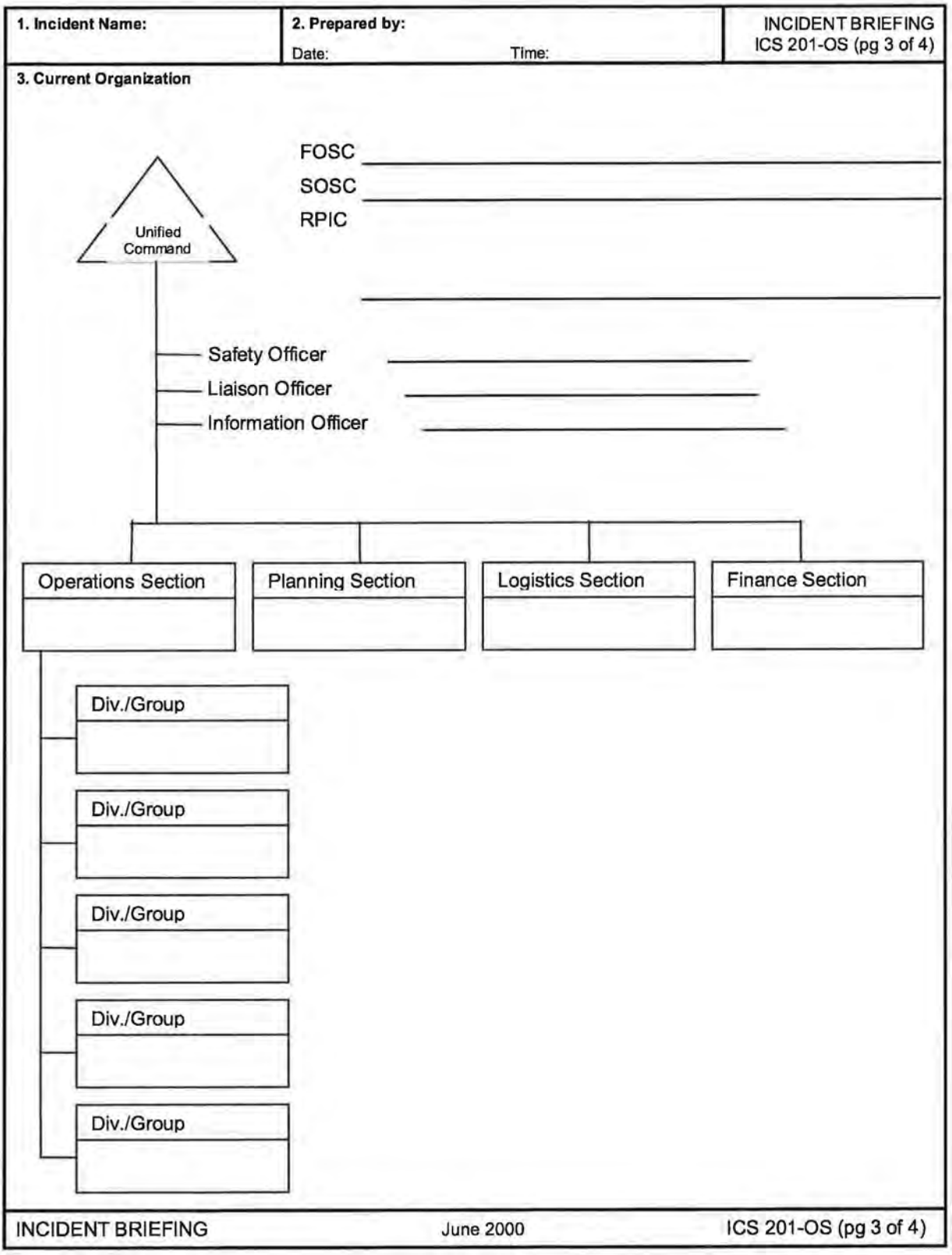
INCIDENT BRIEFING	June 2000	ICS 201-OS (pg 1 of 4)

1. Incident Name:	2. Prepared by: Date: Time:	INCIDENT BRIEFING ICS 201-OS (pg 2 of 4)

4. Initial Incident Objectives

5. Summary of Current Actions

Time	Action/Note


1. Incident Name:
2. Prepared by:
Date:
Time:
INCIDENT BRIEFING
ICS 201-OS (pg 3 of 4)
3. Current Organization
FOSC
SOSC
RPIC
Unified Command
Safety Officer
Liaison Officer
Information Officer
Operations Section
Planning Section
Logistics Section
Finance Section
Div./Group
Div./Group
Div./Group
Div./Group
Div./Group
INCIDENT BRIEFING
June 2000
ICS 201-OS (pg 3 of 4)

1. Incident Name:	2. Prepared by: Date: Time:	INCIDENT BRIEFING ICS 201-OS (pg 4 of 4)

7. Resources Summary

Resources Needed	Time Ordered	Resources Identifier	ETA	On-Scene?	NOTES: (Location/Assignment/Status)

Appendix A2-: **ICS 214A – INDIVIDUAL LOG**

Purpose. The Unit Log is used to record details of unit activity including strike team activity. The file of these logs provides a basic reference from which to extract information for inclusion in any after-action report.

Initiation of Log. A Unit Log is initiated and maintained by head of the spill response effort.

1. Incident Name	2. Operational Period (Date / Time) From: To:	INDIVIDUAL LOG ICS 214a-OS
3. Individual Name	4. ICS Section	5. Assignment / Location

6. Activity Log		Page of
Time	Major Events	

7. Prepared by:	Date / Time

INDIVIDUAL LOG	June 2000	ICS 214a-OS

Record all personal activity --> Supervisor at end of shift --> Documentation Unit

Appendix A3-9: **SAFE ACTION/INITIAL ACTION CHECKLISTS BY SUBSTANCE**

Purpose. The purpose of the Safe Action/Initial Action Checklists by substance are to provide safety measures, PPE to be worn, first aid, emergency response, physical and chemical properties of a particular substance.

Use: These checklists are to be used as initial first action by the first responder.

Appendix A3: **DIESEL FUEL -SAFETY MEASURES**

- May cause eye, respiratory and skin irritation, headache, nausea, mental confusion, unconsciousness and death
  - Wear appropriate PPE
- Combustible liquid, may form explosive vapours
  - Eliminate ignition sources and monitor for combustible gases
- May accumulate static electricity
  - Ground and bond during transfers
- Vapours heavier than air
  - Stay out of low areas and confined spaces

Personal Protection

- If there is a high level of fumes during a spill, ventilate area before entering
- Wear required PPE, as appropriate

First Aid

- **Eyes**
  - Flush eyes immediately with fresh warm water (40C-45C) for at least 15 minutes holding lids open. DO NOT USE excessively hot or cold water
  - Get medical attention
- **Skin**
  - Remove contaminated clothing
  - Wash contaminated skin thoroughly with soap and warm water
  - Obtain medical attention if irritation or redness develops
- **Inhalation**
  - Move person to fresh air
  - Administer oxygen therapy, as necessary
  - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
  - If swallowed, DO NOT INDUCE VOMITING and obtain immediate medical attention
  - Small amounts of materials that enter the mouth should be rinsed out until taste of substance is eliminated. Remove dentures and rinse well, if applicable

For Further Information Consult Product SDS

Appendix A3: **DIESEL FUEL –EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Advise SCC and/or Supervisor (867) 393 5324/ 393 5355
- Request assistance
- Attempt to limit escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO2, foam and/or H20 fog. DO NOT use a direct stream of water as it may spread the fire

Physical & Chemical Properties

Appearance:	Clear white to pale/bright yellow liquid
Odour:	Petroleum
Flashpoint:	Approximately > + 37.8C
Solubility in water:	Insoluble
Specific Gravity:	0.78 – 0.85
Vapour Density:	> than 1 (Air = 1)

For Further Information Consult Product SDS

Appendix A6: **DELVAC 1340- SAFETY MEASURES**

- Excessive exposure may result in eye, skin, or respiratory irritation. Wear appropriate PPE
- Material will not burn unless preheated. Avoid excessive heat as it may cause formation of vapours or mists in which case SCBA must be worn
  - Eliminate ignition sources
- Spilled material may create a slipping hazard

Personal Protection

- Wear required PPE, as appropriate

First Aid

- **Eyes**
  - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
  - Get medical attention if irritation occurs and persists
- **Skin**
  - Wash contaminated skin with mild soap and warm water. Remove contaminated clothing
  - Get medical attention if irritation occurs and persists
- **Inhalation**
  - Remove from further exposure.
  - For those providing assistance, avoid exposure to yourself or others. Use adequate respiratory protection.
  - If respiratory irritation, dizziness, nausea, or unconsciousness occurs, seek immediate medical assistance
  - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
  - Not normally a factor.
  - If swallowed, DO NOT INDUCE VOMITING and get immediate medical attention
  - If vomiting occurs, keep the head low to prevent product entering the lungs

For Further Information Consult Product SDS

Appendix A6: **DELVAC 1340- EMERGENCY RESPONSE**

Spill

- ISOLATE AREA, restrict access and evacuate if necessary
- Eliminate ignition sources
- Spill may create slipping hazard
- Advise Supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Evacuate and isolate area, restrict access
- Advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog. DO NOT use direct stream of water as it may spread fire

Physical & Chemical Properties

Appearance:	Liquid. Brown
Odour:	Hydrocarbon odour
Flashpoint:	+ 230 C (446ºF)
Solubility in water:	Negligible
Specific Gravity:	< 1 (Water = 1)
Vapour Density:	Not available

For Further Information Consult Product SDS

Appendix A7: **COOLANT- CAT EC-1 (238-8650) - SAFETY MEASURES**

- DO NOT taste or swallow antifreeze. DO NOT breathe vapours or fumes
  - Wear appropriate PPE
- Material is unlikely to burn unless preheated
- It may possibly accumulate static electricity
  - Ground and bond containers during transfer

Personal Protection

- If high level of fumes are present during a spill, ventilate area before entering
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
  - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
  - Obtain medical attention if irritation persists
- **Skin**
  - Wash contaminated area with plenty of mild soap and water. Remove contaminated clothing
  - If irritation occurs and persists, obtain medical attention
- **Inhalation**
  - Move exposed person to fresh air
  - Administer oxygen therapy, as necessary and only if trained
  - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
  - If symptoms occur, obtain medical attention
- **Ingestion**
  - Remove dentures, if any, and rinse. Rinse out mouth until taste of product dissipates
  - If swallowed, DO NOT INDUCE VOMITING. Get immediate medical attention
  - If vomiting occurs, keep the head low to prevent product entering the lungs.

For Further Information Consult Product SDS

Appendix A7: **COOLANT- CAT EC-1 (238-8650) - EMERGENCY RESPONSE**

Spill

- ISOLATE area, restrict access and evacuate if necessary
- Eliminate ignition sources though substance unlikely to ignite
- Advise Supervisor and/or SCC # (867) 393 5324/SCC Cell. (867) 393 5355
- Request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using appropriate sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog
  DO NOT use a direct stream of water as it may spread fire

Physical & Chemical Properties

Appearance:	Liquid. Yellow Colour
Odour:	Faint or mild
Flashpoint:	+ 127 C
Solubility in water:	Soluble
Lower/Upper Explosive Limits:	Lower 3.2% Upper: Not stated
Vapour Density:	2.1 (Air = 1)

For Further Information Consult Product SDS

Appendix A8: **MOBILGARD 312 – SAFETY MEASURES**

- Excessive exposure may result in eye, skin, or respiratory irritation.
- Exposure most likely to occur through skin contact or from inhalation of mechanically or thermally generated oil mists. Normally, product has a low level of toxicity
    - Wear appropriate PPE
- Material will not burn unless preheated. Avoid excessive heat as it may cause formation of vapours or mists
    - Eliminate ignition sources
- Spilled material may create a slipping hazard

Personal Protection

- If high level of fumes are present during a spill, ventilate area before entering
- Wear other required PPE, as appropriate
- If contact is likely with eyes, then safety glasses should be worn.

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
    - Get medical attention if irritation occurs and persists
- **Skin**
    - Wash contaminated skin with mild soap and water. Remove contaminated clothing
    - Get medical attention if symptoms occur and persist
- **Inhalation**
    - Move exposed person to fresh air
    - Administer oxygen therapy, as necessary and only if trained
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
    - Remove dentures, if any. Wash out mouth with water. Substance has low oral toxicity
    - First Aid is normally not required. Seek medical attention if discomfort occurs

For Further Information Consult Product SDS

Appendix A8: **MOBILGARD 312 – EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Spill may create slipping hazard
- Advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog. DO NOT use direct stream of water as it may spread the fire

Physical & Chemical Properties

Appearance:	Liquid. Brown colour
Odour:	Hydrocarbon odour
Flashpoint:	> + 225 C (437 F)
Solubility in water:	Insoluble
Specific Gravity:	< 1 (Water = 1)
Vapour Density:	Not available

For Further Information Consult Product SDS

Appendix A9: **TERESSO 46 – SAFETY MEASURES**

- Low order of toxicity. Excessive exposure may result in eye, skin or respiratory inhalation
  - Wear appropriate PPE
- Material will not burn unless preheated. Avoid excessive heat as it may cause formation of vapors or mists
  - Eliminate ignition sources
- Spilled material may create a slipping hazard

Personal Protection

- If high levels of fumes are present during the event of a spill, ventilate area before entering
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
  - Flush eyes immediately with fresh water (40C-45C) for 15 minutes holding lids open. DO NOT USE excessively hot or cold water
  - Get medical attention if irritation occurs
- **Skin**
  - Wash contaminated skin with mild soap and water. Remove contaminated clothing
  - Get medical attention if symptoms occurs or the substances comes in contact with an open wound
- **Inhalation**
  - Move exposed person to fresh air
  - Administer oxygen therapy, as necessary and only if trained
  - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
  - First aid is not normally required. Seek medical attention if discomfort occurs
  - Remove dentures, if any, and rinse before replacing. Rinse out mouth with water until taste of product dissipates. Substance has low oral toxicity

For Further Information Consult Product SDS

Appendix A9: **TERESSO 46 – EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Spill may create slipping hazard
- Advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog. DO NOT use direct stream of water as it may spread fire

Physical & Chemical Properties

Appearance:	Liquid. Amber in colour
Odour:	Lubricating oil odour
Flashpoint:	+ 200 C
Solubility in water:	Negligible
Specific Gravity:	< 1 (Water = 1)
Vapour Density:	> 2 (Air = 1)

For Further Information Consult Product SDS

Appendix A10: **VARSOL – SAFETY MEASURES**

- May cause mild irritation to eyes and skin upon contact, drowsiness, lack of coordination, headache and nausea.
  - Wear appropriate PPE
- Combustible liquid. May form explosive vapours. Use in adequately ventilated area
  - Eliminate ignition sources
- Vapours heavier than air
  - Stay out of low areas and confined spaces
- May accumulate static electricity
  - Ground and bond containers during transfer

Personal Protection

- If high level of fumes are present during a spill, ventilate area before entering
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
  - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
  - Get medical attention if irritation occurs
- **Skin**
  - Flush contaminated skin with plenty of water. Remove contaminated clothing
  - Get medical attention if symptoms occur
- **Inhalation**
  - Move exposed person to fresh air
  - Administer oxygen therapy, as necessary and only if trained
  - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
  - Get medical attention if adverse health effects persist or are severe
- **Ingestion**
  - Remove dentures, if any, and rinse with water. Rinse out mouth with water
  - Obtain medical attention if symptoms occur
  - If swallowed, DO NOT INDUCE VOMITING. Give small quantities of water or milk to drink and get immediate medical attention
  - If vomiting occurs, keep the head low to prevent product entering the lungs

For Further Information Consult Product SDS

Appendix A10: **VARSOL – EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Advise Supervisor and/or SCC # (867) 393 5324/. (867393 5355
- Request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog. DO NOT use direct stream of water as it may spread fire

Physical & Chemical Properties

Appearance:	Clear liquid
Odour:	Petroleum distillate
Flashpoint:	> + 37.8 C (Combustible liquid)
Solubility in water:	Insoluble
Lower/Upper Flammability Limits:	1% - 13%
Vapour Density:	5 (Air = 1)

For Further Information Consult Product SDS

Appendix A11: **VOLTESSO 35 - SAFETY MEASURES**

- May cause eye, respiratory and skin irritation. Frequent or prolonged contact may de-fat and dry the skin
  - Wear appropriate PPE
- Combustible liquid, may form explosive vapours
  - Eliminate ignition sources and monitor for combustible gases
- May accumulate static electricity
  - Ground and bond during transfers
- Vapours heavier than air
  - Stay out of low areas and confined spaces

Personal Protection

- If high level of fumes are present during a spill, ventilate area before entering
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
  - Flush eyes immediately with fresh warm water (40C-45C) for at least 15 minutes holding lids open. DO NOT USE excessively hot or cold water
  - Get medical attention
- **Skin**
  - Remove contaminated clothing
  - Wash contaminated skin thoroughly with soap and warm water
  - Obtain medical attention if irritation or redness develops
  - Launder contaminated clothing before reuse
- **Inhalation**
  - Move person to fresh air
  - Administer oxygen therapy, as necessary and only if trained
  - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
  - If swallowed, DO NOT INDUCE VOMITING and obtain immediate medical attention
  - Small amounts of materials that enter the mouth should be rinsed out until taste of substance is eliminated. Remove dentures and rinse well, if applicable

For Further Information Consult Product SDS

Appendix A11: **VOLTESSO 35–EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources
- Advise Supervisor and/or SCC (867) 393 5324/ 867 393 5355 to request assistance
- Attempt to limit escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO2, foam and/or H20 fog. DO NOT use a direct stream of water as it may spread the fire

Physical & Chemical Properties

Appearance:	Pale Yellow, liquid
Odour:	N/D
Flashpoint:	Approximately > 145C
Solubility in water:	Negligible
Specific Gravity:	-
Vapour Density:	> N/D (Air = 1)

For Further Information Consult Product SDS

Appendix A12: **SF6 GAS- SAFETY MEASURES**

- May cause eye, respiratory and skin irritation. Frequent or prolonged contact may de-fat and dry the skin
- Escaping gas may cause frostbite injury
  - Wear appropriate PPE
  - Eliminate ignition sources and monitor for combustible gases
- May accumulate static electricity
  - Ground and bond during transfers
- Vapours heavier than air
  - Stay out of low areas and confined spaces

Personal Protection

- General mechanical ventilation must be worn
- Ribber gloves
- ANSI approved Chemical Workers Goggles
- Coveralls

First Aid

- **Eyes**
  - Flush eyes immediately with fresh warm water (40C-45C) for at least 15 minutes holding lids open. DO NOT USE excessively hot or cold water
  - Get medical attention if pain or sensitivity to light persists
- **Skin**
  - Wash exposed area extremely thouroughly, but gently in cases of frostbite –like injury, with soap and water
- **Inhalation**
  - Move person to fresh air
  - Administer oxygen therapy, as necessary and only if trained
  - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
  - If swallowed, DO NOT INDUCE VOMITING and obtain immediate medical attention
  - Contact MD immediately

For Further Information Consult Product SDS

Appendix A12: **SF6 GAS –EMERGENCY RESPONSE**

Spill

- Evacuate personnel to safe areas. Wear PPE and self-contained breathing apparatus when entering area unless atmosphere is proved to be safe. Ventilate the area. Monitor oxygen level
- Stay upwind
- If possible, stop the flow of product
- Advise Supervisor and/or SCC (867) 393 5324/ 867 393 5355 Request assistance

Fire

- Isolate area, restrict access and evacuate if necessary
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO2, foam and/or H20 fog. DO NOT use a direct stream of water as it may spread the fire

For Further Information Consult Product SDS

Appendix A13: **WASTE OIL – SAFETY MEASURES**

- Mixture of water, oil and lubricant additives. Concentrations of components will vary. The product is not expected to be irritating and has a low level of toxicity under normal use. Exposure most likely to occur through skin or eye contact
    - Wear appropriate PPE
    - Spill may create slipping hazard
- Material is unlikely to burn unless preheated. Spilled material may produce a slipping hazard
    - Vapour pressure will vary dependent on the composition
- It may possibly accumulate static electricity
    - Ground and bond containers during transfer

Personal Protection

- If high level of fumes are present during a spill, ventilate area before entering
- Wear other required PPE, as appropriate

First Aid

- **Eyes**
    - Flush eyes immediately with fresh warm water (40C-45C) for 15 minutes holding lids open
    - Get medical attention if irritation persists
- **Skin**
    - Wash contaminated area with plenty of mild soap and water for 15 minutes. Remove contaminated clothing
    - If irritation occurs and persists, obtain medical attention
- **Inhalation**
    - Move exposed person to fresh air. Additional First Aid treatment is not usually required
    - Administer oxygen therapy, if necessary and/or obtain medical assistance
    - WHEN OXYGEN IS IN USE, ENSURE NO SMOKING
- **Ingestion**
    - Remove dentures, if any, and rinse with water. Rinse out mouth with water
    - If swallowed, DO NOT INDUCE VOMITING. Get immediate medical attention
    - If vomiting occurs, keep the head low to prevent product entering the lungs. Obtain medical attention

For Further Information Consult Product SDS

Appendix A13: **WASTE OIL – EMERGENCY RESPONSE**

Spill

- Isolate area, restrict access and evacuate if necessary
- Eliminate ignition sources though substance unlikely to ignite
- Spilled material make create a slipping hazard
- Advise Supervisor and/or SCC # (867) 393 5324/ (867) 393 5355
- Request assistance
- Attempt to limit product escape routes and shut off source – IF SAFE TO DO SO
- Contain and recover using appropriate sorbent materials and/or vacuum truck

Fire

- Isolate area, restrict access and evacuate if necessary
- Call Fire Department, advise supervisor and/or SCC # (867) 393 5324/ 393 5355 to request assistance
- Shut off fuel to fire, IF SAFE TO DO SO
- If qualified, extinguish with dry chemical extinguisher, CO_2, foam and/or H_20 fog. DO NOT use a direct stream of water as it may spread fire

Physical & Chemical Properties

Appearance:	Liquid. Colour will vary depending on composition
Odour:	Hydrocarbon
Flashpoint:	Will vary depending on composition. Unlikely to burn
Solubility in water:	Insoluble
Lower/Upper Explosive Limits:	Will vary
Vapour Density:	Will vary

For Further Information Consult Product SDS

14.0 WASTE MANAGEMENT

All equipment and/or material used in clean-up (e.g. used sorbents, oil containment materials etc.) must be disposed of in accordance with Environment Yukon requirements.

Accidental spills may produce special wastes (e.g., material with > 3% used oil) and contaminated soil. All waste disposal must comply with the *Yukon Special Waste Regulations* of the *Yukon Environment Act.*

Compliance with these regulations generally requires:

- Classification of the waste
- Packaging requirements (proper labeling and suitable storage containers)
- Transportation documentation
- All transporters must be properly trained
- Disposal in accordance with the regulations at an appropriate facility
- Spill reporting requirements must also be followed
- Waste sorbent material may not be disposed of in a landfill without prior approval from YTG Environment and the landfill operator.
- Contaminated soil must be treated and dealt with as required on a site specific basis and must comply with the requirements of the Yukon Contaminated Sites and Special Waste Regulations. At a minimum, the contractor must consider soil relocation agreement standards and obtain soil relocation permit as required.

Specific clean up requirements

Fuels and lubricants/Waste oil

After clean up, soiled sorbent materials will be placed inside an over pack or sealed metal drums and contained securely until organized special waste disposal can be coordinated.

Liquid wastes will be contained in a separate over pack or sealed metal drum.

Contaminated soils will be removed by an authorized contaminated soil receptor and transported to a land treatment facility.

All other products

All other products are to be contained in over packs or sealed metal drums separately from other products. Do not mix soiled materials. These materials are also to be picked up by Environment Yukon special wastes pick up, which occurs annually or another organized special waste disposal program at Yukon Energy. Contact the Manager of Environment for further information.

15.0 PLAN ADMINISTRATION

The following table must be filled out when changes are made to the plan.
YEC shall review the spill contingency plan annually and provide a summary of that review, including any revisions to the plan, as a component of the annual report.

Document Release and Revision History

Revision #	Revised Section/Page #	Purpose of Release: Details of Revisions/Amendments	Approved By:	Effective Date
00		New document	Director, Operations	May 2000
01	New cover page #1, #2	New cover page #1, added revision history page #2, updated contact info as required	Director, Operations	March 2004
02	Page #7, #10, #11, #12	Updated contact info as required & updated fuel day tank amounts	Director, Operations	May 2007
03	Pages 5,7, 8, and 11	Updated contact info and reporting chain as required	Manager, Environment	December 2009
04	All	Added site specific spill response procedures, updates contact information, added list of contractors for external resources, added resources at risk, updated on site spill response resources inventory. Added spill classification and clean-up plan. Added Spill Plan acknowledgement form, added sample incident report form. Added CFO to YEC reporting chain	Environmental Coordinator	June 20, 2012
05	Page #'s 6, 10-21, 24, 27, 31	Updated notifications, spill equipment inventory, contacts, site information and forms.	Environmental Coordinator	March 6, 2014
06	Page 3,5, 8,20,27, 35	Referenced Spill Safety Plan instead of Initial Incident Response Plan, Some general changes in wording to improve readability, added details about reporting, added spill response equipment located a Whitehorse Gas facility, added Aishihik Water License details, used the title Site Specific Hypothetical Scenarios. In Hypothetical scenarios changed sequence of response to correspond to proper action	Environmental Coordinator	August 13, 2015
07	Page 3, 4, 7, 11-22, 36	Removed mobile radio information, added map of radio coverage, updated contact flow chart, updated spill kit inventory lists, removed superfluous map of LNG plant	Environmental Coordinator	July 21, 2017
08	Pages, 4,6,7,11-13,16,18,21,22,24	Updated Radio map, purpose and scope, materials and equipment, equipment and services, contact directory, site plan, hazardous materials amounts	Env.and Resource Analyst	Sept 24, 2020

Name:	Signature:	Review Date:
VP, Operations		Nov 17/20
EMS Manager		Nov. 18/20

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References:

EMS-MP-011	Emergency Response
EMS-EWP-006	Spill Response
HS-000-E	MP-4 Incident Reporting & Investigation Procedures
HS-000-E-A	Incident Investigation Form
HS-000-E-B	Incident Reporting Form
EMS-MP-001	Environmental Management System Scope and Structural Overview

For additional copies of this plan please visit the YEC Environmental Management Sharepoint site

YUKON ENERGY CORPORATION

AIR DISPERSION MODELLING ASSESSMENT FOR FARO FACILITY

CONFIDENTIAL

December 17, 2020

AIR DISPERSION MODELLING ASSESSMENT FOR FARO FACILITY

YUKON ENERGY CORPORATION

FINAL REPORT

PROJECT NO.: 191-02438-01
CLIENT REF: 20081
DATE: DECEMBER 17, 2020

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EXECUTIVE SUMMARY

WSP Canada Inc. conducted an air quality dispersion modelling and impact assessment for Yukon Energy Corporation's diesel-fuelled electricity generating facility in Faro, Yukon to evaluate the potential air quality impacts of increasing the facility capacity from the existing permitted capacity at 10.6 MW to 16 MW in the future. WSP understands that while the air quality assessment contained within in this report is based on an expanded facility capacity of 16 MW, Yukon Energy Corporation will only be applying for a permit amendment to allow up to 15.5 MW of capacity on site.

A total of five (5) criteria air contaminants were evaluated based on the emission characteristics of the facility genset engine and diesel fuel use - $PM_{2.5}$ PM_{10}, NO_2, SO_2, and CO. Three years (2016-2018) were modelled using the refined CALPUFF dispersion modelling system in accordance with the requirements of a comprehensive air quality dispersion modelling assessment as stipulated in the British Columbia Air Dispersion Modelling Guideline. To evaluate the facility compliance with the Yukon Ambient Air Quality Standards (YAAQS) and show the change in potential air quality impacts between the current and future operating conditions, two (2) modelling scenarios were considered in this air assessment:

1. Existing Permitted Emission Capacity Scenario (10.6 MW); and,
2. Future Expanded Emission Capacity Scenario (16 MW).

Both the existing and future permit scenarios were evaluated assuming maximum emissions from the facility's generators based upon maximum operating conditions and name-plate capacities. The modelling also conservatively assumed that all generators are emitting simultaneously and continuously at the name-plate capacity year-round.

Despite these conservative assumptions, the ambient air quality dispersion modelling results showed that, with the exception of short-term (1-hour) NO_2 results, the maximum cumulative predicted concentrations for all air contaminants ($PM_{2.5}$ PM_{10}, SO_2, and CO) were well below their respective ambient air quality criteria. The maximum points of impingement (worst-case receptors) were all found either near the Facility or outside the Town of Faro, in both scenarios. Overall, the cumulative predicted air contaminant concentrations from the Future Scenario were higher than those of the Existing Scenario given the increased power generation of the facility expansion.

While the dispersion modelling results predicted short-term NO_2 exceedances for both scenarios, the primary objective of the air quality assessment was to evaluate the potential risks on the human population residing near the facility (in the Town of Faro). The modelling results for the Existing Scenario at the maximally impacted receptor within the Faro Town showed that the cumulative predicted concentrations for all pollutants evaluated were in compliance with the YAAQS.

While the dispersion modelling predicted short-term (1-hour) NO_2 exceedances in the Future Scenario, the predicted air quality impacts for all the other air pollutants – including both fine and coarse particulate matter ($PM_{2.5}$ and PM_{10}), SO_2, and CO – were well below the YAAQS. With regards to the NO_2 predicted short-term (1-hour) NO2 exceedances, it is important to note that the YAAQS for NO_2 were reduced drastically in late 2019 from 401 µg/m^3 previously to 113 µg/m^3 presently. The maximum cumulative predicted 1-hour NO_2 concentrations from both existing and future permit scenarios would be well below the previous NO_2 criteria. When compared to the newly revised NO_2 YAAQS, the maximum cumulative predicted 1-hour NO_2 concentration was 129% of the Yukon Ambient Air Quality Standards for NO_2 at the maximally impacted Faro Town receptor in the Future Scenario. Moreover, the predicted 1-hour NO_2 exceedances were found spatially limited to a confined area surrounding the Facility areas on the outskirts of Faro, with a low frequency of occurrence of 0.21% of the time (56 hours out of 26,304 modelled hours) at the maximally impacted Faro Town receptor.

These short-term (1-hour) NO_2 exceedances were found entirely under calm stable meteorological conditions which typically hinder atmospheric dispersion; primarily during nighttime and in the colder months of the year; and, exclusively under west-northwest winds. Outdoor human activity would be limited during cold nighttime hours and this lowers the probability of human to be exposed to the short-term NO_2 impacts. Combined with the low frequency of model predictions exceeding the NO_2 YAAQS (56

hours out of 26,304 modelled hours),there is an even lower probability of exposure to levels above the YAAQS.

Finally, it is important to note that the modelling results represent the worst-case potential air quality impacts based upon the facility's maximum operating conditions. As such, the model predicted air contaminant concentrations are likely conservative. Furthermore, the conditions giving rise to predicted short-term NO_2 exceedances would be very unlikely to happen because the emission sources at the facility are highly unlikely to operate continuously year-round at the maximum possible emission rates, nor would it be likely that these maximum emissions coincide exactly with the particular meteorological conditions that give rise to the event as they occur, on average, for less than 20 hours per year modelled. The typical facility emissions are expected to be much lower and would not be anticipated to result in adverse air quality impacts given the low risk of predicted exceedance under even conservative assumptions. With model predictions indicating an extremely low risk of predicted short-term NO_2 impacts and low potential impacts from the other air pollutants, the overall air quality impacts from the future expanded facility are not anticipated to pose a significant risk to the Town of Faro and air quality would be anticipated to remain in compliance with YAAQS.

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1 INTRODUCTION

WSP Canada Inc. (WSP) was retained by Yukon Energy Corporation (YEC) to perform an air dispersion modelling and impact assessment in support of its permit amendment pursuit with the Yukon Environmental and Socio-economic Assessment Board (YESAB) to increase capacity at the diesel-fuelled electricity generating facility in Faro, Yukon (the "Project" or the "Facility") from the existing permitted capacity of 10.6 MW to 16 MW in the future. WSP understands that while the air quality assessment contained within in this report is based on an expanded facility capacity of 16 MW, Yukon Energy Corporation will only be applying for a permit amendment to allow up to 15.5 MW of capacity on site.

While the existing permit allows the Facility to operate up to a capacity of 10.6 MW, the Facility has been and is currently operating much below the permitted facility capacity of 10.6 MW with only two existing diesel generators on-site – specifically Mirrlees KV16 (Genset ID: FD1) and Caterpillar (CAT) 3612 (Genset ID: FD7). The existing FD1 and FD7 gensets have also been de-rated from their original nameplate capacity of 5.15 MW and 3.3 MW to 2.4 MW and 2.8 MW, respectively. Once expanded, the Facility will continue to operate the existing FD1 and FD7 at the de-rated 2.4 MW and 2.8 MW levels and the proposed facility capacity expansion of 16 MW would see the installation of additional six (6) CAT 3516C 1.8 MW diesel generators (Genset ID: YM20, YM21, YM22, YM23, YM24, and YM25).

Since there is no air dispersion modelling guideline in Yukon, the air dispersion modelling and impact assessment for the Project (the "Air Assessment") followed recommendations of the British Columbia Air Quality Dispersion Modelling Guideline (BC AQDMG, 2015)[1]. The dispersion modelling was completed following the requirements of a Level 3 Comprehensive Assessment as defined by the BC AQDMG and was conducted using the refined dispersion model called CALPUFF.

The following sections describe the assessment methodology and inputs employed in the dispersion modelling, as well as the model prediction results and findings evaluated for two modelling scenarios - representing the existing permitted and future expanded facility capacities.

[1] *British Columbia Ministry of Environment and Climate Change Strategy (2015, November). British Columbia Air Quality Dispersion Modelling Guideline (AQDMG). Retrieved from Government of British Columbia website: https://www2.gov.bc.ca/assets/gov/environment/air-land-water/air/reports-pub/bc-dispersion-modelling-guideline-2015.pdf*

2 AIR QUALITY CRITERIA

Based on the emission characteristics of the Facility's diesel generators, a total of five (5) key criteria air contaminants (CACs) were evaluated in the Air Assessment (Table 2-1). The current Yukon Ambient Air Quality Standards (YAAQS) used as the air quality criteria against which modelling results are assessed. Since there are no YAAQS established for Carbon Monoxide (CO), the ambient air quality objectives from the nearest jurisdiction – British Columbia, are chosen as the air quality criteria for CO in this Air Assessment.

It should be noted that the YAAQS were revised by the Yukon Government Department of Environment recently on October 23, 2019[i], to follow the new and more stringent Canadian Ambient Air Quality Standards (CAAQS) adopted by the Canadian Council of Ministers of the Environment (CCME) to drive air quality improvements across the country. In particular, both CAAQS and YAAQS reduced the 1-hour NO_2 Standard drastically from 401 µg/m^3 previously to 113 µg/m^3 presently.

Table 2-1 Air Quality Standards for Air Contaminants Evaluated

Air Contaminant	Jurisdiction	Ambient Air Quality Standard (µg/m^3)		Statistical Form of Standard
Particulate Matter Fine ($PM_{2.5}$)	Yukon	24-Hour	27	The 3-year average of the annual 98th percentile of the daily 24-hour average concentrations.
	Yukon	Annual	8.8	The 3-year average of the annual average of all 1-hour concentrations.
Particulate Matter Coarse (PM_{10})	Yukon	24-Hour	50	The maximum 24-hour block average concentration.
Nitrogen Dioxide (NO_2)	Yukon	1-Hour	113	The 3-year average of the annual 98th percentile of the daily maximum 1-hour average concentrations.
		Annual	32	The average over a single calendar year of all 1-hour average concentrations.
Sulphur Dioxide (SO_2)	Yukon	1-Hour	183	The 3-year average of the annual 99th percentile of the daily maximum 1-hour average concentrations.
		Annual	13	The average over a single calendar year of all 1-hour average concentrations.
Carbon Monoxide (CO)	British Columbia	1-Hour	14,300	The maximum 1-hour block average concentration.
		8-Hour	5,500	The maximum 8-hour block average concentration.

3 BASELINE AIR QUALITY

Baseline air contaminant concentrations are determined in dispersion modelling assessments in order to provide a complete indication of cumulative impacts to air quality. In this context, the BC AQDMG states that "baseline" is meant to be the concentrations due to emissions from both natural and anthropogenic sources. In other words, it is intended to be the result of the contribution from all sources except the source(s) being modelled. To evaluate compliance against the YAAQS, selected baseline air quality concentrations for the Town of Faro are added to the dispersion model predictions resulting in a predicted cumulative air contaminant concentration.

It is common practice to determine the baseline from historical air quality monitoring data within the modelled airshed. Continuous ambient air quality monitoring data is only available from one station in Yukon located in Downtown Whitehorse (the "Whitehorse AQ Station") and operated by Yukon's Department of Environment as part of Canada's National Air Pollution Surveillance (NAPS) program (NAPS ID: 119004). This station continuously monitors NO_2, NOx and $PM_{2.5}$. To determine the baseline air contaminant concentrations, the most recent available three (3) years of NO_2, NOx and $PM_{2.5}$ monitoring data from the Whitehorse AQ Station were gathered and analyzed in accordance to the BC AQDMG. Due to the lack of SO_2 and CO monitoring in Yukon, the baseline concentrations for SO_2 and CO were not applied in this Air Assessment. The 24-hour PM_{10} baseline concentration were estimated by pro-rating the 24-hour $PM_{2.5}$ baseline concentrations with the ratio of PM_{10} to $PM_{2.5}$ YAAQS values for the 24-hour averaging period (1.85 based on 50 µg/m^3 to 27 µg/m^3).

Directly applying baseline air contaminant concentrations from the Whitehorse AQ Station would not appropriately represent the expected concentrations in the small Town of Faro since there are significantly greater anthropogenic activities and emission sources in Whitehorse. To better estimate baseline concentrations in Faro, the baseline concentrations calculated from the Whitehorse AQ Station were scaled based on the emissions inventories developed for each community in the previous YEC air assessment (SENES, 2011), as shown in Table 3-1. Specifically, the 2007 annual NO_2 emission in Faro was estimated to be 9.66 tonnes, as compared to 540.12 tonnes in Whitehorse, resulting in 1.8% as the Faro to Whitehorse percentage; for $PM_{2.5}$, 1.5% was computed as the percentage of Faro over Whitehorse using 7.3 tonnes of annual $PM_{2.5}$ emissions in Faro and 503.29 tonnes in Whitehorse.

As a way to substantiate the application of the emission estimates from 2007 in scaling baseline air contaminant concentrations for the current Air Assessment, the most recent available population figures from the Yukon Bureau of Statistics[2] were used to compare the community populations between and growth trends in Faro and Whitehorse. Table 3-2 below demonstrates the small population of Faro when compared to Whitehorse and the incremental change from the historical population counts in each community. This supports our assumption that anthropogenic emissions levels in Faro are a fraction of those in Whitehorse and would not have materially change from the 2007 inventory levels.

Table 3-1 Estimated Annual Community Emissions in 2007

Air Contaminant	Annual Emissions (tonnes/year)		Proportion (%) of Faro to Whitehorse Community Annual Emissions
	Whitehorse	Faro	
NOx (as NO_2)	540.12	9.66	1.8%
$PM_{2.5}$	503.29	7.30	1.5%

[2] *Yukon Bureau of Statistics. Yukon Census Historical Population 1901 to 2016. Retrieved from Government of Yukon website:* https://yukon.ca/sites/yukon.ca/files/ybs/fin-yukon-census-historical-population-1901-2016.pdf

Table 3-2 Comparison of Population Counts Between Faro and Whitehorse

Census Year	Population Counts		Proportion (%) of Faro to Whitehorse Population Counts
	Whitehorse	Faro	
2006	20,461	341	1.7%
2011	23,276	344	1.5%
2016	25,085	348	1.4%

Table 3-3 presents the summary of 2016-2018 baseline concentrations calculated from the Whitehorse AQ Station as well those estimated for Faro using the scaling methods described above. The estimated baseline concentrations for Faro were added to the dispersion modelling results to predict the cumulative air contaminant concentrations for the Air Assessment.

Table 3-3 Summary of Baseline Air Quality Concentrations

Air Contaminant	Averaging Time	Ambient Air Quality Standard ($\mu g/m^3$)	Statistical Form for Baseline Concentrations	Baseline Concentrations (2016-2018)			
				Whitehorse		Faro	
				$\mu g/m^3$	% of Criteria	$\mu g/m^3$	% of Criteria
NO_2	1-hour	113	The 3-year average of the annual 98th percentile of the daily maximum 1-hour average concentrations.	37.5	33%	**0.67**	**0.6%**
	Annual	32	The 3-year average of the annual average of all 1-hour concentrations.	6.0	19%	**0.11**	**0.3%**
PM_{10}	24-hour	50	The 3-year average of the annual 98th percentile of the daily 24-hour average concentrations.	31.5	63%	**0.46**	**0.9%**
$PM_{2.5}$	24-hour	27	The 3-year average of the annual 98th percentile of the daily 24-hour average concentrations.	17.0	63%	**0.25**	**0.9%**
	Annual	8.8	The 3-year average of the annual average of all 1-hour concentrations.	3.3	38%	**0.05**	**0.5%**

4 MODELLED EMISSIONS

4.1 MODELLING SCENARIOS

To evaluate the potential air quality impacts from the Facility's proposed expansion, two (2) modelling scenarios were compared in this Air Assessment:

1. Existing Permitted Emission Capacity Scenario (10.6 MW); and,
2. Future Expanded Emission Capacity Scenario (16 MW).

Both emission scenarios assumed that the generators are operating continuously at the maximum rated capacity. To reflect the worst-case air quality impacts from the Facility, the estimated model emission rates established for each emission scenario were applied to all hours during 2016-2018 modelling years. This conservative approach is common in air dispersion modelling assessments. It allows for emission sources to be assessed at maximum pollutant emission rates under all meteorological condition combinations to predict the potential worst-case air contaminant concentrations. However, it should be noted that this conservative assessment of potential air quality impacts did not account for seasonal load variations whereby the generators operate at or near full capacity for only a small portion of the year, during peak consumption periods, but most of the time operate well below their nameplate or total Facility capacity. The typical Facility emissions are expected to be much lower than the maximum possible emission rates modelled in this Air Assessment.

Table 4-1 summarizes the Facility capacity and genset configurations for the "Existing Scenario" and "Future Scenario". While the Facility has historically operated below the existing permit capacity of 10.6 MW using only two existing gensets (FD1 and FD7) that have been de-rated to 2.4 MW and 2.8 MW respectively, three (3) of the new CAT 3516C 1.8 MW diesel generators (Genset ID: YM20, YM21, YM22) were assumed to be added to the Existing Scenario to model emissions levels at the current permitted capacity. The Future Scenario evaluated a Facility capacity of 16 MW using the existing FD1 and FD7 combined with the six (6) new CAT 3516C 1.8 MW diesel generators (Genset ID: YM20, YM21, YM22, YM23, YM24, and YM25).

Table 4-1 Summary of Modelling Scenarios Evaluated for the Project

Modelling Scenario	Genset Configuration	Genset Unit Output and Facility Capacity
Existing Permitted Emission Capacity (Existing)	FD1 + FD7 + YM20 + YM21 + YM22	2.4 MW + 2.8 MW + 3 x 1.8 MW = **10.6 MW**
Future Expanded Emission Capacity (Future)	FD1 + FD7 + YM20 + YM21 + YM22 + YM23 + YM24 + YM25	2.4 MW + 2.8 MW + 6 x 1.8 MW = **16.0 MW**

4.2 SOURCE PARAMETERS AND MODELLED EMISSION RATES

The genset engine exhaust vents were simulated as vertically-oriented point or stack sources in the CALPUFF model. Table 4-2 below summarized the genset types and source characteristics modelled for the Project. The stack parameters were compiled from a combination of data sources, including manufacturer's specification sheets and drawings, as well as the previous YEC air assessment (SENES, 2011). Building downwash effects on these point sources was analyzed according to the genset configurations specified in Table 4-1 for each modelling scenarios using the Building Profile Input Program (BPIP-PRIME) as recommended by the BC AQDMG (2015). The buildings and structures digitized for the Facility are based on the facility layout drawings provided by YEC and genset enclosure drawings from the manufacturers.

To evaluate the potential worst-case air quality impacts resulting from the maximum possible emissions levels from both existing and future permit scenarios, all of the gensets considered in each scenario are conservatively assumed to be releasing simultaneously in a continuously emitting fashion. The new genset (CAT 3516C) emission rates were estimated using the greater of the maximum or name-plate operating capacity from the gensets manufacturer's specifications (such as full-load sustained output and emission performance data), or the applicable stationary combustion source emission factors from published reference documents (such as the United States Environmental Protection Agency's Compilation of Air Emissions Factors referred to as the AP-42). Emission estimates with respect to the existing gensets FD1 and FD7 were provided by YEC using stack sampling data from the previous YEC air assessment (SENES, 2011). The estimated pollutant emission rates and source characteristics modelled for each genset unit in this assessment are detailed in Table 4-2 below.

Table 4-2 Source Parameters Modelled in CALPUFF for both Existing and Future Scenarios

Genset ID:		FD1	FD7	YM20	YM21	YM22	YM23	YM24	YM25
Fuel Type:		Diesel	Diesel	Diesel	Diesel	Diesel	Diesel	Diesel	Diesel
Manufacturer and Model:		Mirrlees KV16	Caterpillar 3612	Caterpillar 3516C	Caterpillar 3516C	Caterpillar 3516C	Caterpillar 3516C	Caterpillar 3516C	Caterpillar 3516C
Unit Power Generation:		2.4 MW	2.8 MW	1.8 MW	1.8 MW	1.8 MW	1.8 MW	1.8 MW	1.8 MW
Included in Existing Scenario?		✓	✓	✓	✓	✓	x	x	x
Included in Future Scenario?		✓	✓	✓	✓	✓	✓	✓	✓
Source Type		Point	Point	Point	Point	Point	Point	Point	Point
Stack Orientation		Vertical	Vertical	Vertical	Vertical	Vertical	Vertical	Vertical	Vertical
Stack Location (NAD 1983 UTM Zone 8N)	(mE)	585,137	585,185	585,135	585,130	585,126	585,121	585,116	585,112
	(mN)	6,901,223	6,901,277	6,901,211	6,901,209	6,901,206	6,901,204	6,901,201	6,901,199
Base Elevation	(mASL)	707	708	707	707	708	708	708	708
Stack Height	(m)	8.3	8.9	4.0	4.0	4.0	4.0	4.0	4.0
Stack Diameter	(m)	0.76	0.43	0.221	0.221	0.221	0.221	0.221	0.221
Stack Exit Volumetric Flow	(ft^3/min)	14,687	10,982	7,130	7,130	7,130	7,130	7,130	7,130
	(m^3/min)	416	311	202	202	202	202	202	202
	(m^3/s)	6.9	5.2	3.4	3.4	3.4	3.4	3.4	3.4
Stack Exit Velocity	(m/s)	15.28	35.69	87.92	87.92	87.92	87.92	87.92	87.92
Stack Exhaust Gas Temperature	(°C)	384.6	430.8	387.0	387.0	387.0	387.0	387.0	387.0
	(°F)	724.3	807.4	728.0	728.0	728.0	728.0	728.0	728.0
	(°K)	657.8	704.0	660.2	660.2	660.2	660.2	660.2	660.2
Pollutant Model Emission Rates:									
$PM_{2.5}$	(g/s)	0.083	0.049	0.022	0.022	0.022	0.022	0.022	0.022
PM_{10}	(g/s)	0.107	0.055	0.022	0.022	0.022	0.022	0.022	0.022
NOx (as NO_2)	(g/s)	6.022	6.531	3.781	3.781	3.781	3.781	3.781	3.781
SO_2	(g/s)	0.010	0.004	0.003	0.003	0.003	0.003	0.003	0.003
CO	(g/s)	1.148	0.191	0.203	0.203	0.203	0.203	0.203	0.203

5 MODELLING METHODOLOGY

Air dispersion modelling was conducted following the methods recommended in the BC AQDMG (2015), which is referenced by *YESAB Proponent's Guide: Model Documentation Report* (2016) as an exemplary guideline for air dispersion modelling. The CALPUFF air dispersion modelling suite was used for assessing potential air quality impacts. CALPUFF is a suite of numerical models (CALMET, CALPUFF, and CALPOST) that are used in series to determine the potential impact of emissions in the vicinity of a source or group of sources.

Detailed three-dimensional meteorological fields were produced by the diagnostic computer model CALMET Version 6.5.0 (Level 150223), based on digital land use data and terrain data, as well as observed surface and upper air data that are available for the Project domain. In accordance with the BC AQDMG (2015), the most recent three years (2016-2018) of meteorological data were modelled in CALMET. The three-dimensional meteorological fields produced by CALMET were used by CALPUFF Version 7.2.1 (Level 150618), a three-dimensional, multi-species, non-steady-state Gaussian puff dispersion model that can simulate the effects of time and space varying meteorological conditions on air contaminant transport. Finally, post-processing utilities were used to post-process and summarize the modelling output from CALPUFF.

5.1 CALMET – METEOROLOGICAL MODELLING

CALMET Version 6.5.0 (Level 150223), associated with the latest CALPUFF System Version 7, was used to generate the meteorological fields for the time period from January 1, 2016 through December 31, 2018. The CALMET model was run in Observation-only mode. Surface weather observations were extracted from the nearest observational weather station situated at the international airport in Faro – "Faro (AUT)" station operated by Environment and Climate Change Canada (ECCC) (WMO ID: 71949). In addition, upper air soundings were retrieved from the only upper air station located in Yukon, namely the Whitehorse international airport station (WMO ID: 71964) – operated by NAV Canada – for meteorology in the vertical layers above the surface in order to resolve the three-dimensional meteorology in the CALMET modelling.

The meteorological data input and CALMET output for the modelling period was assessed following the Quality Assurance and Quality Control (QA/QC) procedures outlined in Section 9 of the AQDMG. A description of the CALMET modelling methodology and data sets follows.

The Universal Transverse Mercator (UTM, NAD 83) coordinate system was used for this model application. The CALMET domain for the Project was a 12 km by 12 km domain as presented in Figure 5-1. The CALMET model was run with a 200 m horizontal grid resolution. The modelling domain and grid resolution were chosen such that the main topographical features expected to influence the three-dimensional diagnostic meteorological fields around the Project are adequately captured.

5.1.1 OBSERVED METEOROLOGICAL DATA

Surface weather stations that record hourly meteorological data within the Project's CALMET domain include one station – "Faro (AUT)" – operated by ECCC (WMO ID: 71949). The available meteorological data collected from January 1, 2016 through December 31, 2018 at this surface station was used as input to the CALMET model executed in Observation-only mode. Upper air data from the Whitehorse international airport station (WMO ID: 71964) was retrieved for the aforementioned modelling period and used as secondary meteorological input to resolve three-dimensional meteorology in the CALMET modelling. The locations of these meteorological stations are displayed as part of Figure 5-1 below.

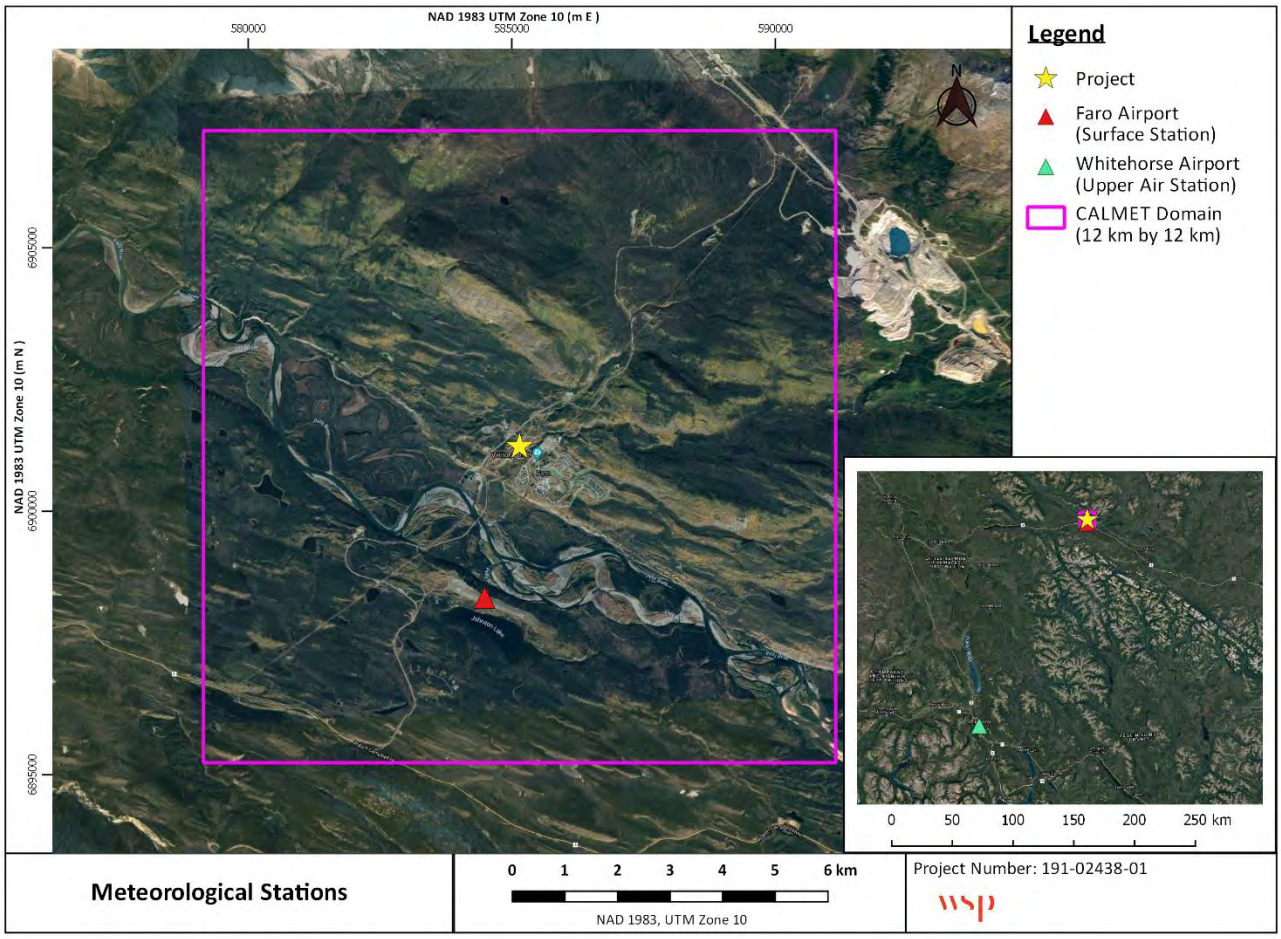

Figure 5-1 Meteorological Stations within CALMET Domain

CALMET requires a measured data value for every hour from at least one meteorological station in order to simulate the three-dimensional fields. Missing data procedures were implemented, when required, according to the AQDMG. The basic meteorological parameters required by the CALMET model were gathered from the surface station and prepared into a CALMET-ready surface data file (SURF.DAT) which includes the following meteorological parameters: wind speed, wind direction, temperature, relative humidity, and station pressure.

Figure 5-2 below illustrates the windrose compiled from the surface wind data observed at the airport in Faro from 2016 to 2018, which shows the prevailing wind patterns.

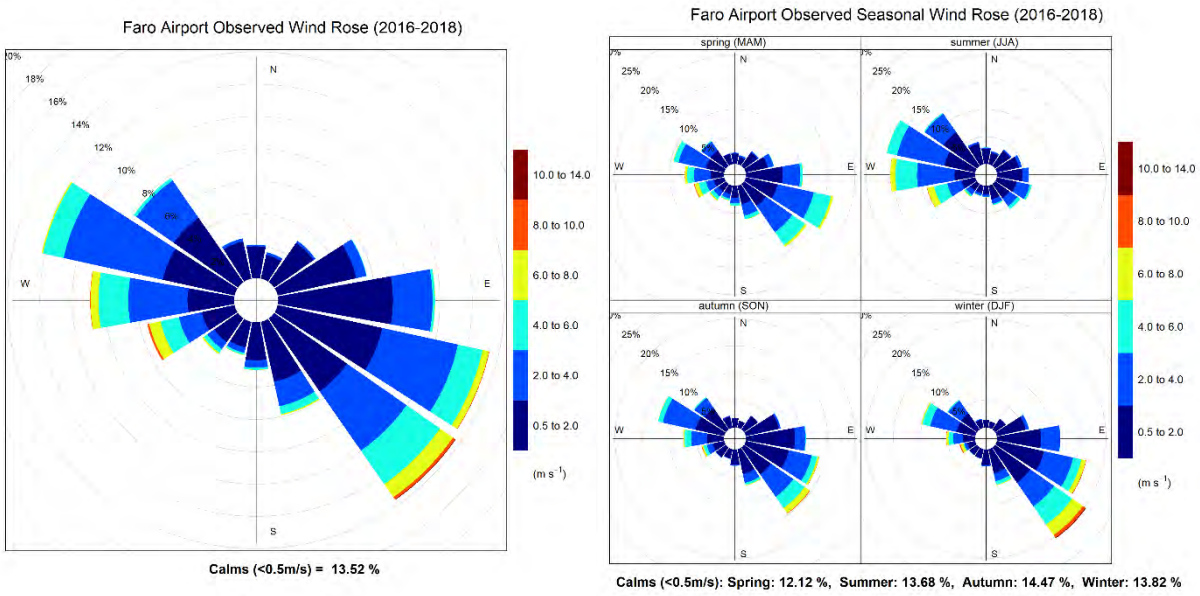

Figure 5-2 Windroses for the Surface Weather Station at Faro International Airport (2016-2018)

5.1.2 GEOPHYSICAL DATA – TERRAIN ELEVATION AND LAND USE

Digital terrain elevation and landuse data covering the CALMET model domain was used to simulate effects of the topography and landscape on the meteorological conditions in the model. In accordance with the AQDMG, the Canadian Digital Elevation Data (CDED) provided by Natural Resources Canada in a 1:50,000 scale was used to generate the terrain elevation inputs for each CALMET grid point, as well as the base elevations of the model emission sources and receptors. Land use characteristics for each grid cell were gathered from 2015 Canada Land Use dataset provided by Natural Resources Canada. Figure 5-3 and Figure 5-4 below show the terrain elevation and land use data used in the CALMET modelling.

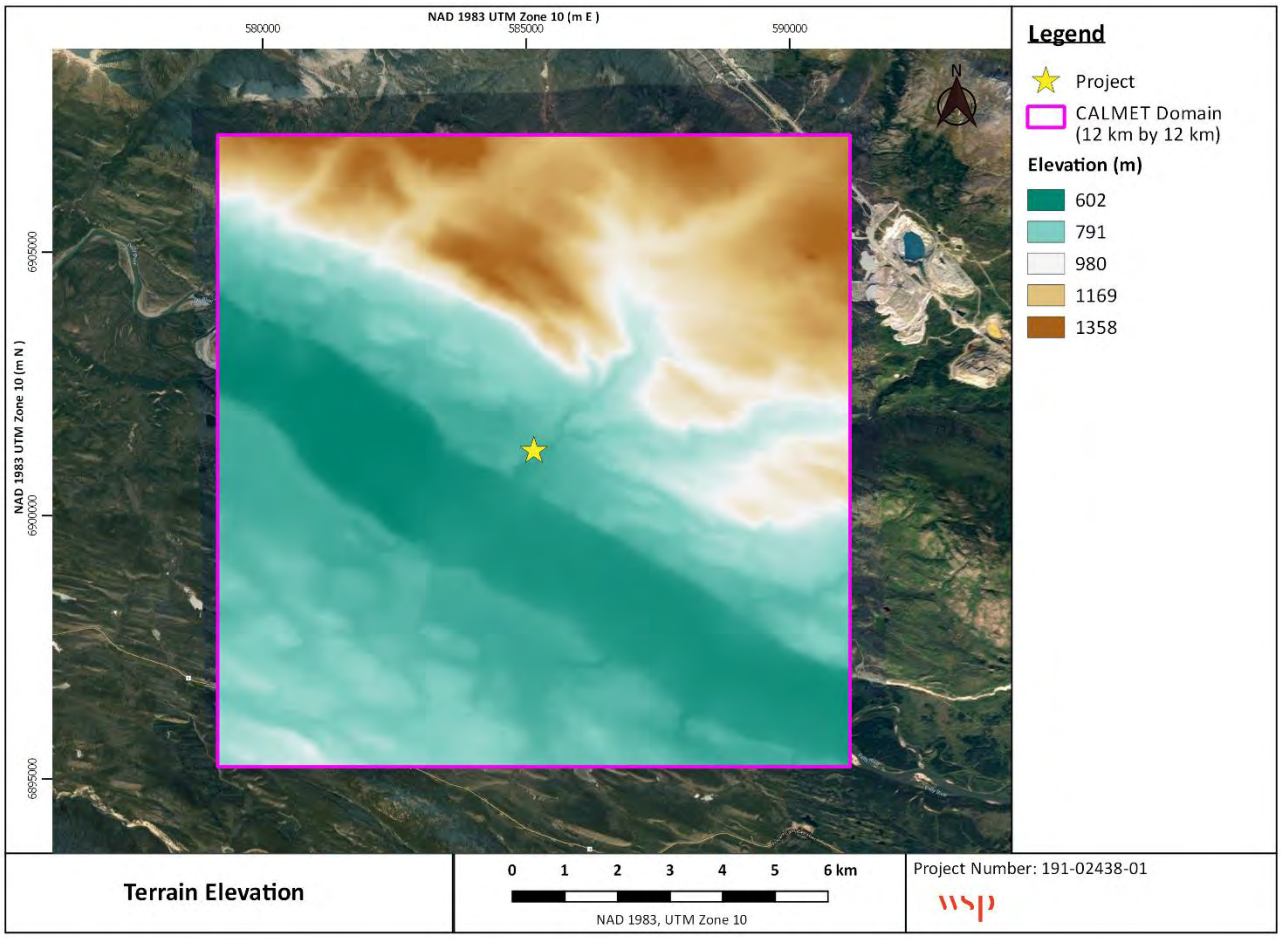

Figure 5-3 Terrain Elevation Data used in CALMET

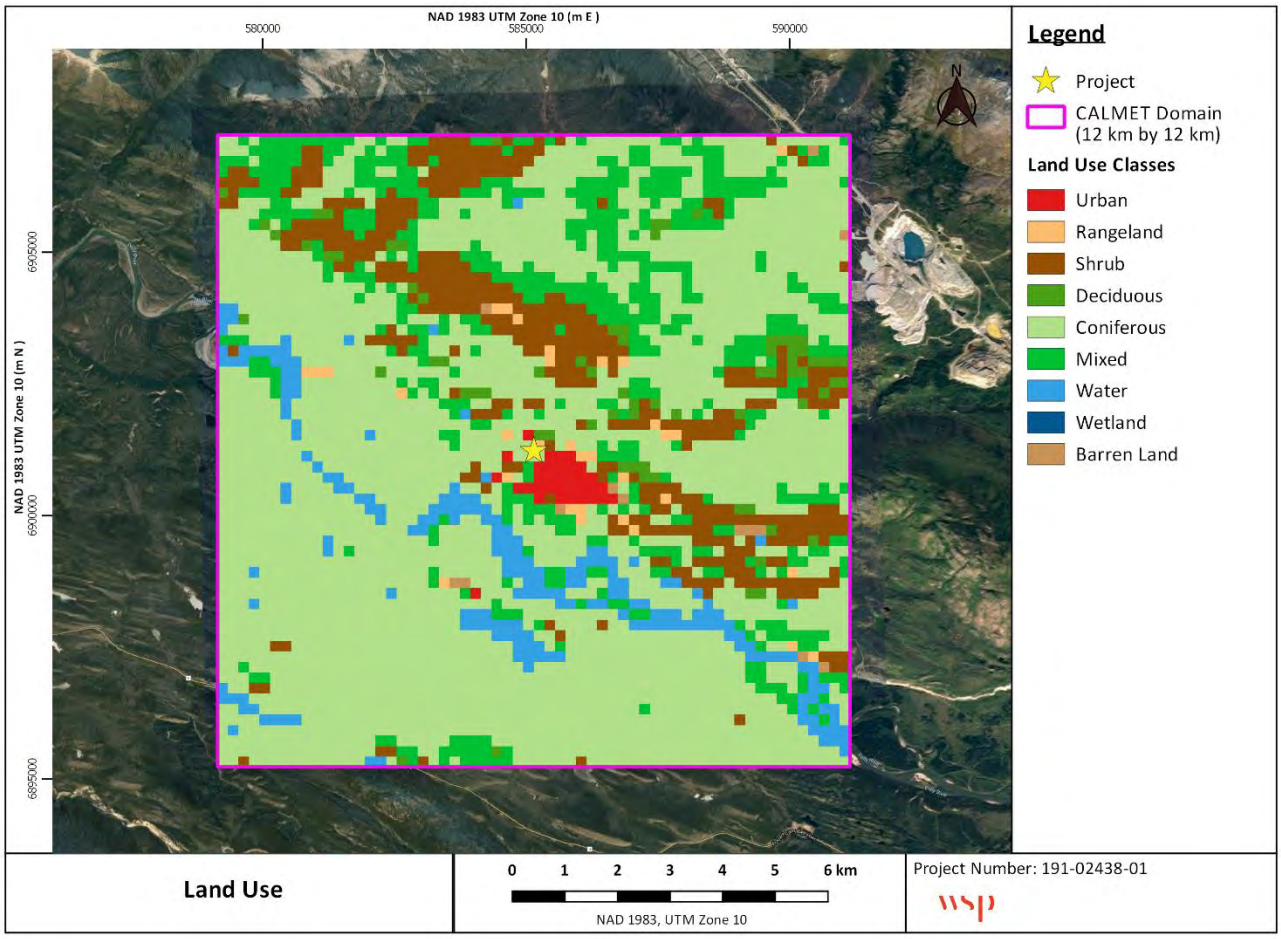

Figure 5-4 Land Use Data used in CALMET

Seasonal parameters were specified for each month based on the seasonal categories outlined in Table 5-1. According to the AQDMG, the seasonal categories are defined as follows:

- Season 1: Midsummer with lush vegetation
- Season 2: Autumn with cropland that has not been harvested
- Season 3: Winter 1, late autumn after frost, no snow on the ground
- Season 4: Winter 2, snow on the ground and subfreezing
- Season 5: Transitional spring with partially green short annuals

Table 5-1 Seasonal Categories for GEO.DAT used in CALMET

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Seasonal Category	4	4	4	4	4	5	1	2	2	3	4	4

5.1.3 CALMET MODEL SWITCHES

The CALMET model has a number of user-specified input switches that determine how the model handles terrain effects, interpolation of observational input data, and so forth. The differences in the modelled and measured meteorological fields were examined as part of QA/QC, and this analysis was utilized to refine and adjust the model options as appropriate. Table 5-2 outlines the options selected in CALMET modelling. The AQDMG default parameters were used wherever applicable.

Table 5-2 Selected CALMET Model Options

CALMET Model Switch	Parameter	Option Selected	BC AQDMG Default
Determines whether observation data are used, or in combination with NWP model output, or NWP data only	NOOBS	0 (Observation Only mode)	No default
Cloud Data Option: 1,2,3,4	MCLOUD	1 (Clouds data generated from surface observations)	No default
Wind field model selection variable	IWFCOD	1 (Yes)	✓
Compute Froude number adjustment effects?	IFRADJ	1 (Yes)	✓
Compute kinematic effects?	IKINE	0 (No)	✓
Use O'Brien procedure for adjustment of the vertical velocity?	IOBR	0 (No)	✓
Compute slope flows?	ISLOPE	1 (Yes)	✓
Extrapolate surface wind observations to upper layers?	IEXTRP	-4 (Extrapolate surface observations using similarity theory)	✓
Extrapolate calm winds aloft?	ICALM	1 (Yes)	No default
Layer-dependent biases	BIAS	-1, -1, -1, -1, -1, -1, -1, -1, -0.5, 0, 0, 0	No default
Minimum distance between upper air station and surface station for which extrapolation of surface winds will be allowed	RMIN2	-1	✓
Gridded prognostic wind field model output fields	IPROG	0 (No, do not use wind fields from MM5/3D.dat file as initial guess field)	✓
Time step (hrs) of the NWP output used as input data	ISTEPPGS	3600	✓
Use coarse CALMET fields as initial guess fields?	IGFMET	0 (Off)	✓
Use varying radius of influence?	LVARY	F (No, stations outside of RMAX1 are excluded)	✓
Maximum radius of influence over land of the surface layer	RMAX1	4.5 km	No default
Maximum radius of influence over land aloft	RMAX2	4.5 km (Set equal to RMAX1)	No default
Maximum radius of influence over water	RMAX3	Not used	No default
Minimum radius of influence used in the wind field interpolation	RMIN	0.1	✓
Radius of influence of terrain features	TERRAD	5 km	No default
Distance from a surface station at which the station observations and 1st guess field are equally weighted	R1	4 km	No default
Distance from an upper air station at which the observations and 1st guess field are equally weighted	R2	4 km (Set equal to R1)	No default
Relative weighting of the prognostic wind field data	RPROG	0	No default
Maximum acceptable divergence in the divergence minimum procedure.	DIVLIM	$5*10^{-6}$	✓

CALMET Model Switch	Parameter	Option Selected	BC AQDMG Default
Maximum number of iterations in the divergence minimum procedure.	NITER	50	✓
Number of passes in the smoothing procedure	NSMTH	2, 4, 4, 4, 4, 4, 4, 4, 4, 0, 0	✓
Maximum number of stations used in each layer for the interpolation of data to a grid point	NINTR2	99	✓
Critical Froude number	CRITFN	1	✓
Empirical factor controlling the influence of kinematic effects	ALPHA	0.1	✓
Multiplicative scaling factor for extrapolation of surface observations to upper layers	FEXTR2	Not used	✓
Number of barriers to interpolation of the wind fields	NBAR	0	✓
Level (1 to NZ) up to which barriers apply.	KBAR	10	✓
X and Y coordinates of barriers	XBBAR, YBBAR, XEBAR, YEBAR	Not used	✓
Diagnostic module surface temperature option	IDIOPT1	0 (Compute internally from hourly surface observations or prognostic fields)	✓
Diag module sfc station to use for the sfc temp (stn ID).	ISURFT	-1 (2-D spatially varying surface temperatures)	✓
Diagnostic module domain-averaged lapse rate option	IDIOPT2	0 (Compute internally from prognostic fields)	✓
Diagnostic module upper air station to use for lapse rate to use	IUPT	-1 (2-D spatially varying potential temperature lapse rate)	✓
Depth through which the domain-scale lapse rate is computed	ZUPT	200	✓
Initial guess field wind components	IDIOPT3	0 (Computed internally from observations or NWP output wind fields)	✓
Upper air station to use for domain-scale winds	IUPWND	-1 (Use 3-D initial guess fields)	✓
Bottom and top of layer through which the initial guess winds are computed	ZUPWND	1,1000	✓
Observed surface wind components for wind field module.	IDIOPT4	0 (Read wind speed and wind direction from SURF.DAT. DIAG.DAT not used.)	✓
Observed upper air wind components	IDIOPT5	0 (Read wind speed and wind direction from upper air data file UP.DAT. DIAG.DAT not used.)	✓
Use Lake Breeze Module?	LLBREZE	F (No, do not use Lake Breeze Module)	✓
# of boxes defining region	NBOX	Not used	✓
X Grid line 1 and line 2 defining the region of interest	XG1, XG2	Not used	✓
Y Grid line 1 and line 2 defining the region of interest	YG1, YG2	Not used	✓
X Point defining the coastline	XBCST	Not used	✓
Y Point defining the coastline	YBCST	Not used	✓

5.2 CALMET QA/QC

Section 9 of the AQDMG with respect to the CALMET/CALPUFF modelling QA/QC process were considered. Key results of the quality tests that were applied to the CALMET modelling are documented and presented in the sections below. The CALMET model outputs at the nearest CALMET grid point to the Project's emission sources were extracted and used to represent the Project and is referred to as the "Facility". In addition, the nearest surface meteorological station ("Faro Airport") was selected for this CALMET QA/QC analysis. Specifically, the observed meteorological data at Faro Airport was used to compare with the CALMET modelled meteorological data extracted at the nearest CALMET grid point to Faro Airport.

5.2.1 TEMPERATURE

Figure 5-5 shows the average monthly surface temperatures at observed and CALMET extracted points. Figure 5-6 shows the average hourly temperatures binned into hour intervals of a day. Both temporal plots show good agreement between the predicted and observed temperature values.

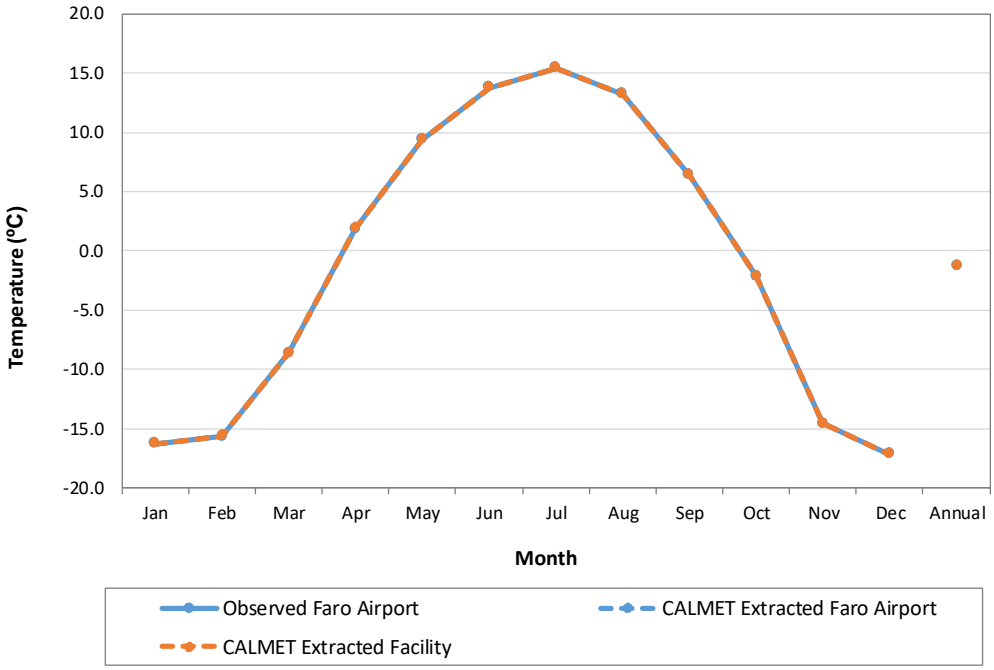

Figure 5-5 Monthly Temperature Variation

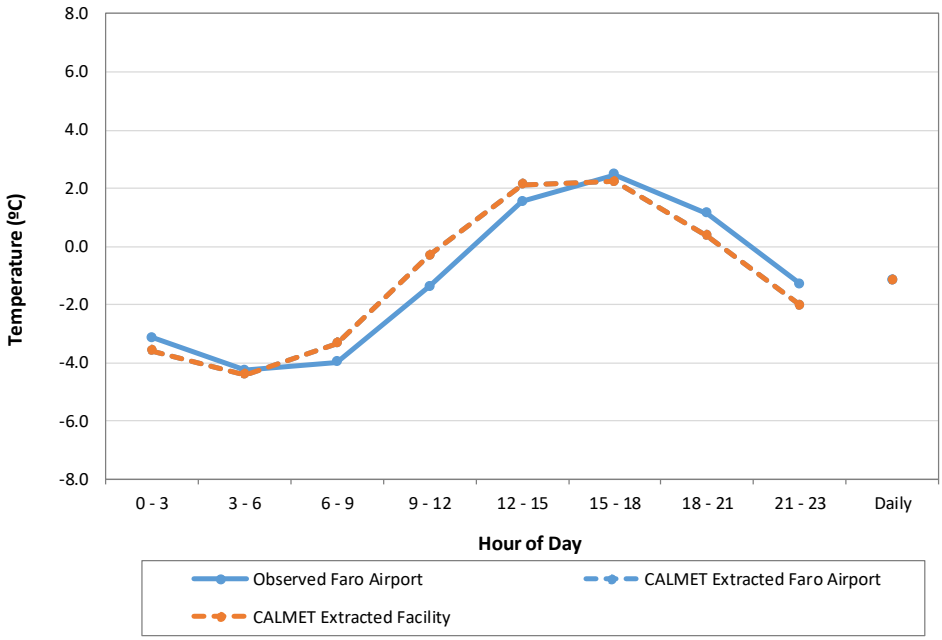

Figure 5-6 Diurnal Temperature Variation

5.2.2 WIND SPEED

The frequency distribution of wind speed at the observed and CALMET extracted points are shown below in Figure 5-7. The modelled wind speeds show good agreement with the observed wind speed data.

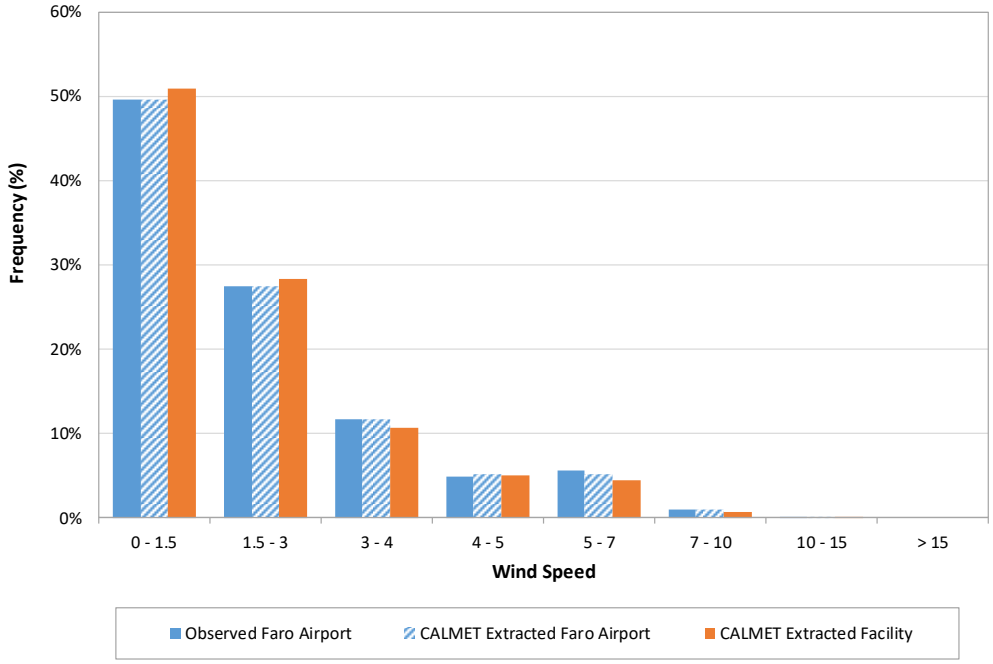

Figure 5-7 Wind Speed Frequency

5.2.3 WIND ROSE

The following figures show full-period and seasonal wind roses for the observed wind data at the selected surface meteorological station (Faro Airport), modelled CALMET wind data extracted at the nearest grid point to Faro Airport, and modelled CALMET wind data extracted at the nearest point to the Facility. The observed and modelled CALMET wind roses show good agreement at Faro Airport station. The wind roses indicate that the predominant winds are from the west-northwest, southeast, and east-southeast directions at Faro Airport station, and east and east-southeast directions at the Facility, which are expected considering the surrounding valley orientation shaped by the Pelly River.

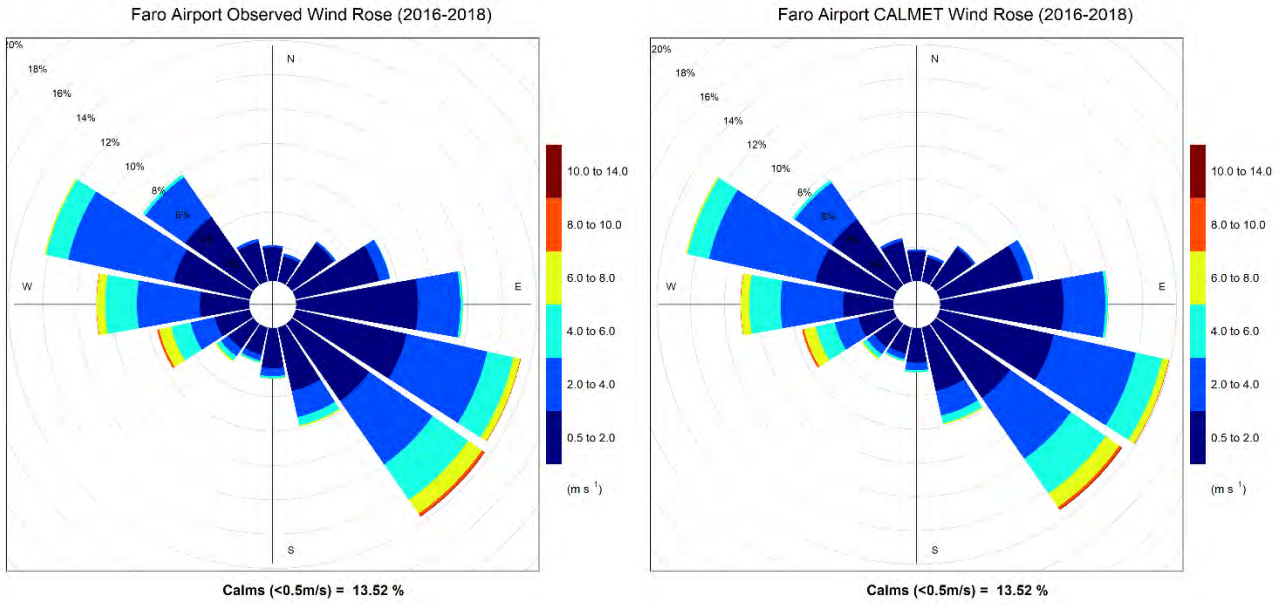

Figure 5-8 Wind Roses at Faro Airport Station

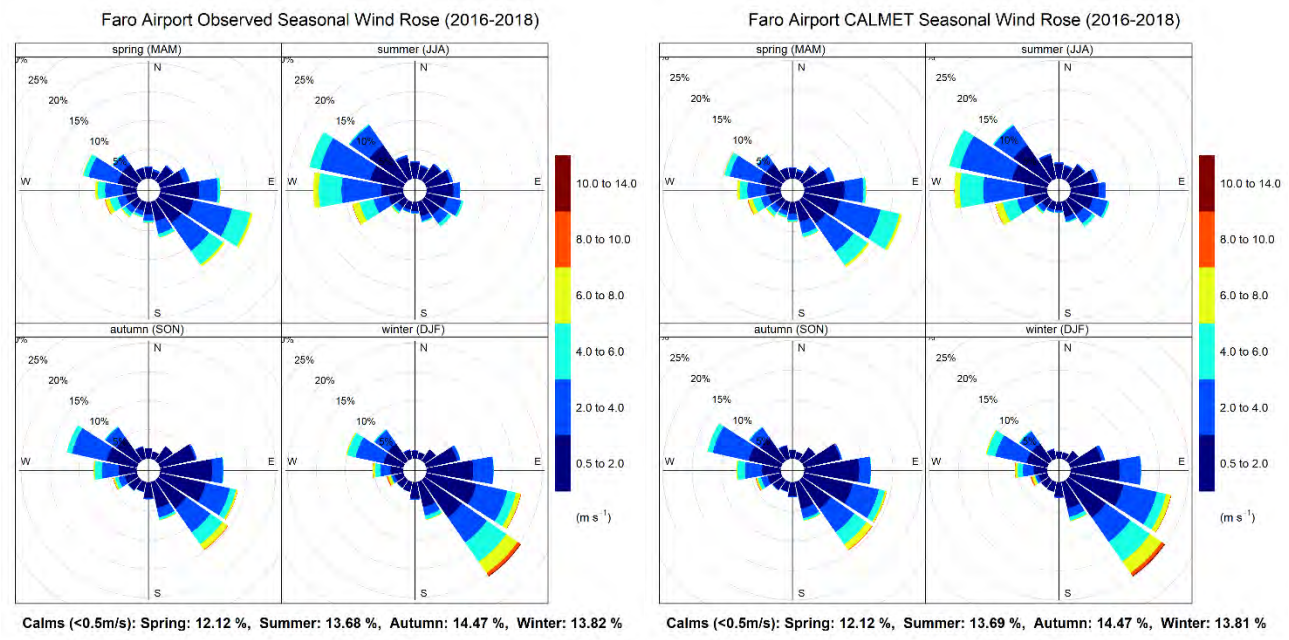

Figure 5-9 Seasonal Wind Roses at Faro Airport Station

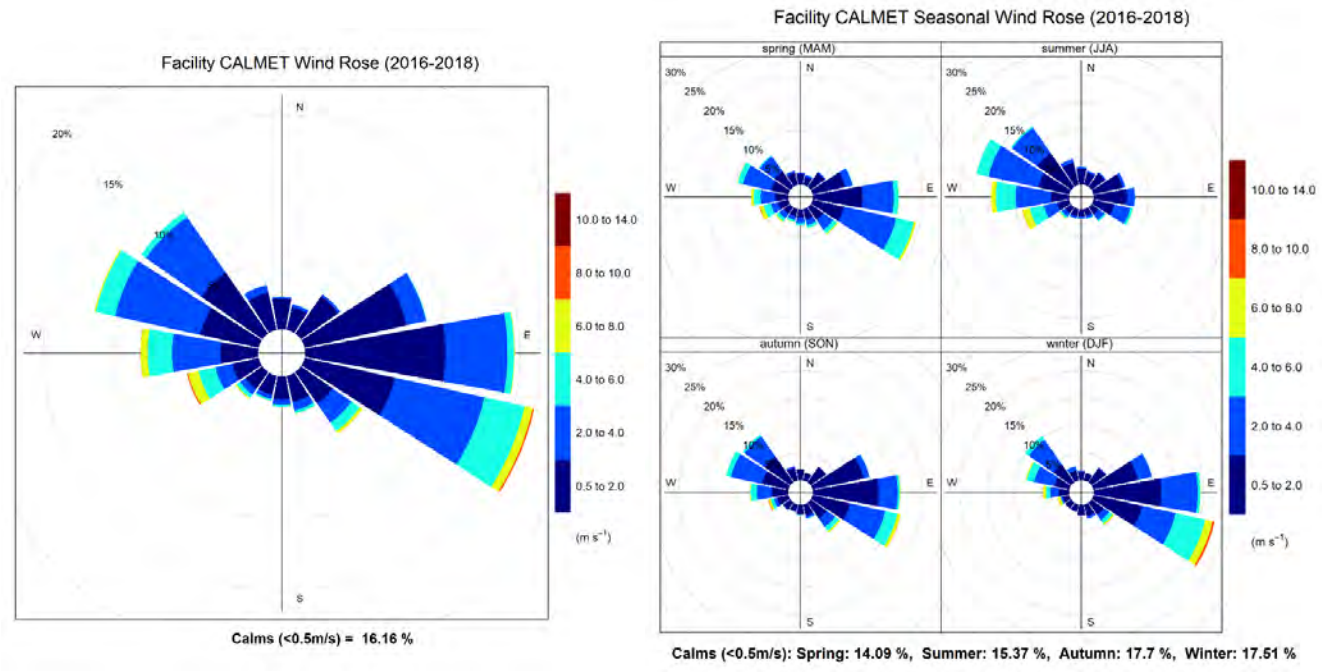

Figure 5-10 Annual and Seasonal Wind Rose at the Facility Location

5.2.4 ATMOSPHERIC STABILITY

Model predicted stability classes are provided in Figure 5-11. The distribution shows higher occurrences of neutral (stability class 4) and stable (stability class 6) conditions near to the Facility and Faro Airport station. There are no observations of atmospheric stability for comparison.

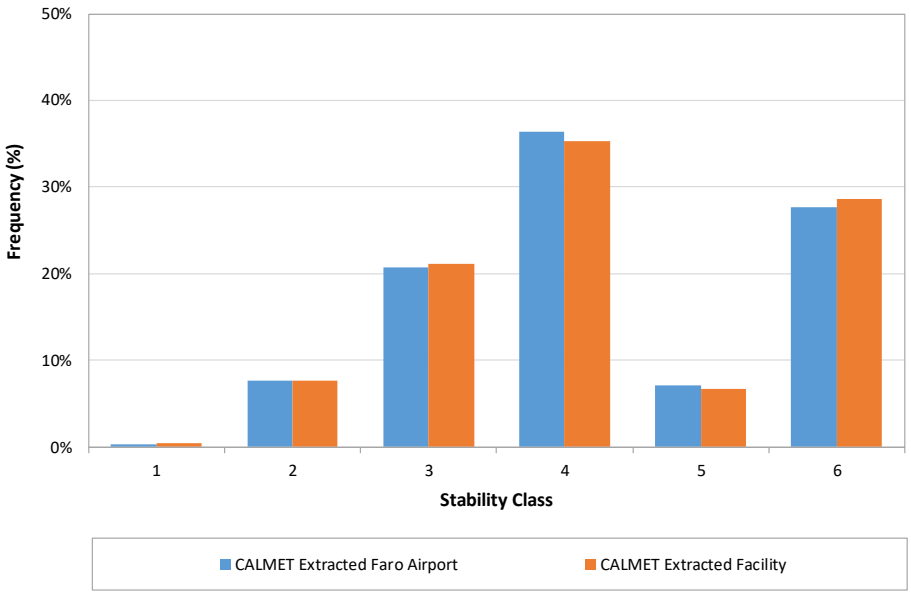

Figure 5-11 Frequency Distribution of Stability Classes

5.2.5 MIXING HEIGHT

Predicted mixing height statistics from CALMET meteorological outputs are below for selected CALMET extracted points. The monthly mixing height variation is shown in Figure 5-12. Figure 5-13 shows the diurnal mixing height variation, illustrating the expected pattern of increasing mixing heights during the daytime and decreasing mixing heights into the nighttime. Figure 5-14 shows the frequency distribution of all the mixing heights predicted by the CALMET model at the selected CALMET extract points. There are no observations of mixing height for comparison.

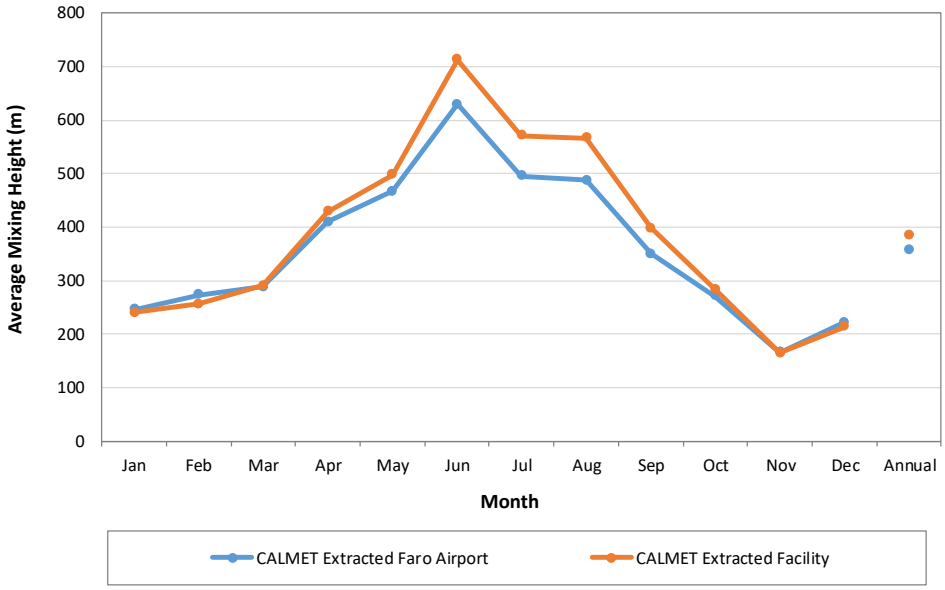

Figure 5-12 Monthly Mixing Height Variation

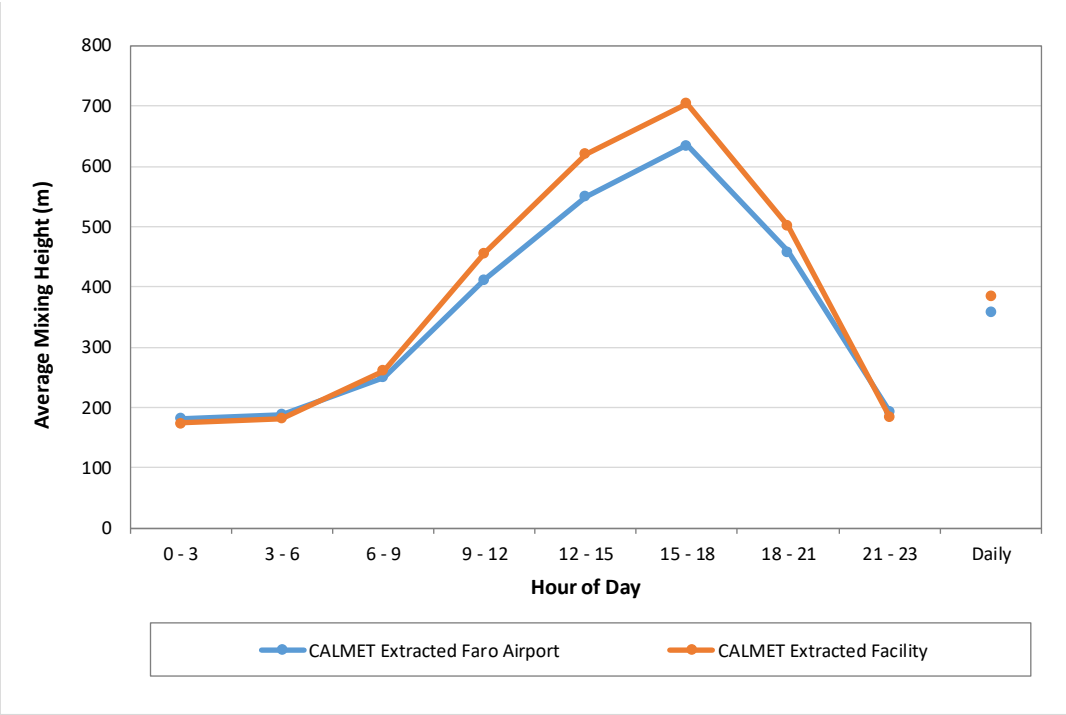

Figure 5-13 Diurnal Mixing Height Variation

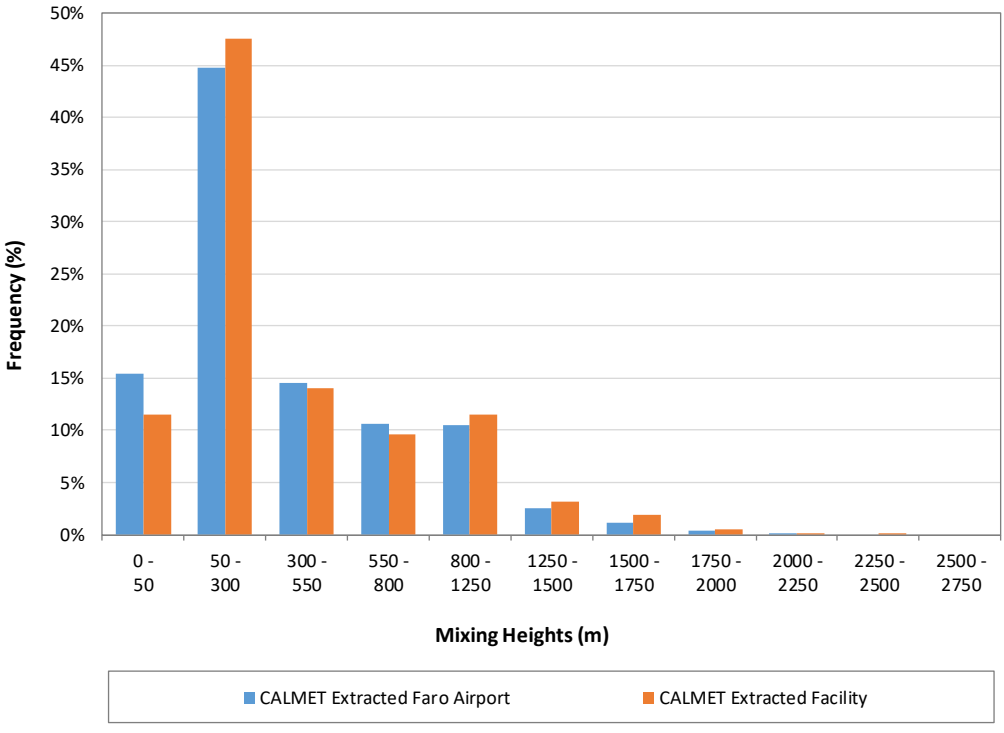

Figure 5-14 Mixing Height Frequency Distribution

5.3 CALPUFF – DISPERSION MODELLING

CALPUFF Version 7.2.1 (Level 150618) was executed for the three-year time period from January 1, 2016 through December 31, 2018. The CALPUFF model uses the meteorological fields generated from CALMET and simulates the dispersion of air emissions from the Project's point sources described in Section 4.

5.3.1 CALPUFF MODEL SWITCHES

Table 5-3 outlines the selected CALPUFF model options. Unless otherwise stated in Table 5-3, the AQDMG default parameters are used wherever applicable.

Table 5-3 Selected CALPUFF Model Options

CALPUFF Model Switch	Parameter	Option Selected	AQDMG Default
Vertical distribution used in the near field	MGAUSS	1 (Gaussian)	✓
Terrain adjustment method	MCTADJ	3 (Partial plume path adjustment)	✓
Subgrid-Scale complex terrain flag	MCTSG	0 (Not used)	✓
Near-field puffs modelled as elongated?	MSLUG	0 (No)	✓
Transitional Plume Rise modelled?	MTRANS	1 (Yes)	✓
Stack-tip downwash?	MTIP	1 (Yes)	✓
Method selected to compute plume rise for point sources not subject to downwash.	MRISE	1 (Briggs plume rise)	✓
Method used to simulate building downwash?	MBDW	2 (PRIME)	✓
Vertical wind shear modelled above stack top?	MSHEAR	0 (No)	✓
Puff splitting allowed?	MSPLIT	0 (No)	✓
Chemical Transformation Scheme?	MCHEM	0 (Not modelled)	✓
Aqueous phase transformation flag (only used in MCHEM =1 or 3)	MAQCHEM	Not used	✓
Wet removal modelled?	MWET	0 (No)	✓
Dry deposition modelled?	MDRY	0 (No)	✓
Gravitational settling (plume tilt)?	MTILT	0 (Not used)	✓
Method used to compute dispersion coefficients	MDISP	2 (Internally calculated)	✓
Sigma measurements used?	MTURBVW	Not used	✓
Back-up method used to compute dispersion when measured turbulence data are missing	MDISP2	Not used	✓
Method used for Lagrangian time scale for σy	MTAULY	0 (Lagrangian time scale)	✓
Advective-Decay timescale for turbulence	MTAUADV	0 (No turbulence advection)	✓
Method used to compute turbulence σv and σw profiles	MCTURB	1 (CALPUFF defaults)	✓
PG sigma y,z adjusted for roughness	MROUGH	0 (Yes)	✓
Partial plume penetration of elevated inversion?	MPARTL	1 (Yes)	✓
Partial plume penetration from buoyant area sources	MPARTLBA	Not used	✓
Strength of temperature inversion provided in PROFILE.DAT extended records?	MTINV	0 (No)	✓
Probability Distribution Function used for dispersion under convective conditions?	MPDF	1 (Yes)	✓
Sub-grid TIBL module used for shore line?	MSGTIBL	Not used	✓
Boundary conditions (concentration) modelled?	MBCON	0 (No)	✓
Configure for FOG Model output?	MFOG	0 (No)	✓
Test options specified to see if they conform to regulatory values?	MREG	0 (No)	✓
Minimum turbulence velocities, sigma v and sigma w for each stability class over land and water	SVMIN, SWMIN	CALPUFF defaults	✓

5.3.2 CALPUFF MODEL DOMAIN AND RECEPTORS

A 12 km by 12 km CALMET model domain and a 10 km by 10 km CALPUFF model domain were defined (Figure 5-15). Receptor grids were then produced for the Project following the instructions established by BC AQDMG (2015). Sensitive receptors - including health care facility, school, child care facility, nearest business and nearest residential location - were also identified and incorporated into the receptor grid. The names and locations of these sensitive receptors are displayed in Figure 5-15.

Model receptors were established according to the receptor spacing and extent requirements as set out in BC AQDMG within the CALPUFF domain. The model receptors created for the Project not only met the minimum requirements outlined in the BC AQDMG, but also included additional dense receptors at 50 m spacing placed over the entire Town of Faro to allow for more model predictions within the community. Receptors representing the sensitive human populations found nearby the Facility were also included in the model receptor grid.

The complete receptor grid used in CALPUFF were generated as follows and also presented in Figure 5-15 below:

- 20 m spacing along the Facility boundary (or Fenceline);
- 50 m spacing within 1.75 km of the Project stack locations, including those encapsulating the entire Faro Town area;
- 250 m spacing within 2 km of the Project stack locations;
- 500 m within 5 km of the Project stack locations;
- Nearest residence (situated approximately 380 m southeast of the Project);
- Nearest business (situated approximately 360 m east-southeast of the Project);
- Nearest child care facility (Bubble's Faro Daycare, situated approximately 785 m southeast of the Project);
- Nearest school (Del Van Gorder School, situated approximately 825 m southeast of the Project), and,
- Nearest health care facility (Faro Health Centre, situated approximately 860 m southeast of the Project).

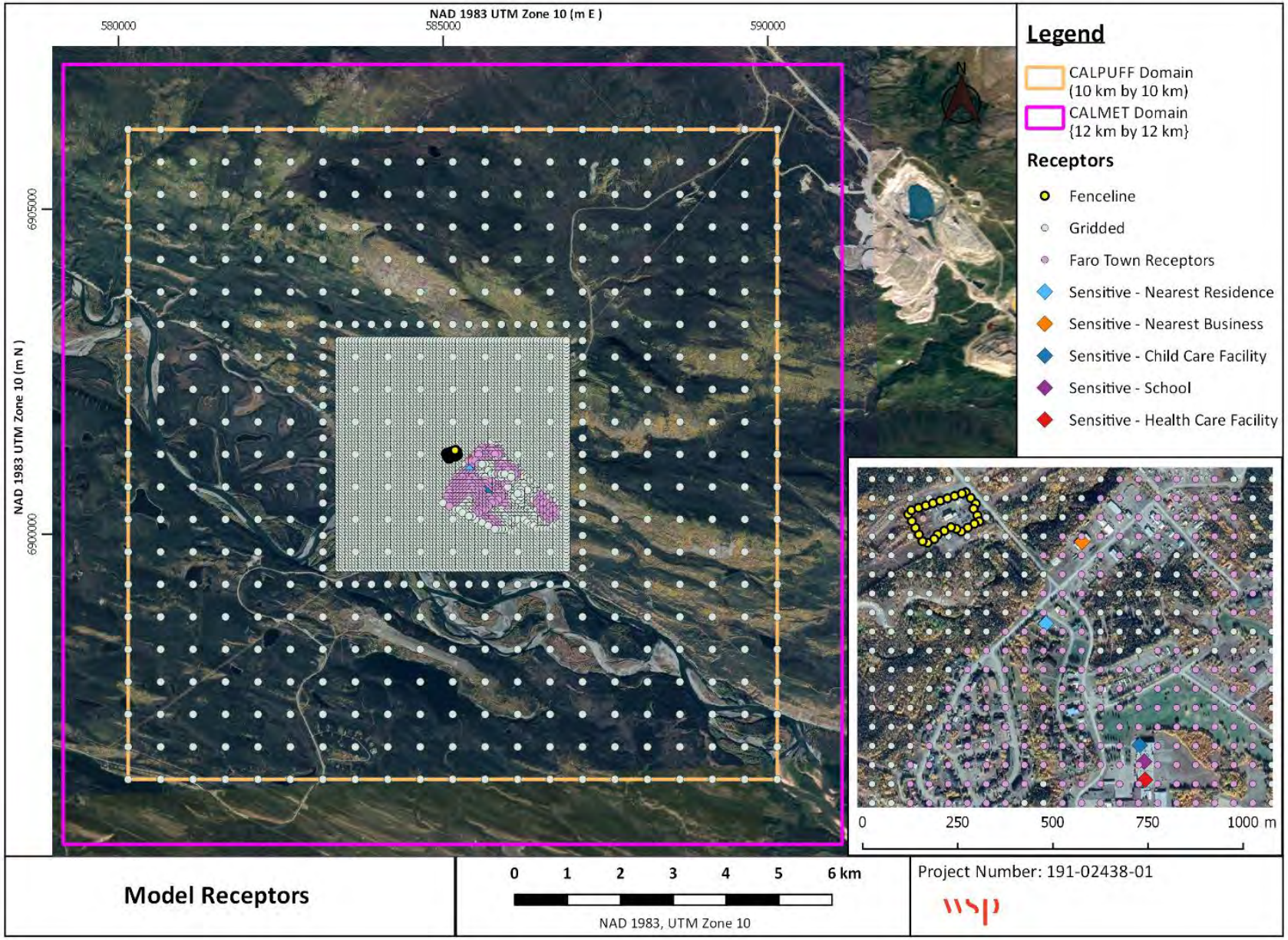

Figure 5-15 Modelled Receptors and Domains

5.3.3 BUILDING DOWNWASH

Buildings or other solid structures may impact air flows in the vicinity of a stack or point source due to the formation of turbulent eddies on the downwind side of the building. On the downwind side of a structure, a recirculating cavity of air forms and it does not mix with other air efficiently. This cavity has the potential to reduce plume rise and impact dispersion. The flow that is affected by the obstruction is known as the "wake".

The CALPUFF model accounts for building downwash with enhanced plume dispersion coefficients due to the turbulent wake and reduced plume rise caused by a combination of the descending streamlines in the lee of the building and the increased entrainment on the wake. Building downwash was considered in this Air Assessment using the US EPA Building Profile Input Program (BPIP-PRIME).

The buildings or structures and their corresponding heights included in the building downwash analysis using BPIP-PRIME are shown in Figure 5-16 and Table 5-4, respectively.

Table 5-4 Building and Structure Heights used in BPIP-PRIME

Building or Structure Name	Building ID	Building Height (m)
Diesel Fuel Tank #1	0	7.4
Diesel Fuel Tank #2	1	4.6
Building #1	2	2.6
FD7 Building	3	9.8
Building #2	6	3.0
FD1 Plant	7	8.9
Office	8	4.9
Control Building	9	4.3
Storage Building	10	5.3
YM20 Enclosure	11	4.0
YM21 Enclosure	12	4.0
YM22 Enclosure	13	4.0
YM23 Enclosure	14	4.0
YM24 Enclosure	15	4.0
YM25 Enclosure	16	4.0

Figure 5-16 Buildings and Structures included in BPIP-PRIME

5.4 NO_X TO NO_2 CONVERSION

As dispersion models only compute and output Nitrogen Oxides (NOx) concentrations, model predicted NOx concentrations need to be converted to NO_2 concentrations using estimation methods in order to compare and demonstrate compliance with the established NO_2 criteria. The regulatory NO_2 conversion methods outlined in BC AQDMG (2015) are conservative and were neither updated nor tested as appropriate for determination of compliance with the new CAAQS. It is generally accepted that with the more stringent NO_2 objectives recently adopted by CCME, that current AQDMG approaches to NOx to NO_2 conversion in dispersion modelling assessments will need to be further refined for most dispersion modelling assessments. Given the overly conservative nature of regulatory NO_2 conversion methods found in any Canadian jurisdictions at the current time, WSP applied the Janssen conversion method for the Project to allow for consistency with past YEC air assessments (SENES, 2011)[3].

[3] *SENES Consultants Limited (2011, October 20). Air Quality Assessment Update in Support of Permit Renewal for Diesel Generator Operations Prepared for Yukon Energy Corporation. Vancouver, British Columbia, Canada.*

The Janssen method is based on an empirically-derived relationship between the source-to-receptor distance and the resulting NO_2-to-NO_x conversion ratios which increases with distance from the source. These NO_2/NO_x conversion ratios are provided in Table 5-5 and applied to the modelled NO_x concentrations in order to estimate the NO_2 concentrations for both modelling scenarios as presented in the air dispersion modelling result tables under Section 6 of this report.

Table 5-5 NO_2/NO_x Conversion Ratios from the Janssen Method

Distance from Source (km)	NO_2/NO_x Conversion Ratios
0 – 1	0.05
1 – 2	0.14
2 – 3	0.19
3 – 4	0.25
4 – 5	0.29
5 – 6	0.33
6 – 7	0.37

6 POST-PROCESSING AND RESULTS

The CALPOST utility from the CALPUFF System Version 7 was used to post-process the CALPUFF dispersion modelling outputs for all air contaminants (NO_2, PM_{10}, $PM_{2.5}$, SO_2, and CO) according to the required statistical forms and averaging periods of the applicable ambient air quality criteria chosen for the Air Assessment (Section 2). The following sections outline the maximum predicted air contaminant concentrations resulting from the two modelling scenarios ("Existing Scenario" and "Future Scenario") defined under Section 4.1. Maximum predicted concentrations are presented in summary tables (Table 6-1 through Table 6-3), summarized by averaging periods (1-hour, 8-hour, 24-hour, and annual) and receptor types. The receptor types are categorized as follows:

- Maximum Point of Impingement (MPOI) – the receptor with the highest predicted ambient concentration across all modelled receptors;
- Faro Town – the receptor with the highest predicted ambient concentration within the Town of Faro;
- Nearest residence (situated approximately 380 m southeast of the Project);
- Nearest business (situated approximately 360 m east-southeast of the Project);
- Nearest child care facility (Bubble's Faro Daycare, situated approximately 785 m southeast of the Project);
- Nearest school (Del Van Gorder School, situated approximately 825 m southeast of the Project), and,
- Nearest health care facility (Faro Health Centre, situated approximately 860 m southeast of the Project).

The maximum predicted air contaminant concentrations from the Existing Scenario and the Future Scenario are outlined in Section 6.1 and Section 6.2, respectively. Tabular summarises of the model predictions at the MPOI for both modelling scenarios are provided in Table 6-1, while Table 6-2 and Table 6-3 present predictions at the sensitive receptors for the Existing and Future Scenarios, respectively. The tables present the total (cumulative) Project concentrations derived by summing the model predicted concentrations with baseline concentrations, where available, and are organized by modelling scenario (as per Table 4-1). Values highlighted in yellow indicate the occurrence of cumulative model predictions exceeding ambient air quality criteria.

In order to illustrate the magnitude compared to the ambient air quality standards considered, percentages of predicted concentrations relative to the applicable standard are also provided in the modelling results summary tables (Table 6-1 through Table 6-3). The spatial distribution and pattern of the dispersion modelling results are depicted by contour plots (isopleths) of maximum predicted concentrations for each air contaminant and averaging period in Figures Figure 6-1 to Figure 6-19. Where appropriate, frequency of exceedances of the applicable ambient air quality criteria are presented. A more in-depth analysis and discussion by each air contaminant are presented in the subsections below.

Table 6-1 Summary of Maximum Cumulative Modelling Results at the MPOI from both Emission Scenarios

AIR CONTAMINANT	AVERAGING PERIOD	AMBIENT AIR QUALITY STANDARD ($\mu g/m^3$)	JURSIDICTION	BASELINE CONCENTRATION		MAXIMUM CUMULATIVE MODEL PREDICTED CONCENTRATION AT THE MPOI			
						Existing Scenario		Future Scenario	
				Value ($\mu g/m^3$)	% of Criteria	Value ($\mu g/m^3$)	% of Criteria	Value ($\mu g/m^3$)	% of Criteria
Nitrogen Dioxide (NO_2)	1-hour	113	Yukon	0.67	0.6%	160.3	142%	243.2	215%
	Annual	32	Yukon	0.11	0.3%	11.0	34%	18.3	57%
Particulate Matter Coarse (PM_{10})	24-hour	50	Yukon	0.46	0.9%	19.7	39%	24.1	48%
Particulate Matter Fine ($PM_{2.5}$)	24-hour	27	Yukon	0.25	0.9%	9.3	34%	12.7	47%
	Annual	8.8	Yukon	0.05	0.5%	1.6	18%	2.2	25%
Sulphur Dioxide (SO_2)	1-hour	183	Yukon	N/A	N/A	3.3	2%	4.3	2%
	Annual	13	Yukon	N/A	N/A	0.2	2%	0.3	3%
Carbon Monoxide (CO)	1-hour	14300	BC	N/A	N/A	480.3	3%	489.0	3%
	8-hour	5500	BC	N/A	N/A	248.8	5%	310.4	6%

Table 6-2 Summary of Maximum Cumulative Modelling Results from the Existing Scenario by Sensitive Receptor Type

AIR CONTAMINANT	AVERAGING PERIOD	AMBIENT AIR QUALITY STANDARD (µg/m³)	JURISDICTION	MAXIMUM CUMULATIVE MODEL PREDICTED CONCENTRATION AT THE SENSITVE RECEPTORS											
				Existing Scenario											
				Most Impacted Faro Town Receptor		Nearest Residence		Nearest Business		Nearest Child Care Facility		Nearest School		Nearest Health Care Facility	
				Value (µg/m³)	% of Criteria	Value (µg/m³)	% of Criteria	Value (µg/m³)	% of Criteria	Value (µg/m³)	% of Criteria	Value (µg/m³)	% of Criteria	Value (µg/m³)	% of Criteria
Nitrogen Dioxide (NO_2)	1-hour	113	Yukon	98.1	87%	42.0	37%	43.0	38%	29.8	26%	31.1	28%	30.5	27%
	Annual	32	Yukon	3.9	12%	2.2	7%	2.2	7%	1.3	4%	1.2	4%	1.1	4%
Particulate Matter Coarse (PM_{10})	24-hour	50	Yukon	5.8	12%	4.9	10%	3.1	6%	4.0	8%	3.9	8%	3.5	7%
Particulate Matter Fine ($PM_{2.5}$)	24-hour	27	Yukon	2.5	9%	1.7	6%	1.6	6%	1.2	4%	1.2	4%	1.1	4%
	Annual	8.8	Yukon	0.5	6%	0.4	4%	0.4	4%	0.2	3%	0.2	2%	0.2	2%
Sulphur Dioxide (SO_2)	1-hour	183	Yukon	1.84	1.0%	1.00	0.5%	0.98	0.5%	0.73	0.4%	0.74	0.4%	0.70	0.4%
	Annual	13	Yukon	0.06	0.4%	0.04	0.3%	0.04	0.3%	0.02	0.2%	0.02	0.2%	0.02	0.2%
Carbon Monoxide (CO)	1-hour	14300	BC	192.2	1.3%	115.5	0.8%	104.9	0.7%	84.9	0.6%	86.3	0.6%	90.2	0.6%
	8-hour	5500	BC	68.1	1.2%	62.5	1.1%	35.7	0.6%	53.5	1.0%	53.2	1.0%	48.7	0.9%

Table 6-3 Summary of Maximum Cumulative Modelling Results from the Future Scenario by Sensitive Receptor Type

AIR CONTAMINANT	AVERAGING PERIOD	AMBIENT AIR QUALITY STANDARD ($\mu g/m^3$)	JURISDICTION	MAXIMUM CUMULATIVE MODEL PREDICTED CONCENTRATION AT THE SENSITVE RECEPTORS											
				Future Scenario											
				Most Impacted Faro Town Receptor		Nearest Residence		Nearest Business		Nearest Child Care Facility		Nearest School		Nearest Health Care Facility	
				Value ($\mu g/m^3$)	% of Criteria	Value ($\mu g/m^3$)	% of Criteria	Value ($\mu g/m^3$)	% of Criteria	Value ($\mu g/m^3$)	% of Criteria	Value ($\mu g/m^3$)	% of Criteria	Value ($\mu g/m^3$)	% of Criteria
Nitrogen Dioxide (NO_2)	1-hour	113	Yukon	145.3	129%	61.5	54%	62.3	55%	43.0	38%	43.5	39%	43.6	39%
	Annual	32	Yukon	5.7	18%	3.4	11%	3.0	9%	1.9	6%	1.8	6%	1.7	5%
Particulate Matter Coarse (PM_{10})	24-hour	50	Yukon	6.9	14%	5.6	11%	3.8	8%	4.9	10%	4.8	10%	4.4	9%
Particulate Matter Fine ($PM_{2.5}$)	24-hour	27	Yukon	3.1	11%	2.2	8%	1.9	7%	1.5	6%	1.5	6%	1.4	5%
	Annual	8.8	Yukon	0.6	7%	0.5	6%	0.4	5%	0.3	3%	0.3	3%	0.3	3%
Sulphur Dioxide (SO_2)	1-hour	183	Yukon	2.40	1.3%	1.33	0.7%	1.32	0.7%	1.00	0.5%	1.05	0.6%	1.00	0.5%
	Annual	13	Yukon	0.08	0.6%	0.06	0.5%	0.05	0.4%	0.03	0.3%	0.03	0.3%	0.03	0.2%
Carbon Monoxide (CO)	1-hour	14300	BC	252.2	1.8%	144.8	1.0%	128.3	0.9%	104.5	0.7%	106.7	0.7%	109.3	0.8%
	8-hour	5500	BC	80.7	1.5%	75.8	1.4%	45.6	0.8%	68.9	1.3%	69.4	1.3%	64.3	1.2%

6.1 RESULTS FOR EXISTING SCENARIO

The first modelling scenario considered the ambient air quality impact of the two existing gensets (FD1 and FD7) that have been de-rated to 2.4 MW and 2.8 MW respectively, and three (3) of the new CAT 3516C 1.8 MW diesel generators (Genset ID: YM20, YM21, YM22). The air dispersion modelling results for each air contaminant and averaging period are discussed below, along with the associated contour plots.

6.1.1 GASEOUS POLLUTANTS (SO_2, CO, AND NO_2)

Predicted concentrations of SO_2 and CO for both short-term and long-term averaging periods are very low compared to the ambient air quality criteria. As there was no ambient SO_2 nor CO data available near the Project location, baseline values were not calculated for these 2 air contaminants. As such, baseline air quality was not considered, and the predicted concentrations were found to be well below the ambient air quality criteria. In particular, the maximum predicted concentrations for each receptor category are as follows:

- SO_2
  - MPOI
    - 3.3 µg/m^3, or 2% of the 1-hour SO_2 YAAQS;
    - 0.2 µg/m^3, or 2% of the annual SO_2 YAAQS;
  - Faro Town
    - 1.84 µg/m^3, or 1% of the 1-hour SO_2 YAAQS;
    - 0.06 µg/m^3, or 0.4% of the annual SO_2 YAAQS;
  - Nearest Sensitive Receptors
    - range from 0.70 µg/m^3 to 1.00 µg/m^3 (0.4% to 0.5%) of the 1-hour SO_2 YAAQS; and,
    - range from 0.02 µg/m^3 to 0.04 µg/m^3 (0.2% to 0.3%) of the annual SO_2 YAAQS.
- CO
  - MPOI
    - 480.3 µg/m^3, or 3% of the 1-hour CO ambient air quality criteria;
    - 248.8 µg/m^3, or 5% of the 8-hour CO ambient air quality criteria;
  - Faro Town
    - 192.2 µg/m^3, or 1.3% of the 1-hour CO ambient air quality criteria;
    - 68.1 µg/m^3, or 1.2% of the 8-hour CO ambient air quality criteria;
  - Nearest Sensitive Receptors
    - range from 84.9 µg/m^3 to 115.5 µg/m^3 (0.6% to 0.8%) of the 1-hour CO ambient air quality criteria; and,
    - range from 35.7 µg/m^3 to 62.5 µg/m^3 (0.6% to 1.1%) of the 8-hour CO ambient air quality criteria.

These results indicate that the contribution of the emissions from the Existing Scenario to ambient SO_2 and CO is low. The contour plots (Figure 6-1 through Figure 6-4) show that the predicted concentrations decrease significantly with increased distance from the Facility.

As discussed in Section 5.4, the Janssen Method was used to convert model predictions from NO_x to NO_2 values. The resulting maximum predicted NO_2 concentrations exceed the YAAQS for the short-term averaging period (1-hour) and are well below the YAAQS for the long-term averaging period (annual) at the MPOI. Within the Town of Faro and at the sensitive receptors, the predicted NO_2 concentrations are predicted to be in compliance with the YAAQS. When baseline NO_2 concentration is considered, the cumulative NO_2 predicted concentrations at the various receptor types are as follows:

- MPOI
    - 160.3 µg/m^3, or 142% of the 1-hour NO_2 YAAQS;
    - 11.0 µg/m^3, or 34% of the annual NO_2 YAAQS;
- Faro Town
    - 98.1 µg/m^3, or 87% of the 1-hour NO_2 YAAQS;
    - 3.9 µg/m^3, or 12% of the annual NO_2 YAAQS;
- Nearest Sensitive Receptors
    - range from 29.8 µg/m^3 to 43.0 µg/m^3 (26% to 38%) of the 1-hour NO_2 YAAQS; and,
    - range from 1.1 µg/m^3 to 2.2 µg/m^3 (4% to 7%) of the annual NO_2 YAAQS.

Based on the spatial distribution as shown by the contour plots below (Figure 6-5 and Figure 6-6), exceedances were only predicted for the short-term averaging period (1-hour) and occur away from the receptors that have potential to impact the human population near the Project (i.e. Faro Town receptors). It is important to note that the observed pattern of predicted 1-hour NO_2 concentration distribution with “pockets” of higher concentrations further away from the facility is due to the discrete distance-based conversion methodology of the Janssen Method.

Oftentimes, predicted exceedances are found to occur infrequently, especially given the fact that there would be limited (if any) hours that the Facility is operating at the maximum capacity level. As such, a frequency of exceedance analysis was conducted to determine the number of modelling hours that are predicted to exceed the 1-hour NO_2 YAAQS at the MPOI (situated approximately 1 km east of the Facility center). The resulting percentage of frequency of exceedance, using the 98th percentile 1-hour NO_2 predictions, was determined to be 0.27% (71 hours) at the MPOI. Since the primary concern of air quality assessment is to evaluate the potential risks of the emissions resulting from the Future Scenario on the human population residing near the Project (i.e. at the Faro Town receptors), rather than at the point of maximum impingement, further investigation into determining patterns of the exceedances was not performed for this modelling scenario.

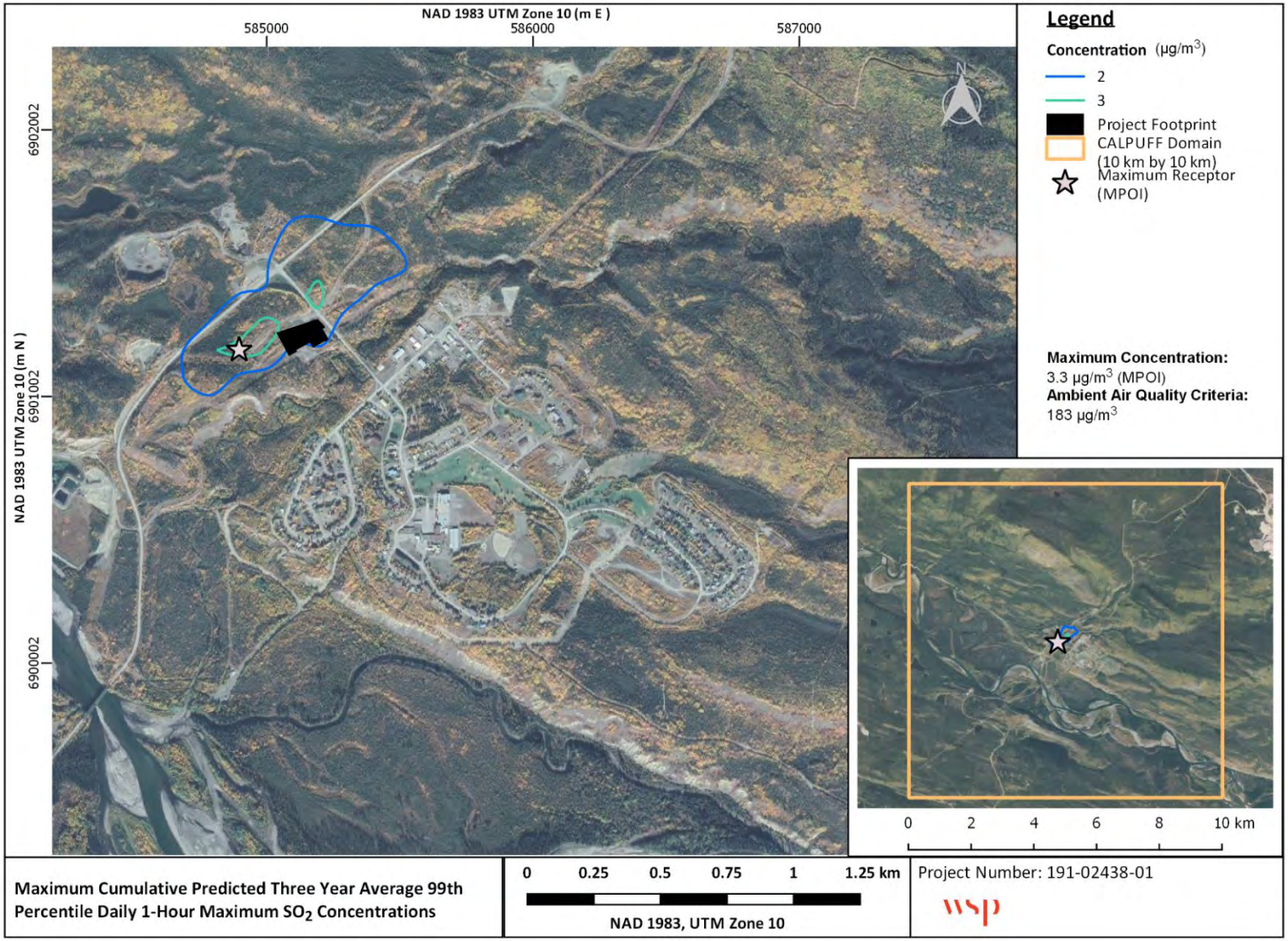

Figure 6-1 Contour Plot of Predicted 1-Hour SO_2 Concentrations for the Existing Scenario

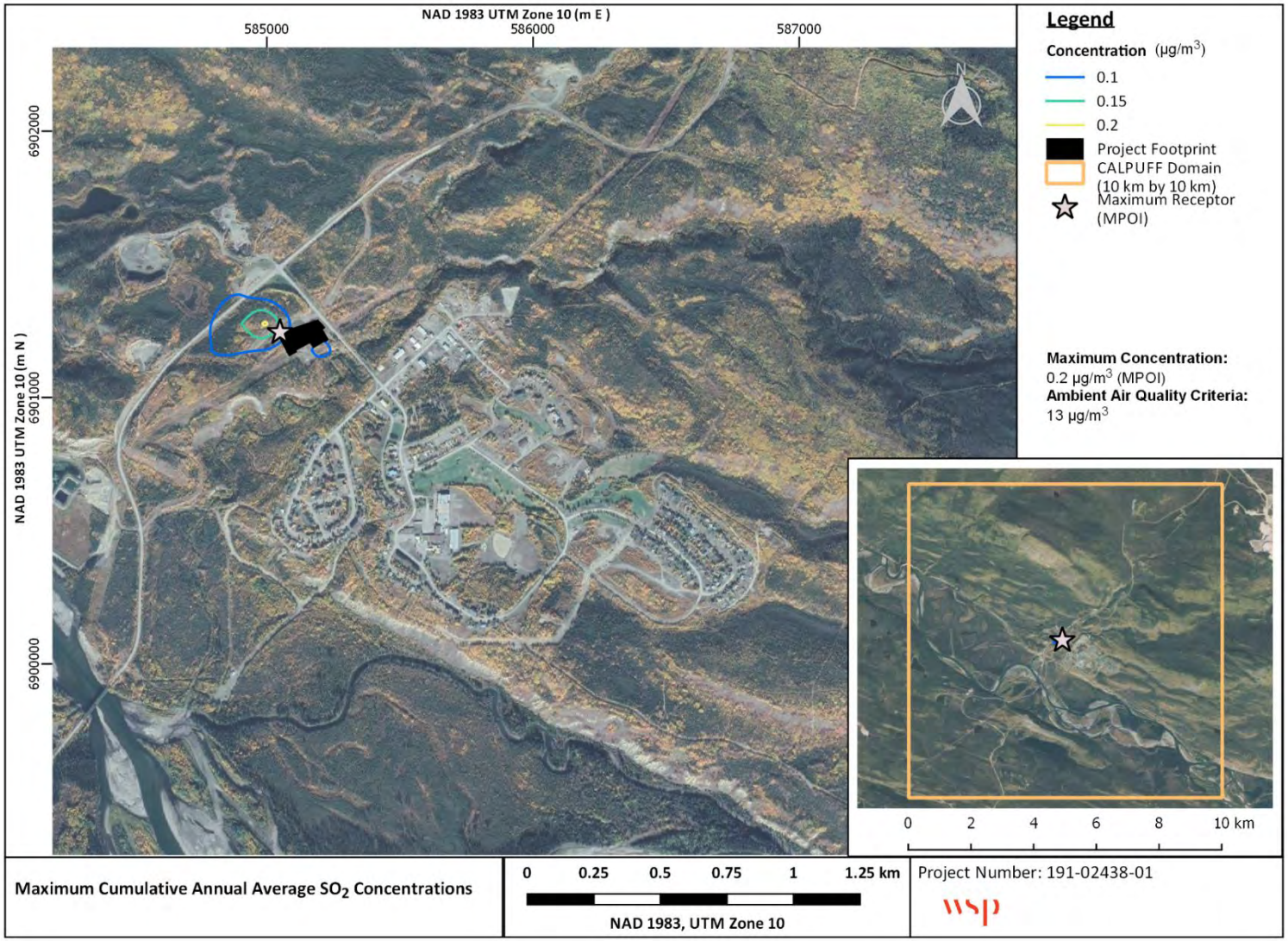

Figure 6-2 Contour Plot of Predicted Annual SO_2 Concentrations for the Existing Scenario

Figure 6-3 Contour Plot of Predicted 1-Hour CO Concentrations for the Existing Scenario

Figure 6-4 Contour Plot of Predicted 8-Hour CO Concentrations for the Existing Scenario

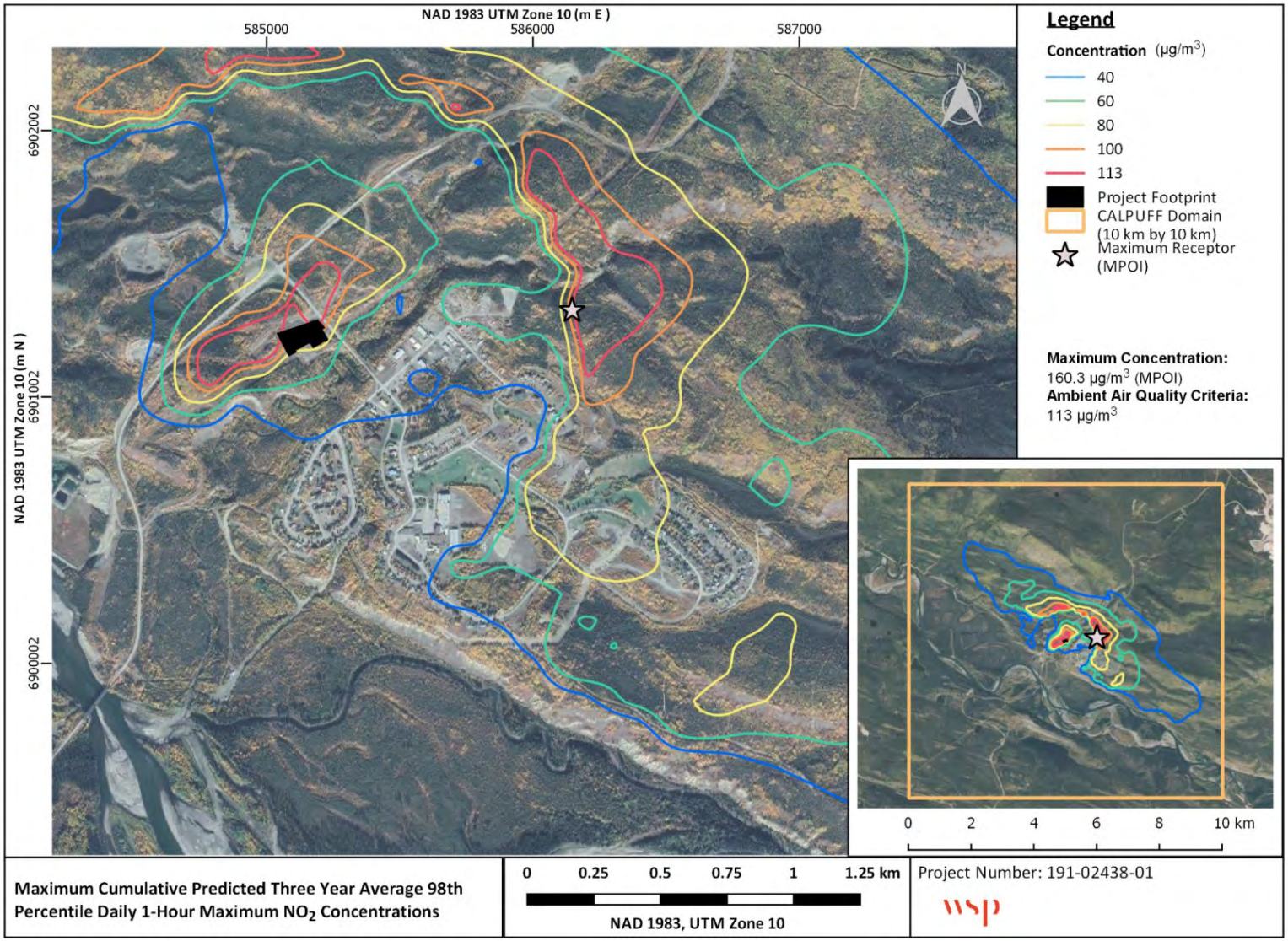

Figure 6-5 Contour Plot of Predicted 1-Hour NO_2 Concentrations for the Existing Scenario

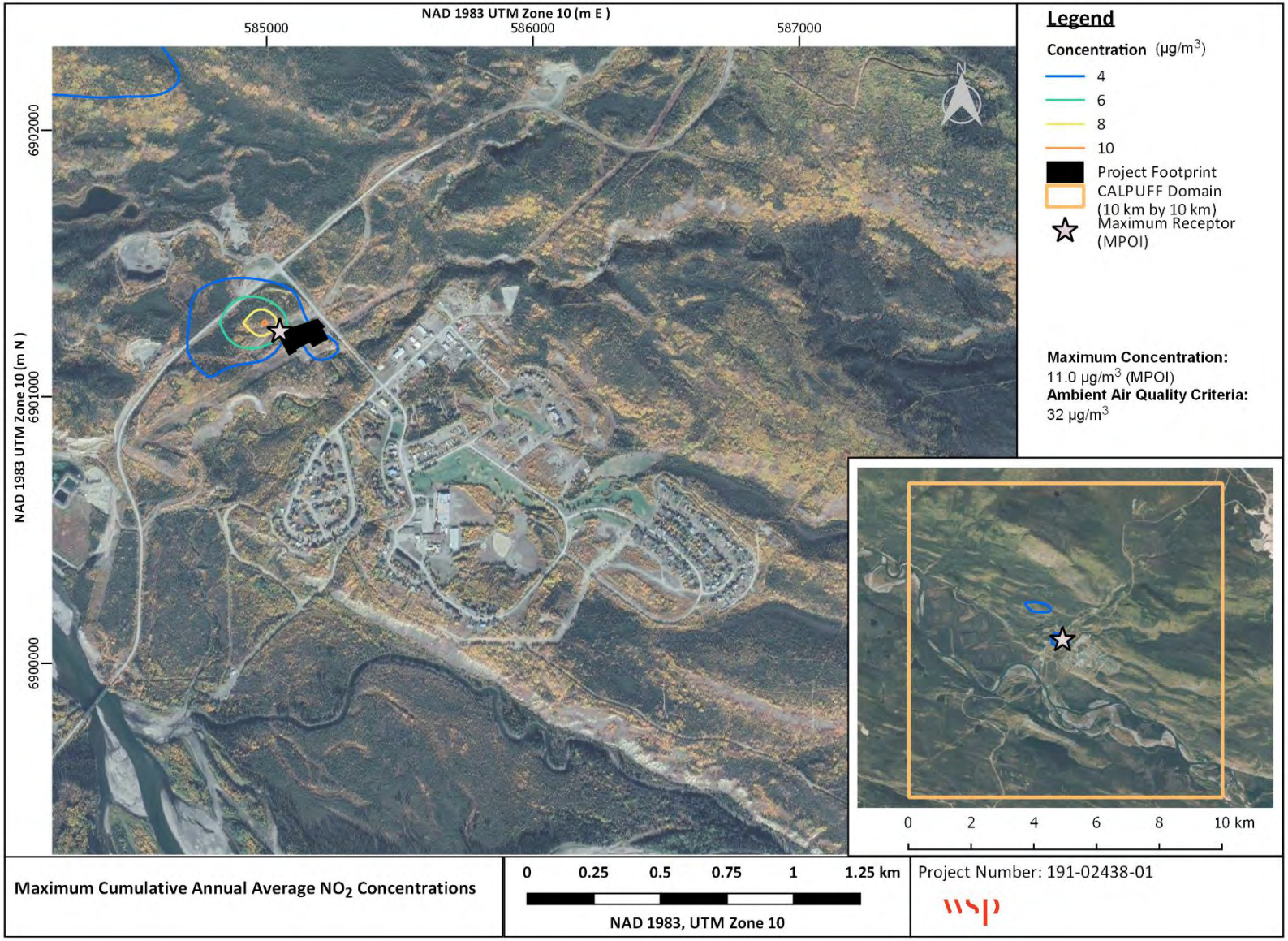

Figure 6-6 Contour Plot of Predicted Annual NO_2 Concentrations for the Existing Scenario

6.1.2 PARTICULATE MATTER ($PM_{2.5}$ AND PM_{10})

With regards to $PM_{2.5}$ and PM_{10}, the predicted concentrations for both short-term and long-term periods showed no exceedances of the associated air quality criteria. When baseline air quality is considered, the cumulative $PM_{2.5}$ and PM_{10} predicted concentrations remain well below the air quality criteria:

- PM_{10}
  - MPOI
    - 19.7 µg/m^3, or 39% of the 24-hour PM_{10} YAAQS;
  - Faro Town
    - 5.8 µg/m^3, or 12% of the 24-hour PM_{10} YAAQS; and,
  - Nearest Sensitive Receptors
    - range from 3.1 µg/m^3 to 4.9 µg/m^3 (6% to 10%) of the 24-hour PM_{10} YAAQS.
- $PM_{2.5}$
  - MPOI
    - 9.3 µg/m^3, or 34% of the 24-hour $PM_{2.5}$ YAAQS;
    - 1.6 µg/m^3, or 18% of the annual $PM_{2.5}$ YAAQS;
  - Faro Town
    - 2.5 µg/m^3, or 9% of the 24-hour $PM_{2.5}$ YAAQS;
    - 0.5 µg/m^3, or 6% of the annual $PM_{2.5}$ YAAQS;
  - Nearest Sensitive Receptors
    - range from 1.1 µg/m^3 to 1.7 µg/m^3 (4% to 6%) of the 24-hour $PM_{2.5}$ YAAQS; and,
    - range from 0.2 µg/m^3 to 0.4 µg/m^3 (2% to 4%) of the annual $PM_{2.5}$ YAAQS.

These results indicate that the contribution of the emissions from the Existing Scenario to ambient concentrations of particulate matter is low relative to YAAQS. In addition, the contour plots (Figure 6-7 through Figure 6-9) show the limited spatial distribution of predicted particulate matter concentrations, where the predicted concentrations decrease significantly with increased distance from the Facility

Figure 6-7 Contour Plot of Predicted 24-Hour PM_{10} Concentrations for the Existing Scenario

Figure 6-8 Contour Plot of Predicted 24-Hour $PM_{2.5}$ Concentrations for the Existing Scenario

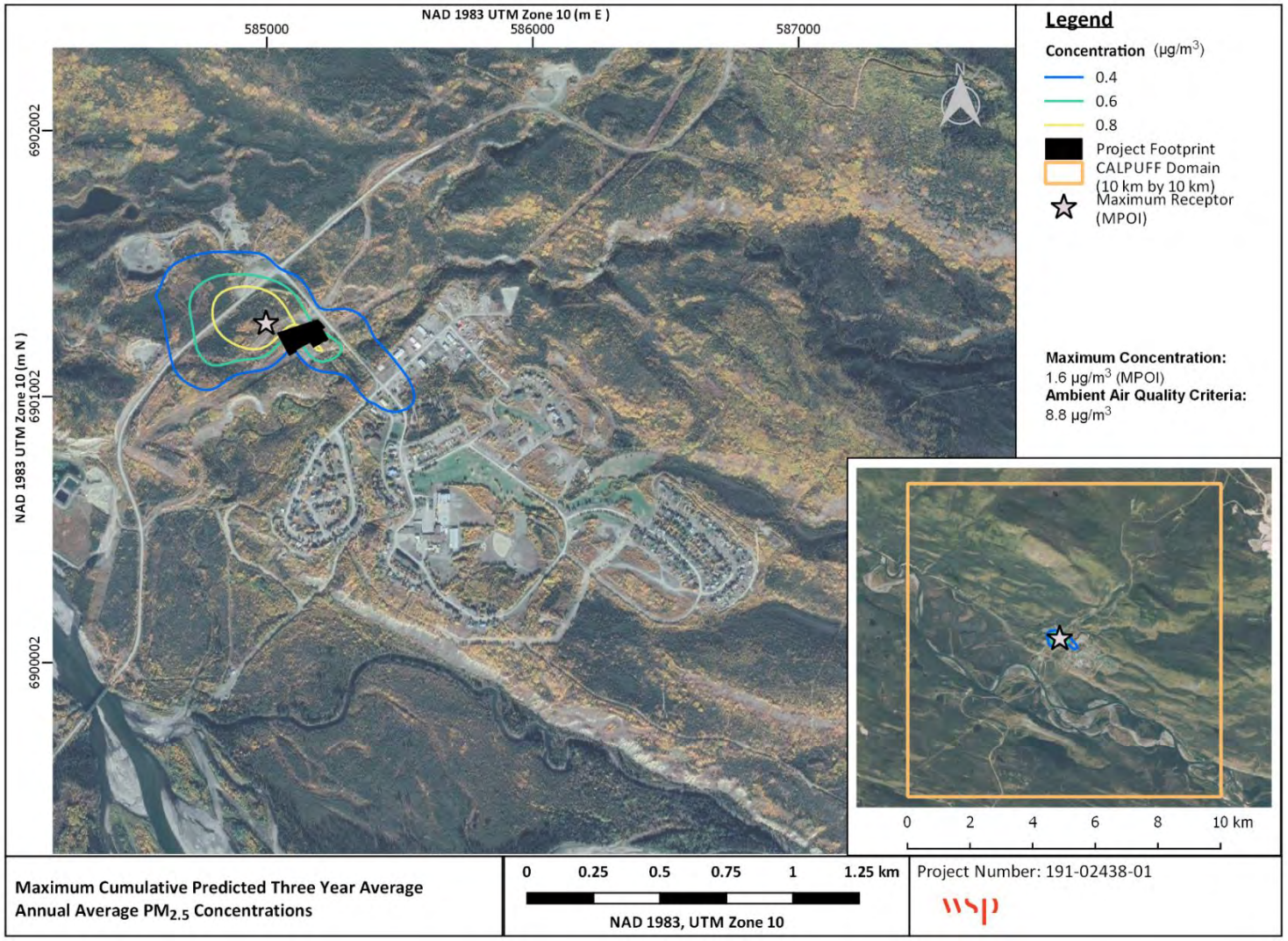

Figure 6-9 Contour Plot of Predicted Annual $PM_{2.5}$ Concentrations for the Existing Scenario

6.2 RESULTS FOR FUTURE SCENARIO

The second modelling scenario considered the ambient air quality impact of the two existing gensets (FD1 and FD7) that had been de-rated to 2.4 MW and 2.8 MW respectively, and six (6) new CAT 3516C 1.8 MW diesel generators (Genset ID: YM20, YM21, YM22, YM23, YM24, and YM25). The air dispersion modelling results for each air contaminant and averaging period are discussed below, along with the associated contour plots.

6.2.1 GASEOUS POLLUTANTS (SO_2, CO, AND NO_2)

Similar to the results of the Existing Scenario, the predicted concentrations of SO_2 and CO for both short-term and long-term averaging periods are very low compared to the ambient air quality criteria. As mentioned in Section 3, baseline values were not available for these two air contaminants, so the predicted values alone are presented below. The predicted concentrations were found to be well below the ambient air quality criteria, where the maximum predicted concentrations for each receptor category are as follows:

- SO_2
  - MPOI
    - 4.3 µg/m^3, or 2% of the 1-hour SO_2 YAAQS;
    - 0.3 µg/m^3, or 3% of the annual SO_2 YAAQS;
  - Faro Town
    - 2.40 µg/m^3, or 1.3% of the 1-hour SO_2 YAAQS;
    - 0.08 µg/m^3, or 0.6% of the annual SO_2 YAAQS;
  - Nearest Sensitive Receptors
    - range from 1.00 µg/m^3 to 1.33 µg/m^3 (0.5% to 0.7%) of the 1-hour SO_2 YAAQS; and,
    - range from 0.03 µg/m^3 to 0.06 µg/m^3 (0.2% to 0.5%) of the annual SO_2 YAAQS.
- CO
  - MPOI
    - 489.0 µg/m^3, or 3% of the 1-hour CO ambient air quality criteria;
    - 310.4 µg/m^3, or 6% of the 8-hour CO ambient air quality criteria;
  - Faro Town
    - 252.2 µg/m^3, or 1.8% of the 1-hour CO ambient air quality criteria;
    - 80.7 µg/m^3, or 1.5% of the 8-hour CO ambient air quality criteria;
  - Nearest Sensitive Receptors
    - range from 104.5 µg/m^3 to 144.8 µg/m^3 (0.7% to 1.0%) of the 1-hour CO ambient air quality criteria; and,
    - range from 45.6 µg/m^3 to 75.8 µg/m^3 (0.8% to 1.4%) of the 8-hour CO ambient air quality criteria.

These results indicate that the contribution of the emissions from the Future Scenario to ambient SO_2 and CO is low. The contour plots (Figure 6-10 through Figure 6-13) show that the predicted concentrations significantly decrease with increased distance from the Facility.

As discussed in Section 5.4, the Janssen Method was used to convert model predictions from NO_x to NO_2 values. The resulting maximum predicted NO_2 concentrations exceed the YAAQS for the short-term averaging period (1-hour) and are well below the YAAQS for the long-term averaging period (annual) at the MPOI. Within the Town of Faro, ambient NO_2 concentrations are predicted to exceed the YAAQS for the short-term averaging period (1-hour) but are well below the YAAQS for the long-term averaging period (annual). The predicted NO_2 concentrations are predicted to be in compliance with the YAAQS at all of the sensitive receptors. When baseline NO_2 concentrations (as defined in Section 3) is considered, the cumulative NO_2 predicted concentrations at the various receptor types are as follows:

- MPOI
    - 243.2 µg/m^3, or 215% of the 1-hour NO_2 YAAQS;
    - 18.3 µg/m^3, or 57% of the annual NO_2 YAAQS;
- Faro Town
    - 145.3 µg/m^3, or 129% of the 1-hour NO_2 YAAQS;
    - 5.7 µg/m^3, or 18% of the annual NO_2 YAAQS;
- Nearest Sensitive Receptors
    - range from 43.0 µg/m^3 to 62.3 µg/m^3 (38% to 55%) of the 1-hour NO_2 YAAQS; and,
    - range from 1.7 µg/m^3 to 3.4 µg/m^3 (5% to 11%) of the annual NO_2 YAAQS.

Based on the spatial distribution as shown by the contour plots below (Figure 6-14 and Figure 6-15), exceedances were predicted for the short-term averaging period (1-hour) only and were found scattered in a confined area surrounding the Facility and also on the outskirts of the Town of Faro. It is important to note that the observed pattern of predicted 1-hour NO_2 concentration distribution with “pockets” of higher concentrations further away from the Facility is due to the discrete distance-based conversion methodology of the Janssen Method.

To characterize the risk associated with the predicted 1-hour NO_2 exceedances, further analysis to evaluate and illustrate the magnitude and extent of these exceedances was performed to determine patterns and provide useful context to the predicted air quality impacts from the Facility’s maximum permitted levels. Since the primary concern of air quality assessment is to evaluate the potential risks on the human population residing near the Project (i.e. at the Faro Town receptors), rather than at the point of maximum impingement, further data analysis of the predicted short-term NO_2 exceedances were analyzed for the maximally impacted receptor within the Faro Town (shown by “Maximum Receptor (Faro Town)” in Figure 6-14)

Specifically, the predicted 1-hour NO_2 exceedances were analyzed for frequency of occurrence, temporal pattern, and meteorological conditions that were attributable to the elevated NO_2 predictions. The frequency of exceedance, using the 98th percentile of 1-hour NO_2 predictions, was determined to be 0.96% (253 hours) at the MPOI and 0.21% (56 hours) at the maximally impacted Faro Town receptor. Moreover, the predicted 1-hour NO_2 exceedances occur entirely under particular wind conditions (light winds predominantly from the west-northwest direction as depicted by Figure 6-16), which primarily follow the prevailing winds at the Facility (as extracted from the CALMET model, shown in Figure 5-10). In fact, based on Table 6-4, all of the predicted exceedances are found from wind directions between 290° and 310°, and low wind speeds (1-3 m/s). Furthermore, according to Table 6-5, the majority of the predicted exceedances (51 out of 56 exceeding hours) occur during the cooler months of the year (January through April and September through December) within the night-time hours (18:00 to 07:00), during which poor dispersion patterns such as temperature inversions and stagnant conditions are more likely to be observed.

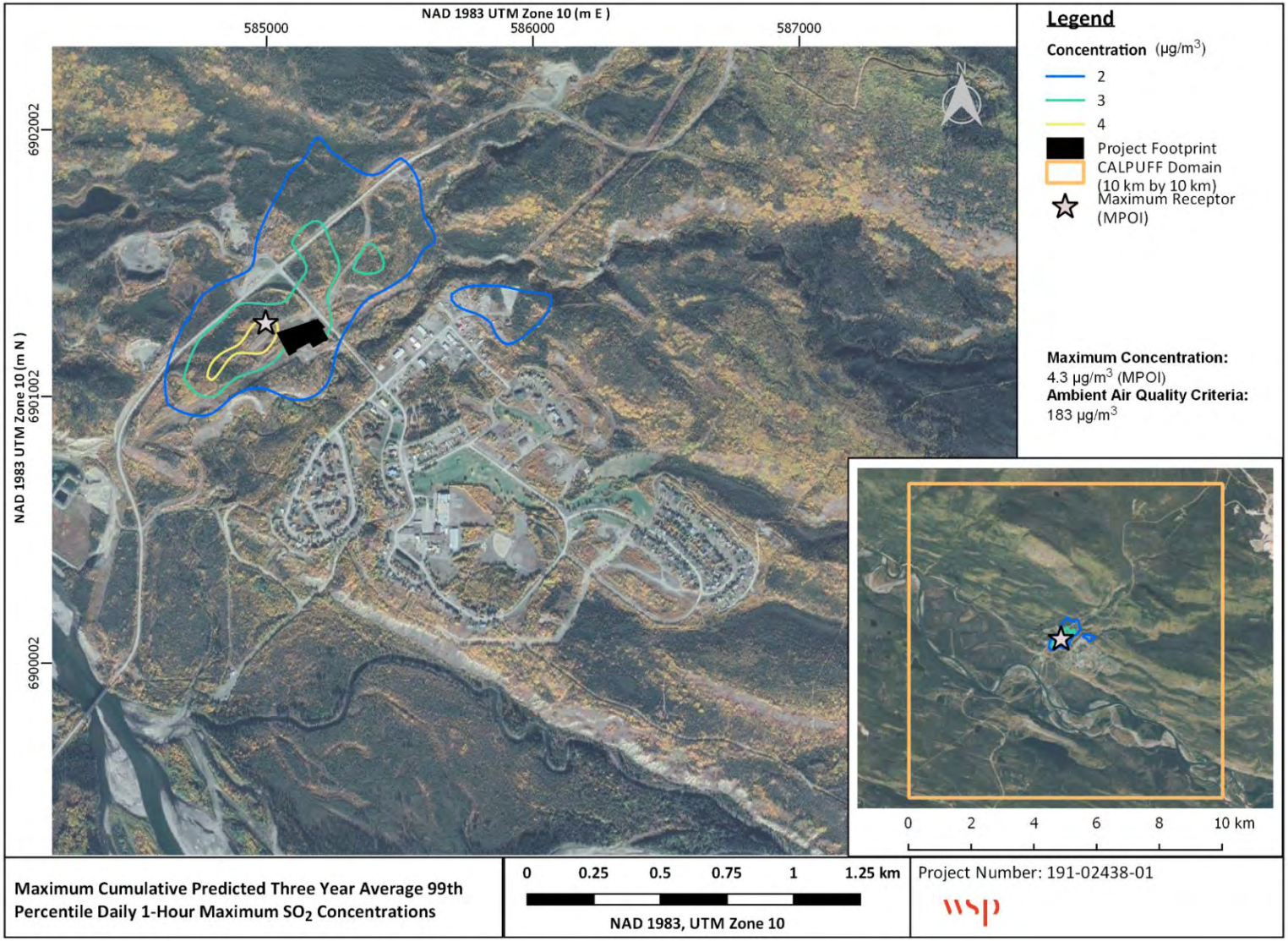

Figure 6-10 Contour Plot of Predicted 1-Hour SO_2 Concentrations for the Future Scenario

Figure 6-11 Contour Plot of Predicted Annual SO_2 Concentrations for the Future Scenario

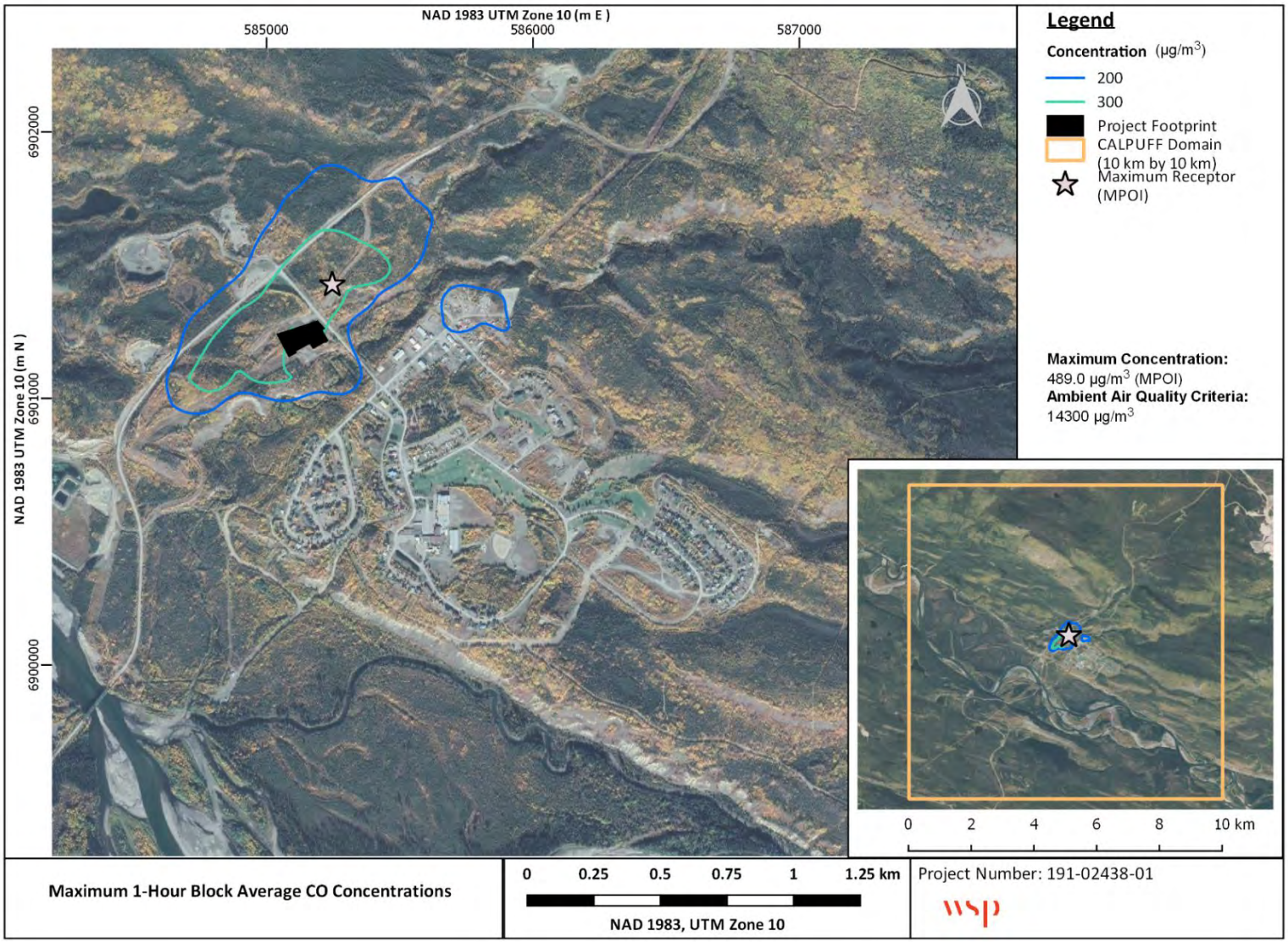

Figure 6-12 Contour Plot of Predicted 1-Hour CO Concentrations for the Future Scenario

Figure 6-13 Contour Plot of Predicted 8-Hour CO Concentrations for the Future Scenario

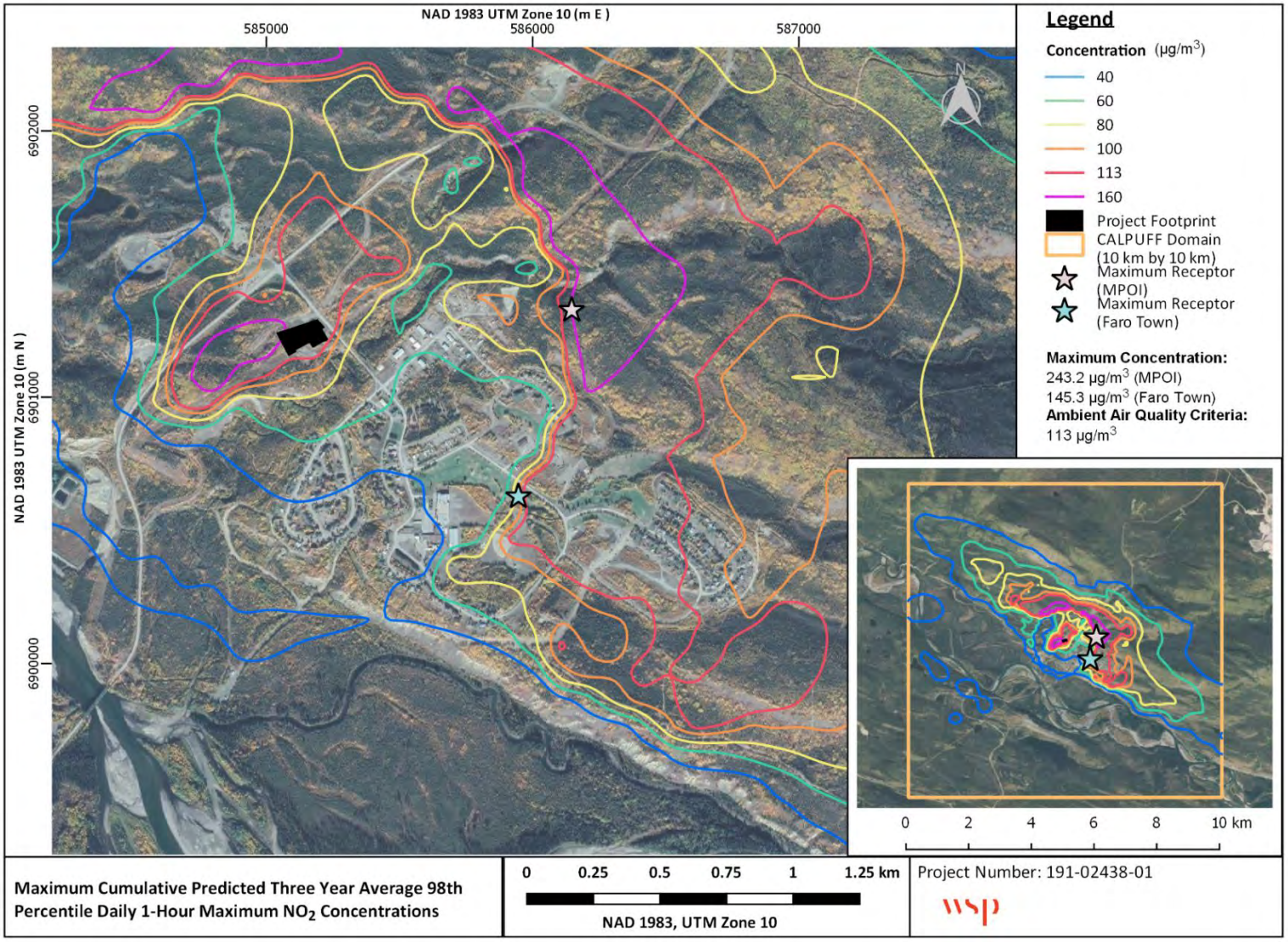

Figure 6-14 Contour Plot of Predicted 1-Hour NO_2 Concentrations for the Future Scenario

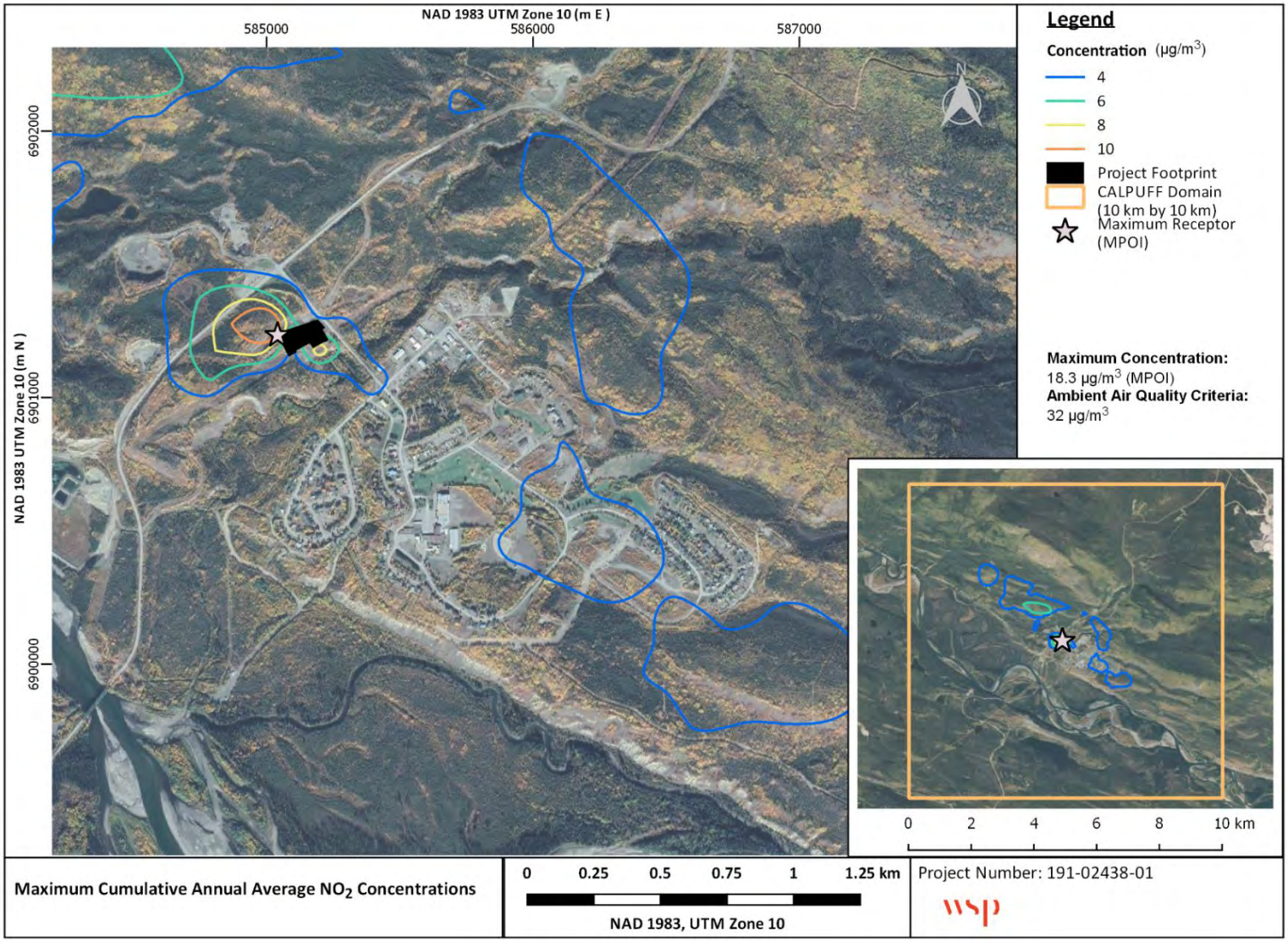

Figure 6-15 Contour Plot of Predicted Annual NO_2 Concentrations for the Future Scenario

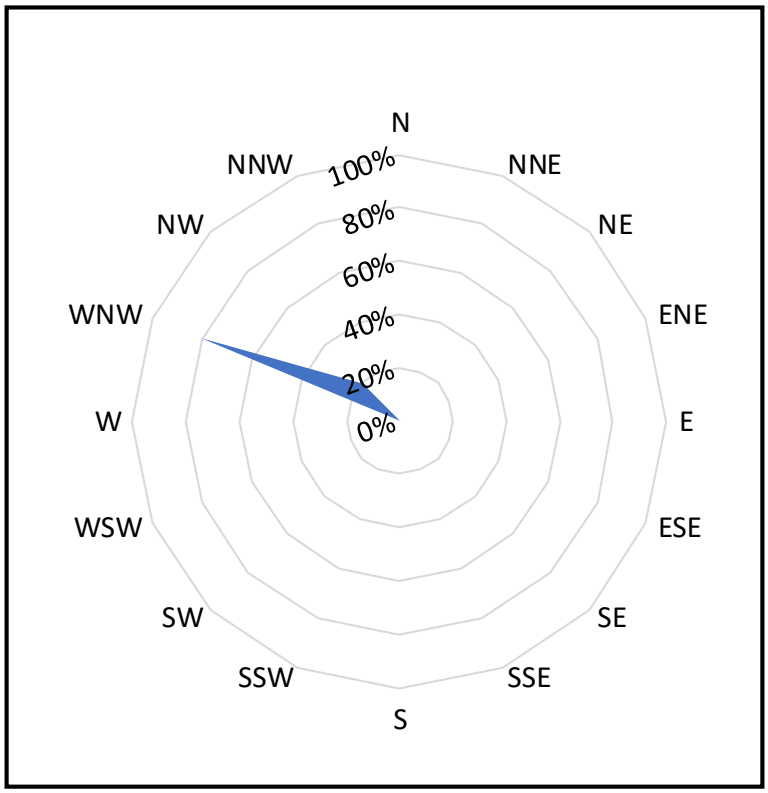

Figure 6-16 Frequency Distribution of Wind Directions Associated with the Predicted 98th Percentile 1-Hour NO_2 YAAQS Exceedances at the Maximally Impacted Faro Town Receptor during Model Years 2016-2018

Table 6-4 Predicted Hours of 98th Percentile 1-Hour NO_2 YAAQS Exceedances at the Maximally Impacted Faro Town Receptor by Wind Speed (m/s) and Wind Direction (°) during Model Years 2016-2018

Number of Exceedance Hours:		Wind Speed										Total Count:
		0-1m/s	1-2m/s	2-3m/s	3-4m/s	4-5m/s	5-6m/s	6-7m/s	7-8m/s	8-9m/s	9-10m/s	
Wind Direction	0-10°	0	0	0	0	0	0	0	0	0	0	0
	10-20°	0	0	0	0	0	0	0	0	0	0	0
	20-30°	0	0	0	0	0	0	0	0	0	0	0
	30-40°	0	0	0	0	0	0	0	0	0	0	0
	40-50°	0	0	0	0	0	0	0	0	0	0	0
	50-60°	0	0	0	0	0	0	0	0	0	0	0
	60-70°	0	0	0	0	0	0	0	0	0	0	0
	70-80°	0	0	0	0	0	0	0	0	0	0	0
	80-90°	0	0	0	0	0	0	0	0	0	0	0
	90-100°	0	0	0	0	0	0	0	0	0	0	0
	100-110°	0	0	0	0	0	0	0	0	0	0	0
	110-120°	0	0	0	0	0	0	0	0	0	0	0
	120-130°	0	0	0	0	0	0	0	0	0	0	0
	130-140°	0	0	0	0	0	0	0	0	0	0	0
	140-150°	0	0	0	0	0	0	0	0	0	0	0
	150-160°	0	0	0	0	0	0	0	0	0	0	0
	160-170°	0	0	0	0	0	0	0	0	0	0	0
	170-180°	0	0	0	0	0	0	0	0	0	0	0
	180-190°	0	0	0	0	0	0	0	0	0	0	0
	190-200°	0	0	0	0	0	0	0	0	0	0	0
	200-210°	0	0	0	0	0	0	0	0	0	0	0
	210-220°	0	0	0	0	0	0	0	0	0	0	0
	220-230°	0	0	0	0	0	0	0	0	0	0	0
	230-240°	0	0	0	0	0	0	0	0	0	0	0
	240-250°	0	0	0	0	0	0	0	0	0	0	0
	250-260°	0	0	0	0	0	0	0	0	0	0	0
	260-270°	0	0	0	0	0	0	0	0	0	0	0
	270-280°	0	0	0	0	0	0	0	0	0	0	0
	280-290°	0	0	0	0	0	0	0	0	0	0	0
	290-300°	0	15	16	0	0	0	0	0	0	0	31
	300-310°	0	18	7	0	0	0	0	0	0	0	25
	310-320°	0	0	0	0	0	0	0	0	0	0	0
	320-330°	0	0	0	0	0	0	0	0	0	0	0
	330-340°	0	0	0	0	0	0	0	0	0	0	0
	340-350°	0	0	0	0	0	0	0	0	0	0	0
	350-360°	0	0	0	0	0	0	0	0	0	0	0
Total Count:		0	33	23	0	0	0	0	0	0	0	56

Note: *Counts of predicted exceedances of the YAAQS are scaled using an orange color gradient according to the count value, such that the higher counts are denoted with darker orange shades while the lower counts are applied with lighter orange shades.*

Table 6-5 Predicted Hours of 98th Percentile 1-Hour NO_2 YAAQS Exceedances at the Maximally Impacted Faro Town Receptor by Hour of the Day and Month of the Year during Model Years 2016-2018

Number of Exceedance Hours:		Hour of the Day																							Total Count:
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	0	
Month of the Year	1	0	1	0	1	1	1	3	0	0	0	0	0	0	0	0	0	0	1	1	2	1	1	0	1	14
	2	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	2	0	1	7
	3	0	1	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	6
	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	9	1	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	5
	10	0	0	0	1	0	0	2	0	0	0	0	0	0	0	0	0	0	2	0	0	1	0	0	0	6
	11	1	0	1	0	0	2	1	0	0	0	0	0	0	0	0	3	1	0	1	0	0	1	0	0	11
	12	1	0	0	0	1	0	0	0	0	0	0	0	0	0	1	0	0	1	1	0	1	0	0	0	6
Total Count:		5	2	2	3	5	4	6	0	0	0	0	0	0	0	1	3	1	4	5	3	5	4	0	3	56

Note: *Counts of predicted exceedances of the YAAQS are scaled using an orange color gradient according to the count value, such that the higher counts are denoted with darker orange shades while the lower counts are applied with lighter orange shades.*

6.2.2 PARTICULATE MATTER ($PM_{2.5}$ AND PM_{10})

With regards to $PM_{2.5}$ and PM_{10}, the predicted concentrations for both short-term and long-term periods showed no exceedances of the associated air quality criteria. When baseline air quality is considered, the cumulative $PM_{2.5}$ and PM_{10} predicted concentrations remain well below the air quality criteria:

- PM_{10}
  - MPOI
    - 24.1 µg/m^3, or 48% of the 24-hour PM_{10} YAAQS;
  - Faro Town
    - 6.9 µg/m^3, or 14% of the 24-hour PM_{10} YAAQS; and
  - Nearest Sensitive Receptors
    - range from 3.8 µg/m^3 to 5.6 µg/m^3 (8% to 11%) of the 24-hour PM_{10} YAAQS.
- $PM_{2.5}$
  - MPOI
    - 12.7 µg/m^3, or 47% of the 24-hour $PM_{2.5}$ YAAQS;
    - 2.2 µg/m^3, or 25% of the annual $PM_{2.5}$ YAAQS;
  - Faro Town
    - 3.1 µg/m^3, or 11% of the 24-hour $PM_{2.5}$ YAAQS;
    - 0.6 µg/m^3, or 7% of the annual $PM_{2.5}$ YAAQS
  - Nearest Sensitive Receptors
    - range from 1.4 µg/m^3 to 2.2 µg/m^3 (5% to 8%) of the 24-hour $PM_{2.5}$ YAAQS; and
    - range from 0.3 µg/m^3 to 0.5 µg/m^3 (3% to 6%) of the annual $PM_{2.5}$ YAAQS.

These results indicate that the contribution of the emissions from the Future Scenario to ambient concentrations of particulate matter is low relative to the YAAQS. In addition, the contour plots (Figure 6-17 through Figure 6-19) show that the predicted concentrations significantly decrease with increased distance from the Facility.

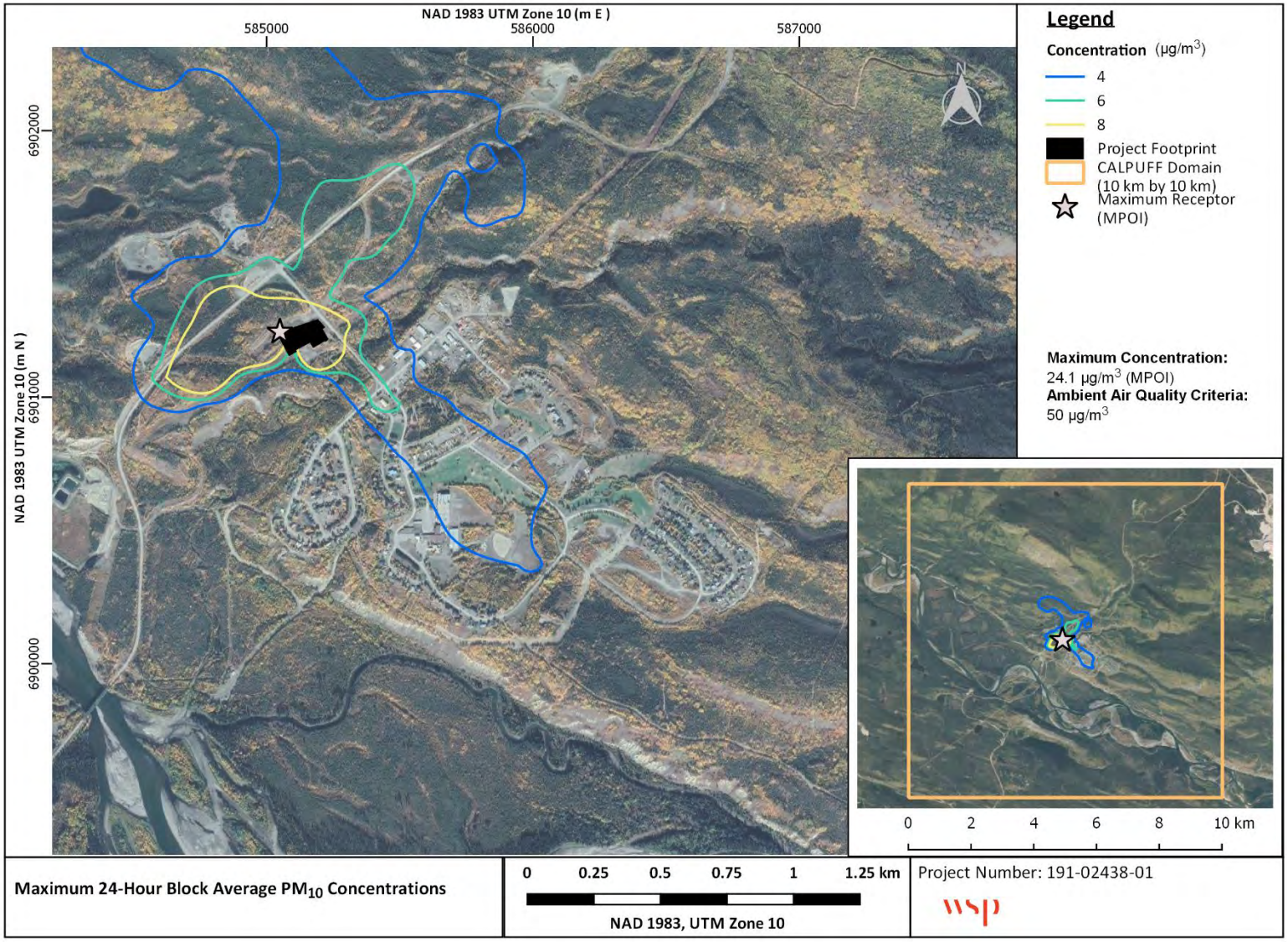

Figure 6-17 Contour Plot of Predicted 24-Hour PM_{10} Concentrations for the Future Scenario

Figure 6-18 Contour Plot of Predicted 24-Hour $PM_{2.5}$ Concentrations for the Future Scenario

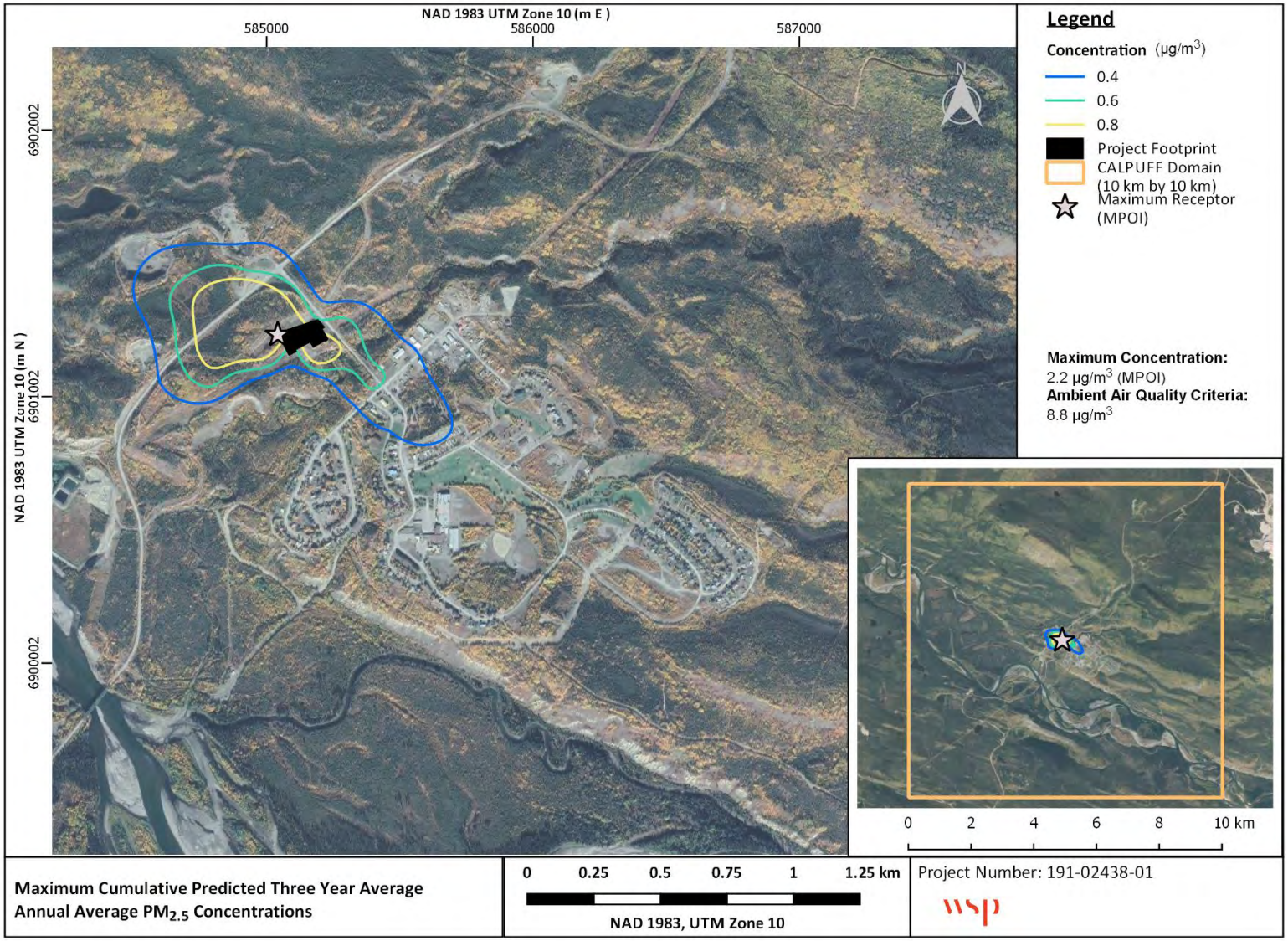

Figure 6-19 Contour Plot of Predicted Annual $PM_{2.5}$ Concentrations for the Future Scenario

7 CONCLUSION

The ambient air quality dispersion modelling results showed that, with the exception of short-term (1-hour) NO_2 results, the maximum total or cumulative predicted concentrations for all air contaminants ($PM_{2.5}$ PM_{10}, SO_2, and CO) were well below their respective ambient air quality standards. The maximum points of impingement (worst-case receptors) were all found either near the Facility or outside the Town of Faro, in both the existing and future permit scenarios. Overall, the cumulative predicted air contaminant concentrations from the Future Scenario were higher than those of the Existing Scenario given the increased power generation of the facility expansion.

While the dispersion modelling results predicted short-term NO_2 exceedances for both scenarios, the primary objective of the air quality assessment was to evaluate the potential risks on the human population residing near the facility in the Town of Faro. The modelling results for the Existing Scenario at the maximally impacted receptor within the Town of Faro showed that the cumulative predicted concentrations for all pollutants evaluated were in compliance with the YAAQS.

For the Future Scenario, the predicted air quality impacts for all the other air pollutants – including both fine and coarse particulate matter ($PM_{2.5}$ and PM_{10}), SO_2, and CO – were well below the YAAQS. With regards to the NO_2 predicted short-term (1-hour) NO_2 exceedances, it is important to note that the YAAQS for NO_2 were reduced drastically in late 2019 from 401 µg/m^3 previously to 113 µg/m^3 presently. The maximum cumulative predicted 1-hour NO_2 concentrations from both existing and future permit scenarios would be well below the previous NO_2 criteria. When compared to the newly revised NO_2 YAAQS, the maximum cumulative predicted 1-hour NO_2 concentration was 129% of the Yukon Ambient Air Quality Standards for NO_2 at the maximally impacted Faro Town receptor in the Future Scenario. Moreover, the predicted 1-hour NO_2 exceedances were spatially limited to a confined area surrounding the Facility and also on the outskirts of Faro, with a low frequency of occurrence of 0.21% of the time (56 hours out of 26,304 modelled hours) at the maximally impacted Faro Town receptor.

These short-term (1-hour) NO_2 exceedances were found entirely under calm stable meteorological conditions which typically hinder atmospheric dispersion; primarily during nighttime and in the colder months of the year; and, exclusively under west-northwest winds. Outdoor human activity would be limited during cold nighttime hours and this lowers the probability of human to be exposed to the short-term NO_2 impacts. Combined with the low frequency of model predictions exceeding the NO_2 YAAQS (56 hours out of 26,304 modelled hours),there is an even lower probability of exposure to levels above the YAAQS.

Finally, it is important to note that the modelling results represent the worst-case potential air quality impacts based upon the facility's maximum operating conditions. As such, the model predicted air contaminant concentrations are likely conservative. Furthermore, the conditions giving rise to predicted short-term NO_2 exceedances would be very unlikely to happen because the emission sources at the facility are highly unlikely to operate continuously year-round at the maximum possible emission rates, nor would it be likely that these maximum emissions coincide exactly with the particular meteorological conditions that give rise to the event as they occur, on average, for less than 20 hours per year modelled. The typical facility emissions are expected to be much lower and would not be anticipated to result in adverse air quality impacts given the low risk of predicted exceedance under even conservative assumptions. With model predictions indicating an extremely low risk of predicted short-term NO_2 impacts and low potential impacts from the other air pollutants, the overall air quality impacts from the future expanded facility are not anticipated to pose a significant risk to the Town of Faro and air quality would be anticipated to remain in compliance with YAAQS.

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REFERENCE: **Page 4-10 and others** ***"assuming that rider F approximates zero effective July 1, 2021..."***

QUESTION:

a) Under what conditions would Rider F now not go to zero?

b) Under what conditions will Rider F be non-zero in the future?

c) Please provide a history of the changes to Rider F and corresponding fuel prices for the last 10 years.

ANSWER:

(a) and **(b)**

Rider F is non-zero when there is a requirement to recover added fuel price costs, or to refund fuel price savings, related to the Fuel Price Variance Account.

The Rider F rate is tied to the Fuel Price Variance Account (FPVA) balance that reflects thermal fuel price variances for YEC and AEY (Companies). The FPVA has a threshold of +/-$200,000. When the balance in the FPVA approaches or reaches the +/-$200,000 threshold, the Companies must inform the Board and interested parties of the Companies' intentions to implement a Rider F rate change to address the outstanding balance.

As indicated in response to CW-YEC-1-23 (a), (b) and (d), although, the actual balance of the Fuel Price Variance Account will depend on volume of actual thermal generation and fuel prices for YEC and AEY, the advisory filed by the companies on September 23, 2020 was the best information available for the companies at the time of filing which aimed to get Fuel Price Variance Account balance to zero by July 1, 2021. Rider F would now not go to zero on July 1, 2021 if the balance in the FPVA as forecast at that time is outside the +/- $200,000 threshold.

(c)

Please see table below that shows Rider F rate changes for the last 10 years. The Rider F change is not tied to the specific fuel price change, but it is tied to the balance of FPVA

as noted in response to (a) and (b). The fuel prices variance calculations for both companies are available in FPVA continuity tables provided to the Yukon Utilities Board in quarterly report which are available on YUB's website.

cents/kW.h	Change Date
0.352	01-Jul-11
0.420	01-May-12
0.191	01-Oct-12
0.000	01-Jan-14
-0.286	01-Jul-15
-0.367	01-Aug-15
-0.487	01-Nov-15
-0.560	01-Feb-16
-0.011	01-Aug-17
0.970	01-Jan-20
1.371	01-Nov-20

REFERENCE: **From the YEC website – page announcing the 2021 GRA: *"Our Board of Directors and staff also understand that paying more for power can be hard for some Yukoners, especially during the COVID pandemic. That's why our 2021 rate application outlines a way for our proposed rate increase to have a nearly zero impact on electricity bills."***

$204.72 Dec 2021 Monthly Bill with 2021 GRA (Residential 1000kWh/month consumption – from Page 4-11 Table 4.3)

$178.50 Dec 2021 Monthly Bill without 2021 GRA ($204.72 minus Rider F ($13.64) and 2017/18 GRA true-up ($12.58) from Page 1-2 Figure 1-1).

QUESTION:

a) For a December 2021 bill as outlined above, what is the percentage increase attributable to the 2021 GRA?

b) What is the decrease absent the 2021 GRA?

c) Please explain how this is promoted as "nearly zero impact on electricity bills?"

d) Why is the "No GRA Scenario" from Figure 1-1 not included in any of the tables or figures of Appendix 4.2?

e) While comparisons with NWT, Toronto, and Yukon (Nov-2020), etc. are interesting, none of these are impacted by the 2021 GRA and only serve to obscure the actual impact of the GRA on future bills. The GRA only impacts bills that are subject to the GRA, meaning Jul-21, Dec-21 and beyond. Please provide new versions of all tables and figures from Appendix 4.2 with the addition of "Yukon, No-GRA (July 2021)" and "Yukon, No-GRA (Dec 2021)" for comparison with the already included Yukon - pre-GRA (Nov-2020), Yukon, Interim (July 2021) and Yukon, Proposed (Dec 2021).

f) Please also provide and update of Table 4.3 (Page 4-11) with the addition of No-GRA calculations/columns for Jul-21 and Dec-21.

ANSWER:

(a)

As illustrated in Table 4.2A-3 in Appendix 4.2 of the Application, the increase in Rider J for residential 1,000 kW.h monthly usage is $20.42, increase from $30.37 to $50.78. This is about 10.0% increase (compared with the November 2020 bill of $204.00) which is attributable to the 2021 GRA. However, the overall bill increase from November 2020 to December 2021 is constrained to $0.72 or 0.4% due to offsetting reductions to Rider F and Rider J1 (total reduction of $19.70).

(b)

Absent the 2021 GRA the residential bill for 1,000 kW.h monthly usage would decrease by $13.71/month on July 1, 2021 when Rider F is reduced to approximate 0, and be further reduced by $12.58/month on December 1, 2021 when Rider J1 expires (total reduction of 12.9% compared with November 2020 bill).

(c)

The proposed approach is described as “nearly zero impact on electricity bills” because that is exactly what results from the Application.

As outlined in section 1.1 of the Application, the proposed rate implementation dated for the 2021 GRA is aimed to avoid any material bill change for customers. Delay in rate adjustments or delay of GRA would lead to bill instability (a sharp decline followed by a sharp increase when new rates as required for this GRA are approved) and higher new true-up rate rider requirements.

Please see section 1.1 of the Application for more details of the proposed approach in the 2021 GRA to reduce customer bill volatility.

(d)

Yukon Energy is not proposing “No GRA Scenario” therefore this scenario was not included in Appendix 4.2 tables and figures. However, throughout the Application the tables show “Existing 2021” which shows the “No GRA Scenario” – and Appendix 4.2

provides the information indicating expected changes to existing rates without the GRA (with the exception of Rider F).

(e) and **(f)**

Please see NY-YEC-1-15 Attachment 1 for versions of Appendix 4.2 tables and figures that include "No 2021 GRA" scenario. Please note that for illustration purposes Rider F is estimated for "No 2021 GRA" scenario using the fuel price variance for the 2021 GRA [about $2.129 million as shown in Table 1-2 in Tab 1]. This is only an estimate, the actual Rider F will depend on actual fuel prices and thermal generations for both YEC and AEY.

The version of Table 4.3 with "No 2021 GRA" scenario is provided below.

		No 2021 GRA *		2021 GRA	
	Nov-20	Jul-21	Dec-21	Jul-21	Dec-21
Residential Non-Government, Whitehorse					
850 kWh/month consumption	$176.48	$172.16	$161.26	$176.70	$177.31
change from Nov 2020		*-$4.31*	*-$15.21*	*$0.22*	*$0.84*
1,000 kWh/month consumption	$204.00	$198.93	$186.35	$204.00	$204.72
change from Nov 2020		*-$5.07*	*-$17.66*	*-$0.00*	*$0.71*
Commercial Non-Government, Whitehorse					
2,000 kWh/month consumption [5 kW demand]	$358.84	$348.70	$326.78	$355.30	$356.54
change from Nov 2020		*-$10.15*	*-$32.06*	*-$3.54*	*-$2.30*
3,500 kWh/month consumption [15 kW demand]	$753.00	$735.24	$688.62	$755.81	$758.45
change from Nov 2020		*-$17.76*	*-$64.38*	*$2.81*	*$5.45*

Note:

1. For illustration purposes Rider F is estimated for "No 2021 GRA" scenario using the fuel price variance for the 2021 GRA [about $2.129 million as shown in Table 1-2 in Tab 1]. The actual Rider F will depend on actual fuel prices and thermal generations for both YEC and AEY.

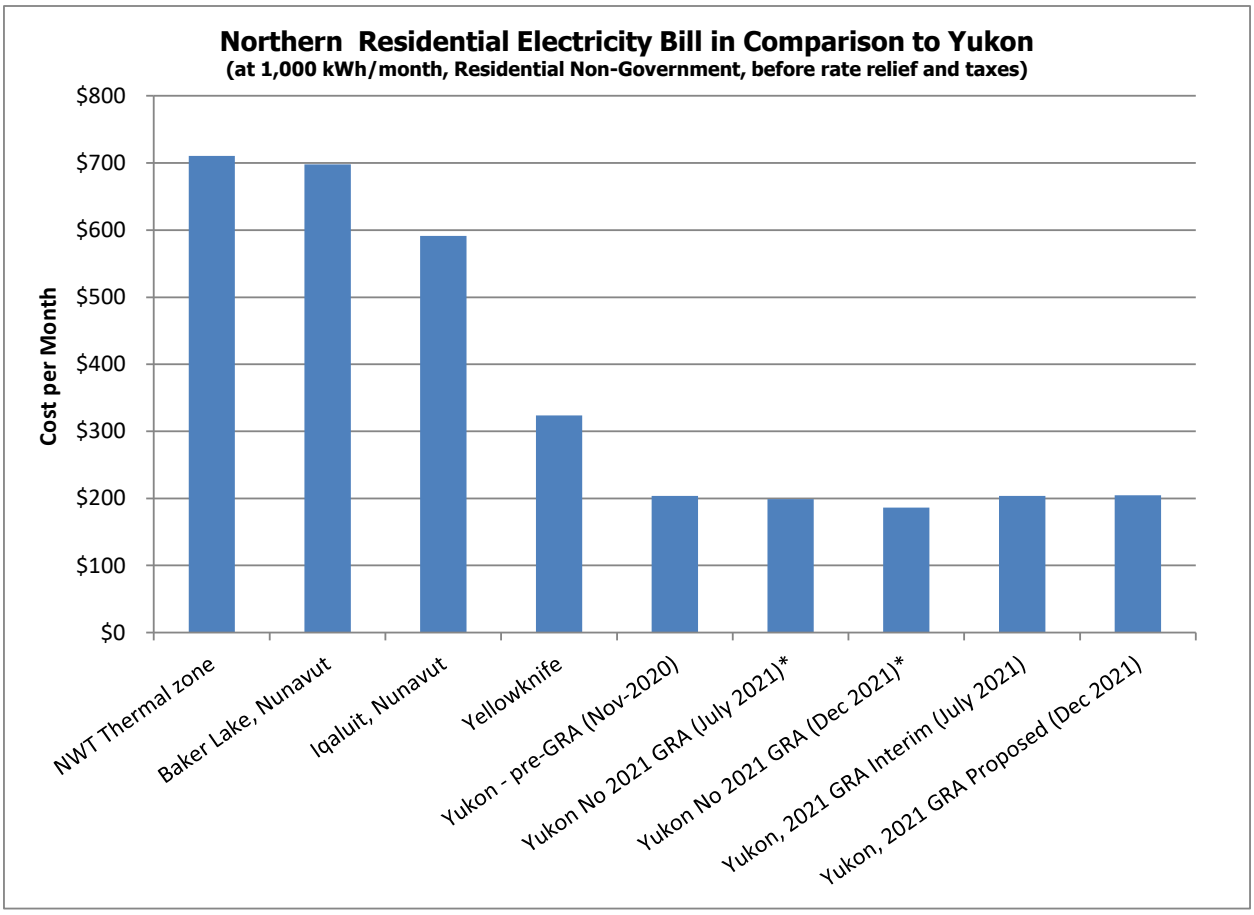
Table 4.2A-1:
Residential Electricity Bills in Comparison to Yukon
(1000 kWh/month consumption, Residential Non-Government, $)

		Monthly Bills before rate relief and taxes
1	NWT Thermal zone	$710.70
2	Baker Lake, Nunavut	$698.00
3	Iqaluit, Nunavut	$591.10
4	Yellowknife	$323.67
5	Yukon - pre-GRA (Nov-2020)	$204.00
6	Yukon No 2021 GRA (July 2021)*	$198.93
7	Yukon No 2021 GRA (Dec 2021)*	$186.35
8	Yukon, 2021 GRA Interim (July 2021)	$204.00
9	Yukon, 2021 GRA Proposed (Dec 2021)	$204.72
10	Toronto, ON	$188.42
11	Ottawa, ON	$173.77
12	Halifax, NS	$168.88
13	Charlottetown, PEI	$168.27
14	Regina, SK	$165.07
15	Calgary, AB	$148.31
16	Edmonton, AB	$142.93
17	St. John's, NL	$135.99
18	Moncton, NB	$134.19
19	Vancouver, BC	$115.13
20	Winnipeg, MB	$96.02
21	Montreal, QB	$72.99

Notes:

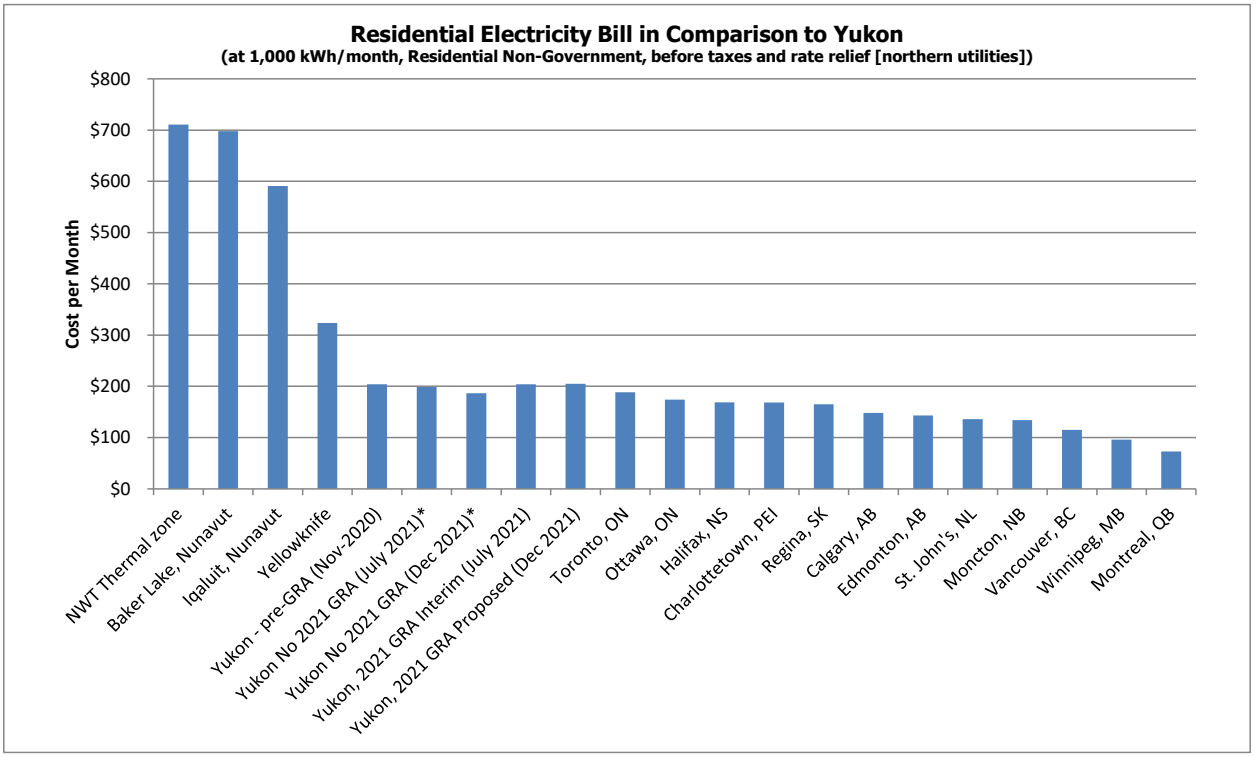
1. Monthly Bills are before taxes and rate relief [Hydro Quebec does not specify if the rate comparison includes rate relief].
2. Yukon existing bills include YEC Rider J [22.32%] and Rider J1 [9.25%], AEY Rider R [8.30%] and Rider F.
3. For illustration purposes Rider F is estimated for "No 2021 GRA" scenario using the fuel price variance for the 2021 GRA [about $2.129 million as shown in Table 1-2 in Tab 1]. The actual Rider F will depend on actual fuel prices and thermal generations for both YEC and AEY.
4. Yukon proposed bills assume interim Rider J increase of 10.08% effective July 1, 2021 and 4.93% Rider J increase effective December 1, 2021.
5. The monthly bills for Yellowknife are calculated using the rates in place in June 2019. Available at https://www.northlandutilities.com/en-ca/customer-billing-rates/bill-calculator/northland-utilities-limited-yellowknife.html [accessed on September 25, 2020].
6. The monthly bills for NWT Thermal Zone are calculated using the rates in place effective September 1, 2020. Available at https://www.ntpc.com/customer-service/residential-service/what-is-my-power-rate [accessed on September 25, 2020].
7. The monthly bills for Iqaluit and Baker Lake are calculated using the rates approved effective April 1, 2019, but also includes fuel rider refund effective October 1, 2020. Available at https://www.qec.nu.ca/customer-care/accounts-and-billing/customer-rates [accessed on September 25, 2020].
8. Bills for Toronto and Ottawa are based on Ontario Energy Board Bill Calculator. Toronto average monthly bill for 1,000 kW.h at $188.42 before taxes and rebates - calculation for Toronto Hydro-Electric System Limited tiered rate that include 12.6 c/kW.h energy rate, $58.15/month delivery charge and $4.27/month Regulatory charges; Ontario Electricity Rebate at $62.56/month is not included. Ottawa average monthly bill for 1,000 kW.h at $173.77 before taxes and rebates - calculation for Ottawa River Power Corporation tiered rate that include 12.6 c/kW.h energy rate, $43.44/month delivery charge and $4.33/month Regulatory charges; Ontario Electricity Rebate at $57.59/month is not included. https://www.oeb.ca/rates-and-your-bill/bill-calculator [accessed on October 21, 2020].
9. The monthly bills for the other cities are from Hydro Quebec's Comparison of Electricity Prices in Major North American Cities, Rates in effect April 1, 2020. Available at http://www.hydroquebec.com/data/documents-donnees/pdf/comparison-electricity-prices.pdf [accessed on October 21, 2020].

Figure 4.2A-1:[1]
Northern Residential Electricity Bill in Comparison to Yukon



[1] Please see notes to Table 4.2A-1.

Figure 4.2A-2:[2]
Residential Electricity Bill in Comparison to Yukon



[2] Please see notes to Table 4.2A-1.

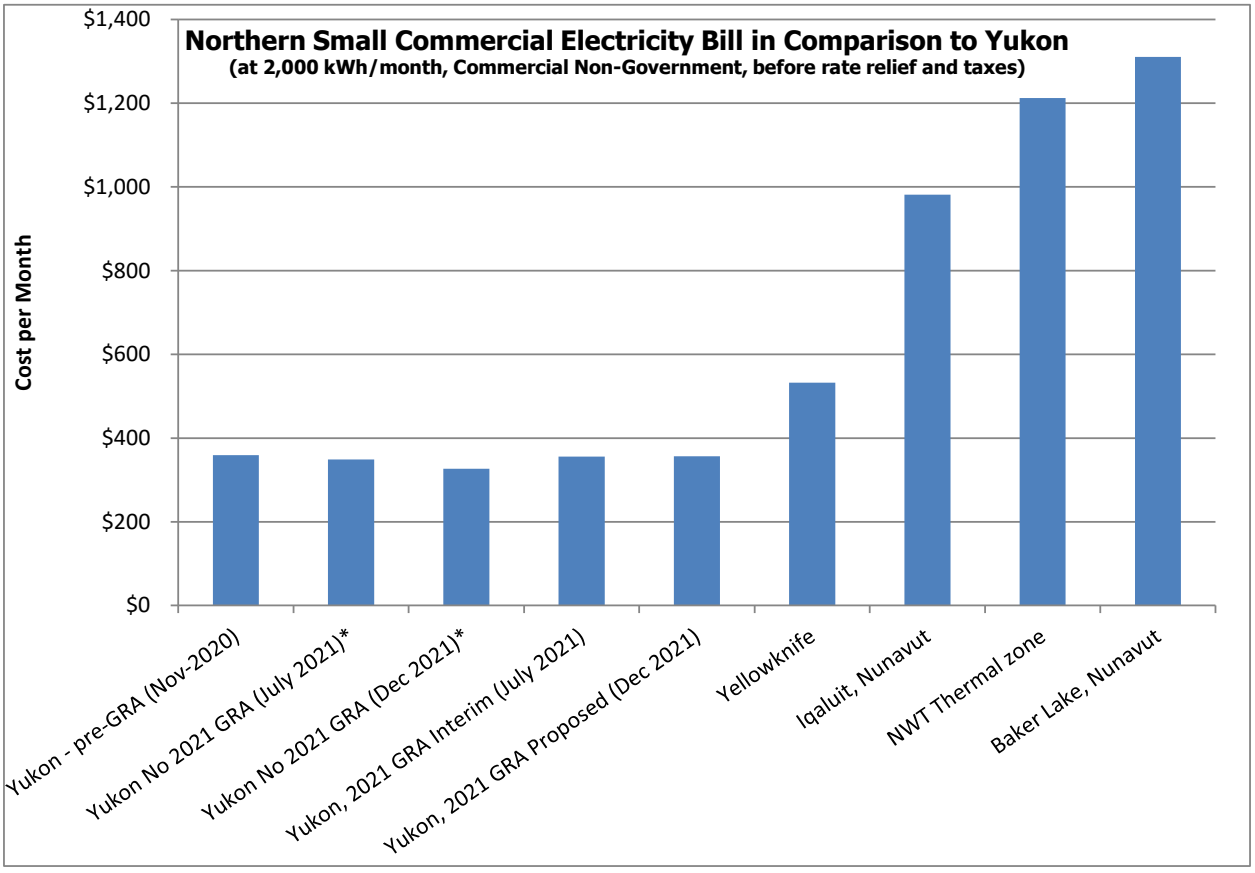
Table 4.2A-2:
Small Commercial Electricity Bills in Comparison to Yukon
(2000 kWh/month consumption, Commercial Non-Government, $)

		Monthly Bills before rate relief and taxes
1	Yukon - pre-GRA (Nov-2020)	$358.84
2	Yukon No 2021 GRA (July 2021)*	$348.70
3	Yukon No 2021 GRA (Dec 2021)*	$326.78
4	Yukon, 2021 GRA Interim (July 2021)	$355.30
5	Yukon, 2021 GRA Proposed (Dec 2021)	$356.54
6	Yellowknife	$532.26
7	Iqaluit, Nunavut	$981.20
8	NWT Thermal zone	$1,212.00
9	Baker Lake, Nunavut	$1,310.00

Notes:

1. Monthly Bills are before Rate Relief and taxes.
2. Yukon existing bills include YEC Rider J [22.32%] and Rider J1 [9.25%], AEY Rider R [8.30%] and Rider F.
3. For illustration purposes Rider F is estimated for "No 2021 GRA" scenario using the fuel price variance for the 2021 GRA [about $2.129 million as shown in Table 1-2 in Tab 1]. The actual Rider F will depend on actual fuel prices and thermal generations for both YEC and AEY.
4. Yukon proposed bills assume interim Rider J increase of 10.08% effective July 1, 2021 and 4.93% Rider J increase effective December 1, 2021.
5. The monthly bills for Yellowknife are calculated using the rates in place in June 2019. Available at https://www.northlandutilities.com/en-ca/customer-billing-rates/bill-calculator/northland-utilities-limited-yellowknife.html [accessed on September 25, 2020].
6. The monthly bills for NWT Thermal Zone are calculated using the rates in place effective April 1, 2019. Available at https://www.ntpc.com/customer-service/business-service/business-rates [accessed on September 25, 2020].
7. The monthly bills for Iqaluit and Baker Lake are calculated using the rates approved effective April 1, 2019, but also includes fuel rider refund effective October 1, 2020. Available at https://www.qec.nu.ca/customer-care/accounts-and-billing/customer-rates [accessed on September 25, 2020].

Figure 4.2A-3[3]
Northern Small Commercial Electricity Bill in Comparison to Yukon



[3] Please see notes to Table 4.2A-2.

Table 4.2A-3
Yukon Bills– Existing vs. Proposed - Non-Government Residential
(prior to consideration of subsidies, rebates and taxes) [4]

Line #	Customer Use per month: 1,000 kWh	Jan-18		Apr-19		Dec-19		Jan-20		Nov-20		No 2021 GRA * Jul-21		No 2021 GRA * Dec-21		YEC's 2021 GRA Jul-21		YEC's 2021 GRA Dec-21	
		Rates	Bill	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	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	$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	$0.1214	$121.40
3=KWh*Base rate	Second Block Energy (kWh)																		
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]	-$0.000110	-$0.11	-$0.000110	-$0.11	-$0.000110	-$0.11	$0.009700	$9.70	$0.013710	$13.71	$0.008637	$8.64	$0.008637	$8.64	$0.0	$0.00	$0.0	$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)	16.51%	$22.46	16.51%	$22.46	22.32%	$30.37	22.32%	$30.37	22.32%	$30.37	22.32%	$30.37	22.32%	$30.37	32.40%	$44.08	37.33%	$50.78
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)		$0.00		$0.00	9.25%	$12.58	9.25%	$12.58	9.25%	$12.58	9.25%	$12.58	0.00%	$0.00	9.25%	$12.58	4.84%	$6.59
7=KWh*Rider E rate	Rider E (kW.h) [LWRF Rider]	-$0.006800	-$6.80	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00
8=(1+2+3)*Rider J rate	AEY Rider J (%)		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00
9=(1+2+3)*Rider R rate	AEY Rider R (%)	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29
10=Sum(1:9)	Total Before Tax Rebate, IER, GST		$162.89		$169.69		$190.18		$199.99		$204.00		$198.93		$186.35		$204.00		$204.72

[4] Please see notes to Table 4.2A-1.

Table 4.2A-4
Yukon Bills– Existing vs. Proposed - Non-Government General Service
(prior to consideration of subsidies, rebates and taxes) [5]

Line #	First Block Energy Use - Customer Use per month:	2,000 kWh	Jan-18		Apr-19		Dec-19		Jan-20		Nov-20		No 2021 GRA *				YEC's 2021 GRA			
		5 kW											Jul-21		Dec-21		Jul-21		Dec-21	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																			
1	Demand Charge (per kW per month)		$7.39	$36.95	$7.39	$36.95	$7.39	$36.95	$7.39	$36.95	$7.39	$36.95	$7.39	$36.95	$7.39	$36.95	$7.39	$36.95	$7.39	$36.95
2=KWh*Base rate	First Block Energy (kWh)		$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00
3=KWh*Rider F rate	Rider F (kW.h)		-$0.00011	-$0.22	-$0.00011	-$0.22	-$0.00011	-$0.22	$0.00970	$19.40	$0.01371	$27.42	$0.008637	$17.27	$0.008637	$17.27	$0.00000	$0.00	$0.00000	$0.00
4=(1+2)*Rider J rate	YEC Rider J (%)		16.51%	$39.12	16.51%	$39.12	22.32%	$52.89	22.32%	$52.89	22.32%	$52.89	22.32%	$52.89	22.32%	$52.89	32.40%	$76.76	37.33%	$88.44
5=(1+2)*Rider J1 rate	YEC Rider J1 (%)						9.25%	$21.92	9.25%	$21.92	9.25%	$21.92	9.25%	$21.92	0.00%	$0.00	9.25%	$21.92	4.84%	$11.48
6=KWh*Rider E rate	Rider E (kW.h) [LWRF Rider]		-$0.00680	-$13.60	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00
7=(1+2)*Rider J rate	AEY Rider J (%)			$0.00		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00
8=(1+2)*Rider R rate	AEY Rider R (%)		8.30%	$19.67	8.30%	$19.67	8.30%	$19.67	8.30%	$19.67	8.30%	$19.67	8.30%	$19.67	8.30%	$19.67	8.30%	$19.67	8.30%	$19.67
9=Sum(1:8)	Total Before Tax Rebate, GST			$281.92		$295.52		$331.20		$350.82		$358.84		$348.70		$326.78		$355.30		$356.54

[5] Please see notes to Table 4.2A-2.

REFERENCE: **Page 10-28 "We expect COVID-19 impacts to have both positive and negative effects on Yukon Energy's financial position, net income and cash flows."**

PREAMBLE:

QUESTION:

a) What are the expected positive effects of COVID-19 on financial position, net income and cash flows?

b) What are the expected negative effects?

ANSWER:

(a)

The expected positive effects of COVID-19 include increases to Residential revenue (which includes YEC's Residential category as well as residential customers for AEY that are included in YEC's Wholesales category) as well as an expected decrease in YEC travel costs.

(b)

The expected negative effects of COVID-19 include decreases to Commercial revenue (which includes YEC's Commercial category as well as commercial customers for AEY that are included in YEC's Wholesales category) as well as increased contractor costs where required work requires workers to travel to Yukon and self-isolate before performing work.

Utilities Consumers' Group
(UCG)

TOPIC: **General Requests**

QUESTION:

a) Identify all persons (in-house and consultants) who have worked on this application to date and cost for each person.

b) Explain what measures Yukon Energy took to simplify this rate application to lower the costs of regulation and lessen the reliance for outside lawyers and consultants to deliberate our future.

c) Give the updated estimated costs for this 2021 GRA.

ANSWER:

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

A very wide range of YEC staff and management, along with InterGroup Consultants, have worked to date on the Application, including responding to IRs. Updated estimated costs and costs by person are not readily available and will be provided to the extent required when the proceeding is concluded and the Board reviews cost submissions.

To the extent GRA preparation cost information is readily available it is provided in the response to UCG-YEC-1-104.

In an effort to simplify this rate application and lower costs of regulation, YEC in this Application separated clearly capital projects that remain in WIP and therefore are not relevant to the 2021 test year revenue requirement in order to help the Board and intervenors reduce IR and other related costs on matters not of priority at this time.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **YUB Rules of Practice October 17, 2012**

Response to information requests
14. (1) Subject to subsection (3) where an information request has been directed to a party and served on that party in accordance with the Board's directions, the party shall prepare a response that:
a) repeats each question in the information request,
b) provides full and adequate response to each question, and
c) identifies the individual or individuals who were responsible for preparing the response

QUESTION:

a) Please be certain to identify each response with the individual/s who prepared it.

ANSWER:

(a)

The requested information cannot be practically or reasonably provided at an individual level.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **Yukon Energy 2021 Rate Application**

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 identify how and when the leadership / Board of YEC approved the General Rate Application as provided to the YUB. Please identify the dates on which these approvals were provided.

ANSWER:

(a) to **(c)**

YEC did not conduct customer or stakeholder consultations during development of the application prior to the filing.

(d)

The Board of Directors of YEC approved filing of the application by normal resolution at a meeting in October 2020.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application page 1**

YEC states "Pursuant to the Order in Council (OIC) 1995/90 (as amended by 2018/220) 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".

REFERENCE: **Board Order 2010-13, Appendix A – Reasons for Decision**

"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."

QUESTION:

a) Since the OIC 2008/149 expired at the end of 2018, please confirm the above Board direction was accomplished. If not, why not?

b) Please explain what Yukon Energy plans to do about following Board directions and orders?

ANSWER:

The reference provided to November 2020 Application page 1 does not appear to be correct. Page 1 of the Application notes:

> Pursuant to the Order in Council (OIC) 1995/90 direction (as amended by OIC 2018/220), the Board must ensure 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, all proposed 2021 rate adjustments for retail customers and industrial customers apply equally, as percentages.

As detailed below the relevant provisions of OIC 2008/149 remain in effect.

The direction outlined in OIC 2008/149 was extended by OIC 2012/68. Insofar as it affects all classes of retail customers, this direction in effect extended the earlier Section 2.1(1) direction in OIC 2008/149 until December 31, 2013; and ensured that the same percentage rate adjustments will also apply to the class of major industrial customers.[1] This direction was extended by OIC 2014/23, and OIC 2018/220 removed subsection 2.1(3) which established an expiry date for Section 2.1. With this change, the provisions of Section 2.1(1) currently remain in effect without any expiry date.

See Tab 4, page 4-7 and 4-8 and Tab 6, page 6-1.

(b)

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."

The provisions of Section 2.1(1) currently remain in effect without any expiry date, and provide that material rate design changes that would result in rebalancing of rates between different customer classes cannot be undertaken at this time. The remaining outstanding directives in Order 2010-13 will be addressed in the next joint cost of service and rate design application.

[1] Subject to certain provisions noted in Tab 4, Section 4.4 of the 2021 GRA.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application page 2**

YEC states: “This GRA addresses a difficult situation, Yukon Energy's actual ROE has continued to fall well short of the 2018 approved ROE, and a new GRA is required to address ongoing revenue shortfalls.”

QUESTION:

a) Please provide details of any measures since the last 2017/18 GRA that have been taken to manage Yukon Energy's ongoing welfare.

b) Did Yukon Energy attempt any debt re-negotiation with Yukon Development Corporation (YDC) or any Promissory Note's flexible debt re-financing provisions to help alleviate some pressure. If not, why not?

c) Did YDC make any contributions that reduced project costs to be recovered from ratepayers? If yes, explain what for and how much.

d) Are there any secondary sales revenues or other related revenues forecast for 2021? If not, what will YEC do with any revenues if these circumstances change?

e) Were there any adjusted thermal fuel costs recouped from the Diesel Contingency Fund operation or the implementation of the Whitehorse Diesel-Natural Gas Conversion Project (LNG Project or LNG Plant project).

f) Please provide specific details YEC realized to:
   i. reduce ongoing costs?
   ii. reduce waste?
   iii. improve performance?

g) Please provide steps YEC has taken to date to study and consider a performance-based regulation mechanism, including earnings sharing.

ANSWER:

(a)

The Application describes measures and actions being undertaken by YEC to ensure its ongoing viability and fiscal health.

(b)

No. Refinancing of YDC debt is undertaken when options exist to reduce existing interest rates, in order to reduce debt costs. No such options were available in 2020 when the GRA was being prepared.

(c)

No.

(d)

Per Tab 2, Table 2.1 there are no secondary sales revenues forecast for 2021. As noted in Tab 2, page 2.2 of the Application, YEC will update 2021 test year forecasts in the compliance filing if any secondary sales are expected to occur in 2021 as a result of surplus water availability.

(e)

It is not clear what this question is addressing. The DCF no longer exists. The Application details operation of the LNG facilities.

(f)

Please see the Application, Tab 3 for details on YEC operations.

(g)

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: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application page 2**

YEC states: "Yukon Energy has developed an approach to enable a rate adjustment for the 2021 test year to address YEC's financial requirements without any material change in customer bills."

REFERENCE: **November 2020 Application, page 4**

YEC states: "In accordance with OIC 1995/90 direction, the Application proposes that Yukon Energy revenue shortfall for the test year be recovered through a Rider J increase of 15.01 percentage points in 2021 applicable to all YEC and AEY retail firm customers and all major industrial firm rates. This Rider J increase results in an overall increase in existing rates (excluding existing Rider J1 true-up and Rider F) of 11.54% for 2021.

QUESTION:

a) Please explain this second reference in simple laymans language as it is massively confusing. How can YEC exclude/deduct true-up and rider F from your requested revenue requirement increase? Why would they not simply come off our bills when paid off?

b) Please confirm the YEC is requesting a 15.01 per cent increase for the 2021 test year. Explain.

c) As YEC proclaims in the first reference that there will not be any material change in the customer bills, please explain how the expected reduction of the fuel Rider F will offset the requested increase for the proposed interim request, i.e. give the amount of Rider F reduction (as a percentage) expected and how this matches with the proposed interim rider of 10.08% increase requested?

d) Please give the amount of the true-up Rider as a percentage that YEC claims will offset the 15.01% increase slated for December 1, 2021 final rates.

e) Does YEC plan to reintroduce a Rider F charge after the first quarter of January, 2022 or when/if the price of diesel fluctuates from the rate hearing decision price? If yes how does the YEC propose this will keep bills from material changes?

f) Please provide detailed calculations of the total bill impacts for non-government residential customers (including customer charges, energy charges, all rate riders), similar to format as Table 4.2A-3 (1000kWh.) for 500, 750, and 15000 kWh. per month comparing bills from Jan /2018 to Dec/2021.

g) Please provide detailed calculations of the total bill for non-government general service customers (including demand charges, energy charges, all rate riders) similar to Table 4.2A-4 (2000kWh.) for 1500, 2500 and 3000 kWh. per month comparing bills from Jan 2018 to Dec/2021.

ANSWER:

(a)

The referenced paragraph meant to clarify that the required rate increase for the 2021 GRA at 11.54% results in an increase of 15.01% to Rider J as this rider only applies to the existing base rates [i.e., does not apply to riders].

Rider F and Rider J1 are not part of YEC's revenue requirement as they do not relate to the 2021 test year costs.

- YEC's Rider J1 is related to YEC's 2017-18 GRA shortfall true-up which is in effect until the earlier of November 30, 2021, or at such earlier month end when the $12.557 million shortfall has been recovered.

- Rider F relates to Fuel Price Variance Account that reflects fuel price variances for both YEC and AEY.

(b)

Not confirmed. Please see response to (a).

The rate increase is 11.54%, while 15.01% is an increase to Rider J.

(c)

Effective July 1, 2021, the Rider F rider is expected to be set to approximate zero which reduces the average residential monthly bill for 1,000 kW.h energy consumption by $13.71 [6.7% of monthly bill].

The proposed interim increase in Rider J by 10.08% would increase the monthly bill by the same amount [$13.71 or 6.7% of monthly bill]. The increase in bills for interim rates will be offset by reduction in Rider F resulting in no change in customer bills for that usage level.

(d)

Effective December 1, 2021, Rider J1 expires which reduces the average residential monthly bill for 1,000 kW.h energy consumption by $12.58 [6.2% of monthly bill].

The expected increase in Rider J by 4.93% [15.01% total increase less 10.08% interim increase] would increase the monthly bill by $6.71. However, a new true-up rider is required to collect 2021 GRA shortfalls which is estimated to be about $6.59/month for 1,000 kW.h consumption for residential customers. This leads to a total bill increase at $13.30/month or 6.5% of monthly bill.

The increase in bills from the 2021 GRA is almost fully offset by the referenced reductions in bills, therefore, the expected bill impact by December 1, 2021 is 0.4%.

The increase in bills for interim rates will be offset by a reduction in Rider F resulting in no change in customer bills for that usage level.

(e)

YEC does not “plan” Rider F adjustments; adjustments are driven by changes in the market value of fuel. Additionally, Rider F for the first quarter of 2022 will depend on the balance in the Fuel Price Variance Account that reflects fuel price variances not only for YEC but also of AEY. Therefore, YEC cannot provide what Rider F would be in 2022.

(f) and **(g)**

Please see UCG-YEC-1-6 Attachment 1.

Table 1

Yukon Bills– Existing vs. Proposed - Non-Government Residential 500 kW.h/monthly Energy Consumption (prior to consideration of subsidies, rebates and taxes)

Line #	Customer Use per month:	500 kWh	Jan-18		Apr-19		Dec-19		Jan-20		Nov-20		YEC's 2021 GRA Jul-21		Dec-21	
			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
2=KWh*Base rate	First Block Energy (kWh)		$0.1214	$60.70	$0.1214	$60.70	$0.1214	$60.70	$0.1214	$60.70	$0.1214	$60.70	$0.1214	$60.70	$0.1214	$60.70
3=KWh*Base rate	Second Block Energy (kWh)															
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		-$0.000110	-$0.06	-$0.000110	-$0.06	-$0.000110	-$0.06	$0.009700	$4.85	$0.013710	$6.86	$0.0	$0.00	$0.0	$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)		16.51%	$12.44	16.51%	$12.44	22.32%	$16.82	22.32%	$16.82	22.32%	$16.82	32.40%	$24.41	37.33%	$28.13
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)			$0.00		$0.00	9.25%	$6.97	9.25%	$6.97	9.25%	$6.97	9.25%	$6.97	4.84%	$3.65
7=KWh*Rider E rate	Rider E (kW.h) [LWRF Rider]		-$0.006800	-$3.40	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00
8=(1+2+3)*Rider J rate	AEY Rider J (%)			$0.00		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00
9=(1+2+3)*Rider R rate	AEY Rider R (%)		8.30%	$6.25	8.30%	$6.25	8.30%	$6.25	8.30%	$6.25	8.30%	$6.25	8.30%	$6.25	8.30%	$6.25
10=Sum(1:9)	Total Before Tax Rebate, IER, GST			$90.59		$93.99		$105.34		$110.24		$112.25		$112.98		$113.38

Notes:

1. The proposed bills assume interim Rider J increase of 10.08% effective July 1, 2021 and 4.93% Rider J increase effective December 1, 2021.

Table 2
Yukon Bills– Existing vs. Proposed - Non-Government Residential 750 kW.h/monthly Energy Consumption
(prior to consideration of subsidies, rebates and taxes)

Line #	Customer Use per month:	750 kWh	Jan-18		Apr-19		Dec-19		Jan-20		Nov-20		YEC's 2021 GRA Jul-21		YEC's 2021 GRA Dec-21	
			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
2=KWh*Base rate	First Block Energy (kWh)		$0.1214	$91.05	$0.1214	$91.05	$0.1214	$91.05	$0.1214	$91.05	$0.1214	$91.05	$0.1214	$91.05	$0.1214	$91.05
3=KWh*Base rate	Second Block Energy (kWh)															
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		-$0.000110	-$0.08	-$0.000110	-$0.08	-$0.000110	-$0.08	$0.009700	$7.28	$0.013710	$10.28	$0.0	$0.00	$0.0	$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)		16.51%	$17.45	16.51%	$17.45	22.32%	$23.59	22.32%	$23.59	22.32%	$23.59	32.40%	$34.24	37.33%	$39.45
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)			$0.00		$0.00	9.25%	$9.78	9.25%	$9.78	9.25%	$9.78	9.25%	$9.78	4.84%	$5.12
7=KWh*Rider E rate	Rider E (kW.h) [LWRF Rider]		-$0.006800	-$5.10	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00
8=(1+2+3)*Rider J rate	AEY Rider J (%)			$0.00		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00
9=(1+2+3)*Rider R rate	AEY Rider R (%)		8.30%	$8.77	8.30%	$8.77	8.30%	$8.77	8.30%	$8.77	8.30%	$8.77	8.30%	$8.77	8.30%	$8.77
10=Sum(1:9)	Total Before Tax Rebate, IER, GST			$126.74		$131.84		$147.76		$155.12		$158.13		$158.49		$159.05

Notes:

1. The proposed bills assume interim Rider J increase of 10.08% effective July 1, 2021 and 4.93% Rider J increase effective December 1, 2021.

Table 3
Yukon Bills– Existing vs. Proposed - Non-Government Residential 1,500 kW.h/monthly Energy Consumption
(prior to consideration of subsidies, rebates and taxes)

Line #	Customer Use per month:	1,500 kWh	Jan-18		Apr-19		Dec-19		Jan-20		Nov-20		YEC's 2021 GRA Jul-21		YEC's 2021 GRA Dec-21	
			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
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
3=KWh*Base rate	Second Block Energy (kWh)	500	$0.1282	$64.10	$0.1282	$64.10	$0.1282	$64.10	$0.1282	$64.10	$0.1282	$64.10	$0.1282	$64.10	$0.1282	$64.10
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		-$0.000110	-$0.17	-$0.000110	-$0.17	-$0.000110	-$0.17	$0.009700	$14.55	$0.013710	$20.57	$0.0	$0.00	$0.0	$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)		16.51%	$33.04	16.51%	$33.04	22.32%	$44.67	22.32%	$44.67	22.32%	$44.67	32.40%	$64.84	37.33%	$74.71
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)			$0.00		$0.00	9.25%	$18.51	9.25%	$18.51	9.25%	$18.51	9.25%	$18.51	4.84%	$9.70
7=KWh*Rider E rate	Rider E (kW.h) [LWRF Rider]		-$0.006800	-$10.20	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00
8=(1+2+3)*Rider J rate	AEY Rider J (%)			$0.00		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00
9=(1+2+3)*Rider R rate	AEY Rider R (%)		8.30%	$16.61	8.30%	$16.61	8.30%	$16.61	8.30%	$16.61	8.30%	$16.61	8.30%	$16.61	8.30%	$16.61
10=Sum(1:9)	Total Before Tax Rebate, IER, GST			$239.44		$249.64		$279.78		$294.50		$300.51		$300.12		$301.17

Notes:

1. The proposed bills assume interim Rider J increase of 10.08% effective July 1, 2021 and 4.93% Rider J increase effective December 1, 2021.

Table 5

Yukon Bills– Existing vs. Proposed - Non-Government General Service 2,500 kW.h/monthly Energy Consumption, 10 kW Demand (prior to consideration of subsidies, rebates and taxes)

Line #	First Block Energy Use - Customer Use per month:	2,500 kWh	Jan-18		Apr-19		Dec-19		Jan-20		Nov-20		YEC's 2021 GRA Jul-21		YEC's 2021 GRA Dec-21	
		10 kW														
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates															
1	Demand Charge (per kW per month)		$7.39	$73.90	$7.39	$73.90	$7.39	$73.90	$7.39	$73.90	$7.39	$73.90	$7.39	$73.90	$7.39	$73.90
2=KWh*Base rate	First Block Energy (kWh)		$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00
2a=KWh*Base rate	Second Block Energy (kWh)		$0.1288	$64.40	$0.1288	$64.40	$0.1288	$64.40	$0.1288	$64.40	$0.1288	$64.40	$0.1288	$64.40	$0.1288	$64.40
3=KWh*Rider F rate	Rider F (kW.h)		-$0.00011	-$0.28	-$0.00011	-$0.28	-$0.00011	-$0.28	$0.00970	$24.25	$0.01371	$34.28	$0.00000	$0.00	$0.00000	$0.00
4=(1+2)*Rider J rate	YEC Rider J (%)		16.51%	$55.85	16.51%	$55.85	22.32%	$75.51	22.32%	$75.51	22.32%	$75.51	32.40%	$109.60	37.33%	$126.28
5=(1+2)*Rider J1 rate	YEC Rider J1 (%)						9.25%	$31.29	9.25%	$31.29	9.25%	$31.29	9.25%	$31.29	4.84%	$16.39
6=KWh*Rider E rate	Rider E (kW.h) [LWRF Rider]		-$0.00680	-$17.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00
7=(1+2)*Rider J rate	AEY Rider J (%)			$0.00		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00
8=(1+2)*Rider R rate	AEY Rider R (%)		8.30%	$28.08	8.30%	$28.08	8.30%	$28.08	8.30%	$28.08	8.30%	$28.08	8.30%	$28.08	8.30%	$28.08
9=Sum(1:8)	Total Before Tax Rebate, GST			$404.96		$421.96		$472.91		$497.43		$507.46		$507.27		$509.04

Notes:

1. The proposed bills assume interim Rider J increase of 10.08% effective July 1, 2021 and 4.93% Rider J increase effective December 1, 2021.

Table 6

Yukon Bills– Existing vs. Proposed - Non-Government General Service 3,000 kW.h/monthly Energy Consumption, 12 kW Demand (prior to consideration of subsidies, rebates and taxes)

Line #	First Block Energy Use - Customer Use per month:	3,000 kWh	Jan-18		Apr-19		Dec-19		Jan-20		Nov-20		YEC's 2021 GRA Jul-21		Dec-21	
		12 kW														
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates															
1	Demand Charge (per kW per month)		$7.39	$88.68	$7.39	$88.68	$7.39	$88.68	$7.39	$88.68	$7.39	$88.68	$7.39	$88.68	$7.39	$88.68
2=KWh*Base rate	First Block Energy (kWh)		$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00
2a=KWh*Base rate	Second Block Energy (kWh)		$0.1288	$128.80	$0.1288	$128.80	$0.1288	$128.80	$0.1288	$128.80	$0.1288	$128.80	$0.1288	$128.80	$0.1288	$128.80
3=KWh*Rider F rate	Rider F (kW.h)		-$0.00011	-$0.33	-$0.00011	-$0.33	-$0.00011	-$0.33	$0.00970	$29.10	$0.01371	$41.13	$0.00000	$0.00	$0.00000	$0.00
4=(1+2)*Rider J rate	YEC Rider J (%)		16.51%	$68.93	16.51%	$68.93	22.32%	$93.18	22.32%	$93.18	22.32%	$93.18	32.40%	$135.25	37.33%	$155.83
5=(1+2)*Rider J1 rate	YEC Rider J1 (%)						9.25%	$38.62	9.25%	$38.62	9.25%	$38.62	9.25%	$38.62	4.84%	$20.22
6=KWh*Rider E rate	Rider E (kW.h) [LWRF Rider]		-$0.00680	-$20.40	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00
7=(1+2)*Rider J rate	AEY Rider J (%)			$0.00		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00
8=(1+2)*Rider R rate	AEY Rider R (%)		8.30%	$34.65	8.30%	$34.65	8.30%	$34.65	8.30%	$34.65	8.30%	$34.65	8.30%	$34.65	8.30%	$34.65
9=Sum(1:8)	Total Before Tax Rebate, GST			$500.33		$520.73		$583.60		$613.03		$625.06		$626.00		$628.18

Notes:

1. The proposed bills assume interim Rider J increase of 10.08% effective July 1, 2021 and 4.93% Rider J increase effective December 1, 2021.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application, page 2**

YEC states: “The 2021 GRA approach will also work to prevent rate and bill instability beyond 2021, and reduce rate increase requirements for subsequent GRA.”

QUESTION:

a) Please explain exactly how the YEC proposes to accomplish this broad statement.

b) Please explain how the YEC will guarantee its' trust to ratepayers that YEC will follow through with this statement. Or does this mean that instead of 20% increase next application, you will only need 15 per cent yet again? Or is this just another statement like 'other rates will go down when we connect the mines'?

ANSWER:

(a)

See discussion provided in Tab 1, Page 1-3 and 1-4, as well as Tab 4, pages 4-9 to 4-11.

(b)

As noted in Tab 1, a new GRA is overdue to enable Yukon Energy to address serious ongoing revenue shortfalls, and further delay in adjusting rates will have material implications for the financial integrity of the corporation. Further delay in implementing rate changes beyond 2021 would result in a material decrease in customer bills in 2021 when Rider F is reduced and the 2017-18 YEC GRA true-up comes off, followed by a later and more material increase in customer bills in 2022 or thereafter (at the time of the next GRA).

Yukon Energy has in its application outlined an approach to resolve outstanding revenue shortfall issues in 2021 without materially disrupting customer bills. Success will depend on completing the regulatory process on a timely basis, and implementing interim and final rates as outlined in the Application.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application, page 4. Summary of Requests #1**

YEC states it requests "approval of a forecast revenue requirement of $75.135 million for 2021.

QUESTION:

a) Please confirm that the YUB approved revenue requirements were $48.544 million for 2017 and $49.864 million for 2018.

b) Please explain, in layman's language, why an increase of $25 million or 50% since the last GRA (in three years) should be acceptable to your ratepayers.

c) Please provide a chart showing approved revenue requirement amounts for all GRA years since YEC took control of Management in 1998.

ANSWER:

(a)

Not confirmed. The numbers noted were the revenue requirements in the 2017-2018 GRA filing. The approved revenue requirement was $49.202 million for 2017 and $49.794 million for 2018 (see Order 2019-08 approving Yukon Energy's second compliance filing).

(b)

Most of the forecast $25 million increase in revenue requirement as referenced is increased sales funded fully at existing rates. The forecast 2021 revenue shortfall to be recovered through increased rates is $10.971 million (see Table 4-1).

The forecast 2021 revenue requirements primarily reflect proposed adjustments to thermal generation requirements (due to increased loads) and fuel prices (beyond YEC's control), changes to labour and non-labour costs, changes to depreciation resulting from a depreciation study provided as directed, and the impact of increases in rate base relative to 2018 approved numbers, the last test year reviewed by the Board during Yukon

Energy's 2017/2018 GRA application. Details on the basis for each area of cost increase are specified in Tab 3 of the Application. These are costs required to be incurred for ongoing operation of the utility.

(c)

The request is unreasonably broad and not directly relevant to the current proceeding. YEC has therefore not provided the requested chart.

TOPIC: Revenue Requirement Requests

REFERENCE: November 2020 Application Tab.1-7

1.3 CHANGES IN FORECAST LOADS
The 2021 load forecast is about 28% higher than the 2018 approved forecast.3 As noted in Table 1-2, revenues from higher loads are largely offset by increases in fuel costs. Higher non-industrial loads also result in capacity shortfalls that must be addressed and that are driving both capital and O&M cost increases.
Test year forecasts for 2021 reflect the following:
Wholesale Load – Actual 2018 (332.3 GWh) 17.6 GWh higher than approved forecast (314.7 GWh); firm wholesales for 2021 are forecast at 343.5 GW.h.
Industrial Load – Actual 2018 industrial load exceeded approved forecast (36.9 GWh vs 32.2 GWh). Forecast firm Yukon Energy sales to industrial customers for the 2021 test year is 102.911 GW.h.

REFERENCE: November 2020 Application Tab1-7/8

Thermal Generation requirements are growing due to higher firm grid loads – The 2018 Compliance Filings approved a forecast of 16.4 GW.h for long-term average (LTA) thermal generation requirements to supply the 2018 forecast grid load of 420 GWh. The 2021 LTA Forecast total firm generation load for the 2021 test year is 538.7 GW.h, compared to the 2018 approved load of 420.3 GWh.
thermal generation forecast is 84.3 GW.h for a forecast grid load 538.7 GW.h. The increased LTA thermal generation accounts for $10.8 million of the 2021 GRA cost increases from the approved 2018 GRA (based on 2018 GRA approved fuel prices). These added LTA thermal generation costs due to load growth are more than fully recovered by the increased revenues ($14.4 million) from the load growth.

QUESTION:

a) If increase revenues from higher loads are largely offset by increases in fuel costs, the reverse holds true in that fuel costs are largely offset by revenues from higher loads, why is Yukon Energy claiming a revenue shortfall of $2.1 million in this application for fuel costs?[1]

b) Please confirm Yukon Energy's policy approach through this application is to apply for forecast costs in fuel and purchased power; set the fuel rider in August to zero which basically offsets the requested interim rider (if the proposed fuel increase is accepted; and then rekindle Rider F at a latter [sic] date in 2022.

[1] Application November 2020, Page 3, Fuel Price Changes (19.4% of revenues shortfall).

c) Please confirm that the wholesale load is forecast to increase by 3.34% in 2021 from the 2018 Actual load.

d) Please confirm that industrial load is forecast to increase by 179% in 2021 from the 2018 Actual load.

e) If this is indeed the case, why does Yukon Energy insist "that higher non-industrial loads result in capacity shortfalls that must be addressed and that are driving both capital and O&M cost increases"? Is it not the industrial loads that are mostly driving these proposed increases?

f) What does Yukon Energy propose to do in this application to offset this blatant discrimination demonstrated for firm wholesale ratepayers?

ANSWER:

(a)

As noted on page 3 of the Application, higher fuel prices account for $2.1 million of the 2021 GRA revenue shortfall. See Tab 3, Section 3.2 of the Application.

(b)

Not confirmed.

As outlined in Tab 4, Section 4.5, the application is proposing that Rider J for 2021 of 32.40% for all firm non-industrial, and 28.75% for all firm industrial, be applied initially as of July 1, 2021 as an interim refundable rate rider, equal to a 10.08 percentage point increase in the existing Rider J rates for non-industrial and industrial rates [reflects about 67% of the total Rider J rate increase for 2021 in the current GRA].

July 1, 2021 is proposed as the effective date for the interim rates to reduce customer bill volatility. The current Rider F rider is forecast to be reduced effective July 1, 2021, and the Rider J 10.08% is set only to offset the Rider F reduction based on estimate for a 1,000 kW.h/month residential customer consumption with Rider F assumed to approximate zero as at July 1, 2021.

The GRA will re-set forecast fuel prices (driven in particular by higher natural gas price) such that Rider F going forward will now be based off updated fuel prices. YEC does not control actual diesel or natural gas prices, and therefore does not control future Rider F changes after mid 2021. Rider F will continue to apply, providing rate adjustments (down or up) depending on changes to fuel prices relative to the 2021 GRA updated forecast prices.

(c)

Per Tab 2, Table 2.1, the 2021 wholesale load is forecast to increase by 3.39% over the 2018 Actual load.

(d)

Confirmed.

(e) and **(f)**

See response to UCG-YEC-1-10 (a), (b) and (d). Industrial loads are not driving the capacity shortfalls noted in the question, as industrial loads are excluded from the determination of the N-1 dependable capacity shortfall.

Industrial loads are contributing to other cost requirements – however, many of the non-fuel O&M and capacity cost requirements are not linked clearly to grid load requirements, e.g., sustaining capital requirements, increased labour requirements, etc.

There is no basis for any suggestion of discrimination in favour of any group of customers.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **Application November 2020, Page 3**

Energy & Peak Load Changes (8.4% of revenue shortfall): Dependable capacity requirements caused by peak load growth for non-industrial sales drives diesel rental costs that account for $3.8 million (34.9%) of the 2021 GRA revenue shortfall. Higher overall loads provide increased revenues at existing rates ($14.4 million) that reduce the 2021 revenue shortfall by $2.9 million after considering load-related cost impacts of $10.8 million for increased long-term average thermal generation fuel cost requirements at 2018 GRA fuel prices (to address added energy generation) and $0.7 million for increased Mayo B Promissory Note interest due to higher loads.

QUESTION:

a) Does this above statement mean that if dependable capacity for peak load growth for non-industrial sales is needed (i.e. running of diesels or LNG) that the industrial loads will be temporarily discontinued during peak time frames? In other words are the mines on SCADA disconnect during peak loads requiring the usage of our rental diesels?

b) If not, why does Yukon Energy state that it is “dependable capacity requirements caused by peak load growth for non- industrial sales” which drives this cost?

c) Please confirm the Mayo B Promissory Note is to Yukon Development Corporation.

d) Should it not be the government/YEC (through edicts and OICs and PPAs) that takes fiscal responsibility for increased mine loads driving such rate increases rather than recouping this from the firm ratepayers through this rate application?

ANSWER:

(a), **(b)** and **(d)**

The diesel rental units are required to meet the N-1 dependable capacity criterion. The N-1 criterion does not include consideration of major industrial customer loads as these loads typically maintain sufficient on-site diesel for their own emergency purposes.

Industrial loads are not discontinued during peak periods – the referenced quote is focused on the requirements to ensure sufficient capacity to meet the N-1 criterion.

As reviewed in various past YUB proceedings, including PPA proceedings for new industrial loads, there is no basis for asserting that industrial loads are driving rate increases.

(c)

See response to UCG-YEC-1-22.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **Application November 2020**

Section 6.1 of OIC 1995/90 requires the Board to ensure that rates charged to major industrial customers are sufficient to recover the cost of service to that customer class.

REFERENCE: **YEC 2003-04 Rate Hearing Transcripts p.649**

Mr. Morrison: "Customers are customers, load is load. And we don't attribute specific diesel costs to different customers.

QUESTION:

a) Please reconcile the above underlined statements, if YEC cannot differentiate what the specific diesel costs are to serve each individual mine, how can YEC guarantee your regulator that you are adhering to the above OIC.

ANSWER:

(a)

The referenced OIC direction addresses "cost of service" which includes all relevant costs (including all historic costs in rate base) allocated to customer classes based on specific rules and procedures. The OIC quote has nothing to do with whether YEC is capable of attributing specific diesel costs to different customer classes, let alone specific customers.

All cost of service studies provided to date to the Board have confirmed that rates charged to major industrial customers as a class continue to recover the cost of service to that customer class, calculated on a Yukon-wide basis as required under OIC 1995/90.

The costs to serve added major industrial customers have also been reviewed by the Yukon Utilities Board (YUB) during the review of Power Purchase Agreements (PPA) with industrial customers. Board reports from these proceedings have not shown any basis for asserting that these customers are driving rate increases.

New industrial customers cover the costs to negotiate and conclude the PPA and incremental costs for connection and also make contributions towards existing and new transmission.

Specifically, YUB in Appendix A to the Order 2018-04 paragraph 26 stated the following:

> Generally, in terms of customer contributions for capital costs, the Board has previously stated the following:
>
> > The incremental costs (spur costs) for connections to existing or new transmission facilities should be completely borne by the industrial customer.
> >
> > Further, the Board agrees with the principle that industrial customers should make a contribution towards an appropriate share of new or to existing bulk transmission.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **Application November 2020, Tab 1-9**

Defined Benefit Pension Deferral Account: In this Application Yukon Energy is requesting approval of defined benefit pension plan deferral account that captures variances in contributions to the defined benefit pension plan from the cost included in the test year revenue requirements as a result of the required annual actuarial evaluations. A similar deferral account was approved for AEY by Board Order 2014-06.

QUESTION:

a) Please explain how this affects the revenue requirement for this application and if it does by how much in dollars and percentage?

ANSWER:

(a)

The proposed Defined Benefit Pension Plan Deferral Account does not impact 2021 GRA revenue requirements, but captures variances in contributions to the defined benefit pension plan between the test years. For example, if the actual contributions for 2021 or after vary from the amount included in the 2021 test year [or future test year forecasts] then the variance is included in the deferral account. The deferral account balance then will be dissolved based on YUB Order in the future GRAs.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **Application November 2020, Tab 1-8/9**

VGC Group and Alexco Fixed Charge: Rate Schedule 39 as currently approved includes a Fixed Charge for VGC Group and for Alexco of $8,402/ month, subject to amendment from time to time, including provision for allocation of the Fixed Charge between VGC Group and Alexco in years when both customers are Major Industrial Customers of YEC.6 As reviewed in Appendix 4.3 of this Application, YEC expects to file with the Board in late November/ early December 2020 for approval of an amended Transmission Facilities Fixed Cost effective January 1, 2021 of $428,812, resulting in an interim Fixed Charge (85% of the Transmission Facilities Fixed Cost) effective January 1, 2021 of $35,734 per month, with allocation of the interim Fixed Charge between VCG Group and Alexco [Table 4.3-2, Appendix 4.3 of this Application]. Aside from changes related to the 2021 GRA, a final Fixed Charge for 2021 would occur after 2021 year end as required to reflect final actual Transmission Facilities Fixed Cost and the actual MWh energy sales in 2021 that occurred to VGC Group and Alexco.

QUESTION:

a) Since Alexco came on line again in November 2020, and it is obvious that Yukon Energy had this amendment to the agreement already to go, why did YEC not include this Filing with this application to reduce the revenue requirement as well as regulatory costs for another process?

b) Will the firm ratepayer benefit from this Alexco agreement amendment in this 2021 rate application?

c) If yes, please show where and how in the application this adjustment is included.

d) If no, please explain why not?

e) Will Alexco be responsible for any of the transmission line and sub-station contribution costs to lower the rate base cost?

f) If not, why not.

ANSWER:

(a) through **(f)**

The Fixed Charge provision referenced in the quote is set to recover the defined Transmission Facilities Fixed Cost, which amount is allocated as directed between major industrial customers using the defined Transmission Facilities. The applicable Transmission Facilities Fixed Cost amount did not change when Alexco once again became a major industrial customer – only the allocation of this amount between VGC Group and Alexco changed. Accordingly, Alexco will be responsible for its share of the Transmission Facilities Fixed Cost as approved by the Board from time to time.

The above quote also references YEC's planned filing for an amendment to the Transmission Facilities Fixed Cost as required within 60 days after the Transmission Facilities Development Operation Date. This amendment cannot be filed until the Transmission Facilities Development Operation Date has occurred, which is now expected to be in March 2021. This amendment will increase the Fixed Charge to be recovered from VGC Group and Alexco. This application requirement exists separate from the 2021 GRA application, and was therefore assumed not to be part of the 2021 GRA application.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **Application November 2020 Tab Table 3.3**

Labour $ 11,932 $ 12,083 $ 11,863 $ 12,727 $ 13,310 $ 13,310
Production 1,799 3,300 3,935 4,876 5,978 5,978
Transmission 1,419 1,058 1,304 1,403 1,394 1,394
Distribution 535 449 293 536 491 491
General O&M 1,219 1,395 1,530 1,352 1,391 1,391
Administration 3,001 3,016 3,365 3,491 3,858 3,858
Insurance and Reserve for
Injuries/Damages 1,510 1,525 1,596 1,778 1,902 2,259
Property Taxes 708 671 673 739 750 750
Total OM&A (Tab 7, Schedule 10) $ 22,125 $ 23,497 $ 24,559 $ 26,903 $ 29,074 $ 29,430

Forecast

Non-labour costs are forecast to increase by $5.928 million in 2021 over 2018 approved costs. The average annual compound increase in non-labour expenses is approximately 16.51% (2021 expenses over 2018 approved) primarily due to $3.834 million costs for diesel rentals required to meet the N-1 single contingency capacity planning criteria (no diesel rental costs were included in the 2018 approved costs).

An increase in labour expense makes up $1.378 million, or 19%, of the total $7.306 million increase in operating and maintenance expense forecast for 2021 over 2018 approved costs. The average annual compound increase in labour expenses is approximately 3.71% (2021 expenses over 2018 approved).

3.3.1 Labour

Total labour expenditure is made up of labour expense for maintenance and administration and capitalized labour. Capitalized labour is charged to capital projects and becomes part of revenue requirement through annual depreciation charges incurred after in service. Maintenance and administration labour expense is charged directly to revenue requirement. Total maintenance and administration labour expense is forecast to be $13.310 million in 2021 as compared to 2018 approved costs of $11.932 million, reflecting an increase of $1.378 million.

QUESTION:

a) Please breakdown expenditure amounts and reason for all non-labour forecast costs of $5.928 minus the $3.834 million diesel rentals; i.e $2.094 million amount.

b) According to Table 3.3 and line 10 above, Labour costs are forecast to increase by $1.378 million or 11.5% since last GRA approval. Please breakdown all labour expenditures for maintenance and explain the need for each increase.

c) Please breakdown all labour expenses for administration and explain the need for each increase.

d) According to Table 3.3 above, Administration costs are forecast to increase by (Administration 3,001 3,016 3,365 3,491 3,858 3,858) $0.857 million or 28.6% since last GRA approval. Please give breakdown of all Administration costs and reason for increase in each partitioning.

e) According to Table 3.3 above, According to Table 3.3 above, (Insurance and Reserve for Injuries/Damages 1,510 1,525 1,596 1,778 1,902 2,259) costs are forecast to increase by $0.749 million or 50% since last GRA approval. Please give details on why this reserve has increased this great amount since the last GRA approval.

ANSWER:

(a)

Breakdowns of expenditures and reasons for all non-labour forecast costs are provided in the Application, starting at section 3.3.2 (page 3-13) through 3.3.8 (page 3-20).

(b) and **(c)**

Breakdowns of expenditures for all labour forecast costs are provided in the Application, starting at section 3.3.2 (page 3-13) through 3.3.8 (page 3-20). Reasons for the increase are provided in the Application at section 3.3.1.

(d)

Breakdowns of expenditures for all Administration costs and reasons for the more significant increases are provided in the Application, starting at section 3.3.6 (page 3-17).

(e)

Breakdowns of expenditures for all Insurance and Reserve for Injuries and Damages costs and reasons for the increases are provided in the Application, starting at section 3.3.7 (page 3-18 to page 3-20).

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application Tab2-3**

21 Actual hydro generation in 2020 is forecast at 86.0% of grid generation, reflecting annual water
22 availability at about LTA. Current forecast hydro generation for 2021 is 94.0% of grid generation,
23 reflecting forecast water availability above LTA.

QUESTION:

a) What does this exactly mean, i.e. do you have the actual hydro generation for 2020 or is it forecast?

b) If not, please rephrase this to make it understandable.

ANSWER:

(a) and **(b)**

The “actual” hydro generation in the preamble refers to the hydro generation forecast to occur based on expected water availability in 2020. This differs from the long-term average generation which was used as the basis for thermal cost calculations.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application Tab2-12**

18 As indicated in Table 2.2, the peak demand for the integrated system is forecast to be 112.7 MW in 2021.
19 The actual peak demand was 93.0 MW in 2018, 90.0 MW in 2019 and 103.8 MW in 2020.

QUESTION:

a) Does this 112.7MW forecast peak demand for 2021 include the three mines now on line? If not, please provide this mining peak load.

b) If this does include the mines, please breakdown the peak demand for firm ratepayers and for industrial ratepayers.

ANSWER:

(a) and **(b)**

The peak forecast of 112.7 MW includes both non-industrial and industrial peak. The forecast non-industrial peak for 2021 is 100.6 MW as noted on page 2-4 of the Application. The remaining 12.1 MW is forecast industrial peak.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application Tab 2-13**

11 To address the severity of a potential
12 outage, Yukon Energy incorporated a second test – the N-1 standard which determines system
13 capacity assuming the loss of the system's single largest generating or transmission-related
14 generation resource. This standard does not include industrial loads as part of the assessment. It
15 ensures there is sufficient grid generation installed to meet firm residential and commercial
16 customers' loads when a failure occurs to the single largest system component

QUESTION:

a) Does this mean that the industrial loads are temporarily taken off the system until the reason for a potential outage is fixed and normal hydro power is restored, i.e. only firm customers are accommodated with the N-1 back-up supply?

b) If not, why not?

ANSWER:

(a) and **(b)**

The N-1 criteria does not include consideration of major industrial customer loads as these loads typically maintain sufficient on-site diesel for their own emergency purposes and therefore can be temporarily taken off the system during an emergency.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application Tab2-15**

5 In summary, under N-1, there is surplus of dependable capacity of approximately 1.25
6 MW in 2021. Without rented diesel units, the N-1 capacity shortfall would be 25.75 MW 567 in 2021.

QUESTION:

a) How much above the standard rental costs for the diesels, when they are being used (i.e. is there a usage fee added to the stand-by rental? And how much?).

b) Please chart the operating-owned YEC diesels with capacity for each in Whitehorse, Faro, Mayo, Dawson. Ross River, Teslin, Carmacks, Carcross, Haines Junction, and any others.

c) Please chart the operating ATCO diesels in all their operating area on the grid with each capacity.

d) Would we today require diesels on the integrated grid if the mines were not operating (answer without peak load and with peak load)?

ANSWER:

(a)

Please see response to CW-YEC-1-17 (a) through (e).

(b)

Please see page 11 of 10-Year Renewable Electricity Plan provided in CW-YEC-1-36 (a) Attachment 1 for the map that shows generation facilities and Appendix A for the list of generation facilities with capacity information.

(c)

AEY would be in a better position to provide the requested information. This information as required for the N-1 capacity criteria is provided in Tab 2 of the Application.

(d)

Yes. When planning the system to the N-1 contingency criterion (used to determine the requirement of system capacity and consequent diesel rentals), the mines are not included in the analysis. Accordingly, the mines have no impact to the diesel requirements, as they have their own diesel backup.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application Tab 2-17**

TAB 2 - SALES AND GENERATION Table 2.2:
Summary of Energy Balance, Losses, and Peak

Forecast Line No.	Description	2018 Approved	2018Actual	2019 Actual	2020 Forecast	2021
Sales and Losses						
1	Total Energy Sales	388,332	412,470	403,492	465,788	495,151
2	Losses - MWh	34,173	37,898	37,185	42,193	43,575
3	Losses - %	8.8%	9.2%	9.2%	9.1%	8.8%
4	Total Generation	422,506	450,368	440,676	507,980	538,726
5	Secondary Sales Related Generation	2,241	282	0	0	0
6	Firm Load Generation	420,265	450,086	440,676	507,980	538,726

QUESTION:

a) Give reason for the continual increase in loss of MWh on the grid through the four year period listed?

b) From above 118,461MWh increase of firm load generation from forecast 2021 to 2018 approved, or 28% (divided by 4 years equals a 7% increase per year) when you state earlier that the yearly firm load is increasing at 3.5% ????which is it?

ANSWER:

(a)

The MWh volume of grid losses increase as grid generation increases. YEC is proposing to maintain 8.8% line losses for the 2021 GRA which is the same as 2017/18 GRA.

(b)

On page 1-7 of the application YEC notes that the 2021 generation forecast for firm load is about 28% higher than the 2018 approved forecast. This is about 8.6% average annual increase.

YEC is unable to confirm the source for 3.5% referenced in the preamble.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application Tab 2-17**
Peak – MW2 Integrated System 92.9 93.0 90.0 103.8 112.7

QUESTION:

a) Please explain the major difference of 19.8MW from 2018 approved to 2021 forecast for integrated peak.

ANSWER:

(a)

The question references "19.8 MW from 2018 approved" – Table 2.2 shows the 2018 approved forecast peak at 92.9 MW (vs actual at 93.0 MW).

The 2018 approved peak was based on the long-term peak forecast from the 2016 Resource Plan. The 2021 forecast peak at 112.7 MW is based on the updated peak forecast from YEC's 2020 10-Year Renewable Electricity Plan, consideration of the most recent peak of 103.8 MW in 2020, and forecast industrial peak load (12 MW). The major change driving an increase in the non-industrial peak since 2018 is the increased number of 100% electrically heated homes.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application Tab 2.1-1**

APPENDIX 2.1: LONG-TERM AVERAGE THERMAL GENERATION CALCULATIONS

As per previous Board directives, Yukon Energy's GRA revenue requirement annual thermal generation costs for test years are based on long-term average (LTA) hydro generation (rather than forecasts of actual hydro generation resulting from actual water conditions). Accordingly, for the purpose of the 2021 GRA to test year, hydro and thermal generation forecasts are based on LTA water supply for hydro generation as updated with the latest information.

The determination of LTA annual hydro availability is adjusted as required in each GRA to address material changes in LTA hydro system capability due to changes in loads, installed capacity, licensing/permits or other factors.

The forecast 2021 LTA thermal generation for the Application is 84.3 GW.h, based on the Table 2.1-1 developed to determine annual expected YEC thermal generation based on long-term average YEC hydro generation at YEC 2021 forecast grid loads (net of expected IPPs and expected Fish Lake generation) ranging from 475 to 585 GW.h/year. The forecast for the test year is based on the following proposed updates to the determination of LTA annual hydro availability for the current GRA: a) Yukon Energy now has more water year records compared to 2017/18 GRA [38 water years, from 1981 to 2018, compared to 35 water years, 1981 to 2015, used in 2017/18 GRA]. This added information has tended to increase LTA hydro estimates.

QUESTION:

a) Does YEC have any management command/influence on the hydro system capability and usage? Explain.

b) Why is not the 2019 year included in your forecast model?

c) Do we now have more than average water conditions in our systems available for generation? Provide latest Update on Forecast Water Conditions for 2020 qualifying answer.

d) If yes, will this increased hydro use not result in a windfall for the utility if this particular forecasting model is accepted.

e) Please explain how the LWRF is functioning under these positive conditions.

ANSWER:

(a)

Yukon Energy optimizes the dispatch of the hydro system within the license requirements to maximize the hydro system capabilities. The main hydro management/influence that YEC conducts is managing the reservoir levels. Many external factors can influence the reservoirs outside of YEC's control, such as precipitation and the timing of freshet.

(b)

The model is updated every 2 to 3 years with hydrological data. 2019 data will be included in the next model update.

(c)

Based on initial calculations it appears the Aishihik and Mayo river system were higher than average and Whitehorse was slightly lower than average for the 2020 water year. All three hydro facilities refilled to at or near Full Supply Level in 2020.

(d) and **(e)**

Increased hydro use does not result in any windfall for the utility so long as LWRF deferral account procedures are in place to address water-related variances in hydro generation from GRA approved forecast that impact thermal generation fuel costs.

By way of example, Table 2.2 in the Application indicates a ST hydro forecast for 2021 that is 54 GWh higher than the LTA hydro forecast. If the ST forecast was to occur in 2021, and the 2021 GRA revenue requirement forecasts based on LTA hydro are approved, the actual thermal generation would be approximately 54 GWh lower than forecast in the GRA – and the full $9.9 million of fuel cost (at the forecast blend fuel price of $0.1838/kWh) would be paid into the LWRF by YEC as part of the 2021 LWRF Annual Report filing.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application Tab 3-3**

12 The forecast Return on Rate Base increases by 20% ($2.832 million) from 2018 approved to 2021
13 forecast as proposed in the Application. The increase primarily reflects about 12% increase in mid-year
14 rate base in 2021 over 2018 approved. Yukon Energy's capital structure continues to be financed with
15 60% long-term debt and 40% equity. The forecast 2021 average cost of long-term debt at 2.81% is 58
16 basis points [or 26%] higher than the 2018 approved cost at 2.23%, primarily reflecting Mayo B related
17 debt's higher interest with higher loads. The forecast 2021 return on equity at 8.70% remains unchanged
18 from the 2018 approved cost.
Yukon Energy's forecast for new long-term debt interest rate for the 2021 test year is based on long-term
10 Canada bonds plus 120 basis points as directed by the Board. Please see Tab 3, Section 3.5.1. The
11 interest rate adopted for new debt forecast in the test year is 2.19%, determined using a formulaic
12 approach based on the long-term Canada Bonds rate plus 120 basis points (Government of Canada Long-
13 Term Bond Benchmark at 0.99% as of June 30, 2020).

QUESTION:

a) Why is long term debt rates proposed to increase by 26% since last approved GRA while the Bank of Canada rate trending downward, now at 0.25 per cent?

b) Is the add-on of 120 basis points non- negotiable for a new application? If not, why not?

c) Why are ratepayers paying, the holder of the Mayo B debt, prime rates when it is to our publicly-owned shareholder who owns the debt?

d) Does not this term note higher load reflect the mines of that area?

e) Does Yukon Energy make increased revenues from selling to the mines?

f) Why are firm ratepayers paying a premium for this term note when it is through a government decision via Yukon Energy to sell to the mines at a pre-determined contract price?

ANSWER:

(a)

The Application explains the impact from the Mayo B note increase relative to interest rate for new debt.

(b)

Directive 24 of Order 2018-10 notes as follows (as summarized in Tab 6):

> In Board Order 2013-01, the Board directed that a formulaic approach be used for forecasting future costs of debt. This direction was not followed. The Board reiterates the direction and expects this direction to be followed. In future GRAs, both Yukon utilities are to provide their cost-of-debt forecast based on the formulaic approach (long-term Canada bonds plus 120 basis points). If a utility chooses to employ a market-based approach, that utility must also provide a forecast based on the approved formulaic approach.

Yukon Energy's forecast for new long-term debt interest rate for the 2021 test year is based on long-term Canada bonds plus 120 basis points as directed by the Board.

(c), **(d)**, **(e)** and **(f)**

Tab 3, page 3-36 summarize the terms of the Mayo B Promissory Note. The terms of this debt have been reviewed in several previous GRAs. The debt interest rate is impacted by load levels on the grid. Higher loads from mines or other customers increase YEC revenues, and enable more effective use of Mayo B hydro generation such that payment of the full interest rate on the Mayo B Promissory Note is justified.

The Mayo B Promissory Note is a mitigation measure established at the time of that project's capitalization to protect ratepayers against low load risk impacts related to Mayo B rate base costs. The instrument contains a flexible interest provision that can reduce the annual interest rate expense to YEC when actual grid loads are lower than a prescribed minimum needed to justify the full interest rate; if the calculated interest expense is negative then YDC pays that amount to YEC in order to reduce the impact of Mayo B costs to ratepayers. The 2017/18 GRA noted that in each year since 2013, YEC's annual

interest expense on the Mayo B Promissory Note has been reduced by the flexible interest provisions. Lower loads in 2014 resulted in negative interest payments from YDC to YEC of $0.112 million.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application 3-6**

8 Purchased power costs also include forecast purchases in
9 2021 under the Yukon government Independent Power Production (IPP) Policy of 1.983 GW.h1 as
10 provided in Table 2.2. The purchase cost for the IPPs in 2021 is assumed at $0.1583/kW.h based on the
11 latest approved thermal fuel cost for YEC in its 2017/18 GRA.2 Total IPP purchase cost is forecast at
12 $0.314 million for 2021.

QUESTION:

a) What is the YEC protocol to purchase from IPP?

b) Please give a cost /benefit analysis of this 2021 forecast IPP purchase cost of $0.134 million?

c) Please provide purchase agreement with this IPP or any IPP?

ANSWER:

(a)

Please see YUB-YEC-1-95(c) for SOP IPP program material, including SOP Program Guide, SOP Program Rules, SOP Application Process, SOP Application Form, Interconnection Standards; and Electricity Purchase Agreement Template.

(b)

Per the quotation provided in the preamble – the Total IPP purchase cost is forecast at $0.314 million for 2021 (not $0.134 million). OIC 2019-25 provides direction regarding IPP costs that the Board must allow the utility to recover, based on paying the IPP the last approved blend fuel price per kWh for each kWh delivered. IPP costs will equal thermal fuel cost savings when all IPP generation can be used to displace thermal generation.

(c)

Please see Attachment 1 to this response.

ELECTRICITY PURCHASE AGREEMENT

BETWEEN

NOMAD CONTRACTING & ELECTRICAL SERVICES LTD.

- and -

YUKON ENERGY CORPORATION

MOUNT SIMA SOLAR PROJECT

(YUKON STANDING OFFER PROGRAM)

Dated the 27th day of August, 2020

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Yukon Energy Corporation

STANDARD FORM ELECTRICITY PURCHASE AGREEMENT

STANDING OFFER PROGRAM

THIS ELECTRICITY PURCHASE AGREEMENT ("**EPA**") is made as of the 27th day of August, 2020

BETWEEN:

NOMAD CONTRACTING & ELECTRICAL SERVICES LTD., a corporation incorporated under the laws of the Yukon ("**Seller**")

- and -

YUKON ENERGY CORPORATION, a corporation incorporated under the laws of the Yukon ("**Buyer**")

WHEREAS:

A. The Government of Yukon issued the *Energy Strategy for Yukon* in January 2009 and in October 2015 issued the *Independent Power Production Policy* as reviewed and updated in October, 2018 (the "**IPP Policy**") as part of the strategy's priority action to "update and develop a policy framework for electricity that emphasizes efficiency, conservation and renewable energy". The IPP Policy created a framework for the development of the Standing Offer Program. In support of the objectives of the IPP Policy, the Government of Yukon issued the SOP OIC and, together with the Utilities, developed the SOP Rules;

B. Seller has proposed the development of the Project on the Electrical Grid pursuant to the Standing Offer Program and such Project has been reviewed and approved in accordance with the SOP Rules; and

C. This EPA is being entered into by the Parties in respect of the Project under the Standing Offer Program in accordance with the SOP Rules.

NOW THEREFORE Seller and Buyer agree as follows:

ARTICLE 1
DEFINITIONS, INTERPRETATION AND SCHEDULES

1.1 Definitions and Interpretation

The definitions and certain principles of interpretation that apply to this EPA are set out in Schedule "A".

1.2 Schedules

The following Schedules attached hereto are incorporated into and made a part of this EPA:

Schedule "A" - Definitions and Interpretation

Schedule "B"	-	Project Description
Schedule "C"	-	Form of Annual Operating Plan
Schedule "D"	-	System Interconnection Study Report
Schedule "E"	-	Monthly Energy Shortfall Payment
Schedule "F"	-	Termination Payment
Schedule "G"	-	System Interconnection Guidelines
Schedule "H"	-	Joint Operating Procedure
Schedule "I"	-	Delivery Time Adjustment Table

ARTICLE 2
CONDITIONS PRECEDENT AND TERM

2.1 Conditions Precedent

(a) Except as provided in this Section, this EPA has no legal force until the Conditions Precedent described in Schedule "B" are satisfied by Seller or waived by Buyer. The Conditions Precedent may only be waived by Buyer by notice in writing to Seller.

(b) Seller will:

(i) seek to satisfy each of the Conditions Precedent on or before the Condition Date;

(ii) keep Buyer informed of any circumstances which may result in any of those Conditions Precedent not being satisfied in accordance with their terms; and

(iii) promptly notify Buyer upon satisfaction of any of those Conditions Precedent and provide such supporting evidence as may be reasonably required by Buyer.

(c) If the Conditions Precedent are not satisfied or waived on or before the Condition Date, or it becomes apparent that the Conditions Precedent will not, in the reasonable opinion of Buyer, be satisfied by the Condition Date, the Conditions Precedent will be taken to have failed and Buyer shall be entitled to terminate this EPA, in which event each Party shall release the other from any and all claims, damages, costs, expenses or liabilities whatsoever incurred by it and its Affiliates in relation this EPA provided that (i) Seller shall remain liable for all costs incurred by Buyer in respect of the System Interconnection Study Report, System Upgrade Costs or New Interconnection Facilities Costs and (ii) otherwise each Party shall be responsible for its own costs incurred by it in connection with this EPA.

(d) Section 2.1(a) does not apply to this Article 2, Section 3.5 and Articles 10, 11, 12, 13 and 15 which shall be in full force and effect from the date of this EPA.

2.2 Term

Subject to Section 2.1, this EPA shall commence on the Effective Date and continues for the period specified in Schedule "B", unless it is terminated earlier in accordance with this EPA.

ARTICLE 3
CONSTRUCTION AND OPERATION

3.1 Construction and Operation Costs, Liabilities and Actions

Seller will be fully responsible for the permitting, design, engineering, construction, Interconnection, commissioning, operation, maintenance, reclamation and decommissioning of the Seller's Plant and shall be responsible for all costs, expenses, liabilities and other obligations associated with such activities.

3.2 Standard of Construction and Operation

Except as otherwise consented to in writing by Buyer, such consent not to be unreasonably withheld, conditioned or delayed, Seller will ensure that the location, design, engineering, construction, Interconnection, commissioning, operation and maintenance of the Seller's Plant, are and will be carried out at all times during the Term:

(a) in accordance with the description of the Seller's Plant in Schedule "B" and the information in the Application in all material respects;

(b) in compliance with the Project Standards; and

(c) by qualified and experienced individuals.

The Parties shall conduct their respective operations in accordance with the Joint Operating Procedure.

3.3 Project Changes

Without Buyer's prior written consent, not to be unreasonably withheld, conditioned or delayed Seller will not make any change to:

(a) the Seller's Plant as described in Schedule "B"; or

(b) any other aspects of the Seller's Plant or the information in any System Interconnection Study Report completed for Seller's Plant prior to the Effective Date which would require changes by Buyer to the System Upgrades where such change would increase Buyer's liability for any costs or otherwise increase the obligations or risks of Buyer with respect to the Seller's Plant or any other project.

Seller acknowledges that Buyer may require, as a condition of its consent to any change described in this Section, that Seller agree in writing to reimburse Buyer for any reasonable incremental liability for any losses, costs and damages incurred by Buyer or any third party, with respect to the Seller's Plant or any other project, as a result of any change described in this Section. Buyer may also require that Seller provide performance assurance or security to Buyer in order to ensure that Buyer has no financial exposure in respect of such reimbursement obligation.

3.4 Development Progress Reports

Seller will deliver a Development Progress Report to Buyer on each January 1, April 1, July 1 and October 1 after the Effective Date until Seller's COD. Buyer shall be entitled to request such

additional information as it may reasonably require from time to time in respect of Seller's development of Seller's Plant.

3.5 Responsibility for Upgrade Costs

Seller will be responsible for and shall pay Buyer for all System Upgrade Costs and New Interconnection Facilities Costs in accordance with the following:

(a) the System Interconnection Study Report sets out Buyer's estimate of System Upgrade Costs and the New Interconnection Facilities Costs. Seller shall (i) pay to Buyer in advance an amount equal to such estimate of System Upgrade Costs and New Interconnection Facilities Costs ("**Upgrade Costs Advance**") and/or (ii) provide such other security in form, substance and amount as may be acceptable to Buyer in its Discretion to secure the obligation of Seller to pay such costs ("**Upgrade Costs Security**"). Buyer shall not be required in any circumstances to accept Upgrade Costs Security except in its Discretion. Buyer shall not be required to perform any work or incur any System Upgrade Costs or New Interconnection Facilities Costs where Buyer determines in its Discretion that the amount of Upgrade Costs Advance it has received together with any Upgrade Costs Security is not sufficient to adequately secure the obligation of Seller to pay all System Upgrade Costs and New Interconnection Facilities Costs and Seller shall forthwith provide to Buyer such additional Upgrade Costs Advance and/or Upgrade Costs Security as may be reasonably required by Buyer;

(b) Buyer will exercise Good Industry Practice to perform, or cause to be performed, the work required in respect of the System Upgrades and the New Interconnection Facilities for the Project. Buyer shall be entitled to draw upon the Upgrade Costs Advance and Upgrade Costs Security from time to time in its Discretion to satisfy any System Upgrade Costs and New Interconnection Facilities Costs as and when incurred by Buyer; and

(c) notwithstanding the estimate of System Upgrade Costs and New Interconnection Facilities Costs provided by Buyer to Seller contemplated in Section 3.5(a) or the amount of any Upgrade Costs Advance and Upgrade Costs Security provided by Seller, Seller shall be responsible for and shall pay Buyer the actual System Upgrade Costs relating to the System Upgrades incurred by Buyer. Following the completion of the System Upgrades and the payment in full by Seller of all System Upgrade Costs incurred by Buyer for such work, Buyer shall release to Seller any undrawn portion of the Upgrade Costs Advance and Upgrade Costs Security**.**

3.6 Metering

As part of the System Upgrades and New Interconnection Facilities, Buyer will install and maintain an appropriate Meter installation at the POI, and ensure that such Meter is tested and sealed according to any Measurement Canada standards. Seller will allow Buyer to access the Seller's Plant as may be necessary from time to time to install and maintain the Meter at the POI. If there is any dispute regarding the accuracy of the Meter, either Party may give notice to the other Party of the dispute. In that case, the Parties will resolve the matter in accordance with the *Electricity and Gas Inspection Act* (Canada).

3.7 Insurance

Seller will, at its cost, obtain and maintain (a) policies of commercial general liability insurance with a per occurrence limit of liability not less than $5,000,000, and (b) property insurance, with limits of liability and deductibles consistent with those a prudent owner of a facility similar to the Seller's Plant would maintain and those the Facility Lender may require. All commercial general liability policies must include Buyer, its directors, officers, employees and agents as additional insureds and must contain a cross liability and severability of interest clause. All policies of insurance must include a waiver of subrogation in favour of Buyer. All policies of insurance must be placed with insurers that have a minimum rating of A- (or equivalent) by A.M. Best Company and are licensed to transact business in the Yukon and must be endorsed to provide to Buyer 30 days' prior written notice of cancellation, non-renewal or any material amendment that results in a reduction in coverage. Seller will give Buyer a copy of the insurance certificate(s) for the insurance required to be maintained by Seller under this Section not more than 30 days after the effective date of coverage and promptly upon renewal thereafter. Seller will be responsible for the full amount of all deductibles under all insurance policies required to be maintained by Seller under this Section.

3.8 Seller's COD

(a) Except with Buyer's prior written consent, Seller's COD may not occur earlier than 90 days prior to Target Seller's COD.

(b) Buyer will not be required to incur any incremental expense or other liability of any kind to enable Seller's COD to occur prior to Target Seller's COD.

3.9 Change in Target Seller's COD

If the estimated date for completing the System Upgrades or the New Interconnection Facilities as required to achieve Buyer's COD is later than 90 days prior to the Target Seller's COD, Buyer shall provide notice to Seller of such delay and, provided Seller is not responsible for any delay in completing the System Upgrades or the New Interconnection Facilities (including a failure to pay amounts contemplated in Section 3.5), upon Seller's written request that the Target Seller's COD be postponed, Buyer will postpone the Target Seller's COD to the estimated date for completing the System Upgrades and the New Interconnection Facilities plus 90 days.

3.10 No Liability For Delay

Buyer shall exercise reasonable commercial efforts to achieve Buyer's COD prior to Target Buyer's COD. Buyer will have no liability under this EPA for delays in completion of (a) any System Upgrades or the New Interconnection Facilities, or (b) other work undertaken by Buyer or any of Buyer's Affiliates on the Seller's Plant side of the POI, in each case howsoever arising.

3.11 Outages

(a) **Notice of Seller's Outage** - Seller will notify Buyer of any Outages in Seller's Plant, or changes in any such Outages, by delivering to Buyer an Outage Notice or revised Outage Notice:

(i) promptly in the case of a Forced Outage or a Maintenance Outage;

(ii) not less than 90 days in advance of any Planned Outage, or such shorter time period with Buyer's written consent, such consent not to be unreasonably withheld, delayed or conditioned; and

(iii) promptly in the case of any changes to the duration, start time or end time of any Outage.

(b) **Notice of Buyer's Outage** - In addition to Buyer's reporting requirements under Section 4.8(d), Buyer will notify Seller of any Planned Outages that will result in a Buyer's Distribution/Transmission Constraint or changes in any such Planned Outages, by delivering to Seller an Outage Notice or revised Outage Notice:

(i) not less than 90 days in advance of any such Planned Outage, or such shorter time period with Seller's written consent, such consent not to be unreasonably withheld, delayed or conditioned; and

(ii) promptly in the case of any changes to the duration, start time or end time of any Outage.

(c) **Coordination and Scheduling of Outages -** Seller will coordinate all Planned Outages or Maintenance Outages with Buyer's maintenance schedule or other requirements where such schedule or requirements are publicly available or otherwise notified to Seller.

3.12 Annual Operating Plan

On or before October 31 in each year during the Term, Seller will provide to Buyer its Annual Operating Plan, including any required update to the then current Annual Operating Plan, for the 12-month period commencing on January 1 of the next year. Seller will promptly provide Buyer with a revised Annual Operating Plan from time to time upon Seller becoming aware of any expected material change in the original Annual Operating Plan for that period. The Parties agree the Annual Operating Plan is provided for planning purposes and does not guarantee or limit the quantity or timing of Delivered Energy to the POI.

ARTICLE 4
PURCHASE AND SALE OBLIGATIONS

4.1 Energy prior to Buyer's COD

Subject to satisfaction of all obligations of Seller under this EPA, upon the occurrence of Seller's COD but prior to the occurrence of Buyer's COD, Buyer will not be obligated to purchase, or accept delivery from Seller of, any Energy, provided if Buyer does accept, in its sole discretion, delivery of Energy at the POI, Buyer will pay for such Energy accepted by Buyer prior to Buyer's COD in accordance with Section 5.1.

4.2 Energy after Buyer's COD

From and after Buyer's COD for the remainder of the Term, Seller will sell and deliver all Energy to Buyer at the POI and Buyer will, subject to Sections 4.3 and 4.4, purchase and accept delivery of all Delivered Energy. Buyer will pay for Delivered Energy from and after Buyer's COD in accordance with Section 5.1.

4.3 Limit on Delivered Energy and Capacity

Notwithstanding the foregoing provisions of this Article 4:

(a) in any hour, Buyer will not be obligated at any time to purchase or accept delivery from Seller at the POI of any Energy generated in excess of the Seller's Plant Capacity in such hour (as measured in KWh) and no amount will be payable by Buyer for Delivered Energy in excess of the Seller's Plant Capacity in such hour, whether prior to or after COD, and regardless of whether Buyer consented to and accepted delivery of such Energy at the POI;

(b) in any calendar year, Buyer will not be obligated to purchase or accept delivery from Seller at the POI of any Energy generated in excess of the Project Energy Volume and no amount will be payable by Buyer for Delivered Energy in any such calendar year in excess of the Project Energy Volume in such calendar year, whether prior to or after COD, and regardless of whether Buyer consented to and accepted delivery of such Energy at the POI; and

(c) in determining the total amount of Delivered Energy for a year, month, hour or any other time period under this EPA for any purpose, the amount of Delivered Energy in each hour of such time period will not exceed the Seller's Plant Capacity in such hour, even if Seller delivered to the POI Energy in excess of such amounts, or the Seller's Plant was capable of generating Energy in excess of such amounts.

4.4 Distribution/Transmission Constraints

Buyer will not be in breach or default of its obligations under Sections 4.1, 4.2 or 5.1 if Buyer is not able to accept delivery of Energy at the POI as a result of a Distribution/Transmission Constraint. Buyer will have no liability with respect to a Distribution/Transmission Constraint, except as set out in Section 4.8, if applicable.

4.5 Exclusivity

(a) Seller will not at any time during the Term commit, sell or deliver any Energy (or related Environmental Attributes) to any Person other than Buyer under this EPA. Seller will not use any Energy (or related Environmental Attributes) for any purpose whatsoever except for sale to Buyer under this EPA. These prohibitions do not apply if, and for so long as, Buyer is in breach of its obligations under Section 4.2.

(b) Seller shall not be entitled to interconnect a generating facility to the Seller's Plant and transmit electricity via the Seller's Plant to the POI.

4.6 Custody, Control, Risk of and Title To Energy

Custody, control, risk of, and title to, all Energy (including any Delivered Energy exceeding the limits set out in Section 4.3 even where Buyer has not paid for such excess Delivered Energy) shall pass from Seller to Buyer at the POI. Seller will ensure that all Energy delivered to Buyer under this EPA is free and clear of all liens, claims, charges and encumbrances.

4.7 Line Losses

Seller will be responsible for all Line Losses, costs and liabilities relating to the transmission of Energy and other electricity, if applicable, from the POI to the interconnection point between the New Interconnection Facilities and the Electrical Grid. Such Line Losses shall be determined in accordance with the Line Loss Methodology.

4.8 Distribution/Transmission Constraint

(a) If, in any month after Buyer's COD, Seller is unable to deliver Energy at the POI or Seller's ability to deliver Energy at the POI is reduced solely as a result of a continuous Distribution/Transmission Constraint which exceeds 30 minutes in duration and which:

(i) is not caused by a Planned Outage by Buyer of the Distribution System or Transmission System;

(ii) is not caused by an event beyond the reasonable control of Buyer; and

(iii) is not caused by Seller, the Seller's Plant or anything on Seller's side of the POI;

(a "**Non-Permitted Distribution/Transmission Constraint**") then, notwithstanding that Buyer is excused under Section 4.4 from its obligations under Section 4.2, Buyer shall pay Seller, for each calendar month in which the Non-Permitted Distribution/Transmission Constraint has occurred, the Monthly Energy Shortfall Payment calculated in accordance with Schedule "E" less any costs Seller avoided or, acting reasonably, could have avoided during the Non-Permitted Distribution/Transmission Constraint.

(b) Buyer will not be required to pay any Monthly Energy Shortfall Amount under this Section in any of the following circumstances:

(i) during any period specified as a Seller's Outage in any Outage Notice, revised Outage Notice or in the Annual Operating Plan or during any other period where the Seller's Plant would otherwise not have been operating;

(ii) during any period when either Party is or would be excused, in accordance with Section 14.1, from its obligation to deliver or to accept delivery of Energy as a result of Force Majeure; or

(iii) if Seller has not provided Buyer with an Annual Operating Plan in accordance with Section 3.12 for the year in which the Non-Permitted Distribution/Transmission Constraint occurs.

(c) Seller will maintain accurate and complete Records of all costs Seller avoided or, acting reasonably, could have avoided during the Non-Permitted Distribution/Transmission Constraint and will report all such costs to Buyer and provide Buyer with all information required to calculate such costs.

(d) Buyer will give Seller notice of all Distribution/Transmission Constraints in each month which individually exceed 30 minutes in duration when it provides its monthly statements in accordance with Section 5.3.

(e) In the event of a Dispute by the Parties in respect of the amount of any Monthly Energy Shortfall Amount, the matter shall be resolved in accordance with Article 12.

4.9 Buyer Dispatch/Turn-Down Right

(a) Buyer may at any time during the Term deliver notice to Seller requiring Seller to Dispatch/Turn-Down and Seller will promptly comply with any such direction except to the extent that any operational, technical or regulatory constraint prevents or limits Seller's ability to comply with such direction.

(b) For each hour of the applicable Dispatch/Turn-Down, Buyer will pay Seller an amount equal to:

(i) the price payable for post-COD Delivered Energy under Section 5.1 multiplied by (A) the aggregate of the duration of the applicable Dispatch/Turn-Down (measured as a fraction determined as the aggregate number of minutes in such Dispatch/Turn-Down period divided by 60) multiplied by (B) an amount equal to the positive difference, if any, of (1) the "Non-Permitted Distribution / Transmission Constraint Hourly Deemed Energy" set out in Table E-1 of Schedule "E" for the applicable calendar month less (2) the amount of Delivered Energy in such hour of Dispatch/Turn-Down (the positive difference being the "**Dispatch/Turn-Down Deemed Energy**"); less

(ii) any costs Seller avoided or, acting reasonably, could have avoided during the period of the Dispatch/Turn-Down.

(c) Buyer will not be required to pay any amount in respect of Dispatch/Turn-Down Deemed Energy under this Section in any of the following circumstances:

(i) during any period specified as a Seller's Outage in any Outage Notice, revised Outage Notice or in the Annual Operating Plan or during any other period where the Seller's Plant would otherwise not have been operating;

(ii) during any period when either Party is or would be excused, in accordance with Section 14.1, from its obligation to deliver or to accept delivery of Energy as a result of Force Majeure;

(iii) if Seller has not provided Buyer with an Annual Operating Plan in accordance with Section 3.12 for the year in which the Dispatch/Turn-Down occurs;

(iv) during any other hour when the Seller's Plant would otherwise not have been operating if there had been no Dispatch/Turn-Down notice; or

(v) where Buyer's requirement for Seller to Dispatch/Turn Down is the result of the operation of the Seller's Plant in a manner inconsistent with Section 3.2.

(d) Where Buyer requires the Dispatch/Turn-Down as result of a Non-Permitted Distribution/Transmission Constraint, Section 4.8 will apply.

4.10 Electric Service to Seller

If at any time Buyer delivers electrical energy to service Seller's Plant Load, then such electrical energy shall be accounted and paid for separately under the applicable agreement for such electricity energy services and will not be netted off of Delivered Energy for the purposes of determining amounts payable by Buyer in accordance with Section 5.1.

ARTICLE 5
PRICE AND PAYMENT TERMS

5.1 Energy Price

In each billing period, Buyer shall pay to Seller, for each KWh of Delivered Energy, the Energy Price calculated in accordance with Schedule "B".

5.2 No Further Payment

The amount payable by Buyer as specified in Section 5.1 is the full and complete payment and consideration payable by Buyer for Delivered Energy and for Environmental Attributes.

5.3 Statements and Payment

(a) **Statements**

(i) Buyer will, by the 15th day of each month after the Buyer's COD, deliver to Seller a statement for the preceding month. The statement must indicate, among other things:

(A) the amount of, and price payable for, Delivered Energy for that month;

(B) any amount owing by Buyer in respect of a Non-Permitted Distribution/Transmission Constraint pursuant to Section 4.8;

(C) any Final Amounts owing by either Party to the other Party.

Where there has been any Delivered Energy purchased by Buyer in the period prior to Buyer's COD, the first statement following Buyer's COD shall also account for all amounts payable by Buyer to Seller for such period prior to Buyer's COD. The statement must set out in reasonable detail the manner by which the statement and the amounts shown thereon were computed and be accompanied by sufficient data to enable Seller, acting reasonably, to satisfy itself as to the accuracy of the statement.

(ii) Either Party may give notice to the other Party of an error, omission or disputed amount on a statement within 36 months after the statement was first issued together with reasonable detail to support its claim. After expiry of that 36 month period, except in the case of willful misstatement, fraud or concealment, amounts on a previously issued statement will be considered accurate and amounts which were omitted will be considered to be nil, other than amounts disputed in accordance with this Section within the 36 month period, which will be resolved in accordance with this EPA.

(iii) If Seller gives notice to Buyer of an error, omission or disputed amount on a statement as described in Section 5.3(a)(ii), Seller may direct Buyer to promptly produce new statements for the relevant month(s). The new statements will show the undisputed amount and disputed amount each in a separate statement or will otherwise separate the amounts in a single statement in a manner acceptable to Seller, acting reasonably.

(b) **Payment**

(i) Within 30 days after receipt of a statement delivered under Section 5.3(a), and subject to Section 5.5, Buyer will pay to Seller or Seller will pay to Buyer the amount set out in the statement, except to the extent Seller in good faith disputes all or part of the statement by notice to Buyer as described in Section 5.3(a)(ii).

(ii) If Seller disputes any portion of a statement, the applicable Party must pay the undisputed net amount payable by it pursuant to the statement or, if applicable, the new statement of the undisputed amount described in Section 5.3(a)(iii).

(iii) The Parties will endeavor to resolve any error, omission or disputed amount on a statement amount within 30 days of the notice described in Section 5.3(a)(ii).

(iv) Any amount required to be paid in accordance with this EPA, but not paid by either Party when due, will accrue interest at an annual rate equal to the Prime Rate plus 2%, compounded monthly. Any disputed amount that is found to be payable will be deemed to have been due within 30 days after the date of receipt of the statement which included or should have included the disputed amount.

(c) **Payment Calculations**

(i) For the purpose of all payment calculations under this EPA:

(A) all payment calculations will be rounded to the nearest cent; and

(B) Energy will be expressed in KWh rounded to two decimal places.

(ii) For the purpose of all payment calculations under this EPA, where CPI is to apply, if Statistics Canada (or the then recognized statistical branch of the Canadian Government):

(A) computes, at any time after the Effective Date, the CPI on a basis different to that employed at the Effective Date, then the CPI will be converted using the appropriate formula recommended by Statistics Canada (or the then recognized statistical branch of the Canadian Government);

(B) at any time ceases to publish or provide the CPI, then the provisions of Section 2.7 of Schedule "A" will apply;

(C) has not published the CPI for a relevant period at the time Buyer is required to provide Seller with a statement, Seller will prepare the invoice based on the CPI in effect at the time the invoice is issued and

when the CPI for the relevant period is published, Buyer will recalculate the invoice amounts in the next succeeding invoice and will include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation; or

(D) recalculates the CPI within 36 months after an invoice affected by that CPI calculation has been issued, then Buyer will recalculate the invoice amounts for the relevant period in the next succeeding invoice and will include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation.

5.4 Taxes

All dollar amounts in this EPA do not include any value added, consumption, commodity or similar taxes, including GST and any successor thereto, which, if applicable, will be added to each statement and paid by Buyer.

5.5 Set-off

If Buyer and Seller each owe the other an amount under this EPA in the same month, then such amounts with respect to each Party will be aggregated and the Parties may discharge their obligations to pay through netting, in which case the Party, if any, owing the greater aggregate amount will pay to the other Party the difference between the amounts owed, provided that this Section applies only to any purchase price for Delivered Energy and any Final Amount owing by either Party to the other Party. Except as otherwise expressly provided herein, each Party reserves all rights, counterclaims and other remedies and defenses which such Party has, or may be entitled to, arising from or related to this EPA.

5.6 Change in Law and GRA Cost Recovery

(a) If at any time after the Effective Date:

(i) the costs to Buyer of complying with its obligations under this EPA are, as a result of one or more Changes in Law, increased or decreased (including, for greater certainty, any increase of the obligations or risks of Buyer with respect to the Seller's Plant, but excluding any increase of the obligations or risks of Buyer with respect to the System Upgrades or New Interconnection Facilities); or

(ii) the costs to Buyer of complying with its obligations under this EPA which were of a category or type previously recovered under a General Rate Application are determined under a General Rate Application to no longer be approved for recovery from Buyer's customers in such General Rate Application;

then, to the extent that Buyer would not have incurred such costs except for the Seller's Project and/or the entering into of this EPA, the amount payable by Buyer as specified in Section 5.1 shall be adjusted by the amount necessary to reflect those changed costs which Buyer is unable to recover from Buyer's customers in a General Rate Application.

(b) For each relevant event in Section 5.6(a)(i) or 5.6(a)(ii), Buyer shall provide Seller with a statement setting out such information as is reasonably necessary to demonstrate that such an event has occurred, the reasonableness and necessity of the measures taken by

Buyer in relation to the event, its efforts to mitigate the costs associated with such event including reasonable efforts of Buyer to recover such costs from its customers in a General Rate Application, the nature and extent of any increase or decrease in the amount payable by Seller as specified in Section 5.1, and any such other information as may be reasonably requested by Seller.

(c) If in Seller's view there has been a Change in Law that may decrease Buyer's costs, Seller may request Buyer to demonstrate how such Change in Law has affected its costs under this EPA by providing the applicable information contemplated in Section 5.6(b).

(d) The payments between the Parties shall thereafter be adjusted effective as of the date such event in Section 5.6(a)(i) or 5.6(a)(ii) affects the costs of Buyer hereunder.

(e) If there is any Dispute between the Parties with respect to this Section 5.6, including as to the appropriate increase or decrease in any payments between the Parties under this Agreement, the Dispute shall be resolved in accordance with Article 12.

ARTICLE 6
ENVIRONMENTAL ATTRIBUTES

6.1 Environmental Attributes

Seller hereby transfers, assigns and sets over to Buyer all right, title and interest in and to the Environmental Attributes. Seller will ensure that all Environmental Attributes transferred to Buyer under this EPA are free and clear of all liens, claims, charges and encumbrances. Seller shall use commercially reasonable efforts to (i) provide information reasonably requested by Buyer in relation to such Environmental Attributes, including as may be required to allow Buyer to verify or certify that such Environmental Attributes exist or have been created and (ii) assist in having Seller's Plant certified, licensed, qualified or approved under any rules, regulations, programs or applicable Laws of any Governmental Authority or independent certification agency in respect of Environmental Attributes, provided that Buyer shall pay Seller all costs reasonably incurred by Seller in respect of the same. Any failure by Seller to exercise such commercially reasonable efforts under this Section 6.1 is a "material default" for the purposes of this EPA, and Buyer may terminate this EPA under Section 9.1(j).

ARTICLE 7
EPA ADMINISTRATION, RECORDS AND AUDITS

7.1 Records

Each of Buyer and Seller will prepare and maintain all Records, or duplicates of such Records, at Buyer's head office or local Yukon office or the Seller's Plant, as applicable, or following the expiry of the Term or the earlier termination of this EPA, at such other location as may be agreed in writing between the Parties, for a period of not less than 7 years from the date on which each such Record is created. The Audit Parties may take copies of such Records for the purposes of an inspection or audit under Section 7.2.

7.2 Inspection and Audit Rights

For the sole purpose of verifying:

(a) compliance with this EPA;

(b) the accuracy of statements, supporting information and calculations delivered by a Party under this EPA;

(c) the qualification of the Seller's Plant and the Energy for the Environmental Certification; or

(d) the liability of Seller for System Upgrades Costs and New Interconnection Facilities Costs,

Buyer or Seller, as applicable, will, on reasonable prior written notice from either Party desiring to conduct an audit, provide the Audit Parties with prompt access during normal business hours to (i) in respect of Buyer, Buyer's records solely relating to this EPA, or (ii) in respect of Seller, Seller's Plant and all records relating to the Seller's Plant, including any Seller Confidential Information, as applicable, to enable the Audit Parties to conduct an inspection or audit thereof. The Audit Parties will exercise any access and audit rights under this Section in a manner that minimizes disruption to the operation of the Party subject to the audit. The audit rights contained in this Section 7.2 shall be subject to the limitations set forth in Section 5.3.

7.3 Seller Consents

Seller will promptly provide any consents required to enable any of the Audit Parties to make enquiries with any Governmental Authority or any Person administering the Environmental Certification concerning any or all of the following: (a) the qualification of the Seller's Plant and the Energy for Environmental Certification, the status of the Environmental Certification and copies of any audits, inspections or reports prepared in connection with the Environmental Certification; and (b) compliance by Seller with Laws and Permits applicable to the Seller's Plant.

ARTICLE 8
FIRST NATION CLAIMS

8.1 Notification of First Nation Claim

Given the ownership and location of the Project, Seller and Buyer do not expect any First Nation Claims. However, if Buyer or Seller receives or obtains evidence of a First Nations Claim, it will notify the other Party as soon as practicable.

8.2 Obligation to Consult

If Buyer receives, obtains evidence or becomes aware of a First Nations Claim, it may direct Seller, at Seller's cost, to:

(a) consult with the First Nations making the First Nation Claim, or, if requested by Buyer, assist Buyer in the consultation process;

(b) take any measures Seller deems necessary to address, prevent, mitigate, compensate or otherwise accommodate any Potential Impacts provided the measures are consented to in advance by Buyer and the First Nations making the First Nation Claim; and

(c) provide regular written reports to Buyer concerning Seller's compliance with this Section, as may be reasonably requested by Buyer.

8.3 Seller Termination for First Nation Claim

At any time prior to Buyer's COD, if:

(a) within 60 days of Buyer receiving, obtaining evidence or becoming aware of a First Nations Claim, Buyer does not make a direction to Seller as contemplated in Section 8.2;

(b) Buyer notifies Seller in writing that it will not make a direction to Seller as contemplated in Section 8.2; or

(c) after consultation with the First Nations making the First Nation Claim it becomes clear that the measure(s) necessary for Seller to resolve the First Nation Claim or to address, prevent, mitigate, compensate or otherwise accommodate any Potential Impacts would, in Seller's discretion, impose a commercially unreasonable cost on Seller, or would require the consent of Buyer under this EPA or agreement by Buyer to amend this EPA in order to address any Potential Impacts and such consent or agreement to amend is not provided within 60 days after Seller's request to Buyer,

then Seller may terminate this EPA on notice to Buyer. Such termination will be effective 30 days after the date of delivery of such notice of termination unless otherwise agreed by the Parties. A termination by Seller under this Section will, for all purposes of this EPA, be treated in the same manner as a termination by Seller under Section 9.3(c) of this EPA (including the obligations of Seller under Section 9.7). The termination of this EPA is the exclusive remedy to which Seller may be entitled to if Seller elects to terminate this EPA under this Section.

8.4 Buyer Termination for First Nation Claim

At any time prior to Buyer's COD, if Buyer receives, obtains evidence or becomes aware of a First Nations Claim, Buyer may, at its sole discretion, terminate this EPA on notice to Seller. Such termination will be effective 30 days after the date of delivery of such notice of termination unless otherwise agreed by the Parties. Upon a termination by Buyer under this Section 8.4, Seller shall reimburse Buyer for costs or liabilities described in Sections 9.7(a), (b) and (c). The reimbursement by Seller of such costs or liabilities, the indemnification by Seller contemplated in Section 8.5 and the termination of this EPA are the exclusive remedies to which Buyer may be entitled to if Buyer elects to terminate this EPA under this Section.

8.5 Seller Indemnity for First Nation Claim

Seller shall indemnify and hold Buyer and its Affiliates harmless from any and all claims, damages, costs, expenses, or liabilities whatsoever incurred by Buyer and its Affiliates in relation to such First Nation Claim and such indemnity shall survive termination of this EPA.

ARTICLE 9
TERMINATION

9.1 Termination by Buyer

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Buyer may have under this EPA or at law or in equity in respect of any of the following events, Buyer may terminate this EPA by notice to Seller if:

(a) Seller's COD does not occur within 730 days following Target Seller's COD for any reason whatsoever (including Force Majeure), provided that Buyer may terminate this EPA under this provision only if Buyer delivers a termination notice prior to Seller's COD; or

(b) at any time after Buyer's COD, Seller fails to deliver at least an average of 25% of the aggregate Projected Monthly Energy as set out in Schedule "E" to Buyer over all hours in a period of 730 continuous days for any reason whatsoever (including Force Majeure, a Distribution/Transmission Constraint), but excluding a Non-Permitted Distribution/ Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or

(c) at any time after Buyer's COD, Buyer is unable to accept delivery of Energy at the POI for a period of 730 continuous days due to Force Majeure invoked by Buyer or a Distribution/ Transmission Constraint other than a Non-Permitted Distribution/ Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or

(d) Seller breaches Section 4.5; or

(e) Seller fails to complete any application, payment, filing, study, document or other step in the process for interconnecting the Seller's Plant to the Distribution System, Transmission System or New Interconnection Facilities, as applicable, in accordance with the requirements of, and within the time limits, including any cure periods, specified by Buyer, and such failure could reasonably be expected to have an adverse impact on Buyer or any third party; or

(f) any System Interconnection Study Report completed after the Effective Date contains information that is inconsistent with the description of the Seller's Plant in Schedule "B" and Seller has not received Buyer's consent under Section 3.3 for the change to Schedule "B"; or

(g) Seller is Bankrupt or Insolvent; or

(h) Seller, as a result of an act or omission of Seller, ceases to be exempt from regulation as a "public utility" as defined in the *Public Utilities Act* with respect to the Seller's Plant and the sale of Energy to Buyer under this EPA, and the loss of such exemption could reasonably be expected to have an adverse effect on the benefit to Buyer of this EPA; or

(i) an amount due and payable by Seller to Buyer under this EPA remains unpaid for 30 days after its due date and such default has not been cured within 30 days after Buyer has given notice of the default to Seller; or

(j) Seller is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by Buyer to Seller of the default Seller has cured the default or, if the default cannot be cured within that 30 day period, Seller demonstrates to the reasonable satisfaction of Buyer that Seller is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time. A "material default" includes any purported Assignment of this EPA without the consent of Buyer.

Any termination pursuant to this Section will be effective immediately upon delivery of the notice of termination to Seller.

9.2 Notice of Termination Event

Seller will notify Buyer promptly if Seller is Bankrupt or Insolvent or if there is a material risk that Seller will become Bankrupt or Insolvent or if Seller has defaulted under any agreement with a Facility Lender or if any Permit or land tenure agreement for the Seller's Plant is terminated or expires.

9.3 Termination by Seller

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Seller may have under this EPA or at law or in equity in respect of any of the following events, Seller may terminate this EPA by notice to Buyer if:

(a) after Buyer's COD, Buyer has not accepted delivery of Energy for a period of 730 continuous days due to an event described in Section 4.4 or any event of Force Majeure and Seller is not entitled to receive any payment pursuant to Section 4.8 in respect of that period; or

(b) the Seller's Plant has suffered major damage where the cost to repair the damage exceeds the net present value (using the Present Value Rate) of the expected revenues under the EPA for the remainder of the Term less the net present value (using the Present Value Rate) of the estimated operating and maintenance costs for the Seller's Plant for the remainder of the Term; or

(c) Seller has been unable to achieve Seller's COD for a period of 730 days after Target Seller's COD or has been unable to deliver Energy to the POI for a period of 730 continuous days after Seller's COD in either case solely as a result of Force Majeure invoked by Seller or a Distribution/Transmission Constraint other than a Non-Permitted Distribution/Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or

(d) Buyer is Bankrupt or Insolvent; or

(e) except where an amount has been disputed in the manner specified in Section 5.3(a)(ii), an amount due and payable by Buyer to Seller under this EPA remains unpaid for 30 days

after its due date and such default has not been cured within 30 days after Seller has given notice of the default to Buyer; or

(f) Buyer is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by Seller to Buyer of the default Buyer has cured the default or, if the default cannot be cured within that 30 day period, Buyer demonstrates to the reasonable satisfaction of Seller that Buyer is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time.

Any termination pursuant to this Section will be effective immediately upon delivery of the notice of termination to Buyer.

9.4 Termination by Buyer for Convenience

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Buyer may have under this EPA or at law or in equity in respect of any of the following events, Buyer may terminate this EPA for convenience upon 90 days prior notice to Seller.

9.5 Effect of Termination

Upon expiry of the Term or earlier termination of this EPA in accordance with its terms:

(a) the Parties may pursue and enforce any rights and remedies permitted by law or equity in respect of any prior breach or breaches of this EPA and may enforce any liabilities and obligations that have accrued under this EPA prior to the expiry of the Term or the date of termination or that are stated to arise on termination of this EPA, subject to any express restrictions on remedies and limitations or exclusions of liability set out in this EPA;

(b) both Parties will remain bound by Section 3.5 with respect to the satisfaction of residual obligations for the period prior to termination or that are specified to arise on, or continue following, termination, and Sections 12.1 and 13.1 associated with Delivered Energy prior to termination of this EPA; and

(c) Seller will remain bound by Sections 7.1 and 7.2 for a period of 36 months following expiry or termination of this EPA;

and, in all such cases, both Parties will remain bound by any other provisions necessary for the interpretation and enforcement of the foregoing provisions.

9.6 Buyer Payment on Termination

If Seller terminates this EPA under any of Sections 9.3(d), 9.3(e) or 9.3(f) or Buyer terminates this EPA for convenience under Section 9.4, Buyer will pay to Seller an amount equal to the applicable Termination Payment due at the time of termination determined in accordance with Schedule "F".

9.7 Seller Payment on Termination

If Buyer terminates this EPA on or before 90 days after Seller's COD or Seller terminates this EPA on or before Buyer's COD under any of Sections 9.3(a), 9.3(b) or 9.3(c), Seller will, within 30 days after receipt of an invoice from Buyer, reimburse Buyer for:

(a) all System Upgrade Costs and New Interconnection Facilities Costs incurred by Buyer, or which Buyer has become contractually obligated to pay, prior to the termination of the EPA including System Upgrade Costs and New Interconnection Facilities Costs Seller would otherwise be responsible for under Section 3.5;

(b) any incremental liability for System Upgrade Costs and New Interconnection Facilities Costs which Buyer will incur as a result of the termination of this EPA; and

(c) any System Upgrade Costs and New Interconnection Facilities Costs which Seller is responsible for under any reimbursement agreement pursuant to Section 3.3.

9.8 Calculation and Payment

Buyer will pay any amount which it owes under Section 9.6 within 30 Business Days after the date of delivery of an invoice by Seller to Buyer. Any amounts owing by Seller to Buyer under this EPA will be netted against any amount owing by Buyer to Seller under Section 9.6.

9.9 Exclusive Remedies

Payment by Buyer of the amount determined under Section 9.6 is the exclusive remedy to which Seller is entitled, and Buyer's limit of liability, for termination of this EPA by Seller pursuant to any of Sections 9.3(d), 9.3(e) or 9.3(f). Subject to Section 9.4 and 9.7, termination of this EPA is the exclusive remedy to which Buyer or Seller, as the case may be, is entitled if Buyer or Seller elects to exercise its right to terminate this EPA under any of Section 9.1, 9.3(a), 9.3(b) or 9.3(c). For greater certainty, subject to Section 9.4 and 9.7, Seller will not be required to pay any termination payment on termination by Buyer of this EPA. Neither Party will have any right to terminate this EPA except as expressly set out herein.

ARTICLE 10
REPRESENTATIONS AND WARRANTIES

10.1 Seller's Representations

Seller represents and warrants to Buyer, and acknowledges that Buyer is relying on those representations and warranties in entering into this EPA, as follows:

(a) Seller is a corporation formed under the laws of the Yukon, is validly existing and is in good standing under the laws of the Yukon, is lawfully authorized to carry on business in the Yukon, and has full corporate power, capacity and authority to enter into and to perform its obligations under this EPA;

(b) this EPA constitutes a valid and binding obligation of Seller enforceable against Seller in accordance with its terms; and

(c) this EPA has been duly authorized, executed and delivered by Seller.

10.2 Buyer's Representations

Buyer represents and warrants to Seller, and acknowledges that Seller is relying on those representations and warranties in entering into this EPA, as follows:

(a) Buyer is a corporation formed under the laws of the Yukon, is validly existing and is in good standing under the laws of the Yukon, is lawfully authorized to carry on business in the Yukon, and has full corporate power, capacity and authority to enter into and to perform its obligations under this EPA;

(b) this EPA constitutes a valid and binding obligation of Buyer enforceable against Buyer in accordance with its terms; and

(c) this EPA has been duly authorized, executed and delivered by Buyer.

ARTICLE 11
LIABILITY LIMITATIONS

11.1 Limit of Liability

Buyer's liability for damages for any failure to take or pay for Delivered Energy under this EPA is limited to the amount payable by Buyer for that Delivered Energy under Article 5, amounts owing under Sections 4.8 and any interest thereon calculated under this EPA.

11.2 Consequential Damages

Neither Party will be liable to the other Party for any special, incidental, exemplary, punitive or consequential damages with respect to, arising out of, relating to or in any way connected with a Party's performance or non-performance under this EPA.

ARTICLE 12
DISPUTES

12.1 Dispute Resolution Procedure

Any dispute, controversy or claim arising out of or relating to this EPA ("**Dispute**") shall be exclusively and finally resolved in accordance with the dispute resolution procedure set forth in this Article 12 (the "**Dispute Resolution Procedure**").

12.2 Commencement of the Dispute Resolution Procedure

The Parties shall make reasonable efforts to first resolve any Dispute. If a Dispute cannot be resolved by the Parties, then either Party may initiate the Dispute Resolution Procedure by giving notice of the Dispute to the other Party (the "**Notice of Dispute**"). The Notice of Dispute shall contain a brief statement of the nature of the Dispute, set out the relief requested, and request that the Dispute Resolution Procedure be commenced.

12.3 Negotiations

Upon the submission of a Notice of Dispute pursuant to Section 12.2, each of the Parties shall refer the Dispute to a designated senior management executive with the authority to negotiate a

settlement of the Dispute for that Party (the "**Senior Management Executives**"). The Senior Management Executives of the Parties shall attempt to resolve the Dispute within 30 days from the date on which the Notice of Dispute was issued, or such longer period as the Senior Management Executives may otherwise unanimously agree. If the Senior Management Executives unanimously agree upon a resolution of the Dispute, such resolution shall be memorialized in a written settlement agreement mutually acceptable to the Parties and shall be binding on the Parties.

12.4 Arbitration

If a Dispute is not resolved by Senior Management Executives within 30 days from receipt of a Notice of Dispute (or such longer period as the Senior Management Executives may otherwise agree in writing), the Dispute shall, at the request of either Party, be resolved by binding arbitration under the Rules of Arbitration of the International Chamber of Commerce (the "**ICC Rules**"), except to the extent of conflicts between the ICC Rules and the provisions of this EPA, in which event the provisions of this EPA shall prevail. The following provisions shall apply to an arbitration commenced pursuant to this Section 12.4:

(a) the number of arbitrators shall be one;

(b) the place, or legal seat, of the arbitration shall be Whitehorse, Yukon;

(c) the language to be used in the arbitral proceedings shall be English;

(d) all awards issued by the arbitrator shall be final, non-appealable and binding on the Parties. Any award may be filed in any court of competent jurisdiction and may be enforced by a Party as a final judgment in such court. The Parties expressly waive, to the maximum extent permitted by law, any right of appeal of any award or reference of any matter to any court, other than as may be necessary to recognize or enforce an award;

(e) the arbitrator shall be guided by the International Bar Association's Rules on the Taking of Evidence in International Commercial Arbitration;

(f) the Parties shall request that the arbitrator render its final award within 12 months of the commencement of the arbitration, or as soon as possible thereafter, provided that no award shall be invalid if it is not rendered within the time period herein specified;

(g) any award for monetary damages shall be made and payable in Canadian Dollars and may include interest from the date of any breach or violation of this EPA until paid in full at the rate determined by the arbitrator;

(h) the Parties agree that any arbitration carried out hereunder shall be kept private and confidential, and that the existence of the proceedings and any element of it (including all awards, the identity of the Parties and all witnesses and experts, all materials created for the purposes of the arbitration, all testimony or other oral submissions, and all documents produced by a Party that were not already in the possession of the other Party) shall be kept confidential, except (i) with the consent of the Parties, (ii) to the extent disclosure may be lawfully required in bona fide judicial proceedings relating to the arbitration, (iii) where disclosure is lawfully required by a legal duty, and (iv) where such information is already in the public domain other than as a result of a breach of this clause. The Parties

also agree not to use any information disclosed to them during the arbitration for any purpose other than in connection with the arbitration;

(i) where a Dispute relates to the EPA, the Parties shall agree to consolidate the matters in Dispute under such agreements in a single arbitration;

(j) the Parties agree that during the resolution of a Dispute pursuant to this Article 12, the Parties shall continue to perform their obligations under this EPA, provided that such performance shall be without prejudice to the rights and remedies of the Parties and shall not be read or construed as a waiver of a Party's right to claim for recovery of any loss, costs, expenses or damages suffered as a result of the continued performance of this EPA; and

(k) each Party will be responsible for its own costs under this Article 12, subject to the award of an arbitrator.

ARTICLE 13
CONFIDENTIALITY

13.1 Confidentiality

(a) **Additional Confidentiality Obligation** - During the Term and for two years thereafter:

(i) Buyer will treat as confidential, and will not disclose to any third Person, Seller Confidential Information, and

(ii) Seller will treat as confidential, and will not disclose to any third Person, Buyer Confidential Information.

(b) **Disclosure of Confidential Information** - Notwithstanding Section 13.1(a) above:

(i) Seller may also disclose Buyer Confidential Information and Buyer may disclose Seller Confidential information in the following circumstances:

(A) disclosures expressly authorized under this EPA or otherwise set out in this EPA;

(B) disclosures to enable a Party to fulfill its obligations under the EPA;

(C) disclosure in any arbitration or legal proceedings for the enforcement of the EPA;

(D) disclosure to the Party's directors, officers, employees, Facility Lenders, consultants and advisors, and purchasers of the Environmental Attributes, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality;

(E) subject to Section 13.1(b)(ii)(D), disclosure required to be made by a Party by an order of a court, a regulatory agency or a tribunal or under any law, regulatory requirements or any requirement of any stock exchange that is binding upon a Party, provided that (i) to the extent

reasonably practicable, the Party intending to make such disclosure gives reasonable notice to the other Party before make the disclosure, and (ii) limits the disclosure to that required by the applicable order, Laws or regulatory or stock exchange requirement;

(F) disclosure to a third Person if such information was known by that third Person before disclosure by Buyer or Seller, as the case may be, provided the third Person did not know of the information as a result of a breach of the non-disclosure obligations in this EPA; or

(G) disclosure with the consent of Buyer, in the case of Buyer Confidential Information, or Seller, in the case of Seller Confidential Information.

(ii) Buyer may disclose Seller Confidential Information in the following circumstances:

(A) disclosure to Buyer's Affiliates or to a third Person, and their respective employees, consultants and advisors, for the purpose of reselling or marketing any Energy, including disclosure of Seller Confidential Information by such Affiliate or third Person to those who have purchased or may purchase the Energy;

(B) for purposes other than those described in Section 13.1(b)(i), to Buyer's Affiliates and to any directors, officers, employees, consultants and advisors of any Affiliates, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality;

(C) to any ministers, deputy ministers, servants or employees of the Yukon or the federal government, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality; or

(D) disclosure in any regulatory proceeding, whether related to this EPA or not, to the extent that Buyer considers disclosure is necessary or desirable to support its position in such proceeding.

ARTICLE 14
FORCE MAJEURE

14.1 Force Majeure

(a) If there is a Force Majeure affecting a Party's ability to perform an obligation under this EPA, and that Party wishes to declare a Force Majeure, that Party will promptly notify the other Party of the Force Majeure. The notice of Force Majeure must identify the nature of the Force Majeure, the date the Force Majeure commenced, the expected duration of the Force Majeure, and the particular obligations affected by the Force Majeure. If (i) a notice of Force Majeure is provided in accordance with this Section, (ii) the event in question is in fact an event of Force Majeure as defined in this EPA, and (iii) the event of Force Majeure commenced on the commencement date in the notice of Force

Majeure, then the Force Majeure will be deemed to have been invoked as of the commencement date stated in the notice.

(b) Neither Party will be in default of any obligation under this EPA if a Party is unable to perform that obligation due to an event or circumstance of Force Majeure, provided notice is delivered in accordance with this Section and the circumstances are, in fact, an event or circumstance of Force Majeure.

(c) Subject to any limitations expressly set out in this EPA, the time for performance of such obligation will be extended by the number of days that Party is unable to perform such obligation as a result of the event or circumstance of Force Majeure. The Party invoking Force Majeure will make commercially reasonable efforts to promptly remove the Force Majeure and will promptly respond to any inquiry from the other Party regarding the efforts being undertaken to remove the Force Majeure and will give prompt notice of the end of the Force Majeure.

ARTICLE 15
GENERAL PROVISIONS

15.1 Independence

The Parties are independent contractors, and nothing in this EPA or its performance creates a partnership, joint venture or agency relationship between the Parties.

15.2 Enurement

This EPA enures to the benefit of the Parties, their successors and their permitted assigns.

15.3 Assignment

(a) Seller may not assign this EPA except with the prior consent of Buyer, which consent may not be unreasonably withheld, conditioned or delayed provided such Assignment is to a Facility Lender. Any Assignment (other than an Assignment to a Facility Lender) is subject to the assignee entering into and becoming bound by this EPA, assuming all the obligations and liabilities of Seller under this EPA arising both before and after the Assignment, and providing the representations and warranties set out in Section 10.1 effective as at the time of Assignment, and Seller not being in default under this EPA. Unless agreed to in writing by Buyer, Seller shall remain jointly and severally liable with the assignee for all obligations of Seller under this EPA.

(b) Any request by Seller for Buyer's consent under Section 15.3(a) must be delivered to Buyer not less than 30 days before the date of the proposed Assignment. A request under this Section must be accompanied by such information as reasonably required by Buyer to assess the request for consent including the name, address and ownership structure of the assignee, details of any consultation with First Nations that may be impacted by the Seller's Plant or the Assignment with respect to the proposed Assignment, list of the directors and officers of the assignee and information concerning the assignee's operations, experience and financial status.

(c) If Seller seeks consent to Assign this EPA to a Facility Lender, Buyer may require, as a condition of its consent to the Assignment, that Seller and the Facility Lender enter into a

Lender Consent Agreement with Buyer containing customary provisions. If required by a Facility Lender, Buyer will enter into a Lender Consent Agreement with the Facility Lender and Seller containing customary provisions. Seller will reimburse Buyer for all costs reasonably incurred by Buyer in connection with any request by Seller for Buyer's consent pursuant to Section 15.3(a).

15.4 Entire Agreement

This EPA contains the entire agreement between the Parties with respect to the purchase and sale of Energy and supersedes all previous communications, understandings and agreements between the Parties with respect to the subject matter hereof. There are no representations, warranties, terms, conditions, undertakings or collateral agreements express, implied or statutory between the Parties other than as expressly set out in this EPA.

15.5 Amendment

This EPA may not be amended except by an agreement in writing signed by both Parties.

15.6 No Waiver

Other than in respect of the specific matter or circumstance for which a waiver is given, and except as otherwise specified in this EPA, no failure by a Party to enforce, or require a strict observance and performance of, any of the terms of this EPA will constitute a waiver of those terms or affect or impair those terms or the right of a Party at any time to enforce those terms or to take advantage of any remedy that Party may have in respect of any other matter or circumstance.

15.7 Notices

Any notice, consent, waiver, declaration, request for approval or other request, statement or bill that either Party may be required or may desire to give to the other Party under this EPA must be in writing addressed to the other Party at the address for that Party stated in Schedule "A" and:

(a) notices under Section 14.1, Article 8 and Article 9 must be delivered by hand or by a courier service during normal business hours on a Business Day and a notice so delivered will be deemed to have been delivered on that Business Day;

(b) all notices other than notices described in Section 15.7(a) may be delivered by email during normal business hours on a Business Day and a notice so delivered will be deemed to have been delivered on that Business Day; and

(c) either Party may change its address for notices under Section 3 of Schedule "A" to this EPA by notice to the other Party.

15.8 Interconnection Notices

Nothing in the System Interconnection Guidelines and no exercise of any right thereunder, restricts or otherwise affects any right, obligation or liability of either Party under this EPA, except to the extent set out expressly herein, and no notice, consent, approval or other communication or decision under or in relation to the System Interconnection Guidelines will

constitute or be relied upon as a notice, consent, approval or communication or decision under this EPA.

15.9 Commodity Contract/Forward Contract

The Parties agree and intend that this EPA constitutes an "eligible financial contract" under the *Bankruptcy and Insolvency Act* (Canada) and *Companies' Creditors Arrangement Act* (Canada).

15.10 Further Assurances

Each Party will, upon the reasonable request of the other Party, do, sign or cause to be done or signed all further acts, deeds, things, documents and assurances required for the performance of this EPA including, in the case of Seller, completing any registration process required in respect of Environmental Attributes as requested by Buyer.

15.11 Severability

Any provision of this EPA which is illegal or unenforceable will be ineffective to the extent of the illegality or unenforceability without invalidating the remaining provisions of this EPA.

15.12 Counterparts

This EPA may be executed in counterparts, each of which is deemed to be an original document and all of which are deemed one and the same document.

[Signature Page Follows]

IN WITNESS WHEREOF each Party by its duly authorized representative(s) has signed this EPA effective as of the date set out on page one of this EPA.

NOMAD CONTRACTING & ELECTRICAL SERVICES LTD.

Per: _____
Sebastien Roy

Per: _____
Anne-Marie Legare

YUKON ENERGY CORPORATION

Per: _____
Andrew Hall
President and Chief Executive Officer

Per: _____
Michael Brandt
Vice-President

IN WITNESS WHEREOF each Party by its duly authorized representative(s) has signed this EPA effective as of the date set out on page one of this EPA.

NOMAD CONTRACTING & ELECTRICAL SERVICES LTD.	**YUKON ENERGY CORPORATION**
Per: _____	Per: _____ 27 August 2020
Sebastien Roy	Andrew Hall President and Chief Executive Officer
Per: _____	Per: _____
Anne-Marie Legare	Michael Brandt VP, Business & Corporate Development

SCHEDULE "A"

DEFINITIONS AND INTERPRETATION

1. DEFINITIONS

References in a Schedule to a section or Section mean a section or Section of this EPA, and not a Schedule, unless otherwise stated. The following words and expressions wherever used in this EPA have the following meaning:

1.1 "**Affiliate**" means, with respect to any Party or any third Person, any Person directly or indirectly Controlled by, Controlling, or under common Control with, such Party or the third Person.

1.2 "**Annual Operating Plan**" means a 12-month operating plan for the Seller's Plant that includes for term of each operating plan, (a) a schedule of the expected total deliveries of Energy at the POI in each month and (b) a schedule of any Planned Outages of the Seller's Plant expected by Seller. The Annual Operating Plan will be consistent with Good Industry Practice and shall be substantially in the form attached hereto as Schedule "C", subject to such modifications thereto as may be reasonably required by Buyer.

1.3 "**Application**" means the application and all supporting documents and information with respect to the Seller's Plant filed by Seller with Buyer in the Standing Offer Program.

1.4 "**Assign**" or "**Assignment**" means to assign or dispose of this EPA or any direct or indirect interest in this EPA, in whole or in part, for all or part of the Term and, without limiting the foregoing, each of the following is deemed to be an Assignment of this EPA by Seller:

(a) any sale or other disposition of all or a substantial part of Seller's ownership interest in the Seller's Plant, or of all or any interest of Seller in this EPA or revenue derived from this EPA;

(b) any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's Plant or Seller's ownership interest therein; and

(c) any change of Control, merger, amalgamation or reorganization of Seller.

1.5 "**Audit Parties**" means the applicable Party conducting an audit under this EPA and its Affiliates, representatives, consultants, advisors and any other third Person retained in respect of the applicable audit.

1.6 "**Bankrupt or Insolvent**" means, with respect to a Person:

(a) the Person has started proceedings to be adjudicated a voluntary bankrupt or consented to the filing of a bankruptcy proceeding against it;

(b) the Person has filed a petition or similar proceeding seeking reorganization, arrangement or similar relief under any bankruptcy or insolvency law;

(c) a receiver, liquidator, trustee or assignee in bankruptcy has been appointed for the Person or the Person has consented to the appointment of a receiver, liquidator, trustee or assignee in bankruptcy;

(d) the Person has voluntarily suspended the transaction of its usual business; or

(e) a court of competent jurisdiction has issued an order declaring the Person bankrupt or insolvent.

1.7 "**Business Day**" means any calendar day which is not a Saturday, Sunday or Yukon statutory holiday.

1.8 "**Buyer**" means Yukon Energy Corporation and its successors and permitted assigns.

1.9 "**Buyer Confidential Information**" means technical or commercial information disclosed by Buyer to Seller that Buyer directs, and clearly marks, as confidential, including the System Interconnection Guidelines and this EPA but excluding information that (i) is or becomes in the public domain, other than as a result of a breach of this EPA by Seller, or (ii) is known to Seller before disclosure to it by Buyer, or becomes known to Seller, thereafter by way of disclosure to Seller by any other Person who is not under an obligation of confidentiality with respect thereto.

1.10 "**Buyer's COD**" shall occur when the System Upgrades have been completed and Buyer provides a notice of completion of the same to Seller.

1.11 "**Change in Law**" means (a) the enactment, adoption, promulgation, modification or repeal of any applicable Laws or any change in the interpretation or administration of any applicable Laws resulting from a decision of a Governmental Authority which occurs after the Effective Date; but in each case excluding a Change in Law relating to income tax, or (b) the requirement for a new Permit (including due to a change in the circumstances in which a Permit is required), a change in the terms of any Permit after the date such Permit is granted, or any change in the interpretation or administration of any Permits resulting from a decision of a Governmental Authority.

1.12 "**Condition Date**" means the date specified as such in Schedule "B".

1.13 "**Conditions Precedent**" means those conditions precedent set out in Schedule "B".

1.14 "**Control**" of any Person means:

(a) with respect to any corporation or other Person having voting shares or the equivalent, the ownership or power to vote, directly or indirectly, shares, or the equivalent, representing 50% or more of the power to vote in the election of directors, managers or Persons performing similar functions;

(b) ownership of 50% or more of the equity or beneficial interest in that Person; or

(c) the ability to direct the business and affairs of any Person by acting as a general partner, manager or otherwise.

1.15 "**CPI**" means the "Canada All Items (Not Seasonally Adjusted)" Consumer Price Index as published by Statistics Canada or any successor agency thereto.

1.16 "**Delivered Energy**" means in each month after Buyer's COD the amount of Energy delivered by Seller at the POI in that month as recorded by Buyer's Meter less the applicable Line Losses.

1.17 "**Development Progress Report**" means a report describing the progress of the financing, design, engineering, construction, Interconnection, and commissioning of the Seller's Plant, that is in form and content acceptable to Buyer, acting reasonably.

1.18 "**Discretion**" (whether or not capitalized) means sole, absolute and unfettered discretion unless this EPA expressly states otherwise.

1.19 "**Dispatch/Turn-Down**" means for Seller to turn down or shut off the Seller's Plant.

1.20 "**Dispatch/Turn-Down Deemed Energy**" has the meaning given to such term in Section 4.9(b)(i).

1.21 "**Distribution System**" means the distribution, protection, control and communication facilities in the Yukon that are or may be used in connection with, or that otherwise relate to, the transmission of electrical energy at 35 kilovolts or less, and includes all additions and modifications thereto and repairs or replacements thereof.

1.22 "**Distribution/Transmission Constraint**" means any disconnection of the Seller's Plant from the Distribution System or Transmission System, or any outage, suspension, constraint or curtailment in the operation of the Distribution System or Transmission System preventing or limiting deliveries of Energy at the POI or within the Distribution System or Transmission System or any direction from Buyer to reduce generation of the Seller's Plant as a result of any outage, suspension, constraint or curtailment in the operation of the Distribution System or Transmission System.

1.23 "**Effective Date**" shall mean the date on which all Conditions Precedent have been satisfied or waived in accordance with Section 2.1.

1.24 "**Electrical Grid**" means the electrical grid into which the Seller's Plant will be interconnected, as identified in Schedule "B"**.**

1.25 "**Eligible Clean Energy**" means wind, hydro, geothermal, biomass and solar energy sources permitted under the IPP Policy for the SOP generated by a Project located in Yukon which is directly connected into the YIS or the WLG through the New Interconnection Facilities.

1.26 "**Energy**" means all electrical energy expressed in KWh generated by the Seller's Plant, excluding electrical energy generated by the Seller's Plant which is required to service the Seller's Plant Load.

1.27 "**Energy Price**" has the meaning given to such term in Schedule "B".

1.28 "**Environmental Attributes**" means the following as attributable to Energy delivered to Buyer under this EPA:

(a) all attributes directly associated with, or that may be derived from, the Energy delivered to Buyer under this EPA having decreased environmental impacts relative to certain other generation facilities or technologies including any existing or future credit, allowance, "green" tag, ticket, certificate or other "green" marketing attribute or proprietary or contractual right, whether or not tradeable;

(b) any credit, reduction right, offset, allowance, allocated pollution right, certificate or other unit of any kind whatsoever, whether or not tradeable and any other proprietary or contractual right, whether or not tradeable, resulting from, or otherwise related to the actual or assumed reduction, displacement or offset of emissions at any location other than the Seller's Plant as a result of the generation, purchase or sale of the Energy delivered to Buyer under this EPA;

(c) any credit, reduction right, off-set, allowance, allocated pollution right, certificate or other unit of any kind whatsoever whether or not tradeable resulting from or otherwise related to the reduction, removal, or sequestration of emissions at or from the Seller's Plant; and

(d) all revenues, entitlements, benefits and other proceeds arising from or related to the foregoing, but for certainty not including:

i. benefits or proceeds from environmental incentive programs offered by Governmental Authorities that do not require a transfer of the attributes in (a) to (c) above; and

ii. benefits or proceeds from social programs, including programs relating to northern or rural development, employment or skills training, or First Nations, that do not require a transfer of the attributes in Sections (a) to (c) above.

1.29 "**Environmental Certification**" means any certification Buyer requires Seller to obtain under Section 6.1.

1.30 "**Facility Lender**" means any lender(s) providing any debt financing or debt hedging facilities for the design, engineering, construction and/or operation of the Seller's Plant and any successors or assigns thereto and any Person taking any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's Plant.

1.31 "**Final Amount**" means an amount owing by either Party to the other Party under this EPA, including as a result of a breach of this EPA, where such amount is: (a) undisputed by the Party owing such amount; or (b) has been finally determined by an arbitration award under Section 12.1 of this EPA or by a court order and all rights of appeal in respect of such award or order have been exhausted or have expired.

1.32 "**First Nation Claim**" means a legal claim or proceeding or written threat to commence a legal claim or proceeding from or on behalf of First Nations where such claim or threat alleges a breach or potential breach of, or an impact to: any First Nations' Treaty rights, rights under a Settlement Agreement (as that term is defined in the Yukon Umbrella Final Agreement), or rights under section 35 of the *Constitution Act*, 1982, by (a) this EPA, (b) the Seller's Plant, (c) the Interconnection or any works related to the Interconnection, or (d) any authorization granted by the Yukon or federal government relating to the Seller's Plant and its operations.

1.33 "**First Nations**" means any one of the 14 First Nations in the Yukon.

1.34 "**Force Majeure**" means any event or circumstance not within the control of the Party, or any of its Affiliates, claiming Force Majeure, but does not include:

(a) any economic hardship or lack of money, credit or markets;

(b) an event or circumstance that is the result of a breach by the Party seeking to invoke Force Majeure of a Permit or of any applicable Laws;

(c) a mechanical breakdown or control system hardware or software failure, unless the Party seeking to invoke Force Majeure can demonstrate by clear and convincing evidence that the breakdown or failure was caused by a latent defect in the design or manufacture of the equipment, hardware or software, which could not reasonably have been identified by normal inspection or testing of the equipment, hardware or software;

(d) an event or circumstance caused by a breach of, or default under, this EPA or a willful or negligent act or omission by the Party seeking to invoke Force Majeure;

(e) any Distribution/Transmission Constraint unless such event is caused by an event or circumstance not within the control of Buyer; or

(f) any acts or omissions of: (i) any Affiliate, employee, director, officer, agent or other representative of the Party invoking Force Majeure; (ii) any vendor, supplier, contractor, subcontractor, consultant or customer of or to the Party invoking Force Majeure; or (iii) any other Person for whom the Party invoking Force Majeure is responsible at law, unless the act or omission is caused by an event or circumstance that would constitute Force Majeure if the Person described above was a party to this EPA in place of a Party invoking Force Majeure.

1.35 "**Forced Outage**" means the immediate removal of one or more generating units of the Seller's Plant or transmission or distribution infrastructure of the Seller's Plant from service in response to equipment alarms or any damage identified during a Planned Outage or Maintenance Outage requiring extension of those Planned Outage or Maintenance Outage.

1.36 "**General Rate Application**" means any application, review, process, or procedure in which the YUB sets and approves rates to be charged by Buyer for the supply of the service for which it is franchised in accordance with the *Public Utilities Act*.

1.37 "**Good Industry Practice**" means:

(a) in respect of Buyer, any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition; provided such practices, methods and acts are not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the Yukon; and provided that Buyer shall be in compliance with Good Industry Practice in respect of any equipment comprising the Distribution System or Transmission System, if it operates such equipment in accordance with all applicable original equipment manufacturer guidelines and requirements provided to Buyer by supplier of such equipment; and

(b) in respect of Seller, any of the practices, methods and acts engaged in or approved by a significant portion of the electric generation industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in

light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition; provided such practices, methods and acts are not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in Western Canada.

1.38 "**Governmental Authority**" means any federal, provincial, local or foreign government or any of their boards or agencies, or any regulatory authority other than Buyer and Seller and entities controlled by Buyer or Seller.

1.39 "**GST**" means the goods and services tax imposed under the *Excise Tax Act* (Canada) as that Act may be amended or replaced from time to time.

1.40 "**Interconnection"** means the POI.

1.41 "**IPP Policy**" has the meaning given to such term in the recitals to this EPA.

1.42 "**Joint Operating Procedure**" means the joint operating procedure attached as Schedule "H" as may be modified by Buyer from time to time.

1.43 "**KW**" means kilowatt.

1.44 "**KWh**" means kilowatt-hour.

1.45 "**Laws**" means any and all statutes, laws (including common law), ordinances, rules, regulations, codes, orders, bylaws, policies, directions, standards, guidelines, protocols and other lawful requirements of any Governmental Authority in effect from time to time.

1.46 "**Lender Consent Agreement**" means a lender consent agreement in the form and substance acceptable to Buyer, acting reasonably.

1.47 "**Line Losses**" means losses of electricity associated with the transmission and transformation of Energy and other electricity, if applicable, from the Seller's Plant to the POI that are recorded by the Meter or reasonably estimated by Buyer.

1.48 "**Line Loss Methodology**" means the Line Loss Methodology set forth in the System Interconnection Study Report for the purposes of this Project.

1.49 "**Maintenance Outage**" means any outage of Buyer's Distribution System or Transmission System or the Seller's Plant that is not a Planned Outage or a Forced Outage that typically has a flexible start and end time and of shorter duration than a Planned Outage.

1.50 "**Meter**" means a meter owned by Buyer that is: (a) capable of accurately measuring the quantity of Energy generated by the Seller's Plant and delivered to the POI independent of all other generation equipment or facilities, (b) capable of being remotely interrogated; and (b) calibrated to measure on an hourly basis the quantity of Energy delivered by Seller to the POI.

1.51 "**Monthly Energy Shortfall Payment**" has the meaning given to such term in Schedule "E".

1.52 "**New Interconnection Facilities**" means those additions, modifications and upgrades required to interconnect the Project to the Electrical Grid which are identified in the System Interconnection Study Report (and as further refined in subsequent interconnection studies, if required by Buyer) and approved by Buyer, but excluding any System Upgrades.

1.53 "**New Interconnection Facilities Costs**" means all costs incurred by Buyer for the design, engineering, procurement, construction, installation and commissioning of the New Interconnection Facilities, including applicable studies required by Buyer, an estimate of which is set out in the System Interconnection Study Report.

1.54 "**Non-Permitted Distribution/Transmission Constraint**" has the meaning given to such term in Section 4.8(a).

1.55 "**Outage**" means a Forced Outage, Maintenance Outage, or Planned Outage of Buyer's Distribution System or Transmission System or Seller's Plant.

1.56 "**Outage Notice**" means a notification of any Outage or revised notification of any Outage required to be delivered by Seller to Buyer or Buyer to Seller under this EPA that describes the timing, frequency, nature and duration of the Outage and that is in a format that may be prescribed by Buyer from time to time.

1.57 "**Party**" means Buyer or Seller, and "**Parties**" means both Buyer and Seller.

1.58 "**Permits**" means permits, certificates, licences, approvals and other authorizations issued by any Governmental Authorities as may be required for the design, construction, ownership, operation, maintenance and decommissioning of (i) the Seller's Plant and the delivery of Energy to the POI, and (ii) the System Upgrades and the New Interconnection Facilities.

1.59 "**Person**" means an individual, body corporate, firm, partnership, joint venture, trust, legal representative or other legal entity.

1.60 "**Planned Outage**" means an outage that is scheduled well in advance for purposes of inspections, maintenance, or repair of Buyer's Distribution System or Transmission System or Seller's Plant, that typically has a predetermined duration and scope of work, occurs only once or twice per year, and may last for several days.

1.61 "**POI**" or "**Point of Interconnection**" means the point at which the Seller's Plant interconnects with the Distribution System or Transmission System, as identified on the Single Line Diagram.

1.62 "**Potential Impacts**" means any adverse or potentially adverse impact on the established or potential aboriginal rights (including title) of First Nations as a result of:

(a) this EPA;

(b) the Project;

(c) the interconnection of the Seller's Plant to the Distribution System or Transmission System; or

(d) any activities directly related to the Seller's Plant that enable Seller to comply with its obligations under this EPA that are carried out by Seller, any Affiliate, consultant or contractor of Seller, or any other Person for whom Seller is responsible at law.

1.63 "**PPT**" means Pacific Prevailing Time, which means Pacific Daylight Time or Pacific Standard Time as applicable.

1.64 "**Present Value Rate**" means the annual yield on a Government of Canada bond having a term and maturity date that most closely matches the remaining Term (as at the date of the applicable calculation) and expiry date of this EPA, plus 3%.

1.65 "**Prime Rate**" means the floating prime interest rate announced from time to time by the main branch of Bank of Montreal in Whitehorse, Yukon, or any successor thereto, expressed as an annual rate, as the reference rate it will use to determine rates of interest payable on Canadian dollar commercial loans made in Canada.

1.66 "**Project**" means the financing, design, engineering, procurement, construction, commissioning, operation and maintenance of the Seller's Plant.

1.67 "**Project Cluster**" means two or more existing or proposed Projects under the SOP Rules that Buyer determines in its Discretion are so closely related to each other that they should be considered a project cluster for the purposes of the Standing Offer Program.

1.68 "**Project Energy Volume**" (in KWh) means the maximum annual Energy which Buyer may sell to Seller from the Project in any calendar year as set out in Schedule "B"; provided that where the Term does not commence on January 1, such amount shall be prorated for the first and last contract year which do not reflect a full calendar year.

1.69 "**Project Standards**" means:

(a) all applicable Laws;

(b) the terms and conditions of all Permits, including land tenure agreements, issued in connection with the Seller's Plant;

(c) Good Industry Practice;

(d) the description of the Seller's Plant in Schedule "B";

(e) the requirement that Energy must qualify as Eligible Clean Energy; and

(f) the terms and conditions of this EPA (including the System Interconnection Guidelines).

1.70 "**Public Utilities Act**" means the *Public Utilities Act* (Yukon) and any successor or replacement legislation.

1.71 "**Records**" means all records and logs required to properly administer this EPA, including:

(a) Energy generation records and operating logs;

(b) Meter readings;

(c) maintenance reports;

(d) invoice support records;

(e) documents concerning compliance with Project Standards, but excluding any such documents that are protected by solicitor-client privilege;

(f) records related to System Upgrade Costs and New Interconnection Facilities Costs;

(g) all information reasonably required to establish the amount of Energy Seller could have sold during a Distribution/Transmission Constraint including logs of all Outages of the Seller's Plant and other reductions in Energy output (specifying the date, time, duration and reasons for each such outage and each reduction in Energy output); and

(h) information relating to the Environmental Certification, information relating to the existence, nature and quality of Environmental Attributes, information required for the purposes of any Environmental Attributes or energy certification or tracking system, and any other information Buyer requires to enable it or any of its Affiliates to obtain and realize the benefit of the Environmental Attributes,

all consistent with Good Industry Practice.

1.72 "**Regulatory Agency Authorizations**" means the issuance of those Permits which are specified as required for the Project in the YESAB assessment report recommendation to proceed issued in respect of the Project.

1.73 "**Seller**" means the Party so identified on page one of this EPA, and its successors and permitted assigns.

1.74 "**Seller Confidential Information**" means any of Seller's confidential technical or financial information provided by Seller to Buyer in confidence with express written notice to Buyer of the confidential nature of the information, but excluding:

(a) this EPA; and

(b) information that (i) is or becomes in the public domain, other than as a result of a breach of this EPA by Buyer, or (ii) is known to Buyer before disclosure to it by Seller, or becomes known to Buyer thereafter by way of disclosure to Buyer by any other Person who is not under an obligation of confidentiality with respect thereto.

1.75 "**Seller's COD**" means the commercial operation date of Seller's Plant which is the date on which all of the following conditions have been satisfied in respect of the Seller's Plant:

(a) Seller has obtained all Permits required for the construction, commissioning, and operation of the Seller's Plant and all such Permits are in full force and effect;

(b) the Seller's Plant has been fully constructed in accordance with the Project Standards;

(c) Seller is not: (A) Bankrupt or Insolvent; (B) in default of any payment obligation or requirement to post security under this EPA; (C) in material default of any of its other covenants, representations, warranties or obligations under this EPA; or (D) in material

default under any Permit or Law applicable to the construction, commissioning or operation of the Seller's Plant or under any land tenure agreement for the site on which the Seller's Plant is located;

(d) a Meter has been installed at the POI in accordance with Section 3.6 of this EPA;

(e) Seller has delivered to Buyer a written notice together with certificate of Seller's professional registered engineer confirming that Seller's COD has been achieved; and

(f) Buyer has delivered a Commission Notice to Operate, or such other document(s) of similar effect as may be substituted therefor, which evidences no material deficiencies, in respect of the Seller's Plant Capacity and Seller's Plant operations;

and for purposes of this EPA, Seller's COD will be deemed to have occurred at 24:00 PPT on the later of the dates set out above.

1.76 "**Seller's Plant**" means Seller's plant described in Schedule "B" and all assets required to interconnect that plant to the Distribution System or Transmission System; all rights, property, facilities, assets, equipment, materials, Permits and contracts required to design, engineer, procure, construct, commission, operate and maintain the plant described in Schedule "B" and to interconnect that plant to the Distribution System or Transmission System, whether real or personal and whether tangible or intangible including all land tenure and all books, Records and accounts with respect to the Seller's Plant described in Schedule "B"; and shall include replacement parts or equipment which are of the same or similar nature as the parts or equipment being replaced and which do not materially increase the amount of Energy available from Seller's Plant.

1.77 "**Seller's Plant Capacity**" means the electrical generating capacity of the Seller's Plant set out in Schedule "B".

1.78 "**Seller's Plant Load**" means any electrical energy consumed by Seller's Plant.

1.79 "**Single Line Diagram**" means the simplified electrical representations of the Seller's Plant, the Interconnection, the Distribution System and Transmission System attached hereto in Schedule "B".

1.80 "**SOP OIC**" means that Order in Council issued by the Government of Yukon on January 24, 2019 regarding, among other things, the Standing Offer Program.

1.81 "**SOP Rules**" means the Standing Offer Program Rules developed by the Government of Yukon which governed this EPA as at the date of this EPA.

1.82 "**Standing Offer Program**" or "**SOP**" means the Standing Offer Program as described in the IPP Policy.

1.83 "**System Interconnection Guidelines**" means those system interconnection guidelines in the form attached as Schedule "G" hereto, as amended or replaced by Buyer from time to time.

1.84 "**System Interconnection Study Report**" means the detailed interconnection study issued to Seller by Buyer which, among other things, (i) evaluates the impact of the Project on the reliability of Buyer's system, (ii) provides a planning-level estimate of the required System

Upgrades and New Interconnection Facilities and associated costs, and (iii) establishes the Line Loss Methodology for this Project, a copy of which is attached as Schedule "D".

1.85 "**System Upgrades**" means additions, modifications and upgrades to the Distribution System, Transmission System or any portion of Buyer's generation system that are determined by Buyer to be required in order to facilitate the interconnection and to allow such Distribution System, Transmission System or any portion of Buyer's generation system to support the integration of the Energy produced by the Seller's Plant in accordance with this EPA and the System Interconnection Guidelines, which are identified in the System Interconnection Study Report (and as further refined in subsequent interconnection studies, if required by Buyer) and approved by Buyer, but excluding any New Interconnection Facilities.

1.86 "**System Upgrade Costs**" means all costs incurred by Buyer for the design, engineering, procurement, construction, installation and commissioning of the System Upgrades, including applicable studies required by Buyer, an estimate of which is set out in the System Interconnection Study Report.

1.87 "**Target Buyer's COD**" means the target date for achieving Buyer's COD, being the date specified for such term in Schedule "B", as may be extended pursuant to Section 3.9, if applicable.

1.88 "**Target Seller's COD**" means the target date for achieving Seller's COD, being the date specified for such term in Schedule "B", as may be extended pursuant to Section 3.9, if applicable.

1.89 "**Term**" has the meaning given to such term in Section 2.1.

1.90 "**Termination Payment**" has the meaning given to such term in Schedule "F".

1.91 "**Transmission System**" means the transmission, substation, protection, control and communication facilities owned and operated by Buyer, and includes all additions and modifications to those facilities and repairs or replacements of those facilities.

1.92 "**Upgrade Costs Advance**" has the meaning given to such term in Section 3.5(a).

1.93 "**Upgrade Costs Security**" has the meaning given to such term in Section 3.5(a).

1.94 "**Utilities**" means both Yukon Energy Corporation or Yukon Electrical Company, doing business as ATCO Electric Yukon, as applicable.

1.95 "**YESAA**" means the *Yukon Environmental and Socio-economic Assessment Act*, SC 2003, c 7.

1.96 "**YESAB**" means the Yukon Environmental and Socio-economic Assessment Board.

1.97 "**YUB**" means the Yukon Utilities Board and any successor thereto appointed from time to time under the *Public Utilities Act*.

2. INTERPRETATION

2.1 **Headings** - The division of this EPA into Articles, sections, Sections, paragraphs and Schedules and the insertion of headings are for convenience of reference only and do not affect the interpretation of this EPA.

2.2 **Plurality and Gender** - Words in the singular include the plural and vice versa. Words importing gender include the masculine, feminine and neuter genders.

2.3 **Governing Law** - This EPA is made under, and will be interpreted in accordance with, the Laws of the Yukon. Subject to Section 12.1, any suit, action or proceeding (a "**Proceeding**") arising out of or relating to this EPA may be brought in the courts of the Yukon at Whitehorse, and those courts have non-exclusive jurisdiction in respect of any Proceeding and the Parties hereby irrevocably attorn to the jurisdiction of such courts in respect of any Proceeding.

2.4 **Industry Terms** - Technical or industry specific phrases or words not otherwise defined in this EPA have the well-known meaning given to those terms as of the date of this EPA in the industry or trade in which they are applied or used.

2.5 **Statutory References** - Reference to a statute means, unless otherwise stated, the statute and regulations, if any, under that statute, in force from time to time, and any statute or regulation passed and in force which has the effect of supplementing or superseding that statute or those regulations.

2.6 **Currency** - References to dollars or $ means Canadian dollars, unless otherwise stated.

2.7 **Reference Indices -** If any index, tariff or price quotation referred to in this EPA ceases to be published, or if the basis therefor is changed materially, there will be substituted an available replacement index, tariff or price quotation that most nearly, of those then publicly available, approximates the intent and purpose of the index, tariff or quotation that has so ceased or changed. This EPA will be amended as necessary to accommodate such replacement index, tariff or price quotation, all as determined by written agreement between the Parties, or failing agreement, by arbitration under Section 12.1 of this EPA.

2.8 **Conversions** - If a value used in a calculation in this EPA must be converted to another unit of measurement for purposes of consistency or to achieve a meaningful answer, the value will be converted to that different unit for purposes of the calculation.

2.9 **Additional Interpretive Rules** - For the purposes of this EPA, except as otherwise expressly stated:

(a) "this EPA" means this EPA as it may from time to time be supplemented or amended and in effect, and includes the Schedules attached to this EPA;

(b) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this EPA as a whole and not to any particular section, Section or other subdivision;

(c) the word "including" or "includes" is not limiting whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto;

(d) the words "year" and "month" refer to a calendar year and a calendar month;

(e) any consent, approval or waiver contemplated by this EPA must be in writing and signed by the Party against whom its enforcement is sought, and may be given, withheld or conditioned in the unfettered discretion of the Party of whom it is requested, unless otherwise expressly stated;

(f) all rights and remedies of either Party under this EPA are cumulative and not exclusive of any other remedies to which either Party may be lawfully entitled, and either Party may pursue any and all of its remedies concurrently, consecutively and alternatively; and

(g) any notice required to be given, or other thing required to be done, under this EPA on or before a day that is not a Business Day, will be deemed to be given or done when required hereunder if given or done on or before the next following Business Day.

3. ADDRESSES FOR NOTICES

3.1 **Notices to Buyer** - Except as noted below, all notices addressed to Buyer will be delivered to the following address:

To: **YUKON ENERGY CORPORATION**
#2 Miles Canyon Road
Box 5920
Whitehorse, YT Y1A 6S7
Attention: IPP Manager
Email: ipp@yec.yk.ca

3.2 **Notices to Seller** - All notices addressed to Seller will be delivered to the following address:

To: **NOMAD CONTRACTING & ELECTRICAL SERVICES LTD.**
62 Mt Sima Rd
Whitehorse, YT Y1A 0A8
Attention: Sebastien Roy
Email: nomad_electric@outlook.com

SCHEDULE "B"

PROJECT DESCRIPTION

CONTRACT PARTICULARS:

1. **Condition Date:**

   Nil.

2. **Conditions Precedent:**

   Nil.

3. **Term:**

   The "**Term**" of this EPA commences on the Effective Date and continues for a period of 25 years following Buyer's COD.

4. **Energy Price and Seasonal Adjustment:**

   (a) In each billing period, Seller shall pay to Buyer, for each KWh of Delivered Energy the "**Energy Price**" calculated as follows:

   $\text{Energy Price}_n = (.5 * \$0.158/\text{KWh} * \text{CPI}_{\text{January 1, n}} / \text{CPI}_{\text{January 1, 2020}}) + (.5 * \$__/\text{KWh})$

   Where:

   n = the year for which the relevant calculation is being conducted

   $\text{CPI}_{\text{January 1, n}}$ = the CPI for December in the year immediately prior to the year for which the relevant calculation is being conducted;

   (b) For each hour, the Energy Price determined above for Delivered Energy during that hour will be adjusted to an amount (expressed in $/KWh) equal to the percentage of that Energy Price applicable for that hour as set out in the table in Schedule "I".

SELLER'S PLANT

1. **Location of Control Building:**

   60° 38’ 045” N and -135° 01’ 050” W

2. **Eligible Clean Energy Type:**

   Solar PV

3. **Seller's Plant Capacity:**

   150kW

4. **Project Energy Volume:**

Month	Energy Volume (KWh)
January	3,126.3
February	13,232.0
March	28,210.3
April	36,987.5
May	37,860.9
June	36,194.0
July	34,918.6
August	32,736.9
September	23,825.4
October	16,396.7
November	4,833.6
December	1,742.6

5. **Seller's Plant Description:**

Please refer to Seller's single line diagram in Exhibit B-1.

Total AC Power: 150 kW
Primary AC line voltage: 480 V
Total AC line current: 180.4 A
Total DC power: 246.4 kW
Open-circuit DC voltage: 1000V/String
Operating DC voltage: 700V/String
Total DC operating current: 352 A

6. **Target Seller's COD:**

June 1, 2021

7. **Electrical Grid:**

Yukon Integrated System.

BUYER'S SYSTEM UPGRADES

1. **System Upgrades:**

No upgrades are required other than a change to OCR5953 reclose interval to allow for the operation of the Nomad solar plant islanding detection

2. **New Interconnection Facilities:**

The proposed interconnection to the AEY SL649 distribution line will consist of:

- One slack-span tap from the mainline

- One OH to UG riser pore
- One switchable 300 kVA pad mount transformer and vault
- Estimated 25m of overhead 1/0 ACSR
- Estimated 15m of underground #1 cable
- 2 pole tap
- 150 kVA 14.4kV/25kV – 277/480V oilfield transformer

Please refer to Buyer's single line diagram in Exhibit B-2.

3. **Target Buyer's COD:**

June 1, 2021

BREAKERS/SWITCHES AND SYNCHRONIZATION

H365NR Safety switch, heavy duty, fusible, 400A, 3 poles, 250 hp, 600 VAC/DC, NEMA 3R, neutral factory installed and a CHU362RB 60A 3P Type3R 600VAC/DC Heavy Duty Non Fusible Safety Switch will be used. The specifications of such switches are attached.

After voltage is restored after an outage no reconnections will be attempted until the Seller has permission to reconnect from the System Control Center (as identified in Schedule "H"). After permission is given, the Seller must check that voltage and frequency are stable and within 10% of nominal values before closing in to reconnect:

- A plus or minus 10% voltage range is acceptable; and
- A plus or minus 10% frequency range is acceptable.

Product data sheet
Characteristics

CHU362RB
60A 3P Type3R 600VAC/DC Heavy Duty Non-Fusible Safety Switch

Main

Product or component type	Single Throw Safety Switch
Disconnector device type	Non-fusible disconnect
Number of poles	3
Electrical connection	Lugs
Series name	Heavy duty

Complementary

Line Rated Current	60 A
Device composition	None
Device mounting	Surface
System Voltage	600 V AC/DC
AWG gauge	AWG 14...AWG 3 (copper or aluminium)

Environment

Product certifications	CSA
NEMA degree of protection	NEMA 3R galvannealed steel

Offer Sustainability

Sustainable offer status	Green Premium product
RoHS (date code: YYWW)	Compliant - since 1313 - Schneider Electric declaration of conformity Schneider Electric declaration of conformity
REACh	Reference not containing SVHC above the threshold Reference not containing SVHC above the threshold
Product environmental profile	Available
Product end of life instructions	Need no specific recycling operations

Disclaimer: This documentation is not intended as a substitute for and is not to be used for determining suitability or reliability of these products for specific user applications

Product data sheet
Characteristics

H365NR
Safety switch, heavy duty, fusible, 400A, 3 poles, 250 hp, 600 VAC/DC, NEMA 3R, neutral factory installed

Product availability : Stock - Normally stocked in distribution facility

Price* : 5,765.00 USD

Main

Product	Single Throw Safety Switch
Current Rating	400 A
Certifications	UL listed file E2875
Enclosure Rating	NEMA 3R galvannealed steel
Factory Installed Neutral	Neutral (factory installed)
Disconnect Type	Fusible disconnect
Short Circuit Current Rating	10 kA H or K 200 kA R, J or L
Mounting Type	Surface
Number of Poles	3
Electrical Connection	Lugs
Duty Rating	Heavy duty
Voltage Rating	600 V AC/DC
Wire Size	AWG 1/0...750 kcmil copper or aluminium

Complementary

Maximum Horse Power Rating	100 hp 480 V AC 50...60 Hz 3 phase NEC 240.6 250 hp 480 V AC 50...60 Hz 3 phase NEC 430.52 125 hp 600 V AC 50...60 Hz 3 phase NEC 240.6 350 hp 600 V AC 50...60 Hz 3 phase NEC 430.52 50 hp 250 V DC 50 hp 600 V DC
Maximum Height	50.31 in (1277.87 mm)
Depth	10.13 in (257.30 mm)
Width	27.88 in (708.15 mm)

* Price is "List Price" and may be subject to a trade discount – check with your local distributor or retailer for actual price.

Disclaimer: This documentation is not intended as a substitute for and is not to be used for determining suitability or reliability of these products for specific user applications

Tightening torque	550 lbf.in (62.14 N.m) AWG 1/0...750 kcmil)

Ordering and shipping details

Category	00054 - H&HU SW,NEMA3R,400-1200A
Discount Schedule	DE1
GTIN	00785901026686
Nbr. of units in pkg.	1
Package weight(Lbs)	186 lb(US) (84.37 kg)
Returnability	Yes
Country of origin	MX

Packing Units

Unit Type of Package 1	PCE
Package 1 Height	14.02 in (35.6 cm)
Package 1 width	28.31 in (71.9 cm)
Package 1 Length	51.50 in (130.8 cm)

Offer Sustainability

Sustainable offer status	Green Premium product
REACh free of SVHC	Yes
EU RoHS Directive	Compliant EU RoHS Declaration
Mercury free	Yes
RoHS exemption information	Yes
China RoHS Regulation	China RoHS declaration Product out of China RoHS scope. Substance declaration for your information.
Environmental Disclosure	Product Environmental Profile

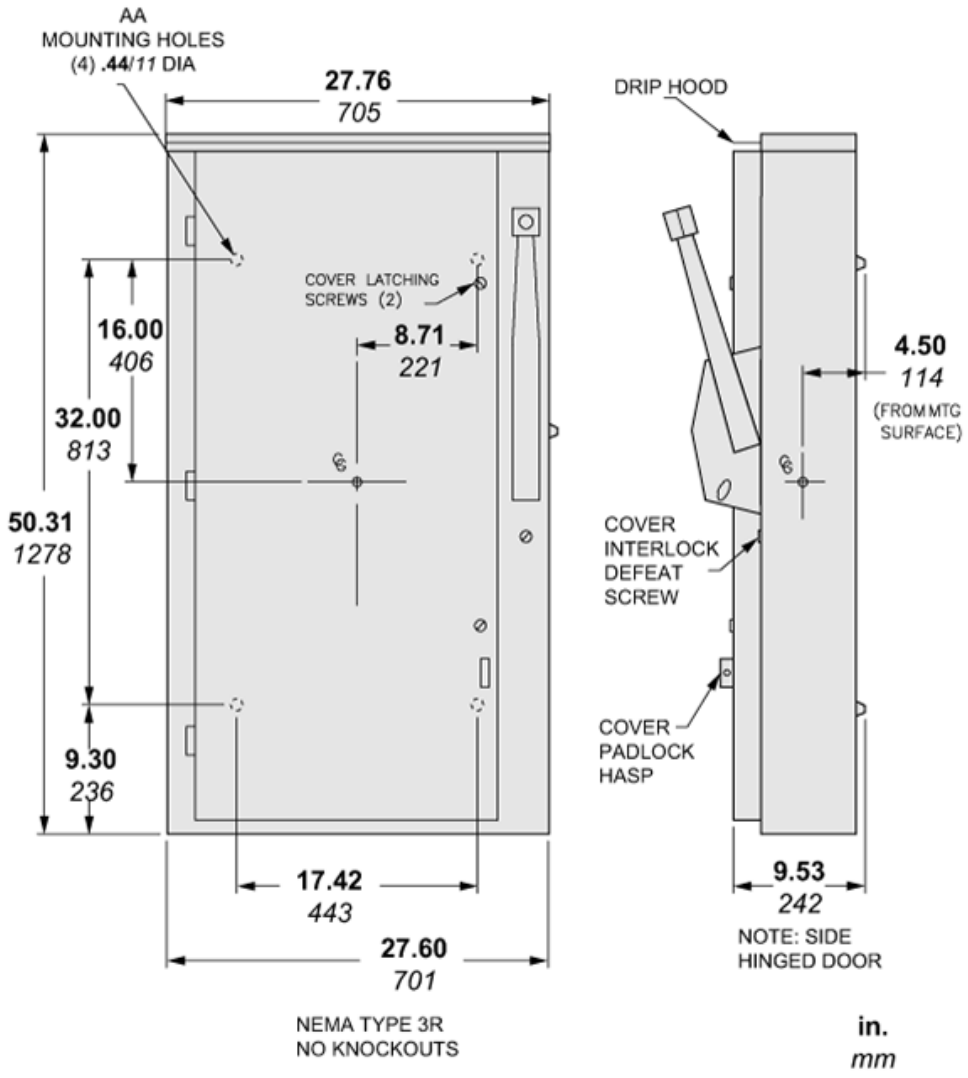
Contractual warranty

Warranty	18 months

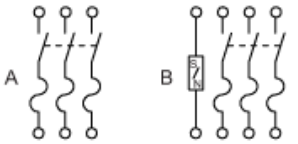
Product data sheet
Dimensions Drawings

H365NR

Approximate Dimensions



Wiring Diagrams

WIRING DIAGRAMS	
FUSIBLE	NOT FUSIBLE
	

TERMINAL LUGS DATA			
AMPERE	MAX WIRE	MIN WIRE	TYPE
400	(1) 750 KCMIL OR (2) 300 KCMIL	(1) #1/0 AWG OR (2) #1/0 AWG	AL OR CU

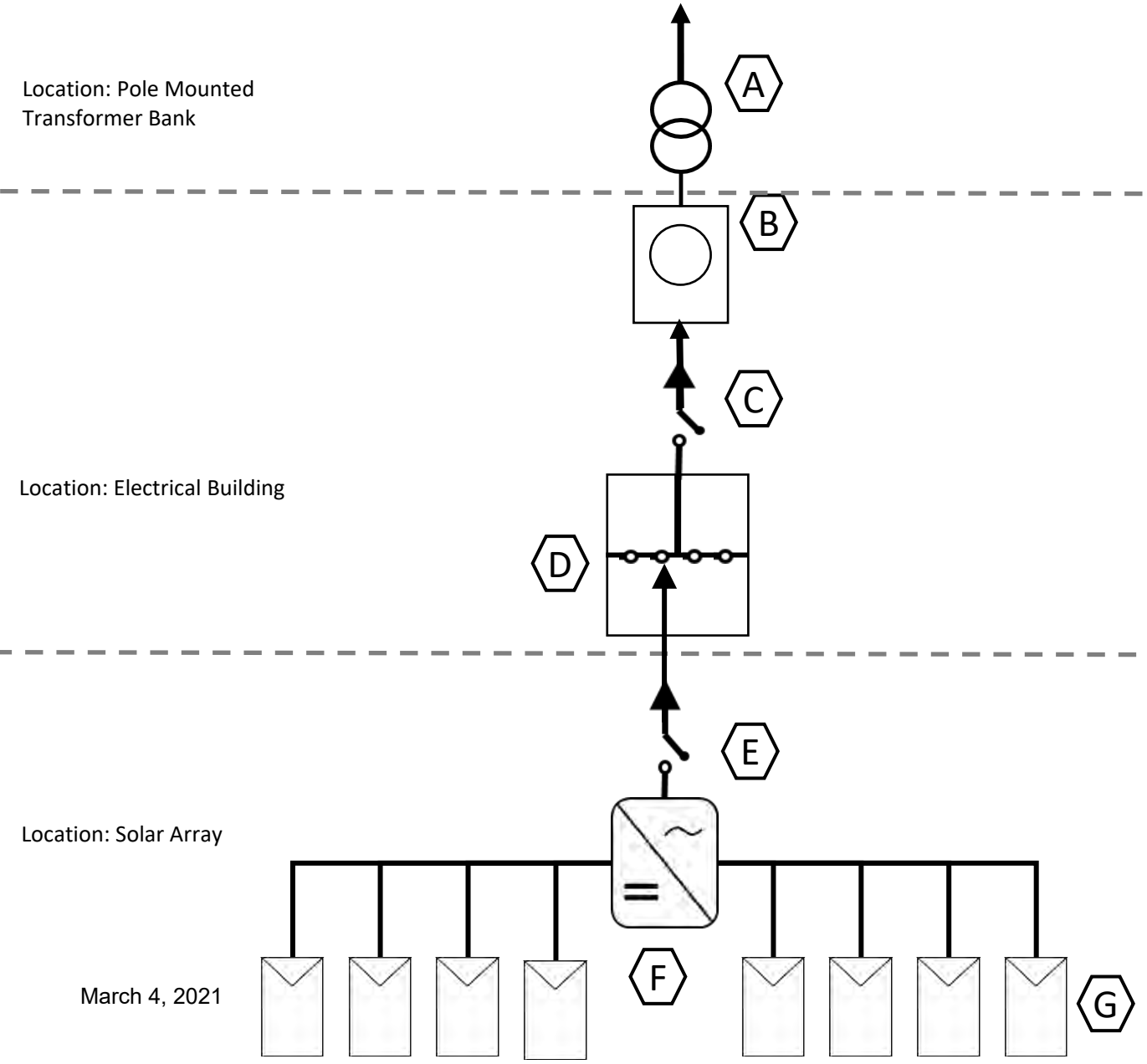
EXHIBIT B-1

Seller's Single Line Diagram

(Please see attached)

SOLVEST
NORTHERN SOLAR SOLUTIONS

Grid Connection as per ATCO Design



Nomad Electric IPP Project
Mount Sima Industrial Area, Yukon

SOLAR PHOTOVOLTAIC

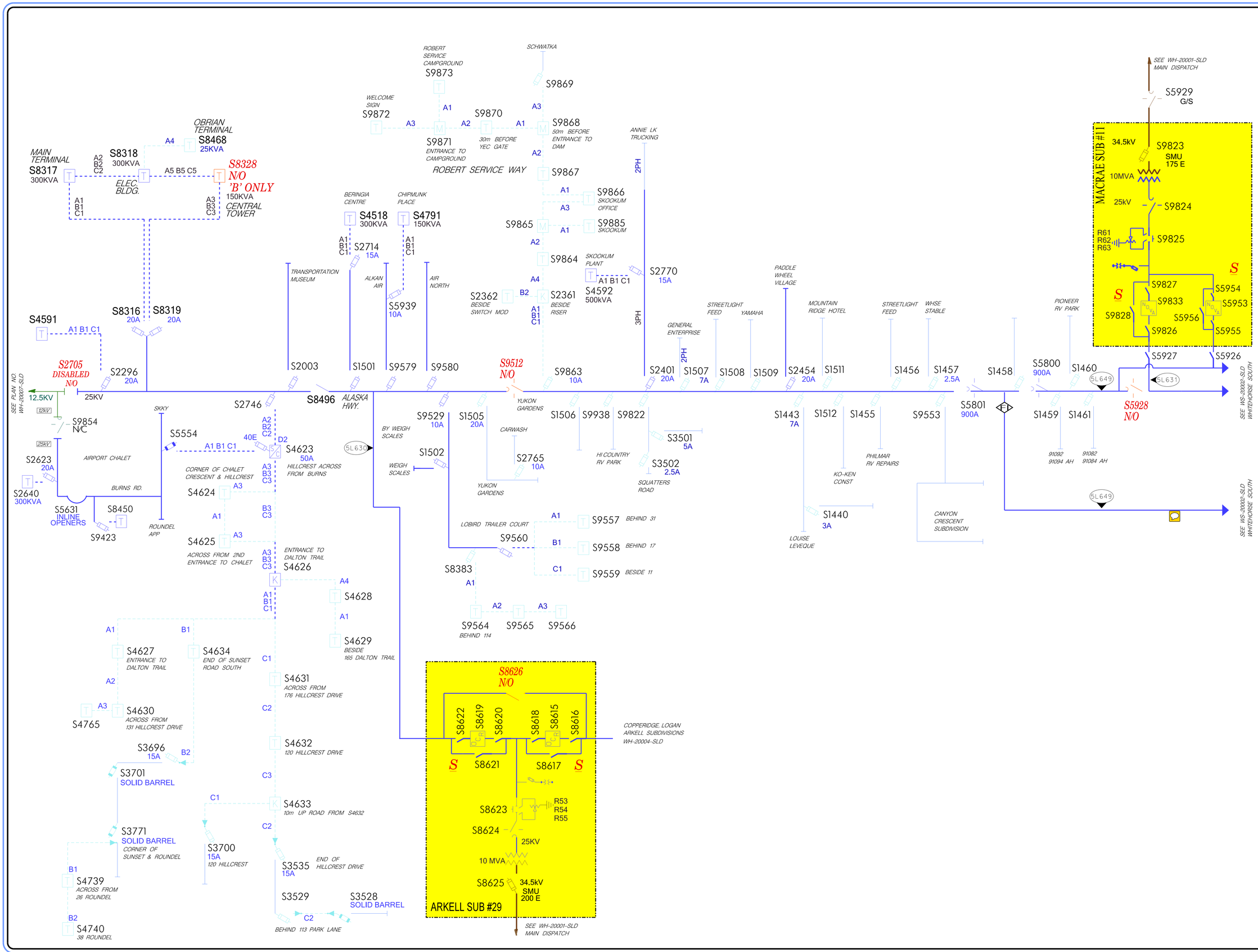
DC Power: 246.4 kW
AC Power: 150 kW at 1.0 Power Factor
Inverter AC Output (x 5): 30 kW
Inverter DC Input (x 5): 49.28 kW
Operating DC Voltage: 700V/String
Number of Strings: 40
Number of Strings per Inverter: 8
Number of Modules per String: 16

A) 150kVA Transformer (25 kV to 480 V)
B) Yukon Energy Meter Base
C) 400A – 3P – FUSED AC Disconnect
D) 400A – 4 Wire Splitter – 5 sub taps
E) 60A – 3P – FUSED AC Disconnect
F) Huawei 30KTL Inverter (480 Vac) with integrated DC Disconnect
G) Canadian Solar CS3U-385W Bi-facial Modules

EXHIBIT B-2

Buyer's Single Line Diagram

(Please see attached)



LEGEND / NOTES

No.	MM-DD-YY	By	Revision
G	03-12-2009	DJS	Revised and Printed 31 Copies March 12/2009
H	09-25-2010	RW	Added S3013 Solid Blades
I	03-13-2014	CS	New Map Added New Hillcrest 25kV UG
J	10-02-2016	CS	Added New Mount Sima Loop, S5801 N/O, S5800 N/O and Close S9512, S5928
K	03-15-2018	CS	Added S4791, S5939, S9885, Hillcrest Conversion

ATCO Electric YUKON

Description WS-20001

WHITEHORSE SOUTH
Hillcrest Subdivision to MacRae Substation
14.4kV /25kV SWITCHING DIAGRAM

SWITCHING DIAGRAM

Scale: NTS

Drawn by: R.Williamson, C.E.T.

Checked by:

Approved by:

YECL PLAN NO: WS-20001

File: WS-20001-SLD.dgn Rev: K

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SCHEDULE "C"

FORM OF ANNUAL OPERATING PLAN

DATE: _____, 20__.

TO: Yukon Energy Corporation ("Buyer")

RE: Electricity Purchase Agreement between Nomad Contracting & Electrical Services Ltd. ("Seller") and Buyer dated the 27th day of August, 2020 (the "EPA")

The following sets out the Annual Operating Plan of Seller for the 12 months commencing on January 1, 20__ (the "**Applicable Period**").

(a) The following (from Table E-1 of Schedule "E" of the EPA) is the schedule of the expected total deliveries of Energy at the POI in each month of the Applicable Period:

	Projected Hourly Energy (KWh/h) **(A)**	**Projected Monthly Energy (KWh)** **(B)**
January		
February		
March		
April		
May		
June		
July		
August		
September		
October		
November		
December		

(b) The following is the schedule of any Planned Outages of the Seller's Plant expected by Seller for the Applicable Period:

[to come]

(c) The following is the schedule of operations and maintenance activities planned for the Seller's Plant expected by Seller for the Applicable Period:

[to come]

Dated effective as of the date set forth above.

**NOMAD CONTRACTING &
ELECTRICAL SERVICES LTD.**

Per: _____
[Name]
[Title]

Per: _____
[Name]
[Title]

SCHEDULE "D"

SYSTEM INTERCONNECTION STUDY REPORT

(Please see attached)

Teshmont
Leaders in Power Delivery Engineering

Yukon Energy Corporation

200 kW Nomad Solar Plant Assessment

Prepared by:

Teshmont Consultants LP
by its General Partner, Teshmont GP Inc.

1190 Waverley Street
Winnipeg, Manitoba, Canada R3T 0P4
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Calgary, Alberta, Canada T2R 1M1

6153.011-Rev01
2019 November 08

Disclaimer

This report was prepared under the supervision of Teshmont Consultants LP ("Teshmont"), whose responsibility is limited to the scope of work as shown herein. Teshmont disclaims responsibility for the work of others incorporated or referenced herein.

Revision History

Revision Number	Date Released	Prepared by	Reviewed by	Comments
Rev00	2019 November 01	Ashraful (Rony) Islam, PEng	David King, PEng Ashraf Haque, PEng	
Rev01	2019 November 08	Ashraful (Rony) Islam, PEng	David King, PEng Ashraf Haque, PEng	

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1. Introduction

Teshmont was requested to perform a grid impact and interconnection study for the connection of the 200 kW Nomad solar plant to the existing Yukon electric system. The proposed plant will be connected to one of the ATCO Electric's 25 kV distribution feeders originating at their MacRae Substation

The system impact study will include:

- Load flow study
- Short circuit study
- Protection assessment

2. ETAP Modelling and Study Assumptions

2.1. Modelling

Teshmont used the ETAP power system analysis software to model the 200 kW Nomad solar plant and the 25 kV feeder to which it will be connected. The feeder was modeled starting at YEC's Whitehorse (S150) Substation, to ATCO's MacRae Substation at downstream to the location where the solar plant will be connected. The model was prepared based on the following information received from YEC:

1. MacRae Substation is approx. 7.6 km downstream from Whitehorse Substation. The solar plant will be connected approximately 1.1 km downstream from MacRae Substation.
2. Construction details.
    a) Line 9L from Whitehorse substation to MacRae Substation is constructed of 267 ACSR (Partridge)
    b) MacRae substation to Nomad solar plant interconnection point is approximately:
        i. 1.1 km of 2/0 ACSR (Quail),
        ii. 0.6 km of 1/0 ACSR (Raven)
3. Load data: Summer Peak (SP) and Winter Peak (WP) load data at S6839, S6840, S9833 and S5953 metering points are prepared as shown in Table 2-1 and Table 2-2 based on the information received from YEC.

Table 2-1: S6839, S6840 and S9833 Meter Data Modeling

Metering Points of Feeder 9L	Summer Peak (SP) Load			Winter Peak (WP) Load		
	MW	Power Factor* (%)	MVA	MW	Power Factor (%)	MVA
S6839	0.196	90	0.218	2.423	90	2.692
S6840	0.441	90	0.49	2.348	90	2.609
S9833	0.702	90	0.78	3.492	90	3.880

*Assumed

Table 2-2: S5953 Load Distribution Across 5L649 Feeder

S5953 Load Distribution	Summer Peak (SP)			Winter Peak (SP)		
	MW	Power Factor (%)	MVA	MW	Power Factor (%)	MVA
5L649 downstream load	0.125	90	0.139	0.417	90	0.463
Nomad solar plant tap line load	0.175	90	0.194	0.583	90	0.647

4. Settings of the voltage regulators in MacRae Substation as shown in Table 2-3.

Table 2-3: R61/R62/R63 Regulator Settings

Function	Setting
Control Mode	Forward
Set Voltage	124 V
Bandwidth, Volts	2 V
Time Delay, Initial	60 Sec
Time Delay, Operating	60 Sec

1. Solar PV Model: Teshmont used a typical PV Panel and Inverter model from the ETAP library and configured it to model a 200 kW solar plant.

The modeled feeder and downstream equipment in ETAP are shown in Figure 1.

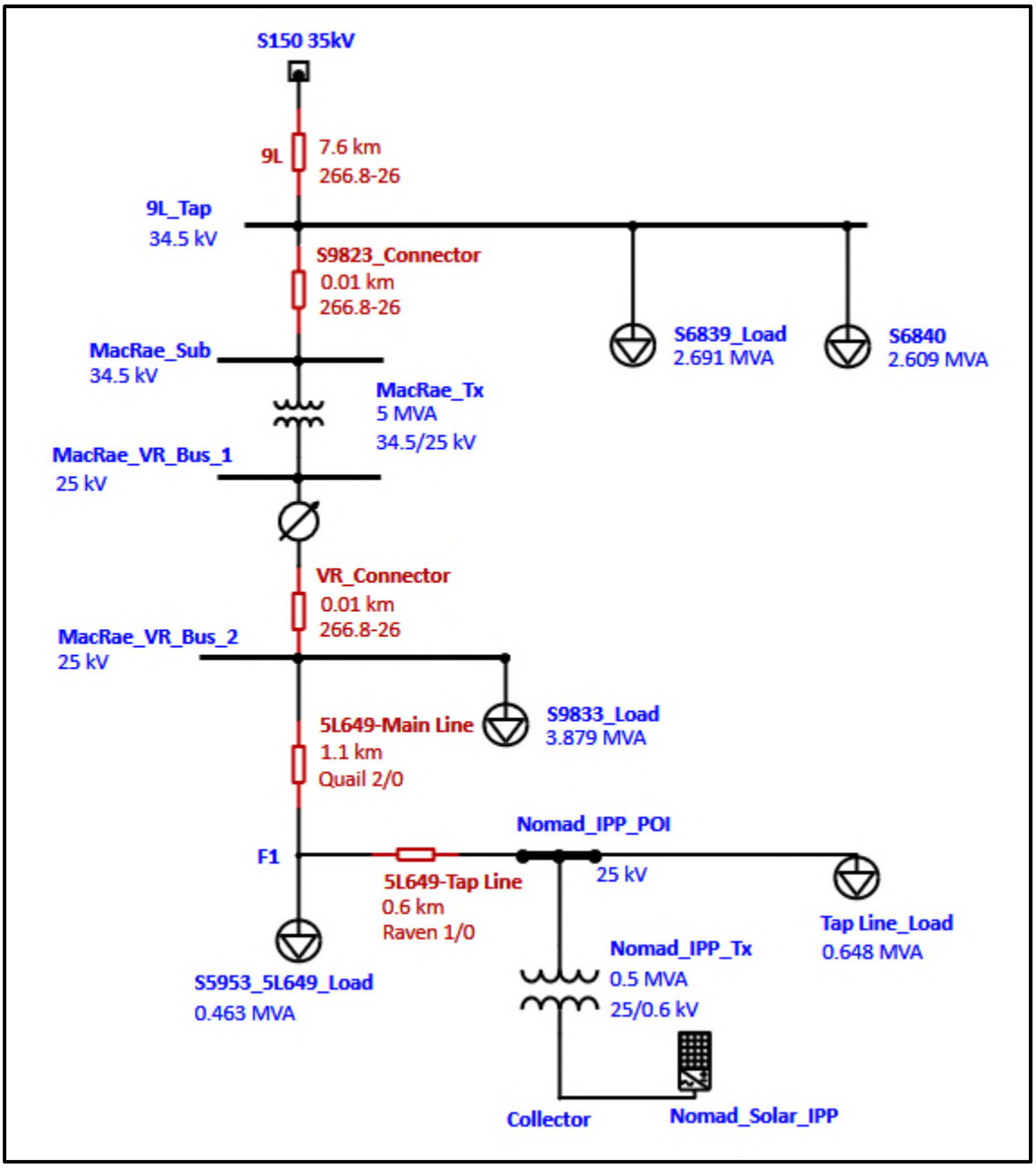

Figure 1: ETAP Single Line Diagram of 9L Feeder

2.2. Assumptions

The following assumptions are taken for this project:

1. The SP and WP loads at S6839, S6840, S9833 and S5953 metering points were prepared and modeled as directed by YEC. The maximum loads during the winter season are assumed as cold load and a 50% reduction factor is applied to obtain the WP loads.

2. The short circuit contribution of the solar plant is assumed to be 150% of the full load current.
3. The Nomad solar plant will be set in power factor control mode at unity power factor.
4. Typical values for settings and assumed configurations are used to model the downstream feeder and associated equipment where data is not available.

3. Analysis

3.1. Short Circuit Study and Protection Coordination Review

Teshmont modeled the solar plant short circuit contribution as 150% of its full load current. As such, the 200 kW solar plant will contribute 7 A of constant fault current.

For a three-phase fault at the solar plant, the estimated minimum three phase fault current is 799 A and maximum three phase fault current is 1156 A.

For a 40 ohm fault impedance, the estimated minimum ground fault current is 317 A and a maximum ground fault current is 331 A.

3.1.1. Equipment Ratings

Existing equipment ratings are adequate.

3.1.2. Overcurrent Protection Settings

The downstream OCR S5953 phase current pickup setting is 140 A and the ground current pick up setting is 110 A.

For 1 MW of downstream load, the load current is 23 A. The relay overcurrent pickup setting is approximately six times the load current. The magnitude of downstream fault currents will remain sufficient to be seen by the OCR.

OCR S5953 will continue to detect and operate for downstream faults at the Solar Plant.

3.1.3. Anti-Islanding Protection

To meet the anti-islanding requirements of IEEE 1547, the solar plant inverters must detect an islanding event and safely separate from the grid within 2 seconds.

The existing first reclose interval for OCR S5953 is set for 0.6 seconds. This will need to be reset to 2 seconds or greater to allow the solar plant to disconnect before the first reclose attempt.

3.2. Load Flow Study and Assessment of Voltage Regulator Settings

The load data provided by YEC/ATCO confirms that the output of the solar plant will always be less than the feeder load. Therefore there will always be forward load flow in the regulators and they can continue to be set in locked-forward mode.

The MacRae substation voltage regulator (VR) settings were modeled according to the settings provided by YEC/ATCO. The voltage regulator is set to control the secondary 25 kV bus at the load side.

Using the study case "VG_S6"case, regulator improves the voltage from 98.52% (source side) to 103.1% at the MacRae 25 kV bus (load side). At Nomad solar plant point of interconnection (POI), the voltage is noted 102.8% in pre-project scenario and 102.9% in post-project scenario.

Using the study case "VG_W6"case, regulator improves the voltage from 94.91% (source side) to 101.4% at the MacRae 25 kV bus (load side). At Nomad solar plant POI, the voltage is noted 101.2% in pre-project scenario and 101.3% in post-project scenario.

4. Conclusion

The connection of the 200 kW Nomad solar plant to the YEC/ATCO distribution feeder 5L649 out of MacRae Substation will have no negative impact on the YEC grid.

Existing equipment ratings and feeder protection settings are adequate, other than a change will be required to OCR5953 reclose interval to allow for the operation of the Nomad solar plant islanding detection.

SCHEDULE "E"

MONTHLY ENERGY SHORTFALL PAYMENT

Monthly Energy Shortfall Payments

In any calendar month in which there has occurred a Non-Permitted Distribution/Transmission Constraint then Buyer shall pay Seller Monthly Energy Shortfall Payment,

where:

"**Monthly Energy Shortfall Payment**" means the Monthly Constraint Shortfall multiplied by the price which is payable for Delivered Energy under Section 5.1 of the EPA; and

"**Monthly Constraint Shortfall**" (expressed in KWh) means, for each calendar month, means the aggregate of the duration of each Non-Permitted Distribution/Transmission Constraint (measured as a fraction determined as the aggregate number of minutes in such Non-Permitted Distribution/Transmission Constraint divided by 60) multiplied by the "Non-Permitted Distribution/Transmission Constraint Hourly Deemed Energy" set out in Table E-1 below for the applicable calendar month.

Table E-1

	Projected Hourly Energy (KWh/h) (A)	**Projected Monthly Energy (KWh) (B)**	**Non-Permitted Distribution/Transmission Constraint Factor (F1)**	**Non-Permitted Distribution/Transmission Constraint Hourly Deemed Energy (KWh/h) (A x F1)**
January	4.20	3,126	_%	
February	19.69	13,232	_%	
March	37.92	28,210	_%	
April	51.37	36,988	_%	
May	50.89	37,861	__%	
June	50.27	36,194	__%	
July	46.93	34,919	__%	
August	44.00	32,737	__%	
September	33.09	23,825	__%	
October	22.04	16,397	__%	
November	6.71	4,834	__%	
December	2.34	1,743	__%	

Revisions to Projected Hourly Energy and Projected Monthly Energy

Within 90 days following the end of the 2nd year after Buyer's COD, the Parties shall review and revise the values in Table E-1 above for Projected Hourly Energy and Projected Monthly Energy to reflect the

average actual amount of Delivered Energy sold to Buyer in the 2 years following Buyer's COD for the applicable months.

SCHEDULE "F"

TERMINATION PAYMENT

The "**Termination Payment**" at any time shall be equal to (a) the Gross Termination Payment set out below for the Contract Year in which the termination occurred, less (b) the actual amounts paid or owing by Buyer to Seller for Delivered Energy for the Contract Year in which the termination occurred.

Table F-1

Termination Year	Gross Termination Payment
Year 1	$477,336
Year 2	$474,530
Year 3	$471,081
Year 4	$466,934
Year 5	$462,026
Year 6	$456,293
Year 7	$449,663
Year 8	$442,059
Year 9	$433,397
Year 10	$423,588
Year 11	$412,533
Year 12	$400,128
Year 13	$386,259
Year 14	$370,801
Year 15	$353,622
Year 16	$334,577
Year 17	$313,511
Year 18	$290,254
Year 19	$264,624
Year 20	$236,423
Year 21	$205,439
Year 22	$171,441
Year 23	$134,179
Year 24	$93,383
Year 25	$48,762

SCHEDULE "G"

SYSTEM INTERCONNECTION GUIDELINES

(Please see attached)

Yukon Energy Corporation

Independent Power Producers Interconnection Technical Guide

Revision: 04b
Release Date: 2019 01 24

Disclaimer

This report was prepared under the supervision of Teshmont Consultants LP ("Teshmont"), whose responsibility is limited to the scope of work as shown herein. Teshmont disclaims responsibility for the work of others incorporated or referenced herein.

Revision History

Revision Number	Date Released	Prepared by	Reviewed by	Comments
00	May 14, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng Robert Baker, PEng	First Draft
01	May 30, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Second Draft
02	June 5, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Third Draft. Incorporated YEC Comments.
03	June 18, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Fourth Draft. Incorporated YEC Comments.
04	September 17, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Fifth Draft. Incorporated YEC Comments.

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Executive Summary

The purpose of the Interconnection Technical Guide is to provide guidelines for Independent Power Producers (IPP) who wish to interconnect a generation facility of greater than 50 kW and up to 10 MW to the Yukon Integrated System (YIS) via the Yukon Energy Corporation (YEC) or ATCO Electrical Yukon (AEY) distribution systems. The maximum allowable generation at the Point of Interconnection (POI) between the distribution system and IPP will depend on the results of a system impact study conducted by YEC. This guide details the technical and operational requirements of the facility and is not intended to be used as a design guide.

The purpose of this document is to:

- Provide technical specifications for the interconnection of IPP generation to the YIS (via YEC or AEY distribution systems).
- Clarify, where necessary, the technical requirements in CSA Standard C22.3 No. 9-08 (R2015) “Interconnection of Distributed Resources and Electricity Supply Systems” [1] and to provide an outline for how each section applies to interconnections with the YIS.

1. Introduction and Scope

1.1. Purpose

This guide establishes criteria and technical requirements for Independent Power Producers (IPP) who wish to interconnect generation, with a net capacity greater than 50 kW and up to 10 MW, to the Yukon Integrated System (YIS), at the distribution level (35 kV and below), or at the transmission level (above 35 kV). This guide has been developed considering CSA Standard C22.3 No. 9-08 (R2015) [1] and IEEE Standard 1547-2018 [2] and is subject to regular review and revision due to evolving standards.

The technical guide is intended to assist IPPs who apply to connect to the YIS through the Standing Offer Program, Call for Power, or through other unsolicited requests to connect.

1.2. Limitations

The criteria and technical requirements described within this section apply to the following generation interconnections:

- Interconnections to the Yukon Energy Corporation (YEC) and ATCO Electric Yukon (AEY) distribution systems at voltages of 34.5 kV and below, and
- Interconnections to the YEC transmission system at voltages over 34.5 kV by means of an existing or new substation. Transmission interconnections will require specific detailed review and approval by YEC and all interconnection costs will be borne by the IPP.

This Guide establishes the minimum requirements for the Point of Interconnection (POI). The IPP generation may be subject to additional requirements to ensure the project meets all applicable standards.

This Guide is not to be used:

- As an Operating Agreement and does not address the following:
    - Joint operating agreements
    - Costs
    - Tariffs
    - Other contractual issues
- As an Interconnection Process and Procedures Guide, and does not include the following:
    - Protection of the IPP's generation facilities
    - Transmission system impact and upgrades
    - System planning and design
    - Operation of the distribution system
    - Other system related issues
- As a design handbook for a generation facility.
- For any IPP generation not connected indirectly or directly to the YIS, i.e. an island grid.

2. Terms, Definitions, and Abbreviations

2.1. Definitions

Accredited Certification Organization – An organization that has been accredited by the Standards Council of Canada to operate a certification program for electrical equipment, such as the Canadian Standards Association (CSA).

Anti-islanding – A means of detecting and preventing a DR from energizing a part of the distribution system that becomes disconnected from the grid.

ATCO Electric Yukon – A private investor-owned utility, and member of the ATCO Group of Companies.

Automatic Circuit Recloser (ACR) – An overcurrent protection device used by utilities to detect faults on distribution system feeders, which has the ability to open and then reclose after a specified time delay allowing adequate time for temporary faults to clear.

Bi-directional Meter – A meter that measures real and reactive power and energy in both directions.

Cease to Energize – The cessation of energy outflow capability.

Clearing Time – The time from the start of the abnormal condition to when the distributed resource ceases to energize the distribution system.

Dispensated Metering Equipment – Any metering equipment that has received Measurement Canada approval under Section 9(2) or 9(3) of the Electricity & Gas Inspection Act.

Disconnecting Means – A device or group of devices that allows the conductors of a circuit to be disconnected from their source of supply.

Distributed Generation (DG) – Small, decentralized electric power generation facilities, typically interconnected to the distribution system.

Distribution System – The portion of the electrical system that operates at a nominal voltage of 34.5 kV line to line and below, and which distributes electric power between distribution substations and customers.

Effectively Grounded Distribution System – Distribution facilities where the neutral conductor is solidly grounded and the ratio of the zero sequence reactance to the positive sequence reactance is less than or equal to 3 and the ratio of the zero sequence resistance to the positive sequence reactance is less than 1.

Electromagnetic Interference (EMI) – Any electromagnetic disturbance that interrupts, obstructs, or otherwise degrades or limits the effective performance of a device, equipment or system.

Exporting – supplying power into the distribution system through the POI.

Facilities – A physical plant including, without limitation, generating plants, transmission and distribution lines, transformers, meters, equipment and machinery.

Flicker – The subjective impression of fluctuating luminance caused by voltage fluctuations.

Frequency – The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz (Hz).

Generation – The process of converting solar, thermal, wind, hydro, or chemical energy into electric energy.

Independent Power Producer (IPP) – An agency or individual other than a public utility (as defined by the Public Utilities Act) who generates electricity to sell (to the utilities). An independent power producer does not own transmission facilities and is dependent on the utilities to purchase and distribute the power it produces.

Interconnection – The physical connection of DG to YEC's distribution system so that parallel operation can occur.

Island Grid – A community power system which is energized solely by one or more local power producers and is separated electrically from the YIS.

Islanding – A condition where a portion of the utility's distribution system is energized exclusively by one or more power producers through their DR interconnection.

Operating Interface Point – See Point of Interconnection.

Parallel Operation – the simultaneous energization at a POI by the generating facility and the utility distribution system.

Point of Interconnection (POI) – The location of the electrical connection between an IPP facility and the utility's distribution system. This will be the point where the ownership changes from the utility to the IPP.

Power Factor – The ratio of active power to apparent power. It is the cosine of the phase angle difference between the current and voltage of a given phase.

Protection Scheme – The protection functions, including associated sensors, relays, and power supplies, intended to protect a distribution system or interconnection equipment.

Public Utility – As defined by the Public Utilities Act and Regulations (i.e., YEC and/or AEY).

Ride-through – The ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.

Secondary Injection Testing – A method in which low level signals obtained from current and voltage signal generators are injected into a power system protective device to test device response.

Stabilized – The state of the distribution system after voltage and frequency has returned to normal range for a period of at least five minutes (or another period of time, as agreed with YEC) following a disturbance.

Stand Alone – The state where a distributed generation can operate by controlling the frequency and voltage of their facility while in islanded or isolated mode.

Telemetering – Transmission of measurable quantities using telecommunications systems.

Total Demand Distortion (TDD) – The ratio of the root mean square of the harmonic content, considering harmonic components up to the 50th order and specifically excluding interharmonics, expressed as a percent of the maximum demand current. Harmonic components of order greater than 50 may be included when necessary.

Total Harmonic Distortion (THD) –The ratio of the root mean square of the harmonic content, considering harmonic components up to the 50th order and specifically excluding interharmonics, expressed as a percent of the fundamental. Harmonic components of order greater than 50 may be included when necessary.

Transfer Trip – A remote signal directed from an upstream device to command a DG to cease to energize the distribution system upon detection of an islanding condition and to prevent re-energization.

Transmission System –The portion of the system that operates above a nominal voltage of 34.5 kV line to line and transmits electric power between YEC substations.

Trip Time – The time between the start of the abnormal condition and the interconnection device ceasing to energize the distribution system.

Type Test – A test performed on a sample of a particular model of a device to verify specific aspects of its design, construction and performance.

Utility – See Public Utility (i.e., YEC and/or AEY).

Visible-Break Disconnect – A switch or circuit breaker by means of which the generator and all protective devices and control apparatus can be simultaneously disconnected under full load entirely from the circuits supplied by the generator. All blades or moving contacts must be connected to the generator side, and the design of the disconnect switch must allow adequate visible inspection of all contacts in the open position.

Voltage Flicker – A condition of fluctuating voltage on a power system that can lead to noticeable fluctuations in the output of lighting systems.

Yukon Energy Corporation (YEC) – A publicly-owned electrical utility that is the main generator and transmitter of electrical energy in Yukon.

Yukon Integrated System – The integrated Whitehorse-Aishihik-Faro and Mayo-Dawson electrical grids which are owned by YEC.

2.2. Abbreviations

ACR	Automatic Circuit Recloser
AEY	ATCO Electric Yukon
AEUC	Alberta Electrical Utility Code
CEA	Canadian Electricity Association
CEC	The Canadian Standards Association's C22.1-98 Safety Standard for Electrical Installations Part 1, also known as the Canadian Electrical Code
CSA	Canadian Standards Association
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers, Inc.
IPP	Independent Power Producer
LTC	Load Tap Changer
NEMA	National Electrical Manufacturers Association
POI	Point Of Interconnection
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SCC	System Control Center
SIS	System Impact Study
YEC	Yukon Energy Corporation
YIS	Yukon Integrated System
YUB	Yukon Utilities Board

3. Party Responsibilities

Refer to the IPP Policy as released in January 2019 for the individual responsibilities of the Government of Yukon, utilities (YEC and AEY), Yukon Utilities Board and the IPP during the generation interconnection process.

3.1. IPP Responsibilities

The IPP is responsible to:

- Provide technical information to the utility as specified in Appendix A and Appendix B;
- Assume ownership of the facility including the design, installation, operation, and maintenance of all equipment, station and distribution line facilities from the POI to the IPP facility, unless otherwise agreed to in writing;
- Pay the costs of system interconnection in accordance with the commercial terms established by the utilities;
- Obtain all regulatory approvals, including environmental assessment approvals, if necessary, for the construction and operation of its facilities. The IPP facilities shall be designed, constructed, operated and maintained in compliance with the applicable statutes, regulations, by-laws, codes and technical requirements specified by the utility (e.g. remote monitoring etc.);
- Submit all specifications of its facilities and detailed plans to the utility for review prior to receiving permission to connect to their distribution system;
- Ensure the technical requirements given in the standards and codes in Appendix D are met;
- Ensure metering requirements are met (see section 12); and
- Negotiate the timing and any testing requirements for the commissioning process with YEC

3.2. YEC Responsibilities

YEC is responsible for the operation of the Yukon Integrated System (YIS) and for certain local distribution systems interconnected with the YIS. This guide applies to all transmission and YEC distribution system interconnections.

YEC is responsible for all system studies performed on the YIS. The IPP and AEY, in the case of an AEY interconnection, shall provide all necessary information to YEC for the interconnection of the IPP facility. The system studies conducted by YEC will be paid for by the IPP.

After receiving the application for interconnection, YEC shall provide the IPP, at the IPP's cost, the information specified in Appendix C.

3.3. AEY Responsibilities

AEY is responsible for the operation of certain local distribution systems interconnected with the YIS. This guide applies to these AEY distribution system interconnections.

After receiving the application for interconnection, AEY shall, in consultation with YEC, provide the IPP, at the IPP's cost, the information specified in Appendix C.

4. General Requirements

4.1. Standards

When planning, designing, and operating an IPP Generation Facility, the IPP shall meet all applicable national, territorial and local construction and safety codes and standards.

The interconnection facility must comply, as a minimum, with the following:

- All CSA Standards, including the Canadian Electrical Code (CEC),
- Applicable YEC and AEY standards and the requirements set forth in this Guide,
- National, Territorial and local Governing law, acts, by-laws and codes, and
- Alberta Electrical Utility Code (AEUC) [4].

Applicable standards are located in Appendix D, however not all may be applicable for the IPP facility and additional standards may apply.

The interconnection of new generation can adversely affect the electric service to existing or future customers. The IPP must work with the utility to mitigate any adverse effects.

The facility must be constructed and maintained to provide a safe environment for employees as well as the public. If the generation facility adversely affects other customers, the utility may disconnect it until such time as the concern has been mitigated. The IPP is responsible for any costs incurred as a result.

The IPP is required to install, operate and maintain the facility and to ensure it is in sufficiently good order and repair at all times. Maintenance shall conform to good electrical practice, adequate for safe parallel operation when connected to the YIS. The utility and the IPP shall share commissioning reports, operating procedures and annual shutdown, maintenance, and inspection reports.

4.2. Operating Requirements

A joint operating agreement template will be developed in conjunction with the utility. The agreement requirements are not included within the scope of this Guide. A sample operating agreement is located in Appendix E.

5. Site Specific Conditions and Capacity Limitations

During the preliminary stage of project development any limitations regarding the proposed interconnection, and any additional system upgrades required, will be determined in consultations between the IPP, YEC and AEY, if interconnected via an AEY distribution system.

A system impact study will be necessary to identify any site-specific conditions and capacity limitations of the distribution and/or transmission system. To facilitate the study, the utility and the IPP will exchange information concerning load, feeder characteristics, protection philosophies, station layouts, capacities, ratings and other relevant information of the distribution and/or transmission system. The utility controls reliability design and reliability standards.

Under certain circumstances, YEC and AEY may limit the size or reconfigure the proposed connection arrangement of the IPP facility in order to maintain the integrity of their system.

6. YIS Transmission and Distribution System Characteristics

6.1. YEC Transmission System

6.1.1. General System Configuration

The YIS is an 'Islanded grid' which has no interconnection with the main North American electric grid. The Yukon must produce all of its own power, and cannot generate more electricity than is there is load, since there are no neighboring markets into which to sell surplus energy.

The YIS includes the 138 kV Whitehorse – Aishihik – Faro (WAF) grid, the 69 kV Mayo-Dawson-Keno (MD) grid, and the 138 kV Carmacks-Stewart Transmission Line (CSTL) which interconnects the WAF and MD grids. YEC provides power to major industrial customers connected to the 69 kV and 138 kV grids.

A map of the YIS is shown in Figure 6–1.

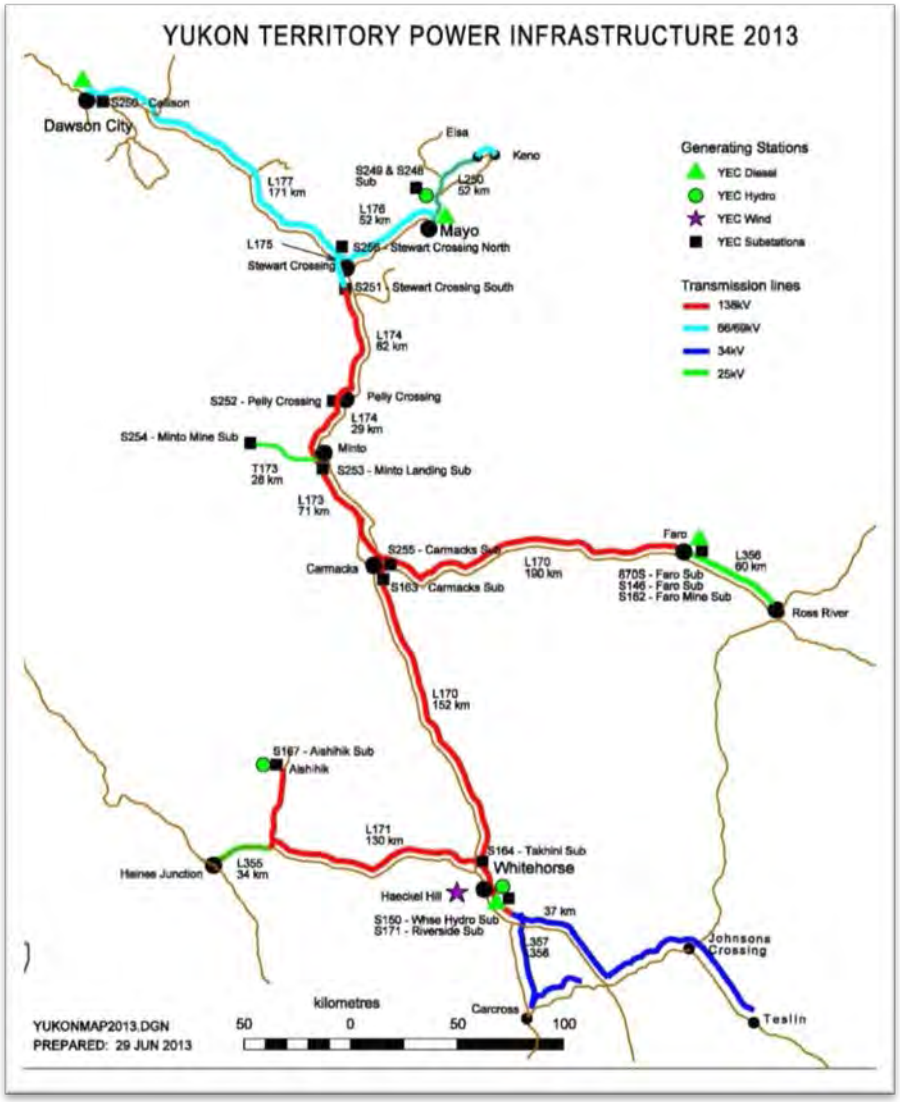

Figure 6–1: YIS Map

6.1.2. System Unbalance

Voltage unbalance on the transmission system is minimal during normal operation. The voltage unbalance under normal operating conditions will be less than three (3) percent. The IPP facilities may be subjected to voltage unbalance and negative sequence current during system disturbances. The generation connected to the transmission system must be able to withstand significantly unbalanced voltages with high negative phase sequence currents for short periods of time.

6.1.3. Frequency

The YEC transmission system operates at 60 Hertz (Hz) Alternating Current (AC) with equipment standard for this frequency. Frequency variations are typically in the range between 59.0 Hz to 61.0 Hz for small contingencies that cause modest disturbances, however variations between 58 Hz to 66 Hz or greater can occur for larger contingencies.

The frequency of the electric system is controlled by synchronous generator governor systems. Such governor systems respond automatically to changes in system frequency to prevent further deviation. These variations are system dependent and subject to change.

6.1.4. Steady State Voltage Levels

During normal steady state conditions, the 69 kV and 138 kV systems can vary between 90% and 105% of nominal voltage. However, under extreme conditions, the 69 kV and 138 kV systems can vary between 85% and 110% of nominal voltage with some 138 kV facilities designed to operate continuously up to 110% of nominal voltage.

6.1.5. System Fault Levels and System Impedances

The IPP generation facilities connecting directly to the transmission system shall be designed for operation at short circuit (fault) levels that take into account reasonable future development of the YIS transmission system. The short circuit levels to be used in the design depend on the point(s) of interconnection and future planned development and are available on request from YEC.

6.1.6. Fault Clearing and Automatic Reclosing

The YIS does not implement auto-reclosing at the transmission level.

6.1.7. System Grounding

The transmission system is effectively grounded.

6.2. YIS Distribution System Characteristics

6.2.1. General

Both YEC and AEY operate distribution systems in the Yukon which are interconnected with the YIS. The systems are predominantly three phase, wye connected, with nominal voltages of 4.16/2.4 kV, 6.9/4 kV, 12.5/7.2 kV, 13.8/8 kV, 25.00/14.4 kV and 34.5/20 kV.

AEY also operates a number of distribution systems which are not interconnected to the YIS, and are not covered by this Guide:

- Watson Lake
- Old Crow
- Beaver Creek
- Destruction Bay / Burwash Landing
- Swift River

For information on connecting to the AEY distribution systems which are isolated from the YIS, refer to AEY's document entitled, "ATCO Electric Yukon's Isolated Community Generation System Interconnection Guidelines".

6.2.2. Voltage Levels

The YEC and AEY distribution systems operate to meet CSA Standard CAN3 C235.83 – "Preferred Voltage Levels for AC Systems 0 to 50,000V" which defines the preferred operating voltage levels for normal and extreme operating conditions. The distribution system steady state voltage is typically maintained between + 5% to 7% and - 5% to 7%.

6.2.3. Power Quality (Harmonics and Voltage Flicker)

The YEC and AEY distribution systems operate to limit the maximum individual frequency voltage harmonics to 3% of the fundamental frequency and the voltage total harmonic distortion (THD) to 5% on the utility side of the POI.

6.2.4. Voltage Regulation

The operating voltages on the low voltage buses of YEC distribution substations are generally regulated by transformer automatic load tap changers (LTC), bus voltage regulators or feeder voltage regulators. YEC will provide set-points for the equipment upon request.

6.2.5. Voltage Unbalance

Distribution facilities are typically three-phase systems, incorporating single-phase distribution taps. The voltage unbalance on a distribution system under normal operating conditions may exceed 3%, due to the unbalanced loading and single-phase regulation. Voltage unbalance will be calculated using the following formula, as derived from CSA Standard C22.3 No. 9-08 (R2015) [1]:

Voltage Unbalance (%) = 100 x (negative sequence voltage of the fundamental frequency component) / (positive sequence voltage of the fundamental frequency component)

6.2.6. Fault Levels

Fault levels and maximum allowable fault currents vary significantly through the distribution system and must be considered in the design of the IPP interconnection.

6.2.7. System Grounding

The utility distribution facilities are typically three phase, four wire, multi-grounded systems that incorporate single phase distribution taps. The lines are normally operated as effectively (solidly) grounded with grounded-wye connected sources at the distribution substation secondary bus.

6.2.8. Phasing

The phase sequence on the utility system may vary, and must be confirmed between the IPP and the utility during the design phase of the installation.

6.2.9. Fault and Line Clearing and Automatic Reclosing

The YEC distribution systems do not currently include auto reclosing. The AEY distribution systems may have auto reclosing and this will be confirmed during the design phase of the application.

7. Power Quality Requirements for the System Interconnection

7.1. Harmonics

The following industry standards may provide guidance for appropriate performance.

- IEEE 1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces, IEEE, 2018 [2]
- IEEE 519-2014 – IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems [5]
- IEC 61000-4-15 – Testing and Measurement Techniques – Flickermeter - Functional and Design Specifications [6]

The generation facility shall not inject harmonic currents such that will cause objectionable voltage distortion as per standard IEEE 519 Harmonic current injections cause intolerable voltage distortions on the distribution system and may damage equipment.

The Utility, at the IPP's expense, shall conduct a Power Quality Assessment of the distribution system in the immediate vicinity of the interconnection using a measurement technique compliant with IEC 61000-4-7.

When performing a Power Quality Benchmark, the measurements at the customer's POI shall be taken over a one week (168 hour) period during typical production load levels.

7.2. Flicker

The generation facility shall meet the requirements of Section 6.2.3 and shall not cause unacceptable levels of flicker on the distribution system. The utility, at the IPP's expense, shall measure the flicker level using a power quality measuring device that meets the requirements of the IEC Flickermeter Standard 61000-4-15.

When performing a Flicker assessment, the measurements at the customer POI shall be taken over a representative load cycle of one day or greater.

7.3. Speed Regulation and Frequency Control

The frequency of the YIS is controlled by the generators operated by YEC.

The YIS operates at 60 Hertz (Hz) Alternating Current (AC). The nominal frequency variations are typically 59.0 Hz to 61.0 Hz for small contingencies that cause modest disturbances, and the frequency may drop to 58 Hz or rise to 66 Hz or higher for larger contingencies.

The frequency of the YIS is automatically controlled by the governor systems of the generators operated by YEC, within the specified limits.

IPP generators rated at 1 MVA and greater are required to have a governor system, capable of operating in droop mode, to respond to system frequency changes. The droop setting of the governor will typically be in the range of 5%.

IPP generators rated less than 1 MVA may operate in base load mode rather than in frequency control mode.

The utility will define frequency requirements on a project by project basis and may require the control of these parameters directly via the YEC SCC.

Equipment connected to the YIS shall be capable of withstanding the dynamic frequency performance criteria listed in Table 1.

Table 1: Transmission Minimum Frequency Performance

Under Frequency Limit	Over Frequency Limit	Minimum Time
60.0-59.0 Hz	60.0-61.0 Hz	N/A (continuous operating range)
58.9-58.5 Hz	61.1-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
less than 56.4 Hz	greater than 61.7 Hz	Instantaneous trip

Under-frequency and over-frequency relaying that automatically disconnects generators from YIS must not operate for frequencies in the range of 59.0 to 61.0 Hz if no other abnormal system event is underway.

7.4. Voltage Regulation and Power Factor

The IPP is responsible for ensuring that the voltage levels at the POI are maintained within this guidelines prescribed by the utility. The IPP interconnection must maintain the voltage levels, under all feeder load conditions, at the same values as they were prior to the interconnection.

Synchronous generators connected to the distribution system must be equipped with adequate excitation controllers. The IPP shall operate generators with Automatic Voltage Regulators (AVR) adjustable from 95% to 105% of nominal bus voltage. The Generation should be run in Voltage control unless required to run in power factor (pf) mode by the Utility. Operation in MW or MVAR control is not acceptable. The AVR response should with no intentional delay when in Voltage Control mode.

Induction generators do not have voltage or reactive power control capability and consume reactive power (VAR). In this case, the generator must provide reactive compensation to correct the power factor to 0.9 lagging or better at the POI, unless other terms are specified by the utility.

Inverter type generating equipment can control the power factor over a wide range, typically ± 0.75. An inverter type generator connected to the distribution facility must be capable of adjusting the power factor in the range of ± 0.9. The IPP may operate outside that range only by prior agreement with the utility.

The utility will define voltage and reactive power requirements on a project by project basis and may require the control of these parameters directly via the YEC SCC. The IPP and utility will identify and

agree on the exact transformer ratio to allow optimal voltage regulation on the system and the IPP will determine whether an on-load tap changer is needed.

In order to coordinate with its existing voltage control devices, the utility may require that the generator operate in a power factor control mode. This means operating within a constant power factor set point range. The voltage/power factor regulator must be capable of controlling the power factor of the generator. The utility shall determine the actual set point between these limits.

In power factor control mode, the voltage regulator must have a voltage override that causes it to reduce excitation if the voltage at the POI exceeds an upper limit to be specified by the utility. The normal upper limit is 105% of nominal; however, the voltage regulator shall have the provision to adjust this upper limit between 100% and 110% of nominal. The voltage regulator must also have provision for a time delay between sensing an excursion of the upper voltage and initiating control action. The power factor control equipment must have the capability to allow for the adjustment of this time delay from between 0 and 180 seconds. The utility will specify the required time delay for each project.

7.5. Voltage Unbalance

Unbalanced phase voltages and currents can affect protective relay coordination and cause high neutral currents and thermal overloading of transformers. Of particular concern is negative sequence voltage and the resulting effect, particularly on rotating generators and motors connected to the system.

To protect the utility and the IPP equipment, the 3-phase generation contribution at the POI should not cause a voltage unbalance greater than 1% or a current unbalance greater than 5%.

If the existing unbalance at the POI is shown to be already close to the maximum unbalance condition, the IPP contribution may cause the unbalance to exceed the specified amount. This will be considered on a case-by-case basis.

7.6. Voltage and Frequency Transients

The IPP is responsible for the cost of any necessary transient or dynamic stability studies, which must be performed in a manner approved by YEC.

7.7. Resonance and Self-Excitation of Induction Generators

The potential effects of resonance should be considered as part of the design of the generating facility. The effects include:

- Ferro-resonance in the transformer,
- Sub-synchronous resonance due to the presence of capacitor banks, and
- Harmonic resonance with other customers when capacitors are being added as part of the installation.

When induction generators are used, the potential for self-excitation should be assessed and addressed as part of the system impact study and mitigated accordingly.

The IPP shall be responsible for the engineering analysis as part of the design process to evaluate the existence of, and to eliminate the harmful effects of resonance and the assessment of the self-excitation effects of induction generators. The engineering analysis of resonance and the assessment of the self-excitation effects of induction generators must be submitted to YEC for approval or further evaluation.

7.8. DC Current Injection

The IPP facility system shall not inject a dc current at the POI.

7.9. Fault Levels

The utility will provide the IPP with the anticipated fault levels or the data necessary for the IPP to calculate the distribution system fault contributions at the POI.

The IPP facility must not increase the fault levels on the utility distribution or transmission system above their design levels for maximum faults.

8. Physical Interconnection

8.1. Safety

The safety of the public, operating personnel and the environment is of primary concern in the design, construction, operation and maintenance of the interconnection facilities.

8.2. Point of Interconnection (POI)

The POI is the point at which the utility (YEC or AEY) distribution facilities or conductors are connected to the IPP's facilities or conductors, and where any transfer of electric power between the IPP and the utility takes place. The POI must be identified in the design and on the Single Line Diagram (SLD).

Depending on ownership, YEC or AEY will coordinate the design, construction, maintenance and operation of the facility on the distribution system side of the POI. The IPP is responsible to coordinate the design, construction, maintenance and operation of the facility on the generation side of the POI.

All voltage and frequency parameters specified in this section must be met at the POI unless otherwise stated.

The IPP is responsible for any incremental costs to the electric systems caused by the interconnection. The responsible utility will carry out the engineering, design and construction required for these installations and charges those costs back to the IPP. Ongoing O&M costs incurred on the distribution feeder side will also be recovered by the utility.

There may be cases where either the utility or the IPP may own equipment located on the other's side of the POI. For example, the utility may own and operate communications, supervisory, or metering equipment, which is located on the IPP side of the POI. The IPP must provide a site with the necessary space for utility to install current transformers, potential transformers, switching equipment, meters, and any other AC and DC auxiliaries, protection and controls, SCADA or communications equipment required to interconnect with the generating facility. The site is to be approved by the utility and a 120-volt AC power service is to be available for the use of portable tools.

8.3. Point of Disconnection

For transmission interconnections, the visible-break disconnect switch shall be located on the high voltage side of the interconnection transformer.

For distribution interconnections, the visible-break disconnect switch may be located on the high or low voltage side of the interconnection transformer.

The disconnect switch must be gang operated to simultaneously isolate all three phases.

If the IPP site interconnects multiple generators, one disconnect switch must be capable of isolating all of the generators simultaneously. There may be other means of meeting this requirement; however the approval of the utility must be obtained before using other means.

The IPP must follow the utility switching, clearance and tagging procedures. The utility is responsible to instruct the IPP in this regard.

8.3.1. High Side and Low Side Disconnect Switches

For transmission interconnections the disconnect switch on the high voltage side of the interconnection transformer shall be installed, owned and maintained by the IPP.

For distribution interconnections the disconnect switch, if on the high voltage side of the interconnection transformer shall be installed, owned and maintained by the utility, and if on the low voltage side of the interconnection transformer shall be installed, owned and maintained by the IPP.

8.3.2. Disconnect Switch Specification

The disconnect switch must be a manual, visible-break disconnect that provides safe isolation for the utility's personnel from the generators and all other possible customer sources of energy.

The disconnect switch must:

- Be adequately rated to break the connected generation/load;
- Be located within five meters (horizontal) of the POI, unless otherwise approved by the utility;
- Provide a direct, visible means to verify contact operation;
- Allow simultaneous disconnection of all ungrounded conductors of the circuit;
- Plainly indicate whether the switch is in the "open" or "closed" position;
- Be lockable in the "open" position;
- Be capable of being energized from both sides;
- Be readily accessible to the utility's operating personnel;
- Be externally operable without exposing the operator to contact with live parts;
- Be capable of being closed without risk to the operator while there is a fault on the system;
- Be labeled with utility's switch number;
- Meet all applicable CSA Part II standards and all applicable codes; and
- Undergo annual inspections and maintenance, with reports submitted to the utility for approval.

8.4. Interconnection Transformer

A generator step-up transformer boosts the voltage of the DG to match the voltage of the utility distribution feeder. The transformer winding configuration impacts how system faults are detected and what type of protection is required (see Section 9.10). The IPP must submit their transformer connection proposal to the utility for review and approval prior to placing an order for purchase.

8.5. Interconnection Grounding

The IPP facility must be grounded in accordance with the latest revisions of the CEC and AEUC. A ground grid of sufficient size to handle the maximum available ground fault current must be designed and installed in order to limit ground potential rise (GPR) step and touch potentials to safe levels as set forth in ANSI/IEEE Std. 80 IEEE Guide for Safety in AC Substation Grounding.

The ground grid will be designed for foreseeable future fault levels obtainable from the System Impact Study.

Grounding of the interconnection shall be designed to provide:

- Solid grounding of the distribution feeder neutral connection,
- Fault detection that isolates all sources of ground fault contribution,
- A circuit to block the transmission of harmonic currents and voltages, and
- Protection of the low voltage side from damage due to high side faults.

The preferred configuration, for an IPP owned interconnection transformer, is delta connection on the generator side of the transformer and a grounded-wye configuration on the utility's side of the transformer. If this configuration is not technically feasible, the configuration chosen must still address the above concerns. Grounding must conform to the AEUC [4].

Sample single line diagrams are shown in Appendix F.

8.6. Phasing and Phasing Sequence

Since phasing is not standardized across distribution facilities, the phase sequence must be coordinated between the IPP and utility's distribution system.

8.7. Interrupting Device Ratings

The design of the generation facility must consider the fault contributions from both the distribution system and the IPP generation facility, to ensure that all circuit fault interrupters are adequately sized. The utility will inform the IPP of the present and anticipated future fault contribution from the interconnected electric system.

9. Interconnection Protection

9.1. General

The purpose of the IPP facility protection is to reduce the risk of damage to IPP and utility equipment and maintain the reliability of supply.

The protection scheme shall be designed to detect the following conditions at the POI:

- Balanced and unbalanced system faults (i.e. line-ground, line-line and three phase faults)
- Frequency variations
- Voltage variations
- Reverse power flow
- Islanding conditions
- Out of synchronism

Depending upon location, the protection scheme may be required to detect additional conditions such as open phase, ferro-resonance, negative sequence voltage, or zero sequence currents.

The protection scheme must fully coordinate with any existing distribution system protective devices. The IPP must submit a complete protection design package, including all relay settings, tripping schemes and schematics, to the utility for review and approval prior to installation. Both existing and ultimate bus fault levels should be considered. A sample Protective Setting Commissioning Sheet with guideline limits is included in Appendix G.

The point of measurement for voltage and frequency shall be at the POI or as agreed upon with the utility.

The IPP must revise and re-submit the protection information for any proposed modification.

9.2. Device Ratings

Equipment shall be rated to carry and interrupt the fault levels that are, or will be, present at the IPP facility - this includes the ultimate fault currents specified by the utility. The IPP's equipment covers all station and distribution facilities, including but not limited to all protection equipment forming the entrance and distribution line protection: circuit breakers, current transformers, potential transformers, secondary cabling, dc system/battery charger, switchboard wiring and protective relays.

9.3. Minimum Protection Requirements

The following minimum protection requirements shall be provided for an interconnected IPP facility:

- Overcurrent
- Over-frequency
- Under-frequency
- Over-voltage
- Under-voltage

Additional protection requirements are dependent upon the transformer configuration and the distribution system characteristics.

9.4. Phase and Ground Fault Protection

The IPP must install utility grade protective devices to detect and promptly isolate the generation facility for faults occurring either in the DG facility itself or on the distribution system. Virtual devices (i.e., computer or programmable-logic controller systems) are acceptable provided they meet standard utility practice for system protection and they have been type tested and approved by an independent testing laboratory.

The protective devices in the IPP generation facility must fully coordinate with the protective relays on the distribution system unless otherwise agreed. The IPP must calculate the protective device settings and submit the relay characteristics and settings to YEC for review and approval.

The generation facility must be able to detect the following situations and isolate itself from the distribution system:

- A short circuit between any phase(s) and ground (if distribution system is a grounded system)
- A short circuit between phase(s)

9.5. Over-Frequency and Under-Frequency Protection

Each synchronous generator must be capable of continuous operation between 59.0 Hz and 61.0 Hz and of limited time operation for larger deviations from normal frequency, as shown in Table 1.

Over/under frequency relays are normally installed to protect the generators from extended off-nominal operation. It is expected that larger (> 1 MW) synchronous generators shall remain connected to the system during frequency excursions. To ensure that the generator is not tripped prematurely, YEC will specify the minimum required time delays and levels for setting the IPP over/under frequency protection relays.

9.6. Over-Voltage and Under-Voltage Protection

The IPP must operate its generation facility such that the voltage levels on the utility's system are not significantly altered by the connection of the generation facility. IPP facility paralleling shall not cause voltage fluctuations of more than ± 5% at the POI.

The IPP must install necessary relays to trip the circuit breaker when the phase-to-ground voltage, measured on any one of the three phases, deviates outside predetermined limits. Under-voltage relays should be adjustable and should have a settable time delay to prevent unnecessary tripping of the generator on external faults. Over-voltage relays should be adjustable and may be instantaneous.

The interconnection facility must cause the generator to cease to energize the utility's system within the trip times indicated in Table 2. "Trip time" refers to the period of time between the start of the abnormal condition and the moment the interconnection device ceases to energize YEC's system.

To ensure that the generator is not tripped prematurely, the utility will specify the minimum required time delays and levels for setting the IPP over/under frequency protection relays.

Table 2: Response to Abnormal Voltages

RMS Voltage (based on 120V nominal)	Trip Time
RMS Voltage: V=<50%	Trip time: Instantaneous

RMS Voltage (based on 120V nominal)	Trip Time
RMS Voltage: 50% < V < 90%	Trip time: 120 cycles
RMS Voltage: 90% < V < 105%	Normal Operation
RMS Voltage: 105% < V < 120%	Trip time: 30 cycles
RMS Voltage: V >= 120%	Trip time: Instantaneous

The IPP may reconnect when the system is stabilized (i.e. voltage and frequency have returned to normal range for a time as identified by the utility).

9.7. Additional Protection

The utility may require additional protection on a case by case basis. Possible protection may include:

- **Unbalance or negative sequence protection**: The IPP generator is tripped on excessive current unbalance. This is important if fuse protection is used on the primary of the generator step-up transformer or for any other open phase condition
- **Broken delta protection (59G)**: Using a grounded wye-broken delta potential transformer, this protection can facilitate detection of ground faults on ungrounded systems.
- **Rate of change of frequency**: Protection to detect a power island condition.
- **Reverse power protection**: Protection to detect a generator motoring condition.

9.8. Anti-Islanding Protection

Islanding is the condition where the generation facilities and a portion of the distribution system have become isolated from the rest of the system, and continue to operate in isolated mode. Unless agreed upon by the utility, generating facilities shall not be permitted to remain connected to an islanded system, i.e. islanding is not generally allowed. Generation facilities may continue to supply station service loads while disconnected from the interconnection system.

Anti-islanding protection is required to:

- Prevent power quality issues to customers connected to the island,
- Avoid out-of-phase reclosing between the utility and the DR facility, and
- Prevent safety hazards created as a result of back feeding isolated portions of the utility distribution system.

For rotating generators, the IPP must install a transfer tripping scheme using tele-protection signals from the system to separate the DG facility from the distribution system in the event of an islanding condition.

Transfer tripping requirements are also applicable to induction generators, unless the IPP can demonstrate that that there is no potential for self-excitation. For inverter-based generation a detection scheme designed in accordance with the requirements of IEEE 1547 [2] may be acceptable.

The IPP is responsible for damage to the YIS caused as a result of failure to safely separate from the system during an islanding event or subsequently during reconnection to the system following the event.

9.9. Transformer Winding Configuration

The winding configuration of any three phase transformer will have an influence on the location of the protection measurement points and the level of protection required for the IPP interconnection. See Appendix F for examples for typical synchronous generator protection single line diagrams for different transformer configurations.

9.10. Conditions for Connecting to an Energized Distribution System

The IPP system must not energize the utility distribution system when the distribution system is de-energized or following the operation of any interconnection protection functions. The utility will inform the IPP facility when it is safe to reconnect to the distribution system.

Where transfer trip protection is installed, the transfer trip protection must ensure that the generator disconnects before a substation feeder breaker or intermediate automatic circuit reclose (ACR) operation. General requirements are:

- Generator lockout within 0.6 seconds of breaker or ACR opening; and
- Fail-safe lockout within 6 seconds of communication loss.

These conditions will be finalized via the operating agreement between the utility and the IPP.

9.11. Synchronization

Any DG facility able to generate voltage while disconnected from the YIS requires synchronization facilities before connection is permitted.

The IPP facility shall maintain in synchronism with the system while operating in parallel. The generating facility has the responsibility of maintaining synchronization with the system. The utility cannot synchronize to the generating facility. Any proposed synchronizing scheme must be submitted to the utility, prior to the installation.

For synchronous generators, an approved automatic synchronizing device must be provided in all cases where the plant is to be operated unattended. Automatic synchronizing shall be supervised by a synchronizing check relay. Synchronizing controls should satisfy the conditions in Table 3 for synchronous generators.

Table 3: Synchronization Criteria for Synchronous Generators

Aggregate Rating of Generators (kVA)	Frequency Difference (Hz)	Voltage Difference (%)	Phase Angle Difference (degrees)
0-500	0.3	10	20
>500 – 1500	0.2	5	15
>1500	0.1	3	10

Induction generators do not require synchronization since there is no generated voltage prior to connecting to the distribution system. The generator speed shall be brought to within 0.5% of its rated value. These units may be started as induction motors using power from the distribution system provided that these units do not cause unacceptable voltage flicker as specified in Section 7.2 on start - up or on connect/disconnect. The interconnection process of the induction generator shall not create a voltage drop pf greater than 5 percent.

Inverter-type or line-commutating voltage-following equipment does not require synchronization facilities. Operation of the interconnection (or disconnecting of the DR facility) shall not cause voltage drop greater that 5 percent and shall meet the flicker requirements

9.12. Protection from Electromagnetic Interference (EMI)

The influence of EMI must not result in a change in state or mis-operation of the interconnection facility.

9.13. Surge Withstand Performance

The interconnection facility must have the capability to withstand voltage and current surges in accordance with the environments described in IEEE/ANSI C62.41 or C37.90.1

9.14. Batteries and Auxiliaries

Batteries and auxiliaries shall have sufficient capacity to ensure the operation of all DC loads during loss of AC supply. Typically the batteries must be capable of supplying the substation DC load for 8 hours.

9.15. Mitigation of Protection Scheme Failure

Relays with self-diagnostic features, which provide information on the integrity of the protection scheme, should be used whenever possible.

The protection scheme must be designed by a qualified professional engineer, or a competent technical person working with the utility's engineers, to ensure that the self-diagnostic feature is integrated into the overall protection scheme for the safe and reliable operation of the system.

Depending on the scheme and its design, where relays with the self-diagnostic feature do not trip the appropriate breaker(s), sufficient redundant or backup protection must be provided for the system. The malfunctioning relay must also send a signal to notify operating personnel to investigate the malfunction.

9.16. Instrument Transformers used for Protection

Instrument transformers used for protection must comply with CAN/CSA-C60044-6 or IEEE C57.13 [8].

10. Remote Monitoring and Information Exchange

The IPP facility shall provide information in real-time to YEC SCC regarding:

a. Connection or circuit breaker status,
b. Real and reactive power output in kW and kVAR,
c. Load Tap Changer (LTC) position of the interconnecting transformer,
d. Communication and RTU failure alarm,
e. Intelligent Electronic Device (IED)/Relay failed status, and
f. Voltage at the POI.

The communication protocol and the equipment required will be specified by YEC.

The IPP facility shall log the operation of any protective device, including which protection elements operated, and the status of the DG facility including power output, voltage, and current waveforms.

YEC may have additional requirements on a case by case basis.

If it is determined that the IPP facility will have an impact on YEC's Transmission Network, the IPP will be required to provide a Remote Terminal Unit (RTU) or Data Link to a YEC RTU capable of exchanging Supervisory Control and Data Acquisition (SCADA) information with the YEC Control Centre. The protocol for data exchange via the RTU shall be compatible with that used for communications used by YEC. The communication protocol and the equipment required will be specified by YEC.

The IPP will be required to provide the following typical data needed by the (SCADA) system:

a. Individual generator(s) MW and MVAR
b. Individual generator(s) MWh and MVARh
c. Generator(s) breaker status
d. Individual generator on/off status, if no generator breaker exists
e. Total station MW and MVAR
f. Station service MW, MVAR, hourly MWh and MVARh
g. Generator transformer(s) high voltage side breaker(s) and isolator(s) status
h. Bus voltage at high voltage bus
i. PSS status, if applicable
j. AVR status, if applicable
k. AVR voltage setpoint, if requested
l. Total plant MW setpoint, if requested
m. Generator step-up transformer tap setting, if requested

11. Construction

The construction and installation of the IPP's generating facility must meet all applicable statutes, regulations, by-laws and codes. The IPP is responsible for obtaining all permits and complying with all safety and environmental regulations, codes and assessment approvals, if necessary, for the construction and operation of its facilities. Copies of all permits, compliance reports and inspection documents must be provided to the utility prior to energizing the POI.

All single line diagrams provided to the utility must be drawn in accordance with IEEE standards and conventions, and must be stamped by a professional engineer assuming responsibility for the design.

12. Metering

12.1. General

Two meters, primary meter and backup meter, will be required at the IPP facility:

- The utility shall install, own, operate and maintain one meter (primary) necessary for measuring the energy and demand supplied to the YIS, unless otherwise specifically provided in a contract with the IPP. This meter shall remain the sole property of YEC. The meter will comply with Measurement Canada requirements and will be owned and maintained by YEC.
- The IPP shall install, own, operate and maintain the other meter (backup) which does not necessarily have to comply with Measurement Canada requirements.

Generators exporting power onto the distribution system shall be equipped with bi-directional meters with four-quadrant measurement capability. An appropriate number of channels are required for four-quadrant meters to separately record active and reactive power in both the export and the import directions.

The high voltage side of the interconnection transformer is designated as the Measured Billing Point for all energy imported and exported from the IPP facility.

The metering equipment will be:

- Suitable for use in the environmental conditions reasonably expected to occur at the installation site; and
- Appropriate for measuring the power system characteristics reasonably expected to exist at the installation under all power system conditions and events.

The IPP shall provide Measurement Canada Approved instrument transformers. Each meter shall be connected to its own individual core/winding. For the utility meter the IPP shall wire from the instrument transformers to the meter receptacle using CSA-approved tamper resistant conduit and accessories suitable for the utility meter or metering equipment.

For transmission interconnections the IPP will provide burden calculations for proposed instrument transformer secondary wiring, for approval by YEC. If necessary the wiring burden may have to be reduced, by increasing the CT secondary conductor size, to meet Revenue Meter requirements.

The IPP shall supply and install the meter base to meet the utility requirements. The utility will provide the specifications for the meter base during the design phase.

12.2. Meter Requirements

The primary meter supplied by the utility will:

- Be Measurement Canada Approved for revenue metering;
- Be dispensated, with accuracy class ratings for active and reactive energy management as per Table 4;
- Be verified and sealed in accordance with the Electricity and Gas Inspection Act;
- Be capable of maintaining the interval boundaries within 60 seconds of the hour and every quarter hour thereafter;

- Measure all quantities required to determine active energy and reactive energy transferred in the required directions at the Measured metering point;
- Provide a separate register to maintain the continuously cumulative readings of the active energy and reactive energy transferred in the required directions at the Measured metering Point;
- Retain readings and, if applicable, all clock functions for at least 14 days in the absence of line power;
- Be equipped with meter failure alarm and communication failure alarm;
- Communicate all metering and equipment status to the YEC system control centre via the IPP's communication equipment;
- Apply loss compensation (such as line losses) factors where applicable to the revenue meters; and
- The meter shall have an accuracy class of 0.2% or better.

The backup meter supplied by IPP will:

- The backup metering will be of the same accuracy class and capability as the primary metering and shall include all equipment to provide the necessary billing data.
- Be non- dispensated, with accuracy class ratings for active and reactive energy management as per Table 5;
- .

Table 4: Schedule of Accuracies for Dispensated Metering Equipment Approved Under Section 9(2) or Section 9(3) of the Electricity and Gas Inspection Act

Metering Point Capacity (MVA)	Points of Delivery	Points of Supply	Measurement Transformers Accuracy Class
10 and above	1.0%	1.0%	0.3%
10	1.0%	1.0%	0.3%

Table 5: Schedule of Accuracies for Non-Dispensated Metering Equipment Approved Under Section 9(2) or Section 9(3) of the Electricity and Gas Inspection Act

Metering Point Capacity (MVA)	Watthour Meter Accuracy Class	Varhour Meter Accuracy Class
10 and above	0.2%	0.5%
10	0.5%	1.0%

12.3. Measurement Transformers

The applicable winding(s) of the current and potential instrument transformers supplied and installed by the IPP must:

- Be approved by Measurement Canada for revenue metering.
- Be burdened to a degree that does not compromise the accuracy required by this guideline.
- Have a minimum of two cores per instrument transformer. One core connection for the utility meter and the other core connection for the IPP meter.
- Be used solely for metering and not to be used for any other purposes.
- Have an accuracy class rating that equals or exceeds the values specified in Table 4.

12.4. Remote Communications Equipment

The remote communications equipment may or may not be an integral part of the meter or the recorder. However, it must incorporate protocol schemes that will prevent the corruption of data during interval data transmission. The protocol must be suitable for the communications equipment type and nature of the communications media and path.

12.5. Password Protection

Two or more levels of password protection will be required for each meter data collection agency. One level is for full access to set time functions and a second level is for read only access to interval data and event logs.

12.6. Safety Requirements

The facility installation must conform to:

- Measurement Canada Standard Drawings;

- AEUC [4];
- CSA Standard C22.2 General requirements - Canadian electrical code, part II [7] ; and
- ANSI/IEEE C57.13-2016 IEEE Guide for Grounding of Instrument Transformers [8].

13. Interconnection Tests

13.1. General Testing Requirements

The IPP must notify YEC (and AEY if the interconnection is via the AEY distribution system) in writing at least three weeks prior to the initial energization and start-up testing of the IPP generation facility. YEC may witness any testing of the equipment and protection schemes associated with the interconnection. Tests must align with the requirements specified in IEEE 1547 and CSA 22.3 No 9-08.

13.2. Type Testing

Type testing is considered an acceptable method of verification where suitable and applicable equipment standards exist, and must be performed once for each specific protection scheme. All interconnection equipment must include a type testing procedure as part of the documentation in order to determine the protection settings meet the requirements set forth within this technical guide. A type test may be performed on one device of a combination of devices. In a case of a combination of devices which comprise a system, the testing will demonstrate that the devices are able to operate as a system.

The type tests shall be performed on a representative unit or system, either in a factory, testing laboratory, or in the field. Results from a resource within a similar product family or design, including hardware or software, shall be acceptable as a representative within the same product family where ratings are within 50% to 200% of the tested resource.

The following type tests must be performed in accordance with IEEE 1547.1 [9]:

- Temperature stability
- Response to abnormal frequency
- Response to abnormal voltage
- Synchronization
- Interconnection integrity
- Unintentional islanding
- Open phase
- Reconnect following abnormal condition disconnect
- DC injection (for inverters without interconnection transformers)
- Harmonics

13.2.1. Temperature Stability

The temperature stability test verifies the interconnection equipment maintains measurement accuracy of parameters over its specified voltage range.

13.2.2. Response to Abnormal Frequency

This test verifies the interconnected generation facility ceases to energize the connected system as specified to IEEE 1547.1 with regards to abnormal frequency.

13.2.3. Response to Abnormal Voltage

This test verifies the interconnected generation facility ceases to energize the connected system as specified to IEEE 1547.1 with regards to abnormal voltage.

13.2.4. Synchronization

This test verifies the interconnected IPP facility will accurately and reliably synchronize with the utility as per IEEE 1547.1.

13.2.5. Interconnection Integrity

The interconnection integrity test verifies the IPP facility meets the surge withstand requirements as specified in Section 9.14 when tested in accordance with IEEE 1547.1.

13.2.6. Unintentional Islanding

Where YEC requires an anti-islanding protection function (other than transfer trip) or minimum import power levels, this test verifies that an IPP facility will cease to energize in accordance with IEEE 1547.1.

13.2.7. Open Phase

The open phase test verifies that the IPP facility will cease to energize the utility interconnection upon the loss of an individual phase on the distribution network when tested in accordance with IEEE 1547.1.

13.2.8. Reconnect following Abnormal Condition Disconnect

This test verifies the functionality of the IPP facility interconnection component or system reconnect timer, which shall delay the reconnection to the utility following a trip event prior to the distribution system stabilization, as specified in Section 9.11.

13.2.9. DC Injection (for Inverters without interconnection transformers)

This test verifies that an inverter-based IPP facility will comply with the DC current inject limit specified in Section 7.9 when tested in accordance with IEEE 1547.1.

13.2.10. Harmonics

The individual current harmonics and the total demand distortion (TDD) of the IPP facility shall be measured and recorded under normal operating conditions to ensure the values are within the limits specified in Section 7.1

13.3. Production Tests

Production tests shall be conducted on each IPP generating unit and interconnection equipment prior to delivery to verify they meet the applicable standards and verify the operability of every generating unit manufactured for customer use.

The tests assume the equipment has met the applicable interconnection and interoperability requirements of the applicable standards and may be conducted as a factory test or performed as part of an evaluation or commissioning test. Facilities with adjustable set points shall be tested at a single

series of test points specified by the manufacturer. The summary report must provide a list of normal and abnormal performance category capability, final function settings, and final operating mode settings.

The following production tests are specified within IEEE 1547.1:

1. Response to abnormal frequency
2. Response to abnormal voltage
3. Synchronization

14. Commissioning Tests and Verifications

14.1. General

Commissioning tests are tests and verification on the IPP facility equipment to confirm the system as delivered, designed, and installed meets the interconnection and interoperability requirements of this guide and the applicable standards. These tests include visual inspections, and may include operability and functional performance tests as required.

Prior to the energization of the IPP facility, or changes to the facility, verification testing must be performed and coordinated with the utility. After the equipment is installed and ready for operation, the testing must be performed by a qualified individual in accordance the manufacturer's published test procedures, or IPP developed procedures that have been approved by the utility. Qualified individuals include: licensed, professional engineers; factory-trained and certified technicians and licensed electricians experienced in testing protective equipment. The utility reserves the right to witness the verification test or to require written certification that the test was performed.

Verification testing must also be performed annually or when major system upgrades or modifications are carried out.

14.2. Interconnection Verifications and Inspections

The following commissioning tests and inspections shall take place:

a. Final IPP facility protection settings shall be verified, recorded, and provided to the utility. A sample protective settings commissioning report is located in Appendix G.

b. Visual inspection shall ensure the grounding coordination requirements in Section 8.5 have been met.

c. Visual inspection shall ensure the presence of a disconnecting means in accordance with Section 8.3 has been met.

d. The polarities, burdens, and ratios of field wired instrument transformers shall be verified as correct and in accordance with the design documentation.

e. Field installed power and control wiring shall be verified to be in compliance with drawings and manufacturer requirements.

f. For three-phase systems, the phase rotation of the distribution system and the IPP facility as installed shall be verified as compatible.

g. All monitoring and information exchange provisions shall be verified as functional in accordance with Section 10.

h. Calibration checks of each protective relay or the equivalent protection device shall be performed using injection of appropriate ac quantities, secondary injection, or set-point adjustment verification.

i. Functionality of the protective relays or the equivalent protection device, circuit breakers, and telecommunications equipment shall be tested to verify the system operates as intended.

j. Load tests of protective relays or the equivalent shall be conducted immediately after energization, where applicable.

k. The ohmic value and connection of the transformer neutral impedance grounding device shall be verified as correct.

l. Upon loss of DC power supply to the protective relays or the equivalent protection device, it shall be verified the protection scheme activates the interconnection circuit breaker.

m. Upon loss of a communication signal, it shall be verified the fail-safe transfer trip occurs when required by the utility in accordance with Section 9.8.

n. Inverter operation must be verified annually by operating the load break disconnect switch and verifying the generation facility shuts down and does not restart for five minutes after the disconnect switch has closed.

o. Any system depending on a battery for trip power must be checked for proper voltage and logged monthly. Once every four years, the battery must be replaced or a discharge test performed.

p. The IPP shall submit to the utility the station LAN design architecture for review during the conceptual design phase of the project.

q. The IPP is responsible for all hardware design, RTU drawings, installation, testing and commissioning.

r. The IPP shall prepare a preliminary but tested version of the RTU Configuration and a preliminary version of the Point Assignment, and send them to the YEC SCC, together with all RTU drawings, P&C drawings and DNP point lists of all LAN devices, at least ten weeks before the in service date.

s. The IPP and YEC SCC shall jointly test all control, status and analog points and confirm visibility at the SCC.

14.3. Disconnection Means Operability

Prior to the operation of the IPP facility, the disconnecting means provided in accordance with Section 8.3 operates as intended.

14.4. Energization Cessation

Tests shall be conducted in accordance with IEEE 1547.1 to verify the functionality of the protection that ensures the IPP facility does not energize the utility under the following conditions described within this standard:

1. Abnormal frequency
2. Abnormal voltage
3. Protection scheme failure

Additional protection functions shall also be verified in accordance with IEEE 1547.1 as needed. The following protective functions must be verified if used at the IPP facility:

1. If available, the anti-islanding function must be checked by operating a load break disconnect switch and verifying that the IPP facility ceases to energize the output terminals and does not restart once the load break disconnect switch has reclosed.
2. If reverse power or minimum power function is used to meet the interconnection requirements, the functionality must be tested using secondary injection techniques. Alternatively, this

function can be tested by the means of a local trip test or by adjusting the IPP output and local loads to verify that the applicable non-export criterion are met.

14.5. Re-Verification

Re-verification of the interconnection and interoperability requirements may be required when any of the following occurs:

- Functional software of firmware changes have been made to the IPP facility equipment;
- Any hardware component of the facility has been modified in the field, been replaced or repaired with parts that are not substitutive components compliant with the applicable standards;
- Protection settings have been changed after factory testing; or
- Protection functions have been adjusted after the initial commissioning / verification process.

15. Maintenance

The IPP has full responsibility for the maintenance of its equipment, up to the Point-of-Interconnection, consistent with the Interconnection Agreement and this Guide. The IPP shall maintain the facilities in accordance with Rule 2-300 of the Canadian Electrical Code to ensure safe parallel operation with the YEC or AEY system. Failure to do so may result in disconnection of the IPP generation facility.

The IPP must present to the utility the planned maintenance procedures and a maintenance schedule for the interconnection protection equipment, and keep records of such maintenance.

The utility reserves the right to periodically inspect the interconnection protection system to verify that it meets the requirements outlined in this document.

Maintenance procedures up to the POI will be performed in accordance with good utility practice and the utility's policies and procedures.

16. Marking and Tagging

The disconnect switch must be clearly marked as the "IPP Disconnect Switch" and tagged with an identification number approved by the utility. The IPP must follow the utility's switching, clearance and tagging procedures. The utility is responsible to instruct the IPP in this regard.

The IPP switchgear equipment must include the manufacturer name and the manufacturer's serial number.

17. Modification of Installation

The IPP shall obtain written approval from the utility before commencing any modification to the generation facility. If the change requires the installation or modification of equipment, the IPP shall provide documentation that the new equipment meets the requirements of Type and Production tests.

If the changes require modifications to the protection and controls information the IPP must obtain approval from the utility for the proposed modifications. Whenever changes are made to interconnection hardware or software that can affect the functions listed below, the potentially affected functions must be retested:

- Over-voltage and under-voltage
- Over-frequency and under-frequency
- Non-islanding function (if applicable)
- Reverse or minimum power function (if applicable)
- Inability to energize dead line
- Time delay restart after utility outage
- Fault detection, if used
- Synchronizing controls (if applicable)

To ensure that commissioning tests are performed correctly, the utility may require the ability to witness the tests and receive written certification of the results.

18. Technical Data Requirements

The following outlines the minimum data required at various stages for planning, design and commissioning the IPP's project. This data is required by YEC (and AEY if connected to AEY distribution system) to ensure suitable steps are taken to interconnect the IPP facility to the YEC system. Expanded data requirements for the proposal and design stages are located in Appendix A and Appendix B. The IPP Policy (in development as of June 2018) shall apply.

18.1. Proposal Stage

During the proposal stage the IPP Facility conceptual design must be submitted before any further detailed studies is approved by the utility. The list of information to be provided for this approval may be the result of preliminary discussions with the utility. Based on the information provided by the IPP, the utility will provide their proposition, their commitment and their own requirements concerning the connection of the IPP facility.

The following list of drawings and data required for the proposal stage of the project includes, but is not limited to:

- A Single Line Diagram (SLD)showing the following :
    - The proposed protection relays, circuit and fuses with fuse type and rating,
    - The connections of all substation equipment with voltage levels and equipment ratings
    - The location of the revenue metering equipment.
- Description of protection scheme
- Generating station site plan showing the layout and location (coordinates) of the generating plant and the location of lockable, "visible" disconnect device
- Based on the size of the project the utility may require more additional generator, exciter and speed governor data for a preliminary interconnection study.

18.2. Approval (Design) Stage

Once the project has been approved by the utility the IPP will proceed to submit the facility detailed design.

The following list of drawings and data required for approval stage of the project includes, but is not limited to:

- Single Line Diagram
- Description of protection scheme
- Control schematic
- Protection and control philosophy
- Major equipment nameplate schedules and statements
- Fuse and protective relay coordination study and settings
- Current transformer characteristic curve
- Measurement Canada approval numbers for instrument transformers

- Generating station site plan showing the layout and land location coordinates and legal description. The drawing should also show the proposed terminal pole or service manhole with the routing of aerial line or underground cables from utility to the generating station.
- SCADA Diagram
- Obtaining all permits and complying with all safety and environmental regulations, codes and assessment approvals, if necessary, for the construction and operation of its facilities.
- Proposed In-Service Date

18.3. Verified Stage

When the project is nearing completion, the IPP must submit the proposed testing, commissioning and start-up procedures to be performed before the facility is connected to the YIS.

The following list of drawings and data required for commissioning and verification stages of the project includes, but is not limited to:

- Commissioning report
- Copies of all permits, compliance reports and inspection documents
- Final Single Line Diagram
- Final protection scheme
- Final control schematic
- Protection and control philosophy
- Major equipment nameplate schedules, statements, test reports and data sheets
- Final fuse and protective relay coordination settings
- Current transformer characteristic curve
- Final generating station site plan showing the layout and land location coordinates and legal description

19. References

The technical guide was created using the following primary reference standards. Additional applicable standards are located within Appendix D.

[1] CSA Standard C22.3 No. 9-08 (R2015) – Interconnection of Distributed Resources and Electricity Supply Systems, CSA Group, 2015.

[2] IEEE 1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces, IEEE, 2018.

[3] Energy Strategy For Yukon Independent Power Production Policy, Yukon Energy, Mines and Resources, 2018

[4] Alberta Electrical Utility Code, latest Edition

[5] IEEE Std 519-2014 - IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems

[6] IEC 61000-4-15: Testing and Measurement Techniques – Flickermeter - Functional and Design Specifications

[7] CSA Standard CAN/CSA-C22.2 NO. 0-10 (R2015) - General requirements - Canadian electrical code, part II

[8] IEEE Std C57.13-2016 (Revision of IEEE Std C57.13-2008) - IEEE Standard Requirements for Instrument Transformers

[9] IEEE 1547.1-2005 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

Appendix A

Information Required from IPP (Proposal Stage)

Appendix A
Information Required from IPP (Proposal Stage)

Independent Power Producer Contact Information

Company Name	
Company Address	
Commercial Contact	
Commercial Contact Name	
Commercial Contact Phone	
Commercial Contact Email	
Commercial Contact Address	
Engineering Contact	
Engineering Contact Name	
Engineering Contact Phone	
Engineering Contact Email	
Engineering Contact Address	
Operating Contact	
Operating Contact Name	
Operating Contact Phone	
Operating Contact Email	
Operating Contact Address	

Project Overview

Land Location	
Legal Location Description	
Proposed In-Service Date	
General Description	

Generator Data

Generation Type (Synchronous, Induction, Inverter)	
Single Phase or Three Phase	
Prime Mover Type	
Number of Generators	
Generator Nominal kW Rating	
Generator Nominal kVA Rating	
Generator Nominal kV Rating	
Power Factor, at Rated Output	
Annual Energy Production (MW-hr)	
Production Capacity Range(MW)	

Transformer Data

Transformer Rating (ONAN/ONAF, kVA)	
Transformer Voltage Rating (kV)	
Load Tap Changer steps	
Winding Connection	
Positive Sequence Impedance (%, ONAN base)	
Zero Sequence Impedance (%, ONAN base)	

Prime Mover Data

Prime Mover Type	

Drawings

General Site Map, Including IPP Generation Facility	
Preliminary Substation Layout Drawings	
Preliminary Protection & Metering Single Line	

Company Authorization

Authorizing Personnel	
Authorization Signature	
Authorization Date	

Appendix B

Information Required from IPP (Design Stage)

Appendix B
Information Required from IPP (Design Stage)

Independent Power Producer Contact Information

Company Name	
Company Address	
Commercial Contact	
Commercial Contact Name	
Commercial Contact Phone	
Commercial Contact Email	
Commercial Contact Address	
Engineering Contact	
Engineering Contact Name	
Engineering Contact Phone	
Engineering Contact Email	
Engineering Contact Address	
Operating Contact	
Operating Contact Name	
Operating Contact Phone	
Operating Contact Email	
Operating Contact Address	

Project Overview

Land Location	
Legal Location Description	
Proposed In-Service Date	
General Description	

Generator Data

Generation Type (Synchronous, Induction, Inverter)	
Single Phase or Three Phase	
Number of Generators	
Manufacturer	
Model	
Nominal kW Rating	
Nominal KVA Rating	
Nominal kV Rating	
Power Factor at Rated Output	
Maximum Authorized Real Power (MARP)	
Leading and Lagging Reactive Power at MARP	
Generator Grounding (Resistive, Reactive, None)	
Individual Generator Parameters - impedances in per unit, on nominal machine base	
Speed (RPM)	
Inertia Constant, H (generator)	
Direct Axis Synchronous Reactance , X_D	
Direct Axis Transient Reactance , X'_D	
Direct Axis Subtransient Reactance , X''_D	
Quadrature Axis Synchronous Reactance , X_Q	
Quadrature Axis Transient Reactance , X'_Q	
Quadrature Axis Subtransient Reactance , X''_Q	
Open Circuit Direct Axis Transient Time Constant, T'_{DO}	

Short Circuit Direct Axis Transient Time Constant, T'_D	
Open Circuit Direct Axis Subtransient Time Constant, T''_{DO}	
Short Circuit Direct Axis Subtransient Time Constant, T''_D	
Quadrature Axis Transient Time Constant, T'_{QO}	
Quadrature Axis Subtransient Time Constant, T''_{QO}	
Saturation Factor (1.0 per unit flux)	
Saturation Factor (1.2 per unit flux)	
Armature Resistance, R_A	
Stator Leakage Reactance, X_L	
Negative Sequence Resistance, R_2	
Negative Sequence Reactance, X_2	
Zero Sequence Resistance, R_0	
Zero Sequence Reactance, X_0	
Armature Short Circuit Time Constant, T_A	
Governor Droop (%)	
Short-time unbalanced current factor (K)	
Continuous negative sequence current level (%).	
Induction Generator Data (if applicable) - impedances in per unit, on nominal machine base	
Rating (kVA)	
Rated Power Factor	
Speed (RPM)	
Inertia Constant, H (generator)	
Stator Resistance, R_S	
Stator Reactance, X_S	
Rotor Resistance, R_R	
Rotor Reactance, X_R	
Armature Magnetizing Reactance, X_M	
Other Attachments	
Reactive capability curve (D-curve) comes with	
a. Under excitation limiter	
b. Over excitation limiter	

Exciter nameplate	
VEE curves	
Single line diagram	

Power Factor Regulator

Reactive Power Limit - Lagging (out)	
Reactive Power Limit - Leading (in)	
Accuracy Tolerance (%)	

Voltage Regulator

Voltage Regulator Range (V)	
Accuracy Tolerance (%)	

Transformer Data

Transformer kVA Ratings	
Transformer kV Ratings	
Cooling Type (ONAN, ONAF)	
Winding Connection	
Transformer Grounding (Resistive, Reactive, None)	
Grounding Impedance in Ohms (if applicable)	
Positive Sequence Impedance (%, ONAN base)	
Zero Sequence Impedance (%, ONAN base)	
Tap Details (if applicable)	
On-Load Tap Range	
On-Load Tap Size	
Off-Load Tap Range	
Off-Load Tap Size	
Other Attachments	
Factory Test Reports (minimum requirements)	
No Load Loss & Exciting Current Measurements	
Measurement of Load Loss & Impedance Voltage and Zero Sequence Impedance Measurements	

Prime Mover Data

Prime Mover Type	
Prime Mover Rating	
Inertia Constant (prime mover)	
Manufacturer	
Model	
Other Attachments	
Elevation versus Output Curve	
Ambient Temperature versus Output Curve	

Drawings Required

General Site Map, Including IPP Generation Facility	
Complete and Accurate Protection Diagrams	

Single Line Diagrams	
AC / DC Schematics	
Wiring Diagrams	
Major Equipment Nameplates (Transformer, Generator, etc.)	

Protection Requirements

Proposed Protection Schemes Provided	
Verified Interconnection Functionality Provided	
Inertia Constant (prime mover) Provided	
Maintenance Plans for Protection Devices Provided	
Maintenance Plans for Interrupting Devices Provided	

Compliance with Electrical Inspector

Permit or Equivalent Compliance Provided (Yes / No)	

Metering Requirements

Element (2 Element, 3 Element)	
Metering Service Provider	
Metering Data Manager	
Asset ID Number	

Company Authorization

Authorizing Personnel	
Authorization Signature	
Authorization Date	

D.1 Modelling Information

In some cases, a generator (or the aggregate generation on a line) is large enough that adjacent customers or the dynamic stability of utility's distribution system could be affected. The IPP is responsible for the cost of any required transient or dynamic stability studies, and the studies must be done in a manner suitable to, and approved by, the utility.

IPPs are responsible for ensuring the data they submit provides an adequate mathematical representation of the facility's electric behavior. If the data is not available prior to purchasing equipment, it must be submitted as soon as it becomes available.

The studies must accurately determine:

1. The impact of the IPP's facility on adjacent customers of the utility.
2. The dynamic stability, in aggregate, of the utility system.

Data may be supplied by the manufacturer or acquired directly by testing. It must include generator characteristics (i.e., speed, reactance, resistance, excitation system etc.) and governor characteristics (i.e., lead time/lag time constants, valve or gate opening data etc.).

The information requirements vary for induction generators and inverter generators, and for hydro or thermal systems.

Appendix C

Information Provided by the Utility

Appendix C

Information Provided by the Utility

After receiving the application for interconnection, the utility will provide the following information to the IPP, if required:

a. Single Line Diagram or maps of the system up to the POI.
b. Minimum and maximum 60 Hz source impedances (positive-sequence, negative- sequence and zero-sequence) at the POI.
c. Maximum and minimum normal and emergency system operating voltage ranges at the POI.
d. Harmonic impedance envelope at the POI if available.
e. Planning, operating and reliability criteria, standards and policies.
f. The results of a planning study (e.g. the System Impact Study) documenting the availability of the requested amount of system capacity and any other specific technical issues to be addressed.
g. Cost estimates and time schedule to build the upstream facilities.
h. Characteristics and settings of protection on the distribution system.
i. Costs to implement any required changes to the distribution system that are identified by the System Impact Study.

Some or all of this information will be required by the IPP to properly design the interconnection protection. The utility will identify when the costs of producing this information are to be assigned to the IPP.

Appendix D

Applicable Codes and Standards

Appendix D
Applicable Codes and Standards

D.1 Primary Standards

CSA Standard C22.3 No. 9-08 (R2015) Interconnection of Distributed Resources and Electricity Supply Systems

IEEE Standard 1547-2018 Standard for Interconnecting Distributed Resources with Electric Power Systems with Associated Electric Power Systems Interfaces

Power Quality Standards

ANSI C84.1-2016 American National Standards for Electric Power Systems and Equipment Ratings (60 Hertz). Establishes nominal voltage ratings and operating tolerances for 60 Hz electric power systems from 100 V through 1200kV.

IEEE Std. 493-2007 IEEE Recommended Practice for Design of Reliable Industrial and Commercial Power Systems (IEEE Gold Book).

IEEE Std. 519-2014 IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.

IEEE Std. 1100-2005 IEEE Recommended Practice for Powering and Grounding Sensitive Electronic Equipment (IEEE Emerald Book).

IEEE Std. 1159-2009 IEEE Recommended Practice for Monitoring Electric Power Quality.

IEEE Std. 1250-2011 IEEE Guide for Identifying and Improving Voltage Quality in Power Systems.

In addition to the power quality standards, the following standards are applicable to the interconnection of generation facilities to YEC's system:

IEEE Std. 100 - 2000 IEEE Standard Dictionary of Electrical and Electronics Terms.

IEEE Std 315-1975 (Reaffirmed 1993) ANSI Y32.3-1975 (R1989) CSA Z99-1975 Graphic Symbols for Electrical and Electronics Diagrams (including Reference Designation Letters).

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic (PV) Systems.

C37.1-2007 ANSI/IEEE Standard Definitions, Specifications and Analysis of Systems Used for Supervisory Control, Data Acquisition and Automatic Control.

C37.2-2008 IEEE Standard Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.

C37.18-1979 ANSI/IEEE Standard Enclosed Field Discharge Circuit Breakers for Rotating Electric Machinery.

C37.20.1-2015 ANSI/IEEE Standard for Metal-Enclosed Low-Voltage (1000 Vac and below, 3200 Vdc and below) Power Circuit Breakers Switchgear.

C37.20.3-2001 ANSI/IEEE Standard for Metal-Enclosed Interrupter Switchgear.

C37.24-2017 ANSI/IEEE Standard for Evaluating the Effect of Solar Radiation on Outdoor Metal-Enclosed Switchgear.

C37.27-2015 ANSI/IEEE Standard Application Guide for Low-Voltage AC (635 V and below) Power Circuit Breakers with Separately Mounted Current-Limiting Fuses.

C37.29-1981 ANSI/IEEE Standard for Low-Voltage AC Power Circuit Protectors Used in Enclosures.

C37.50-1989 ANSI Standard Test Procedures for Low-Voltage AC Circuit Breakers Use In Enclosures.

C37.51-1989 ANSI Standard Conformance Test Procedure for Metal Enclosed Low- Voltage AC Power Circuit-Breaker Switchgear Assemblies.

C.52-1974 ANSI Standard Test Procedures for Low-Voltage AC Power Circuit Protectors Used in Enclosures.

C57.12-2015 IEEE Standard General Requirements for Liquid Immersed Distribution, Power and Regulating Transformers.

C57.12.13-1982 Conformance Requirements for Liquid Filled Transformers Used in Unit Installations including Unit Substations.

C57.13.1-2006 IEEE Guide for Field Testing of Relaying Current Transformers.

C57.13.2-2005 IEEE Standard Conformance Test Procedures for Instrument Transformers.

C37.58-2003 (R2010) ANSI Standard Conformance Test Procedures for Indoor AC Medium- Voltage Switches for Use in Metal-Enclosed Switchgear.

C37.90-2005 ANSI/IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.

C37.90.1-2002 ANSI/IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems.

C37.90.2-2004 ANSI/IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers.

C37.95-2014 IEEE Guide for Protective Relaying of Utility Consumer Interconnections.

C37.98-2013 ANSI/IEEE Standard for Seismic Testing of Relays.

IEC 1000-3-3 Limitation of Voltage Fluctuations and Flicker in Low-Voltage Supply Systems for Equipment with Rated Current Less than 16A.

IEC1000-3-5 Limitation of Voltage Fluctuations and Flicker in Low-Voltage Supply Systems for Equipment with Rated Current Greater than 16A.

UL1008 Transfer Switch Equipment.

UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources

IEEE P1547, DRAFT Standard for Distributed Resources Interconnected with Electric Power Systems. Canadian Electrical Code, CSA no. C22-1, latest version.C22.2 No. 31- M89 (R2000) Switchgear Assemblies.

Can/CSA - C22.2 No. 1071 95Commercial and Industrial Power Supplies.

Can/CSA - C22.2 No. 1010.1-92 Safety Requirements For Electrical Equipment for Measurement, Control and Laboratory Use.

Can/CSA - C22.2 No. 144-M91 (R2015) Ground Fault Circuit Interrupters.

C22.2 No. 193-M1983 (R2014) High-Voltage Full-Load Interrupter Switches.

C22.2 No. 201-M1984 (R2014) Metal Enclosed High-Voltage Busways.

C22.2 No. 229-M1988 (R2014) Switching and Metering Centres.

CSA Standard CAN3 C235 83 Preferred Voltage Levels for AC Systems 0 to 50,000V.

Alberta Electrical and Communication Utility Code (formerly the Alberta Electrical and Communication Utility System Regulation 44/1976 or future amendments).

Measurement System Standard / Transmission Administrator Metering Standard GC301 Practices for Management and Transfer of Metered Data.

C37.04-1999 IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI/DoD).

C37.06-2000 American National Standard for Switchgear--AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis--Preferred Ratings and Related Required Capabilities.

C37.09-1999 IEEE Standard Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI/DoD).

C37.010- IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.011-2011 IEEE Application Guide for Transient Recovery Voltage for AC High- Voltage Circuit Breakers.

C37.012-2014 IEEE Application Guide for Capacitance Current Switching for AC High-Voltage Circuit Breakers Above 1000 V.

C37.013-1997 IEEE Standard for AC High-Voltage Generator Circuit Breaker Rated on a Symmetrical Current Basis.

C37.015-2017 IEEE Application Guide for Shunt Reactor Switching.

C37.081-1981 (R1988) Guide for Synthetic Fault Testing of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.081a-1997 Supplement to IEEE Guide for Synthetic Fault Testing of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.11-2014 IEEE Standard Requirements for Electrical Control for Electrical Control for AC High-Voltage (>1000 V) Circuit Breakers.

C37.13-2008 IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures.

C37.14-2015 IEEE Standard for DC (3200 V and below) Power Circuit Breakers Used in Enclosures.

C37.16-2009 IEEE Standard for Preferred Ratings, Related Requirements, and Application Recommendations for Low-Voltage AC (635 V and below) and DC (3200 V and below) Power Circuit Breakers.

C37.20.2-2015 IEEE Standard for Metal-Clad and Station-Type Cubicle Switchgear.

C37.23-2015 IEEE Standard for Metal-Enclosed Bus.

C37.30-1997 IEEE Standard Requirements for High-Voltage Switches.

C37.32-2002 American National Standard for Switchgear--High-Voltage Air Switches, Bus Supports, and Switch Accessories--Schedules of Preferred Ratings, Manufacturing Specifications, and Application Guide.

C37.34-1994 IEEE Standard Test Code for High-Voltage Air Switches.

C37.35-1995 IEEE Guide for the Application, Installation, Operation, and Maintenance of High-Voltage Air Disconnecting and Load Interrupter Switches.

C37.36b-1990 IEEE Guide to Current Interruption with Horn-Gap Air Switches.

C37.37-1996 IEEE Standard for Loading Guide for AC High-Voltage Air Switches (in Excess of 1000 V).

C37.38-1989 IEEE Standard for Gas-Insulated, Metal-Enclosed Disconnecting, Interrupter, and Grounding Switches.

C37.42-2016 IEEE Standard Specifications for High-Voltage (>1000 V) fuses and Accessories.

C37.44-1981 (R1992) American National Standard Specifications for Distribution Oil Cutouts and Fuse Links.

C37.54-1996 American National Standard for Switchgear--Indoor Alternating-Current High-Voltage Circuit Breakers Applied as Removable Elements in Metal-Enclosed Switchgear Assemblies--Conformance Test Procedures.

C37.55-2002 American National Standard for Switchgear--Metal-Clad Switchgear Assemblies--Conformance Test Procedures.

C37.57-2003 (R2010) American National for Switchgear--Metal-Enclosed Interrupter Switchgear Assemblies-Conformance Testing.

C37.66-2005 American National Standard for Requirements for Oil- Filled Capacitor Switches for AC Systems (1 kV to 38 kV).

C37.81-2017 IEEE Guide for Seismic Qualification of Class 1E Metal- Enclosed Power Switchgear Assemblies.

C37.85-1989 (R1998) American National Standard for Switchgear--Alternating- Current High-Voltage Power Vacuum Interrupters-Safety Requirements for X- Radiation Limits.

ANSI/IEEE C37.90.1-2102 Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus.

120-1989 (Reaff-1997) IEEE Master Test Guide for Electrical Measurements in Power Circuits.

1291-1993 IEEE Guide for Partial Discharge Measurement in Power Switchgear.

IEEE Std C62.23-2017 Application Guide for Surge Protection of Electric Generating Plants.

ANSI /IEEE C62.41-1991 Recommended Practices on Surge Voltages in Low- Voltage AC Power Circuits.

C57.13-2016 IEEE Standard Requirements for Instrument Transformers.

C57.13.3-2014 IEEE Guide for the Grounding of Instrument Transformer Secondary Circuits and Cases.

C57.98-2011 IEEE Guide for Transformer Impulse Tests.

C57.19.100-2012 IEEE Guide for Application of Power Apparatus Bushings.

C57.110-2008 IEEE Recommended Practice for Establishing Liquid-Filled and Dry-Type Power and Distribution Transformer Capability When Supplying Non-sinusoidal Load Currents.

C62.92.4-2014 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part IV – Distribution.

IEEE Std. 242-2001 Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems.

ANSI C12.20-2010 Electricity Meters 0.2 And 0.5 Accuracy Classes.

ANSI C62.1-1981 Surge Arresters for AC Power Circuits.

ANSI C62.11-2012 Metal-Oxide Surge Arresters for AC Power Circuits (>1 kV).

NEMA CC 1-2009 Electric Power Connectors for Substations.

NEMA LA 1-2009 Surge Arresters.

NEMA MG 1-2016 Motors and Generators

Appendix E

Sample Operating Agreement

Appendix E
Sample Operating Agreement

1. Purpose

This agreement outlines the steps to take to ensure a reliable and safe interconnection between the IPP and YEC and/or AEY through a variety of circumstances.

2. Definitions

Operating Authority: The organizational unit assigned responsibility for operating a portion of the electrical system. For each utility the YEC System Control Center (SCC) operator is the operating authority. For the IPP, the *<IPP Contact>* is the operating authority.

Operational Boundary/Interface Point or Point of Interconnection: The location on the electrical system at which responsibilities between Operating Authorities meet. The breaker *<Breaker ID>* is the interface point between the IPP and the utility.

3. Operational Information

Circuit Breaker Identification

List circuit breakers providing interconnection between IPP and the utility.

3.1 Interlocks

List identified circuit breaker interlocks with sequence information

3.2 Contact Information

SCC – Phone (867) *XXX-XXXX* or (867) *XXX-XXXX* (recorded lines)

Contact Name	Title	Phone Number
<Utility Contact>	Leadhand SCC	(867) *XXX-XXXX*
<Utility Contact>	Operation Coordinator	(867) *XXX-XXXX*
<Utility Contact>	Manager Operations	(867) *XXX-XXXX*
<Utility Contact>	Director of Operations	(867) *XXX-XXXX*
<IPP Contact>	<Contact Position>	(867) *XXX-XXXX*

3.3 Normal Operation

Under normal operating conditions the IPP facility will be connected to the utility grid. The breakers status under normal operating conditions is as follows.

Breaker	**Status**
<Breaker ID>	*Open/Closed*
<Breaker ID>	*Open/Closed*
<Breaker ID>	*Open/Closed*
<Breaker ID>	*Open/Closed*

4. Operating Procedures

4.1. Line L### (<Utility Line> to <IPP Facility>) Isolation

L### isolation requires the minimum notification defined in section 4.3, with the exception of emergency repairs. The utility will provide a Condition Guarantee on breaker <Breaker ID>. The Condition Guarantee is used in communications between external parties. It is a formal method of communication that switching has been completed. It ensures the status of the breaker/device will not change until the work is complete, the lock out tag out is surrendered and all workers are clear.

4.2. Voltage Support

Based on the power quality conditions defined in Schedule <*X*> of the Power Purchase Agreement (PPA) and system security requirements, SCC may request voltage support. Voltage support can be accomplished by placing IPP generation on line, or other means such as capacitor banks or transformer tap changing. If such support is part of the operating agreement then:

- When the IPP has generation online, the generators regulate the generator bus voltage between 100 and 105% of nominal and the utility shall have control of this set-point. Generators reactive output will be adjusted by the utility in real time, to regulate the system voltage, by pulsing the AVR voltage set-points. The IPP sets the acceptable range within which the utility can adjust voltage.
- The utility must have full SCADA visibility of the IPP substation and control of critical elements.

4.3. SCC Remote Monitoring and Control

- SCC will have visual indication of the IPP breakers, generator status, capacitor status and electrical measurement information for the IPP facility.
- The utility control will be limited to:
    - Approving requests from the IPP to connect and disconnect from the utility system
    - Approving requests from the IPP for changes in generation output
    - Requesting the IPP to disconnect from the utility system for operational and safety reasons
- All IPP requests must be communicated and approved by the utility
- The utility shall have control (open and close) of incoming line breaker <*Breaker ID*> at the IPP facility.

5. Operational Notification

5.1. Daily Operating Communications

Under normal operating conditions IPP will be supplying <*XXX*> kW to the YIS. Generation changes of more than <*XXX*> kW must be communicated and approved by the utility.

5.2. The transition from winter to summer and conversely summer to winter generation levels must be established with SCC with a minimum of 30 days' notice.

5.3. IPP Facility Planned Maintenance and Scheduling

The IPP shall operate under the utility approved maintenance procedures established.

To meet changing operating conditions and coordinate maintenance efforts, maintenance shutdowns by the IPP need to be communicated to SCC at least one week in advance for shutdowns of up to 12 hours and 30 days for shutdowns longer than 12 hours. Changes in the availability and capacity of the onsite generation need to be communicated to SCC. The utility and the IPP shall share annual shutdown/maintenance plans in February of each year.

5.4. Transmission and Distribution Maintenance and Scheduling

The utility performs annual line maintenance on its transmission and distribution lines, during which grid power to the IPP facility may be curtailed or suspended. The duration of this annual maintenance can be up to 14 days per calendar year.

The utility will provide a minimum of 30 days' notice of the start date and expected duration of work that will curtain or otherwise interrupt the supply of grid power to the IPP facility.

6. Loss of Supply Procedures

6.1. Loss of Supply - Short Term

In the event of a disturbance that results in the loss of grid power to the IPP facility, SCC will make one attempt to re-energize the line to the IPP facility. If successful the following steps apply to resume the IPP facility operation with grid power.

a) SCC will confirm the status of the breakers located at the IPP's POI.

b) SCC will request closed breaker <Breaker ID>.

c) Once complete and with confirmation from SCC the IPP facility may proceed with the restarting of their operation. The IPP will communicate to SCC on generation greater than <XXX> kW. The request to increase generation may be communicated verbally or via SCADA.

6.2. Loss of Supply - Long Term

In the event of a disturbance that results in the loss of grid power to the IPP facility and SCC is unsuccessful in re-energizing the line the following steps will apply.

a) SCC will confirm the status of the breakers.

b) At the direction of SCC the IPP personnel will start and stage their generation on line supplying power to the IPP facility.

c) Once the line to the IPP facility has been re-energized, SCC will request the IPP synchronize and close its POI breaker.

d) The IPP facility is now connected to YEC system. Once complete and with confirmation from SCC the IPP facility may proceed with resuming generation. The IPP will communicate to SCC on generation increases greater than *<XXX>* kW. The request to load up may be communicated verbally or via SCADA.

7. Revision and Approval

7.1. This Agreement comes into effect once it is signed by the IPP and the utility.

7.2. This Agreement will remain in effect unless cancelled upon the mutual agreement of both Parties.

7.3. The Parties shall provide 90 days' notice in writing of the intention to modify the Agreement.

7.4. The Agreement may be revised upon mutual agreement of both Parties. The agreement will be formally reviewed every two (2) years.

Approved by: _____
Yukon Energy Corporation

Approval Date: _____

Approved by: _____
ATCO Electrical Yukon

Approval Date: _____

Approved by: _____
IPP

Approval Date: _____

Appendix F

Typical Interconnection Single Line Diagrams

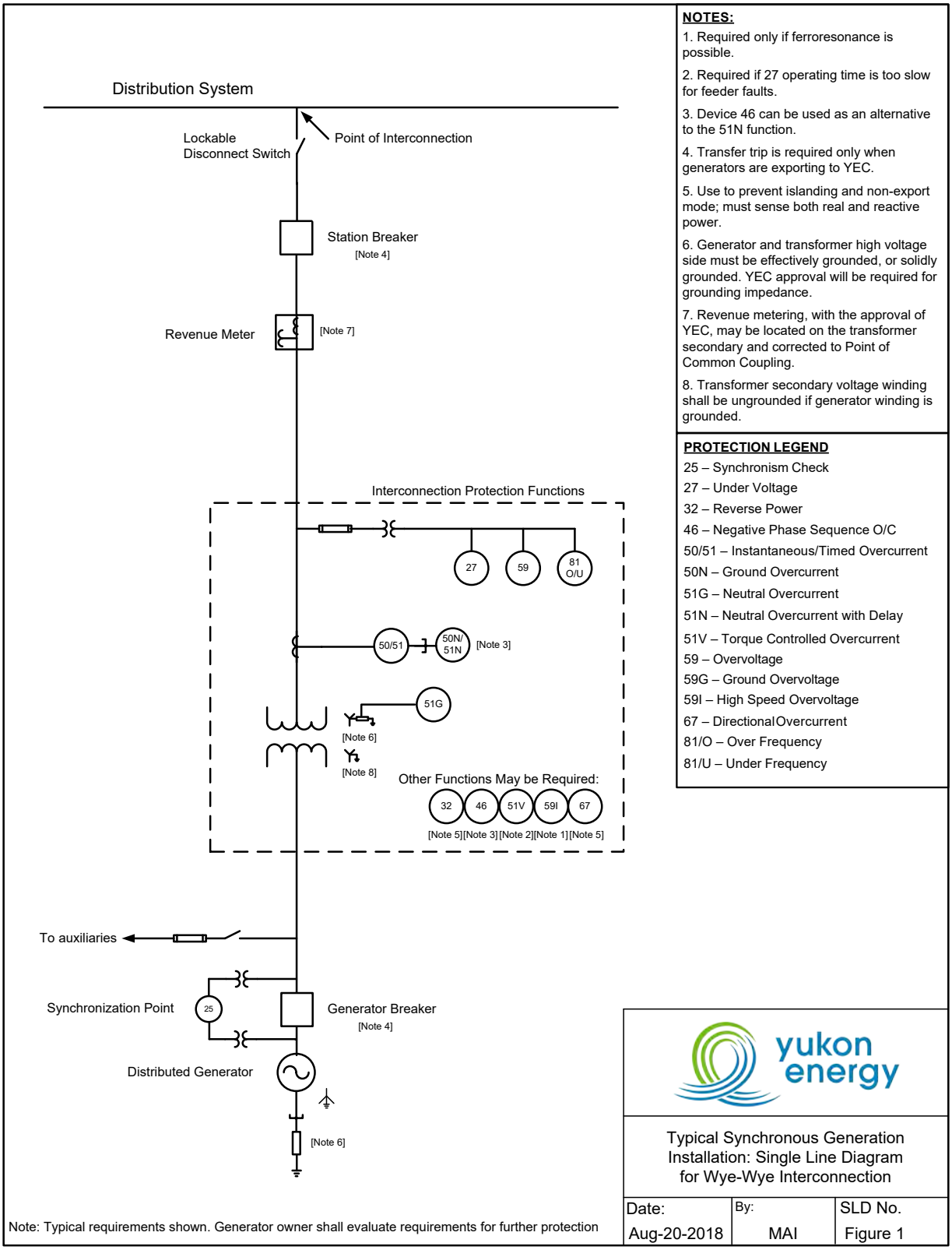

Figure F- 1: Single Line Diagram for Wye-Wye Interconnection

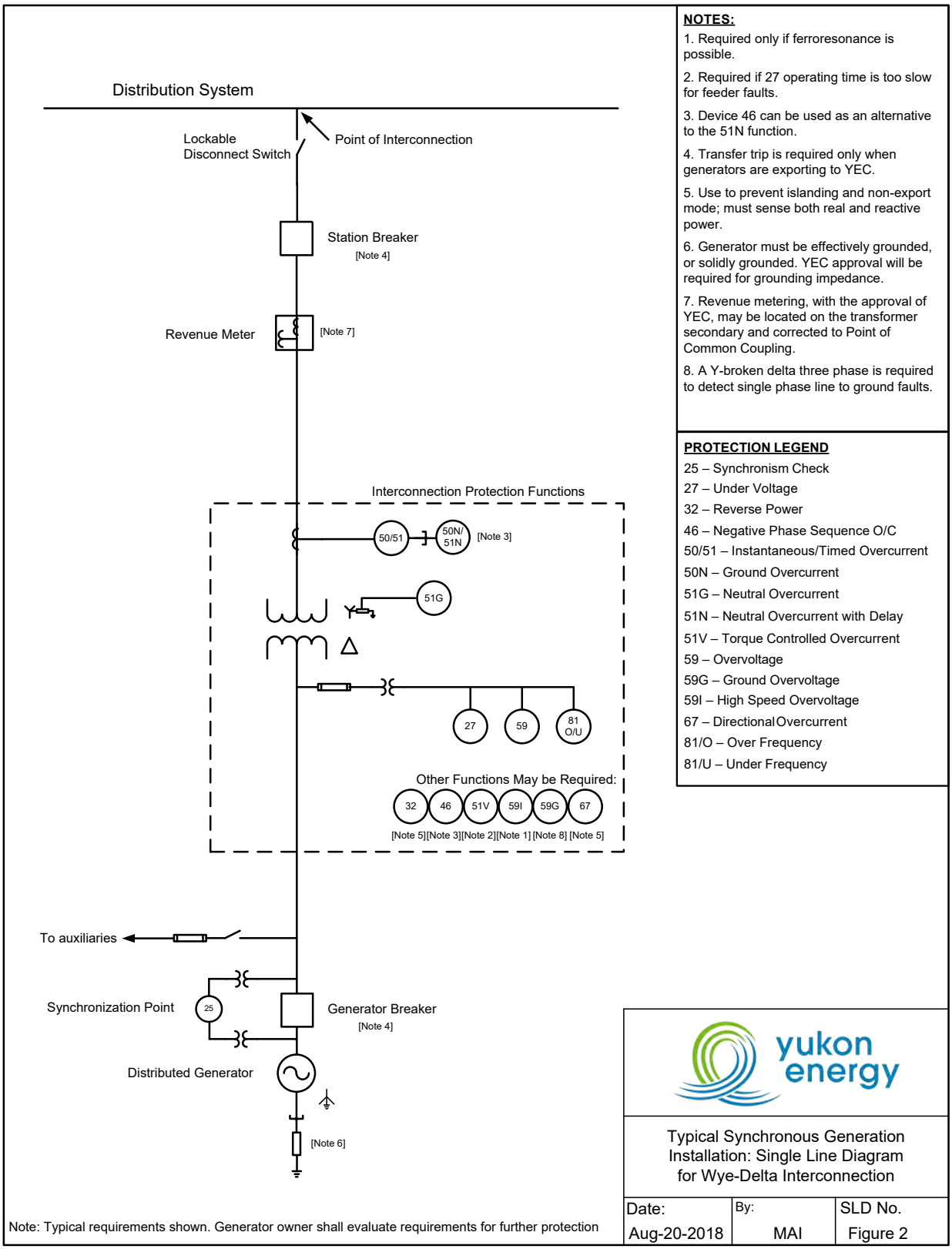

Figure F- 2: Single Line Diagram for Wye-Delta Interconnection

Appendix G

Protective Settings Commissioning Document

Appendix G

Protective Settings Commissioning Document

Over Voltage Protection Parameters

	PHASE VOLTAGE TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	106% - 120% 1% Increments						30 Cycles					
Fast Trip	144% - 120% 1% Increments						100 ms					

Under Voltage Protection Parameters

	PHASE VOLTAGE TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	50% - 90% 1% Increments						120 Cycles					
Fast Trip	Less than 50% 1% Increments						100 ms					

Non-Islanding Function Test

Loss of Utility Voltage	100 ms	
Generator Restart Delay	5 min Minimum	
Dead Bus Test	Fail to Start Successful (Yes/ No)	

Over Frequency Protection Parameters

	FREQUENCY TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	60.5 Hz - 61.5 Hz 1% Increments						3 minutes					
Fast Trip	61.5 Hz - 61.7 Hz 1% Increments						30 seconds					

Under Frequency Protection Parameters

	FREQUENCY TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	59.5 Hz - 58.5 Hz 1% Increments						3 minutes					
Second Trip	58.5 Hz - 57.9 Hz 1% Increments						30 seconds					
Third Trip	57.9 Hz - 57.4 Hz 1% Increments						7.5 seconds					
Fourth Trip	57.4 Hz - 56.9 Hz 1% Increments						45 cycles					
Fifth Trip	56.9 Hz - 56.5 Hz 1% Increments						7.2 cycles					
Fast Trip	Less than 56.4 Hz 1% Increments						100 ms					

Reverse AC Current Protection Function

	CURRENT TO TRIP						DURATION TO TRIP					
	DESIGN VALUE	ADJUSTABLE RANGE	AS SET	TESTED			DESIGN VALUE	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip												

Syncronization Limits for Synchronous Generators

	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET
Frequency Difference	+ 0.2 Hz		
Voltage Difference	5%		
Phase Difference	10° (degrees)		

Phase and Ground Fault Protection

	MAXIMUM CURRENT OR VOLTS TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Phase Current							200 ms					
Neutral Current							200 ms					

Transfer Trip Protection

	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET
Generator Lockout	0.6 seconds		
Fail Safe Lockout	6 seconds		

Test Certification and Historical Data

Type Of Test	**Original Commissioning Test**		**Protection System Re-Test**	

Date of Test

Utility Representative Title

IPP Owner Representative

Signature

IPP Owner Representative Title

Date

Signature

SCHEDULE "H"

JOINT OPERATING PROCEDURE

(Please see attached)

JOINT OPERATING PROCEDURE	DEPARTMENT:	INQUIRIES TO:	TOPIC:
	Operations	Guy Morgan, VP, Operations	IPP / AEY / YEC Operating Agreement
	ISSUED DATE:	REVIEW DATE:	APPROVED BY:
	August __ 2020	September 1, 2021	President & CEO

1.0 Purpose

1.1 This agreement defines the operating arrangement between the **Nomad Contracting & Electrical Services.** (IPP), ATCO Electric Yukon (AEY) and Yukon Energy Corporation (YEC). This agreement defines the roles and responsibilities for each entity to allow the IPP to operate reliably and safely on the Yukon Power System (YPS).

2.0 General Information

2.1 Breaker Identification

Breaker	Description
S6423	Connection between the IPP and AEY distribution

2.2 Definitions

a) **Operating Authority** The organizational unit assigned responsibility for operating a portion of the electrical system.

- For YEC the SCC operator is the operating authority and is responsible for the system generation and security.
- For AEY the Supervisor of Operations is the operating authority and is responsible for the distribution system and security.
- For the IPP the Technical Coordinator is the operating authority of their generation and associated equipment.

b) **Operator in Charge (OIC)** The worker designated by the Operating Authority to coordinate control of the power system or portion thereof, in accordance with the requirements of established operating standards and procedures.

c) Power Systems Work Standards (PSWS) The standards that workers will utilize for establishing conditions on the power system that will, when combined with appropriate work standards, procedures and methods, provide a safe work area.

d) **Condition Guarantee (COG)** Formal assurance to another Operating Authority or Operator in Charge (OIC) that identified devices are in the position requested and will not change status until the device status request is formally released by the requestor.

e) **Point of Interconnection (POI)** The location on the electrical system at which responsibilities between Operating Authorities meet. The IPP Switch – S6359 is the interface point between IPP and AEY.

2.3 YEC Contact Information

- SCC (System Control Center) – phone (recorded lines) 393-5355 or 393-5324
- Mike Hannah (Leadhand SCC) 393-5399, cell 334-6759
- Myles O'Brien (Operation Coordinator) 393-5352
- Ed Peake (Manager Operations) 393-5383, cell 334-6586
- Guy Morgan (Director of Operations) 393-5366, cell 334-6904
- YEC Group Email – SCC@yec.yk.ca

AEY Contact Information

- Tony Badry - Supervisor of Operations 633-7057, cell 335-4002
- Matt Johnson – Operator in Charge 633-7009, cell 334-3145

IPP Control Room Desk

- Sebastien Roy 335-0177

IPP Contact Information

- Sebastien Roy nomad_electric@outlook.com

2.4 Normal Operation

Under normal operating conditions the IPP will generate into the Yukon Power Grid. The breakers status under normal operating conditions are as follows.

Breaker	**Status**
S6423	Closed

3.0 Operating Procedures

3.1 Planned 5L649 (IPP to AEY) Isolation

5L649 isolation requires the minimum notification defined in section 5.1, except for emergency repairs. AEY will provide a condition guarantee on S6423 - Condition Guarantee will be issued in accordance with **Section 800** of the PSWS – **Operating Interface Points.**

3.2 Planned 5L649 (AEY to IPP) Isolation
5L649 isolation requires the minimum notification defined in section 5.2, except for emergency repairs. IPP will provide a condition guarantee on S6423 - Condition Guarantee will be issued in accordance with **Section 800** of the PSWS – **Operating Interface Points**

3.3 SCC Remote Monitoring
SCC will have visual indication of IPP breakers, PV status, and electrical measurement information from the IPP site.

4.0 Power Quality Requirements

4.1 IPP will operate IPP Facilities in accordance with the power quality requirements of YEC as set out in the System Interconnection Guidelines (Schedule D).

5.0 Operational Notification

5.1 IPP Planned Maintenance and Scheduling

To meet changing operating conditions and coordinate maintenance efforts, maintenance shutdowns by the IPP need to be communicated to SCC / ATCO OIC at least one week in advance for shutdowns of up to 12 hours and 30 days for shutdowns longer than 12 hours.

Planned changes in the availability and capacity of the onsite generation needs to be communicated to SCC / ATCO OIC at least 30 days in advance of such changes.

Unplanned availability should be conveyed as soon as possible.

The Parties will share annual shutdown/maintenance plans in February of each year and plan to minimize the impact on IPP generation potential by scheduling outages during off-peak generation months where practicable.

5.2 AEY Distribution Maintenance and Scheduling:

a) AEY performs annual line maintenance on the distribution lines, during which connection to the IPP may be curtailed or suspended. The duration of this annual maintenance can be up to 14 days per calendar year.

b) AEY will provide a minimum of 5 working days' notice of the start date and expected duration of work that will curtain or otherwise interrupt the supply of IPP generation to the YPS.

6.0 Loss of Supply Procedures

6.1 Loss of Supply - Short Term

In the event of a disturbance that results in the loss of the grid connection to the IPP the IPP generation will remain off-line until approval from AEY and YEC.

The following steps apply to resume IPP operation with Grid Electricity.

a) SCC will confirm the status of the breaker located at IPP site. If SCADA communications are down the switch status will be physically verified and reported to AEY before 5L649 will be energized.

Breaker	**Expected Status**
S6423	Open

b) The following switching sequence will be followed to re-energize 5L649 and synchronize IPP back to grid supply.

Step	Switch Sequence	Operation
1	Confirm 5L649 Energized	IPP/AEY
2	S6423 Closed	IPP
3	IPP starts system	IPP/YEC

c) Once complete and with confirmation from SCC**,** IPP may proceed with the restarting of their operation. IPP Group will communicate to SCC once their system is back on line.

6.2 Loss of Supply - Long Term

In the event of a disturbance that results in the loss of the grid connection to the IPP the IPP generation will remain offline until approval from AEY and YEC.

a) SCC will confirm the status of the breaker located at IPP site. If SCADA communications are down the switch status will be physically verified and reported to AEY before 5L649 will be energized.

Breaker	**Expected Status**
S6423	Open

b) The following switching sequence will be followed to re-energize 5L649 and synchronize IPP back to grid supply.

Step	Switch Sequence	Operation
1	Confirm 5L649 Energized	IPP/AEY
2	S6423 Closed	IPP
3	IPP starts system	IPP/YEC

7.0 Revision and Approval

7.1 This Agreement comes into effect once it is signed by IPP, AEY and YEC.

7.2 This Agreement will remain in effect unless cancelled upon the mutual agreement of both Parties.

7.3 The Parties will provide 90 days' notice in writing of the intention to modify this Agreement.

7.4 The Agreement may be revised at any time if operational needs require and are mutually agreed to by all Parties. This agreement will be formally reviewed every two (2) years.

8.0 Appendices

8.1 ATCO Electric's Power System Work Standards (PSWS.pdf)

Approved by: _____

Guy Morgan
Yukon Energy Corporation

Approval Date: August ____, 2020

Approved by: _____

Tony Badry
ATCO Electric Yukon

Approval Date: August ____, 2020

Approved by: _____

Sebastien Roy
Nomad Contracting & Electrical Services

Approval Date: August ____, 2020

POWER SYSTEM WORK STANDARDS

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ATCO Electric Ltd.
Transmission and Distribution
Operating Authority
P.O. Box 610
Vegreville, Alberta, Canada

ATCO Electric

Transmission and Distribution
Operating Authority

DO YOU HAVE ANY SUGGESTIONS

The PSWS is a living breathing document and suggested changes to the document will be reviewed on an ongoing basis. All suggestions and comments will be considered. Any major changes will be immediately issued and any other minor changes will be completed during the next revision.

Please email suggestions to @ Electric SOC PSWS, and include the following information:

Suggested Change:

Reason for Change:

Contact Information:

Your Name *Phone or Email address*

Supervisors Approval

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A MESSAGE FROM THE OPERATING AUTHORITY

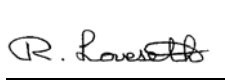
Work on or near the power system involves inherent risks to employees, system security and customer supply. Strict adherence to appropriate work standards, procedures and methods minimizes those risks and allows employees to work safely.

Power System Work Standards (PSWS) was developed by a team of experienced employees, including Operators-in-Charge of the transmission and distribution systems, to complement and support other ATCO Electric safety standards. All employees working on or near the ATCO Electric power system are required to:

- Meet applicable training, knowledge and skill requirements, as per HS&E Practice 1101: Power System Worker Authorization.
- Understand and consistently follow the standards in this document.
- Perform work, only as authorized by their supervisor and the Operator-in-Charge.

Your commitment will help to ensure employee safety and the efficient operation of the power system.

Craig Steinbach
Manager, System Operations
Transmission Operating Authority



Randy Loveseth
Senior Manager, Distribution Operations
Distribution Operating Authority

Chris Clark
Vice President
Transmission Operations

Barry Goy
Vice President
Distribution Operations

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SECTION 100: HOW TO USE THIS DOCUMENT

101 Purpose

Power System Work Standards provides ATCO Electric employees with standards to establish conditions on the power system that will – when combined with appropriate work standards, procedures and methods – allow work to take place on or near the power system.

Employees must obtain permission from the Operator-in-Charge (OIC) before starting any work on the power system.

NO PERMISSION = NO WORK

101.1 Limitations

It is important to note that this document only provides a process for establishing required power system conditions through Worker-Administered switching or the OIC permitting process. Employees must implement barriers to protect against all hazards identified in the job planning process.

102 Scope

Power System Work Standards applies to all employees authorized to work on or near ATCO Electric's power system apparatus and/or supporting control and communication apparatus.

103 Document Compliance

Power System Work Standards complies with the following:

- Alberta Electrical Utility Code (AEUC)
- Occupational Health & Safety Act, Regulation and Code
- ATCO Electric Corporate Health, Safety and Environment Principles and Policies
- Operations HS&E Management System and Best Practices
- Operations HS&E Safety Standards Manual.

104 Definitions

Apparatus – Equipment of every kind and description used in the generation, transformation, distribution, delivery or use of electrical power or energy. The term also includes the supporting control and communication equipment used to manage the delivery and use of electrical power.

Charged – Containing stored electrical energy.

Condition Guarantee (COG) – Formal declaration that a device is in a specific state, tagged to identify that state and guarantee is given that the device will not be operated until the Condition Guarantee is released. This is not a work permit.

Control System Permit (CSP) – Allows work to be performed on apparatus under 750 V that directly impacts or could impede operation of the power system.

De-energized (Dead) – At a potential equal to or not significantly different from that of ground (earth) at the work site.

Device – A type of electrical apparatus used as a switch or control mechanism (e.g., gang switch, recloser, auto-sectionalizing scheme).

Disable – To make a device inoperable.

Do Not Operate Tag– See Appendix B.

Employee – For the purposes of this document, any individual employed by or contracted to ATCO Electric who is competent to perform assigned duties.

Employee-in-Charge – Individual responsible for all employees in a work group or groups working on or near the same related power system apparatus. An employee who works alone is considered the Employee-in-Charge.

Enable – To make a device operable.

Energized (Live) – At a potential that is significantly different from that of ground (earth) at the work site and that presents an electrical hazard.

> ***Note***: A part is energized when it is electrically connected to a source of electric energy. It can also be energized when it is electrically charged under the influence of an electric or magnetic field. Apparatus must be considered energized unless confirmed to be isolated and grounded.

Guarantee of Isolation (GOI) Permit – Allows work on a line or apparatus that has been isolated from all power system sources of potential above 750 volts.

Human Machine Interface (HMI) – A software-based local control and monitoring system.

Hold-Off Permit (HOP) – Prevents automatic or manual restoration following an unplanned circuit outage.

Isolate – To completely disconnect a device or circuit from other devices or circuits, separating it physically, electrically and mechanically from all sources of electrical energy.

> ***Note***: Such separation may not eliminate all the effects of electromagnetic induction.

Live Line Work – All work performed on energized electrical equipment or lines, using protective insulating devices, live line tools or bare-hand techniques.

Locked – Physically secured with a keyed padlock. (This definition only applies to devices where provision for locking is provided.)

Near – For the purposes of electrical operations, distance at which there is a possibility of contacting energized lines or equipment.

Operating Authority – Person designated by ATCO Electric to make policy decisions that affect operations of the power system. Also known as the Operator of a Utility System, as defined in the AEUC.

Operating Interface Point – Location on the power system that separates the responsibilities of respective Operators-in-Charge. Operating interface points are identified on switching diagrams. See Appendix A.

Operator-in-Charge (OIC) – Qualified Worker designated by the Operating Authority to coordinate control of the power system or a portion thereof, in accordance with the requirements of established safety standards, operating standards and procedures.

OIC-Administered Switching – Switching directed by the Operator-in-Charge, in accordance with switching orders developed by the Operator-in-Charge.

Permit – Portion of the switch order that provides authorization to work under established power system conditions.

Permit Holder – Employee to whom authorization has been issued to work on the power system.

Potential – Voltage**,** in the context of electricity.

Power System – All electrical apparatus that comprise the transmission and distribution systems.

Qualified Worker – Worker(s) who, through possession of a recognized degree, certificate, professional standing or through extensive knowledge and training experience, has successfully demonstrated the ability to perform the required duties and tasks of the work.

Release – Surrender of the permit.

Requester – Employee who initiates a work permit.

Return to Normal – Restoration of the power system or apparatus to a desired operating state.

Supervisory Control and Data Acquisition (SCADA) – Computer system that transfers field data and operating control to a centralized location.

Software Tags – Tags applied to computer-based systems by the Operator-in-Charge to prevent the operation of devices by those systems.

Switching – Process by which the electrical configuration of a system is changed, usually through the operation of devices designed for this action, but may also include the removal or installation of jumpers and the making or breaking of normally permanent connections.

Single Line Diagram (SLD) – Simplified electrical representation of substations or power system switch maps or any part thereof.

Switch Order – Documentation that describes the specific switching sequence required to place power system devices in a desired operating state.

System Switching Information (SSI) – Form that contains information required for conditioning the power system.

Switchman – Employee who operates electrical apparatus and performs switching and tagging of devices under the direction of or with the permission of the Operator-in-Charge.

System Security – Integrity of the power system. It is maintained by identifying the next contingency related to the work being considered that could impact power system operations and/or customer supply.

Tailboard – Conversation between Operators-in-Charge, Switchmen and/or Permit Holders that transpires before any switching action or issuing of permits.

Test and Operate (T&O) Permit – Allows apparatus to be operated or energized, without impacting the power system,

so adjustments, repairs, maintenance or commissioning tests can be performed.

Transfer of Authority – Formal transfer of duties, responsibilities or jurisdiction (temporary work zone) from one Operator-in-Charge to another.

Unqualified Worker – Worker(s) who is not a qualified worker; i.e., does not possess a recognized degree or certificate, professional standing or the knowledge/experience to successfully demonstrate the ability to perform the required duties and tasks of the work.

Worker-Administered switching (WA) – Switching performed by an employee who has received permission from the Operator-in-Charge to establish the power system conditions required to work on or near the power system.

Working Day – (for scheduling purposes) Monday through Friday inclusive, excluding statutory holidays.

SECTION 200: RESPONSIBILITIES

201 Operating Authority

The Operating Authorities are responsible for the operation of the transmission and distribution systems. The Operating Authority is also responsible for ensuring the Operator-in-Charge (OIC) responsibility is assigned.

202 Operator-in-Charge

The **Distribution Operator-in-Charge** (DOIC) is responsible for all power system apparatus rated 36 kV and below, excluding that portion shown on transmission Single Line Diagrams.

The **Transmission Operator-in-Charge** (TOIC) is responsible for all power system apparatus rated 72 kV and above and substation equipment rated below 72 kV, as shown on transmission Single Line Diagrams or switching maps. Exceptions to this requirement are identified as interface points on affected switching maps.

The **Operator-in-Charge** must:

- Coordinate the day-to-day operation of the transmission or distribution system, in compliance with approved standards and procedures.
- Establish power system conditions that will – when combined with appropriate work standards, procedures and methods – allow work to take place on or near the power system.
- Issue permits, as required, for all work on the transmission or distribution systems, including the attachment and detachment of apparatus.
- Maintain operational documentation for a minimum of three years.

203 Permit Holder

The Permit Holder is normally the Employee-in-Charge of a single work group or multiple work groups, as applicable.

The Permit Holder must be a Qualified Worker.

The Permit Holder is required to:

- Request and hold the permits that will – when combined with appropriate work standards, procedures and methods – allow work to take place on or near the power system.
- Notify the Operator-in-Charge (OIC) prior to starting work.
- Provide all employees and work groups under their direction permission to work under the permits held.
- Stop work and promptly notify the OIC in the event of any unscheduled occurrence or incident related to the power system that may affect:
  - employee safety
  - power system security
  - continuity of customer supply.
- Release all permits to the OIC when the work is complete.

204 Switchman

The Switchman must be a Qualified Worker.

The Switchman is responsible to:

- Perform switching at the direction of the OIC, or
- Establish their own protection under Worker-Administered (WA) switching , with permission of the OIC.

205 Employees

Employees have a responsibility to comply with all standards provided in the *Power System Work Standards*.

SECTION 300: NOTIFICATION AND PERMISSIONS TO ESTABLISH REQUIRED CONDITIONS

301 Notification and Permission Requirements

301.1 Substation Entry

All persons entering a substation must be a Qualified Worker or be escorted by a Qualified Worker.

The Employee-in-Charge (EIC) must notify the Transmission Operator-in-Charge (TOIC) prior to entering or departing a substation. The EIC must provide the following information:

- first and last name
- substation name or number
- reason for entering
- risks associated with the work
- expected duration of work (and, as applicable, the need for an extension).

This information allows the OIC to contact the EIC, if necessary (e.g., to gather information, to respond to an unplanned outage).

If an entry alarm is received from a remotely-monitored substation without a confirming call, the OIC must:

- Call the substation.
- Contact a local employee to investigate, if no one answers the call.
- Request police assistance, as required.

If the EIC fails to report back after completing the work, the OIC must initiate an investigation.

Note:

- Employees are also required to check in and out of unmanned Isolated Generation Sites (IGS) sites.
- The TOIC is responsible for monitoring entry into IGS sites.
- The preceding section shall also apply to IGS entry.

301.2 Work on the Power System

NO PERMISSION = NO WORK.

Necessary permit request (s) must be sent, in writing, to either the Transmission or Distribution Operations scheduling group.

- Equipment rated 25 kV or less, including apparatus under 750 V that directly impacts or could impede operation of the power system (e.g., relays, voice and data communication systems, protection circuits), requires a minimum notice of:
  - three working days when one OIC is involved
  - five working days when two or more OIC's are involved.
- Equipment rated 72 kV and above requires a minimum notice of 30 days; approval is required from the Alberta Electric System Operator (AESO).

The OIC (s) must review the permit request with the employee to identify any concerns.

The OIC (s) must advise the employee if the permit can be issued, as requested, as soon as possible.

302 Permission to Establish Required Conditions

After considering system security, customer supply and current permits, the OIC will schedule the work and provide permission to establish the required conditions through either OIC-Administered switching or Worker-Administered switching.

302.1 OIC-Administered Switching

The OIC cannot direct any switching without a written switching order, except in the following situations:

- A switch order is not required to operate a device for voltage control (e.g., Static VAR Compensator (SVCs), tap changers, synchronous condensers, capacitors or reactors, regulator banks and auto boosters).
- A switch order is not required in an emergency situation. See Section 1001.
- During troubleshooting situations, the OIC must document each switching step prior to completing that action. All troubleshooting actions must be transferred to the switch order and a second approval received before a permit is issued.

The Switchman must obtain the switch order from the OIC before performing the switching and must verify the switching instructions against the Single Line Diagram (SLD) or switching map. If the written switch order is not available onsite, the OIC will summarize the overall process and will provide the Switchman with step-by-step switching instructions pertinent to the switching location. The Switchman must:

- Record the switching steps, exactly as stated.
- Repeat the switching steps back to the OIC.

Upon completion of the switching, the OIC will issue a permit (e.g., Hold-off, GOI, Test and Operate, CSP) to the Qualified Worker or a Condition Guarantee to a Qualified Worker or to an adjacent OIC who requested the operation or confirmation of devices in order to establish a safe work area.

302.2 Worker-Administered Switching

The Operator-in-Charge (OIC) gives permission to a Qualified Worker to establish their own protection. This only applies to workers establishing protection for themselves or for a crew that is supervised by a Qualified Worker.

NO PERMIT IS ISSUED.

Worker-Administered (WA) switching can only occur with the authorization of the OIC. The OIC gives permission for the Qualified Worker to do the switching, allowing them to work on or near the power system.

WA switching may occur where a single device or multiple devices can easily establish protection and when risk to the power system is minimal (e.g., single- or three-phase radial distribution lines), provided the following conditions are met:

- Status of affected devices must be communicated to the OIC.
- All devices are under the authority of one OIC (e.g., no distribution-connected generation, no operating Rural Electrification Association (REA).
- There is only one Employee-in-Charge (EIC) of the work.
- The work is limited to one continuous work period. (The length of time required to complete the work at a specific work site. Issuance and release of daily permission will still be required.)
- There will be no overlapping WA switching permissions.

The following rules pertain to the administration of WA switching:

- The OIC will give permission for a Qualified Worker to establish their own protection under WA switching.
- The OIC will issue a unique reference number for the WA switching.

- The Qualified Worker will conduct a risk assessment of the work.
- The Qualified Worker will write up the switch order/tag.
- The Qualified Worker will advise the OIC when the work is complete.
- The Qualified Worker and the OIC will document the time of switching.

SECTION 400: ESTABLISHING REQUIRED CONDITIONS

401 Conducting a Power System Risk Assessment

401.1 General

To minimize hazardous situations and/or adverse effects on the power system, the Operator-in-Charge (OIC) must conduct a thorough risk assessment:

- before switching
- during switching
- after switching.

The risk assessment must include a review of the following, as applicable:

- system voltages and line flows
- status of adjacent substations
- status of interconnected utilities and customer loads
- apparatus and system capabilities
- effect of the next worst contingency
- conflicting scheduled outages
- current permits.

401.2 Distribution Tie Switches

Before operating distribution switches that tie different distribution feeders or transmission substations together, the Distribution OIC and/or Transmission OIC must consider:

- the possibility of inadvertently bypassing regulators
- settings and control of voltage regulators
- load shift
- the state of the transmission system
- system capabilities
- protection settings
- settings and switching of capacitors
- existing permits.

402 Switching

402.1 Communicating During Switching

The OIC must communicate switching instructions directly to the Switchman at the worksite. All parties must use full name identification when relaying switching instructions.

Verbal communications must be:

- Repeated back by the receiving party, as heard.
- Verified against the switch order.

402.2 General Switching Procedures

- A tailboard must occur between the OIC and the Switchman immediately before any switching to review the switching steps and to make sure that the switch order is complete, correct, understood and that all related hazards are identified.
- When possible, preference will be to perform switching remote from the device. Remote operation refers to offsite control, using Supervisory Control and Data Acquisition (SCADA), or onsite control, using the

Human Machine Interface (HMI) in the substation control building.

- The Switchman is required to inspect local devices and apparatus and report any deficiencies that could impact the switching to the OIC.
- The switching steps provided on the switch order must be followed.
- If there are inconsistencies or concerns – at any time – about the switching instructions, the switching must be stopped. Switching cannot proceed until the identified concerns are addressed.
- The Switchman must have the switch order in their possession when performing the switching and must record the time each switching step is successfully completed.
- Before operating any switch, the Switchman and OIC must ensure the device is rated for the operation.
- Any device that can be locked shall be locked, using a company system lock.

403 Isolating Apparatus

Isolation points must be fully opened and must be confirmed to have an adequate visible air gap on all phases.

- Where no visible air gap exists, isolated apparatus must be tested for potential and the isolating device must be locked and tagged as inoperable (e.g., padmount transformer with live front bushings and internal switchgear). Isolators and/or open jumpers can be used as isolation points.
- When motor-operated switches or circuit switchers are used as isolation points, the isolation procedure must include disabling the motor mechanism.
- When a normally open switch is used as an isolation point, the switch must be confirmed open onsite and tagged.
- When isolating a portion of the system where a Potential Transformer (PT) or station service is

connected, the PT or station service must also be isolated, using the secondary or primary disconnects, unless it is confirmed to have no known or potential power system source.

- When isolating an indoor switch gear:
  - The breaker must be removed from the cubicle or racked out to the disconnect position and tagged to create the isolation point.
  - If the breaker is not removable, the associated solid blade disconnects or bus switches must be opened and tagged to create the isolation point.

404 Tagging

Employees must understand and utilize the following tagging procedures:

- To prevent unauthorized operation of devices, standard ATCO Electric Do Not Operate tags (or software tags, where available) must be installed, as directed by the Operator-in-Charge (OIC), or, in the case of Worker-Administered (WA) switching, as directed by the employee performing the switching.
- Each active permit must have a corresponding tag at each location that is required to be tagged. Five active GOIs would require five tags on each isolation point.
- Where a Condition Guarantee has been issued, the OIC who receives the Condition Guarantee is allowed to install additional locks and tags on associated isolating devices.
- An OIC who receives a Condition Guarantee can use the associated tags to form part of the permit(s) issued.
- Where possible, a software tag must be installed on the equipment associated with each tag installed on a device in the field.

- Only a Qualified Worker may install or supervise the installation or removal of tags – as directed by the OIC – or, in the case of WA switching, at the direction of the employee who installed the tags.
- When installing tags on field devices, only one tag will be utilized per bag.
- Tags must be installed on the same side as the switch identification number and as close as possible to the switching device (e.g., on the operating handles or, in the case of solid blade disconnects, on the associated structure – preferably at eye level).
- The OIC must be notified if:
  - a tag is discovered on any device or apparatus that appears unsupported by a switch order
  - an employee suspects a device has been operated without a tag or switch order.

  The OIC will initiate an investigation and take appropriate action (e.g., direct removal of the tag, direct tagging and issue a permit or energize), as applicable.
- All tags placed on power system devices and apparatus must be associated with a:
  - unique switch order reference number or
  - WA switching reference/event number.

  Only standard ATCO Electric Do Not Operate tags or OIC-Administered software tags may be used.
- The following information must be legibly recorded on the ATCO Electric Do Not Operate tag:
  - identifying number of the line or apparatus on which work is being done
  - identifying number or legal location of the device to which the tag is applied
  - reason for the isolation or condition
  - switching step(s), if the tag is being used as a switching order
  - person (WA) or OIC requesting the tag

- full name of the Switchman
  - time and date of the tag installation and removal
  - Reference/Event number (e.g., 12345).

  For a sample tag, see Appendix B.

SECTION 500: PERMIT PROCESS

501 Single Line Diagrams

501.1 General

Before performing any switching, the Switchman must have, in their possession: a valid, approved, up-to-date Single Line Diagram (SLD) or switch map that accurately details the apparatus contained within that system.

Copies of interim SLDs or switching maps may be obtained through the Transmission Control Centre (transmission system) or Distribution Control Centre (distribution system) and then authorized by the appropriate Operator-in-Charge (OIC).

501.2 Revisions

Verified and approved interim SLDs or switch maps (i.e., checked, dated and signed by the Employee-in-Charge) must be provided to the OIC whenever modifications are made to the power system.

The OIC may accept verbal notification of a change to an SLD or switch map from an Employee-in-Charge (EIC) if the change is minor and easily understood (e.g., a change to a switch number) and if the EIC commits to provide the OIC with a verified and approved interim SLD or switch map as soon as possible.

The OIC has the discretion to deny the verbal notification and to request a verified and approved interim SLD or switch map before accepting the change.

- Interim and revised SLDs or switch maps used to operate the power system must be authorized by the appropriate OIC.
- The OIC must obtain approval from the affected Operating Authority to change an operating interface point.

502 Permit Scheduling

502.1 General

In preparing to establish the required conditions to work on or near the power system, employees must complete the following seven steps, as applicable:

1. Provide Project Outage Plans and System Switching Information (SSI), as necessary.
2. Submit current SLDs or switch maps.
3. Determine the power system conditions required to accommodate the work.
4. Notify or request permission from the appropriate OIC to establish those conditions.
5. Receive permission to establish required conditions through OIC-Administered switching or Worker-Administered (WA) switching.
6. Obtain or develop switch orders.
7. Establish an onsite means of communication with the OIC.

502.2 System Switching Information/Permit Request

System Switching Information (SSI)/permit requests and work orders on request must include the following:

- line or apparatus affected and the work location
- type of permit(s) required
- dates and times the permit(s) is required and the anticipated duration of the work

- estimated time needed to release the permit in a critical situation
- description of the work
- required isolation points, as applicable
- risks the Permit Holder is able to identify (e.g., local impacts if something goes wrong with the work)
- means of communication to be used between the Permit Holder and OIC
- name of the Permit Holder or Requestor
- updated switch map or SLD.

503 Switch Order/Permit Form

503.1 General

Using the information on the System Switching Information (SSI) request, the OIC will conduct a power system risk assessment, schedule the work and prepare a switching order/permit form with the following information:

- unique reference number
- dates, times and duration the required power system conditions will be in effect
- switching sequence to be used to create those conditions
- switching sequence to be used to return to normal
- permit issuance and release documentation.

503.2 Numbering Switching Steps

Switching step numbers must be sequential at each switch location. To add switching steps to an existing switching order, use alphabetical suffixes to preserve the existing sequence (e.g., 36A, 36B, 36C).

503.3 Numbering Permits

The OIC must assign each permit a unique number.

- A reference number (e.g., 12345) will be generated when a new switching order is documented on the system (e.g., CROW, Maximo, OMS). For each required permit, the OIC will create a unique permit number, using the reference number as a base, followed by a unique alphabetical suffix (e.g., 12345A, 12345B).
- Where an electronic system is not available to assign a unique reference number, the OIC must use the following format: initials-year/month/day-sequence. *The date reflects the work start date. The month must be expressed as a three-letter abbreviation.* For example, reference number LJD-01Aug20-1 would have a permit number of LJD-01Aug20-1A.

504 Issuing and Holding Permits

504.1 General

The permit is the employee's assurance that the power system conditions defined by the switch order will not change until the permit is released. This assurance requires strict adherence to the following:

- In planned situations where switching is involved in establishing the required conditions, the Permit Holder should have, in their possession, a current copy of the Single Line Diagram (SLD) or switch map and the switch order prepared by the Operator-in-Charge (OIC) before the permit is issued.

  If the written switch order is not available onsite, the OIC will verbally provide the portion that contains the permit to the Permit Holder. The Permit Holder must:

  - Record the permit exactly as stated.
  - Repeat the permit back to the OIC.

A tailboard discussion must be held between the Permit Holder and the OIC prior to:

- Issuing a permit to verify required power system conditions have been established through the switch order.
- Releasing a permit to confirm established conditions can be returned to normal.

- All parties must use full name identification and repeat-back procedures whenever issuing, receiving or releasing permits.
- All required switching and tagging on the switch order must be completed before the associated permit is issued.
- The Employee-in-Charge (EIC) may accept a permit only for the work group(s) under their direction.
- If the Permit Holder must leave the work location, he or she must either release the permit(s) or arrange to maintain established conditions with the permission of the OIC (e.g., by providing a means of contact while offsite or changing Permit Holder s). See Section 504.2.
- Permits must be released when no longer required.
  - If permits are not released and the Permit Holder cannot be contacted, the OIC must contact the Permit Holder's immediate supervisor. The supervisor, if unable to locate the Permit Holder, must contact the Operating Authority for approval to release the permits.
- If continuous or scheduled communications cannot be maintained with the OIC, all applicable permits must be released.
- During critical situations, permits must be released as soon as possible at the request of the OIC.

504.2 Changing Permit Holders

If a Permit Holder must leave a site before the work is complete, established conditions can be maintained (with the permission of the OIC) by briefly overlapping the original permit with a new permit issued to another employee.

- The original Permit Holder must personally advise the OIC and everyone working under the permit of the proposed change.
- The new Permit Holder must review and confirm the established conditions with the OIC.
- The OIC will issue the new permit before releasing the original permit.

Note: If a tag is used for Worker-Administered Switching, the new Qualified Worker must place their tag on the device before the original tag is removed.

504.3 Expanding or Contracting Isolated Work Zone

If a work zone has to be expanded or contracted from an existing permit, the OIC must:

- Direct installation of tags on the new devices that are required to be isolated/opened to establish the new work zone.
- Transfer the required existing tags and reference numbers defined in the previous switching order to the new switch order, if a new switching order is required.
- Check that all devices have been identified and tagged to establish required conditions on the new permit.
- Issue the new permit to the Permit Holder.
- Release the previous permit.
- Direct removal of tags from the previous permit that are no longer required.

505 Return to Normal

When the work is complete, the Permit Holder must inform the OIC and – when applicable – provide the appropriate OIC (s) with suitable written documentation (e.g., final inspection, commissioning report stating “Approved to Energize”).

Devices within the confines of the permit will be returned to their original operating state or placed in the operating state desired by the OIC, as applicable.

In the case of Worker-Administered (WA) switching, the Permit Holder must remove all tags and document the time the switching action was completed (and the tag removed).

Return to normal switching may proceed after all permits have been released.

SECTION 600: PERMITS

601 Guarantee of Isolation Permit

The Guarantee of Isolation (GOI) permit allows work on isolated apparatus and guarantees:

- The line or apparatus has been isolated from all known or potential power system sources and has been tagged on all boundaries of isolation.
- Isolation from all known or potential power system sources above 750 V**,** substation Potential Transformers (PT) and station service disconnects, as applicable.
- The operating state of the isolating devices will not change until the permit is released.

601.1 Restrictions and Requirements

- A GOI Permit may be held by any Qualified Worker.
- When a device is being used as an isolation point for a GOI Permit, a Test and Operate (T&O) will not be allowed on that device.
- Before a GOI Permit is issued, tags must be securely placed on all isolating devices.
- Devices located within the isolation points of a GOI Permit – that are not tagged – may be operated by the Permit Holder with the understanding that before the permit is released the devices will be returned to their original operating state or placed in the operating state desired by the Operator-in-Charge (OIC) as applicable.

- When applied potential (e.g., Doble testing, Hypot testing, primary injections) is being used to test apparatus within a GOI zone, the Permit Holder must inform the OIC that such testing will be taking place. No additional GOIs are to be issued within the same zone of isolation while injection testing is in progress.
- In the case of two or more work groups working under the same GOI Permit, the Permit Holder must:
    - Provide each work group with permission to establish their own work protection (e.g., install grounds).
    - Check all grounds are removed when work is completed and before the work zone is restored to normal.

601.2 Issuing a Guarantee of Isolation Permit

When all conditions have been met, the OIC issues the GOI Permit to the Permit Holder, using the following words:

This is (name) informing (name) that (device or line) is now (isolated between/opened at) (location or locations). You may proceed with your work under GOI Permit # _____ Date_____.

601.3 Releasing a Guarantee of Isolation Permit

Before releasing the GOI Permit, the OIC and Permit Holder must verify that the switch order tailboard has been completed.

The Permit Holder releases the GOI Permit to the OIC with these words:

This is (name) informing (name) that I have completed my work on (device or line) and I am releasing my GOI Permit # _____ Date _____.

602 Test and Operate Permit

The Test and Operate (T&O) Permit provides assurance the OIC has assessed system security and that adjustments, repairs or tests can be performed on apparatus that may or may not be energized – as covered by the permit. It allows apparatus to be operated or energized so that adjustments, repairs, maintenance or commissioning tests can be performed.

A Test and Operate Permit is NOT intended to serve as a form of personal protection.

602.1 Restrictions and Requirements

- A T&O Permit may be held by any Qualified Worker.
- Only one T&O Permit will be issued on a single apparatus at any time.
- A T&O Permit will not be issued on any device defined as an isolation point for a GOI Permit.
- A T&O Permit will not be issued on any device that is part of a Hold-Off Permit.
- Before a T&O Permit is issued, tags must be securely placed on the switching devices that create the test condition.
- If a device or apparatus is required to be operated during tests, it may be operated only on instructions from the Permit Holder (e.g., opening/closing a circuit breaker).

602.2 Issuing a Test and Operate Permit

After all requirements have been met, the OIC issues the T&O Permit to the Permit Holder, using the following words:

> *This is (name) informing (name) that it is okay to test and operate (device) at (location) under Test and Operate Permit # ____ Date_____.*

602.3 Releasing a Test and Operate Permit

Before releasing a T&O Permit, the Permit Holder must verify the work has been completed and that devices associated with the permit are in their original operating state or the operating state desired by the OIC, as applicable.

The Permit Holder releases the T&O Permit to the OIC with these words:

> *This is (name) informing (name) that I have completed my work on (device) at (location) and I am releasing my Test and Operate Permit #_____ Date _____.*

603 Hold-Off Permit

A Hold-Off Permit (HOP) prevents automatic or manual restoration after an unplanned circuit outage, preventing further exposure of apparatus and employees to electrical potential. It confirms that restoration and reclosing schemes are disabled.

Normal Open (NO) switches in the field will not be tagged for HOPs.

603.1 Restrictions and Requirements

- A HOP may be held by any Qualified Worker.
- Tags must be placed on devices required to create the HOP, including the:
  - Control Panel – control switches of circuit breakers associated with the electrical apparatus covered by the HOP
  - Control Panel/Structures – control switches of any auto-sectionalizing, auto-transfer or automatic reclosing schemes that could re-energize the apparatus covered by the HOP.
- If the HOP is established through supervisory control, field tags referenced in paragraph one above do not have to be installed; however, the OIC must apply software tags to all devices associated with the permit.

- If the OIC receives an alarm indicating the associated protection may fail to operate under fault conditions (e.g., alarm for loss of DC), the OIC must notify the Permit Holder. The Permit Holder and OIC must then determine if the HOP can continue.
- If the associated protection operates or a loss of potential is suspected, the Permit Holder must notify the OIC or the OIC must notify the Permit Holder, as applicable.
- The Permit Holder must notify the OIC if a contact or incident occurs.
- Any device or line covered by the HOP that becomes de-energized will not be re-energized without the consent of the Permit Holder. (It is permissible to leave insulating equipment and tools connected to the line during the re-energization process).

603.2 Issuing a Hold-Off Permit

After all requirements have been met, the OIC issues the HOP to the Permit Holder, using the following words:

> *This is (name) informing (name) that reclosing has been disabled on (device or line) at (location) and (location) under Hold-Off Permit #_____ Date _____.*

603.3 Releasing a Hold-Off Permit

Before releasing the permit, the Permit Holder must verify the work has been completed and that devices associated with the permit are in their original operating state or the operating state desired by the OIC, as applicable (e.g., as required for attaching or detaching apparatus).

The Permit Holder releases the HOP to the OIC with these words:

> *This is (name) informing (name) that I have completed my work on (device or line) and I am releasing my Hold-Off Permit #_____ Date_____.*

604 Control System Permit

The Control System Permit (CSP) allows the OIC to assess risks and to condition the system to minimize the impact to system security, customer supply and other permits before work is performed on apparatus under 750 V that directly impacts or could impede operation of the power system. A CSP shall be initiated for work on the following apparatus:

- relays
- voice and data communication systems
- protection circuits
- DC systems
- Substation AMR.

If there is any doubt about whether a CSP is required, the employee should contact the OIC.

604.1 Restrictions and Requirements

- A CSP may be held by any Qualified Worker.
- A CSP will not be issued on protective relays or any other apparatus associated with the devices covered by a HOP.
- Before receiving a CSP, the Permit Holder must describe to the OIC what they are doing and outline any local impacts if something goes wrong with the work.
- If unexpected problems are encountered, the Permit Holder must report to the OIC before proceeding.
- If conditions on the power system change and continuation of the work will jeopardize system security or customer supply, the OIC must request the release of the CSP.

604.2 Issuing a Control System Permit

The OIC will review the information provided by the Permit Holder, conduct a power system risk assessment, document any operational impacts and consider other existing permits before issuing a CSP.

The OIC issues the CSP to the Permit Holder, using the following words.

This is (name) informing (name) that it is ok to proceed with your work under Control System Permit # _____ Date_____.

604.3 Releasing a Control System Permit

Before releasing the permit, the Permit Holder must verify that the apparatus associated with the permit is in its original operating state or the operating state desired by the OIC, as applicable.

The Permit Holder releases the CSP to the OIC with these words:

This is (name) informing (name) that I have completed my work and it is ok to close Control System Permit #_____ Date _____.

SECTION 700: CONSTRUCTION – ATTACHING AND DETACHING APPARATUS

701 Procedure

When new construction is physically close to the point where it will eventually be tapped onto the existing electrical system, a tag may be installed on the open span or open jumpers to prevent inadvertent connection to the electrical system. Jumpers and open spans used for isolation purposes shall be assigned a unique identifier. The tag can be installed as part of the Condition Guarantee or alternatively installed as part of Worker-Administered (WA) switching.

When new construction is physically close to the existing electrical system and is only separated by a switch, a lock and/or tag must be installed on the open switch. The lock and/or tag can be installed as part of the Condition Guarantee or alternatively installed as part of WA switching.

To attach or detach apparatus from the energized power system, the Employee-in-Charge (EIC) must:

1. Provide the appropriate OIC with suitable written documentation (e.g., final inspection, commissioning report stating “Approved to Energize” or de-commissioning report stating “Approved to De-Energize”).
2. Provide the OIC (s) with an interim Single Line Diagram (SLD) or switch map, verified and approved by the EIC.
3. Identify the power system conditions required to complete the work and request permission to establish those conditions from the OIC (s).

4. Release associated WA switching permissions, permits or Condition Guarantees.

Note: When a project requires energization in stages, the EIC must:

- Identify isolation points that define each stage in the project work plan and provide a copy of the work plan to the OIC (s).
- Provide the OIC (s) with an interim SLD or switch map (that has been verified and approved by the EIC) before each segment is energized.

SECTION 800: OPERATING INTERFACE POINTS

801 Location of Operating Interface Points

To determine the location of operating interface points, refer to the table provided in Appendix A.

802 Condition Guarantee

The Condition Guarantee (COG) provides the formal assurance to another Operating Authority or Operator-in-Charge (OIC) that identified devices are in the position requested and will not change status until the device status request is formally released by the requestor.

A Condition Guarantee is not a permit.

802.1 Restrictions and Requirements

The OIC must give adjoining OICs prior notification of any action or condition that could impact their system, including, as applicable:

- changes to operating conditions
- operation of adjacent devices
- any work being performed that could present a risk to their system.

When establishing conditions that require switching beyond an operating interface point, the OIC must:

- Exchange copies of corresponding switching orders with the adjoining OIC when coordinated switching is required with the other party.

- Receive, before completing the switching process, a verbal COG from the adjoining OIC that required switching and tagging has been performed on their system and established conditions will not change until released by the OIC making the request.

802.2 Issuing a Condition Guarantee

When all conditions have been met, the OIC issues the COG to the adjacent OIC, using the following words:

This is (name) at the ATCO Electric SOC informing (name) at (company or organizational name) you have a Condition Guarantee that (describe condition) on/at (line number or substation name and number) . Reference # _____, Date_____.

802.3 Releasing a Condition Guarantee

Once the adjacent OIC no longer requires the Condition Guarantee, they release it with these words:

This is (name) at (company or organizational name) informing (name) at the ATCO Electric SOC that work is completed on (line or equipment number and location). I am releasing my Condition Guarantee Reference # _____, Date_____. (line or equipment) can be returned to normal.

SECTION 900: PROCEDURAL TOOLS

901 Voice Communications

Voice communication systems must be available for use between the Permit Holder and the Operator-in-Charge (OIC), and the Switchman and the OIC.

- Employees may use the following devices for communication:
  - cell/satellite phone
  - land line phone
  - company radio.
- All transmission substations must have one or more voice communication systems available for use at all times. If there is any doubt as to the effect of a portable radio or cell phone on apparatus in the building (e.g., a warning sign is posted), it must not be used.
- Where continuous communication is not possible, due to the site location, the OIC may allow scheduled communications. Consideration must be given to the:
  - impact on system security, due to the communication delays
  - possibility that customer outages may be extended, due to the communication delays.

902 Record Keeping

All switch orders for Worker-Administered (WA) switching shall be kept locally for a minimum of one year.

The OIC must maintain the following records for a minimum of three years:

- all switching orders (e.g., electronic, paper) used to issue permits
- documentation of any investigations regarding tagging or unauthorized operation of power system devices or apparatus
- logs – electronic or paper – including:
    - all permit information, including reference numbers
    - all Condition Guarantee information
    - Operator-Administered switching
    - Worker-Administered switching.

SECTION 1000: SPECIAL SITUATIONS

1001 Emergency Situations

Power System Work Standards (PSWS) provides ATCO Electric employees with standards for establishing conditions on the power system that will – when combined with appropriate work standards, procedures and methods – allow work to take place on or near the power system.

In an emergency, (a present or imminent event that requires prompt coordination of action to protect the health, safety or welfare of people or to limit damage to property and/or the environment), a Qualified Worker may take action to remove apparatus from service without prior authorization.

- ALWAYS protect yourself.
- NEVER put yourself in imminent danger or do anything that causes you to doubt your decision – call for help.

After emergency action has been taken, the Qualified Worker must report the action and the reason for the action to the appropriate Operator-in-Charge (OIC) as soon as possible.

The OIC will review the action and take the necessary steps to restore the power system.

Note: An investigation must be completed when emergency action has been taken.

1002 Inadvertent Operation of Apparatus

If an employee inadvertently operates any component of the power system, the employee must NOT attempt to correct the error. The employee must immediately notify the OIC.

The OIC will review the inadvertent operation and take the necessary steps to restore the power system, as applicable.

All employees must realize the potential results of their actions – all incidents must be reported and investigated.

APPENDIX A – Operating Interface Points

	Transmission	Distribution
Transmission	Not Applicable	Any distribution system apparatus downstream from the apparatus shown on the substation switching diagram.
Distribution	Any distribution system apparatus downstream from the apparatus shown on the substation switching diagram.	Not Applicable
Generation	As agreed to by the Operating Authorities and clearly defined on the single line diagrams. Where there is a direct interconnection, a Joint Operating Procedure must be established .	Located on the distribution system apparatus electrically closest to the unit breaker, unit transformer or station auxiliary transformer.
Customer	As agreed to by the Operating Authorities and clearly defined on associated customer and company single line diagrams. Where there is a direct interconnection, a Joint Operating Procedure must be established .	As agreed to by the Operating Authorities and clearly defined on associated customer and company single line diagrams and/or distribution switching maps. Where there is a direct interconnection, a Joint Operating Procedure must be established).
Other Utility	As agreed to by the Operating Authorities and clearly defined on associated utility, company and transmission single line diagrams. Where there is a direct interconnection, a Joint Operating Procedure must be established .	As agreed to by the Operating Authorities and clearly defined on associated utility, company and distribution single line diagrams.

APPENDIX B – Do Not Operate Tag

SCHEDULE "I"

DELIVERY TIME ADJUSTMENT TABLE

Seasonal Adjustment is subject to change.

Month	Seasonal Adjustment
January	100%
February	100%
March	100%
April	100%
May	100%
June	100%
July	100%
August	100%
September	100%
October	100%
November	100%
December	100%

ELECTRICITY PURCHASE AGREEMENT

BETWEEN

536774 YUKON INC.

- and -

YUKON ENERGY CORPORATION

NORTH KLONDIKE HIGHWAY SOLAR PV PROJECT

Under the YUKON STANDING OFFER PROGRAM

Dated the 5th day of June, 2020

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YUKON ENERGY CORPORATION

STANDARD FORM ELECTRICITY PURCHASE AGREEMENT

STANDING OFFER PROGRAM

THIS ELECTRICITY PURCHASE AGREEMENT ("**EPA**") is made as of the 5th day of June, 2020

BETWEEN:

536774 YUKON INC., a corporation incorporated under the laws of the Yukon ("**Seller**")

- and -

YUKON ENERGY CORPORATION, a corporation incorporated under the laws of the Yukon ("**Buyer**")

WHEREAS:

A. The Government of Yukon issued the *Energy Strategy for Yukon* in January 2009 and in October 2015 issued the *Independent Power Production Policy* as reviewed and updated in October, 2018 (the "**IPP Policy**") as part of the strategy's priority action to "update and develop a policy framework for electricity that emphasizes efficiency, conservation and renewable energy". The IPP Policy created a framework for the development of the Standing Offer Program. In support of the objectives of the IPP Policy, the Government of Yukon issued the SOP OIC and, together with the Utilities, developed the SOP Rules;

B. Seller has proposed the development of the Project on the Electrical Grid pursuant to the Standing Offer Program and such Project has been reviewed and approved in accordance with the SOP Rules; and

C. This EPA is being entered into by the Parties in respect of the Project under the Standing Offer Program in accordance with the SOP Rules.

NOW THEREFORE Seller and Buyer agree as follows:

ARTICLE 1
DEFINITIONS, INTERPRETATION AND SCHEDULES

1.1 Definitions and Interpretation

The definitions and certain principles of interpretation that apply to this EPA are set out in Schedule "A".

1.2 Schedules

The following Schedules attached hereto are incorporated into and made a part of this EPA:

Schedule "A"	-	Definitions and Interpretation
Schedule "B"	-	Project Description

Schedule "C"	-	Form of Annual Operating Plan
Schedule "D"	-	System Interconnection Study Report
Schedule "E"	-	Monthly Energy Shortfall Payment
Schedule "F"	-	Termination Payment
Schedule "G"	-	System Interconnection Guidelines
Schedule "H"	-	Joint Operating Procedure
Schedule "I"	-	Delivery Time Adjustment Table

ARTICLE 2
CONDITIONS PRECEDENT AND TERM

2.1 Conditions Precedent

(a) Except as provided in this Section, this EPA has no legal force until the Conditions Precedent described in Schedule "B" are satisfied by Seller or waived by Buyer. The Conditions Precedent may only be waived by Buyer by notice in writing to Seller.

(b) Seller will:

(i) seek to satisfy each of the Conditions Precedent on or before the Condition Date;

(ii) keep Buyer informed of any circumstances which may result in any of those Conditions Precedent not being satisfied in accordance with their terms; and

(iii) promptly notify Buyer upon satisfaction of any of those Conditions Precedent and provide such supporting evidence as may be reasonably required by Buyer.

(c) If the Conditions Precedent are not satisfied or waived on or before the Condition Date, or it becomes apparent that the Conditions Precedent will not, in the reasonable opinion of Buyer, be satisfied by the Condition Date, the Conditions Precedent will be taken to have failed and Buyer shall be entitled to terminate this EPA, in which event each Party shall release the other from any and all claims, damages, costs, expenses or liabilities whatsoever incurred by it and its Affiliates in relation this EPA provided that (i) Seller shall remain liable for all costs incurred by Buyer in respect of the System Interconnection Study Report, System Upgrade Costs or New Interconnection Facilities Costs and (ii) otherwise each Party shall be responsible for its own costs incurred by it in connection with this EPA.

(d) Section 2.1(a) does not apply to this Article 2, Section 3.5 and Articles 10, 11, 12, 13 and 15 which shall be in full force and effect from the date of this EPA.

2.2 Term

Subject to Section 2.1, this EPA shall commence on the Effective Date and continues for the period specified in Schedule "B", unless it is terminated earlier in accordance with this EPA.

ARTICLE 3
CONSTRUCTION AND OPERATION

3.1 Construction and Operation Costs, Liabilities and Actions

Seller will be fully responsible for the permitting, design, engineering, construction, Interconnection, commissioning, operation, maintenance, reclamation and decommissioning of the Seller's Plant and shall be responsible for all costs, expenses, liabilities and other obligations associated with such activities.

3.2 Standard of Construction and Operation

Except as otherwise consented to in writing by Buyer, such consent not to be unreasonably withheld, conditioned or delayed, Seller will ensure that the location, design, engineering, construction, Interconnection, commissioning, operation and maintenance of the Seller's Plant, are and will be carried out at all times during the Term:

(a) in accordance with the description of the Seller's Plant in Schedule "B" and the information in the Application in all material respects;

(b) in compliance with the Project Standards; and

(c) by qualified and experienced individuals.

The Parties shall conduct their respective operations in accordance with the Joint Operating Procedure.

3.3 Project Changes

Without Buyer's prior written consent, not to be unreasonably withheld, conditioned or delayed Seller will not make any change to:

(a) the Seller's Plant as described in Schedule "B"; or

(b) any other aspects of the Seller's Plant or the information in any System Interconnection Study Report completed for Seller's Plant prior to the Effective Date which would require changes by Buyer to the System Upgrades where such change would increase Buyer's liability for any costs or otherwise increase the obligations or risks of Buyer with respect to the Seller's Plant or any other project.

Seller acknowledges that Buyer may require, as a condition of its consent to any change described in this Section, that Seller agree in writing to reimburse Buyer for any reasonable incremental liability for any losses, costs and damages incurred by Buyer or any third party, with respect to the Seller's Plant or any other project, as a result of any change described in this Section. Buyer may also require that Seller provide performance assurance or security to Buyer in order to ensure that Buyer has no financial exposure in respect of such reimbursement obligation.

3.4 Development Progress Reports

Seller will deliver a Development Progress Report to Buyer on each January 1, April 1, July 1 and October 1 after the Effective Date until Seller's COD. Buyer shall be entitled to request such

additional information as it may reasonably require from time to time in respect of Seller's development of Seller's Plant.

3.5 Responsibility for Upgrade Costs

Seller will be responsible for and shall pay Buyer for all System Upgrade Costs and New Interconnection Facilities Costs in accordance with the following:

(a) the System Interconnection Study Report sets out Buyer's estimate of System Upgrade Costs and the New Interconnection Facilities Costs. Seller shall (i) pay to Buyer in advance an amount equal to such estimate of System Upgrade Costs and New Interconnection Facilities Costs ("**Upgrade Costs Advance**") and/or (ii) provide such other security in form, substance and amount as may be acceptable to Buyer in its Discretion to secure the obligation of Seller to pay such costs ("**Upgrade Costs Security**"). Buyer shall not be required in any circumstances to accept Upgrade Costs Security except in its Discretion. Buyer shall not be required to perform any work or incur any System Upgrade Costs or New Interconnection Facilities Costs where Buyer determines in its Discretion that the amount of Upgrade Costs Advance it has received together with any Upgrade Costs Security is not sufficient to adequately secure the obligation of Seller to pay all System Upgrade Costs and New Interconnection Facilities Costs and Seller shall forthwith provide to Buyer such additional Upgrade Costs Advance and/or Upgrade Costs Security as may be reasonably required by Buyer;

(b) Buyer will exercise Good Industry Practice to perform, or cause to be performed, the work required in respect of the System Upgrades and the New Interconnection Facilities for the Project. Buyer shall be entitled to draw upon the Upgrade Costs Advance and Upgrade Costs Security from time to time in its Discretion to satisfy any System Upgrade Costs and New Interconnection Facilities Costs as and when incurred by Buyer; and

(c) notwithstanding the estimate of System Upgrade Costs and New Interconnection Facilities Costs provided by Buyer to Seller contemplated in Section 3.5(a) or the amount of any Upgrade Costs Advance and Upgrade Costs Security provided by Seller, Seller shall be responsible for and shall pay Buyer the actual System Upgrade Costs relating to the System Upgrades incurred by Buyer. Following the completion of the System Upgrades and the payment in full by Seller of all System Upgrade Costs incurred by Buyer for such work, Buyer shall release to Seller any undrawn portion of the Upgrade Costs Advance and Upgrade Costs Security**.**

3.6 Metering

As part of the System Upgrades and New Interconnection Facilities, Buyer will install and maintain an appropriate Meter installation at the POI, and ensure that such Meter is tested and sealed according to any Measurement Canada standards. Seller will allow Buyer to access the Seller's Plant as may be necessary from time to time to install and maintain the Meter at the POI. If there is any dispute regarding the accuracy of the Meter, either Party may give notice to the other Party of the dispute. In that case, the Parties will resolve the matter in accordance with the *Electricity and Gas Inspection Act* (Canada).

3.7 Insurance

Seller will, at its cost, obtain and maintain (a) policies of commercial general liability insurance with a per occurrence limit of liability not less than $5,000,000, and (b) property insurance, with limits of liability and deductibles consistent with those a prudent owner of a facility similar to the Seller's Plant would maintain and those the Facility Lender may require. All commercial general liability policies must include Buyer, its directors, officers, employees and agents as additional insureds and must contain a cross liability and severability of interest clause. All policies of insurance must include a waiver of subrogation in favour of Buyer. All policies of insurance must be placed with insurers that have a minimum rating of A- (or equivalent) by A.M. Best Company and are licensed to transact business in the Yukon and must be endorsed to provide to Buyer 30 days' prior written notice of cancellation, non-renewal or any material amendment that results in a reduction in coverage. Seller will give Buyer a copy of the insurance certificate(s) for the insurance required to be maintained by Seller under this Section not more than 30 days after the effective date of coverage and promptly upon renewal thereafter. Seller will be responsible for the full amount of all deductibles under all insurance policies required to be maintained by Seller under this Section.

3.8 Seller's COD

(a) Except with Buyer's prior written consent, Seller's COD may not occur earlier than 90 days prior to Target Seller's COD.

(b) Buyer will not be required to incur any incremental expense or other liability of any kind to enable Seller's COD to occur prior to Target Seller's COD.

3.9 Change in Target Seller's COD

If the estimated date for completing the System Upgrades or the New Interconnection Facilities as required to achieve Buyer's COD is later than 90 days prior to the Target Seller's COD, Buyer shall provide notice to Seller of such delay and, provided Seller is not responsible for any delay in completing the System Upgrades or the New Interconnection Facilities (including a failure to pay amounts contemplated in Section 3.5), upon Seller's written request that the Target Seller's COD be postponed, Buyer will postpone the Target Seller's COD to the estimated date for completing the System Upgrades and the New Interconnection Facilities plus 90 days.

3.10 No Liability For Delay

Buyer shall exercise reasonable commercial efforts to achieve Buyer's COD prior to Target Buyer's COD. Buyer will have no liability under this EPA for delays in completion of (a) any System Upgrades or the New Interconnection Facilities, or (b) other work undertaken by Buyer or any of Buyer's Affiliates on the Seller's Plant side of the POI, in each case howsoever arising.

3.11 Outages

(a) **Notice of Seller's Outage** - Seller will notify Buyer of any Outages in Seller's Plant, or changes in any such Outages, by delivering to Buyer an Outage Notice or revised Outage Notice:

(i) promptly in the case of a Forced Outage or a Maintenance Outage;

(ii) not less than 90 days in advance of any Planned Outage, or such shorter time period with Buyer's written consent, such consent not to be unreasonably withheld, delayed or conditioned; and

(iii) promptly in the case of any changes to the duration, start time or end time of any Outage.

(b) **Notice of Buyer's Outage** - In addition to Buyer's reporting requirements under Section 4.8(d), Buyer will notify Seller of any Planned Outages that will result in a Buyer's Distribution/Transmission Constraint or changes in any such Planned Outages, by delivering to Seller an Outage Notice or revised Outage Notice:

(i) not less than 90 days in advance of any such Planned Outage, or such shorter time period with Seller's written consent, such consent not to be unreasonably withheld, delayed or conditioned; and

(ii) promptly in the case of any changes to the duration, start time or end time of any Outage.

(c) **Coordination and Scheduling of Outages -** Seller will coordinate all Planned Outages or Maintenance Outages with Buyer's maintenance schedule or other requirements where such schedule or requirements are publicly available or otherwise notified to Seller.

3.12 Annual Operating Plan

On or before October 31 in each year during the Term, Seller will provide to Buyer its Annual Operating Plan, including any required update to the then current Annual Operating Plan, for the 12-month period commencing on January 1 of the next year. Seller will promptly provide Buyer with a revised Annual Operating Plan from time to time upon Seller becoming aware of any expected material change in the original Annual Operating Plan for that period. The Parties agree the Annual Operating Plan is provided for planning purposes and does not guarantee or limit the quantity or timing of Delivered Energy to the POI.

ARTICLE 4
PURCHASE AND SALE OBLIGATIONS

4.1 Energy prior to Buyer's COD

Subject to satisfaction of all obligations of Seller under this EPA, upon the occurrence of Seller's COD but prior to the occurrence of Buyer's COD, Buyer will not be obligated to purchase, or accept delivery from Seller of, any Energy, provided if Buyer does accept, in its sole discretion, delivery of Energy at the POI, Buyer will pay for such Energy accepted by Buyer prior to Buyer's COD in accordance with Section 5.1.

4.2 Energy after Buyer's COD

From and after Buyer's COD for the remainder of the Term, Seller will sell and deliver all Energy to Buyer at the POI and Buyer will, subject to Sections 4.3 and 4.4, purchase and accept delivery of all Delivered Energy. Buyer will pay for Delivered Energy from and after Buyer's COD in accordance with Section 5.1.

4.3 Limit on Delivered Energy and Capacity

Notwithstanding the foregoing provisions of this Article 4:

(a) in any hour, Buyer will not be obligated at any time to purchase or accept delivery from Seller at the POI of any Energy generated in excess of the Seller's Plant Capacity in such hour (as measured in kWh) and no amount will be payable by Buyer for Delivered Energy in excess of the Seller's Plant Capacity in such hour, whether prior to or after COD, and regardless of whether Buyer consented to and accepted delivery of such Energy at the POI;

(b) in any calendar year, Buyer will not be obligated to purchase or accept delivery from Seller at the POI of any Energy generated in excess of the Project Energy Volume and no amount will be payable by Buyer for Delivered Energy in any such calendar year in excess of the Project Energy Volume in such calendar year, whether prior to or after COD, and regardless of whether Buyer consented to and accepted delivery of such Energy at the POI; and

(c) in determining the total amount of Delivered Energy for a year, month, hour or any other time period under this EPA for any purpose, the amount of Delivered Energy in each hour of such time period will not exceed the Seller's Plant Capacity in such hour, even if Seller delivered to the POI Energy in excess of such amounts, or the Seller's Plant was capable of generating Energy in excess of such amounts.

4.4 Distribution/Transmission Constraints

Buyer will not be in breach or default of its obligations under Sections 4.1, 4.2 or 5.1 if Buyer is not able to accept delivery of Energy at the POI as a result of a Distribution/Transmission Constraint. Buyer will have no liability with respect to a Distribution/Transmission Constraint, except as set out in Section 4.8, if applicable.

4.5 Exclusivity

(a) Seller will not at any time during the Term commit, sell or deliver any Energy (or related Environmental Attributes) to any Person other than Buyer under this EPA. Seller will not use any Energy (or related Environmental Attributes) for any purpose whatsoever except for sale to Buyer under this EPA. These prohibitions do not apply if, and for so long as, Buyer is in breach of its obligations under Section 4.2.

(b) Seller shall not be entitled to interconnect a generating facility to the Seller's Plant and transmit electricity via the Seller's Plant to the POI.

4.6 Custody, Control, Risk of and Title To Energy

Custody, control, risk of, and title to, all Energy (including any Delivered Energy exceeding the limits set out in Section 4.3 even where Buyer has not paid for such excess Delivered Energy) shall pass from Seller to Buyer at the POI. Seller will ensure that all Energy delivered to Buyer under this EPA is free and clear of all liens, claims, charges and encumbrances.

4.7 Line Losses

Seller will be responsible for all Line Losses, costs and liabilities relating to the transmission of Energy and other electricity, if applicable, from the POI to the interconnection point between the New Interconnection Facilities and the Electrical Grid. Such Line Losses shall be determined in accordance with the Line Loss Methodology.

4.8 Distribution/Transmission Constraint

(a) If, in any month after Buyer's COD, Seller is unable to deliver Energy at the POI or Seller's ability to deliver Energy at the POI is reduced solely as a result of a continuous Distribution/Transmission Constraint which exceeds 30 minutes in duration and which:

(i) is not caused by a Planned Outage by Buyer of the Distribution System or Transmission System;

(ii) is not caused by an event beyond the reasonable control of Buyer; and

(iii) is not caused by Seller, the Seller's Plant or anything on Seller's side of the POI;

(a "**Non-Permitted Distribution/Transmission Constraint**") then, notwithstanding that Buyer is excused under Section 4.4 from its obligations under Section 4.2, Buyer shall pay Seller, for each calendar month in which the Non-Permitted Distribution/Transmission Constraint has occurred, the Monthly Energy Shortfall Payment calculated in accordance with Schedule "E" less any costs Seller avoided or, acting reasonably, could have avoided during the Non-Permitted Distribution/Transmission Constraint.

(b) Buyer will not be required to pay any Monthly Energy Shortfall Amount under this Section in any of the following circumstances:

(i) during any period specified as a Seller's Outage in any Outage Notice, revised Outage Notice or in the Annual Operating Plan or during any other period where the Seller's Plant would otherwise not have been operating;

(ii) during any period when either Party is or would be excused, in accordance with Section 14.1, from its obligation to deliver or to accept delivery of Energy as a result of Force Majeure; or

(iii) if Seller has not provided Buyer with an Annual Operating Plan in accordance with Section 3.12 for the year in which the Non-Permitted Distribution/Transmission Constraint occurs.

(c) Seller will maintain accurate and complete Records of all costs Seller avoided or, acting reasonably, could have avoided during the Non-Permitted Distribution/Transmission Constraint and will report all such costs to Buyer and provide Buyer with all information required to calculate such costs.

(d) Buyer will give Seller notice of all Distribution/Transmission Constraints in each month which individually exceed 30 minutes in duration when it provides its monthly statements in accordance with Section 5.3.

(e) In the event of a Dispute by the Parties in respect of the amount of any Monthly Energy Shortfall Amount, the matter shall be resolved in accordance with Article 12.

4.9 Buyer Dispatch/Turn-Down Right

(a) Buyer may at any time during the Term deliver notice to Seller requiring Seller to Dispatch/Turn-Down and Seller will promptly comply with any such direction except to the extent that any operational, technical or regulatory constraint prevents or limits Seller's ability to comply with such direction.

(b) For each hour of the applicable Dispatch/Turn-Down, Buyer will pay Seller an amount equal to:

(i) the price payable for post-COD Delivered Energy under Section 5.1 multiplied by (A) the aggregate of the duration of the applicable Dispatch/Turn-Down (measured as a fraction determined as the aggregate number of minutes in such Dispatch/Turn-Down period divided by 60) multiplied by (B) an amount equal to the positive difference, if any, of (1) the "Non-Permitted Distribution / Transmission Constraint Hourly Deemed Energy" set out in Table E-1 of Schedule "E" for the applicable calendar month less (2) the amount of Delivered Energy in such hour of Dispatch/Turn-Down (the positive difference being the "**Dispatch/Turn-Down Deemed Energy**"); less

(ii) any costs Seller avoided or, acting reasonably, could have avoided during the period of the Dispatch/Turn-Down.

(c) Buyer will not be required to pay any amount in respect of Dispatch/Turn-Down Deemed Energy under this Section in any of the following circumstances:

(i) during any period specified as a Seller's Outage in any Outage Notice, revised Outage Notice or in the Annual Operating Plan or during any other period where the Seller's Plant would otherwise not have been operating;

(ii) during any period when either Party is or would be excused, in accordance with Section 14.1, from its obligation to deliver or to accept delivery of Energy as a result of Force Majeure;

(iii) if Seller has not provided Buyer with an Annual Operating Plan in accordance with Section 3.12 for the year in which the Dispatch/Turn-Down occurs;

(iv) during any other hour when the Seller's Plant would otherwise not have been operating if there had been no Dispatch/Turn-Down notice; or

(v) where Buyer's requirement for Seller to Dispatch/Turn Down is the result of the operation of the Seller's Plant in a manner inconsistent with Section 3.2.

(d) Where Buyer requires the Dispatch/Turn-Down as result of a Non-Permitted Distribution/Transmission Constraint, Section 4.8 will apply.

4.10 Electric Service to Seller

If at any time Buyer delivers electrical energy to service Seller's Plant Load, then such electrical energy shall be accounted and paid for separately under the applicable agreement for such electricity energy services and will not be netted off of Delivered Energy for the purposes of determining amounts payable by Buyer in accordance with Section 5.1.

ARTICLE 5
PRICE AND PAYMENT TERMS

5.1 Energy Price

In each billing period, Seller shall pay to Buyer, for each kWh of Delivered Energy, the Energy Price calculated in accordance with Schedule "B".

5.2 No Further Payment

The amount payable by Buyer as specified in Section 5.1 is the full and complete payment and consideration payable by Buyer for Delivered Energy and for Environmental Attributes.

5.3 Statements and Payment

(a) **Statements**

(i) Buyer will, by the 15th day of each month after the Buyer's COD, deliver to Seller a statement for the preceding month. The statement must indicate, among other things:

(A) the amount of, and price payable for, Delivered Energy for that month;

(B) any amount owing by Buyer in respect of a Non-Permitted Distribution/Transmission Constraint pursuant to Section 4.8;

(C) any Final Amounts owing by either Party to the other Party.

Where there has been any Delivered Energy purchased by Buyer in the period prior to Buyer's COD, the first statement following Buyer's COD shall also account for all amounts payable by Buyer to Seller for such period prior to Buyer's COD. The statement must set out in reasonable detail the manner by which the statement and the amounts shown thereon were computed and be accompanied by sufficient data to enable Seller, acting reasonably, to satisfy itself as to the accuracy of the statement.

(ii) Either Party may give notice to the other Party of an error, omission or disputed amount on a statement within 36 months after the statement was first issued together with reasonable detail to support its claim. After expiry of that 36 month period, except in the case of willful misstatement, fraud or concealment, amounts on a previously issued statement will be considered accurate and amounts which were omitted will be considered to be nil, other than amounts disputed in accordance with this Section within the 36 month period, which will be resolved in accordance with this EPA.

(iii) If Seller gives notice to Buyer of an error, omission or disputed amount on a statement as described in Section 5.3(a)(ii), Seller may direct Buyer to promptly produce new statements for the relevant month(s). The new statements will show the undisputed amount and disputed amount each in a separate statement or will otherwise separate the amounts in a single statement in a manner acceptable to Seller, acting reasonably.

(b) **Payment**

(i) Within 30 days after receipt of a statement delivered under Section 5.3(a), and subject to Section 5.5, Buyer will pay to Seller or Seller will pay to Buyer the amount set out in the statement, except to the extent Seller in good faith disputes all or part of the statement by notice to Buyer as described in Section 5.3(a)(ii).

(ii) If Seller disputes any portion of a statement, the applicable Party must pay the undisputed net amount payable by it pursuant to the statement or, if applicable, the new statement of the undisputed amount described in Section 5.3(a)(iii).

(iii) The Parties will endeavor to resolve any error, omission or disputed amount on a statement amount within 30 days of the notice described in Section 5.3(a)(ii).

(iv) Any amount required to be paid in accordance with this EPA, but not paid by either Party when due, will accrue interest at an annual rate equal to the Prime Rate plus 2%, compounded monthly. Any disputed amount that is found to be payable will be deemed to have been due within 30 days after the date of receipt of the statement which included or should have included the disputed amount.

(c) **Payment Calculations**

(i) For the purpose of all payment calculations under this EPA:

(A) all payment calculations will be rounded to the nearest cent; and

(B) Energy will be expressed in kWh rounded to two decimal places.

(ii) For the purpose of all payment calculations under this EPA, where CPI is to apply, if Statistics Canada (or the then recognized statistical branch of the Canadian Government):

(A) computes, at any time after the Effective Date, the CPI on a basis different to that employed at the Effective Date, then the CPI will be converted using the appropriate formula recommended by Statistics Canada (or the then recognized statistical branch of the Canadian Government);

(B) at any time ceases to publish or provide the CPI, then the provisions of Section 2.7 of Schedule "A" will apply;

(C) has not published the CPI for a relevant period at the time Buyer is required to provide Seller with a statement, Seller will prepare the invoice based on the CPI in effect at the time the invoice is issued and when the CPI for the relevant period is published, Buyer will recalculate the invoice amounts in

the next succeeding invoice and will include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation; or

(D) recalculates the CPI within 36 months after an invoice affected by that CPI calculation has been issued, then Buyer will recalculate the invoice amounts for the relevant period in the next succeeding invoice and will include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation.

5.4 Taxes

All dollar amounts in this EPA do not include any value added, consumption, commodity or similar taxes, including GST and any successor thereto, which, if applicable, will be added to each statement and paid by Buyer.

5.5 Set-off

If Buyer and Seller each owe the other an amount under this EPA in the same month, then such amounts with respect to each Party will be aggregated and the Parties may discharge their obligations to pay through netting, in which case the Party, if any, owing the greater aggregate amount will pay to the other Party the difference between the amounts owed, provided that this Section applies only to any purchase price for Delivered Energy and any Final Amount owing by either Party to the other Party. Except as otherwise expressly provided herein, each Party reserves all rights, counterclaims and other remedies and defenses which such Party has, or may be entitled to, arising from or related to this EPA.

5.6 Change in Law and GRA Cost Recovery

(a) If at any time after the Effective Date:

(i) the costs to Buyer of complying with its obligations under this EPA are, as a result of one or more Changes in Law, increased or decreased (including, for greater certainty, any increase of the obligations or risks of Buyer with respect to the Seller's Plant, but excluding any increase of the obligations or risks of Buyer with respect to the System Upgrades or New Interconnection Facilities); or

(ii) the costs to Buyer of complying with its obligations under this EPA which were of a category or type previously recovered under a General Rate Application are determined under a General Rate Application to no longer be approved for recovery from Buyer's customers in such General Rate Application;

then, to the extent that Buyer would not have incurred such costs except for the Seller's Project and/or the entering into of this EPA, the amount payable by Buyer as specified in Section 5.1 shall be adjusted by the amount necessary to reflect those changed costs which Buyer is unable to recover from Buyer's customers in a General Rate Application.

(b) For each relevant event in Section 5.6(a)(i) or 5.6(a)(ii), Buyer shall provide Seller with a statement setting out such information as is reasonably necessary to demonstrate that such an event has occurred, the reasonableness and necessity of the measures taken by Buyer in relation to the event, its efforts to mitigate the costs associated with such event including

reasonable efforts of Buyer to recover such costs from its customers in a General Rate Application, the nature and extent of any increase or decrease in the amount payable by Seller as specified in Section 5.1, and any such other information as may be reasonably requested by Seller.

(c) If in Seller's view there has been a Change in Law that may decrease Buyer's costs, Seller may request Buyer to demonstrate how such Change in Law has affected its costs under this EPA by providing the applicable information contemplated in Section 5.6(b).

(d) The payments between the Parties shall thereafter be adjusted effective as of the date such event in Section 5.6(a)(i) or 5.6(a)(ii) affects the costs of Buyer hereunder.

(e) If there is any Dispute between the Parties with respect to this Section 5.6, including as to the appropriate increase or decrease in any payments between the Parties under this Agreement, the Dispute shall be resolved in accordance with Article 12.

ARTICLE 6
ENVIRONMENTAL ATTRIBUTES

6.1 Environmental Attributes

Seller hereby transfers, assigns and sets over to Buyer all right, title and interest in and to the Environmental Attributes. Seller will ensure that all Environmental Attributes transferred to Buyer under this EPA are free and clear of all liens, claims, charges and encumbrances. Seller shall use commercially reasonable efforts to (i) provide information reasonably requested by Buyer in relation to such Environmental Attributes, including as may be required to allow Buyer to verify or certify that such Environmental Attributes exist or have been created and (ii) assist in having Seller's Plant certified, licensed, qualified or approved under any rules, regulations, programs or applicable Laws of any Governmental Authority or independent certification agency in respect of Environmental Attributes, provided that Buyer shall pay Seller all costs reasonably incurred by Seller in respect of the same. Any failure by Seller to exercise such commercially reasonable efforts under this Section 6.1 is a "material default" for the purposes of this EPA, and Buyer may terminate this EPA under Section 9.1(j).

ARTICLE 7
EPA ADMINISTRATION, RECORDS AND AUDITS

7.1 Records

Each of Buyer and Seller will prepare and maintain all Records, or duplicates of such Records, at Buyer's head office or local Yukon office or the Seller's Plant, as applicable, or following the expiry of the Term or the earlier termination of this EPA, at such other location as may be agreed in writing between the Parties, for a period of not less than 7 years from the date on which each such Record is created. The Audit Parties may take copies of such Records for the purposes of an inspection or audit under Section 7.2.

7.2 Inspection and Audit Rights

For the sole purpose of verifying:

(a) compliance with this EPA;

(b) the accuracy of statements, supporting information and calculations delivered by a Party under this EPA;

(c) the qualification of the Seller's Plant and the Energy for the Environmental Certification; or

(d) the liability of Seller for System Upgrades Costs and New Interconnection Facilities Costs,

Buyer or Seller, as applicable, will, on reasonable prior written notice from either Party desiring to conduct an audit, provide the Audit Parties with prompt access during normal business hours to (i) in respect of Buyer, Buyer's records solely relating to this EPA, or (ii) in respect of Seller, Seller's Plant and all records relating to the Seller's Plant, including any Seller Confidential Information, as applicable, to enable the Audit Parties to conduct an inspection or audit thereof. The Audit Parties will exercise any access and audit rights under this Section in a manner that minimizes disruption to the operation of the Party subject to the audit. The audit rights contained in this Section 7.2 shall be subject to the limitations set forth in Section 5.3.

7.3 Seller Consents

Seller will promptly provide any consents required to enable any of the Audit Parties to make enquiries with any Governmental Authority or any Person administering the Environmental Certification concerning any or all of the following: (a) the qualification of the Seller's Plant and the Energy for Environmental Certification, the status of the Environmental Certification and copies of any audits, inspections or reports prepared in connection with the Environmental Certification; and (b) compliance by Seller with Laws and Permits applicable to the Seller's Plant.

ARTICLE 8
FIRST NATION CLAIMS

8.1 Notification of First Nation Claim

Given the ownership and location of the Project, Seller and Buyer do not expect any First Nation Claims. However, if Buyer or Seller receives or obtains evidence of a First Nations Claim, it will notify the other Party as soon as practicable.

8.2 Obligation to Consult

If Buyer receives, obtains evidence or becomes aware of a First Nations Claim, it may direct Seller, at Seller's cost, to:

(a) consult with the First Nations making the First Nation Claim, or, if requested by Buyer, assist Buyer in the consultation process;

(b) take any measures Seller deems necessary to address, prevent, mitigate, compensate or otherwise accommodate any Potential Impacts provided the measures are consented to in advance by Buyer and the First Nations making the First Nation Claim; and

(c) provide regular written reports to Buyer concerning Seller's compliance with this Section, as may be reasonably requested by Buyer.

8.3 Seller Termination for First Nation Claim

At any time prior to Buyer's COD, if:

(a) within 60 days of Buyer receiving, obtaining evidence or becoming aware of a First Nations Claim, Buyer does not make a direction to Seller as contemplated in Section 8.2;

(b) Buyer notifies Seller in writing that it will not make a direction to Seller as contemplated in Section 8.2; or

(c) after consultation with the First Nations making the First Nation Claim it becomes clear that the measure(s) necessary for Seller to resolve the First Nation Claim or to address, prevent, mitigate, compensate or otherwise accommodate any Potential Impacts would, in Seller's discretion, impose a commercially unreasonable cost on Seller, or would require the consent of Buyer under this EPA or agreement by Buyer to amend this EPA in order to address any Potential Impacts and such consent or agreement to amend is not provided within 60 days after Seller's request to Buyer,

then Seller may terminate this EPA on notice to Buyer. Such termination will be effective 30 days after the date of delivery of such notice of termination unless otherwise agreed by the Parties. A termination by Seller under this Section will, for all purposes of this EPA, be treated in the same manner as a termination by Seller under Section 9.3(c) of this EPA (including the obligations of Seller under Section 9.7). The termination of this EPA is the exclusive remedy to which Seller may be entitled to if Seller elects to terminate this EPA under this Section.

8.4 Buyer Termination for First Nation Claim

At any time prior to Buyer's COD, if Buyer receives, obtains evidence or becomes aware of a First Nations Claim, Buyer may, at its sole discretion, terminate this EPA on notice to Seller. Such termination will be effective 30 days after the date of delivery of such notice of termination unless otherwise agreed by the Parties. Upon a termination by Buyer under this Section 8.4, Seller shall reimburse Buyer for costs or liabilities described in Sections 9.7(a), (b) and (c). The reimbursement by Seller of such costs or liabilities, the indemnification by Seller contemplated in Section 8.5 and the termination of this EPA are the exclusive remedies to which Buyer may be entitled to if Buyer elects to terminate this EPA under this Section.

8.5 Seller Indemnity for First Nation Claim

Seller shall indemnify and hold Buyer and its Affiliates harmless from any and all claims, damages, costs, expenses, or liabilities whatsoever incurred by Buyer and its Affiliates in relation to such First Nation Claim and such indemnity shall survive termination of this EPA.

ARTICLE 9
TERMINATION

9.1 Termination by Buyer

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Buyer may have under this EPA or at law or in equity in respect of any of the following events, Buyer may terminate this EPA by notice to Seller if:

(a) Seller's COD does not occur within 730 days following Target Seller's COD for any reason whatsoever (including Force Majeure), provided that Buyer may terminate this EPA under this provision only if Buyer delivers a termination notice prior to Seller's COD; or

(b) at any time after Buyer's COD, Seller fails to deliver at least an average of 25% of the aggregate Projected Monthly Energy as set out in Schedule "E" to Buyer over all hours in a period of 730 continuous days for any reason whatsoever (including Force Majeure, a Distribution/Transmission Constraint), but excluding a Non-Permitted Distribution/ Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or

(c) at any time after Buyer's COD, Buyer is unable to accept delivery of Energy at the POI for a period of 730 continuous days due to Force Majeure invoked by Buyer or a Distribution/ Transmission Constraint other than a Non-Permitted Distribution/ Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or

(d) Seller breaches Section 4.5; or

(e) Seller fails to complete any application, payment, filing, study, document or other step in the process for interconnecting the Seller's Plant to the Distribution System, Transmission System or New Interconnection Facilities, as applicable, in accordance with the requirements of, and within the time limits, including any cure periods, specified by Buyer, and such failure could reasonably be expected to have an adverse impact on Buyer or any third party; or

(f) any System Interconnection Study Report completed after the Effective Date contains information that is inconsistent with the description of the Seller's Plant in Schedule "B" and Seller has not received Buyer's consent under Section 3.3 for the change to Schedule "B"; or

(g) Seller is Bankrupt or Insolvent; or

(h) Seller, as a result of an act or omission of Seller, ceases to be exempt from regulation as a "public utility" as defined in the *Public Utilities Act* with respect to the Seller's Plant and the sale of Energy to Buyer under this EPA, and the loss of such exemption could reasonably be expected to have an adverse effect on the benefit to Buyer of this EPA; or

(i) an amount due and payable by Seller to Buyer under this EPA remains unpaid for 30 days after its due date and such default has not been cured within 30 days after Buyer has given notice of the default to Seller; or

(j) Seller is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by Buyer to Seller of the default Seller has cured the default or, if the default cannot be cured within that 30 day period, Seller demonstrates to the reasonable satisfaction of Buyer that Seller is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time. A "material default" includes any purported Assignment of this EPA without the consent of Buyer.

Any termination pursuant to this Section will be effective immediately upon delivery of the notice of termination to Seller.

9.2 Notice of Termination Event

Seller will notify Buyer promptly if Seller is Bankrupt or Insolvent or if there is a material risk that Seller will become Bankrupt or Insolvent or if Seller has defaulted under any agreement with a Facility Lender or if any Permit or land tenure agreement for the Seller's Plant is terminated or expires.

9.3 Termination by Seller

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Seller may have under this EPA or at law or in equity in respect of any of the following events, Seller may terminate this EPA by notice to Buyer if:

(a) after Buyer's COD, Buyer has not accepted delivery of Energy for a period of 730 continuous days due to an event described in Section 4.4 or any event of Force Majeure and Seller is not entitled to receive any payment pursuant to Section 4.8 in respect of that period; or

(b) the Seller's Plant has suffered major damage where the cost to repair the damage exceeds the net present value (using the Present Value Rate) of the expected revenues under the EPA for the remainder of the Term less the net present value (using the Present Value Rate) of the estimated operating and maintenance costs for the Seller's Plant for the remainder of the Term; or

(c) Seller has been unable to achieve Seller's COD for a period of 730 days after Target Seller's COD or has been unable to deliver Energy to the POI for a period of 730 continuous days after Seller's COD in either case solely as a result of Force Majeure invoked by Seller or a Distribution/Transmission Constraint other than a Non-Permitted Distribution/Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or

(d) Buyer is Bankrupt or Insolvent; or

(e) except where an amount has been disputed in the manner specified in Section 5.3(a)(ii), an amount due and payable by Buyer to Seller under this EPA remains unpaid for 30 days after its due date and such default has not been cured within 30 days after Seller has given notice of the default to Buyer; or

(f) Buyer is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by Seller to Buyer of the default Buyer has cured the default or, if the default cannot be cured within that 30 day period, Buyer demonstrates to the reasonable satisfaction of Seller that Buyer is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time.

Any termination pursuant to this Section will be effective immediately upon delivery of the notice of termination to Buyer.

9.4 Termination by Buyer for Convenience

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Buyer may have under this EPA or at law or in equity in respect of any of the following events, Buyer may terminate this EPA for convenience upon 90 days prior notice to Seller.

9.5 Effect of Termination

Upon expiry of the Term or earlier termination of this EPA in accordance with its terms:

(a) the Parties may pursue and enforce any rights and remedies permitted by law or equity in respect of any prior breach or breaches of this EPA and may enforce any liabilities and obligations that have accrued under this EPA prior to the expiry of the Term or the date of termination or that are stated to arise on termination of this EPA, subject to any express restrictions on remedies and limitations or exclusions of liability set out in this EPA;

(b) both Parties will remain bound by Section 3.5 with respect to the satisfaction of residual obligations for the period prior to termination or that are specified to arise on, or continue following, termination, and Sections 12.1 and 13.1 associated with Delivered Energy prior to termination of this EPA; and

(c) Seller will remain bound by Sections 7.1 and 7.2 for a period of 36 months following expiry or termination of this EPA;

and, in all such cases, both Parties will remain bound by any other provisions necessary for the interpretation and enforcement of the foregoing provisions.

9.6 Buyer Payment on Termination

If Seller terminates this EPA under any of Sections 9.3(d), 9.3(e) or 9.3(f) or Buyer terminates this EPA for convenience under Section 9.4, Buyer will pay to Seller an amount equal to the applicable Termination Payment due at the time of termination determined in accordance with Schedule "F".

9.7 Seller Payment on Termination

If Buyer terminates this EPA on or before 90 days after Seller's COD or Seller terminates this EPA on or before Buyer's COD under any of Sections 9.3(a), 9.3(b) or 9.3(c), Seller will, within 30 days after receipt of an invoice from Buyer, reimburse Buyer for:

(a) all System Upgrade Costs and New Interconnection Facilities Costs incurred by Buyer, or which Buyer has become contractually obligated to pay, prior to the termination of the EPA including System Upgrade Costs and New Interconnection Facilities Costs Seller would otherwise be responsible for under Section 3.5;

(b) any incremental liability for System Upgrade Costs and New Interconnection Facilities Costs which Buyer will incur as a result of the termination of this EPA; and

(c) any System Upgrade Costs and New Interconnection Facilities Costs which Seller is responsible for under any reimbursement agreement pursuant to Section 3.3.

9.8 Calculation and Payment

Buyer will pay any amount which it owes under Section 9.6 within 30 Business Days after the date of delivery of an invoice by Seller to Buyer. Any amounts owing by Seller to Buyer under this EPA will be netted against any amount owing by Buyer to Seller under Section 9.6.

9.9 Exclusive Remedies

Payment by Buyer of the amount determined under Section 9.6 is the exclusive remedy to which Seller is entitled, and Buyer's limit of liability, for termination of this EPA by Seller pursuant to any of Sections 9.3(d), 9.3(e) or 9.3(f). Subject to Section 9.4 and 9.7, termination of this EPA is the exclusive remedy to which Buyer or Seller, as the case may be, is entitled if Buyer or Seller elects to exercise its right to terminate this EPA under any of Section 9.1, 9.3(a), 9.3(b) or 9.3(c). For greater certainty, subject to Section 9.4 and 9.7, Seller will not be required to pay any termination payment on termination by Buyer of this EPA. Neither Party will have any right to terminate this EPA except as expressly set out herein.

ARTICLE 10
REPRESENTATIONS AND WARRANTIES

10.1 Seller's Representations

Seller represents and warrants to Buyer, and acknowledges that Buyer is relying on those representations and warranties in entering into this EPA, as follows:

(a) Seller is a corporation formed under the laws of the Yukon, is validly existing and is in good standing under the laws of the Yukon, is lawfully authorized to carry on business in the Yukon, and has full corporate power, capacity and authority to enter into and to perform its obligations under this EPA;

(b) this EPA constitutes a valid and binding obligation of Seller enforceable against Seller in accordance with its terms; and

(c) this EPA has been duly authorized, executed and delivered by Seller.

10.2 Buyer's Representations

Buyer represents and warrants to Seller, and acknowledges that Seller is relying on those representations and warranties in entering into this EPA, as follows:

(a) Buyer is a corporation formed under the laws of the Yukon, is validly existing and is in good standing under the laws of the Yukon, is lawfully authorized to carry on business in the Yukon, and has full corporate power, capacity and authority to enter into and to perform its obligations under this EPA;

(b) this EPA constitutes a valid and binding obligation of Buyer enforceable against Buyer in accordance with its terms; and

(c) this EPA has been duly authorized, executed and delivered by Buyer.

ARTICLE 11
LIABILITY LIMITATIONS

11.1 Limit of Liability

Buyer's liability for damages for any failure to take or pay for Delivered Energy under this EPA is limited to the amount payable by Buyer for that Delivered Energy under Article 5, amounts owing under Sections 4.8 and any interest thereon calculated under this EPA.

11.2 Consequential Damages

Neither Party will be liable to the other Party for any special, incidental, exemplary, punitive or consequential damages with respect to, arising out of, relating to or in any way connected with a Party's performance or non-performance under this EPA.

ARTICLE 12
DISPUTES

12.1 Dispute Resolution Procedure

Any dispute, controversy or claim arising out of or relating to this EPA ("**Dispute**") shall be exclusively and finally resolved in accordance with the dispute resolution procedure set forth in this Article 12 (the "**Dispute Resolution Procedure**").

12.2 Commencement of the Dispute Resolution Procedure

The Parties shall make reasonable efforts to first resolve any Dispute. If a Dispute cannot be resolved by the Parties, then either Party may initiate the Dispute Resolution Procedure by giving notice of the Dispute to the other Party (the "**Notice of Dispute**"). The Notice of Dispute shall contain a brief statement of the nature of the Dispute, set out the relief requested, and request that the Dispute Resolution Procedure be commenced.

12.3 Negotiations

Upon the submission of a Notice of Dispute pursuant to Section 12.2, each of the Parties shall refer the Dispute to a designated senior management executive with the authority to negotiate a settlement of the Dispute for that Party (the "**Senior Management Executives**"). The Senior Management Executives of the Parties shall attempt to resolve the Dispute within 30 days from the date on which the Notice of Dispute was issued, or such longer period as the Senior Management Executives may otherwise unanimously agree. If the Senior Management Executives unanimously agree upon a resolution of the Dispute, such resolution shall be memorialized in a written settlement agreement mutually acceptable to the Parties and shall be binding on the Parties.

12.4 Arbitration

If a Dispute is not resolved by Senior Management Executives within 30 days from receipt of a Notice of Dispute (or such longer period as the Senior Management Executives may otherwise agree in writing), the Dispute shall, at the request of either Party, be resolved by binding arbitration under the Rules of Arbitration of the International Chamber of Commerce (the "**ICC Rules**"), except to the extent of conflicts between the ICC Rules and the provisions of this EPA, in which

event the provisions of this EPA shall prevail. The following provisions shall apply to an arbitration commenced pursuant to this Section 12.4:

(a) the number of arbitrators shall be one;

(b) the place, or legal seat, of the arbitration shall be Whitehorse, Yukon;

(c) the language to be used in the arbitral proceedings shall be English;

(d) all awards issued by the arbitrator shall be final, non-appealable and binding on the Parties. Any award may be filed in any court of competent jurisdiction and may be enforced by a Party as a final judgment in such court. The Parties expressly waive, to the maximum extent permitted by law, any right of appeal of any award or reference of any matter to any court, other than as may be necessary to recognize or enforce an award;

(e) the arbitrator shall be guided by the International Bar Association's Rules on the Taking of Evidence in International Commercial Arbitration;

(f) the Parties shall request that the arbitrator render its final award within 12 months of the commencement of the arbitration, or as soon as possible thereafter, provided that no award shall be invalid if it is not rendered within the time period herein specified;

(g) any award for monetary damages shall be made and payable in Canadian Dollars and may include interest from the date of any breach or violation of this EPA until paid in full at the rate determined by the arbitrator;

(h) the Parties agree that any arbitration carried out hereunder shall be kept private and confidential, and that the existence of the proceedings and any element of it (including all awards, the identity of the Parties and all witnesses and experts, all materials created for the purposes of the arbitration, all testimony or other oral submissions, and all documents produced by a Party that were not already in the possession of the other Party) shall be kept confidential, except (i) with the consent of the Parties, (ii) to the extent disclosure may be lawfully required in bona fide judicial proceedings relating to the arbitration, (iii) where disclosure is lawfully required by a legal duty, and (iv) where such information is already in the public domain other than as a result of a breach of this clause. The Parties also agree not to use any information disclosed to them during the arbitration for any purpose other than in connection with the arbitration;

(i) where a Dispute relates to the EPA, the Parties shall agree to consolidate the matters in Dispute under such agreements in a single arbitration;

(j) the Parties agree that during the resolution of a Dispute pursuant to this Article 12, the Parties shall continue to perform their obligations under this EPA, provided that such performance shall be without prejudice to the rights and remedies of the Parties and shall not be read or construed as a waiver of a Party's right to claim for recovery of any loss, costs, expenses or damages suffered as a result of the continued performance of this EPA; and

(k) each Party will be responsible for its own costs under this Article 12, subject to the award of an arbitrator.

ARTICLE 13
CONFIDENTIALITY

13.1 Confidentiality

(a) **Additional Confidentiality Obligation** - During the Term and for two years thereafter:

(i) Buyer will treat as confidential, and will not disclose to any third Person, Seller Confidential Information, and

(ii) Seller will treat as confidential, and will not disclose to any third Person, Buyer Confidential Information.

(b) **Disclosure of Confidential Information** - Notwithstanding Section 13.1(a) above:

(i) Seller may also disclose Buyer Confidential Information and Buyer may disclose Seller Confidential information in the following circumstances:

(A) disclosures expressly authorized under this EPA or otherwise set out in this EPA;

(B) disclosures to enable a Party to fulfill its obligations under the EPA;

(C) disclosure in any arbitration or legal proceedings for the enforcement of the EPA;

(D) disclosure to the Party's directors, officers, employees, Facility Lenders, consultants and advisors, and purchasers of the Environmental Attributes, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality;

(E) subject to Section 13.1(b)(ii)(D), disclosure required to be made by a Party by an order of a court, a regulatory agency or a tribunal or under any law, regulatory requirements or any requirement of any stock exchange that is binding upon a Party, provided that (i) to the extent reasonably practicable, the Party intending to make such disclosure gives reasonable notice to the other Party before make the disclosure, and (ii) limits the disclosure to that required by the applicable order, Laws or regulatory or stock exchange requirement;

(F) disclosure to a third Person if such information was known by that third Person before disclosure by Buyer or Seller, as the case may be, provided the third Person did not know of the information as a result of a breach of the non-disclosure obligations in this EPA; or

(G) disclosure with the consent of Buyer, in the case of Buyer Confidential Information, or Seller, in the case of Seller Confidential Information.

(ii) Buyer may disclose Seller Confidential Information in the following circumstances:

(A) disclosure to Buyer's Affiliates or to a third Person, and their respective employees, consultants and advisors, for the purpose of reselling or marketing any Energy, including disclosure of Seller Confidential Information by such Affiliate or third Person to those who have purchased or may purchase the Energy;

(B) for purposes other than those described in Section 13.1(b)(i), to Buyer's Affiliates and to any directors, officers, employees, consultants and advisors of any Affiliates, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality;

(C) to any ministers, deputy ministers, servants or employees of the Yukon or the federal government, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality; or

(D) disclosure in any regulatory proceeding, whether related to this EPA or not, to the extent that Buyer considers disclosure is necessary or desirable to support its position in such proceeding.

ARTICLE 14
FORCE MAJEURE

14.1 Force Majeure

(a) If there is a Force Majeure affecting a Party's ability to perform an obligation under this EPA, and that Party wishes to declare a Force Majeure, that Party will promptly notify the other Party of the Force Majeure. The notice of Force Majeure must identify the nature of the Force Majeure, the date the Force Majeure commenced, the expected duration of the Force Majeure, and the particular obligations affected by the Force Majeure. If (i) a notice of Force Majeure is provided in accordance with this Section, (ii) the event in question is in fact an event of Force Majeure as defined in this EPA, and (iii) the event of Force Majeure commenced on the commencement date in the notice of Force Majeure, then the Force Majeure will be deemed to have been invoked as of the commencement date stated in the notice.

(b) Neither Party will be in default of any obligation under this EPA if a Party is unable to perform that obligation due to an event or circumstance of Force Majeure, provided notice is delivered in accordance with this Section and the circumstances are, in fact, an event or circumstance of Force Majeure.

(c) Subject to any limitations expressly set out in this EPA, the time for performance of such obligation will be extended by the number of days that Party is unable to perform such obligation as a result of the event or circumstance of Force Majeure. The Party invoking Force Majeure will make commercially reasonable efforts to promptly remove the Force Majeure and will promptly respond to any inquiry from the other Party regarding the efforts

being undertaken to remove the Force Majeure and will give prompt notice of the end of the Force Majeure.

ARTICLE 15
GENERAL PROVISIONS

15.1 Independence

The Parties are independent contractors, and nothing in this EPA or its performance creates a partnership, joint venture or agency relationship between the Parties.

15.2 Enurement

This EPA enures to the benefit of the Parties, their successors and their permitted assigns.

15.3 Assignment

(a) Seller may not assign this EPA except with the prior consent of Buyer, which consent may not be unreasonably withheld, conditioned or delayed provided such Assignment is to a Facility Lender. Any Assignment (other than an Assignment to a Facility Lender) is subject to the assignee entering into and becoming bound by this EPA, assuming all the obligations and liabilities of Seller under this EPA arising both before and after the Assignment, and providing the representations and warranties set out in Section 10.1 effective as at the time of Assignment, and Seller not being in default under this EPA. Unless agreed to in writing by Buyer, Seller shall remain jointly and severally liable with the assignee for all obligations of Seller under this EPA.

(b) Any request by Seller for Buyer's consent under Section 15.3(a) must be delivered to Buyer not less than 30 days before the date of the proposed Assignment. A request under this Section must be accompanied by such information as reasonably required by Buyer to assess the request for consent including the name, address and ownership structure of the assignee, details of any consultation with First Nations that may be impacted by the Seller's Plant or the Assignment with respect to the proposed Assignment, list of the directors and officers of the assignee and information concerning the assignee's operations, experience and financial status.

(c) If Seller seeks consent to Assign this EPA to a Facility Lender, Buyer may require, as a condition of its consent to the Assignment, that Seller and the Facility Lender enter into a Lender Consent Agreement with Buyer containing customary provisions. If required by a Facility Lender, Buyer will enter into a Lender Consent Agreement with the Facility Lender and Seller containing customary provisions. Seller will reimburse Buyer for all costs reasonably incurred by Buyer in connection with any request by Seller for Buyer's consent pursuant to Section 15.3(a).

15.4 Entire Agreement

This EPA contains the entire agreement between the Parties with respect to the purchase and sale of Energy and supersedes all previous communications, understandings and agreements between the Parties with respect to the subject matter hereof. There are no representations, warranties, terms, conditions, undertakings or collateral agreements express, implied or statutory between the Parties other than as expressly set out in this EPA.

15.5 Amendment

This EPA may not be amended except by an agreement in writing signed by both Parties.

15.6 No Waiver

Other than in respect of the specific matter or circumstance for which a waiver is given, and except as otherwise specified in this EPA, no failure by a Party to enforce, or require a strict observance and performance of, any of the terms of this EPA will constitute a waiver of those terms or affect or impair those terms or the right of a Party at any time to enforce those terms or to take advantage of any remedy that Party may have in respect of any other matter or circumstance.

15.7 Notices

Any notice, consent, waiver, declaration, request for approval or other request, statement or bill that either Party may be required or may desire to give to the other Party under this EPA must be in writing addressed to the other Party at the address for that Party stated in Schedule "A" and:

(a) notices under Section 14.1, Article 8 and Article 9 must be delivered by hand or by a courier service during normal business hours on a Business Day and a notice so delivered will be deemed to have been delivered on that Business Day;

(b) all notices other than notices described in Section 15.7(a) may be delivered by email during normal business hours on a Business Day and a notice so delivered will be deemed to have been delivered on that Business Day; and

(c) either Party may change its address for notices under Section 3 of Schedule "A" to this EPA by notice to the other Party.

15.8 Interconnection Notices

Nothing in the System Interconnection Guidelines and no exercise of any right thereunder, restricts or otherwise affects any right, obligation or liability of either Party under this EPA, except to the extent set out expressly herein, and no notice, consent, approval or other communication or decision under or in relation to the System Interconnection Guidelines will constitute or be relied upon as a notice, consent, approval or communication or decision under this EPA.

15.9 Commodity Contract/Forward Contract

The Parties agree and intend that this EPA constitutes an "eligible financial contract" under the *Bankruptcy and Insolvency Act* (Canada) and *Companies' Creditors Arrangement Act* (Canada).

15.10 Further Assurances

Each Party will, upon the reasonable request of the other Party, do, sign or cause to be done or signed all further acts, deeds, things, documents and assurances required for the performance of this EPA including, in the case of Seller, completing any registration process required in respect of Environmental Attributes as requested by Buyer.

15.11 Severability

Any provision of this EPA which is illegal or unenforceable will be ineffective to the extent of the illegality or unenforceability without invalidating the remaining provisions of this EPA.

15.12 Counterparts

This EPA may be executed in counterparts, each of which is deemed to be an original document and all of which are deemed one and the same document.

[Signature Page Follows]

IN WITNESS WHEREOF each Party by its duly authorized representative(s) has signed this EPA effective as of the date set out on page one of this EPA.

536774 YUKON INC.

Per:

Ben Power
Director

Per:

Michael Schultz
Director

YUKON ENERGY CORPORATION

Per: _____

Andrew Hall
President and Chief Executive Officer

Per: _____

Michael Brandt
Vice-President

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YUKON ENERGY CORPORATION

Per: _____
Andrew Hall
President and Chief Executive Officer

Per: _____
Michael Brandt
Vice-President

SCHEDULE "A"

DEFINITIONS AND INTERPRETATION

1. DEFINITIONS

References in a Schedule to a section or Section mean a section or Section of this EPA, and not a Schedule, unless otherwise stated. The following words and expressions wherever used in this EPA have the following meaning:

1.1 "**Affiliate**" means, with respect to any Party or any third Person, any Person directly or indirectly Controlled by, Controlling, or under common Control with, such Party or the third Person.

1.2 "**Annual Operating Plan**" means a 12-month operating plan for the Seller's Plant that includes for term of each operating plan, (a) a schedule of the expected total deliveries of Energy at the POI in each month and (b) a schedule of any Planned Outages of the Seller's Plant expected by Seller. The Annual Operating Plan will be consistent with Good Industry Practice and shall be substantially in the form attached hereto as Schedule "C", subject to such modifications thereto as may be reasonably required by Buyer.

1.3 "**Application**" means the application and all supporting documents and information with respect to the Seller's Plant filed by Seller with Buyer in the Standing Offer Program.

1.4 "**Assign**" or "**Assignment**" means to assign or dispose of this EPA or any direct or indirect interest in this EPA, in whole or in part, for all or part of the Term and, without limiting the foregoing, each of the following is deemed to be an Assignment of this EPA by Seller:

(a) any sale or other disposition of all or a substantial part of Seller's ownership interest in the Seller's Plant, or of all or any interest of Seller in this EPA or revenue derived from this EPA;

(b) any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's Plant or Seller's ownership interest therein; and

(c) any change of Control, merger, amalgamation or reorganization of Seller.

1.5 "**Audit Parties**" means the applicable Party conducting an audit under this EPA and its Affiliates, representatives, consultants, advisors and any other third Person retained in respect of the applicable audit.

1.6 "**Bankrupt or Insolvent**" means, with respect to a Person:

(a) the Person has started proceedings to be adjudicated a voluntary bankrupt or consented to the filing of a bankruptcy proceeding against it;

(b) the Person has filed a petition or similar proceeding seeking reorganization, arrangement or similar relief under any bankruptcy or insolvency law;

(c) a receiver, liquidator, trustee or assignee in bankruptcy has been appointed for the Person or the Person has consented to the appointment of a receiver, liquidator, trustee or assignee in bankruptcy;

(d) the Person has voluntarily suspended the transaction of its usual business; or

(e) a court of competent jurisdiction has issued an order declaring the Person bankrupt or insolvent.

1.7 "**Business Day**" means any calendar day which is not a Saturday, Sunday or Yukon statutory holiday.

1.8 "**Buyer**" means Yukon Energy Corporation and its successors and permitted assigns.

1.9 "**Buyer Confidential Information**" means technical or commercial information disclosed by Buyer to Seller that Buyer directs, and clearly marks, as confidential, including the System Interconnection Guidelines and this EPA but excluding information that (i) is or becomes in the public domain, other than as a result of a breach of this EPA by Seller, or (ii) is known to Seller before disclosure to it by Buyer, or becomes known to Seller, thereafter by way of disclosure to Seller by any other Person who is not under an obligation of confidentiality with respect thereto.

1.10 "**Buyer's COD**" shall occur when the System Upgrades have been completed and Buyer provides a notice of completion of the same to Seller.

1.11 "**Change in Law**" means (a) the enactment, adoption, promulgation, modification or repeal of any applicable Laws or any change in the interpretation or administration of any applicable Laws resulting from a decision of a Governmental Authority which occurs after the Effective Date; but in each case excluding a Change in Law relating to income tax, or (b) the requirement for a new Permit (including due to a change in the circumstances in which a Permit is required), a change in the terms of any Permit after the date such Permit is granted, or any change in the interpretation or administration of any Permits resulting from a decision of a Governmental Authority.

1.12 "**Condition Date**" means the date specified as such in Schedule "B".

1.13 "**Conditions Precedent**" means those conditions precedent set out in Schedule "B".

1.14 "**Control**" of any Person means:

(a) with respect to any corporation or other Person having voting shares or the equivalent, the ownership or power to vote, directly or indirectly, shares, or the equivalent, representing 50% or more of the power to vote in the election of directors, managers or Persons performing similar functions;

(b) ownership of 50% or more of the equity or beneficial interest in that Person; or

(c) the ability to direct the business and affairs of any Person by acting as a general partner, manager or otherwise.

1.15 "**CPI**" means the "Canada All Items (Not Seasonally Adjusted)" Consumer Price Index as published by Statistics Canada or any successor agency thereto.

1.16 "**Delivered Energy**" means in each month after Buyer's COD the amount of Energy delivered by Seller at the POI in that month as recorded by Buyer's Meter less the applicable Line Losses.

1.17 "**Development Progress Report**" means a report describing the progress of the financing, design, engineering, construction, Interconnection, and commissioning of the Seller's Plant, that is in form and content acceptable to Buyer, acting reasonably.

1.18 "**Discretion**" (whether or not capitalized) means sole, absolute and unfettered discretion unless this EPA expressly states otherwise.

1.19 "**Dispatch/Turn-Down**" means for Seller to turn down or shut off the Seller's Plant.

1.20 "**Dispatch/Turn-Down Deemed Energy**" has the meaning given to such term in Section 4.9(b)(i).

1.21 "**Distribution System**" means the distribution, protection, control and communication facilities in the Yukon that are or may be used in connection with, or that otherwise relate to, the transmission of electrical energy at 35 kilovolts or less, and includes all additions and modifications thereto and repairs or replacements thereof.

1.22 "**Distribution/Transmission Constraint**" means any disconnection of the Seller's Plant from the Distribution System or Transmission System, or any outage, suspension, constraint or curtailment in the operation of the Distribution System or Transmission System preventing or limiting deliveries of Energy at the POI or within the Distribution System or Transmission System or any direction from Buyer to reduce generation of the Seller's Plant as a result of any outage, suspension, constraint or curtailment in the operation of the Distribution System or Transmission System.

1.23 "**Effective Date**" shall mean the date on which all Conditions Precedent have been satisfied or waived in accordance with Section 2.1.

1.24 "**Electrical Grid**" means the electrical grid into which the Seller's Plant will be interconnected, as identified in Schedule "B"**.**

1.25 "**Eligible Clean Energy**" means wind, hydro, geothermal, biomass and solar energy sources permitted under the IPP Policy for the SOP generated by a Project located in Yukon which is directly connected into the YIS or the WLG through the New Interconnection Facilities.

1.26 "**Energy**" means all electrical energy expressed in kWh generated by the Seller's Plant, excluding electrical energy generated by the Seller's Plant which is required to service the Seller's Plant Load.

1.27 "**Energy Price**" has the meaning given to such term in Schedule "B".

1.28 "**Environmental Attributes**" means the following as attributable to Energy delivered to Buyer under this EPA:

(a) all attributes directly associated with, or that may be derived from, the Energy delivered to Buyer under this EPA having decreased environmental impacts relative to certain other generation facilities or technologies including any existing or future credit, allowance, "green" tag, ticket, certificate or other "green" marketing attribute or proprietary or contractual right, whether or not tradeable;

(b) any credit, reduction right, offset, allowance, allocated pollution right, certificate or other unit of any kind whatsoever, whether or not tradeable and any other proprietary or contractual right, whether or not tradeable, resulting from, or otherwise related to the actual or assumed reduction, displacement or offset of emissions at any location other than the

Seller's Plant as a result of the generation, purchase or sale of the Energy delivered to Buyer under this EPA;

(c) any credit, reduction right, off-set, allowance, allocated pollution right, certificate or other unit of any kind whatsoever whether or not tradeable resulting from or otherwise related to the reduction, removal, or sequestration of emissions at or from the Seller's Plant; and

(d) all revenues, entitlements, benefits and other proceeds arising from or related to the foregoing, but for certainty not including:

i. benefits or proceeds from environmental incentive programs offered by Governmental Authorities that do not require a transfer of the attributes in (a) to (c) above; and

ii. benefits or proceeds from social programs, including programs relating to northern or rural development, employment or skills training, or First Nations, that do not require a transfer of the attributes in Sections (a) to (c) above.

1.29 "**Environmental Certification**" means any certification Buyer requires Seller to obtain under Section 6.1.

1.30 "**Facility Lender**" means any lender(s) providing any debt financing or debt hedging facilities for the design, engineering, construction and/or operation of the Seller's Plant and any successors or assigns thereto and any Person taking any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's Plant.

1.31 "**Final Amount**" means an amount owing by either Party to the other Party under this EPA, including as a result of a breach of this EPA, where such amount is: (a) undisputed by the Party owing such amount; or (b) has been finally determined by an arbitration award under Section 12.1 of this EPA or by a court order and all rights of appeal in respect of such award or order have been exhausted or have expired.

1.32 "**First Nation Claim**" means a legal claim or proceeding or written threat to commence a legal claim or proceeding from or on behalf of First Nations where such claim or threat alleges a breach or potential breach of, or an impact to: any First Nations' Treaty rights, rights under a Settlement Agreement (as that term is defined in the Yukon Umbrella Final Agreement), or rights under section 35 of the *Constitution Act*, 1982, by (a) this EPA, (b) the Seller's Plant, (c) the Interconnection or any works related to the Interconnection, or (d) any authorization granted by the Yukon or federal government relating to the Seller's Plant and its operations.

1.33 "**First Nations**" means any one of the 14 First Nations in the Yukon.

1.34 "**Force Majeure**" means any event or circumstance not within the control of the Party, or any of its Affiliates, claiming Force Majeure, but does not include:

(a) any economic hardship or lack of money, credit or markets;

(b) an event or circumstance that is the result of a breach by the Party seeking to invoke Force Majeure of a Permit or of any applicable Laws;

(c) a mechanical breakdown or control system hardware or software failure, unless the Party seeking to invoke Force Majeure can demonstrate by clear and convincing evidence that the breakdown or failure was caused by a latent defect in the design or manufacture of the equipment, hardware or software, which could not reasonably have been identified by normal inspection or testing of the equipment, hardware or software;

(d) an event or circumstance caused by a breach of, or default under, this EPA or a willful or negligent act or omission by the Party seeking to invoke Force Majeure;

(e) any Distribution/Transmission Constraint unless such event is caused by an event or circumstance not within the control of Buyer; or

(f) any acts or omissions of: (i) any Affiliate, employee, director, officer, agent or other representative of the Party invoking Force Majeure; (ii) any vendor, supplier, contractor, subcontractor, consultant or customer of or to the Party invoking Force Majeure; or (iii) any other Person for whom the Party invoking Force Majeure is responsible at law, unless the act or omission is caused by an event or circumstance that would constitute Force Majeure if the Person described above was a party to this EPA in place of a Party invoking Force Majeure.

1.35 "**Forced Outage**" means the immediate removal of one or more generating units of the Seller's Plant or transmission or distribution infrastructure of the Seller's Plant from service in response to equipment alarms or any damage identified during a Planned Outage or Maintenance Outage requiring extension of those Planned Outage or Maintenance Outage.

1.36 "**General Rate Application**" means any application, review, process, or procedure in which the YUB sets and approves rates to be charged by Buyer for the supply of the service for which it is franchised in accordance with the *Public Utilities Act*.

1.37 "**Good Industry Practice**" means:

(a) in respect of Buyer, any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition; provided such practices, methods and acts are not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the Yukon; and provided that Buyer shall be in compliance with Good Industry Practice in respect of any equipment comprising the Distribution System or Transmission System, if it operates such equipment in accordance with all applicable original equipment manufacturer guidelines and requirements provided to Buyer by supplier of such equipment; and

(b) in respect of Seller, any of the practices, methods and acts engaged in or approved by a significant portion of the electric generation industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition; provided such practices, methods and acts are not intended to be limited to the optimum practice, method or act to the exclusion of all others,

but rather to be acceptable practices, methods or acts generally accepted in Western Canada.

1.38 "**Governmental Authority**" means any federal, provincial, local or foreign government or any of their boards or agencies, or any regulatory authority other than Buyer and Seller and entities controlled by Buyer or Seller.

1.39 "**GST**" means the goods and services tax imposed under the *Excise Tax Act* (Canada) as that Act may be amended or replaced from time to time.

1.40 "**Interconnection"** means the POI.

1.41 "**IPP Policy**" has the meaning given to such term in the recitals to this EPA.

1.42 "**Joint Operating Procedure**" means the joint operating procedure attached as Schedule "H" as may be modified by Buyer from time to time.

1.43 "**KW**" means kilowatt.

1.44 "**kWh**" means kilowatt-hour.

1.45 "**Laws**" means any and all statutes, laws (including common law), ordinances, rules, regulations, codes, orders, bylaws, policies, directions, standards, guidelines, protocols and other lawful requirements of any Governmental Authority in effect from time to time.

1.46 "**Lender Consent Agreement**" means a lender consent agreement in the form and substance acceptable to Buyer, acting reasonably.

1.47 "**Line Losses**" means losses of electricity associated with the transmission and transformation of Energy and other electricity, if applicable, from the Seller's Plant to the POI that are recorded by the Meter or reasonably estimated by Buyer.

1.48 "**Line Loss Methodology**" means the Line Loss Methodology set forth in the System Interconnection Study Report for the purposes of this Project.

1.49 "**Maintenance Outage**" means any outage of Buyer's Distribution System or Transmission System or the Seller's Plant that is not a Planned Outage or a Forced Outage that typically has a flexible start and end time and of shorter duration than a Planned Outage.

1.50 "**Meter**" means a meter owned by Buyer that is: (a) capable of accurately measuring the quantity of Energy generated by the Seller's Plant and delivered to the POI independent of all other generation equipment or facilities, (b) capable of being remotely interrogated; and (b) calibrated to measure on an hourly basis the quantity of Energy delivered by Seller to the POI.

1.51 "**Monthly Energy Shortfall Payment**" has the meaning given to such term in Schedule "E".

1.52 "**New Interconnection Facilities**" means those additions, modifications and upgrades required to interconnect the Project to the Electrical Grid which are identified in the System Interconnection Study Report (and as further refined in subsequent interconnection studies, if required by Buyer) and approved by Buyer, but excluding any System Upgrades.

1.53 "**New Interconnection Facilities Costs**" means all costs incurred by Buyer for the design, engineering, procurement, construction, installation and commissioning of the New Interconnection Facilities, including applicable studies required by Buyer, an estimate of which is set out in the System Interconnection Study Report.

1.54 "**Non-Permitted Distribution/Transmission Constraint**" has the meaning given to such term in Section 4.8(a).

1.55 "**Outage**" means a Forced Outage, Maintenance Outage, or Planned Outage of Buyer's Distribution System or Transmission System or Seller's Plant.

1.56 "**Outage Notice**" means a notification of any Outage or revised notification of any Outage required to be delivered by Seller to Buyer or Buyer to Seller under this EPA that describes the timing, frequency, nature and duration of the Outage and that is in a format that may be prescribed by Buyer from time to time.

1.57 "**Party**" means Buyer or Seller, and "**Parties**" means both Buyer and Seller.

1.58 "**Permits**" means permits, certificates, licences, approvals and other authorizations issued by any Governmental Authorities as may be required for the design, construction, ownership, operation, maintenance and decommissioning of (i) the Seller's Plant and the delivery of Energy to the POI, and (ii) the System Upgrades and the New Interconnection Facilities.

1.59 "**Person**" means an individual, body corporate, firm, partnership, joint venture, trust, legal representative or other legal entity.

1.60 "**Planned Outage**" means an outage that is scheduled well in advance for purposes of inspections, maintenance, or repair of Buyer's Distribution System or Transmission System or Seller's Plant, that typically has a predetermined duration and scope of work, occurs only once or twice per year, and may last for several days.

1.61 "**POI**" or "**Point of Interconnection**" means the point at which the Seller's Plant interconnects with the Distribution System or Transmission System, as identified on the Single Line Diagram.

1.62 "**Potential Impacts**" means any adverse or potentially adverse impact on the established or potential aboriginal rights (including title) of First Nations as a result of:

(a) this EPA;

(b) the Project;

(c) the interconnection of the Seller's Plant to the Distribution System or Transmission System; or

(d) any activities directly related to the Seller's Plant that enable Seller to comply with its obligations under this EPA that are carried out by Seller, any Affiliate, consultant or contractor of Seller, or any other Person for whom Seller is responsible at law.

1.63 "**PPT**" means Pacific Prevailing Time, which means Pacific Daylight Time or Pacific Standard Time as applicable.

1.64 "**Present Value Rate**" means the annual yield on a Government of Canada bond having a term and maturity date that most closely matches the remaining Term (as at the date of the applicable calculation) and expiry date of this EPA, plus 3%.

1.65 "**Prime Rate**" means the floating prime interest rate announced from time to time by the main branch of Bank of Montreal in Whitehorse, Yukon, or any successor thereto, expressed as an annual rate, as the reference rate it will use to determine rates of interest payable on Canadian dollar commercial loans made in Canada.

1.66 "**Project**" means the financing, design, engineering, procurement, construction, commissioning, operation and maintenance of the Seller's Plant.

1.67 "**Project Cluster**" means two or more existing or proposed Projects under the SOP Rules that Buyer determines in its Discretion are so closely related to each other that they should be considered a project cluster for the purposes of the Standing Offer Program.

1.68 "**Project Energy Volume**" (in kWh) means the maximum annual Energy which Buyer may sell to Seller from the Project in any calendar year as set out in Schedule "B"; provided that where the Term does not commence on January 1, such amount shall be prorated for the first and last contract year which do not reflect a full calendar year.

1.69 "**Project Standards**" means:

(a) all applicable Laws;

(b) the terms and conditions of all Permits, including land tenure agreements, issued in connection with the Seller's Plant;

(c) Good Industry Practice;

(d) the description of the Seller's Plant in Schedule "B";

(e) the requirement that Energy must qualify as Eligible Clean Energy; and

(f) the terms and conditions of this EPA (including the System Interconnection Guidelines).

1.70 "**Public Utilities Act**" means the *Public Utilities Act* (Yukon) and any successor or replacement legislation.

1.71 "**Records**" means all records and logs required to properly administer this EPA, including:

(a) Energy generation records and operating logs;

(b) Meter readings;

(c) maintenance reports;

(d) invoice support records;

(e) documents concerning compliance with Project Standards, but excluding any such documents that are protected by solicitor-client privilege;

(f) records related to System Upgrade Costs and New Interconnection Facilities Costs;

(g) all information reasonably required to establish the amount of Energy Seller could have sold during a Distribution/Transmission Constraint including logs of all Outages of the Seller's Plant and other reductions in Energy output (specifying the date, time, duration and reasons for each such outage and each reduction in Energy output); and

(h) information relating to the Environmental Certification, information relating to the existence, nature and quality of Environmental Attributes, information required for the purposes of any Environmental Attributes or energy certification or tracking system, and any other information Buyer requires to enable it or any of its Affiliates to obtain and realize the benefit of the Environmental Attributes,

all consistent with Good Industry Practice.

1.72 "**Regulatory Agency Authorizations**" means the issuance of those Permits which are specified as required for the Project in the YESAB assessment report recommendation to proceed issued in respect of the Project.

1.73 "**Seller**" means the Party so identified on page one of this EPA, and its successors and permitted assigns.

1.74 "**Seller Confidential Information**" means any of Seller's confidential technical or financial information provided by Seller to Buyer in confidence with express written notice to Buyer of the confidential nature of the information, but excluding:

(a) this EPA; and

(b) information that (i) is or becomes in the public domain, other than as a result of a breach of this EPA by Buyer, or (ii) is known to Buyer before disclosure to it by Seller, or becomes known to Buyer thereafter by way of disclosure to Buyer by any other Person who is not under an obligation of confidentiality with respect thereto.

1.75 "**Seller's COD**" means the commercial operation date of Seller's Plant which is the date on which all of the following conditions have been satisfied in respect of the Seller's Plant:

(a) Seller has obtained all Permits required for the construction, commissioning, and operation of the Seller's Plant and all such Permits are in full force and effect;

(b) the Seller's Plant has been fully constructed in accordance with the Project Standards;

(c) Seller is not: (A) Bankrupt or Insolvent; (B) in default of any payment obligation or requirement to post security under this EPA; (C) in material default of any of its other covenants, representations, warranties or obligations under this EPA; or (D) in material default under any Permit or Law applicable to the construction, commissioning or operation of the Seller's Plant or under any land tenure agreement for the site on which the Seller's Plant is located;

(d) a Meter has been installed at the POI in accordance with Section 3.6 of this EPA;

(e) Seller has delivered to Buyer a written notice together with certificate of Seller's professional registered engineer confirming that Seller's COD has been achieved; and

(f) Buyer has delivered a Commission Notice to Operate, or such other document(s) of similar effect as may be substituted therefor, which evidences no material deficiencies, in respect of the Seller's Plant Capacity and Seller's Plant operations;

and for purposes of this EPA, Seller's COD will be deemed to have occurred at 24:00 PPT on the later of the dates set out above.

1.76 "**Seller's Plant**" means Seller's plant described in Schedule "B" and all assets required to interconnect that plant to the Distribution System or Transmission System; all rights, property, facilities, assets, equipment, materials, Permits and contracts required to design, engineer, procure, construct, commission, operate and maintain the plant described in Schedule "B" and to interconnect that plant to the Distribution System or Transmission System, whether real or personal and whether tangible or intangible including all land tenure and all books, Records and accounts with respect to the Seller's Plant described in Schedule "B"; and shall include replacement parts or equipment which are of the same or similar nature as the parts or equipment being replaced and which do not materially increase the amount of Energy available from Seller's Plant.

1.77 "**Seller's Plant Capacity**" means the electrical generating capacity of the Seller's Plant set out in Schedule "B".

1.78 "**Seller's Plant Load**" means any electrical energy consumed by Seller's Plant.

1.79 "**Single Line Diagram**" means the simplified electrical representations of the Seller's Plant, the Interconnection, the Distribution System and Transmission System attached hereto in Schedule "B".

1.80 "**SOP OIC**" means that Order in Council issued by the Government of Yukon on January 24, 2019 regarding, among other things, the Standing Offer Program.

1.81 "**SOP Rules**" means the Standing Offer Program Rules developed by the Government of Yukon which governed this EPA as at the date of this EPA.

1.82 "**Standing Offer Program**" or "**SOP**" means the Standing Offer Program as described in the IPP Policy.

1.83 "**System Interconnection Guidelines**" means those system interconnection guidelines in the form attached as Schedule "G" hereto, as amended or replaced by Buyer from time to time.

1.84 "**System Interconnection Study Report**" means the detailed interconnection study issued to Seller by Buyer which, among other things, (i) evaluates the impact of the Project on the reliability of Buyer's system, (ii) provides a planning-level estimate of the required System Upgrades and New Interconnection Facilities and associated costs, and (iii) establishes the Line Loss Methodology for this Project, a copy of which is attached as Schedule "D".

1.85 "**System Upgrades**" means additions, modifications and upgrades to the Distribution System, Transmission System or any portion of Buyer's generation system that are determined by Buyer to be required in order to facilitate the interconnection and to allow such Distribution System, Transmission System or any portion of Buyer's generation system to support the integration of the

Energy produced by the Seller's Plant in accordance with this EPA and the System Interconnection Guidelines, which are identified in the System Interconnection Study Report (and as further refined in subsequent interconnection studies, if required by Buyer) and approved by Buyer, but excluding any New Interconnection Facilities.

1.86 "**System Upgrade Costs**" means all costs incurred by Buyer for the design, engineering, procurement, construction, installation and commissioning of the System Upgrades, including applicable studies required by Buyer, an estimate of which is set out in the System Interconnection Study Report.

1.87 "**Target Buyer's COD**" means the target date for achieving Buyer's COD, being the date specified for such term in Schedule "B", as may be extended pursuant to Section 3.9, if applicable.

1.88 "**Target Seller's COD**" means the target date for achieving Seller's COD, being the date specified for such term in Schedule "B", as may be extended pursuant to Section 3.9, if applicable.

1.89 "**Term**" has the meaning given to such term in Section 2.1.

1.90 "**Termination Payment**" has the meaning given to such term in Schedule "F".

1.91 "**Transmission System**" means the transmission, substation, protection, control and communication facilities owned and operated by Buyer, and includes all additions and modifications to those facilities and repairs or replacements of those facilities.

1.92 "**Upgrade Costs Advance**" has the meaning given to such term in Section 3.5(a).

1.93 "**Upgrade Costs Security**" has the meaning given to such term in Section 3.5(a).

1.94 "**Utilities**" means both Yukon Energy Corporation or Yukon Electrical Company, doing business as ATCO Electric Yukon, as applicable.

1.95 "**YESAA**" means the *Yukon Environmental and Socio-economic Assessment Act,* SC 2003, c 7.

1.96 "**YESAB**" means the Yukon Environmental and Socio-economic Assessment Board.

1.97 "**YUB**" means the Yukon Utilities Board and any successor thereto appointed from time to time under the *Public Utilities Act*.

2. INTERPRETATION

2.1 **Headings** - The division of this EPA into Articles, sections, Sections, paragraphs and Schedules and the insertion of headings are for convenience of reference only and do not affect the interpretation of this EPA.

2.2 **Plurality and Gender** - Words in the singular include the plural and vice versa. Words importing gender include the masculine, feminine and neuter genders.

2.3 **Governing Law** - This EPA is made under, and will be interpreted in accordance with, the Laws of the Yukon. Subject to Section 12.1, any suit, action or proceeding (a "**Proceeding**") arising out of or relating to this EPA may be brought in the courts of the Yukon at Whitehorse, and those courts

have non-exclusive jurisdiction in respect of any Proceeding and the Parties hereby irrevocably attorn to the jurisdiction of such courts in respect of any Proceeding.

2.4 **Industry Terms** - Technical or industry specific phrases or words not otherwise defined in this EPA have the well-known meaning given to those terms as of the date of this EPA in the industry or trade in which they are applied or used.

2.5 **Statutory References** - Reference to a statute means, unless otherwise stated, the statute and regulations, if any, under that statute, in force from time to time, and any statute or regulation passed and in force which has the effect of supplementing or superseding that statute or those regulations.

2.6 **Currency** - References to dollars or $ means Canadian dollars, unless otherwise stated.

2.7 **Reference Indices** - If any index, tariff or price quotation referred to in this EPA ceases to be published, or if the basis therefor is changed materially, there will be substituted an available replacement index, tariff or price quotation that most nearly, of those then publicly available, approximates the intent and purpose of the index, tariff or quotation that has so ceased or changed. This EPA will be amended as necessary to accommodate such replacement index, tariff or price quotation, all as determined by written agreement between the Parties, or failing agreement, by arbitration under Section 12.1 of this EPA.

2.8 **Conversions** - If a value used in a calculation in this EPA must be converted to another unit of measurement for purposes of consistency or to achieve a meaningful answer, the value will be converted to that different unit for purposes of the calculation.

2.9 **Additional Interpretive Rules** - For the purposes of this EPA, except as otherwise expressly stated:

(a) "this EPA" means this EPA as it may from time to time be supplemented or amended and in effect, and includes the Schedules attached to this EPA;

(b) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this EPA as a whole and not to any particular section, Section or other subdivision;

(c) the word "including" or "includes" is not limiting whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto;

(d) the words "year" and "month" refer to a calendar year and a calendar month;

(e) any consent, approval or waiver contemplated by this EPA must be in writing and signed by the Party against whom its enforcement is sought, and may be given, withheld or conditioned in the unfettered discretion of the Party of whom it is requested, unless otherwise expressly stated;

(f) all rights and remedies of either Party under this EPA are cumulative and not exclusive of any other remedies to which either Party may be lawfully entitled, and either Party may pursue any and all of its remedies concurrently, consecutively and alternatively; and

(g) any notice required to be given, or other thing required to be done, under this EPA on or before a day that is not a Business Day, will be deemed to be given or done when required hereunder if given or done on or before the next following Business Day.

3. ADDRESSES FOR NOTICES

3.1 **Notices to Buyer** - Except as noted below, all notices addressed to Buyer will be delivered to the following address:

To: Yukon Energy Corporation
#2 Miles Canyon Road
Box 5920
Whitehorse, YT Y1A 6S7
Attention: IPP Manager
Email: ipp@yec.yk.ca

3.2 **Notices to Seller** - All notices addressed to Seller will be delivered to the following address:

To: 536774 Yukon Inc.
110 Titanium Way, Whitehorse, YT, Y1A 0E8
Attention: Attention: Ben Power
Email: bpower@solvest.ca

SCHEDULE "B"

PROJECT DESCRIPTION

CONTRACT PARTICULARS:

1. **Condition Date:**

   Not Applicable.

2. **Conditions Precedent:**

   None.

3. **Term:**

   The "**Term**" of this EPA commences on the Effective Date and continues for a period of 25 years following Buyer's COD.

4. **Energy Price and Seasonal Adjustment:**

   (a) In each billing period, Seller shall pay to Buyer, for each kWh of Delivered Energy the "**Energy Price**" calculated as follows:

   $$\text{Energy Price}_n = (.5 * \$0.158/\text{ kWh} * \text{CPI}_{\text{January 1, n}} / \text{CPI}_{\text{January 1, 2020}}) + (.5 * \$__/\text{kWh})$$

   Where:

   n = the year for which the relevant calculation is being conducted; and

   $\text{CPI}_{\text{January 1, n}}$ = the CPI for December in the year immediately prior to the year for which the relevant calculation is being conducted.

   (b) For each hour, the Energy Price determined above for Delivered Energy during that hour will be adjusted to an amount (expressed in $/kWh) equal to the percentage of that Energy Price applicable for that hour as set out in the table in Schedule "I".

SELLER'S PLANT

1. **Location of Control Building:** 60.946N -135.160W, being Lot 1297-02 on the North Klondike Highway.

2. **Eligible Clean Energy Type:** Solar Photovoltaic

3. **Seller's Plant Capacity:** 1MW AC

4. **Project Energy Volume:** 1,840,200 kWh per year

5. **Seller's Plant Description:**

   Please refer to Seller's single line diagram in Exhibit B-1. *1.72 MW DC -1 MW AC Ground Mount solar farm located on the north Klondike highway consisting of 4000 x 430W bi-facial solar*

modules mounted on fixed 35-degree angle racking. Strings of 25 modules will connect to Huawei 50 kW inverters with an AC output voltage of 600V for combined capacity of 1 MW AC at Power Factor 1.0. The inverters will terminate at 1200A CDP + metering cabinet connecting to the low voltage side of the ATCO transformer.

Total AC Power:	1000 kW
Primary AC line voltage:	600V AC
Total AC line current:	962A
Total DC power:	1560 kW
Open-circuit DC voltage:	1500A
Operating DC voltage:	1100V
Total DC operating current:	1563A

6. **Target Seller's COD:** November 1st, 2020

7. **Electrical Grid:** Yukon Integrated System (YIS)

BUYER'S SYSTEM UPGRADES

1. **System Upgrades:**

   No System Upgrades are required.

2. **New Interconnection Facilities:**

   The Seller is connecting to YIS at ATCO Electric Yukon. Please see the System Interconnection Study Report attached as Schedule "D".

   Please refer to Buyer's single line diagram in Exhibit B-2.

3. **Target Buyer's COD:** November 1st, 2020

BREAKERS/SWITCHES AND SYNCHRONIZATION

A SW Fusible HD 600V 1200A NEMA3R/Neutral and 60A 3P Type 3R 600VAC/DC Heavy Duty Non-Fusible Safety Switch will be used. The specifications of such switches are attached.

After voltage is restored after an outage no reconnections will be attempted until the Seller has permission to reconnect from the System Control Center (as identified in Schedule "H"). After permission is given, the Seller must check that voltage and frequency are stable and within 10% of nominal values before closing in to reconnect:

- A plus or minus 10% voltage range is acceptable; and
- A plus or minus 10% frequency range is acceptable.

Product data sheet
Characteristics

H368NR
SW FUSIBLE HD 600V 1200A NEMA3R/ NEUTRAL

Product availability : Stock - Normally stocked in distribution facility

Price** : 20,993.00 USD

Main

Product	Single Throw Safety Switch
Current Rating	1200 A
Certifications	UL listed file E2875
Enclosure Rating	NEMA 3R galvannealed steel
Factory Installed Neutral	Neutral (factory installed)
Disconnect Type	Fusible disconnect
Short Circuit Current Rating	200 kA maximum L
Mounting Type	Surface
Number of Poles	3
Electrical Connection	Lugs
Duty Rating	Heavy duty
Voltage Rating	600 V AC/DC
Wire Size	AWG 3/0...750 kcmil copper or aluminium

Complementary

Width	36.62 in (930.15 mm)
Height	69.13 in (1755.90 mm)
Depth	17.75 in (450.85 mm)
Tightening torque	375 lbf.in (42.37 N.m) 0.13…0.59 in² (85.01…380 mm²) AWG 3/0...750 kcmil)

Ordering and shipping details

Category	00054 - H&HU SW,NEMA3R,400-1200A
Discount Schedule	DE1
GTIN	00785901442479
Returnability	Yes

Disclaimer: This documentation is not intended as a substitute for and is not to be used for determining suitability or reliability of these products for specific user applications

Country of origin	MX

Offer Sustainability

Sustainable offer status	Green Premium product
California proposition 65	WARNING: This product can expose you to chemicals including: Lead and lead compounds which is known to the State of California to cause Carcinogen & Reproductive harm. For more information go to www.p65warnings.ca.gov
REACh Regulation	REACh Declaration
EU RoHS Directive	Compliant EU RoHS Declaration
Mercury free	Yes
RoHS exemption information	Yes
China RoHS Regulation	China RoHS declaration Product out of China RoHS scope. Substance declaration for your information.
Environmental Disclosure	Product Environmental Profile

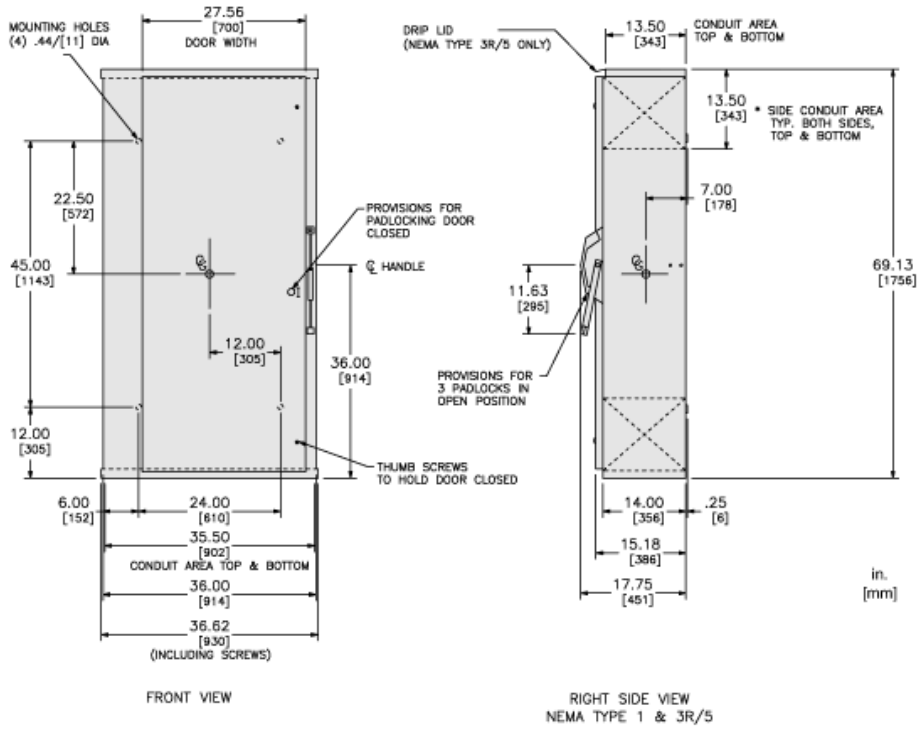
Contractual warranty

Warranty	18 months

Product data sheet
Dimensions Drawings

H368NR

Approximate Dimensions

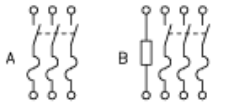


CATALOG NUMBER	VOLTAGE RATINGS	WIRING DIAG.	3 PHASE HORSEPOWER RATINGS						DC HORSEPOWER RATINGS			
			240VAC		480VAC		600VAC		250VDC		600VDC	
			STD	MAX.	STD	MAX.	STD	MAX.	STD	MAX.	STD	MAX.
H32B	240VAC;250VDC	A	100	250	–	–	–	–	50	50	–	–
H32BR	240VAC;250VDC	A	100	250	–	–	–	–	50	50	–	–
H32BN	240VAC;250VDC	B	100	250	–	–	–	–	50	50	–	–
H32BNR	240VAC;250VDC	B	100	250	–	–	–	–	50	50	–	–
H368	600VAC;600VDC	A	100	250	200	500	250	500	–	–	50	50
H368R	600VAC;600VDC	A	100	250	200	500	250	500	–	–	50	50
H368N	600VAC;600VDC	B	100	250	200	500	250	500	–	–	50	50
H368NR	600VAC;600VDC	B	100	250	200	500	250	500	–	–	50	50
HU368	600VAC;600VDC	C	100	100	–	500	–	500	–	–	50	50
HU368R	600VAC;600VDC	C	100	100	–	500	–	500	–	–	50	50

Product data sheet
Connections and Schema

H368NR

Wiring Diagrams

WIRING DIAGRAMS	
FUSIBLE	NOT FUSIBLE
	

TERMINAL LUGS			
AMPERES	MAX. WIRE	MIN. WIRE	TYPE
1200	(4)750 KCMIL	(4)#3/0 AWG	75°C AL OR CU

FUSE PROVISIONS			
AMPERES	TYPE	AMPERES	TYPE
1200	CLASS "L"	800	CLASS "L"

Product data sheet
Characteristics

CHU362RB
60A 3P Type3R 600VAC/DC Heavy Duty Non-Fusible Safety Switch

Main

Product or component type	Single Throw Safety Switch
Disconnector device type	Non-fusible disconnect
Number of poles	3
Electrical connection	Lugs
Series name	Heavy duty

Complementary

Line Rated Current	60 A
Device composition	None
Device mounting	Surface
System Voltage	600 V AC/DC
AWG gauge	AWG 14...AWG 3 (copper or aluminium)

Environment

Product certifications	CSA
NEMA degree of protection	NEMA 3R galvannealed steel

Offer Sustainability

Sustainable offer status	Green Premium product
RoHS (date code: YYWW)	Compliant - since 1313 - Schneider Electric declaration of conformity Schneider Electric declaration of conformity
REACh	Reference not containing SVHC above the threshold Reference not containing SVHC above the threshold
Product environmental profile	Available
Product end of life instructions	Need no specific recycling operations

Disclaimer: This documentation is not intended as a substitute for and is not to be used for determining suitability or reliability of these products for specific user applications

EXHIBIT B-1

Seller's Single Line Diagram

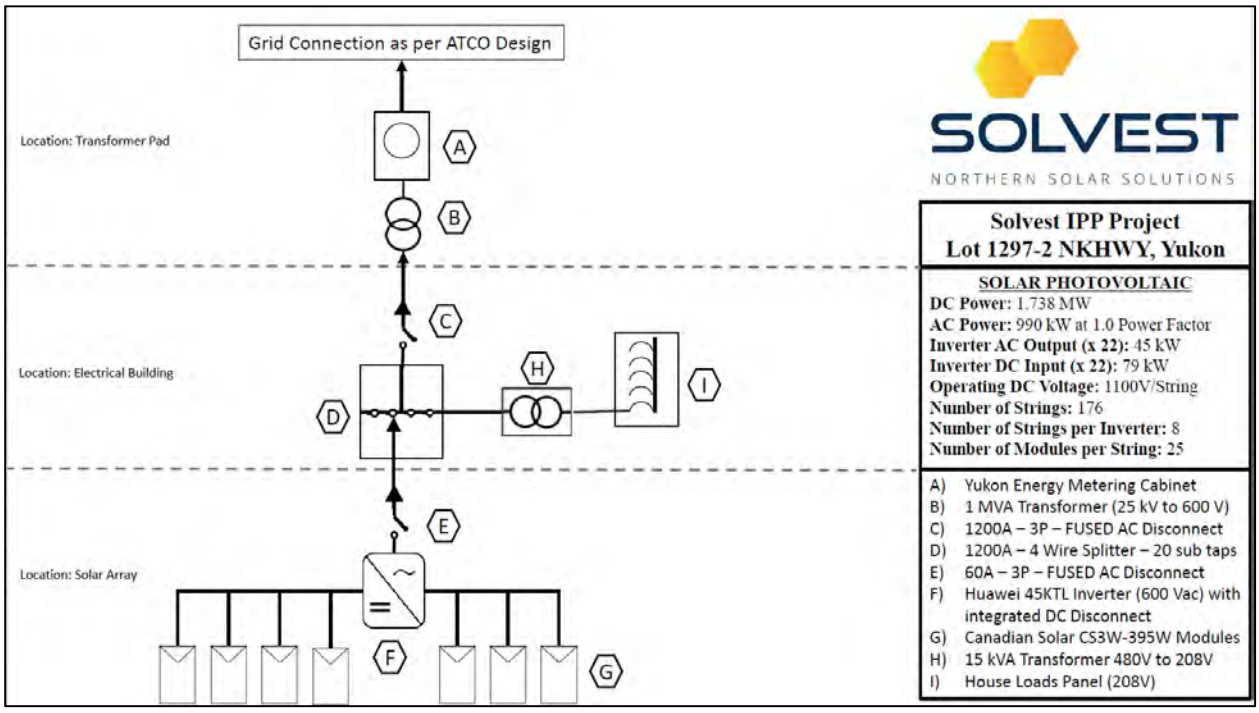


EXHIBIT B-2

Buyer's Single Line Diagram

(Please see attached)

LABERGE SUBSTATION #21
120/240
S8300 N/O
S8301
S8302
10MVA
S8303
34KV Δ
25KV
R50
R51
R52
S8304
S8307
S8306
S8305
S3599
S3600
S3077
S3598
S3148
S1171 15A
S1172 15A
KULAN SUB'D
MACKENZIE TRAILER COURT
PH2
S6181 10A
PUMP STATION
3PH
S4736 300KVA
S3601 25A
S4890
S8395 S/B
S4891 500KVA
S4793 150KVA
S4783 75KVA
S5560
S5565
S3149 N/O
S4783 A3 B3 C3
S3151
S1000 15A
S2110
TRAILS NORTH
CAFE
S3064 N/O
S3452 SOLID BLADES
750MCM
WHISTLEBEND SUBSTATION WH-20009.SLD
TAKHINI SWITCHING STATION WN-_____.SLD
S3915
S3909
S3908
S3907
S8411
CRESTVIEW
65A
40A
S8394
S8397
S1354 7A
KLUKSHU
S4613
SQUANGA
S1299 40A
S4601 237 SQUANGA
S4602 237 SQUANGA
S4603 237 SQUANGA
S1298 SOLID BARREL
RAINBOW ROAD
S6181 10A
S6518 7A
S6519 7A
S6522 15A
S6526
S3186 10A
ECHO VALLEY
HOT TAP
GARDNER ROAD
JACKSON ROAD
IBEX VALLEY FIREHALL
S6531
S6532
S9223
R116 100 AMP REGULATOR
S9888
S1165 20A
PARENT LANE
WANNER'S WAY
S6841 80A
COBALT
S3498 15A
S3485 10A
92337 WELDING SHOP
92281 YUKON SPRINGS
S9454
COUSINS AIRPORT
MAYO ROAD
S7133
McPHERSON SCHOOL
McPHERSON SUB'D
MARION CRESCENT
S3503 10A
S8697 20A
S8686
RODERICH PL.
S3866
COUCH ROAD
TIMOTHY PLACE
S3867
S9457 10A
S9459
S9460
S9461
FEEDS BOTH WAYS
S9468 20A
TAAN SUBDIVISION
S3868
COUCH ROAD
S9551 20A
S3869
MOSSBERRY
2 MILE ROAD
S9426 7A
S3524 15A
GUNNER NILSSON TREE FARM
S3490 R113
S3491 R114
S3492 R115
3x 100A
S3098 10A
1ph
3ph
S3100 90A
MILE 2.3
S3570 7A
S9836 10A
S3739 10A
S6602
GOSSLEN
S2395 10A
S2169 SOLID BARREL
TAKHINI HOTSPRINGS ROAD
TAKHINI HOTSPRINGS
S3902 SOLID BARREL
S4017 600A
S3093 5A
EVERGREEN
S3097 7A KS
S3099 20A KS
S2166 SIMMONS PLACE
S6140 7A
LOT 13,14A,14B
S3870 10A
OLD PILOT MTN SUBDIVISION
S3871
MAYO ROAD
BOREAL ROAD
S9430
NAHANNI DRIVE
S3904 900A
S9437 15A
S2045 10A
5 MILE ROAD
S9167 SOLID BARREL
VISTA ROAD
S7130 15A
SHARON'S WAY
S1840 10A
S9445 20A
BURMA ROAD
S8477
NWTEL MICROWAVE SITE
DUNCAN
RIVER ROAD
S9447
POLICEMANS PT.
S3103 15A
MacKENZIE-GRIEVE POLICEMAN'S POINT RD
SUNDOG RETREAT
S6502 7A
WILLOWMITZER ELDORADO LOGWORKS
10 MILE ROAD
S9583 10A
COOKIES' ROAD
HOT TAP
S5535
S3104 7A
NORTHERN SPLENDOUR DR.
S2704
SHALLOWBAY ROAD
S9584 20A
S3105 7A
S5712
S5711
GRIZZLY VALLEY SUBDIVISION
HOT TAPS BOTH WAYS
S1399 3A
S1400 5A
KODIAK ROAD
S9509 7A
SCOTT ROAD
S9511 15A
S1398 7A
SOURDOUGH SODBUSTERS
S9510 2,5A
S3153 SOLID BARREL
S3532 7A
S9512
NWTEL TOWER
S9508 1A
S9449 2,5A
S3106 G/S
S6842 20A
S9131
TAAN VILLAGE
S1701
JACKFISH BAY SUBDIVISION
HELEN'S FISH CAMP
S3623 SOLID BARREL
S3624 N/O SOLID BARREL
NEW GRIZZLY VALLEY SUBDIVISION
S7510 50A
S3369 10A K
S4004 SOLID
WATER TREATMENT PLANT
S3990 5A
S6843 SOLID BARREL
S1592 SOLID BARREL
S1591 SOLID BARREL
AL ROCK
BAHAI INSTITUTE
S1801 5A
S9887 5A
S6611 10A
S1083 SOLID BARREL
S1606 10A
S1619 5A
A1
S4511
FOSSIL POINT
75KVA
DEEP CREEK SOUTH
DEEP CREEK NORTH
S3692 5A
FAULTY TOWERS
S3693 5A
OLD ALASKA HIGHWAY
S6540
S3760 2,5A
S6541
S6543
S1515 2,5A
S6546
S6547
S6548
S6550
S1879 2,5A
S6542 2,5A
S6544 3A
S6545
S6549
S3716 N/O ?SOLID BARREL MILE 901.7
S6551 10A
SCOUT LAKE ROAD
S6553
S6552
S6554
S6555 2,5A
S9186
S6012 5A
VALLENCOURT CARLICK
ALASKA HIGHWAY NORTH
S9883
S9187 20A
S6160 SOLID
ALASKA HIGHWAY
S3772 0,5A
IDLE
S9228
TAKHINI LOOK OUT
S1920 10A
FAST LANE
S1865
1455 FAULKNER
S2389 5A
S9345 5A
S1330 2,5A
S3188 7A
ANDREW FARM
S9204
S3357 2,5A
LOCKE FARM
S9230 10A
HOT TAP
S1939 SOLID BARREL
S3510 7A
S2005 5A
DRURY CABIN
S9206
DRURY FARM
S3008 2,5A
S1336 1A
S6131 20A
B & B CABIN
S1372 5A
ELK ROAD
S1373 14.4kV RISER
S1375 14.4kV RISER
KLASS HEYNEN & AIRSTRIP
GAIL REDERER
S1334
S1385 7A
S1350 5A
S2319 5A
MILE 944
S1940 SOLID BARREL
S9200
S1905 1A
S9514 IDLE
S7419 SOLID BARREL
S9515 SOLID BARREL
C/A FIRST NATION TAKHINI RIVER SUBDIVISION
RIVENDALE FARM
S2176 3A
FORD FARMS
HOT TAP
S2392 5A
S???
JACK CABLE
SID McKEOWEN
S2393 5A (FEED BOTH WAYS)
TAKHINI AGRICULTURE SUBDIVISION
JONES RD.
S2083 5A
RIVENDALE FARM ROAD
S1377 7A
SMITH'S ROAD
JENSEN &HOLM
S6502 7A
S2775 5A
S1535 5A
S3069 5A
S3786 SECTIONALIZER 15A
TAKHINI RIVER ROAD (BOTTOM OF HILL)
S3673 10A
S9812 10A KS
S1413 2,5A
S2280 5A
S1136 2,5A
S1317 1A
S1301 2,5A KS
WHYMARK
S1091 2,5A
S1381 2,5A
S1382 5A
S2618 2,5A
G. NICOL
CAM DRINNAN
GULLY ROAD
S2281 2,5A
S2282 2,5A
KUHN ROAD
GAME FARM
TAS CAMPGROUND
S1368 10A
S3747 5A
S3755 10A
S2737 10A

LEGEND / NOTES			
No.	MM-DD-YY	By	Revision
N	02-19-2014	CS	ADD S3716 N/O SOLID, Alaska Highway Line & Switches
O	07-09-2014	CS	ADD Mayo Road Double Circuit
P	12-02-2014	DS	Add Deep Creek, 34kV from TSS Add G/S S3904 Adjust Mayo Road 25kV
Q	02-23-2015	CS	Add G/S S4017 Add Fault Indicators Change S9812 S/B - 10A KS Fus
R	08-27-2015	CS	Add Azure Road changes Add Deep Creek Changes Updated Switch Tag S5535
S	10-24-2016	CS	Add Alaska Highway, Add S3369 S4004, S3873, S5931, S5932 S4783, S4793
T	01-09-2018	CS	Add Fault Indicators
U	03-26-2018	CS	Updates
V	12-18-2018	CS	S6140, S6131, S4890, S4891 Update Brookside

ATCO Electric YUKON

Description WN-20001

WHITEHORSE NORTH
MAYO ROAD

25kV/14.4 kV
SWITCHING DIAGRAM

Scale: NTS

Drawn by: R.Williamson, C.E.T.

Checked by:

Approved by:

PLAN NO: WN-20001

File: WN-20001-SLD.dgn Rev: V

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SCHEDULE "C"

FORM OF ANNUAL OPERATING PLAN

DATE: June 5, 2020.

TO: Yukon Energy Corporation ("Buyer")

RE: Electricity Purchase Agreement between 536774 Yukon Inc ("Seller") and Buyer dated the 5th day of June, 2020 (the "EPA")

The following sets out the Annual Operating Plan of Seller commencing on June 5, 2020 (the "**Applicable Period**").

(a) The following (from Table E-1 of Schedule "E" of the EPA) is the schedule of the expected total deliveries of Energy at the POI in each month of the Applicable Period:

	Projected Hourly Energy (kWh/h) **(A)**	**Projected Monthly Energy (kWh)** **(B)**
January	400 kWh/h peak	21,000
February	779 kWh/h peak	100,800
March	850 kWh/h peak	198,300
April	801 kWh/h peak	251,600
May	821 kWh/h peak	263,300
June	814 kWh/h peak	241,100
July	815 kWh/h peak	231,600
August	818 kWh/h peak	216,200
September	862 kWh/h peak	155,400
October	836 kWh/h peak	108,400
November	692 kWh/h peak	40,200
December	347 kWh/h peak	12,500

(b) The following is the schedule of any Planned Outages of the Seller's Plant expected by Seller for the Applicable Period:

The Seller has no Planned Outages for the Applicable Period.

(c) The following is the schedule of operations and maintenance activities planned for the Seller's Plant expected by Seller for the Applicable Period:

The Seller will perform bi-annual maintenance on the Seller's Plant in the first week of March and last week of April. The Seller's Plant will not be shut down during this maintenance activity, however one inverter at a time may be brought offline for thermal scans. This would decrease the output of the Seller's Plant by no more than 45 kW ac.

Dated effective as of the date set forth above.

536774 YUKON INC.

Per: _____
Ben Power
Director

Per: _____
Michael Schultz
Director

SCHEDULE "D"

SYSTEM INTERCONNECTION STUDY REPORT

(Please see attached)

DISTRIBUTED GENERATION FEASIBILITY RESULTS

Project #: n/a
Customer: Solvest Inc.
ISD: TBD
Location: Whitehorse
Substation: Laberge
Feeder: 5L645
Author: Alexandre Nassif, P.Eng.
Reviewed by: John Williams, P.Eng.
Revision: R0
Date: July 30, 2019

ATCO Electric Ltd.
APEGA Permit to Practice
P850

DG Description

Total Generation Requested	1 MW
Type of Generation	Solar
Maximum Allowable Generation	It is possible to accommodate up to 1MW of generation with required system upgrades. The solar farm will need to operate under constant unity power factor (100%)
Number and Size of Units	Eight (8) inverters, 125 kW each
Site Load	No
Transformer Ownership	It is assumed the customer will install a three-phase 1MVA transformer.
PCC Transformer Size and Winding Configuration	25kV-600V with a grounded wye winding configuration on ATCO's side.

DTT Assessment

DTT Required (Y/N)	Not required. It is a pre-requisite that the solar inverters meet all specifications of UL1741 SA

	and IEEE 1547-2018, including the provisions for anti-islanding and open-phase detection and disconnection. If these requirements are met, existing inline reclosers will not need to be retrofitted and no DTT scheme will be required.
Scope	N/A

AESO Requirement Assessment

SCADA Visibility Required? (Y/N)	It is assumed SCADA visibility is not required. The transmission authority must be consulted.

Distribution Assessment

Feeder and Conductor Size	From Laberge to the possible tie-in point, feeder 5L645 consists of: - 1km of 3 x 1/0 ACSR - 4.7km of 3 x #6 ACSR - 2km of 3 x #4 ACSR - 8.2km of 3 x 1/0 ACSR - 5.6km of 3 x 266ACSR It is assumed about 400m of new conductor will be required and will be 3x1/0 ACSR.
Substation rating	Labarge contains a 10MVA 35kV-25kV substation
Maximum generation without upgrades:	1 MW The existing Voltage Regulator (R113 R114 R115) must be reprogramed to operate in co-generation model with forward settings of 124V (existing) and reverse settings of 122V. If the voltage regulator does not allow co-generation operation, it must be replaced.
Feeder 5L645 Loading	Feeder Loading: Max = 4,055 KW Average = 1,758 kW 10th percentile = 997 kW Min (1st percentile; excluding outages) = 745 kW
Substation (Laberge) Loading	Max = 5,512 kW Average = 2,480 kW 10th percentile = 1,446 kW Min (1st percentile) = 1,000 KW
Circuit Distance from the substation	About 22 km

Existing DG on this feeder? (Y/N)	There are other solar generators in the feeder. They are assumed to be very small.
Alternate Feed? (Y/N)	UNKNOWN. If supplied by an alternate feed, this generator will need to be directed offline by the control center.
New Build Required? (Y/N, distance and conductor)	It is assumed about 400m of new line (3 x 1/0 ACSR) will be required.
Reconductoring Required? (Y/N, distance and conductor)	No.
Consideration of ATCO's System's Power Factor	It is expected that the Solar generator will not negatively and substantially impact the substation power factor under peak load condition.
Upstream Regulator Setting Changes Required? (Y/N)	YES: - Voltage regulator R113 R114 R115 will need to be reprogramed or upgraded to operate under co-generation mode. Forward settings can remain at 124V, but reverse settings need to be changed to 122V. - Voltage regulator R50R51R52 at Laberge will need to be reprogramed or upgraded to operate under co-generation mode. Forward settings can remain at 126V, but reverse settings need to be changed to 125V
Upstream Distribution recloser equipment change? (Y/N)	No changes required, as long as the solar inverters comply with all anti-islanding and open-phase detection clauses of UL 1741 SA and IEEE 1547-2018.
Power Transfer to other feeders? (Y/N and amount)	YES Power transfer during feeder max/average/10th percentile /min loading are: Max = no transfer Average = no transfer 10th percentile = very small Min = 255 kW

Power Transfer to 35kV? (Y/N and amount)	Potentially. The minimum load is about 1MW, which is the size of the proposed generation.
Power Transfer to Transmission? (Y/N and amount)	No.

Distribution Scope of Work

Local Scope

1. Build about 400m (to be confirmed by field check) of 3 x 1/0 ACSR line to the PCC.
2. Tie customer transformer to the distribution system
3. Install Bi-Directional Meter with power quality meter
4. Install a three-phase fault interrupter with voltage sensors and a controller that allows for directional protection.

Upgrade Scope

1. Reprogram the existing Voltage Regulator (R113 R114 R115) to operate in co-generation mode. If the voltage regulator does not allow co-generation operation, it must be replaced.
2. Reprogram the existing Voltage Regulator (R50R51R52) to operate in co-generation mode. If the voltage regulator does not allow co-generation operation, it must be replaced.

Assumptions:

- DG will be operating at 100% power factor (unity)
- 25kV-600V transformer will be customer owned
- Routing is assumed

Transmission Assessment (to be completed by the Transmission Authority)

Revision History

Revision	Date	Comment	Initials
R0	July 31, 2019	First Release.	AN

SCHEDULE "D"

SYSTEM INTERCONNECTION STUDY REPORT

(Continued)

Line Losses

ATCO Electric Yukon has established that the only Line Losses will be transformer losses which will be fully quantified upon commissioning.

Initial estimated transformer losses based on the specifications of the transformer to be ordered is approximately 0.5%, but it has been recommend to use 0.75% for budgeting purposes.

SCHEDULE "E"

MONTHLY ENERGY SHORTFALL PAYMENT

Monthly Energy Shortfall Payments

In any calendar month in which there has occurred a Non-Permitted Distribution/Transmission Constraint then Buyer shall pay Seller Monthly Energy Shortfall Payment,

where:

"**Monthly Energy Shortfall Payment**" means the Monthly Constraint Shortfall multiplied by the price which is payable for Delivered Energy under Section 5.1 of the EPA; and

"**Monthly Constraint Shortfall**" (expressed in kWh) means, for each calendar month, means the aggregate of the duration of each Non-Permitted Distribution/Transmission Constraint (measured as a fraction determined as the aggregate number of minutes in such Non-Permitted Distribution/Transmission Constraint divided by 60) multiplied by the "Non-Permitted Distribution/Transmission Constraint Hourly Deemed Energy" set out in Table E-1 below for the applicable calendar month.

Table E-1

	Projected Hourly Energy (kWh/h) (A)	**Projected Monthly Energy (kWh) (B)**	**Non-Permitted Distribution/Transmission Constraint Factor (F1)**	**Non-Permitted Distribution/Transmission Constraint Hourly Deemed Energy (kWh/h) (A x F1)**
January	28.23	21,000	_%	
February	150.00	100,800	_%	
March	266.53	198,300	_%	
April	349.44	251,600	_%	
May	353.90	263,300	__%	
June	334.86	241,100	__%	
July	311.29	231,600	__%	
August	290.59	216,200	__%	
September	215.83	155,400	__%	
October	145.70	108,400	__%	
November	55.83	40,200	__%	
December	16.80	12,500	__%	

Revisions to Projected Hourly Energy and Projected Monthly Energy

Within 90 days following the end of the 2nd year after Buyer's COD, the Parties shall review and revise the values in Table E-1 above for Projected Hourly Energy and Projected Monthly Energy to reflect the average actual amount of Delivered Energy sold to Buyer in the 2 years following Buyer's COD for the applicable months.

SCHEDULE "F"

TERMINATION PAYMENT

The "**Termination Payment**" at any time shall be equal to (a) the Gross Termination Payment set out below for the Contract Year in which the termination occurred, less (b) the actual amounts paid or owing by Buyer to Seller for Delivered Energy for the Contract Year in which the termination occurred.

Table F-1

Termination Year	Gross Termination Payment
Year 1	$3,252,880
Year 2	$3,233,759
Year 3	$3,210,258
Year 4	$3,181,994
Year 5	$3,148,552
Year 6	$3,109,482
Year 7	$3,064,300
Year 8	$3,012,480
Year 9	$2,953,453
Year 10	$2,886,607
Year 11	$2,811,275
Year 12	$2,726,740
Year 13	$2,632,223
Year 14	$2,526,885
Year 15	$2,409,815
Year 16	$2,280,032
Year 17	$2,136,470
Year 18	$1,977,981
Year 19	$1,803,321
Year 20	$1,611,146
Year 21	$1,400,000
Year 22	$1,168,313
Year 23	$914,384
Year 24	$636,374
Year 25	$332,296

SCHEDULE "G"

SYSTEM INTERCONNECTION GUIDELINES

(Please see attached)

Yukon Energy Corporation

Independent Power Producers Interconnection Technical Guide

Revision: 04b
Release Date: 2019 01 24

Disclaimer

This report was prepared under the supervision of Teshmont Consultants LP ("Teshmont"), whose responsibility is limited to the scope of work as shown herein. Teshmont disclaims responsibility for the work of others incorporated or referenced herein.

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Executive Summary

The purpose of the Interconnection Technical Guide is to provide guidelines for Independent Power Producers (IPP) who wish to interconnect a generation facility of greater than 50 kW and up to 10 MW to the Yukon Integrated System (YIS) via the Yukon Energy Corporation (YEC) or ATCO Electrical Yukon (AEY) distribution systems. The maximum allowable generation at the Point of Interconnection (POI) between the distribution system and IPP will depend on the results of a system impact study conducted by YEC. This guide details the technical and operational requirements of the facility and is not intended to be used as a design guide.

The purpose of this document is to:

- Provide technical specifications for the interconnection of IPP generation to the YIS (via YEC or AEY distribution systems).
- Clarify, where necessary, the technical requirements in CSA Standard C22.3 No. 9-08 (R2015) "Interconnection of Distributed Resources and Electricity Supply Systems" [1] and to provide an outline for how each section applies to interconnections with the YIS.

1. Introduction and Scope

1.1. Purpose

This guide establishes criteria and technical requirements for Independent Power Producers (IPP) who wish to interconnect generation, with a net capacity greater than 50 kW and up to 10 MW, to the Yukon Integrated System (YIS), at the distribution level (35 kV and below), or at the transmission level (above 35 kV). This guide has been developed considering CSA Standard C22.3 No. 9-08 (R2015) [1] and IEEE Standard 1547-2018 [2] and is subject to regular review and revision due to evolving standards.

The technical guide is intended to assist IPPs who apply to connect to the YIS through the Standing Offer Program, Call for Power, or through other unsolicited requests to connect.

1.2. Limitations

The criteria and technical requirements described within this section apply to the following generation interconnections:

- Interconnections to the Yukon Energy Corporation (YEC) and ATCO Electric Yukon (AEY) distribution systems at voltages of 34.5 kV and below, and
- Interconnections to the YEC transmission system at voltages over 34.5 kV by means of an existing or new substation. Transmission interconnections will require specific detailed review and approval by YEC and all interconnection costs will be borne by the IPP.

This Guide establishes the minimum requirements for the Point of Interconnection (POI). The IPP generation may be subject to additional requirements to ensure the project meets all applicable standards.

This Guide is not to be used:

- As an Operating Agreement and does not address the following:
    - Joint operating agreements
    - Costs
    - Tariffs
    - Other contractual issues
- As an Interconnection Process and Procedures Guide, and does not include the following:
    - Protection of the IPP's generation facilities
    - Transmission system impact and upgrades
    - System planning and design
    - Operation of the distribution system
    - Other system related issues
- As a design handbook for a generation facility.
- For any IPP generation not connected indirectly or directly to the YIS, i.e. an island grid.

2. Terms, Definitions, and Abbreviations

2.1. Definitions

Accredited Certification Organization – An organization that has been accredited by the Standards Council of Canada to operate a certification program for electrical equipment, such as the Canadian Standards Association (CSA).

Anti-islanding – A means of detecting and preventing a DR from energizing a part of the distribution system that becomes disconnected from the grid.

ATCO Electric Yukon – A private investor-owned utility, and member of the ATCO Group of Companies.

Automatic Circuit Recloser (ACR) – An overcurrent protection device used by utilities to detect faults on distribution system feeders, which has the ability to open and then reclose after a specified time delay allowing adequate time for temporary faults to clear.

Bi-directional Meter – A meter that measures real and reactive power and energy in both directions.

Cease to Energize – The cessation of energy outflow capability.

Clearing Time – The time from the start of the abnormal condition to when the distributed resource ceases to energize the distribution system.

Dispensated Metering Equipment – Any metering equipment that has received Measurement Canada approval under Section 9(2) or 9(3) of the Electricity & Gas Inspection Act.

Disconnecting Means – A device or group of devices that allows the conductors of a circuit to be disconnected from their source of supply.

Distributed Generation (DG) – Small, decentralized electric power generation facilities, typically interconnected to the distribution system.

Distribution System – The portion of the electrical system that operates at a nominal voltage of 34.5 kV line to line and below, and which distributes electric power between distribution substations and customers.

Effectively Grounded Distribution System – Distribution facilities where the neutral conductor is solidly grounded and the ratio of the zero sequence reactance to the positive sequence reactance is less than or equal to 3 and the ratio of the zero sequence resistance to the positive sequence reactance is less than 1.

Electromagnetic Interference (EMI) – Any electromagnetic disturbance that interrupts, obstructs, or otherwise degrades or limits the effective performance of a device, equipment or system.

Exporting – supplying power into the distribution system through the POI.

Facilities – A physical plant including, without limitation, generating plants, transmission and distribution lines, transformers, meters, equipment and machinery.

Flicker – The subjective impression of fluctuating luminance caused by voltage fluctuations.

Frequency – The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz (Hz).

Generation – The process of converting solar, thermal, wind, hydro, or chemical energy into electric energy.

Independent Power Producer (IPP) – An agency or individual other than a public utility (as defined by the Public Utilities Act) who generates electricity to sell (to the utilities). An independent power producer does not own transmission facilities and is dependent on the utilities to purchase and distribute the power it produces.

Interconnection – The physical connection of DG to YEC's distribution system so that parallel operation can occur.

Island Grid – A community power system which is energized solely by one or more local power producers and is separated electrically from the YIS.

Islanding – A condition where a portion of the utility's distribution system is energized exclusively by one or more power producers through their DR interconnection.

Operating Interface Point – See Point of Interconnection.

Parallel Operation – the simultaneous energization at a POI by the generating facility and the utility distribution system.

Point of Interconnection (POI) – The location of the electrical connection between an IPP facility and the utility's distribution system. This will be the point where the ownership changes from the utility to the IPP.

Power Factor – The ratio of active power to apparent power. It is the cosine of the phase angle difference between the current and voltage of a given phase.

Protection Scheme – The protection functions, including associated sensors, relays, and power supplies, intended to protect a distribution system or interconnection equipment.

Public Utility – As defined by the Public Utilities Act and Regulations (i.e., YEC and/or AEY).

Ride-through – The ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.

Secondary Injection Testing – A method in which low level signals obtained from current and voltage signal generators are injected into a power system protective device to test device response.

Stabilized – The state of the distribution system after voltage and frequency has returned to normal range for a period of at least five minutes (or another period of time, as agreed with YEC) following a disturbance.

Stand Alone – The state where a distributed generation can operate by controlling the frequency and voltage of their facility while in islanded or isolated mode.

Telemetering – Transmission of measurable quantities using telecommunications systems.

Total Demand Distortion (TDD) – The ratio of the root mean square of the harmonic content, considering harmonic components up to the 50th order and specifically excluding interharmonics, expressed as a percent of the maximum demand current. Harmonic components of order greater than 50 may be included when necessary.

Total Harmonic Distortion (THD) –The ratio of the root mean square of the harmonic content, considering harmonic components up to the 50th order and specifically excluding interharmonics, expressed as a percent of the fundamental. Harmonic components of order greater than 50 may be included when necessary.

Transfer Trip – A remote signal directed from an upstream device to command a DG to cease to energize the distribution system upon detection of an islanding condition and to prevent re-energization.

Transmission System –The portion of the system that operates above a nominal voltage of 34.5 kV line to line and transmits electric power between YEC substations.

Trip Time – The time between the start of the abnormal condition and the interconnection device ceasing to energize the distribution system.

Type Test – A test performed on a sample of a particular model of a device to verify specific aspects of its design, construction and performance.

Utility – See Public Utility (i.e., YEC and/or AEY).

Visible-Break Disconnect – A switch or circuit breaker by means of which the generator and all protective devices and control apparatus can be simultaneously disconnected under full load entirely from the circuits supplied by the generator. All blades or moving contacts must be connected to the generator side, and the design of the disconnect switch must allow adequate visible inspection of all contacts in the open position.

Voltage Flicker – A condition of fluctuating voltage on a power system that can lead to noticeable fluctuations in the output of lighting systems.

Yukon Energy Corporation (YEC) – A publicly-owned electrical utility that is the main generator and transmitter of electrical energy in Yukon.

Yukon Integrated System – The integrated Whitehorse-Aishihik-Faro and Mayo-Dawson electrical grids which are owned by YEC.

2.2. Abbreviations

ACR	Automatic Circuit Recloser
AEY	ATCO Electric Yukon
AEUC	Alberta Electrical Utility Code
CEA	Canadian Electricity Association
CEC	The Canadian Standards Association's C22.1-98 Safety Standard for Electrical Installations Part 1, also known as the Canadian Electrical Code
CSA	Canadian Standards Association
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers, Inc.
IPP	Independent Power Producer
LTC	Load Tap Changer
NEMA	National Electrical Manufacturers Association
POI	Point Of Interconnection
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SCC	System Control Center
SIS	System Impact Study
YEC	Yukon Energy Corporation
YIS	Yukon Integrated System
YUB	Yukon Utilities Board

3. Party Responsibilities

Refer to the IPP Policy as released in January 2019 for the individual responsibilities of the Government of Yukon, utilities (YEC and AEY), Yukon Utilities Board and the IPP during the generation interconnection process.

3.1. IPP Responsibilities

The IPP is responsible to:

- Provide technical information to the utility as specified in Appendix A and Appendix B;
- Assume ownership of the facility including the design, installation, operation, and maintenance of all equipment, station and distribution line facilities from the POI to the IPP facility, unless otherwise agreed to in writing;
- Pay the costs of system interconnection in accordance with the commercial terms established by the utilities;
- Obtain all regulatory approvals, including environmental assessment approvals, if necessary, for the construction and operation of its facilities. The IPP facilities shall be designed, constructed, operated and maintained in compliance with the applicable statutes, regulations, by-laws, codes and technical requirements specified by the utility (e.g. remote monitoring etc.);
- Submit all specifications of its facilities and detailed plans to the utility for review prior to receiving permission to connect to their distribution system;
- Ensure the technical requirements given in the standards and codes in Appendix D are met;
- Ensure metering requirements are met (see section 12); and
- Negotiate the timing and any testing requirements for the commissioning process with YEC

3.2. YEC Responsibilities

YEC is responsible for the operation of the Yukon Integrated System (YIS) and for certain local distribution systems interconnected with the YIS. This guide applies to all transmission and YEC distribution system interconnections.

YEC is responsible for all system studies performed on the YIS. The IPP and AEY, in the case of an AEY interconnection, shall provide all necessary information to YEC for the interconnection of the IPP facility. The system studies conducted by YEC will be paid for by the IPP.

After receiving the application for interconnection, YEC shall provide the IPP, at the IPP's cost, the information specified in Appendix C.

3.3. AEY Responsibilities

AEY is responsible for the operation of certain local distribution systems interconnected with the YIS. This guide applies to these AEY distribution system interconnections.

After receiving the application for interconnection, AEY shall, in consultation with YEC, provide the IPP, at the IPP's cost, the information specified in Appendix C.

4. General Requirements

4.1. Standards

When planning, designing, and operating an IPP Generation Facility, the IPP shall meet all applicable national, territorial and local construction and safety codes and standards.

The interconnection facility must comply, as a minimum, with the following:

- All CSA Standards, including the Canadian Electrical Code (CEC),
- Applicable YEC and AEY standards and the requirements set forth in this Guide,
- National, Territorial and local Governing law, acts, by-laws and codes, and
- Alberta Electrical Utility Code (AEUC) [4].

Applicable standards are located in Appendix D, however not all may be applicable for the IPP facility and additional standards may apply.

The interconnection of new generation can adversely affect the electric service to existing or future customers. The IPP must work with the utility to mitigate any adverse effects.

The facility must be constructed and maintained to provide a safe environment for employees as well as the public. If the generation facility adversely affects other customers, the utility may disconnect it until such time as the concern has been mitigated. The IPP is responsible for any costs incurred as a result.

The IPP is required to install, operate and maintain the facility and to ensure it is in sufficiently good order and repair at all times. Maintenance shall conform to good electrical practice, adequate for safe parallel operation when connected to the YIS. The utility and the IPP shall share commissioning reports, operating procedures and annual shutdown, maintenance, and inspection reports.

4.2. Operating Requirements

A joint operating agreement template will be developed in conjunction with the utility. The agreement requirements are not included within the scope of this Guide. A sample operating agreement is located in Appendix E.

5. Site Specific Conditions and Capacity Limitations

During the preliminary stage of project development any limitations regarding the proposed interconnection, and any additional system upgrades required, will be determined in consultations between the IPP, YEC and AEY, if interconnected via an AEY distribution system.

A system impact study will be necessary to identify any site-specific conditions and capacity limitations of the distribution and/or transmission system. To facilitate the study, the utility and the IPP will exchange information concerning load, feeder characteristics, protection philosophies, station layouts, capacities, ratings and other relevant information of the distribution and/or transmission system. The utility controls reliability design and reliability standards.

Under certain circumstances, YEC and AEY may limit the size or reconfigure the proposed connection arrangement of the IPP facility in order to maintain the integrity of their system.

6. YIS Transmission and Distribution System Characteristics

6.1. YEC Transmission System

6.1.1. General System Configuration

The YIS is an 'Islanded grid' which has no interconnection with the main North American electric grid. The Yukon must produce all of its own power, and cannot generate more electricity than is there is load, since there are no neighboring markets into which to sell surplus energy.

The YIS includes the 138 kV Whitehorse – Aishihik – Faro (WAF) grid, the 69 kV Mayo-Dawson-Keno (MD) grid, and the 138 kV Carmacks-Stewart Transmission Line (CSTL) which interconnects the WAF and MD grids. YEC provides power to major industrial customers connected to the 69 kV and 138 kV grids.

A map of the YIS is shown in Figure 6–1.

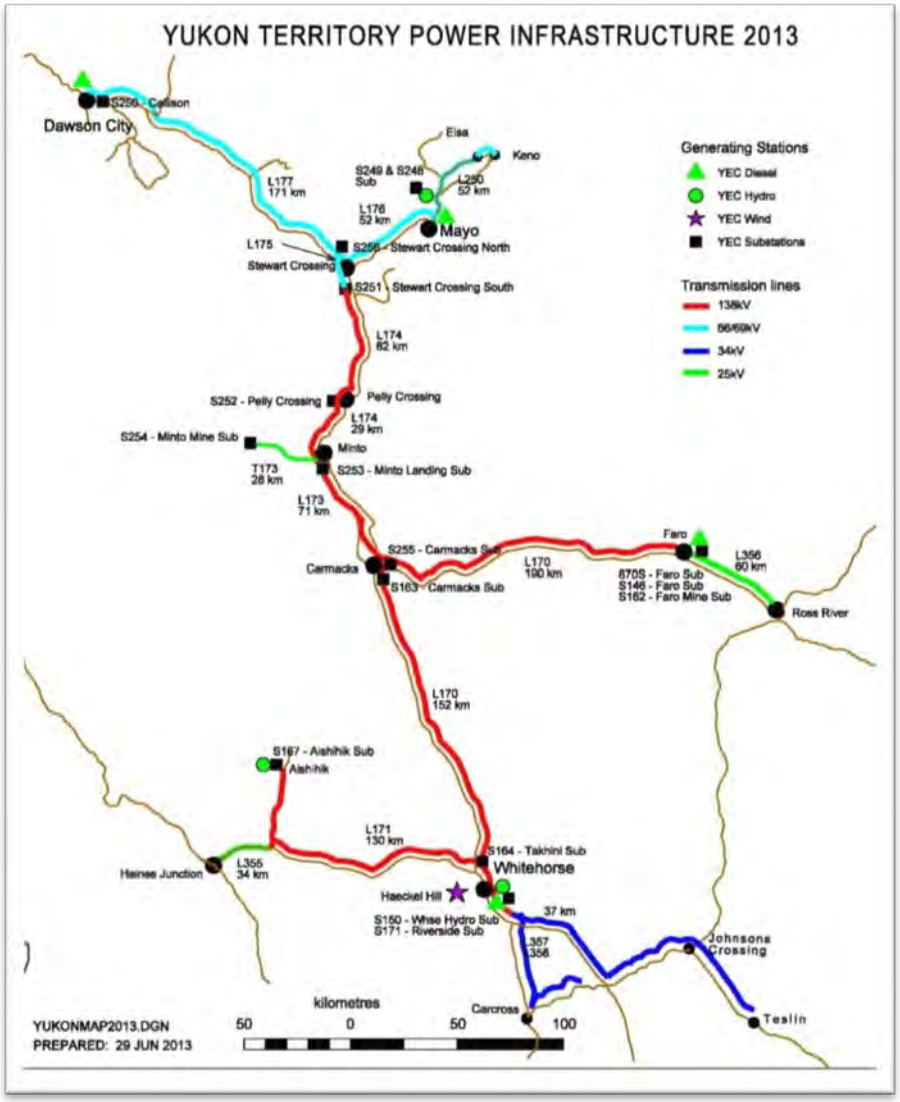

Figure 6–1: YIS Map

6.1.2. System Unbalance

Voltage unbalance on the transmission system is minimal during normal operation. The voltage unbalance under normal operating conditions will be less than three (3) percent. The IPP facilities may be subjected to voltage unbalance and negative sequence current during system disturbances. The generation connected to the transmission system must be able to withstand significantly unbalanced voltages with high negative phase sequence currents for short periods of time.

6.1.3. Frequency

The YEC transmission system operates at 60 Hertz (Hz) Alternating Current (AC) with equipment standard for this frequency. Frequency variations are typically in the range between 59.0 Hz to 61.0 Hz for small contingencies that cause modest disturbances, however variations between 58 Hz to 66 Hz or greater can occur for larger contingencies.

The frequency of the electric system is controlled by synchronous generator governor systems. Such governor systems respond automatically to changes in system frequency to prevent further deviation. These variations are system dependent and subject to change.

6.1.4. Steady State Voltage Levels

During normal steady state conditions, the 69 kV and 138 kV systems can vary between 90% and 105% of nominal voltage. However, under extreme conditions, the 69 kV and 138 kV systems can vary between 85% and 110% of nominal voltage with some 138 kV facilities designed to operate continuously up to 110% of nominal voltage.

6.1.5. System Fault Levels and System Impedances

The IPP generation facilities connecting directly to the transmission system shall be designed for operation at short circuit (fault) levels that take into account reasonable future development of the YIS transmission system. The short circuit levels to be used in the design depend on the point(s) of interconnection and future planned development and are available on request from YEC.

6.1.6. Fault Clearing and Automatic Reclosing

The YIS does not implement auto-reclosing at the transmission level.

6.1.7. System Grounding

The transmission system is effectively grounded.

6.2. YIS Distribution System Characteristics

6.2.1. General

Both YEC and AEY operate distribution systems in the Yukon which are interconnected with the YIS. The systems are predominantly three phase, wye connected, with nominal voltages of 4.16/2.4 kV, 6.9/4 kV, 12.5/7.2 kV, 13.8/8 kV, 25.00/14.4 kV and 34.5/20 kV.

AEY also operates a number of distribution systems which are not interconnected to the YIS, and are not covered by this Guide:

- Watson Lake
- Old Crow
- Beaver Creek
- Destruction Bay / Burwash Landing
- Swift River

For information on connecting to the AEY distribution systems which are isolated from the YIS, refer to AEY's document entitled, "ATCO Electric Yukon's Isolated Community Generation System Interconnection Guidelines".

6.2.2. Voltage Levels

The YEC and AEY distribution systems operate to meet CSA Standard CAN3 C235.83 – "Preferred Voltage Levels for AC Systems 0 to 50,000V" which defines the preferred operating voltage levels for normal and extreme operating conditions. The distribution system steady state voltage is typically maintained between + 5% to 7% and - 5% to 7%.

6.2.3. Power Quality (Harmonics and Voltage Flicker)

The YEC and AEY distribution systems operate to limit the maximum individual frequency voltage harmonics to 3% of the fundamental frequency and the voltage total harmonic distortion (THD) to 5% on the utility side of the POI.

6.2.4. Voltage Regulation

The operating voltages on the low voltage buses of YEC distribution substations are generally regulated by transformer automatic load tap changers (LTC), bus voltage regulators or feeder voltage regulators. YEC will provide set-points for the equipment upon request.

6.2.5. Voltage Unbalance

Distribution facilities are typically three-phase systems, incorporating single-phase distribution taps. The voltage unbalance on a distribution system under normal operating conditions may exceed 3%, due to the unbalanced loading and single-phase regulation. Voltage unbalance will be calculated using the following formula, as derived from CSA Standard C22.3 No. 9-08 (R2015) [1]:

Voltage Unbalance (%) = 100 x (negative sequence voltage of the fundamental frequency component) / (positive sequence voltage of the fundamental frequency component)

6.2.6. Fault Levels

Fault levels and maximum allowable fault currents vary significantly through the distribution system and must be considered in the design of the IPP interconnection.

6.2.7. System Grounding

The utility distribution facilities are typically three phase, four wire, multi-grounded systems that incorporate single phase distribution taps. The lines are normally operated as effectively (solidly) grounded with grounded-wye connected sources at the distribution substation secondary bus.

6.2.8. Phasing

The phase sequence on the utility system may vary, and must be confirmed between the IPP and the utility during the design phase of the installation.

6.2.9. Fault and Line Clearing and Automatic Reclosing

The YEC distribution systems do not currently include auto reclosing. The AEY distribution systems may have auto reclosing and this will be confirmed during the design phase of the application.

7. Power Quality Requirements for the System Interconnection

7.1. Harmonics

The following industry standards may provide guidance for appropriate performance.

- IEEE 1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces, IEEE, 2018 [2]
- IEEE 519-2014 – IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems [5]
- IEC 61000-4-15 – Testing and Measurement Techniques – Flickermeter - Functional and Design Specifications [6]

The generation facility shall not inject harmonic currents such that will cause objectionable voltage distortion as per standard IEEE 519 Harmonic current injections cause intolerable voltage distortions on the distribution system and may damage equipment.

The Utility, at the IPP's expense, shall conduct a Power Quality Assessment of the distribution system in the immediate vicinity of the interconnection using a measurement technique compliant with IEC 61000-4-7.

When performing a Power Quality Benchmark, the measurements at the customer's POI shall be taken over a one week (168 hour) period during typical production load levels.

7.2. Flicker

The generation facility shall meet the requirements of Section 6.2.3 and shall not cause unacceptable levels of flicker on the distribution system. The utility, at the IPP's expense, shall measure the flicker level using a power quality measuring device that meets the requirements of the IEC Flickermeter Standard 61000-4-15.

When performing a Flicker assessment, the measurements at the customer POI shall be taken over a representative load cycle of one day or greater.

7.3. Speed Regulation and Frequency Control

The frequency of the YIS is controlled by the generators operated by YEC.

The YIS operates at 60 Hertz (Hz) Alternating Current (AC). The nominal frequency variations are typically 59.0 Hz to 61.0 Hz for small contingencies that cause modest disturbances, and the frequency may drop to 58 Hz or rise to 66 Hz or higher for larger contingencies.

The frequency of the YIS is automatically controlled by the governor systems of the generators operated by YEC, within the specified limits.

IPP generators rated at 1 MVA and greater are required to have a governor system, capable of operating in droop mode, to respond to system frequency changes. The droop setting of the governor will typically be in the range of 5%.

IPP generators rated less than 1 MVA may operate in base load mode rather than in frequency control mode.

The utility will define frequency requirements on a project by project basis and may require the control of these parameters directly via the YEC SCC.

Equipment connected to the YIS shall be capable of withstanding the dynamic frequency performance criteria listed in Table 1.

Table 1: Transmission Minimum Frequency Performance

Under Frequency Limit	Over Frequency Limit	Minimum Time
60.0-59.0 Hz	60.0-61.0 Hz	N/A (continuous operating range)
58.9-58.5 Hz	61.1-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
less than 56.4 Hz	greater than 61.7 Hz	Instantaneous trip

Under-frequency and over-frequency relaying that automatically disconnects generators from YIS must not operate for frequencies in the range of 59.0 to 61.0 Hz if no other abnormal system event is underway.

7.4. Voltage Regulation and Power Factor

The IPP is responsible for ensuring that the voltage levels at the POI are maintained within this guidelines prescribed by the utility. The IPP interconnection must maintain the voltage levels, under all feeder load conditions, at the same values as they were prior to the interconnection.

Synchronous generators connected to the distribution system must be equipped with adequate excitation controllers. The IPP shall operate generators with Automatic Voltage Regulators (AVR) adjustable from 95% to 105% of nominal bus voltage. The Generation should be run in Voltage control unless required to run in power factor (pf) mode by the Utility. Operation in MW or MVAR control is not acceptable. The AVR response should with no intentional delay when in Voltage Control mode.

Induction generators do not have voltage or reactive power control capability and consume reactive power (VAR). In this case, the generator must provide reactive compensation to correct the power factor to 0.9 lagging or better at the POI, unless other terms are specified by the utility.

Inverter type generating equipment can control the power factor over a wide range, typically ± 0.75. An inverter type generator connected to the distribution facility must be capable of adjusting the power factor in the range of ± 0.9. The IPP may operate outside that range only by prior agreement with the utility.

The utility will define voltage and reactive power requirements on a project by project basis and may require the control of these parameters directly via the YEC SCC. The IPP and utility will identify and

agree on the exact transformer ratio to allow optimal voltage regulation on the system and the IPP will determine whether an on-load tap changer is needed.

In order to coordinate with its existing voltage control devices, the utility may require that the generator operate in a power factor control mode. This means operating within a constant power factor set point range. The voltage/power factor regulator must be capable of controlling the power factor of the generator. The utility shall determine the actual set point between these limits.

In power factor control mode, the voltage regulator must have a voltage override that causes it to reduce excitation if the voltage at the POI exceeds an upper limit to be specified by the utility. The normal upper limit is 105% of nominal; however, the voltage regulator shall have the provision to adjust this upper limit between 100% and 110% of nominal. The voltage regulator must also have provision for a time delay between sensing an excursion of the upper voltage and initiating control action. The power factor control equipment must have the capability to allow for the adjustment of this time delay from between 0 and 180 seconds. The utility will specify the required time delay for each project.

7.5. Voltage Unbalance

Unbalanced phase voltages and currents can affect protective relay coordination and cause high neutral currents and thermal overloading of transformers. Of particular concern is negative sequence voltage and the resulting effect, particularly on rotating generators and motors connected to the system.

To protect the utility and the IPP equipment, the 3-phase generation contribution at the POI should not cause a voltage unbalance greater than 1% or a current unbalance greater than 5%.

If the existing unbalance at the POI is shown to be already close to the maximum unbalance condition, the IPP contribution may cause the unbalance to exceed the specified amount. This will be considered on a case-by-case basis.

7.6. Voltage and Frequency Transients

The IPP is responsible for the cost of any necessary transient or dynamic stability studies, which must be performed in a manner approved by YEC.

7.7. Resonance and Self-Excitation of Induction Generators

The potential effects of resonance should be considered as part of the design of the generating facility. The effects include:

- Ferro-resonance in the transformer,
- Sub-synchronous resonance due to the presence of capacitor banks, and
- Harmonic resonance with other customers when capacitors are being added as part of the installation.

When induction generators are used, the potential for self-excitation should be assessed and addressed as part of the system impact study and mitigated accordingly.

The IPP shall be responsible for the engineering analysis as part of the design process to evaluate the existence of, and to eliminate the harmful effects of resonance and the assessment of the self-excitation effects of induction generators. The engineering analysis of resonance and the assessment of the self-excitation effects of induction generators must be submitted to YEC for approval or further evaluation.

7.8. DC Current Injection

The IPP facility system shall not inject a dc current at the POI.

7.9. Fault Levels

The utility will provide the IPP with the anticipated fault levels or the data necessary for the IPP to calculate the distribution system fault contributions at the POI.

The IPP facility must not increase the fault levels on the utility distribution or transmission system above their design levels for maximum faults.

8. Physical Interconnection

8.1. Safety

The safety of the public, operating personnel and the environment is of primary concern in the design, construction, operation and maintenance of the interconnection facilities.

8.2. Point of Interconnection (POI)

The POI is the point at which the utility (YEC or AEY) distribution facilities or conductors are connected to the IPP's facilities or conductors, and where any transfer of electric power between the IPP and the utility takes place. The POI must be identified in the design and on the Single Line Diagram (SLD).

Depending on ownership, YEC or AEY will coordinate the design, construction, maintenance and operation of the facility on the distribution system side of the POI. The IPP is responsible to coordinate the design, construction, maintenance and operation of the facility on the generation side of the POI.

All voltage and frequency parameters specified in this section must be met at the POI unless otherwise stated.

The IPP is responsible for any incremental costs to the electric systems caused by the interconnection. The responsible utility will carry out the engineering, design and construction required for these installations and charges those costs back to the IPP. Ongoing O&M costs incurred on the distribution feeder side will also be recovered by the utility.

There may be cases where either the utility or the IPP may own equipment located on the other's side of the POI. For example, the utility may own and operate communications, supervisory, or metering equipment, which is located on the IPP side of the POI. The IPP must provide a site with the necessary space for utility to install current transformers, potential transformers, switching equipment, meters, and any other AC and DC auxiliaries, protection and controls, SCADA or communications equipment required to interconnect with the generating facility. The site is to be approved by the utility and a 120-volt AC power service is to be available for the use of portable tools.

8.3. Point of Disconnection

For transmission interconnections, the visible-break disconnect switch shall be located on the high voltage side of the interconnection transformer.

For distribution interconnections, the visible-break disconnect switch may be located on the high or low voltage side of the interconnection transformer.

The disconnect switch must be gang operated to simultaneously isolate all three phases.

If the IPP site interconnects multiple generators, one disconnect switch must be capable of isolating all of the generators simultaneously. There may be other means of meeting this requirement; however the approval of the utility must be obtained before using other means.

The IPP must follow the utility switching, clearance and tagging procedures. The utility is responsible to instruct the IPP in this regard.

8.3.1. High Side and Low Side Disconnect Switches

For transmission interconnections the disconnect switch on the high voltage side of the interconnection transformer shall be installed, owned and maintained by the IPP.

For distribution interconnections the disconnect switch, if on the high voltage side of the interconnection transformer shall be installed, owned and maintained by the utility, and if on the low voltage side of the interconnection transformer shall be installed, owned and maintained by the IPP.

8.3.2. Disconnect Switch Specification

The disconnect switch must be a manual, visible-break disconnect that provides safe isolation for the utility's personnel from the generators and all other possible customer sources of energy.

The disconnect switch must:

- Be adequately rated to break the connected generation/load;
- Be located within five meters (horizontal) of the POI, unless otherwise approved by the utility;
- Provide a direct, visible means to verify contact operation;
- Allow simultaneous disconnection of all ungrounded conductors of the circuit;
- Plainly indicate whether the switch is in the "open" or "closed" position;
- Be lockable in the "open" position;
- Be capable of being energized from both sides;
- Be readily accessible to the utility's operating personnel;
- Be externally operable without exposing the operator to contact with live parts;
- Be capable of being closed without risk to the operator while there is a fault on the system;
- Be labeled with utility's switch number;
- Meet all applicable CSA Part II standards and all applicable codes; and
- Undergo annual inspections and maintenance, with reports submitted to the utility for approval.

8.4. Interconnection Transformer

A generator step-up transformer boosts the voltage of the DG to match the voltage of the utility distribution feeder. The transformer winding configuration impacts how system faults are detected and what type of protection is required (see Section 9.10). The IPP must submit their transformer connection proposal to the utility for review and approval prior to placing an order for purchase.

8.5. Interconnection Grounding

The IPP facility must be grounded in accordance with the latest revisions of the CEC and AEUC. A ground grid of sufficient size to handle the maximum available ground fault current must be designed and installed in order to limit ground potential rise (GPR) step and touch potentials to safe levels as set forth in ANSI/IEEE Std. 80 IEEE Guide for Safety in AC Substation Grounding.

The ground grid will be designed for foreseeable future fault levels obtainable from the System Impact Study.

Grounding of the interconnection shall be designed to provide:

- Solid grounding of the distribution feeder neutral connection,
- Fault detection that isolates all sources of ground fault contribution,
- A circuit to block the transmission of harmonic currents and voltages, and
- Protection of the low voltage side from damage due to high side faults.

The preferred configuration, for an IPP owned interconnection transformer, is delta connection on the generator side of the transformer and a grounded-wye configuration on the utility's side of the transformer. If this configuration is not technically feasible, the configuration chosen must still address the above concerns. Grounding must conform to the AEUC [4].

Sample single line diagrams are shown in Appendix F.

8.6. Phasing and Phasing Sequence

Since phasing is not standardized across distribution facilities, the phase sequence must be coordinated between the IPP and utility's distribution system.

8.7. Interrupting Device Ratings

The design of the generation facility must consider the fault contributions from both the distribution system and the IPP generation facility, to ensure that all circuit fault interrupters are adequately sized. The utility will inform the IPP of the present and anticipated future fault contribution from the interconnected electric system.

9. Interconnection Protection

9.1. General

The purpose of the IPP facility protection is to reduce the risk of damage to IPP and utility equipment and maintain the reliability of supply.

The protection scheme shall be designed to detect the following conditions at the POI:

- Balanced and unbalanced system faults (i.e. line-ground, line-line and three phase faults)
- Frequency variations
- Voltage variations
- Reverse power flow
- Islanding conditions
- Out of synchronism

Depending upon location, the protection scheme may be required to detect additional conditions such as open phase, ferro-resonance, negative sequence voltage, or zero sequence currents.

The protection scheme must fully coordinate with any existing distribution system protective devices. The IPP must submit a complete protection design package, including all relay settings, tripping schemes and schematics, to the utility for review and approval prior to installation. Both existing and ultimate bus fault levels should be considered. A sample Protective Setting Commissioning Sheet with guideline limits is included in Appendix G.

The point of measurement for voltage and frequency shall be at the POI or as agreed upon with the utility.

The IPP must revise and re-submit the protection information for any proposed modification.

9.2. Device Ratings

Equipment shall be rated to carry and interrupt the fault levels that are, or will be, present at the IPP facility - this includes the ultimate fault currents specified by the utility. The IPP's equipment covers all station and distribution facilities, including but not limited to all protection equipment forming the entrance and distribution line protection: circuit breakers, current transformers, potential transformers, secondary cabling, dc system/battery charger, switchboard wiring and protective relays.

9.3. Minimum Protection Requirements

The following minimum protection requirements shall be provided for an interconnected IPP facility:

- Overcurrent
- Over-frequency
- Under-frequency
- Over-voltage
- Under-voltage

Additional protection requirements are dependent upon the transformer configuration and the distribution system characteristics.

9.4. Phase and Ground Fault Protection

The IPP must install utility grade protective devices to detect and promptly isolate the generation facility for faults occurring either in the DG facility itself or on the distribution system. Virtual devices (i.e., computer or programmable-logic controller systems) are acceptable provided they meet standard utility practice for system protection and they have been type tested and approved by an independent testing laboratory.

The protective devices in the IPP generation facility must fully coordinate with the protective relays on the distribution system unless otherwise agreed. The IPP must calculate the protective device settings and submit the relay characteristics and settings to YEC for review and approval.

The generation facility must be able to detect the following situations and isolate itself from the distribution system:

- A short circuit between any phase(s) and ground (if distribution system is a grounded system)
- A short circuit between phase(s)

9.5. Over-Frequency and Under-Frequency Protection

Each synchronous generator must be capable of continuous operation between 59.0 Hz and 61.0 Hz and of limited time operation for larger deviations from normal frequency, as shown in Table 1.

Over/under frequency relays are normally installed to protect the generators from extended off-nominal operation. It is expected that larger (> 1 MW) synchronous generators shall remain connected to the system during frequency excursions. To ensure that the generator is not tripped prematurely, YEC will specify the minimum required time delays and levels for setting the IPP over/under frequency protection relays.

9.6. Over-Voltage and Under-Voltage Protection

The IPP must operate its generation facility such that the voltage levels on the utility's system are not significantly altered by the connection of the generation facility. IPP facility paralleling shall not cause voltage fluctuations of more than ± 5% at the POI.

The IPP must install necessary relays to trip the circuit breaker when the phase-to-ground voltage, measured on any one of the three phases, deviates outside predetermined limits. Under-voltage relays should be adjustable and should have a settable time delay to prevent unnecessary tripping of the generator on external faults. Over-voltage relays should be adjustable and may be instantaneous.

The interconnection facility must cause the generator to cease to energize the utility's system within the trip times indicated in Table 2. "Trip time" refers to the period of time between the start of the abnormal condition and the moment the interconnection device ceases to energize YEC's system.

To ensure that the generator is not tripped prematurely, the utility will specify the minimum required time delays and levels for setting the IPP over/under frequency protection relays.

Table 2: Response to Abnormal Voltages

RMS Voltage (based on 120V nominal)	Trip Time
RMS Voltage: V=<50%	Trip time: Instantaneous

RMS Voltage (based on 120V nominal)	Trip Time
RMS Voltage: 50% < V < 90%	Trip time: 120 cycles
RMS Voltage: 90% < V < 105%	Normal Operation
RMS Voltage: 105% < V < 120%	Trip time: 30 cycles
RMS Voltage: V >= 120%	Trip time: Instantaneous

The IPP may reconnect when the system is stabilized (i.e. voltage and frequency have returned to normal range for a time as identified by the utility).

9.7. Additional Protection

The utility may require additional protection on a case by case basis. Possible protection may include:

- **Unbalance or negative sequence protection**: The IPP generator is tripped on excessive current unbalance. This is important if fuse protection is used on the primary of the generator step-up transformer or for any other open phase condition
- **Broken delta protection (59G)**: Using a grounded wye-broken delta potential transformer, this protection can facilitate detection of ground faults on ungrounded systems.
- **Rate of change of frequency**: Protection to detect a power island condition.
- **Reverse power protection**: Protection to detect a generator motoring condition.

9.8. Anti-Islanding Protection

Islanding is the condition where the generation facilities and a portion of the distribution system have become isolated from the rest of the system, and continue to operate in isolated mode. Unless agreed upon by the utility, generating facilities shall not be permitted to remain connected to an islanded system, i.e. islanding is not generally allowed. Generation facilities may continue to supply station service loads while disconnected from the interconnection system.

Anti-islanding protection is required to:

- Prevent power quality issues to customers connected to the island,
- Avoid out-of-phase reclosing between the utility and the DR facility, and
- Prevent safety hazards created as a result of back feeding isolated portions of the utility distribution system.

For rotating generators, the IPP must install a transfer tripping scheme using tele-protection signals from the system to separate the DG facility from the distribution system in the event of an islanding condition.

Transfer tripping requirements are also applicable to induction generators, unless the IPP can demonstrate that that there is no potential for self-excitation. For inverter-based generation a detection scheme designed in accordance with the requirements of IEEE 1547 [2] may be acceptable.

The IPP is responsible for damage to the YIS caused as a result of failure to safely separate from the system during an islanding event or subsequently during reconnection to the system following the event.

9.9. Transformer Winding Configuration

The winding configuration of any three phase transformer will have an influence on the location of the protection measurement points and the level of protection required for the IPP interconnection. See Appendix F for examples for typical synchronous generator protection single line diagrams for different transformer configurations.

9.10. Conditions for Connecting to an Energized Distribution System

The IPP system must not energize the utility distribution system when the distribution system is de-energized or following the operation of any interconnection protection functions. The utility will inform the IPP facility when it is safe to reconnect to the distribution system.

Where transfer trip protection is installed, the transfer trip protection must ensure that the generator disconnects before a substation feeder breaker or intermediate automatic circuit reclose (ACR) operation. General requirements are:

- Generator lockout within 0.6 seconds of breaker or ACR opening; and
- Fail-safe lockout within 6 seconds of communication loss.

These conditions will be finalized via the operating agreement between the utility and the IPP.

9.11. Synchronization

Any DG facility able to generate voltage while disconnected from the YIS requires synchronization facilities before connection is permitted.

The IPP facility shall maintain in synchronism with the system while operating in parallel. The generating facility has the responsibility of maintaining synchronization with the system. The utility cannot synchronize to the generating facility. Any proposed synchronizing scheme must be submitted to the utility, prior to the installation.

For synchronous generators, an approved automatic synchronizing device must be provided in all cases where the plant is to be operated unattended. Automatic synchronizing shall be supervised by a synchronizing check relay. Synchronizing controls should satisfy the conditions in Table 3 for synchronous generators.

Table 3: Synchronization Criteria for Synchronous Generators

Aggregate Rating of Generators (kVA)	Frequency Difference (Hz)	Voltage Difference (%)	Phase Angle Difference (degrees)
0-500	0.3	10	20
>500 – 1500	0.2	5	15
>1500	0.1	3	10

Induction generators do not require synchronization since there is no generated voltage prior to connecting to the distribution system. The generator speed shall be brought to within 0.5% of its rated value. These units may be started as induction motors using power from the distribution system provided that these units do not cause unacceptable voltage flicker as specified in Section 7.2 on start - up or on connect/disconnect. The interconnection process of the induction generator shall not create a voltage drop pf greater than 5 percent.

Inverter-type or line-commutating voltage-following equipment does not require synchronization facilities. Operation of the interconnection (or disconnecting of the DR facility) shall not cause voltage drop greater that 5 percent and shall meet the flicker requirements

9.12. Protection from Electromagnetic Interference (EMI)

The influence of EMI must not result in a change in state or mis-operation of the interconnection facility.

9.13. Surge Withstand Performance

The interconnection facility must have the capability to withstand voltage and current surges in accordance with the environments described in IEEE/ANSI C62.41 or C37.90.1

9.14. Batteries and Auxiliaries

Batteries and auxiliaries shall have sufficient capacity to ensure the operation of all DC loads during loss of AC supply. Typically the batteries must be capable of supplying the substation DC load for 8 hours.

9.15. Mitigation of Protection Scheme Failure

Relays with self-diagnostic features, which provide information on the integrity of the protection scheme, should be used whenever possible.

The protection scheme must be designed by a qualified professional engineer, or a competent technical person working with the utility's engineers, to ensure that the self-diagnostic feature is integrated into the overall protection scheme for the safe and reliable operation of the system.

Depending on the scheme and its design, where relays with the self-diagnostic feature do not trip the appropriate breaker(s), sufficient redundant or backup protection must be provided for the system. The malfunctioning relay must also send a signal to notify operating personnel to investigate the malfunction.

9.16. Instrument Transformers used for Protection

Instrument transformers used for protection must comply with CAN/CSA-C60044-6 or IEEE C57.13 [8].

10. Remote Monitoring and Information Exchange

The IPP facility shall provide information in real-time to YEC SCC regarding:

a. Connection or circuit breaker status,
b. Real and reactive power output in kW and kVAR,
c. Load Tap Changer (LTC) position of the interconnecting transformer,
d. Communication and RTU failure alarm,
e. Intelligent Electronic Device (IED)/Relay failed status, and
f. Voltage at the POI.

The communication protocol and the equipment required will be specified by YEC.

The IPP facility shall log the operation of any protective device, including which protection elements operated, and the status of the DG facility including power output, voltage, and current waveforms.

YEC may have additional requirements on a case by case basis.

If it is determined that the IPP facility will have an impact on YEC's Transmission Network, the IPP will be required to provide a Remote Terminal Unit (RTU) or Data Link to a YEC RTU capable of exchanging Supervisory Control and Data Acquisition (SCADA) information with the YEC Control Centre. The protocol for data exchange via the RTU shall be compatible with that used for communications used by YEC. The communication protocol and the equipment required will be specified by YEC.

The IPP will be required to provide the following typical data needed by the (SCADA) system:

a. Individual generator(s) MW and MVAR
b. Individual generator(s) MWh and MVARh
c. Generator(s) breaker status
d. Individual generator on/off status, if no generator breaker exists
e. Total station MW and MVAR
f. Station service MW, MVAR, hourly MWh and MVARh
g. Generator transformer(s) high voltage side breaker(s) and isolator(s) status
h. Bus voltage at high voltage bus
i. PSS status, if applicable
j. AVR status, if applicable
k. AVR voltage setpoint, if requested
l. Total plant MW setpoint, if requested
m. Generator step-up transformer tap setting, if requested

11. Construction

The construction and installation of the IPP's generating facility must meet all applicable statutes, regulations, by-laws and codes. The IPP is responsible for obtaining all permits and complying with all safety and environmental regulations, codes and assessment approvals, if necessary, for the construction and operation of its facilities. Copies of all permits, compliance reports and inspection documents must be provided to the utility prior to energizing the POI.

All single line diagrams provided to the utility must be drawn in accordance with IEEE standards and conventions, and must be stamped by a professional engineer assuming responsibility for the design.

12. Metering

12.1. General

Two meters, primary meter and backup meter, will be required at the IPP facility:

- The utility shall install, own, operate and maintain one meter (primary) necessary for measuring the energy and demand supplied to the YIS, unless otherwise specifically provided in a contract with the IPP. This meter shall remain the sole property of YEC. The meter will comply with Measurement Canada requirements and will be owned and maintained by YEC.
- The IPP shall install, own, operate and maintain the other meter (backup) which does not necessarily have to comply with Measurement Canada requirements.

Generators exporting power onto the distribution system shall be equipped with bi-directional meters with four-quadrant measurement capability. An appropriate number of channels are required for four-quadrant meters to separately record active and reactive power in both the export and the import directions.

The high voltage side of the interconnection transformer is designated as the Measured Billing Point for all energy imported and exported from the IPP facility.

The metering equipment will be:

- Suitable for use in the environmental conditions reasonably expected to occur at the installation site; and
- Appropriate for measuring the power system characteristics reasonably expected to exist at the installation under all power system conditions and events.

The IPP shall provide Measurement Canada Approved instrument transformers. Each meter shall be connected to its own individual core/winding. For the utility meter the IPP shall wire from the instrument transformers to the meter receptacle using CSA-approved tamper resistant conduit and accessories suitable for the utility meter or metering equipment.

For transmission interconnections the IPP will provide burden calculations for proposed instrument transformer secondary wiring, for approval by YEC. If necessary the wiring burden may have to be reduced, by increasing the CT secondary conductor size, to meet Revenue Meter requirements.

The IPP shall supply and install the meter base to meet the utility requirements. The utility will provide the specifications for the meter base during the design phase.

12.2. Meter Requirements

The primary meter supplied by the utility will:

- Be Measurement Canada Approved for revenue metering;
- Be dispensated, with accuracy class ratings for active and reactive energy management as per Table 4;
- Be verified and sealed in accordance with the Electricity and Gas Inspection Act;
- Be capable of maintaining the interval boundaries within 60 seconds of the hour and every quarter hour thereafter;

- Measure all quantities required to determine active energy and reactive energy transferred in the required directions at the Measured metering point;
- Provide a separate register to maintain the continuously cumulative readings of the active energy and reactive energy transferred in the required directions at the Measured metering Point;
- Retain readings and, if applicable, all clock functions for at least 14 days in the absence of line power;
- Be equipped with meter failure alarm and communication failure alarm;
- Communicate all metering and equipment status to the YEC system control centre via the IPP's communication equipment;
- Apply loss compensation (such as line losses) factors where applicable to the revenue meters; and
- The meter shall have an accuracy class of 0.2% or better.

The backup meter supplied by IPP will:

- The backup metering will be of the same accuracy class and capability as the primary metering and shall include all equipment to provide the necessary billing data.
- Be non- dispensated, with accuracy class ratings for active and reactive energy management as per Table 5;
- .

Table 4: Schedule of Accuracies for Dispensated Metering Equipment Approved Under Section 9(2) or Section 9(3) of the Electricity and Gas Inspection Act

Metering Point Capacity (MVA)	Points of Delivery	Points of Supply	Measurement Transformers Accuracy Class
10 and above	1.0%	1.0%	0.3%
10	1.0%	1.0%	0.3%

Table 5: Schedule of Accuracies for Non-Dispensated Metering Equipment Approved Under Section 9(2) or Section 9(3) of the Electricity and Gas Inspection Act

Metering Point Capacity (MVA)	Watthour Meter Accuracy Class	Varhour Meter Accuracy Class
10 and above	0.2%	0.5%
10	0.5%	1.0%

12.3. Measurement Transformers

The applicable winding(s) of the current and potential instrument transformers supplied and installed by the IPP must:

- Be approved by Measurement Canada for revenue metering.
- Be burdened to a degree that does not compromise the accuracy required by this guideline.
- Have a minimum of two cores per instrument transformer. One core connection for the utility meter and the other core connection for the IPP meter.
- Be used solely for metering and not to be used for any other purposes.
- Have an accuracy class rating that equals or exceeds the values specified in Table 4.

12.4. Remote Communications Equipment

The remote communications equipment may or may not be an integral part of the meter or the recorder. However, it must incorporate protocol schemes that will prevent the corruption of data during interval data transmission. The protocol must be suitable for the communications equipment type and nature of the communications media and path.

12.5. Password Protection

Two or more levels of password protection will be required for each meter data collection agency. One level is for full access to set time functions and a second level is for read only access to interval data and event logs.

12.6. Safety Requirements

The facility installation must conform to:

- Measurement Canada Standard Drawings;

- AEUC [4];
- CSA Standard C22.2 General requirements - Canadian electrical code, part II [7] ; and
- ANSI/IEEE C57.13-2016 IEEE Guide for Grounding of Instrument Transformers [8].

13. Interconnection Tests

13.1. General Testing Requirements

The IPP must notify YEC (and AEY if the interconnection is via the AEY distribution system) in writing at least three weeks prior to the initial energization and start-up testing of the IPP generation facility. YEC may witness any testing of the equipment and protection schemes associated with the interconnection. Tests must align with the requirements specified in IEEE 1547 and CSA 22.3 No 9-08.

13.2. Type Testing

Type testing is considered an acceptable method of verification where suitable and applicable equipment standards exist, and must be performed once for each specific protection scheme. All interconnection equipment must include a type testing procedure as part of the documentation in order to determine the protection settings meet the requirements set forth within this technical guide. A type test may be performed on one device of a combination of devices. In a case of a combination of devices which comprise a system, the testing will demonstrate that the devices are able to operate as a system.

The type tests shall be performed on a representative unit or system, either in a factory, testing laboratory, or in the field. Results from a resource within a similar product family or design, including hardware or software, shall be acceptable as a representative within the same product family where ratings are within 50% to 200% of the tested resource.

The following type tests must be performed in accordance with IEEE 1547.1 [9]:

- Temperature stability
- Response to abnormal frequency
- Response to abnormal voltage
- Synchronization
- Interconnection integrity
- Unintentional islanding
- Open phase
- Reconnect following abnormal condition disconnect
- DC injection (for inverters without interconnection transformers)
- Harmonics

13.2.1. Temperature Stability

The temperature stability test verifies the interconnection equipment maintains measurement accuracy of parameters over its specified voltage range.

13.2.2. Response to Abnormal Frequency

This test verifies the interconnected generation facility ceases to energize the connected system as specified to IEEE 1547.1 with regards to abnormal frequency.

13.2.3. Response to Abnormal Voltage

This test verifies the interconnected generation facility ceases to energize the connected system as specified to IEEE 1547.1 with regards to abnormal voltage.

13.2.4. Synchronization

This test verifies the interconnected IPP facility will accurately and reliably synchronize with the utility as per IEEE 1547.1.

13.2.5. Interconnection Integrity

The interconnection integrity test verifies the IPP facility meets the surge withstand requirements as specified in Section 9.14 when tested in accordance with IEEE 1547.1.

13.2.6. Unintentional Islanding

Where YEC requires an anti-islanding protection function (other than transfer trip) or minimum import power levels, this test verifies that an IPP facility will cease to energize in accordance with IEEE 1547.1.

13.2.7. Open Phase

The open phase test verifies that the IPP facility will cease to energize the utility interconnection upon the loss of an individual phase on the distribution network when tested in accordance with IEEE 1547.1.

13.2.8. Reconnect following Abnormal Condition Disconnect

This test verifies the functionality of the IPP facility interconnection component or system reconnect timer, which shall delay the reconnection to the utility following a trip event prior to the distribution system stabilization, as specified in Section 9.11.

13.2.9. DC Injection (for Inverters without interconnection transformers)

This test verifies that an inverter-based IPP facility will comply with the DC current inject limit specified in Section 7.9 when tested in accordance with IEEE 1547.1.

13.2.10. Harmonics

The individual current harmonics and the total demand distortion (TDD) of the IPP facility shall be measured and recorded under normal operating conditions to ensure the values are within the limits specified in Section 7.1

13.3. Production Tests

Production tests shall be conducted on each IPP generating unit and interconnection equipment prior to delivery to verify they meet the applicable standards and verify the operability of every generating unit manufactured for customer use.

The tests assume the equipment has met the applicable interconnection and interoperability requirements of the applicable standards and may be conducted as a factory test or performed as part of an evaluation or commissioning test. Facilities with adjustable set points shall be tested at a single

series of test points specified by the manufacturer. The summary report must provide a list of normal and abnormal performance category capability, final function settings, and final operating mode settings.

The following production tests are specified within IEEE 1547.1:

1. Response to abnormal frequency
2. Response to abnormal voltage
3. Synchronization

14. Commissioning Tests and Verifications

14.1. General

Commissioning tests are tests and verification on the IPP facility equipment to confirm the system as delivered, designed, and installed meets the interconnection and interoperability requirements of this guide and the applicable standards. These tests include visual inspections, and may include operability and functional performance tests as required.

Prior to the energization of the IPP facility, or changes to the facility, verification testing must be performed and coordinated with the utility. After the equipment is installed and ready for operation, the testing must be performed by a qualified individual in accordance the manufacturer's published test procedures, or IPP developed procedures that have been approved by the utility. Qualified individuals include: licensed, professional engineers; factory-trained and certified technicians and licensed electricians experienced in testing protective equipment. The utility reserves the right to witness the verification test or to require written certification that the test was performed.

Verification testing must also be performed annually or when major system upgrades or modifications are carried out.

14.2. Interconnection Verifications and Inspections

The following commissioning tests and inspections shall take place:

a. Final IPP facility protection settings shall be verified, recorded, and provided to the utility. A sample protective settings commissioning report is located in Appendix G.

b. Visual inspection shall ensure the grounding coordination requirements in Section 8.5 have been met.

c. Visual inspection shall ensure the presence of a disconnecting means in accordance with Section 8.3 has been met.

d. The polarities, burdens, and ratios of field wired instrument transformers shall be verified as correct and in accordance with the design documentation.

e. Field installed power and control wiring shall be verified to be in compliance with drawings and manufacturer requirements.

f. For three-phase systems, the phase rotation of the distribution system and the IPP facility as installed shall be verified as compatible.

g. All monitoring and information exchange provisions shall be verified as functional in accordance with Section 10.

h. Calibration checks of each protective relay or the equivalent protection device shall be performed using injection of appropriate ac quantities, secondary injection, or set-point adjustment verification.

i. Functionality of the protective relays or the equivalent protection device, circuit breakers, and telecommunications equipment shall be tested to verify the system operates as intended.

j. Load tests of protective relays or the equivalent shall be conducted immediately after energization, where applicable.

k. The ohmic value and connection of the transformer neutral impedance grounding device shall be verified as correct.

l. Upon loss of DC power supply to the protective relays or the equivalent protection device, it shall be verified the protection scheme activates the interconnection circuit breaker.

m. Upon loss of a communication signal, it shall be verified the fail-safe transfer trip occurs when required by the utility in accordance with Section 9.8.

n. Inverter operation must be verified annually by operating the load break disconnect switch and verifying the generation facility shuts down and does not restart for five minutes after the disconnect switch has closed.

o. Any system depending on a battery for trip power must be checked for proper voltage and logged monthly. Once every four years, the battery must be replaced or a discharge test performed.

p. The IPP shall submit to the utility the station LAN design architecture for review during the conceptual design phase of the project.

q. The IPP is responsible for all hardware design, RTU drawings, installation, testing and commissioning.

r. The IPP shall prepare a preliminary but tested version of the RTU Configuration and a preliminary version of the Point Assignment, and send them to the YEC SCC, together with all RTU drawings, P&C drawings and DNP point lists of all LAN devices, at least ten weeks before the in service date.

s. The IPP and YEC SCC shall jointly test all control, status and analog points and confirm visibility at the SCC.

14.3. Disconnection Means Operability

Prior to the operation of the IPP facility, the disconnecting means provided in accordance with Section 8.3 operates as intended.

14.4. Energization Cessation

Tests shall be conducted in accordance with IEEE 1547.1 to verify the functionality of the protection that ensures the IPP facility does not energize the utility under the following conditions described within this standard:

1. Abnormal frequency
2. Abnormal voltage
3. Protection scheme failure

Additional protection functions shall also be verified in accordance with IEEE 1547.1 as needed. The following protective functions must be verified if used at the IPP facility:

1. If available, the anti-islanding function must be checked by operating a load break disconnect switch and verifying that the IPP facility ceases to energize the output terminals and does not restart once the load break disconnect switch has reclosed.
2. If reverse power or minimum power function is used to meet the interconnection requirements, the functionality must be tested using secondary injection techniques. Alternatively, this

function can be tested by the means of a local trip test or by adjusting the IPP output and local loads to verify that the applicable non-export criterion are met.

14.5. Re-Verification

Re-verification of the interconnection and interoperability requirements may be required when any of the following occurs:

- Functional software of firmware changes have been made to the IPP facility equipment;
- Any hardware component of the facility has been modified in the field, been replaced or repaired with parts that are not substitutive components compliant with the applicable standards;
- Protection settings have been changed after factory testing; or
- Protection functions have been adjusted after the initial commissioning / verification process.

15. Maintenance

The IPP has full responsibility for the maintenance of its equipment, up to the Point-of-Interconnection, consistent with the Interconnection Agreement and this Guide. The IPP shall maintain the facilities in accordance with Rule 2-300 of the Canadian Electrical Code to ensure safe parallel operation with the YEC or AEY system. Failure to do so may result in disconnection of the IPP generation facility.

The IPP must present to the utility the planned maintenance procedures and a maintenance schedule for the interconnection protection equipment, and keep records of such maintenance.

The utility reserves the right to periodically inspect the interconnection protection system to verify that it meets the requirements outlined in this document.

Maintenance procedures up to the POI will be performed in accordance with good utility practice and the utility's policies and procedures.

16. Marking and Tagging

The disconnect switch must be clearly marked as the "IPP Disconnect Switch" and tagged with an identification number approved by the utility. The IPP must follow the utility's switching, clearance and tagging procedures. The utility is responsible to instruct the IPP in this regard.

The IPP switchgear equipment must include the manufacturer name and the manufacturer's serial number.

17. Modification of Installation

The IPP shall obtain written approval from the utility before commencing any modification to the generation facility. If the change requires the installation or modification of equipment, the IPP shall provide documentation that the new equipment meets the requirements of Type and Production tests.

If the changes require modifications to the protection and controls information the IPP must obtain approval from the utility for the proposed modifications. Whenever changes are made to interconnection hardware or software that can affect the functions listed below, the potentially affected functions must be retested:

- Over-voltage and under-voltage
- Over-frequency and under-frequency
- Non-islanding function (if applicable)
- Reverse or minimum power function (if applicable)
- Inability to energize dead line
- Time delay restart after utility outage
- Fault detection, if used
- Synchronizing controls (if applicable)

To ensure that commissioning tests are performed correctly, the utility may require the ability to witness the tests and receive written certification of the results.

18. Technical Data Requirements

The following outlines the minimum data required at various stages for planning, design and commissioning the IPP's project. This data is required by YEC (and AEY if connected to AEY distribution system) to ensure suitable steps are taken to interconnect the IPP facility to the YEC system. Expanded data requirements for the proposal and design stages are located in Appendix A and Appendix B. The IPP Policy (in development as of June 2018) shall apply.

18.1. Proposal Stage

During the proposal stage the IPP Facility conceptual design must be submitted before any further detailed studies is approved by the utility. The list of information to be provided for this approval may be the result of preliminary discussions with the utility. Based on the information provided by the IPP, the utility will provide their proposition, their commitment and their own requirements concerning the connection of the IPP facility.

The following list of drawings and data required for the proposal stage of the project includes, but is not limited to:

- A Single Line Diagram (SLD)showing the following :
    - The proposed protection relays, circuit and fuses with fuse type and rating,
    - The connections of all substation equipment with voltage levels and equipment ratings
    - The location of the revenue metering equipment.
- Description of protection scheme
- Generating station site plan showing the layout and location (coordinates) of the generating plant and the location of lockable, "visible" disconnect device
- Based on the size of the project the utility may require more additional generator, exciter and speed governor data for a preliminary interconnection study.

18.2. Approval (Design) Stage

Once the project has been approved by the utility the IPP will proceed to submit the facility detailed design.

The following list of drawings and data required for approval stage of the project includes, but is not limited to:

- Single Line Diagram
- Description of protection scheme
- Control schematic
- Protection and control philosophy
- Major equipment nameplate schedules and statements
- Fuse and protective relay coordination study and settings
- Current transformer characteristic curve
- Measurement Canada approval numbers for instrument transformers

- Generating station site plan showing the layout and land location coordinates and legal description. The drawing should also show the proposed terminal pole or service manhole with the routing of aerial line or underground cables from utility to the generating station.
- SCADA Diagram
- Obtaining all permits and complying with all safety and environmental regulations, codes and assessment approvals, if necessary, for the construction and operation of its facilities.
- Proposed In-Service Date

18.3. Verified Stage

When the project is nearing completion, the IPP must submit the proposed testing, commissioning and start-up procedures to be performed before the facility is connected to the YIS.

The following list of drawings and data required for commissioning and verification stages of the project includes, but is not limited to:

- Commissioning report
- Copies of all permits, compliance reports and inspection documents
- Final Single Line Diagram
- Final protection scheme
- Final control schematic
- Protection and control philosophy
- Major equipment nameplate schedules, statements, test reports and data sheets
- Final fuse and protective relay coordination settings
- Current transformer characteristic curve
- Final generating station site plan showing the layout and land location coordinates and legal description

19. References

The technical guide was created using the following primary reference standards. Additional applicable standards are located within Appendix D.

[1] CSA Standard C22.3 No. 9-08 (R2015) – Interconnection of Distributed Resources and Electricity Supply Systems, CSA Group, 2015.

[2] IEEE 1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces, IEEE, 2018.

[3] Energy Strategy For Yukon Independent Power Production Policy, Yukon Energy, Mines and Resources, 2018

[4] Alberta Electrical Utility Code, latest Edition

[5] IEEE Std 519-2014 - IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems

[6] IEC 61000-4-15: Testing and Measurement Techniques – Flickermeter - Functional and Design Specifications

[7] CSA Standard CAN/CSA-C22.2 NO. 0-10 (R2015) - General requirements - Canadian electrical code, part II

[8] IEEE Std C57.13-2016 (Revision of IEEE Std C57.13-2008) - IEEE Standard Requirements for Instrument Transformers

[9] IEEE 1547.1-2005 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

Appendix A

Information Required from IPP (Proposal Stage)

Appendix A
Information Required from IPP (Proposal Stage)

Independent Power Producer Contact Information

Company Name	
Company Address	
Commercial Contact	
Commercial Contact Name	
Commercial Contact Phone	
Commercial Contact Email	
Commercial Contact Address	
Engineering Contact	
Engineering Contact Name	
Engineering Contact Phone	
Engineering Contact Email	
Engineering Contact Address	
Operating Contact	
Operating Contact Name	
Operating Contact Phone	
Operating Contact Email	
Operating Contact Address	

Project Overview

Land Location	
Legal Location Description	
Proposed In-Service Date	
General Description	

Generator Data

Generation Type (Synchronous, Induction, Inverter)	
Single Phase or Three Phase	
Prime Mover Type	
Number of Generators	
Generator Nominal kW Rating	
Generator Nominal kVA Rating	
Generator Nominal kV Rating	
Power Factor, at Rated Output	
Annual Energy Production (MW-hr)	
Production Capacity Range(MW)	

Transformer Data

Transformer Rating (ONAN/ONAF, kVA)	
Transformer Voltage Rating (kV)	
Load Tap Changer steps	
Winding Connection	
Positive Sequence Impedance (%, ONAN base)	
Zero Sequence Impedance (%, ONAN base)	

Prime Mover Data

Prime Mover Type	

Drawings

General Site Map, Including IPP Generation Facility	
Preliminary Substation Layout Drawings	
Preliminary Protection & Metering Single Line	

Company Authorization

Authorizing Personnel	
Authorization Signature	
Authorization Date	

Appendix B

Information Required from IPP (Design Stage)

Appendix B
Information Required from IPP (Design Stage)

Independent Power Producer Contact Information

Company Name	
Company Address	
Commercial Contact	
Commercial Contact Name	
Commercial Contact Phone	
Commercial Contact Email	
Commercial Contact Address	
Engineering Contact	
Engineering Contact Name	
Engineering Contact Phone	
Engineering Contact Email	
Engineering Contact Address	
Operating Contact	
Operating Contact Name	
Operating Contact Phone	
Operating Contact Email	
Operating Contact Address	

Project Overview

Land Location	
Legal Location Description	
Proposed In-Service Date	
General Description	

Generator Data

Generation Type (Synchronous, Induction, Inverter)	
Single Phase or Three Phase	
Number of Generators	
Manufacturer	
Model	
Nominal kW Rating	
Nominal KVA Rating	
Nominal kV Rating	
Power Factor at Rated Output	
Maximum Authorized Real Power (MARP)	
Leading and Lagging Reactive Power at MARP	
Generator Grounding (Resistive, Reactive, None)	
Individual Generator Parameters - impedances in per unit, on nominal machine base	
Speed (RPM)	
Inertia Constant, H (generator)	
Direct Axis Synchronous Reactance , X_D	
Direct Axis Transient Reactance , X'_D	
Direct Axis Subtransient Reactance , X''_D	
Quadrature Axis Synchronous Reactance , X_Q	
Quadrature Axis Transient Reactance , X'_Q	
Quadrature Axis Subtransient Reactance , X''_Q	
Open Circuit Direct Axis Transient Time Constant, T'_{DO}	

Short Circuit Direct Axis Transient Time Constant, T'_D	
Open Circuit Direct Axis Subtransient Time Constant, T''_{DO}	
Short Circuit Direct Axis Subtransient Time Constant, T''_D	
Quadrature Axis Transient Time Constant, T'_{QO}	
Quadrature Axis Subtransient Time Constant, T''_{QO}	
Saturation Factor (1.0 per unit flux)	
Saturation Factor (1.2 per unit flux)	
Armature Resistance, R_A	
Stator Leakage Reactance, X_L	
Negative Sequence Resistance, R_2	
Negative Sequence Reactance, X_2	
Zero Sequence Resistance, R_0	
Zero Sequence Reactance, X_0	
Armature Short Circuit Time Constant, T_A	
Governor Droop (%)	
Short-time unbalanced current factor (K)	
Continuous negative sequence current level (%).	
Induction Generator Data (if applicable) - impedances in per unit, on nominal machine base	
Rating (kVA)	
Rated Power Factor	
Speed (RPM)	
Inertia Constant, H (generator)	
Stator Resistance, R_S	
Stator Reactance, X_S	
Rotor Resistance, R_R	
Rotor Reactance, X_R	
Armature Magnetizing Reactance, X_M	
Other Attachments	
Reactive capability curve (D-curve) comes with	
a. Under excitation limiter	
b. Over excitation limiter	

Exciter nameplate	
VEE curves	
Single line diagram	

Power Factor Regulator

Reactive Power Limit - Lagging (out)	
Reactive Power Limit - Leading (in)	
Accuracy Tolerance (%)	

Voltage Regulator

Voltage Regulator Range (V)	
Accuracy Tolerance (%)	

Transformer Data

Transformer kVA Ratings	
Transformer kV Ratings	
Cooling Type (ONAN, ONAF)	
Winding Connection	
Transformer Grounding (Resistive, Reactive, None)	
Grounding Impedance in Ohms (if applicable)	
Positive Sequence Impedance (%, ONAN base)	
Zero Sequence Impedance (%, ONAN base)	
Tap Details (if applicable)	
On-Load Tap Range	
On-Load Tap Size	
Off-Load Tap Range	
Off-Load Tap Size	
Other Attachments	
Factory Test Reports (minimum requirements)	
No Load Loss & Exciting Current Measurements	
Measurement of Load Loss & Impedance Voltage and Zero Sequence Impedance Measurements	

Prime Mover Data

Prime Mover Type	
Prime Mover Rating	
Inertia Constant (prime mover)	
Manufacturer	
Model	
Other Attachments	
Elevation versus Output Curve	
Ambient Temperature versus Output Curve	

Drawings Required

General Site Map, Including IPP Generation Facility	
Complete and Accurate Protection Diagrams	

Single Line Diagrams	
AC / DC Schematics	
Wiring Diagrams	
Major Equipment Nameplates (Transformer, Generator, etc.)	

Protection Requirements

Proposed Protection Schemes Provided	
Verified Interconnection Functionality Provided	
Inertia Constant (prime mover) Provided	
Maintenance Plans for Protection Devices Provided	
Maintenance Plans for Interrupting Devices Provided	

Compliance with Electrical Inspector

Permit or Equivalent Compliance Provided (Yes / No)	

Metering Requirements

Element (2 Element, 3 Element)	
Metering Service Provider	
Metering Data Manager	
Asset ID Number	

Company Authorization

Authorizing Personnel	
Authorization Signature	
Authorization Date	

D.1 Modelling Information

In some cases, a generator (or the aggregate generation on a line) is large enough that adjacent customers or the dynamic stability of utility's distribution system could be affected. The IPP is responsible for the cost of any required transient or dynamic stability studies, and the studies must be done in a manner suitable to, and approved by, the utility.

IPPs are responsible for ensuring the data they submit provides an adequate mathematical representation of the facility's electric behavior. If the data is not available prior to purchasing equipment, it must be submitted as soon as it becomes available.

The studies must accurately determine:

1. The impact of the IPP's facility on adjacent customers of the utility.
2. The dynamic stability, in aggregate, of the utility system.

Data may be supplied by the manufacturer or acquired directly by testing. It must include generator characteristics (i.e., speed, reactance, resistance, excitation system etc.) and governor characteristics (i.e., lead time/lag time constants, valve or gate opening data etc.).

The information requirements vary for induction generators and inverter generators, and for hydro or thermal systems.

Appendix C

Information Provided by the Utility

Appendix C

Information Provided by the Utility

After receiving the application for interconnection, the utility will provide the following information to the IPP, if required:

a. Single Line Diagram or maps of the system up to the POI.
b. Minimum and maximum 60 Hz source impedances (positive-sequence, negative- sequence and zero-sequence) at the POI.
c. Maximum and minimum normal and emergency system operating voltage ranges at the POI.
d. Harmonic impedance envelope at the POI if available.
e. Planning, operating and reliability criteria, standards and policies.
f. The results of a planning study (e.g. the System Impact Study) documenting the availability of the requested amount of system capacity and any other specific technical issues to be addressed.
g. Cost estimates and time schedule to build the upstream facilities.
h. Characteristics and settings of protection on the distribution system.
i. Costs to implement any required changes to the distribution system that are identified by the System Impact Study.

Some or all of this information will be required by the IPP to properly design the interconnection protection. The utility will identify when the costs of producing this information are to be assigned to the IPP.

Appendix D

Applicable Codes and Standards

Appendix D
Applicable Codes and Standards

D.1 Primary Standards

CSA Standard C22.3 No. 9-08 (R2015) Interconnection of Distributed Resources and Electricity Supply Systems

IEEE Standard 1547-2018 Standard for Interconnecting Distributed Resources with Electric Power Systems with Associated Electric Power Systems Interfaces

Power Quality Standards

ANSI C84.1-2016 American National Standards for Electric Power Systems and Equipment Ratings (60 Hertz). Establishes nominal voltage ratings and operating tolerances for 60 Hz electric power systems from 100 V through 1200kV.

IEEE Std. 493-2007 IEEE Recommended Practice for Design of Reliable Industrial and Commercial Power Systems (IEEE Gold Book).

IEEE Std. 519-2014 IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.

IEEE Std. 1100-2005 IEEE Recommended Practice for Powering and Grounding Sensitive Electronic Equipment (IEEE Emerald Book).

IEEE Std. 1159-2009 IEEE Recommended Practice for Monitoring Electric Power Quality.

IEEE Std. 1250-2011 IEEE Guide for Identifying and Improving Voltage Quality in Power Systems.

In addition to the power quality standards, the following standards are applicable to the interconnection of generation facilities to YEC's system:

IEEE Std. 100 - 2000 IEEE Standard Dictionary of Electrical and Electronics Terms.

IEEE Std 315-1975 (Reaffirmed 1993) ANSI Y32.3-1975 (R1989) CSA Z99-1975 Graphic Symbols for Electrical and Electronics Diagrams (including Reference Designation Letters).

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic (PV) Systems.

C37.1-2007 ANSI/IEEE Standard Definitions, Specifications and Analysis of Systems Used for Supervisory Control, Data Acquisition and Automatic Control.

C37.2-2008 IEEE Standard Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.

C37.18-1979 ANSI/IEEE Standard Enclosed Field Discharge Circuit Breakers for Rotating Electric Machinery.

C37.20.1-2015 ANSI/IEEE Standard for Metal-Enclosed Low-Voltage (1000 Vac and below, 3200 Vdc and below) Power Circuit Breakers Switchgear.

C37.20.3-2001 ANSI/IEEE Standard for Metal-Enclosed Interrupter Switchgear.

C37.24-2017 ANSI/IEEE Standard for Evaluating the Effect of Solar Radiation on Outdoor Metal-Enclosed Switchgear.

C37.27-2015 ANSI/IEEE Standard Application Guide for Low-Voltage AC (635 V and below) Power Circuit Breakers with Separately Mounted Current-Limiting Fuses.

C37.29-1981 ANSI/IEEE Standard for Low-Voltage AC Power Circuit Protectors Used in Enclosures.

C37.50-1989 ANSI Standard Test Procedures for Low-Voltage AC Circuit Breakers Use In Enclosures.

C37.51-1989 ANSI Standard Conformance Test Procedure for Metal Enclosed Low- Voltage AC Power Circuit-Breaker Switchgear Assemblies.

C.52-1974 ANSI Standard Test Procedures for Low-Voltage AC Power Circuit Protectors Used in Enclosures.

C57.12-2015 IEEE Standard General Requirements for Liquid Immersed Distribution, Power and Regulating Transformers.

C57.12.13-1982 Conformance Requirements for Liquid Filled Transformers Used in Unit Installations including Unit Substations.

C57.13.1-2006 IEEE Guide for Field Testing of Relaying Current Transformers.

C57.13.2-2005 IEEE Standard Conformance Test Procedures for Instrument Transformers.

C37.58-2003 (R2010) ANSI Standard Conformance Test Procedures for Indoor AC Medium- Voltage Switches for Use in Metal-Enclosed Switchgear.

C37.90-2005 ANSI/IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.

C37.90.1-2002 ANSI/IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems.

C37.90.2-2004 ANSI/IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers.

C37.95-2014 IEEE Guide for Protective Relaying of Utility Consumer Interconnections.

C37.98-2013 ANSI/IEEE Standard for Seismic Testing of Relays.

IEC 1000-3-3 Limitation of Voltage Fluctuations and Flicker in Low-Voltage Supply Systems for Equipment with Rated Current Less than 16A.

IEC1000-3-5 Limitation of Voltage Fluctuations and Flicker in Low-Voltage Supply Systems for Equipment with Rated Current Greater than 16A.

UL1008 Transfer Switch Equipment.

UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources

IEEE P1547, DRAFT Standard for Distributed Resources Interconnected with Electric Power Systems. Canadian Electrical Code, CSA no. C22-1, latest version.C22.2 No. 31- M89 (R2000) Switchgear Assemblies.

Can/CSA - C22.2 No. 1071 95Commercial and Industrial Power Supplies.

Can/CSA - C22.2 No. 1010.1-92 Safety Requirements For Electrical Equipment for Measurement, Control and Laboratory Use.

Can/CSA - C22.2 No. 144-M91 (R2015) Ground Fault Circuit Interrupters.

C22.2 No. 193-M1983 (R2014) High-Voltage Full-Load Interrupter Switches.

C22.2 No. 201-M1984 (R2014) Metal Enclosed High-Voltage Busways.

C22.2 No. 229-M1988 (R2014) Switching and Metering Centres.

CSA Standard CAN3 C235 83 Preferred Voltage Levels for AC Systems 0 to 50,000V.

Alberta Electrical and Communication Utility Code (formerly the Alberta Electrical and Communication Utility System Regulation 44/1976 or future amendments).

Measurement System Standard / Transmission Administrator Metering Standard GC301 Practices for Management and Transfer of Metered Data.

C37.04-1999 IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI/DoD).

C37.06-2000 American National Standard for Switchgear--AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis--Preferred Ratings and Related Required Capabilities.

C37.09-1999 IEEE Standard Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI/DoD).

C37.010- IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.011-2011 IEEE Application Guide for Transient Recovery Voltage for AC High- Voltage Circuit Breakers.

C37.012-2014 IEEE Application Guide for Capacitance Current Switching for AC High-Voltage Circuit Breakers Above 1000 V.

C37.013-1997 IEEE Standard for AC High-Voltage Generator Circuit Breaker Rated on a Symmetrical Current Basis.

C37.015-2017 IEEE Application Guide for Shunt Reactor Switching.

C37.081-1981 (R1988) Guide for Synthetic Fault Testing of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.081a-1997 Supplement to IEEE Guide for Synthetic Fault Testing of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.11-2014 IEEE Standard Requirements for Electrical Control for Electrical Control for AC High-Voltage (>1000 V) Circuit Breakers.

C37.13-2008 IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures.

C37.14-2015 IEEE Standard for DC (3200 V and below) Power Circuit Breakers Used in Enclosures.

C37.16-2009 IEEE Standard for Preferred Ratings, Related Requirements, and Application Recommendations for Low-Voltage AC (635 V and below) and DC (3200 V and below) Power Circuit Breakers.

C37.20.2-2015 IEEE Standard for Metal-Clad and Station-Type Cubicle Switchgear.

C37.23-2015 IEEE Standard for Metal-Enclosed Bus.

C37.30-1997 IEEE Standard Requirements for High-Voltage Switches.

C37.32-2002 American National Standard for Switchgear--High-Voltage Air Switches, Bus Supports, and Switch Accessories--Schedules of Preferred Ratings, Manufacturing Specifications, and Application Guide.

C37.34-1994 IEEE Standard Test Code for High-Voltage Air Switches.

C37.35-1995 IEEE Guide for the Application, Installation, Operation, and Maintenance of High-Voltage Air Disconnecting and Load Interrupter Switches.

C37.36b-1990 IEEE Guide to Current Interruption with Horn-Gap Air Switches.

C37.37-1996 IEEE Standard for Loading Guide for AC High-Voltage Air Switches (in Excess of 1000 V).

C37.38-1989 IEEE Standard for Gas-Insulated, Metal-Enclosed Disconnecting, Interrupter, and Grounding Switches.

C37.42-2016 IEEE Standard Specifications for High-Voltage (>1000 V) fuses and Accessories.

C37.44-1981 (R1992) American National Standard Specifications for Distribution Oil Cutouts and Fuse Links.

C37.54-1996 American National Standard for Switchgear--Indoor Alternating-Current High-Voltage Circuit Breakers Applied as Removable Elements in Metal-Enclosed Switchgear Assemblies--Conformance Test Procedures.

C37.55-2002 American National Standard for Switchgear--Metal-Clad Switchgear Assemblies--Conformance Test Procedures.

C37.57-2003 (R2010) American National for Switchgear--Metal-Enclosed Interrupter Switchgear Assemblies-Conformance Testing.

C37.66-2005 American National Standard for Requirements for Oil- Filled Capacitor Switches for AC Systems (1 kV to 38 kV).

C37.81-2017 IEEE Guide for Seismic Qualification of Class 1E Metal- Enclosed Power Switchgear Assemblies.

C37.85-1989 (R1998) American National Standard for Switchgear--Alternating- Current High-Voltage Power Vacuum Interrupters-Safety Requirements for X- Radiation Limits.

ANSI/IEEE C37.90.1-2102 Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus.

120-1989 (Reaff-1997) IEEE Master Test Guide for Electrical Measurements in Power Circuits.

1291-1993 IEEE Guide for Partial Discharge Measurement in Power Switchgear.

IEEE Std C62.23-2017 Application Guide for Surge Protection of Electric Generating Plants.

ANSI /IEEE C62.41-1991 Recommended Practices on Surge Voltages in Low- Voltage AC Power Circuits.

C57.13-2016 IEEE Standard Requirements for Instrument Transformers.

C57.13.3-2014 IEEE Guide for the Grounding of Instrument Transformer Secondary Circuits and Cases.

C57.98-2011 IEEE Guide for Transformer Impulse Tests.

C57.19.100-2012 IEEE Guide for Application of Power Apparatus Bushings.

C57.110-2008 IEEE Recommended Practice for Establishing Liquid-Filled and Dry-Type Power and Distribution Transformer Capability When Supplying Non-sinusoidal Load Currents.

C62.92.4-2014 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part IV – Distribution.

IEEE Std. 242-2001 Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems.

ANSI C12.20-2010 Electricity Meters 0.2 And 0.5 Accuracy Classes.

ANSI C62.1-1981 Surge Arresters for AC Power Circuits.

ANSI C62.11-2012 Metal-Oxide Surge Arresters for AC Power Circuits (>1 kV).

NEMA CC 1-2009 Electric Power Connectors for Substations.

NEMA LA 1-2009 Surge Arresters.

NEMA MG 1-2016 Motors and Generators

Appendix E

Sample Operating Agreement

Appendix E
Sample Operating Agreement

1. Purpose

This agreement outlines the steps to take to ensure a reliable and safe interconnection between the IPP and YEC and/or AEY through a variety of circumstances.

2. Definitions

Operating Authority: The organizational unit assigned responsibility for operating a portion of the electrical system. For each utility the YEC System Control Center (SCC) operator is the operating authority. For the IPP, the *<IPP Contact>* is the operating authority.

Operational Boundary/Interface Point or Point of Interconnection: The location on the electrical system at which responsibilities between Operating Authorities meet. The breaker *<Breaker ID>* is the interface point between the IPP and the utility.

3. Operational Information

Circuit Breaker Identification

List circuit breakers providing interconnection between IPP and the utility.

3.1 Interlocks

List identified circuit breaker interlocks with sequence information

3.2 Contact Information

SCC – Phone (867) *XXX-XXXX* or (867) *XXX-XXXX* (recorded lines)

Contact Name	Title	Phone Number
<Utility Contact>	Leadhand SCC	(867) *XXX-XXXX*
<Utility Contact>	Operation Coordinator	(867) *XXX-XXXX*
<Utility Contact>	Manager Operations	(867) *XXX-XXXX*
<Utility Contact>	Director of Operations	(867) *XXX-XXXX*
<IPP Contact>	<Contact Position>	(867) *XXX-XXXX*

3.3 Normal Operation

Under normal operating conditions the IPP facility will be connected to the utility grid. The breakers status under normal operating conditions is as follows.

Breaker	**Status**
<Breaker ID>	*Open/Closed*
<Breaker ID>	*Open/Closed*
<Breaker ID>	*Open/Closed*
<Breaker ID>	*Open/Closed*

4. Operating Procedures

4.1. Line L### (<Utility Line> to <IPP Facility>) Isolation

L### isolation requires the minimum notification defined in section 4.3, with the exception of emergency repairs. The utility will provide a Condition Guarantee on breaker <Breaker ID>. The Condition Guarantee is used in communications between external parties. It is a formal method of communication that switching has been completed. It ensures the status of the breaker/device will not change until the work is complete, the lock out tag out is surrendered and all workers are clear.

4.2. Voltage Support

Based on the power quality conditions defined in Schedule <*X*> of the Power Purchase Agreement (PPA) and system security requirements, SCC may request voltage support. Voltage support can be accomplished by placing IPP generation on line, or other means such as capacitor banks or transformer tap changing. If such support is part of the operating agreement then:

- When the IPP has generation online, the generators regulate the generator bus voltage between 100 and 105% of nominal and the utility shall have control of this set-point. Generators reactive output will be adjusted by the utility in real time, to regulate the system voltage, by pulsing the AVR voltage set-points. The IPP sets the acceptable range within which the utility can adjust voltage.
- The utility must have full SCADA visibility of the IPP substation and control of critical elements.

4.3. SCC Remote Monitoring and Control

- SCC will have visual indication of the IPP breakers, generator status, capacitor status and electrical measurement information for the IPP facility.
- The utility control will be limited to:
    - Approving requests from the IPP to connect and disconnect from the utility system
    - Approving requests from the IPP for changes in generation output
    - Requesting the IPP to disconnect from the utility system for operational and safety reasons
- All IPP requests must be communicated and approved by the utility
- The utility shall have control (open and close) of incoming line breaker <*Breaker ID*> at the IPP facility.

5. Operational Notification

5.1. Daily Operating Communications

Under normal operating conditions IPP will be supplying <*XXX*> kW to the YIS. Generation changes of more than <*XXX*> kW must be communicated and approved by the utility.

5.2. The transition from winter to summer and conversely summer to winter generation levels must be established with SCC with a minimum of 30 days' notice.

5.3. IPP Facility Planned Maintenance and Scheduling

The IPP shall operate under the utility approved maintenance procedures established.

To meet changing operating conditions and coordinate maintenance efforts, maintenance shutdowns by the IPP need to be communicated to SCC at least one week in advance for shutdowns of up to 12 hours and 30 days for shutdowns longer than 12 hours. Changes in the availability and capacity of the onsite generation need to be communicated to SCC. The utility and the IPP shall share annual shutdown/maintenance plans in February of each year.

5.4. Transmission and Distribution Maintenance and Scheduling

The utility performs annual line maintenance on its transmission and distribution lines, during which grid power to the IPP facility may be curtailed or suspended. The duration of this annual maintenance can be up to 14 days per calendar year.

The utility will provide a minimum of 30 days' notice of the start date and expected duration of work that will curtain or otherwise interrupt the supply of grid power to the IPP facility.

6. Loss of Supply Procedures

6.1. Loss of Supply - Short Term

In the event of a disturbance that results in the loss of grid power to the IPP facility, SCC will make one attempt to re-energize the line to the IPP facility. If successful the following steps apply to resume the IPP facility operation with grid power.

a) SCC will confirm the status of the breakers located at the IPP's POI.

b) SCC will request closed breaker <Breaker ID>.

c) Once complete and with confirmation from SCC the IPP facility may proceed with the restarting of their operation. The IPP will communicate to SCC on generation greater than <XXX> kW. The request to increase generation may be communicated verbally or via SCADA.

6.2. Loss of Supply - Long Term

In the event of a disturbance that results in the loss of grid power to the IPP facility and SCC is unsuccessful in re-energizing the line the following steps will apply.

a) SCC will confirm the status of the breakers.

b) At the direction of SCC the IPP personnel will start and stage their generation on line supplying power to the IPP facility.

c) Once the line to the IPP facility has been re-energized, SCC will request the IPP synchronize and close its POI breaker.

d) The IPP facility is now connected to YEC system. Once complete and with confirmation from SCC the IPP facility may proceed with resuming generation. The IPP will communicate to SCC on generation increases greater than *<XXX>* kW. The request to load up may be communicated verbally or via SCADA.

7. Revision and Approval

7.1. This Agreement comes into effect once it is signed by the IPP and the utility.

7.2. This Agreement will remain in effect unless cancelled upon the mutual agreement of both Parties.

7.3. The Parties shall provide 90 days' notice in writing of the intention to modify the Agreement.

7.4. The Agreement may be revised upon mutual agreement of both Parties. The agreement will be formally reviewed every two (2) years.

Approved by: _____
Yukon Energy Corporation

Approval Date: _____

Approved by: _____
ATCO Electrical Yukon

Approval Date: _____

Approved by: _____
IPP

Approval Date: _____

Appendix F

Typical Interconnection Single Line Diagrams

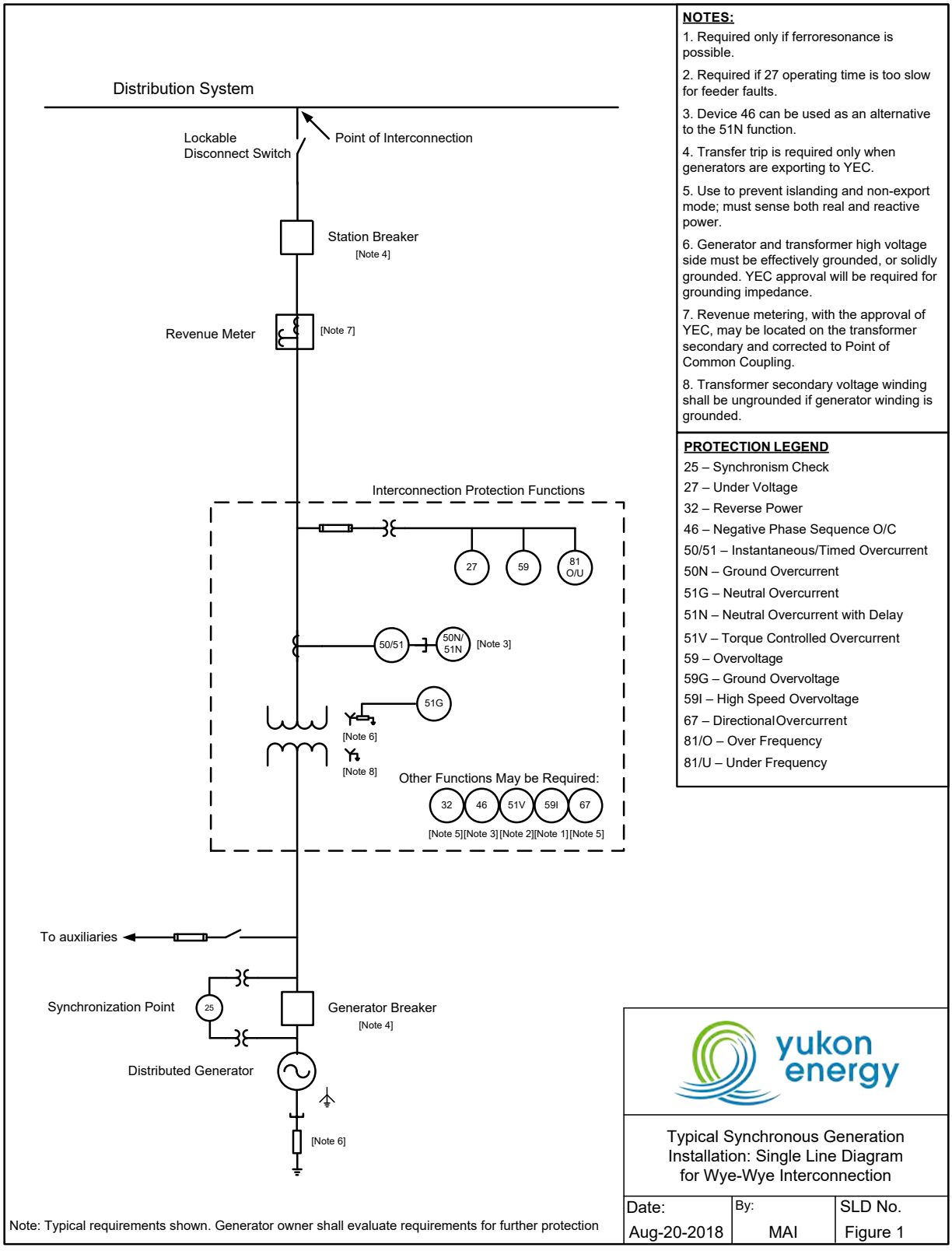

Figure F- 1: Single Line Diagram for Wye-Wye Interconnection

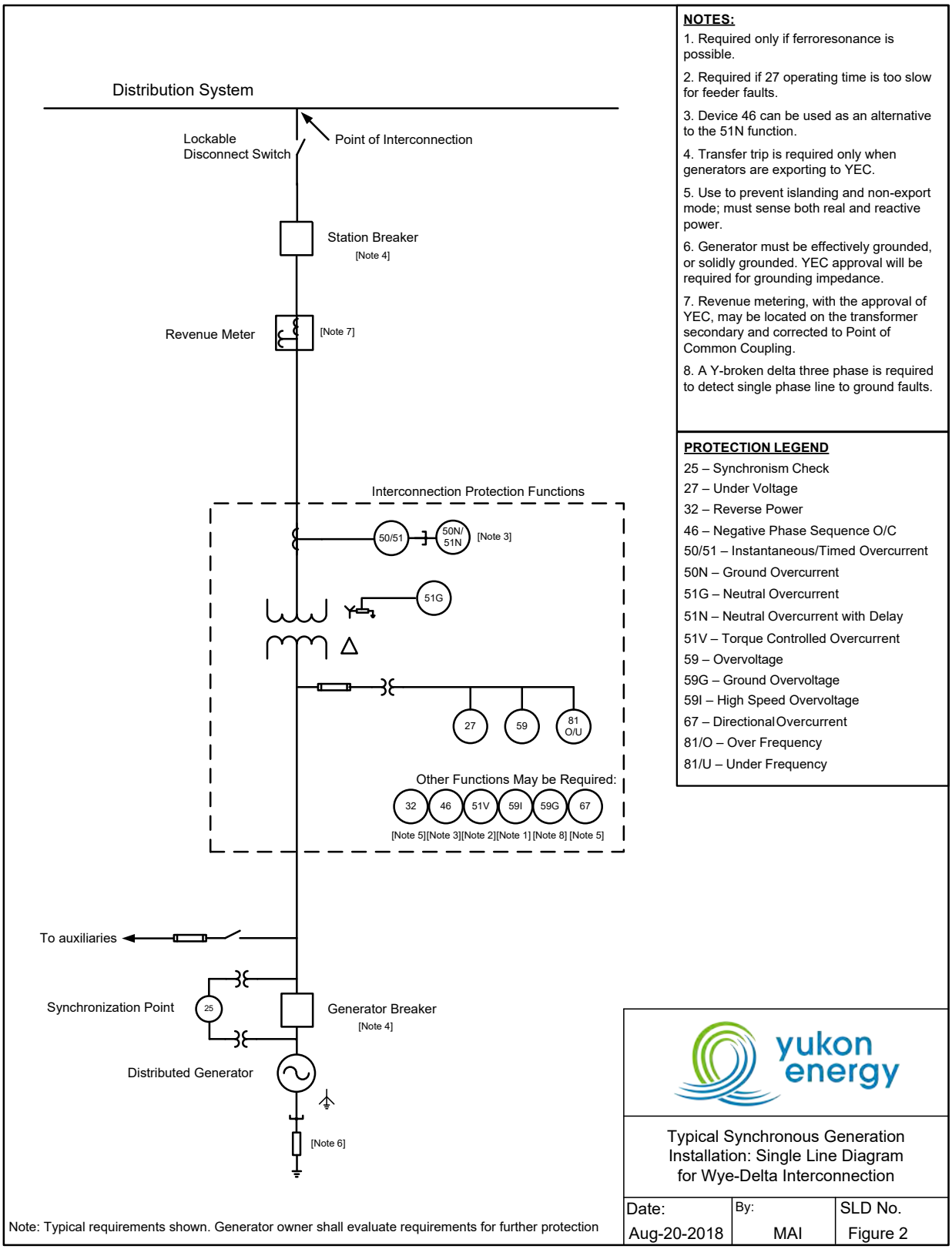

Figure F- 2: Single Line Diagram for Wye-Delta Interconnection

Appendix G

Protective Settings Commissioning Document

Appendix G

Protective Settings Commissioning Document

Over Voltage Protection Parameters

	PHASE VOLTAGE TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	106% - 120% 1% Increments						30 Cycles					
Fast Trip	144% - 120% 1% Increments						100 ms					

Under Voltage Protection Parameters

	PHASE VOLTAGE TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	50% - 90% 1% Increments						120 Cycles					
Fast Trip	Less than 50% 1% Increments						100 ms					

Non-Islanding Function Test

Loss of Utility Voltage	100 ms	
Generator Restart Delay	5 min Minimum	
Dead Bus Test	Fail to Start Successful (Yes/ No)	

Over Frequency Protection Parameters

	FREQUENCY TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	60.5 Hz - 61.5 Hz 1% Increments						3 minutes					
Fast Trip	61.5 Hz - 61.7 Hz 1% Increments						30 seconds					

Under Frequency Protection Parameters

	FREQUENCY TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	59.5 Hz - 58.5 Hz 1% Increments						3 minutes					
Second Trip	58.5 Hz - 57.9 Hz 1% Increments						30 seconds					
Third Trip	57.9 Hz - 57.4 Hz 1% Increments						7.5 seconds					
Fourth Trip	57.4 Hz - 56.9 Hz 1% Increments						45 cycles					
Fifth Trip	56.9 Hz - 56.5 Hz 1% Increments						7.2 cycles					
Fast Trip	Less than 56.4 Hz 1% Increments						100 ms					

Reverse AC Current Protection Function

	CURRENT TO TRIP						DURATION TO TRIP					
	DESIGN VALUE	ADJUSTABLE RANGE	AS SET	TESTED			DESIGN VALUE	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip												

Syncronization Limits for Synchronous Generators

	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET
Frequency Difference	+ 0.2 Hz		
Voltage Difference	5%		
Phase Difference	10° (degrees)		

Phase and Ground Fault Protection

	MAXIMUM CURRENT OR VOLTS TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Phase Current							200 ms					
Neutral Current							200 ms					

Transfer Trip Protection

	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET
Generator Lockout	0.6 seconds		
Fail Safe Lockout	6 seconds		

Test Certification and Historical Data

Type Of Test	**Original Commissioning Test**		**Protection System Re-Test**	

Date of Test

Utility Representative Title

IPP Owner Representative

Signature

IPP Owner Representative Title

Date

Signature

SCHEDULE "H"

JOINT OPERATING PROCEDURE

(Please see attached)

		DEPARTMENT:	INQUIRIES TO:	TOPIC:
yukon energy	**JOINT OPERATING PROCEDURE**	Operations	Guy Morgan, Director, Operations	IPP / AEY / YEC Operating Agreement
		ISSUED DATE:	**REVIEW DATE:**	**APPROVED BY:**
		May x, 2020	May 3, 2021	President & CEO

1.0 Purpose

1.1 This agreement defines the operating arrangement between the **536774 Yukon Inc. dba Solvest Inc.** (IPP), ATCO Electric Yukon (AEY) and Yukon Energy Corporation (YEC). This agreement defines the roles and responsibilities for each entity to allow the IPP to operate reliably and safely on the Yukon Power System (YPS).

2.0 General Information

2.1 Breaker Identification

Breaker	Description
Switch #1	Connection between the IPP and AEY distribution

2.2 Definitions

a) **Operating Authority** The organizational unit assigned responsibility for operating a portion of the electrical system.

- For YEC the SCC operator is the operating authority and is responsible for the system generation and security.
- For AEY the Supervisor of Operations is the operating authority and is responsible for the distribution system and security.
- For the IPP the Technical Coordinator is the operating authority of their generation and associated equipment.

b) **Operator in Charge (OIC)** The worker designated by the Operating Authority to coordinate control of the power system or portion thereof, in accordance with the requirements of established operating standards and procedures.

c) Power Systems Work Standards (PSWS) The standards that workers will utilize for establishing conditions on the power system that will, when combined with appropriate work standards, procedures and methods, provide a safe work area.

d) **Condition Guarantee (COG)** Formal assurance to another Operating Authority or Operator in Charge (OIC) that identified devices are in the position requested and will not change status until the device status request is formally released by the requestor.

e) **Point of Interconnection (POI)** The location on the electrical system at which responsibilities between Operating Authorities meet. The IPP Switch – S6359 is the interface point between IPP and AEY.

2.3 YEC Contact Information

- SCC (System Control Center) – phone (recorded lines) 393-5355 or 393-5324
- Mike Hannah (Leadhand SCC) 393-5399, cell 334-6759
- Myles O'Brien (Operation Coordinator) 393-5352
- Ed Peake (Manager Operations) 393-5383, cell 334-6586
- Guy Morgan (Director of Operations) 393-5366, cell 334-6904
- YEC Group Email – SCC@yec.yk.ca

AEY Contact Information

- Tony Badry - Supervisor of Operations 633-7057, cell 335-4002
- Matt Johnson – Operator in Charge 633-7009, cell 334-3145

Control Room Desk

- Dispatch 633-7022
- Brock Kelsch 334-7239

IPP Contact Information

- Brock Kelsch bkelsch@solvest.ca

2.4 Normal Operation

Under normal operating conditions the IPP will generate into the Yukon Power Grid. The breakers status under normal operating conditions are as follows.

Breaker	Status
Switch #1	Closed

3.0 Operating Procedures

3.1 Planned 5L645 (IPP to AEY) Isolation

5L645 isolation requires the minimum notification defined in section 5.1, except for emergency repairs. AEY will provide a condition guarantee on S6359 - Condition Guarantee will be issued in accordance with **Section 800** of the PSWS – **Operating Interface Points.**

3.2 Planned 5L645 (AEY to IPP) Isolation
5L645 isolation requires the minimum notification defined in section 5.2, except for emergency repairs. IPP will provide a condition guarantee on S6359 - Condition Guarantee will be issued in accordance with **Section 800** of the PSWS – **Operating Interface Points**

3.3 SCC Remote Monitoring
SCC will have visual indication of IPP breakers, PV status, and electrical measurement information from the IPP site.

4.0 Power Quality Requirements

4.1 IPP will operate IPP Facilities in accordance with the power quality requirements of YEC as set out in the System Interconnection Guidelines (Schedule D).

5.0 Operational Notification

5.1 IPP Planned Maintenance and Scheduling

To meet changing operating conditions and coordinate maintenance efforts, maintenance shutdowns by the IPP need to be communicated to SCC / ATCO OIC at least one week in advance for shutdowns of up to 12 hours and 30 days for shutdowns longer than 12 hours.

Planned changes in the availability and capacity of the onsite generation needs to be communicated to SCC / ATCO OIC at least 30 days in advance of such changes.

Unplanned availability should be conveyed as soon as possible.

The Parties will share annual shutdown/maintenance plans in February of each year and plan to minimize the impact on IPP generation potential by scheduling outages during off-peak generation months where practicable.

5.2 AEY Distribution Maintenance and Scheduling:

a) AEY performs annual line maintenance on the distribution lines, during which connection to the IPP may be curtailed or suspended. The duration of this annual maintenance can be up to 14 days per calendar year.

b) AEY will provide a minimum of 5 working days' notice of the start date and expected duration of work that will curtain or otherwise interrupt the supply of IPP generation to the YPS.

6.0 Loss of Supply Procedures

6.1 Loss of Supply - Short Term

In the event of a disturbance that results in the loss of the grid connection to the IPP the IPP generation will remain off-line until approval from AEY and YEC.

The following steps apply to resume IPP operation with Grid Electricity.

a) SCC will confirm the status of the breaker located at IPP site. If SCADA communications are down the switch status will be physically verified and reported to AEY before 5L645 will be energized.

Breaker	Expected Status
Switch #1	Open

b) The following switching sequence will be followed to re-energize L### and synchronize IPP back to grid supply.

Step	Switch Sequence	Operation
1	Confirm 5L645 Energized	IPP/AEY
2	Switch #1 Closed	IPP
3	IPP starts system	IPP/YEC

c) Once complete and with confirmation from SCC**,** IPP may proceed with the restarting of their operation. IPP Group will communicate to SCC once their system is back on line.

6.2 Loss of Supply - Long Term

In the event of a disturbance that results in the loss of the grid connection to the IPP the IPP generation will remain offline until approval from AEY and YEC.

a) SCC will confirm the status of the breaker located at IPP site. If SCADA communications are down the switch status will be physically verified and reported to AEY before 5L645 will be energized.

Breaker	Expected Status
Switch #1	Open

b) The following switching sequence will be followed to re-energize 5L645 and synchronize IPP back to grid supply.

Step	Switch Sequence	Operation
1	Confirm 5L645 Energized	IPP/AEY
2	Switch #1 Closed	IPP
3	IPP starts system	IPP/YEC

7.0 Revision and Approval

7.1 This Agreement comes into effect once it is signed by IPP, AEY and YEC.

7.2 This Agreement will remain in effect unless cancelled upon the mutual agreement of both Parties.

7.3 The Parties will provide 90 days' notice in writing of the intention to modify this Agreement.

7.4 The Agreement may be revised at any time if operational needs require and are mutually agreed to by all Parties. This agreement will be formally reviewed every two (2) years.

8.0 Appendices

8.1 ATCO Electric's Power System Work Standards

Approved by: _____
Guy Morgan
Yukon Energy Corporation

Approval Date: _____, 2020

Approved by: _____
Tony Badry
ATCO Electric Yukon

Approval Date: _____, 2020

Approved by: _____
Ben Power
536774 Yukon Inc. dba Solvest Inc.

Approval Date: _____, 2020

SCHEDULE "I"

DELIVERY TIME ADJUSTMENT TABLE

Seasonal Adjustment is subject to change.

Month	Seasonal Adjustment
January	100%
February	100%
March	100%
April	100%
May	100%
June	100%
July	100%
August	100%
September	100%
October	100%
November	100%
December	100%

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application 3-8**

TAB 3 - REVENUE REQUIREMENT

1 Labour expense is generally a function of the following factors:
2 **Labour Rates** – This includes factors such as base pay, benefit cost, annual increments
3 (performance increments, cost of living adjustments), etc.

QUESTION:

a) Please explain how performance increments are assessed and valued.

ANSWER:

(a)

Yukon Energy Corporation employs two employee groups: In Scope and Out of Scope.

Performance increments are applied to these groups according to their applicable agreement. In Scope employees' pay, performance and job evaluation are governed by the Collective Agreement between Yukon Energy Corporation and P.S.A.C. Y024 as well as Human Resource Policy HR-003 (excerpted below). Management and Professional employees' pay and performance are administered according to the agreement between Yukon Energy Corporation and Management and Professional Employees.

It is noted that both of these agreements expired December 31, 2019. The Union and Yukon Energy Corporation agreement will be going to Interest Arbitration on April 6 – 7, 2021 to facilitate ratification of the contract.

In Scope (Unionized employees)

Yukon Energy relies on an established procedure within its Collective Agreement to guide both the percentage and timing of performance increments. Article 14: Wage Administration is the established agreement for these increments.

At time of hire, management offers a salary within the wage band of the position evaluation, based on the individual's experience and time in the trade or industry they are

entering at Yukon Energy. Then, the Corporation stewards to the expectations of Article 14.02 (below) whereby an employee is advanced 3% in the wage range subject to satisfactory performance. Then, 3% increments are earned every six months, based on satisfactory performance, until the employee reaches the top of the pay band.

Once at the top of the pay band, an employee receives any yearly negotiated economic increase.

Additional increments can occur when:

- An employee is promoted (see Article 14:04)
- A position is re-evaluated (see Article 22)

Yukon Energy reviews the performance of all employees on a yearly basis.

Out of Scope (Management and Professional Employees)

YEC relies on an established procedure within its Management and Professionals Agreement to guide both the percentage and timing of performance increments. This is found in Section 9 and Section 10 of the Management and Professionals Agreement (excerpted below). Management and Professional Employees' performance is evaluated based on the level of performance in relation to performance objectives and job responsibilities.

Job Evaluation

In Scope

Yukon Energy relies on the procedures are set out in the collective agreement with respect to Job Evaluation. This procedure is stated in Article 22: Job Evaluation (below).

Out of Scope

Yukon Energy relies on Korn Ferry, an independent contractor, for the evaluation of all jobs. Yukon Energy participates in the salary benchmarking service provided by Korn Ferry whereby our jobs are compared against the market and our peers (utilities), adjusted

for our geographical location.
The Korn Ferry Hay Job Evaluation Method relies on these principles in determining a job profile:

- Know-How
  - Practical / technical knowledge
  - Planning, organizing and integrating (managerial) knowledge
  - Communicating and influencing skills
  - Scope of knowledge required and the depth of understanding needed for the job
- Problem Solving
  - Thinking environment – freedom to think
  - Thinking challenge – complexity of the problems encountered and the extent to which original thinking must be employed to reach decision
- Accountability
  - Freedom to act
  - Nature of impact
  - Magnitude of impact
- Working conditions
  - Physical demands
  - Mental pressures

Article 14
Wage Administration

14.01 New employees entering the service of the Corporation will be appropriately placed within the wage range at the discretion of the Corporation.

14.02 On the first of the month following successful completion of the probationary period, an employee will be advanced 3% in the wage range subject to satisfactory performance. Thereafter, 3% increments reflecting progression through the range will be semi-annually based on the employee's anniversary date, subject to satisfactory performance.

14.03 The Employer acknowledges the value and importance of timely performance evaluations, and further agrees to maintain a performance evaluation policy through the Joint Consultation Committee.

14.04 When a promotion occurs, the employee concerned shall be placed in that position within the new range which reflects an increase in wage which shall be no less than 3% in the range from which they were promoted up to the maximum of the new pay range.

14.05 If an employee is accepted under a posting for a lower level job or is transferred at their own request, they will be appropriately placed within the wage range for such job at the discretion of the Corporation.

14.06 An employee temporarily assigned, in writing, for a period of more than two (2) continuous working days to a position of higher classification shall, from the first day, be paid;

a) The minimum wage for the temporary position where that minimum is more than four percent (4%) above their present wage; or
b) Receive four percent (4%) where their wage or temporary assignment does not exceed the maximum of the range for the temporary position; or
c) Where the application of (b) above would provide for a temporary assignment which would exceed the maximum of the range for the temporary position, the employee would receive the maximum rate in the range for the temporary position.

Article 22
Job Evaluation

22.01 a) The parties agree the Job Evaluation Plan developed jointly and signed-off shall form part of the Collective Agreement.

b) The Employer agrees that any changes to the Plan factor or factor weightings shall be subject to agreement between the parties.

22.02 a) When new positions are established, an independent consultant trained in job evaluation and mutually agreed upon by both parties, shall evaluate the jobs and shall notify the parties thereof within fifteen working (15) days of the evaluation being completed.

b) When significant differences, or changes, in job content effect the existing job evaluation to the extent that the Union or an employee request that the job be re-evaluated, the following procedure shall be followed:

(i) An employee or the Union shall initiate a written request to HR for a job

to be re-evaluated within fifteen working (15) days of significant changes in job content arising.

(ii) An employee initiating a written request for re-evaluation must file a copy of the request with the Union.

(iii) An independent consultant trained in job evaluation and mutually agreed upon by both parties shall complete the re-evaluation as soon as possible but not later than ninety (90) working days upon receipt of the written request for review.

(iv) HR shall notify the Union and the employee of the results of the re-evaluation and provide a copy of the evaluation within fifteen (15) working days of the completion of any evaluation.

(v) If the re-evaluation results in a higher pay level, it shall be retroactive to the date that HR received the written request for review.

(vi) If the re-evaluation results in a lower pay level, the employee shall retain their current rate of pay and any adjustments negotiated by the parties for as long as they remain in that position.

c) When significant differences or changes, in job content affect the existing job evaluation to the extent that the Employer requests that the job be re-evaluated, the following procedure shall be followed:

(i) The Employer shall initiate a request for re-evaluation within fifteen (15) working days of the significant changes in job content arising.

(ii) The Employer shall notify the Union of the initiation of the review.

(iii) An independent consultant trained in job evaluation and mutually agreed upon by both parties shall complete the re-evaluation as soon as possible but not later than ninety (90) working days upon receipt of the written request for review.

(iv) HR shall notify the Union and the employee of the results and provide a copy of the evaluation within fifteen (15) working days of the completion of any evaluation.

(v) If the re-evaluation results in a higher pay level, it shall be retroactive to the date the Employer initiated the request for re-evaluation.

(vi) If the re-evaluation results in a lower pay level, the employee shall retain their current rate of pay and any adjustments negotiated by the parties for as long as they remain in that position.

d) Where an employee and the Union are not satisfied with the independent consultant's evaluation decision, and the Union agrees to represent the employee, the Union may refer the independent consultant's decision to arbitration by letter within thirty (30) working days of receipt of the re-evaluation decision. The letter shall state the matter sought to be arbitrated and the names of proposed arbitrators. The Corporation shall, within thirty (30) days of the receipt of such letter notify the first party in writing of the acceptance of one of the arbitrators named or propose others. The Corporation also has the right to appeal under this process.

e) An independent Arbitrator trained in job evaluation, mutually agreed upon by both parties, will hear appeals of the independent consultant's decisions within one hundred and twenty (120) working days or at the earliest mutually agreed upon date by both parties. A decision of the Arbitrator is final and binding. Each party shall pay one half (1/2) of the fees and expenses of the Arbitrator.

f) The Union may withdraw the appeal from the arbitration process at any time.

g) Unless the parties agree otherwise, the time lines in this article are mandatory.

Human Resource Policy HR-003

1.1 Performance management is intended to be an ongoing process of communication between the immediate supervisor and the employee, focused on helping the employee achieve their best workplace results. An effective performance management system accomplished the following goals:

- Provides direction and clarifies performance expectations;
- Provides feedback and coaching to employees concerning job performance, identifying both what is being done well and what needs improvement;
- Identifies training and professional development needs;
- Documents performance; and
- Substantiates performance increments.

2.0 Policy Guidelines

2.1 Yukon Energy supports a performance management system that should include the four components listed below:

1) Performance Planning:

Clear performance expectations should be communicated to the employee. These expectations should provide the employee with a clear understanding of what is required for the employee to successfully fulfill job responsibilities. These expectations should also help the employee align individual goals and objectives with those of the department and Yukon Energy.

2) Coaching:
Coaching employees for improved performance is an integral part of performance management. Coaching should occur on a regular basis and may take various forms, from observation and informal direction to formal meetings and written documentation.

3) Multiple Sources of Feedback:
To increase the potential for improvement, in some cases, it may be helpful to receive feedback from customers, peers, and direct reports.

4) Performance Review:
This is the culminating communication of the performance cycle, focusing on areas of achievement, areas for improvement and goals for the future.

3.0 Performance Review Guidelines

3.1 All probationary employees should have their performance reviewed with them prior to the final thirty (30) days of the probation period.

3.2 All employees should have their performance reviewed with them semi-annually, based on their anniversary date if there is room for an increment in the salary range for their position. All other employees should have their performance reviewed at least once a year.

3.3 Performance Reviews should have the following characteristics:

- Results Oriented – Goals should specify an end result to be accomplished. For goals to be evaluated there must be a clear understanding of what is to be achieved.
- Measurable – Goals should contain appropriate measurement criteria such as quantity, quality, time or cost. These criteria are necessary for the monitoring of progress toward or accomplishment of the goals. Where the goals cannot be measured in quantitative terms, there should be a statement specifying what constitutes acceptable performance.
- Clear and Concise – Goals should be written so as to eliminate misunderstanding between the employee and the supervisor. The commitment to action is basic to the formulation of goals and therefore, the expectation should be prefaced with an action verb whenever possible.
- Timeframe – Goals should specify a target date for completion.

- Realistic – Goals should take into account both the abilities and competence of the employee, and the goals of the department.

3.4 Performance review forms should be discussed and signed by both the supervisor and employee. An employee's signature indicates only that the form has been reviewed and discussed with them. It does not imply agreement with the review.

3.5 Employees submitting concerns relating to their performance review will receive a written response from their supervisor in a timely manner. A copy of the employee's concerns and the supervisor's response will be placed on the employee's personnel file.

3.6 The original performance review must be forwarded to Human Resources and placed on employees' personnel file. Employees should receive a copy of the form, and other copies should be retained at the supervisory level.

3.7 Human Resources will process authorized performance increments in accordance with the terms set out in the collective agreement.

Management and Professional's Agreement

Section 9
Performance Reviews

9.1 The Corporation recognizes that performance reviews provide feedback to employees on their job performance and assists them in becoming more effective in their jobs.

9.2 Performance reviews will be conducted at least once each year. Completed performance reviews will be retained in the employee's personnel file.

Section10
Performance Increments

10.1 Following the successful completion of the probationary period and on January 1st of each year thereafter, the employee may be awarded a performance increment based on the supervisor's assessment of their performance during the previous year, up to the maximum of their salary range. When an employee has received a performance increment following their probation, and that increment occurs at any time other than January 1st, the performance increment on the following January 1st will be prorated to reflect the number of months since the last increase.

10.2 Performance increments for Management & Professional employees will be based on the level of performance in relation to performance objectives and job responsibilities. The annual increment will not exceed 9% of current salary and will be guided by the following table. The maximum of the salary range applicable to the position shall not be exceeded.

Rating	% Performance Reward
Unacceptable	0%
Needs Development	0%
Meets Expectations	1% - 3%
Occasionally Exceeds Expectations	4% - 6%
Consistently Exceeds Expectations	7% - 9%

10.3 An employee who is rated as “Unacceptable” or “Needs development” is expected to improve their performance. The employee’s supervisor along with the employee will create an appropriate development plan to assist the employee with improving their performance. Unacceptable performance will not be permitted to continue and appropriate steps up to and including termination will be taken.

10.4 The completed performance review and recommended salary adjustment must be approved by the President & CEO prior to communication to the employee by the immediate supervisor.

10.5 Performance increments will be rolled into base salary.

Collective Agreement between Yukon Energy and P.S.A.C. Y024 - Article 14: Wage Administration.

- Collective Agreement between Yukon Energy and P.S.A.C. Y024 - Article 14: Job Evaluation
- Management and Professionals’ Agreement Section 9
- Management and Professionals’ Agreement Section 10
- Yukon Energy Human Resource Policy HR-03

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application 3-8**

Head Count – This relates to the number of full time equivalent positions. The Yukon Energy employee complement is shown in Table 3.4.
Of the total labour expense increase from 2018 approved, approximately $0.882 million relates to additional headcount and $0.740 million relates to labour rate increases. The balance is made up of other factors impacting labour costs such as changes in overtime, vacancies and capital allocation.

QUESTION:

a) Since labour head count costs are proposed to increase more than $1.6 million, explain.

ANSWER:

(a)

Breakdowns of expenditures for all labour forecast costs are provided in the Application, starting at section 3.3.2 (page 3-13) through 3.3.8 (page 3-20). Reasons for the increase are provided in the Application at Section 3.3.1.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application 3-8**

Table 3.4:
Employee Complement History 2018Approved Actual2018 Actual2019 Forecast 2020 Proposed2021

President	4.16	5 .14	4.82	4.01	4.16
First Nation Relations - - - -				1.00	
Communications, Cust. Acctg.	1.00	1 .00	1.00	3.10	4.60
Human Resources & Info. Mgmt.	5.25	5 .27	5.34	5.32	5.25
Resource Planning and Environment	5.00	5 .00	5.75	5.51	7.05
Finance, Cust. Acctg. & Purchasing	16.79	1 6.89	17.24	13.54	14.79
Operations	44.50	4 6.58	47.12	48.75	49.25
Engineering Services	15.00	1 3.03	15.16 1	5.63	15.50
Health, Safety & Environment	2.00	2 .00	2.00	2.00	2.00
Total	93.70	94.91	98.44	9 7.86	103.60

Note:
1. The employee complement numbers are net of allocation to YDC.
2. Customer Accounting was transferred from Finance to Communications in 2020.
Table 3.4 shows that the total position count is forecast to increase by 9.90 positions since 2018 approved to 2021 test year.

QUESTION:

a) Why are Approved 2018 compliments different from Actual 2018?

b) Explain what positions make up the four employee complement with job description in the presidents office.

c) Explain why the vice president cannot do the job of FN relations?

d) What exactly is the VP job description?

e) Explain the 3.6 positions added in communications, customer Acctg.

f) Explain the 2 positions added in resource planning and environment.

g) Explain why environment is in two locations in this above chart.

h) Provide a chart giving each of the YEC positions (management and non-management) pay grade/scale and performance bonus.

i) Explain how each of these compare with other utilities in Canada.

ANSWER:

(a)

Approved 2018 compliments are what was approved by the YUB for rate-setting purposes. Actual 2018 compliments represent what YEC required operationally.

(b)

The employee complement of the President category consists of the following:

- **President and Chief Executive Officer -** The President and CEO has the authority, and is accountable to the Board of Directors, for the Yukon Energy Corporation's achievement of corporate goals and objectives within the established authority delegated by the Board. This includes providing leadership and direction regarding the following daily organizational activities of the Yukon Energy Corporation to ensure the achievement of reasonable organizational results, benefits and cost effectiveness within the established corporate goals, objectives and priorities; and to ensure the avoidance of unacceptable conditions and actions.

- **Vice-President, Business and Corporate Development -** In conjunction with the President, liaises with key stakeholders to promote positive relationships and strong partnerships for the benefit of the corporation. Ensures that the Human Resources, IT, Health and Safety and Communications departments corporate objectives are met and in line with Yukon Energy's mission and vision. Contributes in the development of corporate goals, business plans, and strategies to ensure the effective planning and delivery of programs and services to achieve the Corporate mandate Contributes to the vision, mission and values of Yukon Energy through responsible, accountable and effective work performance. As a key

member of the senior management team is accountable for overall organizational performance.

- **Corporate Secretary -** This position provides executive support to Yukon Energy's Board of Directors (Board), the President and CEO (President) and the Sr. Management Team, and is responsible preparation of board meetings including the drafting of agendas, resolutions, and board material as well as the drafting of board and committee minutes in accordance with Yukon Energy's policies, guidelines and procedures. The position is responsible for all Access to Information and Protection of Privacy (ATIPP) matters on behalf of the corporation.

- **Records Management Analyst -** Performs a range of records management activities for the Corporation. Maintains and controls the use, protection and disposition of corporate records and information and provides library support services in accordance with Yukon Energy's policies, guidelines and procedures.

(c) and **(d)**

The questions are unclear; each department at YEC has a vice president as the department head. The question is not clear which vice president is being referred to.

(e)

The explanation for the 3.6 positions added in Communications, Customer Billing/Accounting is provided in the Application under the heading Communications, Customer Billing/Accounting on page 3-10.

(f)

The explanation for the 2.0 positions added in Resource Planning and Environment is provided in the Application under the heading Resource Planning and Environment starting on page 3-10.

(g)

For the years provided in Table 3.4, there are no Environmental employees allocated to the Health & Safety department. Therefore, it would be more appropriate for the department labelled “Health, Safety & Environment’ to be changed to “Health & Safety”.

(h)

Please see the Table below.

Table 1: Union Pay Grants (2019)

2019 Rates	Steps	1	2	3	4	5	6
Level	Hourly Min	0.5 Year	1 Year	1.5 Year	2 Year	2.5 Year	3 Year
Level 1	14.47	14.91	15.35	15.82	16.30	16.78	17.29
Level 2	16.74	17.25	17.77	18.30	18.84	19.41	19.99
Level 3	19.24	19.83	20.42	21.02	21.65	22.31	22.98
Level 4	22.30	22.97	23.65	24.36	25.09	25.84	26.61
Level 5	25.77	26.53	27.34	28.15	29.00	29.87	30.76
Level 6	29.74	30.64	31.57	32.52	33.49	34.49	35.52
Level 7	34.53	35.57	36.63	37.73	38.86	40.02	41.23
Level 8	40.11	41.31	42.55	43.82	45.15	46.49	47.89
Level 9	44.05	45.38	46.75	48.14	49.59	51.08	52.61
Level 10	46.34	47.73	49.16	50.64	52.17	53.73	55.35
Level 11	48.98	50.45	51.95	53.52	55.12	56.78	58.49

* Annual Economic Increase 2.0%.
* Performance Increase 3% up to max of pay grade.

(i)

YEC does not have (management and non-management) pay grade/scale and performance bonus information of other utilities in Canada to provide.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application**

SUPPORTING DOCUMENTS PAGE 3-9
TAB 3 - REVENUE REQUIREMENT
At the historic staff level, 1 employees were finding it difficult to keep pace with increased demands, more 2 so as additional assets are added and increasing burden for planning and executing capital works.

QUESTION:

a) Please identify any/each consultant/contract hiring and cost amounts for planning and executing capital works.

ANSWER:

(a)

The request is unreasonably broad. 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.

TOPIC: Revenue Requirement Requests

REFERENCE: November 2020 Application

SUPPORTING DOCUMENTS PAGE 3-9
TAB 3 - REVENUE REQUIREMENT

6 There are a number of corporate factors that directly affect employee complement:
7 * Increasing assets;
8 * Strategic importance of improving First Nation and public engagement, relationships and
9 communications;
10 Steady growth in customer accounts;
11 Increased planning requirements for projects recommended through the 2020 Ten Year
12 Renewable Electricity Plan; and
13 Continuing high capital demands to maintain existing aging assets.
14 To combat the above issues, YEC is forecasting an increased employee complement. The increase in
15 employee complement has resulted in a significant decrease in forecast overtime costs for 2021. Also, the
16 increased employee complement in 2019 through 2021 is due to an effort, where possible, to do more
17 work internally as opposed to hiring outside consultants and contractors. YEC has made a conscience
18 effort to limit increases to only those areas where required as reviewed below.

QUESTION:

a) Please identify the decrease in actual and forecast overtime costs for each of the years since 2018.

b) Please identify all cost savings for doing work internally as opposed to hiring outside consultants and contractors.

ANSWER:

(a)

YEC did not state that overtime costs decreased for each of the years since 2018; YEC stated “the increase in employee complement has resulted in a significant decrease in forecast overtime costs for 2021. For details of overtime costs, see CW-YEC-1-14 (b).

(b)

It is not possible to identify all cost savings for doing work internally as opposed to hiring outside consultants or contractors. As indicated in the Application, some new positions are being created to help reduce external costs in 2021 and the future such as those mentioned for Operations and Engineering. In reality, almost all work could be outsourced so all labour costs contribute to reduced outside consultants or contractors.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application Tab 3**

3.3.6 Administration

As shown in Table 3.9, Administration expense is forecast to increase $1.640 million (18%) in 2021 over 2018 approved primarily due to increase in labour costs by $0.783 million (13%) in 2021 over 2018 approved reflecting labour cost changes as well as functional changes noted in section 3.3.1. Non-labour costs are forecast to increase $0.856 million (29%) in 2021 over 2018 approved.

Table 3.9:12 Administration ($000) 2018Approved Actual2018 Actual2019 Forecast 2020 Existing 2021 Proposed 2021

Labour	$ 5,916	$ 5,949	$ 5,835	$ 6,113	$ 6,699	$ 6,699
Resource Planning	48	48	29	174	84	84
Communications	130	126	129	125	155	155
Customer Accounting	225	208	244	206	240	240
Environmental Mgmt	238	184	197	259	535	535
General	662	688	742	620	790	790
Information Systems	645	555	771	803	741	741
Fish Hatchery	168	158	169	200	210	210
Safety	182	210	168	168	226	226
Training	175	173	131	124	200	200
Recruitment	229	245	379	323	255	255
Board of Directors	182	246	280	274	252	252
Union	20	119	60	148	90	90
Regulatory Affairs	33	26	11	15	20	20
Material Management	37	9	31	32	32	32
Contracting	12	5	7	12	12	12
Professional Development	15	15	17	7	15	15
Total Administration	$ 8,917	$ 8,966	$ 9,201	$ 9,603	$ 10,557	$ 10,557

The increase in Administration costs 1 reflect ongoing cost pressusre [sic] related to recruitment, training, safety and other cost categories, including: Environmental Management expenses are forecast to increase by $0.297 million (124%) in 2021 over 2018 approved due to increased environmental monitoring activities associated with the new 3 year water license of the Aishihik Generating Station.

General administration expenses are forecast to increase by $0.129 million (19%) in 2021 over 2018 approved primarily due to new licenses required for the new asset management software.

Information Systems expenses are forecast to increase by $0.096 million (15%) in 2021 over 2018 approved due to increased costs for data circuits.

Union expenses are forecast to increase by $0.070 million (350%) in 2021 over 2018 approved but is $0.029 less than 2018 actual. Fluctuations in Union expenses are due to cyclical renegotiation of the Collective Bargaining Agreement, which expired December 31, 2019.

Board of Directors expenses are forecast to increase by $0.069 million (38%) in 2021 over 2018 approved due to additional training and increased meeting costs, as reflected in 2018 actuals.

QUESTION:

a) Please explain what is meant by administration labour costs and breakdown the cost for each of these admin labour costs.

b) Was/were outside consultants hired for resource planning. If so, please name the contractor/s and provide costs?

c) Was/were outside consultants hired for environmental management. If so, please name the contractor/s and provide costs.

d) Breakdown general administration expenses with costs.

e) Provide each new license required and final costs for the new asset management software.

f) Explain what function the communications have and how they are cost/accounted.

g) Explain what material management is and how it is cost/accounted.

h) Explain how you know you will need new data circuits until need?

i) If you do not have to purchase any/some of new circuit boards how will this discrepancy be accounted?

ANSWER:

(a)

Administration labour costs means the cost of YEC employees to perform work categorized as Administration. A breakdown of Administration labour costs forecast for 2021 is provided in the table below:

	($M)
Engineering Services	$ 1.008
Board of Directors	0.083
President's Office	0.899
Corporate Communications	0.125
Corporate Services	0.193
Customer Billing	0.318
Environment	0.202
Finance & Regulatory Affairs	1.267
Health & Safety	0.317
Human Resources	0.304
Information Technology	0.662
Materials Management	0.264
Procurement	0.583
Resource Planning	0.473
	$ 6.699

(b)

In 2020, the Resource Planning department spent $90,000 on outside consultants (Sussex Group).

(c)

In 2020, the Environmental department spent $176,000 on outside consultants, including $113,000 paid to Environmental Dynamics, $25,000 paid to Canadian Wildlife Federation and $20,000 paid to Hemmera Envirochem.

(d)

Below is a breakdown of general Administration costs forecast for 2021:

	($M)
Engineering Services	$ 0.287
President's Office	0.109
Corporate Services	0.136
Finance & Regulatory Affairs	0.258
	$ 0.790

(e)

Forecast 2021 license cost relating to the new asset management software is $0.108 million. The $0.108 million can be broken down as follows:

- $0.093 million for annual vendor support and software upkeep.
- $0.015 million for User Acceptance Platform software. This software is used for training and testing; it is used to test scenarios and to train others through a view and walkthrough process, and will also support onboarding of new employees in the future.

(f)

See also the response to YUB-YEC-1-39(g). The function includes the following activities:

- **Corporate/ strategic communications** - includes activities to build and protect Yukon Energy's corporate reputation;
- **Engagement** - includes providing communications support and direction on all Yukon Energy major capital projects; and
- **Leading the customer service team** - includes directly supervising Yukon Energy's Customer Service Team in Dawson City, and managing Yukon Energy customer accounting and billing function.

Costs are accounted for in accordance with International Financial Reporting Standards.

(g)

Materials Management represents costs to operate the inventory at the warehouse in Kulan Industrial Park in Whitehorse. Operations include supply chain management, receipt, stocking and issuance of materials to O&M and capital jobs throughout the YEC franchise area. Material management[1] also indirectly supports materials warehousing in the communities of Faro, Mayo and Dawson. Costs to manage the warehouse include materials, contractors (e.g. snow removal) and utilities. Costs are accounted for in accordance with International Financial Reporting Standards.

[1] Note currently "materials" relates almost exclusively to transmission and distribution line poles, wire, transformers and hardware.

(h)

Data circuits are required primarily for SCADA (system Control and Data Acquisition), Corporate applications, grid protection (Remedial Action Scheme), Revenue Metering and voice services. The number of devices and the volume of data moving over the network is driven by new assets, locations and services. Communications requirements are a common element. This necessitates additional data circuits as the service provider (Northwestel) does not offer bulk (dark fiber) communications service.

(i)

The circuits are purchased in response to growing needs in volume and speed of data. The data circuits are a service paid monthly (not hardware or an asset) and are a growing O&M line item. Communications requirements are assessed on a long term basis to standardize technology and make the best capital investments possible to support current and future needs. Communications are also assessed on a case-by-case basis in response to equipment or facility upgrades or new capital projects.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application, Table 3.13:**

5 **Mid-Year Net Rate Base6 ($000)**
Approved 2018 Actual 2018 Actual 2019 Forecast 2020 Existing 2021 Proposed 2021
Year-End:
Net plant in service1 $ 278,702 $ 287,713 $ 293,199 $ 303,158 $ 323,642 $ 322,649
Mid-Year:
Net plant in service
Before contributions $ 445,367 $ 449,441 $ 458,678 $ 475,781 $ 498,719 $ 498,223
Less contributions 167,112 166,677 168,222 177,603 185,319 185,319
Net plant in service 278,255 282,764 290,456 298,178 313,400 312,904
Mid-year regulatory deferral2 3,879 3,805 3,009 2,484 2,732 2,732
Working capital 5,344 5,617 5,935 6,592 6,985 7,141
Net Rate Base $ 287,478 $ 292,186 $ 299,399 $ 307,255 $ 323,117 $ 322,777
Notes:
2 This reflects the regulatory deferred costs, excluding DSM and the balance of the hearing reserve account.
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.
Forecast
8 Yukon Energy's 2021 mid-year forecast rate base in this Application is $322.777 million (an increase of
9 $35.3 million or 12% from 2018 approved mid-year rate base of $287.5 million).

QUESTION:

a) Is this proposed $35.3 million increase in rate base since the last GRA only for plants that are now providing a service?

b) If no, identify cost amounts separating plants now providing a service from other costs not providing a service.

c) Explain what mid-year regulatory deferral means.

d) Please provide a chart identifying the approved rate base for each GRA year since 1998.

e) Identify and explain each separate contribution donor and amount for all years in chart.

f) Explain why 2018 actual rate base is different from 2018 approved?

g) Explain why difference between existing 2021 and proposed 2021?

h) Since $11.861M 2019 increase, $7.856 M 2020 increase, $35.3M increase in rate base since 2018 approved, identify amounts for each year already approved. Identify where and when these were approved.

ANSWER:

(a) and **(b)**

$35.3 million is the increase in mid-year rate base in 2021 test year over 2018 test year. This includes increase in property, plant and equipment [in-service or forecast to be in-service by end of 2021], closed deferred project costs as well as provision for working capital requirements. Please see Schedule 1 in Tab 7 for details.

(c)

The mid-year balance of regulatory deferred projects [e.g., Resource Plan, IFRS transition costs, etc.].

(d)

This question is unclear as to what chart is being requested, as well as to any relevance to the current 2021 GRA of charting approved revenue requirements for prior years going back to 1998. Accordingly, YEC has not provided the requested information.

(e)

As indicated in the Table, the amounts are mid-year balances, so they are not the actual amount of contributions received in the year. Also as indicated in the Table, the amounts are for assets in-service, so the Table does not include contributions received for assets that remain as work in progress. Finally, as these amounts are asset in-service, they include amortization of the contributions. The Table represents the balance of all current and historical contributions at their net book value. New contributions since 2018 include $11.5 million from VGC Group to fund McQuesten Substation and system improvement

capital costs. YEC is also forecasting $23.7 million in 2020 and 2021 from the Federal government for the Mayo to McQuesten Transmission Line.

(f)

Actual vs approved rate base for 2018 simply reflects the extent that actual numbers varied from the forecast approved by the Board.

(g)

Existing vs proposed for 2021 mainly reflects the impact of adjusted depreciation rates. See working capital tables in Tab 7 for review of adjustments to this element.

(h)

The Application focuses on changes to rate base and identifies specific capital, deferred and other rate base cost changes for review and approval. YEC is not able to respond to the question as it seeks a broad review as to all costs approved in the past that would require considerable effort to address without providing any assistance to the 2021 GRA approvals sought in this application.

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application, Appendix 3.1 2017-19 KPI Report:**

Generation Source
Hydro 441,048 413,052 370,819
% of Total 96.8% 91.7% 84.1%
Diesel 4,618 7,186 3,793
% of Total 1.0% 1.6% 0.9%
LNG 9,856 30,130 66,065
% of Total 2.2% 6.7% 15.0%
Wind 32.582 0 0
% of Total 0.0% 0.0% 0.0%

QUESTION:

a) Is the LNG still classed as back-up with this amount of usage? Explain.

b) How much is wind expected to replace diesel and LNG in 2021?

c) Identify how each SAIDI,SAIFI and CADI compare to Fortis BC (Electric) in 2019.

ANSWER:

(a)

Yes; LNG is available to support grid load under unusual circumstances, e.g., low water, cold temperature, loss of renewable generation. The high loads in 2018 and 2019 are examples of higher generation due to low reservoir conditions.

(b)

No wind generation is forecast for 2021 as shown in Table 2.2.

(c)

YEC was not able to find CAIDI for Fortis (BC). Other stats are below:

	SAIFI	SAIDI	CAIDI
Yukon Energy	12.39	6.88	0.56
Fortis BC	1.21	2.45	Not reported

1

TOPIC: **Revenue Requirement Requests**

REFERENCE: **November 2020 Application, Return on Common Equity Tab 3-27**

Risk Premium Adder for YEC: Order 2018-10 established a 45 basis point risk premium for YEC over the BCUC benchmark ROE. A 45 basis point risk premium for YEC was considered to be fair and reasonable based on: (1) recognition of small size and principles established for AEY in Order 2017-01;7 and (2) recognition of YEC risk related to generation, isolated grid, and customer diversity.8 As noted in Tab 8, there are no new issues or material changes in circumstance at this time that would alter the basis for approving a risk premium of 45 basis points for Yukon Energy

QUESTION:

a) Does Fortis BC (Electric) borrow the majority of its' money/debt from a government mother corporation?

b) Does Fortis BC (Electric) receive federal and provincial contributions for various programs? Explain.

c) Does Fortis BC (Electric) have a rider or mechanism for Fuel price changes, a Low Water Reserve Fund/ similar mechanism, or any other mechanism for stabilizing rates?

d) Identify the gross margin for YEC in 2019 and 2020.

e) Identify the earnings before interest, taxes and amortization for YEC in 2019 and 2020.

f) Compare the numbers in 113 [d] and 114 [e] for the YEC to those of Fortis BC (Electric).

ANSWER:

(a) through **(f)**

Tab 8 of the GRA Application provides information relevant to the Board's assessment of comparative ROE risk for YEC and Fortis BC (Electric). The GRA also provides detailed

reporting on YEC's actual earnings in 2019 and forecast earnings in 2020, summarized as regards ROE in Table 1-1. The comparative risks of YEC and Fortis BC (Electric) (FBC) were extensively reviewed during the 2017-18 YEC GRA proceedings, with follow up questions on YEC Undertakings [YUB-YEC-3-5] providing additional detail related to FBC's power supply context and arrangements with BC Hydro and information showing that the context for FBC is very different and less risky than YEC. The power supply context for FBC was also reviewed in the 2017-18 GRA Undertaking #38 and Undertaking #39 as well as the following follow-up questions on YEC Undertakings: YUB-YEC-3-3,[1] YUB-YEC-3-4,[2] and YUB-YEC-3-6.[3] In summary, it has been well documented in YEC proceedings that FBC is not on an isolated grid, and is not exposed to the same thermal cost risks that YEC is exposed to given that FBC has access to renewable generation resource options available on BC's integrated grid system.

Additional information requested by UCG in this information request will not change the assessments already provided, or assist the Board in this proceeding.

[1] Reviews the Power Purchase Expense Variance Deferral Account [PPEVDA] and clarifies that the relevant provisions continue to operate in non-test years. The response notes that the account was discontinued by Decision G-138-14, but that per the Decision, the expenses and revenues related to the PPEVDA would continue to be flowed through to ratepayers each year through the annual flow-through mechanism.

[2] In addressing variances due to water variability for FBC, it is necessary to understand the context of FBC's hydro power supply arrangements with BC Hydro, the BCUC-approved cost flow through mechanisms and the extent that these arrangements collectively remove risk from FBC related to water variability cost impacts.

[3] Notes that FBC is not exposed to water risks that would merit or require a specific and separate deferral or contingency account mechanism similar to the DCF. Accordingly, the absence of a specific FBC deferral account similar to the DCF is of no importance when comparing risks for FBC relative to YEC.

TOPIC: **Capital Projects**

REFERENCE: **November 2020 Application, p. 5-1**

21 Total spending on PP&E projects in the 2021 test year as shown in Table 5.1 totals $61.767 million, with
22 91% of this spending in major projects over $1 million ($56.266 million) and 48% ($29.801 million, Table
23 5.2-1) included in 2021 rate base. Total PP&E spending was $21.300 million in 2018, $31.154 million in
24 2019, and is forecast at $36.171 million in 2020. Overall, PP&E transfers to rate base since the end of
25 2018 approximate $92 million. Contributions transferred to rate base to offset some of these
26 expenditures since the end of 2018 approximate $37 million (Table 5.1).
27 Deferred cost capital spending (including Work in Progress [WIP] and after contributions) was $4.3
28 million in 2018 (Table 5.3), $3.7 million in 2019 (Table 5.4), and is forecast at $5.4 million in 2020 (Table
29 5.5) and $10.5 million in 2021 (Table 5.6). The current GRA results in approximately $7.4 million of
1 Deferred costs being brought into rate base in the current GRA (including relevant test year spending and
2 before transfers to the Hearing Reserve Account), with approximately $1.5 million for 2019, $4.0 million
3 for 2020, and $1.9 million for 2021.
4 Actual and forecast intangible asset spending (including WIP) over 2018 to 2021 is $6.062 million, all of
5 which is forecast to be brought into rate base by 2021, as illustrated in Table 5.7

QUESTION:

a) Are PP&E spending for 2018, 2019 and 2020 assumed approved or will they have to wait the outcome of this hearing?

b) Do the PP&E requested transfers to rate base since the end of 2018 approximate $92 million include the 2021 test year? Explain.

c) Are total deferred capital costs for 2018, 2019 and 2020 assumed approved or will they have to wait the outcome of this hearing?

d) If only $7.4 million of deferred capital costs requested into rate base, would the remaining $7.5 million go into WIP? Explain.

e) Provide a table identifying (PP&E, deferred and intangible) approved capital costs that were placed into rate base for each GRA year since 1990, including requested 2021 amounts.

ANSWER:

(a) and **(c)**

The GRA provides PP&E, deferred cost and other cost forecasts for the Board's approval of the revenue requirement used to determine changes to rates.

(b)

The $92 million includes transfers to rate base (actual or forecast) for 2019, 2020 and 2021 as documented in Table 5.1.

(d)

The referenced information indicates $19.6 million of (actual or forecast) deferred cost capital spending (including WIP, and net of contributions) for 2019, 2020 and 2021 with approximately $7.4 million being brought into rate base. The balance of $12.2 million would remain in WIP.

(e)

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.

TOPIC: **Capital Projects**

REFERENCE: **November 2020 Application,5-1 Capital Projects**

2 Capital project investments in rate base are generally grouped in one of three categories: capital works
3 on property, plant and equipment; deferred cost studies (including new supply and other feasibility
4 studies, studies required by regulation or relicensing and dam safety works); and intangible assets.

QUESTION:

a) Provide all related stages a capital project undergoes from concept planning to a plant in use. Include all regulatory stages as well.

b) Identify how each stage cost is accounted for.

c) Provide a table/chart demonstrating stages for each capital project greater than $1 million applied for in this application rate base[1] since 2017/18 approved. On this chart for each stage, identify all consultant firm/s name and cost, all contract firm name and cost, all in-house costs with reason, a total of each stage cost. Provide and identify all contributions amounts (government, mining, others) for each stage.

d) Identify any cost overruns and amounts for each stage of each project in #8 above.

ANSWER:

(a)

YEC follows a stagegate process. Depending on the complexity of the project, multiple gates may be initiated. Each stage has deliverables, timelines and responsibilities assigned as well as an estimated cost to reach the next stagegate. Upon successful completion of deliverables through each gate, a final project charter is drafted which encompasses the construction aspect of the project and is approved by Sr Management

[1] Capital Projects > $1 million to include: LNG 3rd.Turbine; N-1 Capacity Shortage Whitehorse site; N-1 Capacity Shortage Faro site; Mayo to McQuesten Transmission Line; McQeusten Sub-Station; Transmission Line Refurbishment; Transmission Line 178 Refurbishment; Breaker Replacement Program; Replace P125 Headgate; WH2 Uprate; WH4Upr.

as well as the Board of Directors. The project is executed and when completed is transitioned to Operations for operation and maintenance.

Regulatory tasks may or may not have separate stagegates. They are typically combined with other deliverables within a gate however treated like any other deliverable such that should the regulatory task not be completed, the project will not pass through the associated gate.

(b)

Costs for each stagegate are tracked separately and are included in the total project cost upon completion.

(c) and **(d)**

The detailed information requested cannot be reasonably provided in the time available. Information regarding project costs breakdowns for major capital projects is provided in a number of information requests, including the response to YUB-YEC-1-49.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

21 **LNG Third Engine/ Critical Spares** – actual cost of approximately $8.261 million,
22 completed and in service in 2018, but not included in rate base approved in 2017/18
23 GRA.

REFERENCE: June 22, 2017 Application, page 5-26

LNG Third Engine ($6.2 million)

QUESTION:

a) Is $8.261million actual cost or approximate cost?

b) Exactly what was the projected cost for this project from the 2017/18 GRA.

c) If different from the above $8.261 million, explain cost overruns.

ANSWER:

(a) to **(c)**

As noted in Tab 5, Section 5.2.1.1 the project was completed and in service in 2018. Page 5-6 of the GRA specifically notes, “the project was completed on schedule with total actual project costs for the LNG Third Engine of $8.261 million. This was below the 2017/18 forecast budget of $8.9 million.”

TOPIC: Capital Projects

REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

1 5.2.1.2 N-1 Capacity Shortage Thermal Rental Site Infrastructure
2 N-1 Capacity Shortage Whitehorse Thermal Rental Site Infrastructure6 ($0.227 million in
3 WIP at end of 2018 and $1.070 million in 2019)
4 The 2016 Resource Plan identified a dependable capacity shortfall for the Yukon Integrated System under
5 its single contingency (N-1) capacity reliability criterion that approximated 6 MW in 2017, increasing to
6 10-11 MW by 2019. Yukon Energy is required to provide sufficient dependable winter capacity to meet
7 the single contingency capacity reliability criterion, i.e., there is no acceptable "do nothing" option given
8 the need to maintain reliable service and to address an ongoing and growing dependable capacity
9 shortfall.
10 The project involved the design of infrastructure to accommodate temporary rented thermal generators
11 at Whitehorse substation to address the capacity shortfall projected under the N-1 for 2018/19 and
12 2019/20 winters.
13 In winter 2018/19 six temporarily rented 1.8 MW units were installed in the proximity of S150 Whitehorse
14 Rapids Substation. The 2019 project included installation of two additional temporarily rented 1.8 MW
15 units in the area between P126 Whitehorse Diesel and S150 Whitehorse Substation. The project scope
16 included planning support, limited engineering design assistance, protection settings and installation
17 support temporary seasonal diesel power generators to meet seasonal N-1 load requirements and assist
18 with meeting winter system peaks. Total project cost was approximately $1.298 million.
19 **N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure7 ($2.037 million forecast in**
20 **2020)**
21 The project involves the design and installation of temporary rental site electrical infrastructure at Faro
22 (870S) to ensure Yukon Energy can continue to meet its N-1 capacity planning requirements.
23 The project scope includes engineering and design, procurement of materials, installation and
24 construction and other internal and project management costs. Specifically, the major scopes of work
25 include:
26 Preliminary design and feasibility studies (system impact study and grounding studies); and
6 Table 5.2-1 references this project as "N-1 Capacity Shortage Mobile Genset."
7 Table 5.2-1 references this project as "N-1 Capacity Shortage Thermal Rental Site Electrical Infrastructure".
Faro 870S 1 temporary diesel generator infrastructure – design, procurement, construction and
2 commissioning, including: civil/ structural work; 138 kV line tap and substation work; 4160V
3 collection system; fuel system; stations service power; protection, control, communication and
4 SCADA integration.
5 The project is expected to be completed in 2020 at an estimated budget of $2.037 million. The project is
6 on track for a mid-November 2020 in service date.

REFERENCE: YUB's Order 2009-8 directions to YEC

"In future GRA applications, YEC to include business cases for major capital projects that included the following information: • 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."

QUESTION:

a) Chart all YEC diesels with capacity amounts available in Whitehorse, Faro, Mayo, Dawson, and other towns. Identify for each unit when last retrofitted and at what cost. Identify for each unit when end of life.

b) Chart all ATCO Electric Yukon diesels with capacity amounts, on the grid.

c) Chart natural gas units with each unit capacity.

d) Since these two project are jointly concerned and YEC is now requesting to place costs of over $3 million onto the rate base for 2021 test year, with the very limited information for each of these projects, provide the businesses case for each following the above Board directives.

e) In which year did YEC first rent gensets? How many?

f) Explain when and why YEC chose to move 7 generators to Faro.

g) Explain precisely why so much was expended to accommodate these rentals.

ANSWER:

(a) and **(c)**

Please see page 11 of 10-Year Renewable Electricity Plan provided in CW-YEC-1-36 (a) Attachment 1 for the map that shows generation facilities and Appendix A for the list of generation facilities with capacity information.

Please see table below for overhauls.

	2012 (+)	2013 (+)	2014 (+)	2015 (+)	2016 (+)	2017 (+)	2018 (+)	2019 (+)	2020 (+)
(P09-092) DD5 Bottom End Overhaul - (-)	696,893.47	358,797.07	39,843.64	24,819.12	24,508.20	.00			
(P11-008) DD2 Engine Overhaul - (-)	338,707.43	362,386.95	13,236.00	8,254.30	8,070.72	.00			
(P11-009) WD4 Engine Overhaul - (-)			506,717.60	12,348.98	12,074.04	.00			
(P11-012) DD3 Engine Overhaul - (-)			374,408.12	9,174.70	8,970.60	.00			
(P13-004) WD-5 Engine Overhaul - (-)		348,387.19	16,618.11	8,400.36	8,213.52	.00			
(P13-070) Whitehorse Spillway Diesel Overhaul - (+)			145,025.18						
(P13-088) Faro FD7 - 16K Hours Overhaul - (-)					120,657.77	.00			

(b)

AEY would be in a better position to provide the requested information. This information as required for the N-1 capacity criteria is provided in Tab 2 of the Application.

(d)

As reviewed in the referenced Tab 5 information on each of these projects, YEC must provide reliable firm capacity to the Yukon. New firm capacity requirements are assessed based on a “N-1” contingency, meaning the generating capacity must supply the Yukon load in the event that its largest generating facility is lost. YECs largest facility is Aishihik and has a capacity of 37MW.

Available information and forecasts since YEC’s 2016 Resource Plan have documented an N-1 dependable capacity shortfall. Section 2.4 of the 2021 GRA updated this information for 2021, showing the determination of a forecast N-1 dependable capacity shortfall of 25.75 MW in 2021 without the rented diesels and a surplus of 1.25 MW with the 15 rented diesel units (27 MW).

YEC continues to examine and pursue a range of non-rental options to address the forecast N-1 dependable capacity shortfall, including diesel retirement replacement, the Battery Energy Storage System project, the Atlin Hydro EPA, and pumped storage. Until such time as sufficient new dependable capacity can be developed through one or more of these non-rental options, rented diesel units continue to be the only cost effective option for YEC to adopt to ensure that sufficient dependable capacity is connected to the Yukon Integrated System to meet firm reliability standards during the peak load winter months. The referenced diesel rental infrastructure is required to accommodate the required diesel rental units.

(e)

2017/2018 - 4 rentals
2018/2019 – 6 rentals
2019/2020 – 9 rentals
2020/2021 - 17 rentals

(f)

When YEC determined that 17 rentals would be required for 2020/21, it was concluded that some of these additional rentals would be located at Faro. This decision reflected the following:

- Whitehorse is at capacity and could not accept any more rentals.

- Faro has established diesel infrastructure from the time of the Faro mine, and could accommodate cost effectively the required diesel rental units, i.e., the Faro facility air emission permit allowed for added generation; transformation, control and communication was available; and YEC owned land accommodated the infrastructure and rentals.

(g)

This was the least cost option considering the available infrastructure at Faro and the existence of the air emission permit that allowed for the addition of the rental fleet.

TOPIC: **Capital Projects**

REFERENCE: **Mayo to Keno Transmission Line and McQuesten Sub- Station**

QUESTION:

a) Identify forecast 2021 kWhr. usage for all non-government and government residential and commercial ratepayers on grid from Mayo to Keno (do not include Mayo).

b) Identify forecast 2021 kWhr. usage for each of the two mines, VCG and Alexco.

ANSWER:

(a)

The load forecast is prepared at the community level. YEC does not prepare forecast sales at non-government and government customer level, and therefore is unable to provide the requested information.

(b)

Victoria Gold forecast load at 43.1 GW.h for 2021 and Alexco forecast load at 24.1 GW.h for 2021 as provided on page 1-7 of the Application.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5-11**

11 Table 5.2.1-2: Project Cost and Contributions

	Actual2018	*Actual2019*	*Forecast2020*	*Forecast2021*
MMTL Upgrade ($000)	0	501	20,000	11,200
MMTL Contribution ($000)	0	274	15,000	8,400
Net Expense	**0**	**227**	**5,000**	**2,800**

12 The total spending of $20.501 million for 2019 and 2020 is offset by $15.274 million in contributions [net
13 $5.227 million] and is forecast to be closed and included in rate base in December 2020; the spending of
14 $11.200 million in 2021 is offset by $8.400 million in contributions [net $2.800 million] and is forecast to
15 be closed and included in rate base in December 2021.

QUESTION:

a) Identify contribution amount and contributor for each year and explain precisely what used for. (Not adequately explained in business profile).

b) If none of these contributions were from Alexco please explain why not?

ANSWER:

(a)

See Tab 5, Section 5.2.1.3 of the Application. As noted at Tab 5, page 5-11, the project received a Federal Government contribution of $23.674 million which covers 75% of the eligible project budget. The contributions for 2019 (of $0.274 million), 2020 (of $ 15 million) and 2021 (of $8.4 million) total to this amount. Contributions are applied against total project costs in each year in order to reduce the impact on rates.

(b)

Industrial mine connections are subject to Power Purchase Agreements (PPAs) as approved by the Board. The PPA for Alexco Resources (as well as the PPA for VGC Group) sets out when contributions are required up front from the customer to cover all costs for the installation of transmission facilities used only for each mine. No such up

front contributions are required for transmission facilities (such as the Mayo-McQuesten new transmission) that also service other customers on the Yukon Integrated System.

The Alexco and VGC Group PPA provisions also provide for industrial customers that connect to the Mayo to Keno common transmission facilities that service this region to make significant contributions (i.e., 85%) through the Fixed Charge towards the annual YEC depreciation and return expenses related to the rate base cost for these Transmission Facilities. These provisions will result in these two industrial customers paying for 85% of the annual depreciation and return expenses for the new Mayo-McQuesten transmission facilities

Yukon Energy has been pursuing the SKTP to improve 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. With regard to the line segment between Mayo and Keno City, it has been well documented that the line facilities are significantly deteriorated and need to be rebuilt due to safety and reliability concerns. As such, recent capital costs related to these facilities are not directly due to the VGC Group Mine or the Alexco mine facilities.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5-12**

22 5.2.1.4 McQuesten Substation (including Asset Contribution) – ($0.123 million in 2018 and
23 $11.496 million in 2019; with $10.688 million contribution)

QUESTION:

a) Identify contribution amount and contributor for each year and explain precisely what each was used for. (Not adequately explained in business profile).

b) If none of these contributions were from Alexco please explain why not?

ANSWER:

(a) and **(b)**

See Tab 5, Section 5.2.1.4 of the Application. Pursuant to the VGC Group PPA, the McQuesten Substation was developed by VGC Group and YEC, with the intention that it would be owned and operated by YEC. Except as otherwise specified in the PPA, VGC Group was responsible for all capital costs related to the McQuesten Substation development.

YEC has received an asset contribution from VGC Group valued at $10.688 million, and has incurred a net cost of $0.931 million (related to added facilities to enable future 138 kV service operation if required).

Development of this facility did not involve Alexco.

TOPIC: **Capital Project**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

5.2.1.5 Transmission Line Refurbishment - L70, L171 and L172 in 2018 and 2019 ($4.272 15 million in 2019)

Yukon Energy's 138 kV Whitehorse-Aishihik-Faro (WAF) transmission system was constructed in the late 1960's and early 1970's, and plays a critical role linking key hydro generation sources to load centres in Whitehorse and on the northern grid. Recent studies as well as a detailed line assessment in 2017 indicated that key components of the WAF system were at end of life, in poor condition, and required replacement.

This project was initiated to address replacement of key components of the following YEC transmission lines which are approaching the end of their economic life.

At the time future Step Down transformer costs were estimated at $1.34 million.

QUESTION:

a) Who made and why was the decision made to expense this money all at once rather than stepping-up the yearly maintenance program utilizing in-house personnel?

b) Does this $4.272 million cost in 2019 include the $1.34 costs for Step Down transformers.

c) If yes, demonstrate that this work was done.

ANSWER:

(a)

The project review committee made the decision. The results from the transmission test and treat and line assessments defined the scope of work. The scope of the work and YEC's capacity to perform the work in house dictated the decision to make TLR a large project. YEC has one line crew consisting of four personnel.

The assessment determined that a number of transmission line components were end of life. There is no accepted practice to life extending these components (e.g., cracked laminar beams, cracked ceramic insulation).

(b) and **(c)**

TLR did not include any work on stepdown transformers.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

5.2.1.6 Transmission Line Refurbishment – L178 (forecast $1.3 million in 2021)

The final phase of the Transmission Line Refurbishment Project will commence in 2021 for the Carmacks to Faro Transmission Line (L178), as refurbishment has been completed for L170, L171 and L172 (see Section 5.2.1.5).

Outages on the L178 currently trip at S164 (Takhini Substation) and can result in an outage on the Takhini-Carmacks L170 transmission line. Failure to complete this element of the refurbishment project would increase the risk of component failure on L178 resulting in a split in the North-South grid and significant thermal generation costs in the northern gird to maintain supply to all customers

QUESTION:

a) Has outages of the L178 line ever caused a failure on the grid?

b) If so, how often and when?

c) Has utilizing the yearly maintenance in-house team considered as a viable alternative. If not, why not?

ANSWER:

(a)

Yes. Outages of the L178 line have caused multiple events. See also response to YUB-YEC-1-54.

(b)

See response to YUB-YEC-1-54(a).

(c)

YEC has one transmission crew comprised of four staff. The primary responsibility of the in house crew is minor transmission maintenance, outage response and customer connects. Work on the transmission system requires the line to be isolated, and this results

in customer outages and diesel generation for the duration of the work. Operating agreements with commercial customers typically allow for two weeks disruption (off grid power). Due to the quantity of work and the short timelines to complete the work, YEC must supplement the YEC crew with contractors or project manage the work of the selected contractor.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

5.2.1.8 Replacement of P125 Head Gate ($0.093 million in 2019, $2.300 million forecast in 2020, and $3.500 million forecast in 2021)

QUESTION:

a) If an adequate response charting breakdown is met in UCG-IR Capital 8 and 9 includes this project, then UCG has no further questions for now.

ANSWER:

(a)

No question is being posed above and no response appears to be required. A cost breakdown for the P125 Head Gate Project is provided in YUB-YEC-1-49.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

5.2.1.10 WH4 Uprate - Servomotor Replacement ($0.052 million in 2018; $0.079 million in 2019; $0.400 million forecast in 2020; and $1.000 million forecast in 2021)
The total project budget is $1.531 1 million and includes work from 2018 through to project completion 2 (expected in Q3 2021).

QUESTION:

a) Provide all prior work done on WH4, years work completed, along with each cost for the WH4 Uprate program, that have been already been approved and placed in rate base.

ANSWER:

(a)

In 2017, YEC performed a major overhaul on hydro unit #WH4 including replacement of both the exciter and rotor spider. This work was unrelated to the current servomotor replacement uprate project. The Hydro Unit #WH4 Overhaul was reviewed as part of the 2017/18 General Rate Application (see Tab 5, Section 5.2.1.5 of the 2017/18 GRA and Board Order 2018-10, paragraph 421).

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

5.3.1 Major Projects >$1 Million – Rate Base Additions

Aishihik Relicensing (Three Year Licence Renewal) - ($1.004 million net increase in rate base by the end of 2021, excluding reductions due to amortization).

5.3.1.1 Aishihik Generating Station Three Year Licence Renewal – ($0.805 million to end of 2019; and $0.200 million in 2020)

Costs for the 3-year AGS licence renewal were incurred from January 2019 through to end of February 2020 (when the 3-year licence renewal was obtained). Costs over this period include regulatory costs for the Designated Office review; costs related to the preparation of the Yukon Water Board Application for the 3-year renewal and for the 60-day renewal and for the related review processes; and costs related to preparation of an application to extend the DFO Fisheries Act Authorization and related review processes;
and costs related to negotiations with CAFN and for negotiation of compensation with claimants pursuant to the Waters Act .

The DFO evaluation concluded in August 2019 with the issuance of an Evaluation Report. Decision Documents were
issued in September 2019.

Issued December 24, 2019.

A 60-day renewal was issued in December 2019 extending the licence to February 29, 2020, and a 3-Year renewal was
issued on February 19, 2020.

QUESTION:

a) Provide all costs allocated for AGS YESAB review (each consultant name, work done and cost for each. Provide all inhouse costs with work done.

b) Provide all costs allocated for AGS Water Board review (any and all consultant costs and in-house costs).

c) Were both these licenses granted?

d) How much did it cost for FN negotiations and compensation and how was this accounted for?

ANSWER:

(a) and **(b)**

Please note AGS YESAB review and AGS Water Board review costs cannot be readily broken out in the time available. Both cost items were included in permitting activities for this project. Permitting activities broken out by consultant are summarized in Table 1 below. Table 2 provides YEC internal costs.

Table 1: AGS Three Year Licence Renewal Permitting Activities Costs by Consultant

Consultant	2019	2020
DLA Piper (Canada) LLP	148,265.52	
Environmental Dynamics Inc.	52,869.26	7,588.09
Intergroup Consultants Ltd.	109,017.75	77,819.75
Morrison Hershfield Limited	48,293.25	
	358,445.78	85,407.84

Table 2: YEC Internal Costs for AGS Three Year Licence Renewal

Internal Costs	2019	2020
Internal Labour	17,236.99	
Other Internal Costs	667.74	3,062.09
AFUDC	122.47	2,314.17
Grand Total	**18,027.20**	**5,376.26**

(c)

All regulatory authorizations required to operate the project until December 31, 2022 were issued. The YESAA Designated Office review was completed in 2019 with issuance of the YESAA Report and Recommendations on September 4, 2019. Decision Documents were issue October 21, 2019. The Fisheries Act Authorization extension was issued December 20, 2019 and the three year Water Use Licence renewal was issued February 19, 2020.[1]

(d)

See response to YUB-YEC-1-59(a) which provides a breakdown Three-Year Licence Renewal Project Costs.

[1] A 60-day renewal was also issued on December 19, 2019 [Water Use Licence HY-19-057].

TOPIC: **Capital Projects**

REFERENCE: **June 22, YEC 2017 Application, page 5-31 and Table 5.3, page 5-56Aishihik**

Relicensing ($2.899 million) $2.899 million cost identified at page 5-31 and $8.9 million cost identified on Table 5.3 at page 5-56.

QUESTION:

a) Identify which amount was approved as a WIP for 2017/2018 GRA.

b) What portion of these costs allocated from WIP to rate base?

c) Identify how these costs were different from the ones now requested to place into rate base.

d) Identify any and all consultant firms, work performed and each cost for this phase of the relicensing.

e) Please confirm that costs related to the Aishihik Relicensing will not be recovered in rates until approved by the YUB this general rates application process.

ANSWER:

(a) through **(e)**

The Board approves costs that affect rates – and costs allocated to WIP in the last GRA did not affect rates. All cost forecast to be added to rate base in the current GRA will not be recovered in rates until approved by the Board in the GRA process.

Please see response to YUB-YEC-1-90 for review of this project's changes since the 2017-18 GRA.

TOPIC: Capital Projects

REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

17 o Demand Side Management (DSM) – ($1.737 million net increase in rate base by the
18 end of 2021, excluding reductions due to amortization).
5.3.1.2 Demand Side 1 Management – ($0.833 million to the end of 2019; $0.375 million
2 forecast in 2020 and $0.894 million forecast in 2021, with contributions of $0.365
3 million).
The Board made the following DSM related determination in Board Order 2018-10
6 (paragraph 482):
7 "The Board is not persuaded that YEC should continue to operate DSM projects. YEC has
8 indicated the benefits of expanding the program and submitted that its programs have
9 met or exceeded key performance indicators. However, the Board notes that the Yukon
10 government has DSM incentive programs in place, and the Board is of the view that it is
11 better to leave DSM projects to government, rather than having ratepayers fund these
12 projects. For these reasons, the Board is of the view that continuation of DSM programs
13 by YEC is not necessary."
22 DSM Program Development
A Capacity DSM Feasibility Study and an updated CPR model,35 to design 1 a suite of new DSM
2 programs to complement the existing inCharge program. This work was completed in early 2019. Minimal costs to provide
brand and education continuity have also been incurred since early
5 2019 to maintain the inCharge program in the local market. Project expenditures to be included in rate
6 base of $1.279 million ($0.385 in 2019 and $0.894 million in 2021) are amortized over 10 years.

Board Order 2013-01 Appendix A determined:

"that it was not approving the DSM program for the five-year term and that YEC was to make a formal application to the Board before expanding the DSM program elements beyond that approved or beyond 2015."

QUESTION:

a) Has there been a court determination on the YEC request to Review and Vary Board Decision 2018-10?

b) If the courts have not rendered a favourable decision on this matter, why is YEC still proceeding with DSM expenditures?

c) Did YEC get prior authorization from the Board to proceed with new DSM programming as directed by the Board to undergo these studies and models with costs of $1.279 million?

d) What are the programs complementing the inCharge that have been implemented?

e) Confirm that YEC requires acceptance from the YUB before rates can be set which recover any expenditures for energy efficiency or conservation (DSM measures).

ANSWER:

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

The Court of Appeal of Yukon dismissed the appeal in a written decision on February 5, 2021. The Appeal addressed historic DSM costs (2016-2018) and in no way precluded YEC from advancing new DSM programming. With respect to the balance of the referenced questions, please see response to YUB-YEC-1-46 (a to f).

(d)

YEC has not yet initiated the implementation of any complimentary DSM programs. Continued work on DSM programming, including potential complimentary programs, will now be advanced given OIC 2021/16 directions enabling YEC to recover through rates the costs reasonably incurred to provide or participate in a demand side management program.

(e)

YEC confirms that rates cannot be adjusted without prior authorization from the YUB.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

17 **Demand Side Management (DSM)** – ($1.737 million net increase in rate base by the
18 end of 2021, excluding reductions due to amortization).
7 **DSM Residential Demand Response Pilot**
20 Yukon Energy has pursued a pilot program testing internet connected, wifi enabled
21 demand response technology designed to control residential baseboard and hot water heating during
22 winter peak periods to help reduce system peak and reduce reliance on thermal generation such as
diesel
23 or natural gas.
34 Yukon Energy also noted plans to undertake a Capacity DSM Feasibility Study to quantify the potential
cost and
achievable uptake
of capacity-focused DSM programs such as demand response, behaviour change and other demand-
focused measures.
35 At the time Yukon Energy also noted plans to update the Conservation Potential Review (CPR) model
used to inform DSM
program design, to better match the inputs needed for resource planning; and to develop in house capacity
to use the CPR
model
to extract data for resource planning and program design purposes.
The objective of the program is to: 1 evaluate the technical feasibility of the demand response technology;
2 model and test the peak shifting effect of the pilot; test the reliability of the peak shifting effects of the
3 pilot; and evaluate customer acceptance of the demand response events.
4 The project is managed by Yukon Energy with funding support from Atco Electric Yukon (AEY), Yukon
5 Development Corporation (YDC) and Natural Resources Canada (NRCan). Project expenditures of $0.809
6 million ($0.434 million in 2019 and $0.375 million in 2020) are to be included in rate base, offset by
7 contributions of $0.365 million in 2019, are amortized over 10 years.

REFERENCE: https://www.yukon-news.com/news/smart-grid-pilot-project-announced/

"It's worth $1.3 million, with the federal government chipping in $650,000 and the Yukon government contributing $250,000.
ATCO and Yukon Energy cover the rest — $300,000 and $100,000, respectfully."

QUESTION:

a) Explain precisely what the $0.809 million costs are for?

b) How much exactly is YEC requesting to rate base?

c) Why is YEC costing any of this to the ratepayer rate base when all of the costs were to be recovered from contributions (see above)?

d) Confirm that YEC requires acceptance from the YUB before rates can be set which recover any expenditures on this demand response program.

ANSWER:

(a)

Please see response to YUB-YEC-1-59.

(b) and **(c)**

As quoted in the preamble, the DSM net addition to rate base (after contributions) is $1.737 million. The quoted announcement did not reference all of the DSM activities included in this project.

(d)

The Board must approve costs prior to such costs being included in rates.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

8 LED Streetlight Retrofit Program

The 2017/18 GRA outlined the basis for the LED Streetlight Replacement program noting that Yukon Energy decided to move forward with the retrofit of streetlight assets with LEDs.37 Streetlights in downtown Dawson and Mayo were retrofit in 2016 with plans to retrofit the remaining streetlights in Faro, Mendenhall and Champagne in 2018. As illustrated in Table 5.3, $0.273 million was added to rate base in 2018.

REFERENCE: **Appendix A to Board Order 2018-10 Reasons, p.91 #480 and 481**

Board determined as a result of above: “The Board considers that retrofitting streetlights at end of life with LED lights were prudent expenditures. Any LED installations that are not end-of-life conversions are not to be included in rate base.”

QUESTION:

a) Did YEC receive prior authorization from the Board to spend the $0.273 million demonstrating end-of-life conversions?

b) Confirm that YEC requires acceptance from the YUB before rates can be set which recover any expenditures on this streetlight conversion.

ANSWER:

(a) and **(b)**

The Board must approve costs prior to their inclusion in rates. The Board does not provide “prior authorization” for project costs, and YEC did not therefore seek or receive any prior authorizations for the referenced costs.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

5.4-1: FEASIBILITY STUDIES – POTENTIAL RENEWABLE GENERATION OPTIONS
IPP Standing Offer Program Implementation

2018WIP	2019 Addition	2020Addition 2	021Addition
$48,127	$183,912		

Yukon Energy and ATCO Electric Yukon (AEY) are responsible for implementing the Yukon Government's Independent Power Producers (IPP) Policy. The Standing Offer Program (SOP) was developed based on the model used in British Columbia.

The utilities were directed to implement the policy by the Yukon Government and are required to execute the policy.

OIC 2019-25 requires that utility costs be recovered in rates. With total expenditures of $232,039 to be amortized over five years.

QUESTION:

a) If the YEC model was based on one produced in British Columbia, explain why a quarter million dollars in cost be needed to re-invent the template?

b) Identify the section of OIC 2019-25 that states precisely that the utilities costs be recovered from rates for developing an IPP standing offer program.

c) Why could not the Yukon Energy staff implement this policy in-house?

ANSWER:

(a)

YEC received formal permission from BC Hydro to utilize their Standing Offer Program documents as a starting point for Yukon's program. The permission came with the full recognition that significant changes would be required to be make it useful in the Yukon context. The number of documents required to launch the Standing Offer Program is significant. The program was a collaboration between YEC and ATCO Electric Yukon which required shared learning to firstly understand the BC program and then make

modifications that would work with Yukon Government policy and the Yukon context. This was a daunting task for both Utilities to understand a model Standing Offer Program and then customize it for the Yukon.

There are significant differences between BC's and Yukon's Standing Offer Program. However, it was much more efficient to start from a working model than try developing this program "from scratch".

(b)

The utilities were directed to implement the IPP policy by the Government of Yukon.

While the costs for developing an IPP standing offer program are not specifically referenced in OIC 2019/25 – the OIC specifies costs that the Board must allow the utility to recover in relation to electricity purchase agreements which include: (a) the cost of purchasing electricity under an electricity purchase agreement; (b) third party consultant costs, including legal fees, incurred by an electrical utility in relation to the development and implementation of the agreement; and (c) the cost of maintaining or replacing equipment or infrastructure necessary to purchase electricity under the agreement.

(c)

YEC and ATCO Electric Yukon are both signatories to the Standing Offer Program. The sheer volume of documents required to implement this policy is a testament to the technical and legal work that was required to develop it. Compounded by the need to collaborate and the significance of contracting for 20 GWh (now expected to increase to 40 GWh) of renewable electricity from Independent Power Producers for 25 years, the investment in third party legal and technical support was necessary.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab**

FACTORS DRIVING THE 2021 RATE INCREASE REQUIREMENT

Other Cost Changes ($0.7 million impact, 6.0% of shortfall): Other cost changes affecting the 2021 GRA revenue shortfall include depreciation rate changes ($0.6 million increase), Reserve for Injuries and Damages (RFID) updates ($0.4 million increase), and new Independent Power Production (IPP) costs ($0.3 million).

QUESTION:

a) Explain the difference in the business case cost of $232,039 million for IPP and the impact to rates of $0.3 million for new IPP costs.

b) Which is relevant and how is this reflected in application costs?

ANSWER:

(a) and **(b)**

The question references two different IPP cost items included in the 2021 test year:

1. Costs for power purchased from IPPs (per Table 3.2 in Application, and page 3-6, lines 8 to 12) – this is $0.314 million forecast for 2021 purchase cost for 1.983 GWh forecast to be supplied by IPPs. All of this cost is included in 2021 revenue requirement.

2. Costs for IPP Standing Offer Program Implementation (per Appendix 5.4, section 5.4-1, page 5.4-2) – deferred studies cost of $232,039 (not $232,039 million as shown in question) incurred in 2018 and 2019, that was closed and included in rate base in 2020 and is being amortized over five years. The 2021 revenue requirement includes annual amortization costs plus return on 2021 mid-year rate base amount.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab**

Mt Sumanik Wind Feasibility Studies

2018WIP	2019Addition	2020Addition	2021Addition
$694,427	$31,155	$50,000	

Mt Sumanik was identified as a particular site of interest for wind development given the advantages of its proximity to Whitehorse. From 2014 to 2015, work on this project focused on the siting, engineering, environmental assessment, permitting and installation of wind monitoring equipment at Mt Sumanik. This included completion of applicable studies such as a grid impact study and wind integration study. A Lidar unit and power supply system was installed on Mt Sumanik to track wind data.

From 2016 to 2017, the project work consisted mostly of data collection and management, as well as evaluating upgrades to the power system for the monitoring equipment which experienced difficulties. In 2018 work was conducted to repair the laser of the Lidar unit as the equipment was malfunctioning. Yukon Energy's 2016 Resource Plan identified a potential energy gap under the High Industrial Activity scenario. The Action Plan identified one wind supply option under this scenario. Accordingly, as wind was still a resource of interest, Yukon Energy considered whether further data monitoring should be conducted given missing data from the malfunctioning equipment. The need for Yukon Energy to directly conduct resource wind monitoring and site assessments has since been eliminated due to the high likelihood that future wind resources will be developed by Independent Power Producers. As such, the project was decommissioned in 2020 with total expenditures of $775,581 to be amortized over five years.

QUESTION:

a) Breakdown all costs associated, including consultant firms and costs for each; i.e. for siting, engineering, environmental assessment, permitting and installation of wind monitoring equipment on Mt. Sumanik.

b) In what year was IPP policy presented by YTG to Yukon Energy for implementation?

c) In what year was YEC first made aware that Northern Energy was planning a wind farm in the Whitehorse area?

ANSWER:

(a)

Please see YUB-YEC-1-96.

(b)

The current IPP policy was implemented in 2019 through OIC 2019/25 and 2019/26.

(c)

2018.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

WH2 Uprate Engineering1

2018WIP	2019Addition	2020Addition	2021Addition
$207,944	$44,448	$6,679	

In 2016, Hatch assessed the uprate options at the WRGS. Uprate of the WH2 was considered the most economically attractive option. The WH2 Uprate project would include completion of the WH2 unit's rehabilitation, replacement of the turbine runner and stator rewind and rotor refurbishment. The WH2 uprate engineering study was the first stage of a multi-year, phased project. The initial stage involved selection of an Owners Engineer to conduct preliminary design work (commenced in 2018 and completed in 2020). An external engineer was required to undertake this work as uprate studies are a specialized skillset that YEC does not employ internally. By end of 2021 WH2 Uprate Engineering costs will be transferred to Property, Plant and Equipment and added to WH2 Uprate total cost [amortized over 72 years starting in 2022]. However, this requires replacement of the existing stator winding and refurbishment of the rotor field poles and windings. before the end of 2021. The project is to be closed in 2021 with total expenditures of $259,072 to be amortized over 72 years.

QUESTION:

a) Was the total cost of $250K for work given to Hatch?'

b) If not, which engineering firm did study and at what cost?

c) If not, were there additional costs?

d) Confirm that existing WH2 stator has been replaced, winding and refurbishment of rotor field poles and windings complete.

e) At what cost?

ANSWER:

(a)

The assessment work completed by Hatch in 2016 was prior to the WH2 Uprate project. Hatch did not complete any work included in the $259,071 spent on WH2 Uprate Engineering between 2018 and 2020.

(b)

In 2018, YEC spent $165,646.78 on consultants (SNC Lavalin). The remainder was internal labor, legal fees (for contract negotiation), AFUDC and materials.

(c)

There were no other additional costs.

(d)

The original stator has not been replaced, nor have the refurbishment of rotor poles and windings. This work is a part of the WH2 uprate project.

(e)

The cost of the stator rewind and refurbishment of the rotor poles are part of the overall project cost of $12,257,000. The cost of the rewind is $601,857. Refurbishment of the stator frame is $24,457. Overall, YEC is spending $972,440 on the WH2 generator rewind/refurbish during the WH2 Uprate. This is included in the overall project budget of $12.257 Million.

TOPIC: **Capital Projects**

REFERENCE: **5.2.1.9 WH2 Uprate ($3.044 million in 2019, $1.693 million forecast in 2020, and $7.300 million forecast in 2021)**

In 2017, Hatch completed an economic assessment of various uprate options at the Whitehorse Rapids 24 Generating Station (WRGS).
28 The project is planned to be implemented over a three year period (2019-21).
The WH2 uprate scope 1 of work will include unit rehabilitation, runner replacement, generator stator and 2 rotor re-winding, governor replacement, exciter replacement and upgrading of the control and condition 3 monitoring systems.
4 Yukon Energy contracted Litostroj Power to undertake the runner fabrication with the following 5 concurrent activities planned for 2020: governor fabrication, balance of plant civil construction; balance of 6 plant P&C design completion, relace of balance of plant request for proposal, and delivery of materials to 7 Whitehorse. The balance of plant civil scope work included rehabilitation of the tailrace crane 8 superstructure and concrete piers. Due to significant new damage to the WH1 and WH2 penstocks 9 discovered in 2020, the planned penstock work was cancelled and will be completed as part of the 10 penstock repairs.
11 The WH2 uprate project is currently expected to be delivered on time with total project cost of $12.038 12 million.28

QUESTION:

a) Further to reference above giving WH2 business plan, is the first reference engineering costs of $259,039 included in this business plan?

b) If not, why not?

c) WH2 scope of work include unit rehabilitation, runner replacement, rotor re-winding, governor replacement, exciter replacement and upgrading of the control and condition monitoring systems. Did Listostroj Power do all the work in scope above and at what cost.

d) If Listostroj Power did not do all the work outlined above to the cost of $12,038 million, identify which firm/s was/were hired, what work done and at what cost.

e) Identify work done in-house and at what cost.

f) Identify any costs above associated with the balance of work identified above including rehab of tail race crane and concrete piers.

g) Identify all costs and for what work completed to WH2 for 2018 and any prior years.

h) Confirm that $12.038 million is the total amount for overhaul of WH2.

ANSWER:

(a)

No, the costs are not included in the 2019-21 spending identified in Tab 5, Section 5.2.1.9.

(b)

These costs were considered a Feasibility Study before the actual fix was determined. In accordance with YEC's policy, the project will be kept open and added to the 'Asset' when in-service.

(c) and **(d)**

This work has not yet been completed.

Litostroj has been contracted to complete all of the aforementioned deliverables at a contract value of $6,806,558.

(e)

Internal work includes: YEC engineering, Project Management, procurement, health and safety, operations, and site construction monitoring support. The estimated cost of YEC internal support is $500,000.

(f)

There is no additional work outside what has been defined above. Rehab of tailrace cranes and concrete piers are not a part of this Project.

(g)

No WH2 Uprate project work was completed prior to 2018. The 2018 work included developing project specifications and tendering as well as internal PM and engineering work.

(h)

Total Amount for this project is $12.297 million as per footnote 28 on Tab 5, page 5-19 of the Application, i.e., this includes the engineering related costs shown in Appendix 5.4 of $0.259 million.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

5.2.1.10 WH4 Uprate - Servomotor Replacement ($0.052 million in 2018; $0.079 million in 2019; $0.400 million forecast in 2020; and $1.000 million forecast in 2021)
The project involves detailed design, procurement and installation of two new Servomotors for Whitehorse Hydro Unit 4 (WH4) wicket gate operation.
Contracts with Andritz (OEM), L&S Electric (to review documentation and develop a governor commissioning plan) and Hatch (owners engineer) have been finalized. Procurement has not yet been undertaken for testing services and installation of a lifting device.
Yukon Energy entered into a contract with ANDRITZ Hydro for the design and supply of two new servo motors. Final design is nearing completion and manufacturing is expected to commence in Q3 2020.
Other work is proceeding in parallel including planning for changes to the governor, signature testing and characteristic testing with assistance from Hatch and L&S Electric. Delivery of the Servos is expected by January 2021. Contractor mobilization and installation, testing and commissioning is expected to occur in June 2021. The project is expected to be in service in June 2021.

QUESTION:

a) Detail which contracts and work performed with costs to Andritz(OEM), L&S Electric, and Hatch.

b) Identify any other contracts with work performed and costs.

c) Identify all work performed and costs for in-house.

d) Identify all costs and for what work completed to WH4 for 2018 and prior years.

e) Give total cost of WH4 overhaul to date.

ANSWER:

(a)

This project is not yet complete. YEC currently has a contract with Andtridtz for $744,000. L&S Electric will support with governor work, tuning and commissioning at a cost of $70,000. Hatch is acting as owner’s engineer at a cost of $35,000.

(b)

No additional contracts have been put in place at this point in time.

(c)

This project is not yet complete. The work YEC will be performing includes, Engineering, Operations, Procurement, Health and Safety, and Project Management support. It is estimated that YEC internal cost will be $153,000.

(d)

Total costs for 2018 and prior were $51,894.08. This covered initial feasibility studies and specification development.

(e)

Total costs up to December 31st, 2020 are $385,000.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

5.2-1: GENERATION PROJECTS
Dam Safety Review
Dam Safety Program

2019Actual	2020Forecast	2021Forecast
		$300,000

A full dam safety review (DSR) is performed every 5 years by an external consultant as recommended by the Canadian Dam Association (CDA).

A DSR was completed in 2020 and included an extensive inspection of all water control facilities, underwater inspection of structural elements by divers, geotechnical investigation of the Whitehorse power canal, and research into historical records of YEC assets. The 2020 DSR resulted in a detailed report that prioritized recommendations for work to be completed in future years. Spending in 2021 is required to address 2020 DSR outcomes and priorities identified for 2021. Some of the high priority items that will be addressed include:

- Wareham dam spillway design
- Warning and danger signage around the six dams
- Public safety around Marsh Lake

Dam Safety Recommendations 2017/18

2019Actual	2020Forecast	2021Forecast
$272,000	$300,000	

The 2015 DSR resulted in a detailed report that outlined a list of observed deficiencies and corresponding recommended actions to address identified deficiencies and eliminate hazardous conditions which could adversely affect the safety of the public and YEC staff. 2019 spending included required maintenance around the Marsh Lake control structure, and replacement of Whitehorse piezometers; while planned 2020 activities include replacement of the Mayo Lake Dam wood planking, Wareham Dam seismic upgrades, and the implementation of a public safety plan at the Marsh Lake control structure.

QUESTION:

a) Confirm all projects listed in Appendix 5.2 need to undergo a prudence test and approval from the Board before any/all can be entered into rate base.

b) Confirm the last DSR was done in 2015.

c) Confirm each project must be confirmed to be 'used and useful' before it can be entered into rate base.

d) Why were the 2015 recommendation of DSR not done until 2019 and forecast 2020, if they are so hazardous?

e) Are not some of the forecast work for 2021 the same as the 2021 safety recommendations?

ANSWER:

(a) and **(c)**

Projects are included in rate base the year they are completed and in service. Project costs must be reviewed and approved by the Board before being included in rates. The Board's review and approval process includes assessment of cost prudence and that assets are used and useful.

(b)

The last DSR was performed in 2015.

(d)

YEC plans and prioritizes projects throughout the year, taking into account any actions needed to reduce or remove hazardous conditions that could potentially pose a threat to the public, YEC staff, or property. At times, projects are shifted due to unforeseen events which results in project deferral.

(e)

Forecasted 2021 work was driven from the 2020 Dam Safety Reviews. The 2015 Dam Safety recommendations and the 2020 Dam Safety review both flagged work to be undertaken to address public safety at Marsh Lake – this appears to be the only common element between the 2017/18 Dam Safety Recommendations and the 2020 Dam Safety Review. The response to YUB-YEC-1-75 provides an update the 2017/18 Dam Safety Recommendations Project. This response notes that the Public Safety Plan was not completed due to the fact that YEC was waiting for results from the 2020 Dam Safety Review for inclusion into the Public Safety Plan.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

P126 LNG Boil-Off Gas Heat Exchanger

2019Actual	**2020Forecast**	**2021Forecast**
$194,000		

Prior to decommissioning of the Mirrlees diesel generators, LNG boil off gas was piped to P126 and burned in the P126 plant boiler and/or dissipated through the WD1 jacket water heat exchanger. With retirement and removal of the three Mirrlees gensets at the Whitehorse Diesel Plant (P126) there was a requirement to replace this heat dissipation function and to design, supply and install a new heat exchanger at the plant to dissipate extra heat from the combustion of LNG boil off gas. Work related to the installation of the heat exchanger included hiring an owners engineer to prepare design, drawings and specifications for the new heat exchanger, piping, a new pump with VFD, and a temperature sensing device, and provide mechanical and electrical drawings and technical specifications for equipment and piping installation for tendering the construction work.

QUESTION:

a) Confirm this work has been completed and operational.

b) Why is this extra heat not utilized to heat buildings or some other cross purpose?

ANSWER:

(a)

This work has been completed.

(b)

The extra heat is typically available only during summer months (when the LNG plant is offline). The heat can be used for building heat or dyke heat if needed, but this is rarely the case.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

5.2-1: GENERATION PROJECTS

Wareham Gate Heater

2019Actual	2020Forecast	2021Forecast
$574,000	$100,000	

The Wareham Gate Heating project replaced an old and ineffective heating system on both Wareham Spillway Gates. The new system is designed to keep both spillway gates operational through the winter. Passing flows during outages and times of high inflows is a critical function of the spillway.

QUESTION:

a) Confirm this work has been completed and operational.

ANSWER:

(a)

The project is complete and operational.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

5.2-1: GENERATION PROJECTS

Wareham Gate Refurbishment

2019Actual	2020Forecast	2021Forecast
		$250,000

The Wareham Dam impounds Wareham Lake and is classified as an extreme hazard Dam.1 The Wareham Spillway Gates have been in service since 1953 and are critical infrastructure for the Wareham Dam. The spillway gates at Wareham Dam have had significant leakage problems over a number of years, primarily due to age-related wear and corrosion. Recent observations, including an external engineering assessment, indicated that the gates were deteriorating in several ways. Specifically, the skinplates were experiencing pitting corrosion2 and needed to be repaired by sandblasting, adding additional plates and plug welding and seal welding the plates in an array to add strength. During testing of the hoist following repairs in 2019, extremely high friction forces were also observed acting on the gate; the wheel bushing was worn; and there was evidence of fretting wear on the wheel paths. Side seals were also leaking at a high rate at times; and copper staunching rod links and retaining clips required refurbishment with new self lubricated bushings to allow them to seal smoothly. Spending in 2020 was focused on undertaking work as identified above to address each of these issues.

QUESTION:

a) Confirm this work has been completed and operational.

ANSWER:

(a)

This work has not been completed.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

5.2-1: GENERATION PROJECTS

Whitehorse Diesel System Grounding for Generators

2019Actual	2020Forecast	2021Forecast
$218,000	$10,000	

This project prepared grounding calculations and installed acceptable grounding equipment for all Whitehorse diesel generators in order to address the following issues: (1) WD4 and WD5 generators were ungrounded and in the case of a ground fault there was risk of significant damage to this equipment; and (2) the grounding for WD6 and WD7 generators was not identical, and this was an inadequate configuration when several generators were running in parallel.

a) Confirm this work has been completed and operational.

b) Why would Yukon Energy have any facility that is not properly grounded?

ANSWER:

(a)

This work has been completed and is operational.

(b)

Standards and system site conditions change over time. It is prudent for YEC to continuously assess its grounding systems to ensure design functionality is being realized as expected. YEC determines if there are any issues resulting from the assessments and puts a plan in place to fix.

TOPIC: Capital Projects

REFERENCE: APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE

5.2-1: GENERATION PROJECTS

WH1 and WH2 Design and Install Dewatering System
2019Actual 2020Forecast 2021Forecast
$137,000

A suitable system was not in place to automatically control the water levels in the WH1 and WH2 draft tube during dewatering activities. This project installed a redundant and automatic dewatering system integrated with the station PLC to provide visibility and status alarms to increase safety and reduce the risk of a flood in the P125 plant. Prior to implementation of the project, the existing system was oversized, and required large volumes of makeup water to be.

a) Confirm this work has been completed and operational.

b) Why would the existing system be oversized in the first place?

ANSWER:

(a)

The project is completed and is operational.

(b)

It is unknown as to why the existing system is oversized.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

5.2-1: GENERATION PROJECTS

WH4 Ventilation

2019Actual	2020Forecast	2021Forecast
		$750,000

The WH4 plant is overheating during the summer. Given that YEC is adding additional capacity to the WH4 hydro unit with new servo motors in 2021, removing the restriction placed on output by the overheating issue will enable the extra capacity to be used reliably throughout the year.

QUESTION:

a) Why is this program not included in the WH4 overhaul?

b) Confirm this work has been completed and operational.

ANSWER:

(a)

Both the ventilation and uprate projects are different in nature and as a result YEC decided to keep them separate.

(b)

This project has not started. Engineering, estimating and planning will occur in 2021 with project commencement and completion in 2022.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

5.2-2: TRANSMISSION PROJECTS

Alexco Mobile Substation Connection

2019 Actual	**2020Forecas**	**2021Forecast**
$178,000		
($178,000contribution)		

Alexco plans to use a 3 MVA, 69 kV/4.16 kV mobile self-contained substation to feed their Birmingham site at Keno. The substation must be connected to the McQuesten-Keno 69 kV line. The project includes supply, installation and commissioning of the new line tap including connection to existing 69 KV line, engineering and commissioning support for the new mobile substation. YEC has engaged Chimax to complete a 69 kV line tap design to connect the Alexco mobile substation to the McQuesten-Keno 69 kV line. The actual project costs will be fully recovered from the customer.

QUESTION:

a) Is this to be included in the rate base account and how is this accommodated?

ANSWER:

(a)

This project is included in rate base. With the contribution there is no net impact to rate base. Costs are not included in rates until approved by the Board.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

Line 177 Re Route

2019Actual	**2020Forecast**	**2021Forecast**
	$105,000	$250,000

Some areas of L177 are on the border, or within, the highway right of way (ROW). The Yukon Highways Department is undertaking road construction upgrades; and the design will have cuts for a new ditch starting where some YEC poles are currently located. Three poles fall within a highway cut and at least one will be within 2 m of a highway cut. As a condition of our permit with YG, YEC is required to move the affected poles, and poles adjacent, in order to meet Yukon Government's construction requirements.

QUESTION:

a) Why would Yukon Energy not be liable for this error?

b) Should not Yukon Energy or their contractor absorb this cost?

c) Confirm this work completed and operational.

ANSWER:

(a) and **(b)**

Portions of L177 are within the highway ROW and the terms and conditions of the YEC permit require YEC to move assets at YEC's expense when directed to by YG. This is a regulatory requirement. As such, Yukon Energy considers it a prudent expenditure that should be considered recoverable in rates.

The existing location of the L177 reflects assessments and action done when the facilities were originally installed, and does not confirm any "error" or liability as assumed in the question.

(c)

Work is complete and operational.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

Minto Mine Substation – Neutral Ground Resistor

2019 Actual	**2020Forecast**	**2021Forecast**
$105,000		
($184,000 contribution3)		

The Minto mine requires that the following equipment be installed at the S254 Minto mine substation to be in compliance with regulatory direction: 25 kV recloser c/w bypass switch, instrument transformers, protection and controls; and 5 kV NGR c/w instrument transformers, protection and control. As this equipment is being installed at the customer's request, the full cost of the work will be recovered from the customer.

QUESTION:

a) Is this to be included in the rate base account and how is this accommodated?

ANSWER:

(a)

Projects are included in ratebase the year they come into service. The project was completed in 2019. The project includes a contribution amount that exceeds the cost incurred in 2019 due to the contribution also addressing a cost incurred in a prior year – the net impact will therefore reduce rate base. Project costs are not included in rates until reviewed and approved by the Board.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

5.2-1: GENERATION PROJECTS

Line 177 Re Route
Protection and Control Program

2019 Actual	2020Forecast	2021Forecast
		$300,000

The protection and control program is a capital replacement program under development as part of the Asset Management Framework. YEC has engaged SNC to conduct an asset condition assessment for all protection and control equipment in all generating plants and substations throughout the YEC system. The protection and control review will develop a 20-year capital plan to prioritize the replacement of aging protection and control assets throughout the YEC grid. The program is being undertaken to improve system reliability, protect generating and transmission assets, and reduce outage frequency.

QUESTION:

a) Since the YEC has spent millions on a Asset Management Program, explain why Yukon Energy would need to hire an outside consultant to do this work?

ANSWER:

(a)

This is an output of the Asset Management Program. Protection and Control is a specialized industry and as a result, consultants with this expertise are required to support YEC in development and implementation.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

Line 177 Re Route Transmission Line Access

2019 Actual	2020Forecast	2021Forecast
$324,000	$300,000	

YEC requires access to transmission lines for maintenance, inspection, and brushing activities. A number of temporary access points lacked the necessary permitting and were potentially not constructed to an acceptable standard. The Yukon government authority has indicated this situation is no longer acceptable and must be rectified. 3The project included the completion of a management plan for transmission access points including current condition, work and permits required, and estimated costs, specifically for accesses required to complete the Transmission Line Refurbishment project (see Section 5.2.1.5). It also included construction of new accesses and upgrades to existing accesses. Completion is expected to result in faster response times for emergency line work, avoidance of potential YG penalties and reliable access to key YEC assets.

QUESTION:

a) Is this not included in another area of capital works?

b) Since the YEC has spent millions on a Asset Management Program, explain why Yukon Energy would need to hire an outside consultant to do this work?

ANSWER:

(a)

No. It is not included in any other area of capital works.

(b)

This requires the support from a consultant with the expert skillset to develop a program which will be a component of the Asset Management system.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

Van Gorda Substation

2019Actual	**2020Forecast**	**2021Forecast**
$54,000	$199,000	
($188,000 contribution)		

Crown Indigenous Relations and Northern Affairs Canada (CIRNAC) is responsible for the Faro Mine Site; they are working to design, supply, install and commission a substation at the Van Gorda mine which is part of the Faro mine complex. CIRNAC has also expressed interest in transferring ownership of an existing stepdown transformer (138kV: 4.16 kV / 12 MVA) at the Faro substation which is currently out of service. CIRNAC has requested that Yukon Energy support their project. Yukon Energy's role in the project would be to support CIRNAC and its technical consultants with respect to technical and operational matters, support transfer of ownership of the T1 Transformer, supply YEC approved meters, complete SCADA works for YEC monitoring, and monitor commissioning activities. YEC will witness all commissioning and start up activities.

QUESTION:

a) Why is this not fully recovered from CIRNAC?

b) Is this to be included in the rate base account and how is this accommodated.

ANSWER:

(a)

CIRNAC is making a full contribution for costs related to YEC supporting CIRNAC and its technical consultants with respect to technical and operational matters, support transfer of ownership of the T1 Transformer, supply YEC approved meters, complete SCADA works for YEC monitoring, and monitor commissioning activities. The application included a forecast contribution of $188k for this work in 2020 in error. It should have shown a contribution of $54k in 2019 and $134k in 2020 (total forecast contribution for both years of $188k).

The variance in forecast costs in 2020 of $65k ($199k forecast spending -134k contribution from CIRNAC) relates to additional costs incurred by YEC to complete SCADA works for

YEC monitoring that were not part of the CIRNAC scope of work. The scope of this work included the following:

- Installation/commissioning of radio communication equipment at the Faro diesel plant and the CKRW tower to ensure YEC has the ability to send and receive SCADA information from Vangorda substation and Faro mine;

- A new revenue meter and CTs for the revenue meter purchased and installed at Faro mine; and

- Replacement of the revenue meter PTs at Vangorda to meet ATCO's metering system requirements.

(b)

The project was completed in 2020 and included in rate base. Contributions would reduce the impact on rate base. Costs are not included in rates until approved by the Board.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

WAF Transmission Upgrades

2019Actual	**2020Forecast**	**2021Forecast**
$793,000		

The WAF transmission system allows low cost hydro generation supplied from Aishihik, Whitehorse, or Faro to be transmitted to other locations on the grid. 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 were in various stages of deterioration. 2019 project work focused on L178 (Carmacks to Faro). The remainder of the WAF line was addressed as part of the Transmission Line Refurbishment (TLR) project (see Tab 5, Section 5.2.1.5); and the remainder of the deficient L178 structures will be replaced as part of the L178 portion of the TLR project (see Tab 5, Section 5.2.1.6).

QUESTION:

a) Appears to be a duplicate of the L178 capital request? Explain.

ANSWER:

(a)

The 2019 WAF Transmission Upgrades project work focused on L178 (Carmacks to Faro). This work was completed separately from the L178 portion of the TLR project.

The excerpt referenced in the preamble to this question specifies that the remainder of the WAF line upgrade work (not included in the WAF Transmission Upgrades) was addressed as part of the Transmission Line Refurbishment (TLR) project (see Tab 5, Section 5.2.1.5); and the remainder of the deficient L178 structures will be replaced as part of the L178 portion of the TLR project (see Tab 5, Section 5.2.1.6). Table 5.2-1 in Tab 5 of the Application does not show spending on the L178 portion of the TLR project prior to 2021.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

5.2-3: DISTRIBUTION PROJECTS

Customer Extensions

2019Actual	2020Forecast	2021Forecast
$626,000		
($698,000 contribution)		
	$600,000	
	($426,000 contribution)	
		$600,000
		($400,000 contribution)

Yukon Energy is required to provide service to new customers connecting to the grid system. Customer extensions are forecast and budgeted as capital items without identifying specific projects. Most costs of customer extensions are covered by customer contributions pursuant to the Terms and Conditions of Service.

QUESTION:

a) Explain how you forecast extensions and contribution?

ANSWER:

(a)

YEC uses a rolling average for the customer extensions budget. It is difficult to predict the number and type projects YEC may see on an annual basis (e.g., commercial projects where contributions can be quite high). The number of customer connects can be quite variable year to year.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

L355 Voltage Regulator

2019Actual	2020Forecast	2021Forecast
$144,000	$35,000	

Atco Electric Yukon (AEY) has reported low voltage levels (below CSA standards) at the AEY Haines Junction substation, which is supplied from Aishihik via distribution line L355. The project identified the voltage profile of L355, determined the appropriate location and settings of voltage regulators, and completed all installation and commissioning work.

QUESTION:

a) Were these new voltage regulators and are they now in use?

b) What is the forecast work for 2020? And why to rate base?

ANSWER:

(a)

These are new voltage regulators and are now in use.

(b)

The forecast work in 2020 was to install additional ground conductor and to commission once complete. This was a capital expenditure.

TOPIC **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

System Improvements for Eagle Gold Mine

2019 Actual	**2020Forecast**	**2021Forecast**
$487,000		
($487,000		
Contribution)		

The VGC Group PPA provides for development on the Yukon grid of the McQuesten Substation plus the Initial YEC Facilities Improvements, as described in Schedule C of the VGC Group PPA, prior to Commencement of Delivery to the Eagle Gold Mine. These Yukon grid enhancements and facilities are required to connect the Mine to the existing transmission grid, to maintain acceptable system voltages while supplying this new load, and to address potential contingent operating conditions such as loss of generation at Mayo or loss of the transmission connection between Mayo and Whitehorse. The VGC Group PPA provides in Section 6.1 for YEC to recover from the mine the reasonably incurred capital costs for the Initial YEC System Improvements as set out in Schedule C of the PPA.

QUESTION:

a) How is this accounted for in the rate base?

ANSWER:

(a)

Project costs are included in rate base the year the project is completed. With the contribution there is no net addition to ratebase. Costs are not included in rates until approved by the Board.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

5.2-4: GENERAL PLANT AND EQUIPMENT PROJECTS

Communications Upgrades

2019Actual	**2020Forecast**	**2021Forecast**
$801,000		

The project completed a number of recommendations that resulted from a Communications Needs Assessment undertaken by an independent consultant that were required to achieve necessary improvements in security, integration, performance and redundancy. The project was reviewed in detail in the 2017/18 GRA.4 YEC noted at the time that the project was planned to be executed over multiple years –"The 2017/18 review noted that satellite installations for SCADA and fibre communications upgrades were required to create redundancy for disaster planning; network access controls were needed due to changes resulting from the satellite installations, and that the SCADA communications upgrades would facilitate satellite communication at YEC's various sites. Key projects completed in 2019 included: fibre communication upgrades; SCADA upgrades, the Takhini Redundant Datacentre; Satellite installations for SCADA.

QUESTION:

a) Identify the independent consultant for the Communications Needs Assessment, work completed and cost.

b) Identify the contractor/s who did the upgrades, work completed and costs.

c) Are all these upgrades now operating efficiently?

ANSWER:

(a)

The Communications Needs Assessment was completed by BBA to provide a holistic assessment of YEC's communications infrastructure and a guide to evolving it to meet future needs and requirements. The BBA assessment was completed in 2016 at an approximately cost of $60,000. A review/ update of this work was undertaken in 2018 to finalize the scope of the capital project at a cost of $10,788.

The study looked at both information technology and operations technology and addressed the following:

- 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, etc.
- Review of current network topography
- Review of existing SCADA, data, voice and video communications infrastructure
- Risk identification and qualification
- Identification of gaps with equipment capabilities
- Maintenance requirements and life cycle estimates
- Limitations and risks summary
- Available Technology, options.
- Simple cost/benefit/risk analysis.
- Office and mobile workforce equipment requirements.
- Substation and plant equipment requirements.
- Bridging strategies in existing facilities and requirements in new plant.
- Overall Data Communications strategy.
- Opportunities for improvement.
- Opportunities for joint-ventures (Government, First Nations, Northwestel, Private)
- Growth strategy including an examination of maintenance workforce requirements.

(b)

The project was completed at a total cost of $1.152 million.[1] 2019 actual spending was $0.801. million.

[1] $0.351 million was included in ratebase as part of the 2017/18 GRA Application; and $0.801 million was incurred in 2019. The project was completed in 2019.

A summary of costs by contractor is as follows:

Table 1: Project Cost by Contractor

Vendor	Note	Activity	2017	2018	2019	Total
Charter Telecom	A	Data Centre materials and some network programming	25,097	145,072	354,611	524,780
Northwestel Inc.	B	Fiber work for Takhini and Mayo			208,350	208,350
Total North Communications	C	Satellite equipment and installations (includes costs related ot UPH Networks)			49,596	49,596
Dell Computer Corporation	D	Dawson and Mayo Community Servers	30,415			30,415
Westower Communications Ltd	E	New Ashihik Headgate Tower			26,490	26,490
BBA Engineering Ltd.	F	Update to original communications needs assessment		10,953		10,953
McWatters Network Engineering LTD	G	Nwtel Service Upgrade Project Management and Fiber Design consulting	5,700	17,550		23,250
Alpha Technologies	H	Radio equipment for Ashihik	189		7,348	7,537
CDW Canada	I	Radio equipment for Ashihik			7,517	7,517
Walters Construction & Industrial Corp	J	Aishihik Tower pad construction costs			6,670	6,670
Teshmont Consultants LP	K	Aishihik Tower erection costs			4,708	4,708
R.C. Crane and Construction	L	Aishihik Tower erection costs			4,130	4,130
IBEX Construction Ltd.	M	Aishihik Tower erection costs			1,487	1,487
Maven Consulting Limited	N	Aishihik Tower engineering costs			1,063	1,063
			61,401	**173,574**	**671,971**	**906,946**
YEC Materials, Overhead and Other		Labour, design, materials , and Mayo Communiations Shack	**34,463**	**81,175**	**129,324**	**244,961**
Total			**95,864**	**254,749**	**801,294**	**1,151,907**

(c)

Yes, these upgrades have been installed successfully and are delivering the functionality and benefits as per the objectives of the program.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

Building Upgrades

2019Actual	**2020Forecast**	**2021Forecast**
$370,000	$275,000	

In 2016, an external consultant was hired to perform an asset assessment on YEC-owned buildings and facilities, mainly consisting of staff houses and administration buildings.

2019 work included: exterior works,7 HVAC retrofits,8 flooring replacement,9 electrical panel replacements,10 and equipment replacement. 2020 costs relate to replacement of the WH4 hydro plant (P127 roof). During 2019 the roof membrane failed, and an interim patch was installed to address a leak. If the roof was not repaired additional leaks would develop and need to be addressed at a much higher cost.

QUESTION:

a) Identify the external consultant hired to perform asset assessment and costs associated.

b) Is all the work now completed?

c) Does Yukon Energy have a maintenance person for its buildings?

ANSWER:

(a)

Golder Associates Ltd was hired to perform the asset assessment. The cost for this work was $131,350 + GST.

(b)

Work was completed as per priorities identified and budgeting, another assessment was due to be done in 2020 as part of a 5 year renewal plan. This has yet to occur as there are still some outstanding deficiencies being addressed in 2021.

(c)

A property manager is in place. There is no maintenance personnel dedicated to buildings, and the work is primarily outsourced.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

Compact Digger Truck

2019Actual	**2020Forecast**	**2021Forecast**
		$185,000

The purchase of a 4 to 5 ton chassis compact digger truck for use in Dawson...

QUESTION:

a) Is this digger truck now purchased and operating in Dawson?

ANSWER:

(a)

No. Procurement will happen in 2021.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

Crane Inspection

2019Actual	**2020Forecast**	**2021Forecast**
	$165,000	$400,000

During an annual crane inspection, three YEC cranes (Aishihik service building, P127 powerhouse, & P127 stop log hoist) were identified as needing significant structural, electrical, and mechanical repairs in order remain in acceptable working condition. 2020 spending will provide for a detailed assessment of each crane to determine an engineered plan for replacement or refurbishment as required. Actual construction activities are planned for 2021.

QUESTION:

a) Has this inspection and construction been completed and now operating?

ANSWER:

(a)

The inspection has been completed and the cranes are functional. However, there is work still to be completed.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

5.2-4: GENERAL PLANT AND EQUIPMENT PROJECTS

Mayo Earthworks
2019Actual 2020Forecast 2021Forecast
$300,000

A number of issues at and around the Mayo Hydro facilities have been identified. These include slope instability and erosion issues near access roads (Mayo A, Mayo B, and Wareham dam), both powerhouse buildings, surge tank, and both substations. During 2019 a complete site inventory of civil issues was undertaken to identify and prioritize embankments. 2020 spending developed a detailed work plan for identified issues including a geotechnical assessment, topographic survey, detailed engineering design (including drawings and specifications), construction methodology, and project scope, schedule & budget development.

QUESTION:

a) Is this earthworks all completed or was this just for the assessment work?

b) Identify contractor, work completed and cost for each job.

ANSWER:

(a)

Only assessment work has been completed.

(b)

Assessment and engineering work was completed by CAP Engineering at a total cost of $101,985.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

5.2-4: GENERAL PLANT AND EQUIPMENT PROJECTS

New Mobile Office Unit – IT

2019Actual	2020Forecast	2021Forecast
		$230,000

The existing IT trailer houses five offices and a closed storage space. It is aging and requires additional O&M support each year. The project involves replacement of the aging, undersized IT trailer with a larger unit able to accommodate eight office spaces and storage. Additional office spacing would allow for staff expansion as a less costly solution than building onto the main building.

QUESTION:

a) Has this IT trailer been bought, set up and operational?

ANSWER:

(a)

No. The procurement process has not started for the new IT trailer.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

Vehicle Purchases

2019Actual	**2020Forecast**	**2021Forecast**
$258,000 $	476,000	$580,000

Fleet vehicles...

QUESTION:

a) Identify which vehicles have been purchased and are operational?

ANSWER:

(a)

Please see response to YUB-YEC-1-85.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

Water Improvement Upgrades

2019Actual	**2020Forecast**	**2021Forecast**
$150,000		

The cooling water and potable water systems in the YEC main corporate office have experienced pre-mature piping failure and select cooling coil leaks for at least the past 10 years. An external engineering firm was engaged to assess the current systems and provide recommendations to address the issues. The project will implement those recommendations including the installation of a particulate filter, a VFD drive for the existing pump, a heat exchanger, new cooling water piping and valves, and fan coil drip pans with leak detection.

QUESTION:

a) Which firm did assessment, and at what cost?

b) Are the necessary changes made and operational?

ANSWER:

(a)

Stantec Architecture Ltd. was retained to do the assessment at a cost of $7,450.00 + GST.

(b)

With the exception of an exchanger all changes have been made, and the water system is currently functional.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

5.2-5: OVERHAULS & RESERVE FOR SITE RESTORATION PROJECTS

FD7 Overhaul

2019Actual	2020Forecast	2021Forecast
		$580,000

Faro Diesel #7 (FD7) is located at the Faro Diesel Plant and uses as 12-cylinder Caterpillar Model 3612 diesel engine as its prime mover (vintage 1992).

QUESTION:

a) Is FD7 overhauled and now operational?

ANSWER:

(a)

FD7 has not been overhauled. It is operational.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

5.2-5: OVERHAULS & RESERVE FOR SITE RESTORATION PROJECTS

Decommissioning on WD3

2019Actual	2020Forecast	2021Forecast
		$999,000

After removing the third Mirrlees engines from service, all three units were fully decommissioned. Decommissioning included disassembly and removal of all ancillary equipment and piping, asbestos abatement as required, separation and hoisting of major engine components, and backfill and compaction of the engine pits. All decommissioned equipment was removed from site and appropriately disposed of.

QUESTION:

a) Is this work complete or is it forecast?

b) Identify contractor and cost for each project.

ANSWER:

(a)

This work is complete.

(b)

The contractor for this project was Klondike Welding and the total cost for the project was $999,000.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.2: CAPITAL PROJECTS TO RATE BASE**

Site Restoration Transmission Lines
2019Actual 2020Forecast 2021Forecast
$174,000

The Utility maintains a regulatory provision for future removal and site restoration related to property, plant and equipment. Costs of dismantling capital assets, including site remediation, are applied to this account. In 2019, YEC spent $0.174 million on site remediation relating to the L178 and L355 Transmission Lines.

QUESTION:

a) Identify contractor/s work completed and costs.

ANSWER:

(a)

In 2019, YEC spent $0.174 million on site remediation relating to the L178 and L355 Transmission Lines. Work included site restoration after the structure repairs and or replacement. Some of the work was related to failed test and treat structures where the pole shell thickness was less than 2 inches, this requires a pole change out. Work on structures included:

- 61 structures L178
- 15 structures L355

Costs were allocated as follows:

- Ibex Construction performed the work on L178 ($122,436);
- YEC performed the work on L355 (approximately $52,000).

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

1. Aishihik Generating Station (AGS) Long Term Year Water Use Licence Renewal

2018 WIP	2019Additions	2020Additions	2021Additions
$4,957,199	$512,755	$1,488,000	$960,000

The planned long term AGS Water Use Licence renewal project and related costs were initially reviewed as part of the 2017/18 GRA. At that time, it was noted that the total forecast budget for the project was $3.569 million spread over five years (2015-2019). Project expenditures to support the long term licence renewal were reviewed in detail in the 2017/18 GRA (See Section 5.3.1.2 and response to YUB-YEC-1-77 in that GRA). Total deferred costs to the end of 2018 were forecast at $2.899 million.

In 2018, Yukon Energy prepared a long-term Project Proposal application for filing with YESAA Designated Office in December 2018, prior to Yukon Energy's decision in early 2019 to secure a three-year licence renewal.1 The longterm Project Proposal document was updated over Q1 and Q2 2020 and filed with the Haines Junction Designated Office in July 2020. It is expected that the Designated Office review process will be completed in Q2 2021. Yukon Energy expects to prepare and file its long term water use licence renewal application with the Yukon Water Board in early 2021, and that a hearing regarding the licence renewal would occur sometime in 2022. The deferred costs forecast in the Application include spending in WIP increasing from $4.957 million at the end of 2018 to $7.918 million by the end of 2021. The project is forecast to be complete by the end of 2022. A three-year licence renewal was secured in February 2020, extending the licence to December 31, 2022.

QUESTION:

a) Outline project related work completed, costs and contracts awarded, as prepared for 2017/18 GRA.

b) Were these approved? If so, give relevant Board decision.

c) If forecast cost to end of 2018 were forecast at $2.899 million, why is the 2018 WIP listed at $4.957,199 million.

d) Identify firms hired, contract amount and work completed for the $512,755, 2019 additions.

e) Identify in-house work completed and costs for 2019 additions.

f) Identify firms hired, contract amount and work completed for the $1.488 million 2020 additions.

g) Identify in-house work completed and costs for 2020 additions.

h) Identify firms hired, contract amount and work completed for the $0.966 million 2021 additions.

i) Identify in-house work completed and costs for 2021 additions.

ANSWER:

(a)

In the 2017/18 GRA, the total budget for the project was forecast at $3.569 million spread over five years (2015 – 2019). The information prepared for the 2017/18 GRA with regards to the work is detailed in YUB-YEC-1-77 from the 2017/2018 GRA (see Attachment 1 to this response).

(b)

This was a deferred project in the 2017/18 GRA. The project was not forecast at that time to be completed until the end of 2019. As such these costs were not approved as part of that prior proceeding.

(c)

The 2018 costs were forecast costs at the time of the GRA filing; actual 2018 costs as reported in the 2021 GRA are higher than the 2017-18 GRA forecast. In both GRA's, these costs remain in WIP.

(d)

Table 1 below provides the contractors, work completed, and costs incurred in 2019 for the project. YEC internal costs incurred in 2019 are addressed in response to part (e).

Table 1: Contractor Costs and Work Completed (2019)

Contractor	Cost	Work Completed
Ecofor Consulting Ltd	$90,923	Archaeological and heritage resources technical support
Environmental Dynamics Inc.	$80,631	Support of YESAB DO Assessment Project Proposal development, Biophysical technical work, Canyon Lake monitoring
InterGroup Consultants Ltd.	$113,479	Project management, Preparation of YESAA Project Proposal, YESAB DO Assessment Support, Preparation of Monitoring & Adaptive Management Plan, Participation in technical working group, support to compensation and other project negotiations
Morrison Hershfield Limited	$85,124	MAMP Technical Development, YESAB DO Assessment Support, Responses to Information Requests, Downstream technical work.
Total	**$370,157**	

(e)

Table 2 below provides YEC internal costs incurred in 2019 for the project.

Table 2: Yukon Energy Internal Costs (2019)

Element	Cost	Description
Internal Labour	$4,023	Project Management, Development of Project Proposal
Other Internal Costs	$3,046	Materials, travel, communications
AFUDC	$135,528	Accrual of AFUDC
Total	**$142,597**	

(f)

Table 3 below provides the contractors, work completed, and updated costs incurred in 2020 for the project (the updated costs are higher than the forecast in the Application).

Table 3: Contractor Costs and Work Completed (2020 Forecast)

Consultants	Cost	Work Completed
Aasman Brand Communications Inc.	11,469	Communications and materials development, graphic design
Daryn R.Leas Law Corporation	87,211	Consulting and advisory services for Project Agreement negotiation
DLA Piper (Canada) LLP	172,305	Legal support
Ecofor Consulting Ltd	18,705	Archaeological and heritage resources technical support
Environmental Dynamics Inc.	175,238	MAMP Technical Development, YESAB DO Assessment Support, Biophysical technical work, Canyon Lake monitoring,
InterGroup Consultants Ltd.	340,517	Project management, Preparation of YESAA Project Proposal, YESAB DO Assessment Support, Preparation of Monitoring & Adaptive Management Plan, Participation technical working group, support to compensation and other project negotiations.
Morrison Hershfield Limited	303,389	MAMP Technical Development, YESAB DO Assessment Support, Responses to Information Requests, Downstream technical work, Technical Support for Water Board Application
Champagne & Aishihik First Nations	770,510	Contributions to support technical review of project; Chemi narrows payment from 2002 relicensing process
Total	**$1,879,433**	

(g)

Table 4 below provides updated YEC internal costs incurred in 2020 for the project.

Table 4: Yukon Energy Internal Costs (2020 Forecast)

Element	Cost	Description
Internal Labour	67,201	Project Management, Development of Project Proposal, Attendance at Technical Working Group meetings, Attendance at Technical Subgroup Meetings, Attendance at Steering Committee Meetings, disbursements for printing, venue rental, telecommunications, etc.
Other Internal Costs	27,594	Materials, printing, travel, communications
AFUDC	164,665	Accrual of AFUDC
Total	**$259,460**	

(h) and **(i)**

Table 5 below provides the costs for the 2021 current contracts budgeted to the end of March 2021. Additional work for the remainder of 2021 has not been contracted or completed.

Table 5: Contractor Costs and Work Budgeted to end of March 2021 (Forecast)

Contractor	Cost	Work Anticipated
Morrison Hershfield Limited	$59,945	MAMP Technical Development, YESAB DO Assessment Support, Responses to Information Requests, Downstream technical work, Technical Support for Water Board Application
Environmental Dynamics Inc.	$89,528	MAMP Technical Development, YESAB DO Assessment Support, Responses to Information Requests, Biophysical technical work, Technical support for Fisheries Act Authorization
InterGroup Consultants Ltd.	$129,320	Project management, YESAB DO Assessment Support, Preparation of Monitoring & Adaptive Management Plan, Participation in technical working group, Support for Water Board Application development; support to compensation and other project negotiations
Ecofor	$6,600	Heritage and socio-cultural technical support
Champagne & Aishihik First Nations	$90,000	Contributions to support technical review and participation in project committees

To date, YEC has incurred $18,389 of internal labour costs in 2021 for project management and technical resources to support the YESAB DO Assessment development of the Monitoring and Adaptive Management Plan.

Please see response to YUB-YEC-1-90 for a review of updated project costs by activity through to forecast completion at the end of 2022.

Yukon Energy Corporation
2017 – 2018 General Rate Application
YUB-YEC-1-77

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: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

2. Whitehorse Generating Station Water Use Licence Renewal

2018 WIP	2019Additions	2020Additions	2021Additions
			$260,000

The existing water use licence for the Whitehorse Rapids Generating Station (WRGS) expires at end of 2025 and must be renewed in order to ensure ongoing, lawful operation of the WRGS hydro facilities. This is a multi-year project to renew the existing long-term project authorizations for the WRGS Hydro Plants and associated infrastructure. Project activities include conducting required baseline studies (e.g., environmental, socio-economic, engineering), and undertaking environmental and socio-economic effects assessment, First Nation engagement and consultation, other stakeholder engagement as required to submit a YESAA project proposal to the Whitehorse Designated Office. Project activities will also include completing the YESAA review process, the water use renewal process with the Yukon Water Board, and Fisheries Act Authorization (DFO) regulatory process.

QUESTION:

a) Identify firms hired, contract amount and work completed for the $0.260 million 2021 additions.

b) Identify in-house work completed and costs for 2021 additions.

ANSWER:

(a) and **(b)**

No work on this project has been initiated to date.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

Diesel Retirement Replacement (12.5 MW)

2018 WIP	2019Additions	2020Additions	2021Additions
$41,007	$554,224	$800,000	$5,000,000

it was determined that considering the results of the technical, environmental and socio-economic research, as well as public feedback, YEC would focus potential options to add or replace capacity at existing generation facilities on an incremental basis as diesel engines are retired. This includes consideration of the following near term activities:

- Installation of 5 MW of thermal capacity at the Whitehorse Diesel Plant (P126);
- Replacement of 5.1 MW of diesel to be retired at the Faro Diesel Plant with a 5 MW diesel unit;
- Retirement of the existing 2.5 MW of diesel capacity in Dawson City with installation of 2.5 MW of diesel capacity at the Callison Substation.

Efforts in 2020 have focused on preliminary engineering and finalizing a procurement strategy, defining vendor contracts and milestones, and updating the overall project schedule.
The deferred costs forecast in the Application assume that the project continues, with spending in WIP increasing from $0.041 million at the end of 2018 to $6.395 million by the end of 2021. Dependable capacity from these projects is expected to be available by winter 2023/24. In the interim, Yukon Energy will continue to rent diesel generators each winter to ensure an adequate supply of back-up power in case of an emergency.

QUESTION:

a) Identify all diesels with capacity now retired.

b) Identify all consultant firms hired, work performed and each cost for 2018WIP, 2019 and 2020 years totaling $1,395.231 million.

c) Identify all in house work performed and cost for these years.

d) Is the $5 million for 2021 for a new diesel generator? Explain.

ANSWER:

(a)

WD3 in Whitehorse was retired in March 2019. In addition, Yukon Energy plans to retire the following diesel units as follows:

- Faro Diesel 1 (FD1) - March 2022;
- Dawson Diesel 2 (DD2) - March 2023; and
- Dawson Diesel 5 (DD5) - March 2023.

(b)

Please see Table 1 below.

Table 1: Summary of Consultant Firms Hired and Work Performed - 2018 to 2020

Consulting Firm	Work Conducted	2018 Costs	2019 Costs	2020 Costs
Aasman Brand Communications Inc.	Consulting for public communications and engagement		$89,931.57	
ArticCan Energy Services	GHG Lifecycle Analysis		$31,130	
Asher Engineering Ltd.	Initiation work for generator technical specification engineering			$4,749.76
Associated Engineering	Road upgrade estimates		$4,930	
Associated Environmental Consultants Inc.	YESAA DO Level Assessment preparation for Dawson project			$8,777.64
BBA Engineering Ltd.	P126 Building Retrofit engineering		$12,423.37	$60,067.16
Core Geosciences Services	Air Quality Modeling			$1,757.50
DLA Piper (Canada) LLP	Legal support			$3,576.64
Environmental Dynamics Inc.	Environmental Attributes desktop review			$10,344.85
Geotech Drilling Services Ltd.	P126 geotechnical drilling			$50,403.93
Hatch Ltd.	Technical study support		$44,800	$19,200
Hemmera Envirochem Inc.	Noise monitoring for Whitehorse project			$38,000
IBEX Construction Ltd.	Construction support for geotechnical drilling			$3,784.5
InterGroup Consultants Ltd.	Socioeconomic Attributes report support and project regulatory analysis		$18,611.5	$12,905

Consulting Firm	Work Conducted	2018 Costs	2019 Costs	2020 Costs
Laberge Environmental Services	Vegetation mapping and rare plant survey		$7,670.56	
Maven Consulting Limited	Procurement scope development support			$1,537.5
Midgard Consulting Inc	Feasibility engineering	$6,775	$221,659.70	$117,566.30
Orbis Engineering Field Service Ltd.	Public engagement technical support		$2,572.50	
Teshmont Consultants LP	System Impact Study support		$9,017.25	
Tetra Tech Canada Inc.	Geotechnical reporting		$7,152.36	
Vector Research	Participation on Advisory Committee		$1,837.5	
WSP Canada Inc.	Air quality and plume modeling		$12,870	$16,330

(c)

In-house work conducted on the project consisted primarily of project management for the feasibility engineering and support of the public engagement activities. Internal labour costs for the project are summarized in the table that follows:

Table 2: Internal Labour Costs

2018	2019	2020
$19,533.50	$108,294.96	$61,131.57

(d)

Please response to YUB-YEC-1-92.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

5.2-3: SPENDING TO MAXIMIZE RENEWABLE GENERATION FROM EXISTING FACILITIES

4. Southern Lakes Enhanced Storage (Marsh Lake Storage Project)

2018 WIP	2019Addition	2020Additions	2021Additions
$7,319,000	$374,899	$485,000	$1,200,000

Forecast MLSEP project costs and actual expenditures were reviewed in detail in the 2012/13 and the 2017/18 GRAs. The 2012/13 GRA, identified the project as a relatively small project, with earliest in-service assumed in 2014 (first full year 2015) at a capital cost (2010$) of $10.5 million, with mitigation design (shoreline erosion and surface water) expected to comprise about one-half of this total cost (actual costs for mitigation were stated in the 2012/13 GRA as an item that at that time could not be known with any certainty). In the 2017/18 GRA, forecast total project costs increased to $15.377 million ($9.795 million forecast for effects assessment; $0.300 million forecast for YESAA assessment and permitting; and $7.127 million forecast for mitigation implementation).3 Annual incremental hydro generation was estimated at 6.4 GW.h on average, focused in winter months at the current Whitehorse plant. Annual operating cost (2010$) was estimated at $8/MW.h. Full Utilization LCOE (2010$) was estimated at 8.5 cents/ kW.h. Marsh Lake Storage was also assumed in the 2012/13 GRA.

Project Update

During the 2017/18 GRA, Yukon Energy indicated that the next major milestone was obtaining First Nation support for the project in order to progress to the YESAB assessments stage. The deferred costs forecast in the Application assumes that the project continues, with spending in WIP increasing from $7.319 million at the end of 2018 to $9.379 million by the end of 2021. Potential in service for the Project is 2023.

QUESTION:

a) Does Yukon Energy now have all involved First Nations and Southern Lakes property owners on board with this project. Provide documents demonstrating this.

b) Identify all consultant firms hired, work performed and each cost for 2018WIP, 2019, 2020 and 2021 years totaling $9.319 million.

c) Identify all in-house work performed and cost for these years.

d) What is the new estimated cost to do the construction and mitigation for this project?

e) What would be the updated LCOE?

ANSWER:

(a)

YEC is committed to continuing to work with all affected First Nations and impacted property owners as part of advancing the project. Engagement with First Nations and impacted property owners will be a key element of the workplan in drafting of a YESAA Designated Office Project Proposal in 2021. The outcomes of the engagement will inform YEC's Board of Directors on its decision on whether to submit the Project Proposal to YESAB.

(b)

The consultant firms, work performed, and cost for 2018WIP, 2019 and 2020 are shown in the table below. Costs for the project have not yet been incurred in 2021.

Table 1: Southern Lakes Enhanced Storage Costs: 2018 to 2020

Contractor	2018 WIP Cost	2019 Costs	2020 Costs	Work Performed
1140609 Alberta Ltd.	6,600			Consultant engaged by TKC to conduct technical review on items including ice hydraulics and downstream impacts in Yukon River of project.
Aasman Brand Communications Inc.		65,313	7,491	Communications support, development of ads, development of online and print materials, graphic design.
AECOM Canada Ltd.	1,133,551			Prime project consultant 2009 through 2013. Baseline biophysical and engineering studies, preliminary effects assessments, conceptual mitigation design and comparative analysis, support for community/government engagement and consultation.
Ben's Electric	935			Army Beach pump
Bill Slater Environmental Consulting	2,220			Technical consultant engaged by TKC to review Project

Contractor	2018 WIP Cost	2019 Costs	2020 Costs	Work Performed
Brimar and Associates Survey Ltd	20,013			Army Beach Drainage/Ditch mitigation design
Canada Post Corporation		2,837		Mailouts
Carcross Tagish Renewable Resource Council	5,500			Contribution for Cisco Fish Study
Carcross/Tagish First Nation	41,207			Contribution Agreement for workshops, meetings, and consultation in support of technical review of project.
DataPath Systems			600	Hosting of Southern Lakes Water Level Committee's website
Dexter Kotylak	160			Army Beach honorarium
Environmental Dynamics Inc.	27,201			Lake trout beach seining data collection, miscellaneous mapping of Southern Lakes, Army Beach draining frog salvage
GW Solutions Inc.	7,998			Groundwater technical support
Hemmera Envirochem Inc.	1,437,068	14,977	21,434	Technical support, workplan development, erosion/groundwater/other technical studies, First Nations engagement support, technical reviews, support of public engagement sessions
Horizon Helicopters	2,278			Helicopter for Southern Lakes erosion recon
Industrial Electric Services Ltd.	133			Technical contractor work on the mitigation trial of the drainage control valve and water pump at the end of the Army Beach Road.
Keith' Plumbing & Heating Co. Ltd	42,810			Sump pump and related hardware supply and installation
Kwanlin Dun First Nation	25,104			Contribution Agreement for workshops, meetings, consulting services for technical reviews
M.Miles & Associates Ltd	34,640			Technical advisory services for Water Level Committee, technical review of river geomorphology
Morrison Hershfield Limited	4,994			Minor consulting services to transition from AECOM to new prime consultant

Contractor	2018 WIP Cost	2019 Costs	2020 Costs	Work Performed
Northwest Hydraulic Consultants			2,425	Follow up questions and request for information on previous technical work NHC completed on the project related to erosion impact assessment and mitigation design.
Nunatak Contracting & Construction	270			Installation of Army Beach pump
Stantec Consulting Ltd. (Vancouver)		51,746	25,728	Technical consulting services; Public Engagement planning, facilitation and support, preparation of What We Heard report
Toews, Don	1,500			Senior review of Project Proposal
Wildstone Industrial Ltd	52,307			Mash Lake Army Beach Drainage Mitigation
Yukon Bureau of Statistics		46,170		Southern Lakes and Yukon-wide surveys
Yukon Conservation Society	117,697			SLWLC contribution agreement funding and acting as treasury for Committee
Earlier work without easy record access*	2,684,603			
Grand Total	**5,648,788**	**181,043**	**57,677**	

*Earlier work done prior to current financial reporting. Given that this project remains in WIP for the 2021 GRA, the effort to try and secure information from prior records was not feasible for the current IR response process.

(c)

Internal costs for 2018 WIP, 2019, 2020, and 2021 to date are provided in Table 2 below.

Table 2: Southern Lakes Enhanced Storage Internal Costs

	2018 WIP	2019	2020	2021
1-Labor	294,331	32,601	10,733	935
2-Travel Exp	5,988	74	11	-
3-Matl, Supl, Inv	165,893	-	-	-
5-Rental	2,174	-	-	-
6-General	67,023	-	-	-
7-Fuel & Util	2,900	908	967	87
8-AFUDC	1,131,979	160,262	175,572	-
Total	**1,670,289**	**193,846**	**187,283**	**1,022**

(d)

Please see response to YUB-YEC-1-93.

(e)

Please see response to YUB-YEC-1-93.

TOPIC: **Capital Projects**

REFERENCE: **5. Mayo Lake Storage Enhancement Project – including Mayo Lake Outlet Dredging**

2018 WIP	2019Additions	2020Additions	2021Additions
$3,373,374	$262,379	$460,000	$525,000

E (2010$) of 6.3 centres/kWh

[6] Section 5.3.1.4 of the 2012/13 GRA Application reviewed the project concept, work completed to date (including environmental and socio-economic fieldwork activities, analysis and assessment, project proposal preparation, engineering support, and public consultation), and project risks, costs and benefits. The project was included in the 2012/13 GRA under Relicensing rather than Feasibility Study deferred cost projects, reflecting the central objective to modify the current water licence affecting water storage at Mayo Lake.

[7] Section 5.3.1.9 of the 2017/18 GRA provided an update on the project progress, costs, and potential in service. Further detail was provided in response to YUB-YEC-1-85 in the 2017/18 GRA. In Order 2018-10, the Board noted that it had approved the Mayo Lake storage enhancement in Order 2013-01, and that given that sediment removal was necessary to realize any benefits from this project it was prudent to expand the scope of work for this project accordingly.

Project Update
In 2018, Northwest Hydraulic Consultants (NHC) was retained to provide a technical assessment regarding whether sediment remediation steps in the Mayo Outlet Channel were feasible and cost effective. The deferred costs forecast in the Application assume that the project continues, with spending in WIP increasing from $3.373 million at the end of 2018 to $4.621 million by the end of 2021.

QUESTION:

a) Confirm the N'acho Nyak Dun has been in favour of this proposal from the start and continuing until this day. Provide documents demonstrating this.

b) What is the estimated total cost to complete this project?

c) What is the updated LCOE?

ANSWER:

(a)

YEC continues to work with the First Nation of Na-Cho Nayak Dun to obtain their feedback on the project and their specific input into the YESAA Project Proposal and the Monitoring and Adaptive Management Plan. The FNNND supported the prior YESAA Project Proposal submission on this project that YEC had to withdraw to address Mayo outlet channel dredging planning. Obtaining FNNND's support to move forward to a YESAA Designated Office assessment is an objective of YEC's project plan.

(b)

Please refer to YUB-YEC-1-94.

(c)

Please refer to YUB-YEC-1-94.

TOPIC: Capital Projects

REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

5.4-2: FEASIBILITY STUDIES – CONTINUED RELIABILITY & ASSET IMPROVEMENTS

Building Condition Reports 2020-2024

2018WIP	**20192020Addition**	**2021Addition**
		$175,000

Building condition reports are required to formally document the structure and fabric of a property, describe the construction of the building and its current condition, and outline work required, timing and costs for completion.

An external engineering firm will undertake site visits for all owned YEC properties and provide an assessment of the condition of each site that outlines requirements for immediate maintenance and repairs; maintenance and repairs required over the next five years; code violations; and cost estimates for required work. The building condition report will be used to forecast O&M projects building condition assessment capital works over 2020-2024. The project is to be closed in 2021 with total expenditures of $175,000 to be amortized over five years.

QUESTION:

a) Why does Yukon Energy not simply get a building inspector from the YTG or Whitehorse to building inspections as that is what they do, instead of hiring an expensive engineer, most of who are even not qualified to do all the necessary tasks.

b) Identify which engineering firm received contract.

ANSWER:

(a)

Regulatory building inspectors only review assets for compliance with code; YEC required an asset health assessment which is not a service offered by compliance authorities.

(b)

Please see response to UCG-YEC-1-73.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

Business Continuity Plan

2018WIP	2019Addition	2020Addition	2021Addition
		$80,000	$75,000

A gap analysis was undertaken by a third party consultant regarding Yukon Energy's current Business Continuity Plan (BCP). This identified substantial work required to address the identified gaps in order to meet current industry standards. This includes development of technical recovery procedures, based on identified Recovery Time Objectives (RTO) for the various business processes related to IT applications and infrastructure components; developing a defined methodology for evaluating the criticality of vendors, establishing vendor Business Continuity/Disaster Recovery (BC/DR) requirements, and monitoring vendor BC/DR compliance; and developing a formal BC/DRP/Emergency Response Planning training program or exercise and testing program. If the current BC/DR program deficiencies are not addressed, YEC will face a number of risks in the event of an actual emergency. This includes delays in poorly defined Incident Command System, unclear priorities for returning critical support systems to service, lack of adequate employee training or potential communication breakdowns. The project is to be closed in 2020 and 2021 with total expenditures of $155,000 to be amortized over five years.

QUESTION:

a) How did Yukon Energy identify this was a problem?

b) Identify which consultant firm/s got contracts for what work and what cost.

ANSWER:

(a)

Historically, YEC has run formal disaster recovery scenarios to ensure appropriate response procedures were in place and staff understood their responsibilities in various emergency situations. These scenarios tended to focus on front-line operational readiness especially IT systems to deal with a given situation in a short time. In working with consultants and discussing with peer organizations, it was concluded that a comprehensive BCP/DRP program is a normal risk management tool used by entities similar to YEC and that YEC could improve its current approach.

(b)

The work planned for 2020 was delayed due to internal resource constraints. As a result, no contractors were awarded for this work. The timeline for completion will slip to 2021/22 so there is no impact to rates from this project in 2021.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

Mayo and Aishihik Hydro Climate Change

2018WIP	2019Addition	2020Addition	2021Addition
	$474,313	$124,249	$40,000

A partnership was developed in 2016 between Yukon College and INRS, a university institution which developed a successful joint ARD/CRD proposal to leverage funding from NSERC. The project is to be closed in 2020 with total expenditures of $638,562 to be amortized over five years.

QUESTION:

a) Does Yukon Energy have engineers in their personnel?

b) Does Yukon Energy have a hydrologist in their personnel?

c) If Yukon Energy aligned with Yukon College and INRS why would YEC need an expensive independent consultant?

d) Identify which consultant firm/s received contracts for this study and at what cost.

ANSWER:

(a)

Yes.

(b)

No.

(c)

Yukon Energy's alignment with Yukon College and Institut national de la recherche scientifique (INRS) included funding the work conducted by both academic institutions, which made up the majority of the external costs. An independent consultant was also

engaged to verify the study methodology and review the model to ensure it was of appropriate quality and standards for YEC's continued future use.

(d)

See Table 1 below.

Table 1: Mayo and Aishihik Hydro Climate Change Study Costs

Contractor	**Total Cost**
Aasman Brand Communications Inc.	849.49
INRS	316,073.77
Rousseau, Alain	1,761.10
Smith, Douglas Ian	25,652.26
Yukon University	112,500.00
Total	**456,836.62**

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

PMF Flood Study

2018WIP	2019Addition	2020Addition	2021Addition
			$150,000

A Probable Maximum Flood (PMF) study is required for Aishihik Lake and Canyon Lake. The project is to be closed in 2021 with total expenditures of $150,000 to be amortized over five years.

QUESTION:

a) Does Yukon Energy have a hydrologist on staff?

b) Why would this project not be included in the Aishihik Water License costs?

c) Which consultant firm/s did this project work and at what cost?

d) Provide latest Hydrology Report.

ANSWER:

(a)

YEC does not have a hydrologist on staff.

(b)

The PMF study is a separate project related to dam safety.

(c)

YEC will be hiring a consultant in 2021 through a competitive process to perform the study.

(d)

Please see Attachment 1 to this response.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

Transmission Access Road Program Study

2018WIP	2019Addition	2020Addition	2021Addition
		$132,787	$200,000

Yukon Energy does not have a proper inventory of all the road accesses for transmission line access; and does not know the status of all the accesses that are required to maintain approximately 1,110 km of transmission line. The objective of the study is to engage an external consultant to provide a GIS database outlining access locations; the current status of accesses; and to prepare a GIS data base and report that includes a gap analysis of what needs to be addressed to complete the GIS database. The project is to be closed in 2020 and 2021 with total expenditures of $332,787 to be amortized over five years.

QUESTION:

a) Does Yukon Energy personnel not routinely inspect and work on all transmission line locations?

b) Why would these staff workers not be able to inventory locations, need and GPS these locations?

c) Which consultant firm/s did this expensive work and at what cost?

ANSWER:

(a)

YEC routinely inspects all of its transmission lines both aerially and by use of Snow machines, UTVs, trucks and on foot. These various types of inspections drive the maintenance program. Lines receive maintenance based on priority and available budget. Not every line gets worked on every year as it much more efficient to focus work in a particular area.

(b)

An initial assessment was completed by YEC staff to inventory existing access trails along transmission lines that were coming up for priority maintenance. To maintain or modify these trails in any way requires proper permitting and many of them require modification to make them suitable for YEC equipment. Due to the level of assessment needed to meet highways permitting requirements and due to the amount of permitting required, outside support was needed. Additionally, this assessment identifies gaps where we do not have appropriate access which can be due to a variety of reasons including sensitive lands interests. This level of assessment gives us a comprehensive data base that will help us assess future maintenance programs.

(c)

The firm that did this work is Tetra Tech. The final invoice was $87,526.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

5.4-2: FEASIBILITY STUDIES – CONTINUED RELIABILITY & ASSET IMPROVEMENTS

Whitehorse Diesel Rental Substation Improvements

2018WIP	2019Addition	2020Addition	2021Addition
		$100,000	

The temporary substation behind the diesel plant is the grid connection point for the rental diesel fleet, was built using repurposed/ savaged equipment, and has temporary fencing. The cables for the temporary substation were reused from the WD1 and WD2 units and are aged. Cabling from this substation to S150 is a direct connection, and a cable fault will result in the shutdown of S150, which is the primary generating and distribution station on the grid. In order to prevent risk of such a failure, the cables, breakers, and enclosures must be replaced and a permanent fence must be installed. The natural gas pipe and regulator must also be relocated and cable protection at S150 must be installed. Spending in 2021 relates to developing an engineered solution, including a budget and risk analysis. The project is to be closed in 2021 with total expenditures of $100,000 to be amortized over 45 years.

QUESTION:

a) From Yukon Energy preamble above it appears as if YEC knew all of the relevant problems existed from their own staff and engineers. As such, explain why an independent study was necessary?

b) Which firm received this study contract?

ANSWER:

(a)

An engineered solution is required to validate what has been identified and detect any additional items that were not previously discovered.

(b)

The IR “quote” above shows the project cost in 2020, which is not accurate – Section 5.4-2 of the application shows this cost in 2021. At this time, it has not been determined which firm will receive this study contract.

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

5.4-2: FEASIBILITY STUDIES – CONTINUED RELIABILITY & ASSET IMPROVEMENTS

10 Year Renewable Energy Plan

2018WIP	2019Addition	2020Addition	2021Addition
	$310,842	$402,125	

A desktop update of the 2016 Resource Plan was completed with additional renewable energy project considerations. The update consisted of a new long term load forecast, expansion of existing hydro inventory, update of financial resource attributes, portfolio analysis and an action plan charting the path for resource development and implementation over the next 10 years. The outcome of this project and its acceptance will allow YEC to establish and follow a plan to ensure that reliability criteria are met. The project is to be closed in 2020 with total expenditures of $712,967 to be amortized over five years.

The Tab 5 test year forecasts include capital costs for the Ten Year Renewable Energy Plan which addresses resource planning updates as required for current YEC resource planning. This includes consideration of impacts on future peak load growth and energy generation requirements as a result of Yukon's strategy for climate change, energy and a green economy, particularly as regards IPP policy resource project development impacts on energy and capacity resource balances, and policy impacts on future peak loads related to ongoing initiatives for electrification, electric vehicles, and heat pumps.

Directive #62 (paragraph 490) – Resource Plan Update

* However, the Board is of the view that it is not prudent for YEC to continue with these significant expenses to update the resource plan every five years. Accordingly, the Board directs YEC to seek Board approval prior to any future updates of its resource plan. Any such application must be accompanied by a detailed proposal for both costs and scope of work, including a description of work to be carried out internally and by consultants. YEC must also include an explanation of why any work to be done by consultants cannot be carried out by internal staff.

QUESTION:

a) Did Yukon Energy seek prior approval of the Board and was this approval given? Identify Board decision

b) If no, as this was almost three quarters of million dollars update, should not Yukon Energy have followed Board directions?

c) Identify which consultant firm/s received contracts, for what work to be done and at what cost.

ANSWER:

(a) and **(b)**

The Board's mandate relates to approval of rates, and does not include approval of public utility programs, plans or projects. Yukon Energy did not seek prior Board approval to update its resource plan in response to new conditions and Yukon Government policy requirements related to its Climate Change policy initiative. The expenditures for this resource plan update were prudently incurred and modest compared with the 2016 Resource Plan costs.

(c)

Please see Table 1 below for a summary of work completed by consultant and costs.

Table 1: Summary of 10-Year Renewable Energy Plan Costs by Consultant

Consultant	Work Completed	Total Cost
Aasman Brand Communications Inc.	Communications & engagement materials; Graphic design & formatting	$ 52,842.81
Campbells North Consulting	Technical and project management support	$ 3,822.50
DLA Piper LLP	Legal support	$ 44,706.99
Itron Canada Inc.	Load Forecast Modeling; Electric Vehicle Load Update	$ 36,646.10
InterGroup Consultants	Strategic studies, Southern Lakes Transmission Investment and development options	$ 59,487
Knight Piesold Limited	Technical Attribute & Cost Studies for Resources	$ 99,064.62
Midgard Consulting Inc	Resource Options & Market Assessment Update; Technical Report	$ 129,751.95
Northern Governance Institute (nGI)	Public engagement facilitation and organization; What We Heard Report	$ 70,576.06

TOPIC: **Capital Projects**

REFERENCE: **GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5**

Atlin Hydro EPA Preparation

2018WIP	2019Addition	2020Addition	2021Addition
			$200,000

The Atlin (Pine Creek) Hydro Expansion project was selected as a key project in the 10 Year Renewable Electricity Plan, given its relatively advanced stage of development as a brown-field expansion project, when compared to other potential greenfield hydro developments. The project also has a lower Levelized Cost of Energy (LCOE) than the Drury Lake project. In 2020, YEC engaged in discussions with Xeitl Limited Partnership (Xeitl LP) (Taku River Tlingit development corporation) regarding the Atlin project being planned by Xeitl LP, and key principles and terms for an Agreement-in-Principle (AIP), as well as potential IPP contract provisions. An AIP has been signed, and discussions towards an EPA are underway. The project is to be closed in 2020 with total expenditures of $200,000 to be amortized over five years.

QUESTION:

a) Explain exactly what study is needed here?

b) Identify which consultant firm/s performed tasks, what work done and costs.

ANSWER:

(a)

As noted, the project relates to negotiation key principles and terms for an Agreement-in-Principle (AIP) and IPP contract provisions with Xeitl Limited Partnership (Xeitl LP) (Taku River Tlingit development corporation) regarding the Atlin project being planned by Xeitl LP. An AIP has been signed, and discussions towards an EPA are underway.

(b)

The work is forecast to occur in 2021 and has not been completed. Consultant work to date has primarily been undertaken by DLA Piper and InterGroup Consultants Ltd. InterGroup has provided support related to financial analysis and EPA development; and DLA Piper has provided support related to EPA development and negotiation. Costs to the extent that they are readily available are provided in UCG-YEC-1-104.

TOPIC: Capital Projects

REFERENCE: GENERAL RATE APPLICATION NOVEMBER 2020 Tab 5

5.4-2: FEASIBILITY STUDIES – CONTINUED RELIABILITY & ASSET IMPROVEMENTS

Dam Safety Review

2018WIP	2019Addition	2020Addition	2021Addition
			$315,000

A full dam safety review (DSR) is performed every 5 years by an external consultant as recommended by the Canadian Dam Association (CDA). Reporting on outcomes of this review is also required by each Yukon Energy generating facility water use licence. The DSR includes a comprehensive review of all of Yukon Energy's dam structures, and includes consideration of all civil, structural, geotechnical, electrical, mechanical and safety issues that may affect YEC personnel and the general public. The review identifies hazards and potential problems of high risk that require immediate attention (within one year) as well as lower risk items that can be performed over time. The project is to be closed in 2020 with total expenditures of $315,000 to be amortized over five years.

QUESTION:

a) Identify which firm/s performed these reviews, work performed and what cost.

ANSWER:

(a)

Encora performed this work at a cost of $139,510.

TOPIC: **Capital Projects**

REFERENCE: **5.4 INTANGIBLE ASSETS**

Intangible assets are reviewed in Table 5.7 and include financial software, customer service costs and costs related to development of an asset management framework (i.e., Enterprise Asset Management Purchase and Implementation).

5.4.1.1 Enterprise Asset Management (EAM) System Purchase 1 and Implementation – ($0.809 million in 2019, $3.854 million forecast in 2020, and $0.275 million forecast in 2021)[38]

The 2017/18 GRA included feasibility costs for development of an Asset Management Program that would document plans to systematically assess major asset groups (hydro, substations and transmission and distribution) and manage the planning of investments to meet overall corporate goals.[39]

The existing Computerized Maintenance Management System (CMMS) does not meet Yukon Energy's current or future asset management needs. An EAM system is an enterprise level software application that enables an organization – particularly an asset intensive organization – to manage and optimize its assets throughout the entire asset lifecycle including asset needs identification, asset investment planning and prioritization, advanced asset maintenance management and asset performance tracking.

EAM project activities since 2018 relate to the selection, purchase, planning and implementation of an EAM system. A procurement process to evaluate and select a replacement system was initiated in 2018; and selection of a replacement EAM system was completed in 2019. The tool will be integrated with the Microsoft Dynamics GP, YEC's financial management solution, and other legacy applications to provide an integrated solution that ties to YEC's financial and inventory management systems.

The following project activities have been completed:

$0.276 million was spent in 2018 under PP&E and transferred to Intangibles in 2019. The 2019 spending was $0.533 million to total 2019 cost to rate base at $0.809 million.

[39] 2017/18 GRA, Appendix 5.4, page 5.4-2 provides a summary of this project, with forecast spending of $0.200 million in 2017 and$0.150 million in 2018. In Order 2018-10, the Board found the project reasonable and the associated costs prudent and approved the deferred costs as filed.

[40] The ISO 55000 standard is an international standard covering management of assets of any kind.

Procurement of Project 1 Management Services: In 2019, YEC issued a Request for Proposals (RFP) for project management of the EAM implementation, and KPMG was selected as the proponent for this work. The KPMG team is well qualified and experienced and its team members successfully implemented a similar EAM system at NTPC (demonstrating knowledge and competence to deal with issues faced by small, northern Crown utilities).

Procurement of Software Solution: A multi-stage competitive procurement was administered in 2018. A total of 27 potential suppliers were invited to participate in a request for information process. From this, 8 vendors were invited to a full request for proposal (RFP) process. As a final step, three vendors were invited to participate in vendor presentations and site visits and full cost work up. Based on this extensive process, YEC awarded a time and materials contract to Infor ERP Software.

Over 2020, YEC has worked towards implementation of the software solution provided by Infor. This has

included the following:
Inception (completed in 2020): Undertaking activities related to project kickoff; training workshops by vendor (Infor) with YEC team members; workshops conducted by Infor to define as-is process models, technical strategy and architecture and KPIs as a basis for the EAM solution; workshop conducted by KPMG (OCM lead) to gather YEC executive input on expected organizational challenges and ensure alignment project objectives; and prioritization requirements for next phase.
Elaboration (commenced in 2020 and ongoing): Involves detailed scoping and finalization of business requirements and integration design, advanced training for core team members, development of a testing strategy, scope and defining data structures and plan integration strategy and requirements.
Construction (commenced in Q2 2020 and Completed in Q4 2020): Development of user acceptance testing plan, initial testing and final data conversion preparation by vendor. This includes development of training curriculum and methodology and approach; assessment of impact of EAM project on YEC; test all modules of AEM solution, going through business processes and verifying functionality; determine if designed and configured solution meets YEC's requirements and specifications; build EAM integrations with YEC legacy systems; local testing of integrations developed; and end to end system testing of AEM system and integrations.
Transition (commenced in Q4 2020 and ongoing): Finalization 1 of EAM solution and preparation to launch into production; including preparing for training for broader YEC users; outline and convert data from non-EAM systems to EAM systems and checking redundancies involved while going live; change impact assessment based on enhanced understanding of project; assessment of readiness for launch and finalize EAM for users and convert to production 'live' environment.
Optimize (commence late Q4 2020 and complete early 2021): After launch into production review of project successes and lessons learned, including limited support work from vendor as required.
Total costs to complete the project are currently estimated at $4.938 million. The project is expected to be fully implemented in early 2021.

QUESTION:

a) Identify which firm did the feasibility plan and at what cost.

b) Identify where Yukon Energy received approval to add 2019 costs of $0.809 million to rate base.

c) Reconcile the difference in the approved 2017/18 deferred costs of $0.350 million and the $0.276 million 2018 spending and transfer to intangibles.

d) Provide breakdown of 2019 spending of $0.533 million, i.e. job description, consultant/s firms hired and cost for each.

e) Identify which firm/consultant received contract for project management services and at what cost.

f) Provide cost for actual Enterprise Asset Management System and related software.

g) Provide breakdown of costs for Inception project kickoff, various training workshops, etc.

h) Provide costs for Elaboration finalization, integration, advanced training, etc.

i) Provide a breakdown of all costs with reasons for Construction, Transition and Optimize phases of program.

j) Provide any in-house costs for all of this project phases.

k) Is this new model of EAM now fully implemented and operational?

l) If some of total cost of $4.938 million for EAM already on approved rate base?

m) If yes, identify amount and Board reference decision.

ANSWER:

(a)

Hatch was retained to undertake a CMMS current state assessment and market survey at a total cost of $46,400.

(b)

The 2019 costs are included in the Application for approval with the 2021 GRA.

(c)

The actual costs in 2018 were $0.276 million. The $0.350 million cost was an early estimate in 2017 to perform the work.

(d)

Please see the information provided in the table below for break out of the $0.533 million cost for the project.

UCG-YEC-1-97 Section C: #172 (1 of 2)

Cost Code		Sum of Amount
1-Labor	$	80,561.03
2-Travel Exp	$	22,279.64
3-Matl, Supl, Inv	$	172.49
4-Contractors	$	419,568.83
5-Rental	$	240.00
8-AFUDC	$	10,691.33
Grand Total	**$**	**533,513.32**

A summary of contractors hired and description of work and costs is as follows:

Vendor		Sum of Amount
Charter Telecom	$	1,080.00
eCorall Solutions Inc.	$	7,412.80
Hatch Ltd.	$	77,662.72
Infor (Canada) Ltd.	$	100,000.00
KPMG LLP (Vancouver)	$	233,413.31
Grand Total	**$**	**419,568.83**

(e)

KPMG received the contract for PM services, at a cost of $133,972. As noted in part (d) final costs for KPMG were $233,413. Added costs for KMPG relate to an expansion of scope to establish more firm pricing of the implementation estimate, and extensions to the project deadline.

(f)

The Cost of the EAM Software System at time of purchase is as follows:

1. $464,789 – Software; and

2. $113,450 (annual Licensing and upkeep fees).

(g), (h) and **(i)**

There is no specific breakdown of costs to this detail. For a project cost breakdown please see response to YUB-YEC-1-64(c).

(j)

The YEC internal costs are estimated to be $462,000.

(k)

The EAM system is not yet in service. The system will be in service Q1 2021.

(l) and **(m)**

No costs for the EAM project as presented in the Application are currently included in rate base or approved by the Board to include in rates.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.5: DEFERRED STUDIES**

Deferred cost projects with total spending since 2018 greater than $100,000 million and less than $1 million that remain in WIP in 2021, excluding General Rate Application costs in WIP, have total expenditures of $0.400 million and EV Infrastructure Project

2018WIP	2019Addition	2020Addition	2021Addition
			$200,000

Strategy development will assess the potential impact of electric vehicles on the Yukon electrical system and identify a path forward for YEC to meet these challenges.

QUESTION:

a) Has this assessment been completed?

b) If this cost is for strategy development why is this not done inhouse with the many personnel on staff?

c) Identify which firm/s performed tasks concerning this assessment, what work was done and at what cost?

ANSWER:

(a)

No.

(b)

The costs of internal labour and consulting for the project have not yet been determined. Limited resources are available to complete this work, as a result of the large number of ongoing projects outlined in YUB-YEC-1-39.

(c)

The work has not been initiated and is no longer planned to be done in 2021.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.5: DEFERRED STUDIES**

P125 Trashrack Study

2018WIP	2019Addition	2020Addition	2021Addition
		$200,000	

The P125 intake is becoming blocked with debris and frazil ice. These blockages are currently being removed manually by divers and plant operators. This results in multiple outages each year to address blockages. Not addressing this issue will mean continued outages and requirement for divers to address the issue manually. A track rack must be installed that can permanently address the variety of debris encountered at the intake. The study will confirm the deck structural capacity and other details such as power supply and trash rack geometry.

QUESTION:

a) Confirm that this cost and work is not identified in another area of work to be performed.

b) Has this work been completed and finalized?

ANSWER:

(a)

This is a standalone project. The cost and work is not identified in any other area of work to be performed.

(b)

This work is in the assessment phase and has not been completed nor finalized.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.6: INTANGIBLE ASSETS >$100,000 AND<$1 MILLION ADDED**

TO RATE BASE
ERP System Upgrades

2019Actual	**2020Forecast**	**2021Forecast**
$200,000		

Given Yukon Energy's role as the primary generator of electricity for an isolated grid, it is critical to maintain a modern and robust Enterprise Resource Planning (ERP) system. ERP system refers to a type of software that organizations use to manage day-to-day business activities such as accounting, procurement, project management, maintenance management and supply chain operations. Best practice is to update systems regularly to ensure that the systems are up to date. The project involves upgrades to the ERP system components to the recommended latest stable versions. System experts are contracted to help with individual components as these are critical systems and Yukon Energy has no inhouse expertise.

QUESTION:

a) Given the cost of this program upgrade, will Yukon Energy now use this in-house capability instead of hiring your consultant?

ANSWER:

(a)

To be clear, this is not a new system with new in-house capabilities.

As described in the Application, this is an upgrade to the existing system. YEC performs upgrades as considered necessary. As with any software, external consulting will be used as necessary. As noted in YUB-YEC-1-103, one of risks of not doing an upgrade is that there will be no support for the software.

TOPIC: **Capital Projects**

REFERENCE: **Feasibility Study**

Table 5.4 2017-18
Total Feasibility Study WIP 8,589,838 1,090,716 (132,667) 9,547,887
Table 5.6 2021
Total Feasibility Study WIP 9,833,270 7,370,000 (979,072) 16,224,199

QUESTION:

a) Confirm increase in WIP Feasibility Studies from 2017-18 to 2021 is $6,676,312.

b) Confirm increase in Total WIP from 201-18 GRA to 2021 is $11,394,258.

ANSWER:

(a)

The increase in feasibility study WIP noted in the question [$6.676 million] is the increase in 2021 test year over 2018 actuals. The feasibility study WIP in 2021 test year is reduced from the 2018 test year by $5.565 million mostly due to delays with Energy Storage System Assessment and YEC's decision not to go ahead with 20 MW thermal plant assessment assumed in the 2017/18 GRA.

(b)

The increase in total WIP in 2021 test year over 2018 test year is $9.468 million [net of contributions] that reflects increase PP&E WIP by $29.769 million plus increase in deferred cost WIP by $0.475 million offset by increase in contributions WIP by $20.776 million as illustrated in Tab 7, Schedule 1.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.3: DEFERRED PROJECTS >$1 MILLION NOT ADDED TO RATEBASE**

Deferred expenditure test year spending on major projects (i.e., expenditures over $1 million) retained in WIP is focused on projects required to address sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance),investments to ensure sufficient dependable capacity for the integrated grid, and continued planning expenditures to meet other potential future generation and transmission requirements. Approximately $28.573 million of deferred costs are forecast to be incurred in WIP for major projects by the end of 2021. Details on actual and forecast expenditures by year are reviewed in Tables 5.2 to 5.6.
Spending on Sustaining Capital: Net deferred costs in WIP by end of 2021 of approximately$8.178 million:
1. Aishihik Generating Station Water Use 25 Year Licence Renewal – (forecast WIP cost of approximately $7.918 million by end of 2021 - project planned for completion in2022).
2.Whitehorse Rapids Generating Station Water Use Licence Renewal - (forecast Spending to address Capacity
Planning Requirements: Net deferred costs in WIP by end of 2021 of approximately $6.395 million:
3. Diesel Retirement Replacement (12.5 MW) – (forecast WIP cost of approximately $6.395 million by end of 2021 planning, engineering, permitting, long-lead equipment procurement – total project planned for completion by 2024, with certain portions completed and in service starting in 2022).
Spending on planning to maximize renewable energy generation from existing facilities: Net deferred costs in WIP by end of 2018 of approximately $14.000 million:
4. Southern Lakes Storage (Marsh Lake Storage Enhancement Project) – (forecast WIP cost of approximately $9.379 million by end of 2021 - project subject to ongoing review, potential in-service by 2023).
5. Mayo Lake Storage Enhancement Project (including Mayo Lake Outlet Channel) – (forecast WIP cost of approximately $4.621 million

QUESTION:

a) Although it appears Yukon Energy will not place these projects onto the rate base for the test year, is Yukon Energy now using this process to get regulatory approval for all of these projects liningup for $28.573 million in the WIP? Explain.

b) As Aishihik relicencing is lining up for almost $8 million in the WIP, explain how Yukon Energy justifies this cost?

c) Identify which firm/s managed/is managing this Aishihik license renewal from the beginning until now, what work was performed and at what cost

d) Identify which firm/s managed/is managing the Whitehorse Station license renewal from the beginning until now, what work was performed and at what cost.

e) Does the Diesel Retirement Replacement cost of $6.395 million include the purchasing of any new generators? Explain.

f) Justify the costs for Southern Lakes Storage and Mayo Lake Enhancement, for each, including discussion of risks of not proceeding with these projects as well as discussion of assumptions included in the business case for escalation factors, loading, financial measures, term of project and associated ancillary costs, as per Board Order 2009-8.

ANSWER:

(a)

The projects identified in Appendix 5.3 are forecast to remain in WIP during the 2021 test year. As noted in the response to YUB-YEC-1-89 the purpose of this appendix is to identify major projects with costs that will not affect forecast test year rate base and therefore do not require detailed review at this time for the purpose of the 2021 GRA Application. As such, Yukon Energy is not using this process to get regulatory approval for these projects. They will be brought to the regulator for a prudence review at a later date.

(b)

The Aishihik hydro facility is a key power plant in Yukon's electricity system, providing 25% of the renewable electricity available on the Yukon grid. It also plays an important role in winter months, providing 40% of the energy Yukoners need when demand for electricity is greatest. Although the 40-megawatt Whitehorse Rapids hydro facility is larger than Aishihik, the effective capacity of the Whitehorse plant is reduced by close to half during the coldest months of the year because of reduced water flow on the Yukon River. Aishihik is the only hydroelectric facility in Yukon that can store energy in the summer when demand is low to be used in the winter when demand is high. It can also store energy during wet years to be used in dry years when the levels of the lake water are lower. Replacement of the energy and capacity provided by the Aishihik facility would cost significantly more than the referenced $8 million for the 25 year relicensing process. Please see response to YUB-YEC-1-90 (b through e) for added detail.

(c)

Morrison Hershfield, working with other consultants (InterGroup, EDI, Palmer, Ecofor) was the lead consultant through 2018. Since then, YEC has contracted each firm separately to carry out the required work, and InterGroup has been the key technical leading consulting firm. Please refer to UCG-YEC-1-83 for cost information.

(d)

Work on this project has not commenced.

(e)

Please refer to YUB-YEC-1-92.

(f)

The project justifications are based on an incremental savings on an LCOE basis compared to the next best alternative (thermal energy generation). Both of these projects remain in WIP and are not part of forecast revenue requirement for 2021.

Please see responses to YUB-YEC-1-93 and YUB-YEC-1-94 for more detailed information on updated justification for continuing to pursue each of these projects.

TOPIC: **Capital Projects**

REFERENCE: **APPENDIX 5.1: CAPITAL PROJECTS > $1 MILLION NOT IMPACTING RATE BASE**

Appendix 5.1 provides project summaries for capital projects with spending over the period from 2019 to 2021 exceeding $1 million that remain in WIP at the end of 2021 (and therefore do not affect the 2021 GRA revenue requirement). Total forecast spending on these projects is forecast to grow from $1.129 million in 2019, to $2.860 million in 2020 to $31.966 in 2021. The forecast material increase in 2021 spending relates largely to the Battery Energy Storage System project which has $25 million forecast spending in 2021. However, it is noted that spending for this project will be offset by a $16.5 million contribution. Further details on annual spending are summarized in Table 5.2-2.

As outlined below, spending for these projects is largely focused on: (1) capital works to address sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance); (2) investments to ensure sufficient dependable capacity for the integrated grid; and other projects.

Capital Works to Address Sustaining Capital Requirements:
1. Dawson Voltage Conversion
2. MH0 (Mayo A) Generating Station Slope Stability
3. Replacement of Mayo A Surge Chamber
4. Stop Log Crane WH Main Spillway
5. Asset Management Framework

Investments to Ensure Dependable Capacity:
6. Battery Energy Storage System (transfer from Feasibility)
7. Pumped Storage
8. Southern Lakes Transmission Line
9. Whitehorse Interconnection

Other:
10. Aishihik Contract DisputeWIP cost of approximately $0.260 million by end of 2021 - project planned for completion in 2025)

QUESTION:

a) Is the total spending requested to go in WIP $31.966 million, or is this just forecast 2021?

b) Although it appears Yukon Energy will not place these projects onto the rate base for the test year, is Yukon Energy planning to use this process to get regulatory approval for all of these projects lining up for at least $31.966 million in the WIP? Explain.

c) Does Yukon Energy consider this a complete final capital review for each of these these above projects, to then transfer into rate base next rate hearing?

ANSWER:

(a)

Projects included in Appendix 5.1 are currently in WIP will remain in WIP at the end of 2021. The total includes actual amounts incurred to the end of 2019 and forecast amounts for 2020 and 2021.

(b) and **(c)**

See YUB-YEC-1-89 (a) to (c). Appendices 5.1 and 5.3 review Major Projects (i.e., projects with forecast costs exceeding $1 million) for PPE (Appendix 5.1) and deferred costs (Appendix 5.3) that are forecast to remain in WIP during the 2021 test year. The purpose of these appendices is to clearly identify major projects with costs that will not affect forecast test year rate base and therefore do not require detailed review at this time for the purpose of the 2021 GRA Application. Accordingly, it is confirmed that no costs for projects listed in these appendices have been added to rate base or revenue requirement for 2021.

Costs for these projects will be fully reviewed at a subsequent proceeding when YEC applies to have the costs included in rates.

TOPIC: **Capital Projects**

REFERENCE: **Sole-Sourced Contracts**

QUESTION:

a) Since 2018, including the 2017-18 regulatory proceedings before the Yukon Utilities Board, identify all expenditures related to work completed by InterGroup Consultants Ltd. on behalf of Yukon Energy Corporation.

b) Identify any of the above contracts given through a request for proposal or tender/bidding process.

c) Since 2018, including the 2017-18 regulatory proceedings before the Yukon Utilities Board, identify all expenditures related to work completed by John Landry LLB /DLAPiper on behalf of Yukon Energy Corporation.

d) Identify any of the above contracts given through a request for proposal or tender/bidding process.

ANSWER:

(a)

Department/Project	Amount
Aishihik Generating Station Water Use Licence Renewal	814,564.82
General Rate Application 2019-2020	273,326.93
Mayo Lake Storage	121,208.71
Atlin Hydro EPA Preparation	79,693.27
10 Year Renewable Energy Plan	59,487.97
BESS	48,847.50
Finance	42,190.59
Thermal Replacement	31,516.50
Resource Planning	4,532.75
Vista Integration	3,614.07

(b)

Formal tender processes were issued for the original contracts awarded for involvement in the largest projects:

- Aishihik Generating Station Water Use Licence Renewal; and

- General Rate Application 2019-20.

Note these tenders do not explicitly cover all spending to date; extensions to scope and budget occurred in both cases as project plans were developed and changed based on circumstances. YEC issues extensions for work based on successful delivery to date and reasonable estimates for the expanded scope.

(c)

Department/Project	Amount
AH3 Legal Defense	496,919.05
Aihsihik Relicencing	421,626.21
Human Resources	292,571.83
Finance	237,013.25
Executive	91,726.97
2017/18 GRA R&V	91,556.50
Atlin Hydro EPA	71,673.00
IPP Program Implementation	76,984.88
MMTP	41,106.93
Ten Year Renewable Energy Plan	44,706.99
2021 GRA	25,508.00
WH2 Uprate	21,332.67
IPP - Other	18,995.50
WH4 Uprate	12,117.77
Victoria Gold PPA Review	9,122.60
EAM	7,170.45
BESS	6,247.50
LNG Third Engine	4,075.40
Thermal Plant	3,576.64
Corporate Administration	2,046.56
Residential Demand Response Pilot	1,984.50
Communications	1,682.00

(d)

YEC does not tender legal services.

Yukon Utilities Board
(YUB)

REFERENCE: **Application - Overview, Energy & Peak Load Changes, pages 1 to 4**

ISSUE: **Energy and Peak Load Changes (8.4% of revenue shortfall)**

QUOTE: "Dependable capacity requirements caused by peak load growth for non-industrial sales drives diesel rental costs that account for $3.8 million (34.9%) of the 2021 GRA revenue shortfall."

PREAMBLE:

QUESTION:

a) Based on the current load forecast, please provide the incremental costs on a per kWh basis for the diesel rental units using only the rental and set-up costs.

b) Based on the current load forecast, please provide the incremental variable costs on a per kWh basis for the diesel rental units.

c) Considering YEC's current load forecast, does the sum of the rental costs (response to part (a)) and the variable costs (response to part (b)) equal YEC's incremental cost of generation? If not, please explain and provide the incremental cost for generation, separately identifying the portion based on fixed costs, variable costs and total costs on a per kWh basis.

ANSWER:

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

Dependable capacity requirements caused by peak load growth lead to requirements for dependable capacity to be in place during the critical winter grid peak period. Options to meet this requirement are assessed based on fixed costs (capital and fixed non-fuel O&M costs) without any focus on variable fuel costs, i.e., the facilities are primarily in place to provide for the N-1 contingency event and would not normally be called upon to use fuel in order to generate electricity. Accordingly, dependable capacity options are assessed based on cost per kW of dependable capacity rather than based on costs per kWh of possible generation.

The identified $3.8 million of diesel rental costs for 2021 represent the incremental rental costs for 17 units (15 units, each 1.8 MW to provide 27 MW as required for the N-1 dependable capacity shortfall, plus 2 spare units for reliability). These are fixed costs, i.e., they remain regardless of any generation; however, the units are rented and therefore the costs can be removed when the rental period ends.

Please also see response to NY-YEC-1-3 (a) and CW-YEC-1-17 for details on diesel rental unit costs.

REFERENCE: **Application – Overview: PDF pgs. 2-5; Summary of Requested Orders: PDF pgs. 5-7; Retail & Industrial: PDF pg. 62**

ISSUE: **2021 Rates**

QUOTE: "Approval of an increase of the current YEC Rider J by 15.01 percentage points, starting no later than December 1, 2021 applicable to all YEC and AEY retail firm rates (all AEY recoveries from this rider would flow through to YEC) and to all major industrial firm rates, including the fixed Rider F charge of 0.211 cents/kWh."

PREAMBLE:

QUESTION:

a) Please provide a discussion of rebasing, and not rebalancing, the rates — by incorporating Rider J into base rates, for example — in a potential compliance filing to any decision on this application. Include a discussion of any challenges and benefits to implementing a rebasing of rates.

ANSWER:

(a)

In order to comply with OIC 1995/090, Section 2.1(1), any rate adjustments must apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers; this direction includes the customers of both YEC and AEY.

Accordingly, simple rebasing of rates in practice would require adjusting all base rates for all retail and industrial customers by the same percentage increase to cover all existing YEC and AEY percentage rate riders (excluding Rider F and any Rider E). Individual ratepayers, and each customer class, would then see no change to bills as a result of this rate rebasing. In addition, added measures would be required to ensure that YEC and AEY each continued to secure rate rider revenues recovered from the other utility's customers but due to be passed through to the utility with the current rate rider.

In summary, simple rate rebasing as described above would provide little real benefit but would add complexities in that all base rates for both utilities must then be changed each time rates change, as compared with the current efficient process of charging specific rate riders that may be adjusted as required from time-to-time.

Historically, rate rebasing has been accomplished whereby rate revenues for each retail and industrial customer class remains unchanged as required by OIC 1995/90, but rates within each customer class are restructured in response to an updated cost of service study (COSS) assessment. This option would require the involvement of both utilities, based on a common approved test year revenue requirement for the two utilities and a joint COSS. It would result in changes to wholesale rates to address revenue allocation between the two utilities in the absence of rate riders, and would remove each utility's direct rate rider revenue access to the other utility's' customers, e.g., YEC rate riders apply to all AEY customers in the hydro and diesel rate zones, and AEY rate riders apply to all YEC customers (including major industrial customers where load growth has been material since the last AEY GRA). This more complex rate rebasing would require a separate joint YEC/ AEY proceeding and could not be implemented through a compliance filing for any decision on the current YEC GRA.

REFERENCE: **Application, Section 1.1, Need, context and proposed approach for 2021 GRA, Table 1.1, page 1-1**

ISSUE: **YEC Return on Equity**

QUESTION:

a) Please revise Table 1.1 to include 10 years of historical information on both an approved and actual basis commencing with the year 2012. Please state all assumptions relied on as a result of the requested revision.

ANSWER:

(a)

Please see Table 1 for the requested information.

Table 1: YEC Historical ROE: Approved and Actuals/Forecasts

	Approved	Actual	Note for Approved
2012	8.25%	6.75%	2012/13 GRA
2013	8.25%	7.42%	
2014	8.25%	8.44%	
2015	8.25%	8.10%	
2016	8.25%	8.69%	
2017	8.70%	8.72%	2017/18 GRA
2018	8.70%	6.25%	
2019	8.70%	3.81%	
2020 F	8.70%	3.88%	
2021 F		3.10%	

Notes:

1. The Yukon Utilities Board (YUB) uses the benchmark ROE from the British Columbia Utilities Commission (BCUC). However, at the time of filing 2012/13 GRA a low-risk utility ROE benchmark from the BCUC was not available. Therefore, in 2012/13 GRA YEC proposed an ROE at 8.77% based on Alberta Utilities Commission (AUC) ROE benchmark of 8.75% plus 52-basis-point risk

premium as was applied in YEC's 2008-09 GRA, and subtract 50 basis points pursuant to the direction provided in OIC 1995/90. In its Order 2013-01 [Appendix A, Reasons for Decision] the YUB approved an ROE for YEC at 8.25% for the 2012/13 GRA noting that "the AUC model does not allow for an equity premium, and since it is the model that is followed, no equity premium is allowed".

2. In 2017/18 GRA YEC proposed an ROE at 8.82% based on the BCUC low-risk utility benchmark ROE at 8.75% plus 57-basis-point risk premium, and subtract 50 basis points pursuant to the direction provided in OIC 1995/90. In its Order 2018-10 [Appendix A, Reasons for Decision] the YUB approved an ROE for YEC at 8.70% noting that the Board awards YEC 25 basis points for its small size plus "in recognition of YEC's risks for generation, isolated grid and customer diversity, the YUB awards YEC an additional 20 basis points" for a total risk premium of 45 basis points above the BCUC benchmark utility. The YUB also noted that "the additional 20 basis points acknowledges the overall risk of YEC as being greater than that of FortisBC (Electric) and greater than that of AEY."

REFERENCE: **Application, Section 1.3, Changes in Forecast Loads, page 1-7**

ISSUE: **Industrial Load**

QUOTE: "Forecast firm Yukon Energy sales to industrial customers for the 2021 test year is 102.9 GW.h."

PREAMBLE:

QUESTION:

a) The 2021 load increase over 2018 approved load forecast for Victoria Gold Group and Alexco Resources is 67.2 GWh. Please provide the 2018 approved load forecast for Minto mine.

ANSWER:

(a)

The 2018 Minto mine load forecast approved in YEC's 2017-18 GRA compliance filing is 32,193 MWh, i.e., this was the only mine load included in the approved 2018 forecast.

REFERENCE: **Application, Section 1.3, Peak Capacity and N-1/LOLE requirements in test years, page 1-8**

ISSUE: **Diesel Rental Units**

QUOTE: "Diesel rental unit costs of approximately $3.8 million are forecast for the diesel rental units expected to be required for the 2021 GRA test year."

PREAMBLE:

QUESTION:

a) Please provide the additional firm capacity of the diesel rental units.

b) For 2021, how much energy is forecast to be generated from the diesel rental units?

ANSWER:

(a)

The firm capacity provided by the 15 diesel rental units for 2021 is 27 MW (1.8 MW per unit). Note the contract price includes two additional 1.8 MW units for reliability.

(b)

The forecasted 2021 energy to be generated by temporary rented diesel units is 2.5 GWh.

REFERENCE: **Application, Section 1.4, pages 1-8, 1-9**

ISSUE: **VGC Group and Alexco Fixed Charge**

QUOTE: "As reviewed in Appendix 4.3 of this Application, YEC expects to file with the Board in late November/ early December 2020 for approval of an amended Transmission Facilities Fixed Cost effective January 1, 2021 of $428,812, resulting in an interim Fixed Charge (85% of the Transmission Facilities Fixed Cost) effective January 1, 2021 of $35,734 per month, with allocation of the interim Fixed Charge between VCG Group and Alexco [Table 4.3-2, Appendix 4.3 of this Application]."

QUESTION:

a) Please confirm that the amended Transmission Facilities Fixed Cost application is part of this application. If not confirmed, then please explain when the application will be filed with the Board.

ANSWER:

(a)

The amended Transmission Facilities Fixed Cost application and related interim Fixed Charge are required to be filed within 60 days of the Transmission Facilities Development Operation Date as directed by YUB in Order 2018-04. This requirement exists separate from the 2021 GRA application, and was therefore assumed not to be part of the 2021 GRA application.

Since drafting of the 2021 GRA, the Transmission Facilities Development Operation Date has been delayed to March 2021. YEC therefore now expects to file the amended Transmission Facilities Fixed Cost application in March 2021, requesting an interim Fixed Charge adjustment effective May 1, 2021.

Please also see response to YUB-YEC-1-45.

REFERENCE: **Application, Section 2.1, pages 2-1**

ISSUE: **Sales – Overview**

QUOTE: "Yukon Energy directly serves about 2,300 customers at the distribution (retail) level, most of whom live in and around Dawson City, Mayo and Faro. Indirectly, Yukon Energy also provides power to Yukon retail customers served on the Integrated System (including those located in Whitehorse, Carcross, Carmacks, Haines Junction, Ross River and Teslin, Pelly Crossing, Keno and Stewart Crossing) through its wholesale sales to ATCO Electric Yukon (AEY)."

QUESTION:

a) Please provide the incremental per unit ($/kWh) of sales revenue YEC would receive for the next kWh of energy sold above the forecast: 1) Using a blended rate based on this application that incorporates retail, wholesale and industrial customers; and 2) including and specifying all applicable riders. Please explain any assumptions that are necessary in your response.

ANSWER:

(a)

Incremental per unit ($/kWh) of sales revenue that YEC would receive for the next kWh of energy sold above the 2021 forecast based on the Application will vary considerably depending on the customer class and the customer group within each customer class (i.e., which rate block is affected).

An overall blended average rate is about 13 cents per kWh before 2021 GRA rate increases [9.7 cents/kW.h before rider as shown in Tab 7, Schedule 9, line 45 plus 3.2 cents/kW.h Rider J revenues] and about 15 cents per kWh with 2021 GRA increases which adds about 2.2 cents/kW.h [$10.971 million GRA shortfall in Schedule 9, line 48 divided by 495.151 GW.h sales shown in line 43].

Blended incremental energy-only revenue rates per kWh resulting from added energy sales will be lower than the averages shown above for all rate revenues (which include

customer charges, demand charges and varying retail energy rates for different customers). Based on last block energy rates applicable to YEC sales for different customer groups, a blended incremental YEC energy sales revenue of about 13 cents per kWh is estimated for forecast 2021 sales assuming Rider J as proposed in the Application.

REFERENCE: **Application, Appendix 2.1, Table 2.1-1, page 2.1-1**

ISSUE: **Expected Thermal Generation**

QUESTION:

a) Please expand Table 2.1-1 down to grid load of 350 GWh.

ANSWER:

(a)

Please see Table 1 for extended version of Table 2.1-1. Please note that the table is extended to minimum 385 GW.h compared to 350 GW.h requested in the question as the LTA thermal generation for the loads lower than 385 GW.h is insignificant.

Table 1: Expected Thermal Generation Based on LTA Hydro Generation (2021)

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	385.0	383.525	1.475			
2	390.0	387.708	2.292	5.0	0.817	16%
3	395.0	391.622	3.378	5.0	1.085	22%
4	400.0	395.303	4.697	5.0	1.319	26%
5	405.0	398.782	6.218	5.0	1.522	30%
6	410.0	402.084	7.916	5.0	1.698	34%
7	415.0	405.233	9.767	5.0	1.851	37%
8	420.0	408.247	11.753	5.0	1.986	40%
9	425.0	411.142	13.858	5.0	2.105	42%
10	430.0	413.928	16.072	5.0	2.214	44%
11	435.0	416.613	18.387	5.0	2.315	46%
12	440.0	419.198	20.802	5.0	2.414	48%
13	445.0	421.685	23.315	5.0	2.514	50%
14	450.0	424.066	25.934	5.0	2.618	52%
15	455.0	426.334	28.666	5.0	2.732	55%
16	460.0	428.476	31.524	5.0	2.858	57%
17	465.0	430.474	34.526	5.0	3.002	60%
18	470.0	432.169	37.831	5.0	3.306	66%
19	475.0	433.735	41.265	5.0	3.434	69%
20	480.0	435.293	44.707	5.0	3.441	69%
21	485.0	436.810	48.190	5.0	3.484	70%
22	490.0	438.277	51.723	5.0	3.532	71%
23	495.0	439.690	55.310	5.0	3.587	72%
24	500.0	441.043	58.957	5.0	3.647	73%
25	505.0	442.334	62.666	5.0	3.710	74%
26	510.0	443.557	66.443	5.0	3.776	76%
27	515.0	444.713	70.287	5.0	3.844	77%
28	520.0	445.800	74.200	5.0	3.913	78%
29	525.0	446.819	78.181	5.0	3.982	80%
30	530.0	447.769	82.231	5.0	4.049	81%
31	535.0	448.654	86.346	5.0	4.115	82%
32	540.0	449.477	90.523	5.0	4.177	84%
33	545.0	450.242	94.758	5.0	4.235	85%
34	550.0	450.954	99.046	5.0	4.288	86%
35	555.0	451.618	103.382	5.0	4.335	87%
36	560.0	452.243	107.757	5.0	4.375	88%
37	565.0	452.836	112.164	5.0	4.407	88%
38	570.0	453.406	116.594	5.0	4.430	89%
39	575.0	453.963	121.037	5.0	4.443	89%
40	580.0	454.519	125.481	5.0	4.444	89%
41	585.0	455.085	129.915	5.0	4.434	89%

Notes:

1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid net of IPP generation, secondary sales related generation and Fish Lake hydro generation. The load will also be adjusted for WH2 and WH4 uprates as noted in #7 below.
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, 38 "water years" on record (1981-2018) 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), current Mayo Lake operation rule (no additional storage, impact of sedimentation at the outlet of Mayo Lake) and restricted Mayo GS winter flows (based on new Mayo Ice Protocol Mayo GS outflows are restricted at max 19 cms in November and 15 cms in December, after which restrictions are relaxed by 1.75 cms/week reaching 20 cms by early January and 24 cms by February [compared to 20 cms restriction through winter used in the 2017/18 GRA]).
5. The simulation model results are based on 2021 forecast load and IPP distributions, and requires modifications when new mines, industrial loads or IPP generation are connected to [or disconnected from] the grid.
6. The table assumes max YEC Grid Load (i.e., excluding IPP generation) at 585 GW.h and minimum YEC Grid Load at 385 GW.h. If the YEC Grid Load exceeds these limits then the table needs to be updated.
7. YEC is undertaking capital projects that will increase hydro generation output in Whitehorse GS [WH2 and WH4 uprates]. The preliminary estimates show that these capital projects will increase generation output by 7.1 GW.h/year [4.2 GW.h for 2021 considering expected in service date effective July 1, 2021 - monthly allocation based on Whitehorse GS monthly generation forecast]. Therefore, the YEC Grid Load is reduced to reflect increased output from these capital projects [not all incremental generation will directly displace LTA thermal].
8. Numbers are subject to rounding.

Example

Expected YEC Thermal Generation for the YEC generation at 536.743 GW.h (net of expected IPP & Fish Lake)

Remove Expected Generation for WH uprates [estimate for 2021 at 4.213 GW.h] to get net load at 532.530 GW.h

Step 1. Find the closest load from Column A that is less than 532.530 GW.h = 530 GW.h (Line 12).

Step 2. Find the thermal generation from Column C = 82.231 GW.h (Line 12).

Step 3. Find the difference between the given load (532.530 GW.h) and load from Step 1 (530 GW.h) = 2.530 GW.h

Step 4. Apply the percentage from Column F (Line 12, 82%) to the difference from Step 3 (2.530 GW.h) = 2.075 GW.h

Step 5. Add numbers from Step 2 (82.231 GW.h) and Step 4 (2.075 GW.h) = 84.306 GW.h

19 The expected thermal generation at 536.743 GW.h load [net of Fish Lake and IPPs] is 84.306 GW.h.

REFERENCE: **Application, Tab 2, page 2-2, line 16**

ISSUE: **Total Firm Generation Load**

QUOTE: "Overall, **total firm generation load** to be supplied by Yukon Energy on the Yukon Integrated System was forecast at 420.3 GW.h in the 2018 Compliance Filing. Actual total firm generation load was 450.1 GW.h in 2018 reflecting higher sales compared to the forecast. Actual total firm generation load in 2019 was 440.7 GW.h, and full year forecast for 2020 is 508.0 GW.h. Forecast total firm generation load for the 2021 test year is 538.7 GW.h."

QUESTION:

a) What was the forecast total firm generation load on the Yukon Integrated System for 2019?

ANSWER:

(a)

The 2017-18 GRA proceeding did not provide any forecast for 2019 load on the YIS. Aside from YEC internal business plan forecasts, the only public forecast was provided in YEC's 2016 Resource Plan where the forecast total firm generation load on the Yukon Integrated System for 2019 was 443 GW.h, which compared relatively well with the actual 440.7 GWh.

REFERENCE: **Application, Tab 2, page 2-3, line 19**

ISSUE: **Independent Power Production**

QUOTE: "Independent Power Production (IPP) renewable generation is forecast to commence in November 2020 with less than 0.4% of forecast generation impact for 2021."

QUESTION:

a) What is YEC's level of certainty regarding the forecast IPP amounts for 2021? Please explain.

b) How have IPP projects been affected to date by the COVID-19 pandemic? Did the IPP commence in November 2020, as scheduled?

ANSWER:

(a)

YEC has considerable uncertainty as to timing for forecast IPP amounts for 2021. The first project that was to be operational in November 2020 has been delayed into spring 2021.

(b)

We do not know how IPP projects have been affected to date by the COVID-19 pandemic. The IPP did not commence in 2020 as scheduled.

REFERENCE: **Application, Tab 2, page 2-4, line 2**

ISSUE: **Forecast Renewable Generation**

QUOTE: "This impact is starting to be offset by new renewable generation planned as part of Yukon Energy's 10 Year Renewable Electricity Plan, commencing with the new IPP generation forecast to provide 0.06 GW.h of solar generation in 2020 and 2.0 GW.h of new renewable generation in 2021 based on information available at the time of filing."

PREAMBLE: The Board requires additional information with respect to YEC's forecasts being based on "information available at the time of filing."

QUESTION:

a) What specific information did YEC rely on to forecast the new renewable generation?

b) To what date was information available in preparing these forecasts?

ANSWER:

(a) and **(b)**

The information available on IPPs when the generation forecasts were finalized for the 2021 GRA Application in September/ early October 2020 was the forecast IPP deliveries and target dates noted in the following two agreements signed with potential IPP projects:

- North Klondike Highway Solar PV Project with target commercial operation date of November 1, 2020 with 1,840 MWh annual energy delivered.

- Mount Sima Solar Project with target commercial operation date of June 1, 2021 with 270 MWh annual energy delivered.

REFERENCE: **Application, Tab 2, page 2-5, line 21**

ISSUE: **Working with ATCO Electric Yukon on Forecasts**

QUOTE: "YUB Order 2018-10 directed YEC to refine its methodology of forecasting Wholesale Sales to ensure its forecasts align closely with the AEY forecasts in future applications. To develop YEC's Wholesale Sales forecasts for the test years, YEC worked closely with AEY. YEC reached out to the AEY Regulatory team and YEC and AEY staff worked closely to understand forecasting methodology and inputs into the respective forecasts. AEY cautioned YEC that AEY's forecast is for business plan purposes and it did not necessarily undergo the same rigor as a forecast that AEY would file in a GRA.

QUESTION:

a) Please explain how the forecasting process for business planning is different from the forecasting process for a GRA.

ANSWER:

(a)

Based on YUB Order 2018-10 YEC communicated with AEY during the development of wholesale forecast for the test year. YEC's forecast wholesales sales for 2021 test year are very close to the power purchase forecast provided by AEY [as reviewed in section 2.2.1 of the Application the AEY forecast for 2021 is 0.7% higher than YEC's forecast].

During the forecast exchanges AEY cautioned YEC that AEY's forecast is for business plan purposes and it did not necessarily undergo the same rigor as a forecast that AEY would file in a GRA. Beyond this, YEC does not have specific information on how AEY's forecasting process for business planning is different from its forecasting process for an AEY GRA.

REFERENCE: **Application, Tab 2, page 2-5, footnote 4**

ISSUE: **Information Provided by Energy, Mines and Resources**

QUOTE: "YEC has forecast a micro-generation impact of about 1.5 GW.h for 2021. The micro-generation forecasts are based on information available from Energy Mines & Resources of the Yukon government."

QUESTION:

a) Please provide the source information provided to YEC by the Department of Energy, Mines and Resources and any other information from the Department that informed or influenced YEC's micro-generation forecasts for this application.

ANSWER:

(a)

The Micro-generation data below was provided by the Manager, Energy Programs in the Energy Branch at Energy Mines & Resources. The actual 2020 program total is embedded in historical sales and is included in the regressed forecasted load. Only the 2021 incremental program total of 1.5 GWh has been used to reduce the 2021 load. No adjustments were made to the peak forecast related to microgen as solar installations do not provide energy during peak winter hours.

	Installed DC Capacity At Year End [kWdc]	Capacity Added This Year [kWdc]	Exported Energy [kWh]	Payout Value	Forecasted Payout Value
2014	31		2,484	$1,643	$535
2015	83	51	16,576	$4,768	$3,573
2016	424	341	66,586	$16,925	$14,352
2017	972	549	259,673	$57,028	$55,970
2018	2,135	1,163	666,333	$143,623	$143,623
2019	3,058	923	1,357,079	$285,000	$292,508
2020	4,500	1,442	1,951,685	TBD	$420,671
2021	5,918	1,418	2,826,307	TBD	$609,188

	Installed DC Capacity At Year End [kWdc]	Capacity Added This Year [kWdc]	Exported Energy [kWh]	Payout Value	Forecasted Payout Value
2022	6,917	999	3,660,798	TBD	$789,057
2023	7,530	613	4,242,805	TBD	$914,504
2024	7,877	346	4,597,937	TBD	$991,050

1

REFERENCE: **Application, Tab 2, page 2-7, line 5**

ISSUE: **Potential Mine Load Additions**

QUOTE: "Yukon Energy continues to monitor the situation with respect to prospects for additional connected industrial mine loads within the next few years. Yukon Energy is not aware of any other potential near term mine loads that could be connected to the grid."

QUESTION:

a) Please explain how and using what methods YEC monitors for potential additional industrial connections.

ANSWER:

(a)

YEC keeps abreast of developments in the mining sector through direct contact with key stakeholders (e.g., Chamber of Mines, YG Energy Mines & Resources), monitoring of media disclosure on new developments, participation in and monitoring of key mining forums/conferences in Whitehorse (Geoscience) and Vancouver (Roundup) and monitoring of regulatory proceedings (YESAB, Water Board). Potential mining customers will also contact the utility directly with questions regarding interconnection to the YEC system; YEC tracks these contacts and confirms the stage of development. While YEC keeps track of most major mining development projects in Yukon, for obvious reasons the utility focus is on those developments with a likely potential to connect to the YEC grid.

REFERENCE: **Application, Tab 2, Section 2.2, page 2-4**

ISSUE: **Sales Forecast**

QUESTION:

a) How does YEC incorporate new residential and commercial construction into its sales forecasts?

b) How has YEC incorporated the effect of increased numbers of people working from home, due to the COVID-19 pandemic, into its sales forecasts?

ANSWER:

(a)

Finance reaches out to staff in each community who provides Finance with an update of activity in the area (for example, new residential projects and commercial activity). For larger commercial customers, Finance receives power consumption forecasts from the commercial customer.

(b)

For residential and commercial sales forecasts, YEC has not incorporated the effect of increased numbers of people working from home. This is primarily due to uncertainty and, at the time of preparation of the residential and commercial sales forecasts, Yukon people working from home were starting to go back to working at work. For residential and commercial sales, YEC uses a three year average to forecast sales, subject to other adjustments as considered necessary such as those that result from part (a) above.

REFERENCE: **Application, Tab 2, page 2-7, line 15**

ISSUE: **Residential Sales Forecasts**

QUOTE: "Actual firm residential retail sales were 15.6 GW.h in 2018 and 15.4 GW.h in 2019; the full year forecast for 2020 is 16.7 GW.h and for the 2021 test year is 16.2 GW.h. The higher forecast sales in 2020 reflect colder than normal weather and modest growth in the number of customers. Residential sales forecasts are done on a community by community basis and are based on historical averages and input from YEC staff that is obtained through their work in the communities."

QUESTION:

a) With respect to YEC's statement that "higher forecast sales in 2020 reflect colder than normal weather", what is the time period used by YEC to determine "normal weather"?

b) With respect to YEC's statement that higher forecast sales in 2020 reflect modest growth in the total number of customers, please provide the number of customers served by AEY and YEC for the last ten years, along with forecast customer counts for 2020 and 2021.

c) What input from YEC staff was obtained from work in the communities?

d) Please provide tables showing actual and forecast residential sales for the past ten years, both with and without demand side management. In your response, please comment on the YEC's residential sales forecasting accuracy for those years.

ANSWER:

(a)

The time period used by YEC to determine "normal weather" is ten years. YEC uses the Environment Canada Canadian Climate Normal for Whitehorse Airport found at the link below:

https://climate.weather.gc.ca/climate_normals/results_1981_2010_e.html?searchType=stnProv&lstProvince=&txtCentralLatMin=0&txtCentralLatSec=0&txtCentralLongMin=0&txtCentralLongSec=0&stnID=1617&dispBack=0

YEC uses the daily average monthly temperature and the most current data set is 1981 to 2020. The analysis is updated once every 10 years (industry standard) and includes a full statistical update of temperatures and Heating Degree Days.

(b)

AEY customers on the grid are supplied by YEC through Wholesales, and are not included in YEC residential customers. Average annual YEC residential customers for the last ten years, along with forecast counts for 2021 are as follows:

Table 1: Summary of Average Annual YEC Residential Customers (2011-2021)

Year	Customers
2011	1515
2012	1529
2013	1559
2014	1561
2015	1588
2016	1609
2017	1653
2018	1689
2019	1730
2020	1778
2021	1780

(c)

As noted in YUB-YEC-1-15 (a), Finance reaches out to staff in each community who provide Finance with an update of activity in the area (for example, new residential projects and commercial activity). YEC does not have a record of specific adjustments that were tied to this information.

(d)

Below is a table showing actual and forecast (annual budgeted) residential sales generation for the past 10 years. Sales are not calculated with or without demand side management. YEC's forecasting accuracy is very strong as evidenced by 4 years being below business plan and 6 years being above business plan.

Table 2: Actual and Forecast Residential Sales

Year	Forecast (MWh)	Actuals (MWh)
2011	11,601	12,710
2012	12,325	13,102
2013	12,639	13,385
2014	13,596	13,327
2015	13,625	13,121
2016	13,441	13,390
2017	13,480	14,965
2018	14,607	15,626
2019	15,705	15,384
2020	16,730	15,646

REFERENCE: **Application, Tab 2, page 2-8, line 5**

ISSUE: **Sales for Lighting**

QUOTE: "Actual firm retail sales for lighting were 235 MW.h in 2018, 178 MW.h in 2019 and forecast to remain at 178 MW.h for 2020 and for the 2021 test year. The decrease in lighting sales in 2019 was primarily due to conversion to LED street lights."

QUESTION:

a) Please provide the quantity, type and power consumption of all lights for the past ten years.

ANSWER:

(a)

YEC does not have the level of detail requested. Available information on sales for lighting is below. From project records, YEC notes 429 streetlights were retrofitted from High Pressure Sodium to LED between 2016 and 2018.

	Street Lights		Sentinel Lights		Total	
Year	Sales (MWh)	Number of Lights	Sales (MWh)	Number of Lights	Sales (MWh)	Number of Lights
2010	282.8	576	14.3	25	297	601
2011	283.0	577	13.9	25	297	602
2012	283.1	577	14.0	25	297	602
2013	283.2	578	14.1	25	297	603
2014	286.7	584	14.1	25	301	609
2015	291.8	594	14.3	25	306	619
2016	263.3	604	14.3	27	278	631
2017	228.2	614	11.6	26	240	640
2018	227.0	623	11.2	25	238	648
2019	167.8	632	10.1	23	178	655
2020	167.6	632	9.8	24	177	656

REFERENCE: **Application, Tab 2, page 2-8, line 21**

ISSUE: **Loses**

QUOTE: "Total generation is based on the sum of total sales plus losses. The 2018 approved forecast losses were 8.8%. Actual losses were 9.2% in 2018 and 2019, and full year forecast for 2020 is 9.1%. The losses are forecast at 8.8% for the 2021 test year which is the same as the 2018 approved level in the 2017/18 GRA and also within the range of historical losses for last three years, from 2017 (at 8.1%) through 2018 and 2019 (each at 9.2%)."

QUESTION:

a) Please provide the detailed working document, with formulas intact, used to determine and justify YEC's forecast for losses in the test year.

ANSWER:

(a)

The losses for the 2021 test year are forecast at 8.8% which is the same as the 2018 approved level in the 2017/18 GRA. It is also within the range of historical losses for the last three years as illustrated in Table 1 below. Attachment 1 to this response provides an excel copy of the calculations.

Table 1: Line Losses for 2017, 2018 and 2019 Years (GWh)

Year	Firm Generation (GWh)	Firm Sales (GWh)	Losses (GWh)	Losses as % of Sales
2017	446.5	413.2	33.3	8.1%
2018	450.1	412.2	37.9	9.2%
2019	440.7	403.5	37.2	9.2%
Average				8.8%

Table 1: Line Losses for 2017, 2018 and 2019 Years

Year	Firm Generation (GWh)	Firm Sales (GWh)	Losses (GWh)	Losses as % of Sales
2017	446.5	27.3	419.2	1538.3%
2018	450.1	27.6	422.5	1532.4%
2019	440.7	27.5	413.2	1502.0%
Average				1524.3%

REFERENCE: **Application, Tab 2, page 2-11, line 23**

ISSUE: **Thermal Generation Forecast and Weather**

QUOTE: "For the 2020 full year forecast actual LNG is forecast to be about 74% of the total thermal due to colder-than-normal weather (specifically January 2020 was colder than normal weather) that resulted in high loads with diesel generation being required to supply baseload energy as LNG units were running at max output."

QUESTION:

a) Please explain what constitutes "colder-than-normal weather" and how it is determined (e.g. coldest temperature during the month, average temperature, number of days below a certain temperature).

b) Please outline the performance of the LNG facility in 2020, including any mechanical issues or outages, and any increased costs resulting from failures due to burning diesel required to make up for any loss or shortfall in LNG output.

ANSWER:

(a)

Yukon Energy historically uses a peak design mean temperature of -35 deg C at Whitehorse Airport. On Jan 13, 2020, the daily average temperature at the Whitehorse Airport was -37.8 deg C and this resulted in a 'colder-than-normal' or colder than design event.

(b)

Mechanical issues include premature wear of valves, failures of exhaust valves, failures of heat exchangers and premature wear of engine block. There was 2.6 GWh of added diesel generation due to LNG outages. The net increase in fuel cost due to burning

diesel was $303,160 based on the 2018 approved GRA forecast average fuel costs per kWh for diesel ($0.2633/kWh) and LNG ($0.1467/kWh).[1]

[1] LNG costs of $381,420 at 14.67 c/kWh, compared to Diesel costs of $684,580 at 26.33 c/kWh, results in difference of $303,160.

REFERENCE: **Application, Tab 2, page 2-12, footnote 14**

ISSUE: **Hydro Generation**

QUOTE: "This reflects 37 MW at Aishihik, 6.5 MW at Mayo and 27 MW at Whitehorse. The Mayo GS dependable capacity has been reduced from 9 MW assumed in the 2017-18 GRA to reflect updated winter downstream flow restrictions and Whitehorse GS increased from 24.5 MW to 27 MW to reflect increased winter max flows."

PREAMBLE: YEC's website states: "The Mayo A hydro facility has served Yukoners since 1951. It was developed to supply electricity to the United Keno Hill Mine at Elsa, about 45 kilometres north of Mayo. It also generates power for other Yukon communities via Yukon Energy's transmission system.

The Mayo B hydro project, completed in 2011, involved building a new powerhouse 3.7 kilometres downstream from the existing hydro plant (Mayo A). This increased our capacity to generate additional renewable energy at the existing site from five megawatts to 15 megawatts, without the need for a new dam or reservoir.

Together the two plants can supply electricity to as many as 7,000 non electrically heated homes."

QUESTION:

a) Please explain the changes, and when the changes occurred, which led to the increased winter max flows for Whitehorse GS.

b) Please provide the dependable capacity and the energy generated per year of Mayo A and Mayo B (each shown separately) from the time period previous to the re-runnering of Mayo A.

c) Please compare the results provided in part (b) to the expected performance of Mayo A and B as stated in the preamble to this question. Please explain any variances.

d) If there is a deviation between the expected performance of Mayo A and B and actual performance, please explain if this will be an issue with the re-runnering project for the Whitehorse GS. If it will not be an issue, then explain how the issue will be avoided.

ANSWER:

(a)

The maximum flows for Whitehorse GS are limited to the ice conditions in Marwell area in Whitehorse. After reviewing the past data, Yukon Energy was able to increase the maximum allowable flow without causing problems in Marwell.

(b) to **(d)**

Mayo Generation has not recently been re-runnered.[1] Dependable capacity at Mayo has therefore not been recently affected by re-runnering.

Mayo was expanded in 2011 with a new plant (Mayo B) which has a higher head and efficiency from Mayo A. The dependable winter capacity from the combined Mayo facility was always expected to be well under the 15 MW of installed capacity. As noted in the Application, Mayo dependable winter capacity in the 2017-18 GRA was estimated at 9 MW.

In recent years a Mayo River ice protocol has been implemented to reduce the risk of flooding in the town of Mayo due to ice jams. This protocol limits the flow to 15 CMS (6.5MW) until an ice cover is formed. Once the Ice is formed the river flows can increase by 0.5CMS every 2 days to the maximum output.

Without the flow restriction, Mayo has a 9MW dependable capacity. With the flow restriction Mayo can provide 6.5MW of N-1 dependable capacity. YEC does ramp up Mayo to maximum flows by the end of each winter.

[1] Mayo B is a new facility developed in 2011. Mayo was developed in 1951, and two units were re-runnered in 2001.

REFERENCE: **Application, Tab 2, page 2-13**

ISSUE: **Dependable Capacity Requirements**

QUESTION:

a) In YEC's view, are revisions to the loss of load expectation and emergency N-1 standard warranted? Please explain why or why not.

ANSWER:

(a)

The loss of load expectation and emergency N-1 standards were first developed as part of the 2006 Resource Plan, and were reconfirmed with the 2016 Resource Plan. YEC is not aware of any basis to seek revisions to these standards at this time. The N-1 dependable capacity standard continues to be very relevant for non-industrial load reliability during winter months on this isolated Yukon grid. Consideration of an N-1 contingency is standard in the industry.

REFERENCE: **Application, Tab 2, Table 2-1 and Table 2-2, pages 2-16 and 2-17**

ISSUE: **Additional Historical Information**

QUESTION:

a) Please provide new versions of Table 2-1 and Table 2-2 that include the previous ten years.

ANSWER:

(a)

Please see Attachment 1 to this response for the requested information.

Table 2.1
Summary of Customers, Energy Sales and Revenues

Line No.	Description	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Forecast	Forecast 2021
1	**Residential**										
2	Customers	1,529	1,559	1,561	1,588	1,609	1,653	1,689	1,730	1,756	1,780
3	Sales in MWh	13,102	13,385	13,327	13,121	13,390	14,965	15,626	15,384	16,730	16,210
4	MWh sales per customer	8.6	8.6	8.5	8.3	8.3	9.1	9.3	8.9	9.5	9.1
5	Revenue ($000s)	1,927	1,943	1,938	1,913	1,956	2,203	2,262	2,262	2,413	2,384
6	Cents per KWh	14.7	14.5	14.5	14.6	14.6	14.7	14.5	14.7	14.4	14.7
7	**General Service**										
8	Customers	464	470	475	480	488	499	506	517	516	514
9	Sales in MWh	22,432	22,283	23,616	24,551	24,994	26,132	27,171	29,148	32,250	32,323
10	MWh sales per customer	48.4	47.4	49.8	51.1	51.2	52.4	53.7	56.4	62.5	62.9
11	Revenue ($000s)	3,622	3,621	3,894	4,048	4,180	4,350	4,490	4,833	5,351	5,388
12	Cents per KWh	16.1	16.3	16.5	16.5	16.7	16.6	16.5	16.6	16.6	16.7
13	**Industrial**										
14	Sales in MWh	44,030	40,513	36,302	37,186	41,169	43,419	36,910	27,286	64,856	102,904
15	Revenue ($000s)	5,083	4,595	3,958	4,159	4,478	4,829	4,378	3,673	7,260	11,535
16	Cents per KWh	11.5	11.3	10.9	11.2	10.9	11.1	11.9	13.5	11.2	11.2
17	**Street lights**										
18	Sales in MWh	283	281	290	290	256	228	224	168	168	168
19	Revenue ($000s)	90	89	92	92	88	88	87	82	82	82
20	Cents per KWh	31.7	31.6	31.6	31.6	34.5	38.6	39.1	48.8	48.8	48.8
21	**Space lights**										
22	Sales in MWh	14	14	14	14	14	12	11	10	10	10
23	Revenue ($000s)	4	4	4	4	4	3	3	3	3	3
24	Cents per KWh	27.2	26.5	26.6	25.9	26.0	28.6	29.2	26.7	28.1	26.6
25	**Total Company - Firm Retail & Ind.**										
26	Customers	1,992	2,029	2,036	2,068	2,098	2,152	2,195	2,247	2,272	2,293
27	Sales in MWh	79,861	76,476	73,549	75,162	79,823	84,756	79,941	71,997	114,013	151,614
28	Revenue ($000s)	10,725	10,252	9,886	10,214	10,705	11,474	11,221	10,853	15,108	19,392
29	Cents per KWh	13.4	13.4	13.4	13.6	13.4	13.5	14.0	15.1	13.3	12.8
30	**Wholesale sales**										
31	Sales in MWh	310,264	307,927	295,284	297,961	301,207	328,426	332,270	331,495	351,775	343,537
32	Revenue ($000s)	25,809	25,546	24,503	24,725	24,994	27,253	27,572	27,507	29,190	28,507
33	Cents per KWh	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
34	**Total Company - Firm**										
35	Sales in MWh	390,125	384,403	368,833	373,122	381,030	413,182	412,212	403,491	465,788	495,151
36	Revenue ($000s)	36,534	35,798	34,388	34,939	35,700	38,727	38,792	38,360	44,298	47,899
37	Cents per KWh	9.4	9.3	9.3	9.4	9.4	9.4	9.4	9.5	9.5	9.7
38	**Secondary**										
39	Sales in MWh	1,993	3,959	5,415	7,030	4,835	8,385	258	0	0	0
40	Revenue ($000s)	141	275	410	544	371	470	20	0	0	0
41	Cents per KWh	7.1	6.9	7.6	7.7	7.7	5.6	7.6	0.0	0.0	0.0
42	**Total Company**										
43	Sales in MWh	**392,118**	**388,363**	**374,248**	**380,152**	**385,865**	**421,567**	**412,470**	**403,492**	**465,788**	**495,151**
44	Revenue ($000s)	**36,676**	**36,073**	**34,798**	**35,483**	**36,071**	**39,196**	**38,812**	**38,360**	**44,298**	**47,899**
45	Cents per KWh	**9.4**	**9.3**	**9.3**	**9.3**	**9.3**	**9.3**	**9.4**	**9.5**	**9.5**	**9.7**
46	Rider J ($000s)	1,882	6,288	6,167	6,172	6,342	7,883	13,329	13,842	15,289	15,897
47	**Total Sales Revenues[1]**	**38,557**	**42,360**	**40,966**	**41,655**	**42,413**	**47,079**	**52,141**	**52,203**	**59,588**	**63,796**
48	**Total Sales Revenues excluding secondary sales**	**38,416**	**42,086**	**40,556**	**41,111**	**42,042**	**46,610**	**52,121**	**52,203**	**59,588**	**63,796**

Note:
1. Excludes revenues from other revenues.

Table 2.2
Summary of Energy Balance, Losses, Peak and Load Factor

Line No.	Description	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Forecast	Forecast 2021
	Sales and Losses										
1	Total Energy Sales	392,118	388,363	374,248	380,152	385,865	421,567	412,470	403,492	465,788	495,151
2	Losses - MWh	34,588	35,127	28,076	37,883	32,186	33,987	37,898	37,185	42,193	43,575
3	Losses - %	8.8%	9.0%	7.5%	10.0%	8.3%	8.1%	9.2%	9.2%	9.1%	8.8%
4	Total Generation	426,706	423,490	402,323	418,035	418,051	455,554	450,368	440,676	507,980	538,726
5	Secondary Sales Related Generation	2,168	4,318	5,821	7,731	5,238	9,061	282	0	0	0
6	Firm Load Generation	424,538	419,172	396,502	410,304	412,812	446,493	450,086	440,676	507,980	538,726
	Actual Generation - MWh										
	Hydro Generation										
7	Whitehorse	230,216	221,312	219,243	234,063	232,820	224,583	228,695	233,673	263,231	259,116
8	Aishihik	143,253	137,991	112,095	97,330	100,111	156,857	126,748	97,293	118,792	176,165
9	Mayo	49,736	62,000	69,082	81,123	78,480	59,607	57,610	39,853	54,703	71,201
10	Total Hydro	423,206	421,303	400,421	412,517	411,411	441,048	413,052	370,819	436,725	506,483
11	**Wind Turbine**	445	277	337	650	509	33	0	0	0	0
12	**IPPs**	0	0	1	2	3	0	0	0	56	1,983
	Diesel Generation[1]										
13	Whitehorse	2,205	840	978	1,672	1,727	3,848	5,518	2,188	13,848	1,870
14	Faro	530	900	338	405	193	281	302	802	889	237
15	Dawson	298	135	223	1,477	938	451	1,279	720	2,936	823
16	Mayo	22	34	26	20	22	39	87	84	748	21
17	Total Diesel	3,055	1,910	1,566	3,574	2,879	4,618	7,186	3,793	18,422	2,951
18	**LNG Generation[1]**	0	0	0	1,295	3,251	9,856	30,130	66,065	52,778	27,309
19	**Total Thermal[1]**	3,055	1,910	1,566	4,868	6,131	14,474	37,316	69,858	71,199	30,260
	Source - %										
20	**Hydro Generation**	99.2%	99.5%	99.5%	98.7%	98.4%	96.8%	91.7%	84.1%	86.0%	94.0%
21	**LNG Generation**	0.0%	0.0%	0.0%	0.3%	0.8%	2.2%	6.7%	15.0%	10.4%	5.1%
22	**Diesel Generation**	0.7%	0.5%	0.4%	0.9%	0.7%	1.0%	1.6%	0.9%	3.6%	0.5%
23	**IPP Generation**	0.1%	0.1%	0.1%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.4%
	LTA Generation - MWh										
24	**LTA Hydro Generation**		405,643	390,976	400,055	402,038	433,199	418,695	415,377	438,905	452,437
25	**LTA Wind Generation**		238	238	238	238	33	0	0	0	0
26	**IPP Generation**		0	0	0	0	0	0	0	56	1,983
27	**LTA Thermal Generation**		13,291	5,288	10,011	10,536	13,261	31,391	25,300	69,019	84,306
28	**Total LTA Generation**		419,172	396,502	410,304	412,812	446,493	450,086	440,676	507,980	538,726
	Peak - MW[2]										
29	**Integrated System**	82.2	82.7	76.5	82.1	88.1	91.8	93.0	90.0	103.8	112.7

Notes:

1 Actual thermal generation reflects actual generation required for maintenance, capital, RFID and all other generation, e.g., peaking. Forecast Actual Generation includes peaking, maintenance (diesel of 0.198 GW.h in 2021, and LNG of 0 MW.h) and capital (0.234 GW.h diesel) requirements reflecting short-term hydro generation forecasts.

2 Peak load is one-hour maximum load on the grid (forecasts assume weather normalized temperature).

REFERENCE: **Application, Tab 2, Table 2-2, line 7, page 2-17**

ISSUE: **Whitehorse Hydro Generation**

QUESTION:

a) Please explain why Whitehorse hydro generation is forecast to decrease from 2020 to 2021.

ANSWER:

(a)

The year 2020 is a partial forecast and part actuals. In 2020, freshet started a month early which increased the generation in May and June. 2021 is based on long-term average inflows and does not assume a similar high-water year such as that experienced in 2020.

REFERENCE: **Application, Section 3.5.1, page 3-27**

ISSUE: **Cost of debt**

QUOTE: "As per Board Order 2018-10, the interest rate is a formulaic approach based on the long-term Canada Bonds rate plus 120 basis points (Government of Canada Long-Term Bond Benchmark at 0.99% as of June 30, 2020)."

QUESTION:

a) Please provide the long-term Canada Bonds rate as of September 30, 2020 and December 31, 2020.

ANSWER:

(a)

The long-term Canada Bonds rate as of September 30, 2020 was 1.11%, and as of December 31, 2020 was 1.21%.

REFERENCE: **Application, Section 3.5.2, Return on Common Equity, page 3-27**

ISSUE: **BCUC Benchmark ROE**

QUOTE: "The current BCUC benchmark ROE continues to be 8.75%."

QUESTION:

a) Please identify the most recent BCUC decision approving a BCUC benchmark ROE of 8.75%. Please identify the date the decision was issued and relevant paragraph(s) and page reference(s) regarding the BCUC benchmark ROE in the response.

b) Is YEC aware of any generic cost of capital (GCOC) or equivalent proceedings currently before the BCUC? If so, please provide further context.

ANSWER:

(a)

The current low-risk utility ROE benchmark at 8.75% was approved by the BCUC Order G-75-13[1] effective January 1, 2013. The BCUC by its Order G-129-16[2] reaffirmed the benchmark ROE at 8.75% and stated that it remains in effect until otherwise determined by the BCUC.

(b)

Yukon Energy is aware that the BCUC issued a notice of Initiating a Generic Cost of Capital Proceeding by letter dated January 18, 2021.

[1] 1 BCUC, Generic Cost of Capital, Order G-75-13 dated May 10, 2013, page 3, paragraph 2 https://www.bcuc.com/Documents/Proceedings/2013/DOC_34699_BCUC-GCOC-Stage1DecisionWEB.pdf [accessed on February 12, 2021].

[2] 2 FortisBC Energy Inc. Application for its Common Equity Component and Return on Equity for 2016, Order G-129-16 dated August 10, 2016, page 1, paragraphs 2 and 5 https://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/169143/index.do [accessed on February 12, 2021].

However, it is unlikely the new benchmark ROE will be approved before YEC's 2021 GRA proceeding is completed. The 2013 Generic Cost of Capital Proceeding was initiated in February 2012 and final order by the BCUC was issued in May 2013, i.e., it took more than a year to complete the review.

REFERENCE: **Application, Section 3.2, page 3-3**

ISSUE: **Fuel and Purchased Power**

QUOTE: "As reviewed in Section 2.3.2, Yukon Energy's annual fuel costs are based on forecast hydro and thermal generation determined on a long-term average basis. This analysis applies only to firm load requirements."

QUESTION:

a) Please confirm that the long-term average forecast hydro and thermal generation used in the forecast includes industrial load. If not included, please explain.

ANSWER:

(a)

Confirmed that the forecast 2021 firm load used to determine the 2021 long-term average forecast hydro and thermal generation used in the Application forecast in Table 2.2 includes the forecast industrial load for 2021.

REFERENCE: **Application, Section 2.3.2, page 2-11**

ISSUE: **Diesel and LNG Thermal Generation**

QUOTE: "The forecast 2021 LTA thermal generation for the Application is 84.3 GW.h. The forecast for the test year is based on proposed updates to the determination of LTA annual hydro availability for the current GRA as outlined in Appendix 2.1…"

QUESTION:

a) Relative to LTA water flows, is YEC expecting water levels to be higher than LTA for 2021 and therefore higher than LTA hydro generation for 2021? Please explain why or why not.

ANSWER:

(a)

Based on available information at the time of drafting, YEC expects water levels to be higher than LTA. Table 2.2 in the Application shows forecast ST 2021 hydro generation at 506.5 GWh, and shows LTA hydro generation for 2021 at the lower level of 452.4 GWh. The ST forecast reflects conditions in the fall of 2020, following high inflows to Aishihik and Mayo during the preceding summer that reversed the prior year's low water conditions.

As shown in prior years, water availability forecasts provided in the fall for the following year are subject to review in following spring and again during the following summer – and can display material changes as actual conditions unfold. For example, snowpack measurements are not available until Q2; these measurements can have a significant impact on the inflow expectations for the reservoirs.

REFERENCE: **Appendix A to Board Order 2018-10, paragraphs 76 and 77; Application, Section 3.2, page 3-3; Application - Overview, pages 2 to 5; Application, Section 1.1, Need, Context and Proposed Approach for 2021 GRA, page 1-3**

ISSUE: **Short-term Versus Long-Term Average Hydro Generation Forecast**

QUOTE: From Appendix A to Board Order 2018-10:

"76. The Board recognizes that each method of forecasting, being LTA or ST, has advantages and disadvantages for GRA purposes. As submitted by YEC, during a period of favorable water conditions an ST hydro generation forecast would have a lower revenue requirement than one based on an LTA hydro generation forecast. The converse holds for periods when water conditions are unfavorable. With ST hydro generation forecasts, the impacts on revenue requirements, rate changes and resulting bills will change with each GRA depending on changes in ST water conditions and forecasts. LTA hydro generation forecasts will tend to be more stable for revenue requirements from GRA to GRA. However, items affected by this forecast may not be as accurate or representative of current GRA circumstances. For the current GRA, major differences in ratepayer bill impacts with ST versus LTA hydro generation forecasts are likely to be limited if the current rate stabilization mechanism is retained. The Board accepts that short-term thermal generation may vary materially between GRAs due to changes in actual water conditions. LTA hydro generation forecasts are based on available historic annual water records as well as current grid conditions and generation facilities to indicate ongoing average hydro generation capability over a longer period of the hydro asset life.

77. Given the above-noted advantages and disadvantages of LTA and ST hydro generation forecasts, the Board finds that, for purposes of this proceeding, it will not use the ST forecast for forecasting levels of hydro electric generation and thermal generation nor direct its use for future GRAs. In determining the revenue requirements for these and future test years, the Board is focusing on the reasonableness of the forecasts

and forecasting accuracy. Further, the onus is on YEC to adequately explain any variance between actual results and its forecast amounts. For these reasons, the Board directs YEC in future GRA filings to show actual hydro and thermal generation results when comparing previous and forecast test years." (footnotes removed; underlining added)

From page 3-3 of the Application:

"Fuel and Purchased Power costs as set out in Table 3.2 for the 2021 test year increase to $15.897 million (from $2.677 million in 2018 approved), reflecting primarily both increased load and higher fuel prices, as well as added purchased power cost [$0.314 million] for Independent Power Production (IPP)."

From page 2 of the Application:

"Yukon ratepayers have also experienced large bill increases in late 2019 and many are now experiencing ongoing disruptions due to the COVID-19 pandemic."

From page 1-3 of the Application:

"Yukon ratepayer bills – Concurrent with Yukon Energy's dilemma, Yukon ratepayers now are experiencing ongoing disruptions from the impacts of COVID-19. Any material increases to ratepayer bills at this time (and in the near future) would raise concerns."

PREAMBLE: There have been instances in the past where LTA was not used to determine YEC's thermal generation forecast costs. Most recently, this occurred when the Board directed YEC to use actual thermal costs for the 2017 test year.

QUESTION:

If water levels and the concomitant hydro generation are expected to be higher in 2021, for customer rate relief, should YEC utilize a ST hydro forecast thus reducing the upward

pressure of increased thermal generation costs for this test period? In the response, please address the following:

a) For YEC's revenue requirement forecasts, the Board focuses on reasonableness of the forecasts and the forecasting accuracy;

b) YEC, in the past, has stated that its LTA forecast cannot be retroactively verified;

c) If ST hydro forecasts are used, what the impact would be on required revenue; and

d) The ongoing impacts of COVID-19 and related costs pressures on Yukon ratepayers.

ANSWER:

(a) through **(d)**

YEC does not recommend using a short-term (ST) hydro forecast for the 2021 GRA as a means for customer rate relief that reduces "the upward pressure of increased thermal generation costs for this test period". The 2021 GRA already proposes specific measures that will prevent any material increase in customer bills during 2021 in recognition of ongoing impacts of COVID-19 and related cost pressures on Yukon ratepayers (see Sections 1.1 and 4.5 of Application). Increased thermal generation costs outlined in the Application are also already being fully funded by increased revenues from higher loads and/or by Rider F adjustments for higher fuel prices (see Table 1-2 in Application).

Long-term (LT) hydro generation forecasts have been adopted to provide a consistent and stable forecasting approach that avoids the uncertainties and instabilities associated with ST hydro generation forecasts in the context of GRA rate setting procedures, with their extended time periods required from preparing an initial GRA filing to the receipt of final Board approval of a compliance filing. Rates based on short term hydro generation are inherently more volatile; that is, any rate relief offered in 2021 due to excess water could quickly become material rate increases in future years or financial burden to the utility for a risk factor that is beyond its control when water conditions return to "normal" or below.

Experience (including extensive review during the 2017-18 GRA proceedings) has demonstrated the inherent inaccuracy of ST hydro generation forecasts made in the summer / fall of one year as regards water availability in the next calendar year. Outcomes can and do change radically during any given summer period. Although LTA hydro forecasts cannot be retroactively verified, their stability and predictability relative to ST hydro forecasts has been well established.

The Board directed use of actual thermal results for the 2017 test year simply in recognition that these results were already known at the time of the Board's decision in December 2018.

Adoption of the 2021 ST hydro forecast developed around mid-2020 and provided in Table 2.2 of the Application would increase forecast test year hydro generation (and reduce forecast test year thermal generation) by 54.046 GWh; based on the forecast 2021 fuel prices in Table 3.2-1 and the assumed 90% LNG/ 10% diesel fuel mix, the resulting revenue requirement reduction would approximate $9.932 million or 64% of the Application's forecast fuel costs of $15.530 million and 90% of the Application's forecast revenue shortfall (see Table 4.1 of Application). This reduction highlights the extent to which test year forecast fuel costs become subject to high instabilities, with potentially very wide ranging changes, as soon as ST hydro forecasts are considered for GRA rate setting purposes. The ST revenue requirement reduction for 2021 from such a change would establish with certainty the need for similarly large offsetting increases to future GRA revenue requirements simply to restore LTA hydro generation forecast requirements.

REFERENCE: **Application - Overview, Summary of Requested Orders, pages 2 to 6**

ISSUE: **Low Water Reserve Fund (LWRF) Term Sheet**

QUOTE: "Yukon Energy acknowledges that it has been directed in Board Order 2019-08 to review and update the LWRF Term Sheet in this GRA, and to provide any further views on its risk and ratepayer risks that YEC considers relevant. Yukon Energy has been required, given COVID 19 conditions and other factors related to minimizing any bill impacts on ratepayers, to focus first on completion and filing of its 2021 forecast revenue requirement and rates Application. Yukon Energy is working to complete and file an updated LWRF Term Sheet with the Board as soon as feasible."

QUESTION:

a) Without a LWRF term sheet, how is YEC able to determine its LTA thermal generation requirements? Please explain.

b) Without a LWRF term sheet, how is YEC able to determine any transaction or amounts with respect to the LWRF deferral account? Please explain.

ANSWER:

(a)

LTA thermal generation is generated based on the YECSIM long term forecasting model, represented in the application by Table 2.1-1 in Appendix 2.1. Table 2.2 in Tab 2 includes the LTA thermal generation forecast for the test year.

(b)

An updated LWRF term sheet, approved by the Board, is required to determine any transactions or amounts with respect to the LWRF deferral account following the end of the 2021 test year. These transactions do not affect the determination of revenue requirement or rates in this application.

REFERENCE: **Application, page 6; Application, LWRF, Section 3.6.3, Tab 3, pages 3 30 to 3-31**

ISSUE: **Low Water Reserve Fund (LWRF)**

QUOTE: "Yukon Energy has been required, given COVID 19 conditions and other factors related to minimizing any bill impacts on ratepayers, to focus first on completion and filing of its 2021 forecast revenue requirement and rates Application. Yukon Energy is working to complete and file an updated LWRF Term Sheet with the Board as soon as feasible."

QUESTION:

a) Please state when an updated LWRF Term Sheet will be made available. If a precise date is not available, please provide YEC's best estimate.

b) How can the Board or interveners test the reasonableness of the LWRF in the absence of an updated term sheet? Please explain.

ANSWER:

(a) and **(b)**

Yukon Energy is working to provide an updated LWRF Term Sheet in March, along with related LWRF Annual Reports for 2019 and 2020.

An updated Term Sheet is required for determining dollar impacts to the LWRF deferral account when evaluating actual 2021 results as defined by the fund rules. The LWRF Term Sheet, however, does not have any impact on the 2021 GRA revenue requirement forecasts.

REFERENCE: **Application, Tab 2, Table 2-2, page 2-17, lines 13-17; Application, Tab 3, page 3-3, line 2**

ISSUE: **Diesel Generation**

QUOTE: "The increase from 2018 to 2021 reflects higher production and labour costs, including $3.834 million costs for diesel rentals required to meet the N-1 single contingency capacity planning criteria (no diesel rental costs were included in the 2018 approved costs)."

QUESTION:

a) Within the context of forecast reductions in thermal generation from 2020 to 2021 as shown in Table 2-2, why is YEC forecasting an additional $3.834 million for rental of diesel generators?

ANSWER:

(a)

The rental of 15 diesel generator units plus two spare units is required to address the N-1 dependable capacity shortfall, as explained in Section 2.4 of the Application (the specific measurement of the shortfall is addressed at pages 2-14 and 2-15). This requirement is related to the factors noted regarding the N-1 capacity shortfall, and is not related to forecast thermal generation.

REFERENCE: **Application, Section 3.2, Fuel and Purchased Power, page 3-3**

ISSUE: **Thermal Generation Mix**

QUOTE: "The test year long-term average forecasts for hydro generation have been updated to reflect new information, 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, the same ratio as approved in the 2018 GRA."

QUESTION:

a) Please provide the actual thermal generations ratios/percentages for each year since YEC has been utilizing LNG as a fuel source.

b) In regard to the response to part (a), please explain how an LTA of 90% LNG and 10% diesel generation was derived and determined to be accurate for use in this proceeding.

c) Does YEC take on all risk with respect to any changes between actual and forecast results for changes in the thermal generation fuel ratios?

ANSWER:

(a)

Please see Table 1 below that shows actual thermal generations by source and percentages for 2015 (the first year with partial LNG generation) through 2019, and forecast for 2020 and 2021. Table 1 also shows annual thermal generation as a percent of LTA thermal generation, highlighting the extent that annual hydro generation is below or in excess of LTA hydro generation.

Table 1: Thermal Generation for 2015-2021 Years

Annual Thermal Generation - MWh	2015 Actual [2]	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast
Diesel Generation	3,574	2,879	4,618	7,186	3,793	18,422	2,951
LNG Generation	1,295	3,251	9,856	30,130	66,065	52,778	27,309
Total Thermal[1]	4,868	6,131	14,474	37,316	69,858	71,199	30,260
Thermal Generation Source - %							
Diesel Generation	73%	47%	32%	19%	5%	26%	10%
LNG Generation	27%	53%	68%	81%	95%	74%	90%
Annaul Thermal % of LTA		58%	103%	119%	276%	103%	36%

Notes:

1 Actual thermal generation reflects actual generation required for maintenance, capital, RFID and all other generation, e.g., peaking. Forecast Actual Generation includes peaking, maintenance (diesel of 0.198 GW.h in 2021, and LNG of 0 MW.h) and capital (0.234 GW.h diesel) requirements reflecting short-term hydro generation forecasts.

2 Partial year generation from LNG in 2015.

(b)

Since LNG was added as a generation source in 2015, Yukon Energy has used a split of 90% LNG and 10% diesel generation in GRA's based on the expected thermal mix applicable to the LTA thermal generation estimates rather than basing the thermal mix on the short-term water conditions that may occur in any specific year. The LTA thermal mix is the ratio applicable to the LTA thermal forecast adopted for rate setting in GRAs.

The 90/10 LNG/diesel ratio was adopted based on expectation that LNG would be heavily used during drought or low water conditions (i.e., LNG share would exceed 90%). This very high usage tends to dominate the long-term thermal generation estimates over all water conditions. That is, while diesel would be used for peaking, emergencies and other specific uses such that diesel's share of thermal in many years with average or higher-than-average water conditions may well significantly exceed 10%, the impact of high LNG use in low water conditions favors the average mix of 90:10 on LTA basis.

This theory is proven out in in Table 1 above; the actual LNG generation was about 53% of the total thermal generation in 2016, increasing to 68% in 2017, 81% in 2018 and 95%

in 2019.[1] This percentage has been below 90% when hydro generation was similar to or in excess of LTA, and was above 90% in 2019 when hydro generation was well below LTA.

As noted, higher LNG generation numbers in 2019 reflect water conditions materially below LTA. For the 2020 full year forecast actual LNG is forecast to be about 74% of the total thermal due to colder-than-normal weather (specifically January 2020 was colder than normal weather) that resulted in high loads with diesel generation being required to supply baseload energy as LNG units were running at max output. For the 2021 test year actual LNG is currently expected to be about 90% of the total thermal.

The 90/10 ratio has been confirmed to be reasonable ratio for the 2021 test year based on actual results for 2018 and 2019 [average for all thermal in 2018 and 2019 is 90% LNG and 10% diesel]. YEC has no reason to believe there should be a change at this time to the 90% LNG/10% diesel for the LTA thermal split purposes under LTA water conditions.

(c)

YEC does not take on all risk with respect to any changes between actual and forecast results for changes in the thermal generation fuel ratios.

The “forecast” 90/10 LNG/diesel fuel mix in each GRA is intended to reflect LTA fuel mix as reviewed in “b” above, and does not forecast actual fuel mix. In contrast, actual fuel mix in any year reflects actual water availability and hydro generation, and can therefore vary materially from the LTA fuel mix.

YEC’s final thermal generation costs for each fiscal year are determined through the LWRF deferral account determinations after the end of the calendar year. YEC’s last LWRF Term Sheet filed in December 2019 set YEC’s final fiscal year expense for the total expected thermal generation (i.e., YEC expense after all transfers) to provide 90% LNG and 10% diesel mix, subject to the constraint (when setting the LWRF based on actual load) that the LNG share of any transfer into or out of the LWRF cannot exceed 100%. In practice, this constraint could result in YEC’s final expense diesel share exceeding 10%.

[1] As noted on page 2-11 of the Application, the numbers slightly inflate diesel share due to inclusion of thermal generation for capital projects and RFID, i.e., LNG share was 83% of net thermal generation excluding capital and RFID loads in 2018 (versus 81% in Table 1) and 97% in 2019 (versus 95% in Table 1).

REFERENCE: **Application, Section 3.2, Fuel and Purchased Power, page 3-5**

ISSUE: **Forecast Thermal Costs – LNG**

QUOTE: "Forecast LNG delivered price to Yukon Energy's Whitehorse thermal facility for the 2021 test year is $0.4824 per litre, which reflects the expected average delivered LNG cost. This forecast for LNG cost is based on the results of a public competitive tender process completed in late 2019 for liquefaction and shipping costs and current market price for commodity value. Yukon Energy forecasts average efficiency for LNG generation of 2.66 kW.h/litre, which is the average efficiency based on actual results for 2019. The resulting forecast LNG cost is $0.1814/kW.h. The approved 2018 LNG price was $0.1467/kW.h."

QUESTION:

a) Please explain why a 2020 competitive tender process was not used to determine the forecast delivered price.

b) Please provide a breakdown and reasons for the increase in LNG costs from $0.1467/kWh to $0.1814/kWh.

c) Please explain why only a 2019 average efficiency was used for LNG generation.

d) Please include the fuel price forecasts for LNG and diesel from the Part 3 LNG proceeding in 2014 and compare with actuals.

ANSWER:

(a)

The competitive tender process completed in 2019 was for 4 supply years commencing in 2020 and subject to minimum supply volumes. Prices for liquefaction and transport are locked in for each year based on the winning bid. Commodity price fluctuates based on an established market reference (NGX Alberta).

(b) and **(c)**

Please see Table 1 that provides a breakdown of LNG fuel cost components for 2017/18 GRA and 2021 GRA. The LNG fuel cost increase is mostly due to increase in transportation costs. Based on the competitive tender process completed in 2019, the prices for liquefaction remain unchanged from 2021 through 2023 [excluding the commodity price which fluctuates based on market price], while transportation cost reduces in 2023 by about 27% compared to the cost for 2021 [reduces to $0.159/l in 2023 compared to $0.218/l as shown in table below].

Table 1: LNG Fuel Cost Comparison

	2017/18 GRA $/L	2021 GRA $/L
Liquifaction [inc. commodity cost]	$0.228	$0.264
Transportation	$0.149	$0.218
	$0.377	$0.482
Efficiency, kW.h/litre	2.57	2.66
LNG fuel cost, $/kW.h	$0.1467	$0.1814

Fuel efficiency for LNG and diesel for the 2021 GRA is in each case based on actual average results for 2019, which is the last full year with actual information at the time of filing of the application. The fuel efficiency for LNG improved from 2.57 kW.h/litre in 2017/18 GRA to 2.66 kW.h/litre in 2021 GRA. The forecast average efficiency of 2.66 kW.h/litre is the average efficiency based on actual results for 2019.

(d)

The Application for an Energy Project Certificate and An Energy Operation Certificate Regarding the Whitehorse Diesel-Natural Gas Conversion Project [LNG Part 3 application] filed on December 9, 2013 assumed LNG fuel cost at $0.135/kW.h, including commodity cost at $0.038/kW.h, liquefaction costs at $0.053/kW.h and transportation cost at $0.044/kW.h.

The transportation cost in the application assumed that the LNG haul from Calgary with A-Train with a cost of $5.16/MMBtu which was based on a cost estimate of $4.37/MMBtu plus approximately 18% increase for potential underutilization of equipment for initial YEC requirements from Calgary.

During the interrogatory process, YEC provided an update to the transportation costs to reflect the need to secure LNG from FortisBC's LNG facility, higher assumed fuel consumption per mile for the haul, higher hourly labour costs, increased unload time at Whitehorse, and reduction in assumed operating days per year.[1] YEC's update to YUB-YEC-1-4 filed March 27, 2014 estimated LNG delivered costs from the FortisBC LNG facility in 2015 at $0.156/kW.h assuming Tridem units for transportation.

For the 2021 GRA forecast cost of liquefaction is $0.082/kW.h plus $0.017/kW.h commodity cost and $0.082/kW.h transportation cost. In 2021 GRA the combined cost for liquefaction and commodity at $0.099/kW.h compared to $0.091/kW.h in LNG Part 3 application and $0.089/kW.h in 2017/18 GRA; while transportation cost increased to $0.082/kW.h in 2021 GRA compared to $0.044/kW.h in LNG Part 3 application and $0.058/kW.h in 2017/18 GRA.

The diesel fuel cost in the LNG Part 3 application was $0.246/kW.h compared to $0.2633/kW.h in 2017/18 GRA and $0.2051/kW.h in 2021 GRA. As indicated in the 2021 GRA application the diesel fuel prices are as of July 1, 2020 and reflect lower fuel prices during 2020 in response to oil market conditions and COVID-19.

[1] Response to YUB-YEC-1-44 during the review of the Application for an Energy Project Certificate and An Energy Operation Certificate Regarding Whitehorse Diesel-Natural Gas Conversion Project.

REFERENCE: **Application, Section 3.2, Fuel and Purchased Power, page 3-6**

ISSUE: **Purchase Power Costs**

QUOTE: "The purchase cost for the IPPs in 2021 is assumed at $0.1583/kW.h based on the latest approved thermal fuel cost for YEC in its 2017/18 GRA. Total IPP purchase cost is forecast at $0.314 million for 2021." (footnote removed)

QUESTION:

a) Why are the purchase costs from intermittent IPPs in 2021 based on the forecast thermal fuel cost for YEC?

b) Given the IPPs currently in place, is the expected purchase of 1.983 GWh of energy likely to occur? Please explain why or why not.

c) Has there been discussion of variable rates for IPPs that would recognize the increased value of winter generation?

ANSWER:

(a)

Purchase prices applicable to IPPs are set according to applicable Standing Offer Rules. The footnote removed from the quote explained that Standing Offer Rules, Section 42(a) state that "the Base Fuel Price is to be equal to the YEC's average blended fuel price per kWh for thermal generation most recently approved by the YUB before the date on which the EPA takes effect." Accordingly, the purchase price for the IPPs in 2021 is assumed as stated in the above quote.

Furthermore, section 3(2) of OIC 2019/25 as provided in Tab 11 of the Application provides the same direction regarding the price paid by YEC for a kWh of electricity under an on-grid electricity purchase price agreement; Section 4 (subsections 1 and 3) provide for annual increases in the price in subsequent years at 50% of any increase in the CPI. Section 2(1) of OIC 2019/25 directs that, in setting rates, the Board must allow the utility

to recover specific costs which include the cost of purchasing electricity under an electricity purchase agreement.

(b)

YEC is not able to confirm that the forecast 2021 IPP purchase of 1.983 GWh of energy is likely to occur. The first IPP project did not get completed in November 2020 as forecast in the IPP agreement and as assumed in the Application. YEC has no control or responsibility as regards when each of the two forecast IPP projects commences production in 2021, or whether any other potential IPPs may be able to advance their plans to commence production later in 2021.

(c)

The concept seasonal IPP rates was discussed in earlier Yukon government policy papers related to potential IPP development. Current policy directions on IPP pricing for Standing Offer Program projects do not include any provision for lower prices to apply during summer periods.

REFERENCE: **Application, page 5 and Section 3.6.2, Defined Benefit Pension Deferral Account, page 3-29**

ISSUE: **Stabilization Mechanisms**

QUOTE: From page 5:

"Defined Benefit Pension Deferral Account: Approval of defined benefit pension plan deferral account as set out in Section 3.6.2 that captures variances in contributions to the defined benefit pension plan from the cost included in the test year revenue requirements as a result of the required annual actuarial evaluations."

From page 3-29:

"Yukon Energy is required to file updated actuarial valuation reports on an annual basis with valuation reports determining the required funding for the next year. The actual contributions for the year can vary from the forecast depending on market conditions and the performance of the pension plan assets. The proposed deferral account protects both the utility and ratepayers from variances in required contributions over the amounts included in test year revenue requirement. For the 2021 test year, the defined benefits pension plan cost is $0.720 million."

QUESTION:

a) Please prepare a high-level outline of YEC's history (including the relevant timeline and events) with respect to any previous use or request to use a defined benefit pension deferral account.

b) Please explain why the "similar deferral account … approved for [ATCO Electric Yukon] AEY by Board Order 2014-06" should apply in the circumstances of YEC. Please identify the similarities and differences between the "similar deferral account" approved for AEY in 2014 and the defined benefit pension deferral account proposed by YEC in the current GRA.

c) Please clarify if the "required annual actuarial evaluation" was submitted by YEC and, if so, provide a reference to where details of the evaluation can be found in the current application. If not submitted, please provide the "required annual actuarial evaluation".

d) Please provide historical details of YEC's "defined benefits pension plan cost" for the years 2018-2020 on an approved and actual basis in comparison to YEC's forecast 2021 cost of $0.720 million. Please include any details respecting current service payments from special payments.

e) Given there is an annual actuarial evaluation conducted, on what basis would there be variances in required contributions over the amounts included in the test year revenue requirement that would support deferral treatment as necessary?

f) What circumstances have changed recently such that YEC now considers a defined benefit pension deferral account necessary?

g) Please provide details addressing both the requirement for and the specific mechanics of YEC's proposed defined benefit pension deferral account including proposals for a future true-up of the same.

ANSWER:

(a)

YEC has not previously requested nor used a defined benefit pension deferral account.

(b)

While YEC has not specifically reviewed the terms and conditions governing the AEY pension plan, YEC believes the risks are similar based on the fact that the YEC plan was inherited from ATCO as part of the termination of the management contract in 1997. Of note, the YEC DB plan was closed to new members in 2001 while we understand the ATCO plan continues to be available to new hires. Irrespective of that fact, the risks from market fluctuations and the resultant impact on funding exists if the plan is closed or not.

(c)

Please see Attachment 1. Note this attachment is not the formal actuarial valuation from 2020 (see Attachment 2); however, YEC, as an IFRS-compliant public entity, uses IAS 19 as guidance for pension funding. Attachment 1 is the actuarial estimate of funding required

for 2020 based on IAS 19. YEC is seeking a deferral account to accumulate differences from GRA approved funding v. future directions.

(d)

Fiscal Year	Pension Cost	
2018	$657,984	Approved
2018	$678,600	Actual
2019	$605,900	Actual
2020	$720,200	Forecast (per GRA)
2020	$741,300	Actual

(e)

The GRA process essentially locks in the pension recovered from rates whereas the funding requirements vary every year and the variance is beyond the utility's ability to control.

(f)

As noted in the AEY application, current OSFI guidance has created a situation where actuarial valuations are essentially required every year (unless solvency calculations exceed 120%). This required has increased funding volatility year over year.

(g)

As discussed above, YEC is seeking a deferral account to absorb the differences between the IAS 19 pension expenses as directed by the plan actuary. The accumulated differences will be reviewed by the YUB at each GRA and balances will be refunded or collected as necessary.

REFERENCE: **Application, Section 3, Revenue requirement**

ISSUE: **YEC Revenue Requirement**

QUOTE: Please revise Table 3.1, Table 3.3, Table 3.4, Table 3.5, Table 3.8, and Table 3.9 to include 10 years of historical information on both an approved and actual basis commencing with the year 2012.

QUESTION:

a) Please revise Table 3.1, Table 3.3, Table 3.4, Table 3.5, Table 3.8, and Table 3.9 to include 10 years of historical information on both an approved and actual basis commencing with the year 2012.

ANSWER:

(a)

Please see YUB-YEC-1-36 Attachment 1 for requested information.

Table 3.1
Yukon Energy Revenue Requirement
($000)

	2012 Approved	Actual 2012	2013 Approved	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Actual 2017	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Fuel and Purchased Power	$ 2,316	$ 827	$ 3,200	$ 3,878	$ 1,569	$ 2,756	$ 2,159	$ 2,460	$ 2,677	$ 5,348	$ 6,211	$ 11,874	$ 13,153	$ 15,897
Non-Fuel Operating and Maintenance	17,210	17,941	18,111	19,381	19,957	19,580	20,470	22,476	22,125	23,497	24,559	26,903	29,074	29,430
Depreciation and Amortization	7,927	8,225	8,604	9,500	7,783	8,690	7,816	10,848	11,141	11,104	11,053	11,007	12,489	13,125
Return on Rate Base	11,396	10,313	12,348	11,139	11,938	10,829	12,242	13,584	13,850	12,110	9,480	10,163	9,448	16,682
Revenue Requirement/Revenue	$ 38,850	$ 37,306	$ 42,263	$ 43,897	$ 41,247	$ 41,855	$ 42,686	$ 49,367	$ 49,794	$ 52,059	$ 51,302	$ 59,947	$ 64,164	$ 75,135

REFERENCE: **Application, Section 3.3, Non-Fuel Operating and Maintenance (O&M) Expenses, pages 3-7 and 3-8**

ISSUE: **Non-labour and labour inflation rates**

QUESTION:

a) Please clarify if YEC applied or used an inflation rate (or escalation factor) in arriving at its forecast non-labour O&M expenses for the year 2021. If confirmed, please provide all support for the non-labour inflation rate used in YEC's 2021 forecast amounts (for example, provide excerpts from the most recent Yukon Economic Outlook documentation) and identify which non-labour O&M expenses the inflation rate was applicable to. If not confirmed, please explain YEC's method for forecasting its non-labour O&M expenses for the year 2021.

b) Please provide the actual 2018-2020 non-labour inflation rates experienced by YEC.

c) Please provide the actual 2020 labour inflation rate experienced by YEC and clarify whether the labour costs shown on Table 3.3 (page 3-7) and included in the forecast 2020 costs of $12,727 reflect this inflation rate.

d) Please clarify if any collective bargaining agreements that will be settled in 2021 for the fiscal period 2020 are expected to be applied retroactively to January 2020 or some other date and, if so, explain if and how YEC has accounted for this anticipated future liability for regulatory purposes.

e) Please confirm YEC's statement that the "forecast 2020 and 2021 labour rates include estimated economic increments of 2%" means that 2019 actual labour costs were inflated by 2% to arrive at 2020 forecast labour costs, followed by 2020 forecast labour costs being inflated by an additional 2% to arrive at 2021 forecast labour costs. If not confirmed, please fully explain how the increments of 2% were applied.

f) Please explain why a labour inflation rate of 2% remains reasonable for either of the years 2020 or 2021 given the current economic conditions surrounding the COVID-19 pandemic. Please clarify whether YEC's forecast labour inflation rate of

2% is consistent with Yukon Economic Outlook documentation. If so, please provide the relevant excerpts from the most recent Yukon Economic Outlook documentation for each of the years 2020 and 2021.

g) Please identify any additional costs or savings experienced by or actively sought by YEC during 2020 as a result of the current economic conditions surrounding the COVID-19 pandemic.

h) Referring to the response to part (g) above, are any additional costs or savings experienced by or actively sought by YEC during 2020 as a result of the current economic conditions surrounding the COVID-19 pandemic anticipated to continue into the year 2021? If so, please identify and quantify the additional costs or savings to YEC for the year 2021.

ANSWER:

(a)

YEC does not use a general inflation factor in arriving at its non-labour O&M forecasts. YEC budget owners are given a blank template and they build up a budget based on their experience, knowledge and expectations in the upcoming year. Budgets are submitted to Finance and Senior Management, where they are vetted and adjusted as necessary.

(b)

As stated in (a), YEC did not use inflation rates in 2018-2020.

(c)

The actual 2020 labour inflation rate has not been determined due to the ongoing collective bargaining agreement process applicable to the period commencing January 1, 2020. YEC expects this process to be completed in late 2021. The 2020 labour costs shown on Table 3.3 of $12,727 reflect an assumed inflation rate of 1.75% plus 0.25% for other costs resulting from the collective bargaining process (e.g., performance increments) for a total estimated annual increment of 2.00%.

(d)

As stated in response (c), YEC has assumed a total economic increment of 2.00% resulting from the collective bargaining process. The collective bargaining process is for the period commencing January 1, 2020, so YEC will calculate any differences in amounts owing to/from employees retroactively, and adjust 2021 labour expense for this difference (assuming the collective bargaining process is completed in 2021). There will be no retroactive application of settled amounts into 2020.

(e)

The statement is confirmed.

(f)

Historically, YEC has benchmarked CBA annual increments against other local public entity increases (e.g., Yukon Government, Yukon Hospital Corporation, Yukon University, etc.). It is worth noting that the arbitrator has agreed with these benchmarks in each of the last three CBA settlements. Yukon Economic Outlook documentation has historically not been the basis for YEC economic increases decided by the arbitrator, so YEC does not consider this applicable.

(g)

Significant additional costs as a result of the current economic conditions surrounding the COVID-19 pandemic are included as RFID. Savings as a result of the current economic conditions surrounding the COVID-19 pandemic include significantly reduced travel costs for YEC employees.

(h)

YEC expects there to be both costs and savings that as a result of the current economic conditions surrounding the COVID-19 pandemic continue into the year 2021. The amount is not determinable.

REFERENCE: **Application, Section 3.3, Non-Fuel Operating and Maintenance (O&M) Expenses, pages 3-8 and 3-9**

ISSUE: **Labour Costs (Section 3.3.1)**

QUOTE: "Table 3.4 shows that the total position count is forecast to increase by 9.90 positions since 2018 approved to 2021 test year.

At the historic staff level, employees were finding it difficult to keep pace with increased demands, more so as additional assets are added and increasing burden for planning and executing capital works. In recent years overtime hours have increased creating additional workload and adverse effect for the existing employees which in turn resulted in an increase in employee turnover. The increase in employee turnover has increased the recruiting and relocation costs for the forecast years."

"To combat the above issues, YEC is forecasting an increased employee complement. The increase in employee complement has resulted in significant decrease in forecast overtime costs for 2021. Also, the increased employee complement in 2019 through 2021 is due to an effort, where possible, to do more work internally as opposed to hiring outside consultants and contractors. YEC has made a conscience effort to limit increases to only those areas where required as reviewed below."

QUESTION:

a) Please update Table 3.4 to include YEC's actual employee complement as of December 31, 2020. Please include an explanation for any variances between YEC's 2020 forecast 97.86 employee complement and 2020 actual employee complement.

b) In light of the current economic conditions surrounding the COVID-19 pandemic, does YEC anticipate an increase or decrease in employee turnover in 2021?

c) Please provide YEC's employee turnover (number of employees resigned or retired) and vacancy rate on an actual basis for the years 2018-2020 and forecast basis for the years 2020 and 2021.

d) Please prepare a table quantifying the "recruiting and relocation costs for the [2020 and 2021] forecast years" and compare these amounts to the recruitment and relocation costs experienced by YEC on an actual basis for the years 2018-2020.

e) Please prepare a table quantifying the "forecast overtime costs for [2020 and] 2021" and compare this amount to the overtime costs (including both O&M and capital related) experienced by YEC on an actual basis for the years 2018-2020.

f) Please prepare a table quantifying the costs of outside consultants and contractors on an actual basis for the years 2018-2020 and on a forecast basis for the years 2020-2021. In the response, please ensure that the type of consultant and contractor work being performed on behalf of YEC has been identified. (For example, the cost of the consultant and contractor work as related to O&M, capital, administrative, regulatory or other).

ANSWER:

(a)

Table 1 below represents Employee Complement History as presented in the Application updated for Actual 2020 results.

Table 1: Employee Complement History

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Actual 2020	Proposed 2021
President	4.16	5.14	4.82	4.01	4.01	4.16
First Nation Relations	-	-	-	-	0.50	1.00
Communications, Cust. Acctg.	1.00	1.00	1.00	3.10	3.10	4.60
Human Resources & Info. Mgmt.	5.25	5.27	5.34	5.32	5.30	5.25
Resource Planning and Environment	5.00	5.00	5.75	5.51	5.93	7.05
Finance, Cust. Acctg. & Purchasing	16.79	16.89	17.24	13.54	13.56	14.79
Operations	44.50	46.58	47.12	48.75	48.30	49.25
Engineering Services	15.00	13.03	15.16	15.63	15.72	15.50
Health & Safety	2.00	2.00	2.00	2.00	2.00	2.00
Total	93.70	94.91	98.44	97.86	98.41	103.60

There are no significant variances from Forecast 2020 to Actual 2020. The largest variance of 0.50 is in First Nation Relations. YEC added this position to its Employee Complement effective July 1, 2020; however, as of December 31, 2020, this position remains vacant.

(b)

YEC does not forecast turnover and has no basis to assess the impact of the global pandemic on the job markets that YEC is active in. YEC continues to plan and execute recruitment efforts consistent with prior years.

(c)

YEC's employee turnover (number of employees resigned or retired) on an actual basis for the years 2018-2020 is summarized in Table 2 below:

Table 2: Employee Turnover: 2018-2020

2018	5
2019	9
2020	6

YEC does not have a specific employee turnover forecast for 2021.

YEC's vacancy rate on an actual basis for the years 2018-2020 and forecast basis for the years 2020 and 2021 is summarized in Table 3 below:

Table 3: Vacancy Rate: 2018-2020

Year	**Vacancy Rate**
Actual 2018	-6.05
Actual 2019	-9.91
Actual 2020	-9.30
Forecast 2020	-3.00
GRA 2021	-5.00

(d)

Recruiting and relocation costs are summarized in Table 4 below:

Table 4: Recruiting and Relocation Costs

	Actual	Forecast
2018	$ 190,319.04	
2019	$ 334,005.84	
2020	$ 311,044.72	$ 279,080.00
2021		$ 211,260.00

(e)

Overtime costs are summarized in Table 5 below:

Table 5: Overtime Costs

	Actual	Forecast
2018	$ 901,416	
2019	$ 938,858	
2020	$ 992,155	$ 735,768
2021		$ 760,960

(f)

The costs of outside consultants and contractors on an actual basis for the years 2018-2020 and on a forecast basis for the years 2020-2021 is summarized in Table 6 below:

Table 6: Costs for Outside Consultants and Contractors

($M)	Admin	O&M	Capital
2018 Actual	1.375	2.965	17.900
2019 Actual	1.358	2.520	17.124
2020 Actual	1.523	3.869	31.654
2020 Forecast	1.575	2.831	
2021 Forecast	1.532	2.942	

Capital project forecasts are not done on a cost-element basis, so we are unable to provide a forecast for Capital outside consultants and contractors.

REFERENCE: **Application, Section 3.3.1, Non-Fuel Operating and Maintenance (O&M) Expenses, pages 3-8 to 3-13**

ISSUE: **Labour Costs (Section 3.3.1)**

QUESTION:

a) Please clarify how many employees will report to YEC's proposed "1.00 position increase in 2021 due to … a Vice President, First Nation Relations." (page 3-10)

b) Please confirm whether "Yukon Energy's 5-Year Strategic Plan, published in 2019, confirmed YEC's commitment to establishing mutually beneficial and strategic partnerships with Yukon First Nations governments" (page 3-9) and is intended to be subject to testing in the current GRA. If confirmed, please explain fully why this is the case.

c) Please explain whether it is YEC's understanding that it is responsible for fulfilling consultation obligations where they arise with respect to potential impacts on s. 35 rights (Section 35 of the Constitution Act, 1982).

d) Please elaborate on YEC's new position (Vice President, First Nation Relations) and how it will expand YEC's current ability to move projects forward.

e) Given that the name for the "Finance, Customer Billing/Accounting and Purchasing" category (page 3-11) continues to reference the words "Customer Billing/Accounting," please clarify whether any "Customer Billing/Accounting" personnel remain in the originating group after the 2020 transfer of 2.10 positions to the "Communications, Customer Accounting" (page 3-10) category.

f) Referring to the categories identified in Table 3.4 (page 3-8) and including the proposed "1.00 position increase in 2021 due to the addition of a new full-time position, Senior Communications Advisor" (page 3-10), please clarify how many communication personnel in total will be employed by YEC and in which Table 3.4 category or categories these employees reside.

g) Please clarify the role of YEC's communication personnel in relation to YEC's internal versus external communication requirements.

h) Please quantify how many external communication issues, such as customer complaints, were submitted to YEC for resolution during each of the years 2018-

2020. Of these submissions, please quantify how many were resolved in each year by YEC and how many were forwarded to the YUB for resolution.

i) With respect to YEC's Resource Planning and Environment category, please clarify what is referred to as the "backlog of planning work designation for completion" (pages 3-10 and 3-11) for which YEC has proposed to add a two-year resource planning engineer position to assist with. In the response, please also clarify which capital projects have been delayed as a result of the referenced planning work backlog.

j) With respect to YEC's Resource Planning and Environment category, please clarify if YEC's "2020 10-Year Renewable Electricity Plan" (pages 3-10 and 3-11) is intended to be considered by the Board in the current GRA. If confirmed, please explain fully why this is the case. Please provide a reference to where YEC's Electricity Plan has been provided in its application; otherwise, please submit a copy of the report in response to this IR.

k) With respect to YEC's Resource Planning and Environment category, please identify the priority initiatives recommended in the "2020 10-Year Renewable Electricity Plan" (pages 3-10 and 3-11) which YEC has proposed to address by adding a senior project manager. In the response, please also quantify how many employees are currently engaged in any of the priority initiatives and whether any are proposed to now report to the new senior project manager.

l) Please explain whether procurement personnel have historically been within the "Finance, Customer Billing/Accounting and Purchasing" group and provide the quantity of employees responsible for procurement in that or any other group up to the year 2020. Will YEC's proposed "1.00 position increase … of a new full-time position, Procurement Administrator" (page 3-11) result in less work for those employees previously responsible for procurement work up to the year 2020? If so, please explain where has YEC incorporated the incremental benefits of hiring a full-time procurement administrator in its revenue requirement.

m) In relation to YEC's procurement activities, please provide quantifiable evidence that YEC has experienced "increased workload in the department due to greater volume of high dollar projects" (page 3-11) during each of the years 2018-2020 on an actual basis.

n) In relation to YEC's procurement activities, please explain why there are "increasingly complex contracting strategies for some capital projects, including the additional requirements of the First Nation procurement policy, which has increased the complexity and administrative support required for large project

procurement." (page 3-11) In the response, please confirm that it is the Yukon Government First Nation Procurement Policy being referred to, whether that policy applies to Yukon Energy, and also identify the additional requirements of YEC to follow that policy.

o) In relation to YEC's procurement activities, please explain and provide context with respect to "the need to allow departmental management to concentrate on policy renewal and development and education for client managers new to YEC." (page 3-11).

p) In relation to YEC's operations, please confirm that the "1.00 position increase in 2018 due to the addition of a new full-time position, Maintenance Mechanic to address additional responsibilities (e.g., LNG assets)" was contemplated in YEC's original LNG project business case. If confirmed, please provide a reference to the business case where an increase in employee complement was identified as being required.

q) In relation to YEC's operations, please provide the per cent increase over 2020 actual plant operator personnel that the total 1.75 position increase in plant operators will represent. (page 3-12)

r) In relation to YEC's engineering services, please confirm that the "1.00 position increase in 2020 … of a new full-time position, Electric Engineer" (page 3-12) occurred on an actual basis during the year 2020.

s) Please provide YEC's capital to maintenance allocation ratios on an actual basis for the years 2018-2020. (page 3.13)

ANSWER:

(a)

YEC is not proposing any direct reports to this position at this time. The VP will be the primary liaison with First Nations and will work through other departments as required depending on the nature of the issue (e.g., planning, engineering, operations, finance).

(b)

In this context, the reference to the 2019-24 strategic plan was intended to demonstrate the Corporation's commitment to working with First Nations. It is self-evident that YEC

owes a duty to Yukon First Nations as a landowner and further, as a legal obligation under various treaty agreements.

(c)

YEC is not directly responsible for fulfilling the Crown's duty to consult and accommodate Yukon First Nations with respect to a potential impact on s. 35 rights. However, the Crown has given effect to its duty to consult, in part, through the framework established under YESAA, and YEC has duties as a proponent under that framework, including statutory consultation obligations, with respect to the environmental and socio-economic assessment of YEC projects. In addition, in certain circumstances, YEC may have further consultation duties arising directly under the provisions of Yukon First Nation Final Agreements (e.g., under Specific Economic Measures provisions included in Chapter 22).

(d)

Any significant project that occurs in the Traditional Territory of a Yukon First Nation requires the proponent to engage and consult with that First Nation. In YEC experience, the consultation process is most effective when an established relationship already exists with the affected First Nation. The Vice President First Nation Relations will be responsible for establishing and maintaining relationships with First Nations in Yukon Energy's service area. As well, when a project is identified, the Vice President will lead the negotiations of the benefits agreements thereby capitalizing on the relationship.

(e)

No Customer Billing/Accounting personnel remain in the group after the 2020 transfer. To be clear, certain aspects of customer accounting is retained by the core Finance group (e.g., account reconciliation, cash management) but staff who are responsible for direct interactions with customers, account set up and maintenance, bill preparation and distribution, account collection, etc. have transferred out of Finance.

(f)

There will be two communication personnel in total employed by YEC and both are in the category labelled Communications, Cust. Acctg.

(g)

Yukon Energy communications personnel are responsible for developing and delivering the Corporation's external communications and supporting company-wide internal communications on key topics and projects. The latter can include writing and reviewing company-wide messages, presentations, campaigns and other collateral.

(h)

Yukon Energy does not track all external issues and complaints in one central repository. External issues and complaints are addressed and actioned by individual departments, as required. Yukon Energy is not aware of how many external issues or complaints were forwarded to the YUB.

In terms of specifics, YEC offers the following as indicative of increased work load:

- Weekly briefings for the Minister and YDC started in Q4 2019 and have continued since.

- We started tracking the number of media calls, Ask Steph (online) emails and social media comments/questions we receive in 2020.
    - 84 media calls were received in 2020;
    - 44 Ask Steph inquiries in 2020;
    - More than 200 questions and comments on Facebook and Twitter in 2020;

- Table 1 below highlights the impact of additional duties with respect to increased communications involvement in capital works and customer service.

Table 1: Allocation of Manager of Communications Time, 2018-2020 (Year-to-date)

Year	Communication Admin.	Customer Billing Admin.	Capital
2018	99.24%	0.0%	0.76%
2019	66.43%	0.0%	33.57%
2020	44.13%	15.53%	40.34%

Additionally, as a one-position department with critical responsibilities during unplanned events, the Manager Communications is effectively on call 24/7, 365 days a year. The extra position will help provide an additional resource for this important function.

(i)

The general challenge is that YEC is unable to advance concurrently, as required, all of its projects given limited internal planning resources. The planning projects which are currently designated for completion include the ones listed below. It's difficult to clarify which projects have been delayed due to insufficient internal resources – all projects tend to be adversely impacted in this situation, and YEC has had to address delays in dealing with almost all of the active projects listed below. The concern looking forward is that the upcoming work requirement is expected to be even more challenging than that experienced to date.

- Aishihik Generating Station Water Use 25 Year License Renewal;
- Whitehorse Rapids Generating Station Water Use License Renewal;
- Mayo Generating Station Water Use License Renewal;
- Diesel Retirement Replacement;
- Southern Lakes Storage;
- Mayo Lake Storage Enhancement Project;
- Battery Energy Storage System;
- Pumped Storage;
- Southern Lakes Transmission Line; and
- Demand Side Management Programs.

(j)

YEC's "2020 10-Year Renewable Electricity Plan" is intended to be considered by the Board in the current GRA in that it is included as a deferred cost Regulatory project added to rate base, as disclosed in Section 5.3.2 of the Application (page 5-26) as well as in Table 5.5. The Plan, however, generally addresses project planning for development beyond the 2021 test year. Please see CW-YEC-1-36(a) Attachment 1 for a copy of the 10-Year Renewable Electricity Plan.

(k)

YEC anticipates the Senior Project Manager will lead the completion of the Southern Lakes Transmission Line and Pumped Storage projects (each of which remain in WIP in 2021). Current employees are engaged on these projects on an ad hoc basis given limited resource capacity, and the focus on securing federal funding before advancing either project. YEC does not anticipate any employees will report to the new senior project manager.

(l)

Procurement personnel have been within the "Finance, Customer Billing/Accounting and Purchasing" group for many years (i.e., > 10 years). The number of full time equivalent employees responsible for procurement in the group for year 2020 is 3.5. The addition of the Procurement Administrator will not result in less work for other staff. YEC recognized that the volume of purchasing was exceeding the capacity of the department to the point where some projects were delayed due to backlogs in procurement. As well, procurement volumes have increased (see (m) below) and other managerial tasks were not being addressed on a timely basis (see (o) below).

(m)

See Table 1 below for the volume of purchase orders processed at YEC back to 2018, demonstrating the greater volume of high dollar projects.

Table 1: Volume of Purchase Orders: 2018 to 2020

Fiscal Year	Count of PO Number	Sum of Originating Subtotal
2018	586	27,855,025.96
2019	630	33,480,891.75
2020	765	62,313,928.33

(n)

YEC has had to address, or is addressing, a number of complex procurements. This includes the following examples:

- BESS – new technology both for YEC and the Canadian industry, international vendors, long lead time;
- EAM – software acquisition, high dollar, US vendor, acquisition of licences implementation and post-go live support; and
- MMTP – high dollar, large number of contracts, federal funding requirements, large FN components.

YEC approved a First Nation Procurement Policy in 2016, although implementation has occurred gradually since that time. YEC was aware that YG was working on a similar policy since 2019. While YEC is not obligated to follow YG policy, the shareholder expects that our policy approach should not materially diverge from YG.

(o)

The department includes one manager who has responsibility for providing supervision and leadership to the team. In addition, this position is responsible for advising management on complex transactions, conducting market research, developing and maintaining long-term vendor relationships, policy update/development, procurement system access and functionality and training for client staff.

With respect to procurement policy, there is a recognized need to adapt current policy for external factors e.g., Canadian Free Trade Agreement, YG FN Procurement Policy. As

well, policies are over 10 years old and need to be updated for industry best practice and general improvement for efficiency and effectiveness.

Training is becoming a critical issue as YEC has experienced significant turnover in recent years. While the company has been successful at attracting skilled replacements, it is normal for new project managers to require training on the specific rules of procurement at YEC. Prior to the addition of an additional position, the manager was required to participate in the preparation and management of procurement processes to the point there was no time available to other matters as described.

(p)

The "1.00 position increase in 2018 due to the addition of a new full-time position, Maintenance Mechanic to address additional responsibilities (e.g., LNG assets)" was not specifically contemplated in YEC's original LNG project business case. The position was required to address the workload of all generation assets based on the workload at that time, which changed from the time when the LNG business case was prepared. The process to justify the additional position was done using a spreadsheet that assigned annual tasks at each facility. This process determined the staff complement against the work. The latest iteration of the work indicated a deficit in mechanical trades staff. With the addition of the LNG facility there was an obvious lack of person hours to complete the suggested maintenance.

(q)

The 1.75 position increase represents a 16% increase in plant operators.

(r)

Confirmed.

(s)

YEC's capital to maintenance allocation ratios on an actual basis for the years 2018-2020 is provided in Table 2 below:

Table 2: Capital to Maintenance Allocation Ratios

	Capital	Maintenance
2018	14.7%	85.3%
2019	16.0%	84.0%
2020	18.2%	81.8%

REFERENCE: **Application, Section 3.3.2, Production, pages 3-13 and 3-14**

ISSUE: **Production Costs – Diesel Rentals**

QUOTE: "Diesel rentals [cost increase of $3.834 million over 2018 approved GRA]: Costs of mobile diesels to address dependable capacity shortfalls (see Tab 2, section 2.4) is forecast to increase to $3.834 million in 2021 as compared to actual 2018 costs of $1.048 million and no costs included as part of 2018 Approved costs. Forecast mobile diesel costs are based on negotiated contracts with the vendor."

QUESTION:

a) Please provide all quantitative evidence demonstrating a competitive supply for YEC's diesel rental costs on an actual basis for the period 2018-2020.

ANSWER:

(a)

2018/19

- YEC ran one-year public competitive tender process for 6 – 2 MW diesel generators for placement at Whitehorse Rapids Generation Station for the winter heating season (approximately 5 months).

- Two bids were received:

Vendor	Quote
Trinity Power	$1,860,059
Finning Canada	$1,557,881

- A contract was awarded to Finning Canada.

2019/20

- YEC ran a three year public competitive tender process for up to 8 – 2 MW units for the season; annual renewals are at the discretion of YEC.

- Three bids were received; one bid was deemed non-compliant and was therefore excluded from the price evaluation:

Vendor	Quote
United Rentals	$3,706,685
Finning Canada	$1,913,234

- Due to additional generation risk from low water in Mayo, YEC elected to rent one additional 2 MW unit.

2020/21

- Based on forecast model, 17 – 2 MW units required for 20/21 heating season.

- 10 units placed in WRGS under the unit rates per 19/20 RFP; 7 units were placed in Faro through a contract extensions with Finning Canada; unit rates for Faro units were based on market conditions at the time.

REFERENCE: **Application, Sections 3.3.3 and 3.3.4, Non-Fuel Operating and Maintenance (O&M) Expenses, pages 3-14 to 3-16**

ISSUE: **Transmission and Distribution Brushing Allocations**

QUOTE: "The major portion of the transmission cost variance relates to changes in the annual brushing cost requirements and changes in the allocation of brushing budgets between transmission and distribution lines. Table 3.6.1 provides further details on the brushing allocations." (pages 3-14 and 3 15)

"The fluctuation results from changes in brushing allocations between transmission and distribution lines. Table 3.6.1 provides further details on the brushing allocations." (page 3-16)

QUESTION:

a) Please identify and fully explain all reasons for the changes in "brushing allocations between transmission and distribution lines" noted by YEC and referenced in the above quotes.

b) Referring to Table 3.6.1 (page 3-15), please explain why YEC's 2019 Actual brushing costs were almost exclusively related to transmission brushing activities (98%) as compared to a more typical 78-85% (transmission related) as observed for the other years identified in the table.

ANSWER:

(a)

Brushing allocation is determined based on priority, planned work on infrastructure, vegetation outage stats and growth rate.

(b)

The high allocation of funding in 2019 can be directly attributed to the transmission line refurbishment (TLR) project where site access was a priority.

REFERENCE: **Application, Section 3.3.5, General Operation and Maintenance, pages 3-16 and 3-17**

ISSUE: **General Operation and Maintenance**

QUOTE: "Labour costs are forecast to decrease by $0.017 million in 2020 from 2018 approved. Total forecast costs in the non-labour General O&M categories in 2021 are $0.172 million higher than approved 2018 costs of $1.219 million. Transportation expenses are forecast to increase $0.051 million (10%) in 2021 over 2018 approved. Maintenance of Company Owned Properties is expected to increase $0.090 million (18%) in 2021 over 2018 approved. SCADA Communication expenses are forecast to increase by $0.031 million (15%) in 2021 under 2018 approved."

QUESTION:

a) Please provide variance explanations for all per cent changes between 2018 approved and 2021 forecast costs noted by YEC in the above quote.

b) Please respond to part (a) on the basis of changes between 2020 and 2021 forecast costs.

c) Please detail any measures to be taken by YEC to control or reduce its overall general operation and maintenance costs in 2021.

ANSWER:

(a)

Labour costs are forecast to decrease primarily due to a reduction in time allocated to Communications. Transportation expenses are forecast to increase primarily due to insurance and maintenance of an aging and larger fleet. Maintenance of Company Owned Properties is expected to increase primarily due to increased rental of land and buildings. SCADA Communications expenses are forecast to increase due to an increase in the cost of communication rentals.

(b)

Labour costs are forecast to increase primarily due to an increase in time allocated to Fleet. Transportation expenses are forecast to increase primarily due to resumption of more normal activities as the first half of 2020 was low due to decreased travel resulting from the Covid-19 pandemic. Maintenance of Company Owned Properties is expected to decrease primarily due to an overall general reduction in various Whitehorse costs. SCADA Communications expenses are forecast to remain consistent with 2020.

(c)

YEC has an intense budget process where budget owners build a budget based on a blank template. Budgets are scrutinized by Finance, Senior Management and the board of directors. Budgets are adjusted as considered necessary.

REFERENCE: **Application, Section 3.3.6, Administration, pages 3-17 and page 3-18**

ISSUE: **Administration Costs**

QUESTION:

a) Please detail any measures taken by YEC to control or reduce its overall administration costs forecast for 2021.

b) Please clarify whether YEC's forecast increase in general administration expense related to new asset management software was contemplated in any related business case and, if so, please provide a reference to the cost benefit analysis conducted in that business case.

c) Please clarify why YEC's general administration expense forecast for 2021 is anticipated to increase over 2020 forecast costs given the explanation for the increase between 2018 and 2021 costs as noted in part (b) above.

d) Please explain why YEC's Board of Directors expenses have not decreased given restrictions related to the COVID-19 pandemic and requirements to conduct meetings virtually.

e) Please quantify the number of Board of Directors meetings held during the year 2020 on an actual basis and forecast for the year 2021.

f) Please describe the nature of and reason for any training proposed for YEC's Board of Directors.

ANSWER:

(a)

YEC has an intense budget process where budget owners build a budget based on a blank template. Budgets are scrutinized by Finance, Senior Management and the Board of Directors. Budgets are adjusted as considered necessary.

(b)

The business case is reviewed in YUB-YEC-1-64, and includes consideration of managing ongoing software management costs. The estimated ongoing annual costs start in 2021 and are used in the business case and NPV calculations.

(c)

The primary reason for the increase in general administration expense for 2021 over 2020 are the costs related to the new asset management software as noted in part (b), as the system is to be implemented in 2021.

(d)

Travel cost was not a significant cost of the Board of Directors budget prior to the pandemic; therefore, there is no significant savings on this budget due to pandemic restrictions.

(e)

In 2020, YEC had 14 Board meetings and 24 Committee meetings. Of the 14 Board meetings, 5 were scheduled and the other 9 were Special Meetings. YEC has scheduled 4 quarterly meetings, 2 special meetings for strategic planning and business plan approval for 2021. There is a possibility that additional unscheduled meetings will be required for time sensitive issues.

(f)

YEC's Board of Directors are looking at focusing their training on finance and oversight for the Audit Committee (and possibly expanding to the full Board) for 2021. This is based on the outcome of a Director Evaluation that was completed in 2020 and identified oversight of financials and strategic priorities as a key focus area for the Board.

REFERENCE: **Application, Section 3.3.7, pages 3-18 to 3-20**

ISSUE: **Insurance and Reserve for Injuries and Damages (RFID)**

QUOTE: "Yukon Energy's costs for insurance in 2021 are forecast to increase by $0.392 million (38%) above approved 2018 costs of $1.031 million, and are based on the completed 2020 annual renewal process. Costs in 2020 increased due to mid-year market rate adjustments (overall rate increase of 25% on commercial package) and increased insured asset value. Costs in 2021 increase primarily due to a full year impact of the 2020 rate increase [most of the costs for the 2021 fiscal year are already locked by the insurance policy renewables in 2020 due to insurance year cycle differences from YEC's fiscal year]. The market rate increases experienced by YEC as part of 2020 renewals are consistent with peer utilities in Canada."

"The large expense in 2020 reflect works required in Whitehorse hydro generation facility penstock [about $0.730 million], Whitehorse LNG Unit #2 [$0.4 million], LNG Vapourizer [$0.3 million] and other small projects. In 2021 test year, YEC is forecasting annual costs of $0.411 million."

QUESTION:

a) Please provide the availability statistics for each of the LNG units by year since inception.

b) In light of your response to part (a), please comment on the reliability of each of the LNG units.

c) Please clarify whether the insurance year or renewal cycle has changed for either YEC or its insurance company from those used in prior GRAs.

d) Please clarify whether YEC examined alternative insurance coverage from other providers in order to keep insurance cost increases to a minimum. Please explain all resources and alternatives YEC examined.

e) Please provide further details for each of the respective LNG-related RFID claims comprising the $1,598 thousand Forecast 2020 annual cost as noted in Table 3.11.1.

f) Please clarify whether YEC follows a policy for processing of claims against its RFID account and, if so, please provide the policy or a reference to the most recent version of the RFID policy by which YEC is guided.

g) Please explain the rationale for amortizing the $2,121 thousand Forecast 2020 RFID balance over a period of five years, as opposed to any other period of time.

h) Please explain why YEC did not include 2020 forecast RFID charges in its determination of a 10-year average annual charge as shown in Table 3.11 (page 3-19).

i) Please revise Table 3.11 and Table 3.11.1 to include an Actual 2020 column that incorporates a 10-year average annual charge that incorporates 2020 actual (annual charge) information.

ANSWER:

(a)

Please see Attachment 1 to this response.

(b)

Most of the issues with the LNG units relate to valve recession on the cylinder heads. YEC is running the third version of the cylinder heads, as the OEM attempts to resolve the problem. The majority of the costs associated with the valve recession have been covered by the OEM.

In late Q4 2020, WG1 had a generator fault, the stator will need to be rewound. In Q2 2020 WG2 had extensive damage as a result of a valve failure.

(c)

Neither the insurance year nor renewal cycle has changed. Insurance periods start approximately mid-year.

(d)

During 2020, YEC directed its broker to conduct a full marketing effort for YEC's property insurance policy. The insurers on the program were selected in order to obtain the lowest rate while still providing adequate coverage. Rate increases were compared with industry peers to validate the market conditions experienced by YEC.

(e)

Further details for each of the LNG-related RFID claims are as follows:

- **LNG Vapourizer – [$0.3 million] –** Three failures of the shell and tube heat exchangers in the LNG storage and re-gas package significantly increased the risk of failure of the vapourizer coil. This work involved the replacement of the coils with an improved design in order to avoid an unexpected lengthy outage of the LNG facility.

- **LNG Unit #2 [$0.4 million] –** An exhaust valve failure in one of the cylinder heads of LNG unit #2 resulted in damage to 16 power cylinders as well as two turbo chargers. The extensive damage resulted in a complete block replacement, with a portion of the costs being covered by the OEM.

(f)

The RFID Policy was most recently filed with the YUB as Appendix 3.1 in the 2012-13 General Rate Application. Annual appropriation was updated by the YUB as per Board Order 2018-10 as part of the 2017-18 General Rate Application.

(g)

Amortization of the RFID opening balance over five years was selected as that is what the YUB approved in the 2017-18 GRA.

(h)

YEC did not include 2020 forecast RFID charges in its determination of a 10-year average annual charge as shown in Table 3.11 as this Table reflects 'actual' charges, not 'forecast'.

(i)

2020 actual RFID costs are not yet finalized due to ongoing 2020 year-end accounting procedures.

KPI Report: Unit Status

02/23/2021 15:28

			2021-Q1 1287 hrs			2020-Q1,Q2,Q3,Q4 8784 hrs			2019-Q1,Q2,Q3,Q4 8760 hrs			2018-Q1,Q2,Q3,Q4 8760 hrs		
			AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED
			66.20%	Reliablity 66.7%	0.5%	68.1%	Reliablity 78.3%	10.2%	90.7%	Reliablity 99.8%	9.1%	48.7%	Reliablity 99.1%	20%
WHITEHORSE	THERMAL	WG1	-	100%	-	76%	8%	17%	88%	1%	11%	77%	2%	21%
		WG2	99%	-	1%	41%	57%	2%	93%	0%	7%	61%	-	39%
		WG3	100%	-	0%	87%	0%	12%	91%	0%	9%	8%	0%	0%

KPI Report: Unit Status

02/23/2021 15:28

			2017-Q1,Q2,Q3,Q4 8760 hrs			2016-Q1,Q2,Q3,Q4 8784 hrs			2015-Q1,Q2,Q3,Q4 8760 hrs		
			AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED
			56.1%	Reliablity 99.8%	10.5%	62.8%	Reliablity 99.9%	3.8%	63.3%	Reliablity 99.4%	3%
WHITEHORSE	THERMAL	WG1	84%	0%	16%	95%	0%	5%	96%	0%	4%
		WG2	84%	0%	16%	93%	0%	7%	94%	1%	5%
		WG3	-	-	-	-	-	-	-	-	-

REFERENCE: **Application, Section 4.4.2, pages 4-6 to 4-8**

ISSUE: **VGC and Alexco Fixed Charge**

QUOTE: "Board Order 2018-04 also directs YEC to submit a limited scope application to amend the firm mine rate within 60 days of the Transmission Facilities Development Operation Date (Paragraph 57). The Transmission Facilities Development Operation Date is forecast to occur in late November 2020/early December 2020 when the Transmission Facilities Development comes into service, connecting the McQuesten Substation with a substation at Mayo. Yukon Energy's limited scope application to the Board to be filed when this development comes into service is described in Appendix 4.3 based on forecast costs and YEC's approved 2018 GRA cost of capital."

"The interim Fixed Charge for 2021 will also be subject to adjustment and Board review and approval as part of YEC's 2021 GRA. YEC understands that the final Transmission Facilities Fixed Cost and an adjusted Fixed Charge for VGC Group and Alexco for 2021 will be determined subsequently based on YEC's final compliance filing as approved for the 2021 GRA (including actual costs as then known for the relevant new facilities) and also based on adjustments as required after 2021 year end to reflect actual MWh loads of VGC Group and Alexco and any adjustments as needed for actual costs as then known for the relevant new facilities."

QUESTION:

a) Please clarify what YEC is requesting from the Board in the above quotes. Specifically, is YEC asking the Board to approve an interim Fixed Charge for 2021 in the current proceeding and to determine the final Fixed Charge in a separate application to be filed within 60 days of the Transmission Facilities Development Operation Date?

ANSWER:

(a)

YEC is not asking the Board to approve the Fixed Charge for 2021 at this time.

The amended Transmission Facilities Fixed Cost application and related interim Fixed Charge are required to be filed within 60 days of the Transmission Facilities Development Operation Date, i.e., the date that YEC provides to VGC Group to confirm that the Transmission Facilities Development has been completed and is in service to deliver Grid Electricity to the Mine Facilities through the Mine Facilities Spur (all terms as defined in the approved VGC Group PPA). This application, which is required to establish at that time the adjusted Fixed Charge related to the amended Transmission Facilities Fixed Cost, exists separate from the 2021 GRA application, and was therefore assumed not to be part of the 2021 GRA application.

The Transmission Facilities Development Operation Date has been delayed to March 2021. YEC therefore now expects to file the amended Transmission Facilities Fixed Cost application in March 2021, requesting an interim Fixed Charge adjustment effective May 1, 2021 in order to establish a necessary rate adjustment for VGC Group and Alexco as soon as feasible. This filing will be based on the 2020-2021 to date forecast costs of the new facilities and YEC's approved 2018 GRA cost of capital at 4.82%, i.e., these initial adjustments do not include any changes related to YEC's 2021 GRA proposed cost of capital.

The Transmission Facilities Fixed Cost and Fixed Charge for 2021 related to the completed Transmission Facilities Development will be updated once the STATCOM is commissioned and final costs are available, which will not occur until late 2021 after the GRA is scheduled to be finalized. After the 2021 year end, adjustments will be made as required by Section 7.7(c)(ii) of the approved VGC Group PPA to reflect actual 2021 MWh loads of VGC Group and Alexco.

REFERENCE: **Application, page 5-23**

ISSUE: **Section 5.3.1.2, Demand Side Management**

QUOTE: "The context within which Yukon Energy has approached Demand Side Management (DSM) has materially changed since the Board made the following DSM related determination in Board Order 2018-10 (paragraph 482):

> The Board is not persuaded that YEC should continue to operate DSM projects. YEC has indicated the benefits of expanding the program and submitted that its programs have met or exceeded key performance indicators. However, the Board notes that the Yukon government has DSM incentive programs in place, and the Board is of the view that it is better to leave DSM projects to government, rather than having ratepayers fund these projects. For these reasons, the Board is of the view that continuation of DSM programs by YEC is not necessary.
>
> Since that determination the Yukon Government has put in place a Climate Change policy initiative called "Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy" which emphasizes the importance of DSM as a valuable resource to reduce the Yukon's energy and capacity requirements. As part of that policy the government fully expects Yukon Energy to pursue a cost-effective DSM program.
>
> Pursuant to this policy initiative and the Government's expectations, and further given DSM remains a cost-effective means of reducing energy and capacity requirements, Yukon Energy has included in the proposed 2021 rate base the expenditures for the programs and activities as reviewed below. (footnotes removed)

QUESTION:

a) What is meant by the statement "the context within which Yukon Energy has approached Demand Side Management (DSM) has materially changed"?

b) Given your response in part (a), how should the Board evaluate whether there is a "material change" in the context (i.e., circumstances) since Board Order 2018-10 was issued?

c) To the extent that the content of discussions can be disclosed, please describe Yukon government discussions with YEC regarding the DSM programs YEC has applied for in this proceeding, particularly in light of the Board's finding in paragraph 482 of Appendix A of Board Order 2018-10 that the continuation of DSM programs by YEC was not necessary. Please also summarize any discussions on scope, quantum, and timing of the applied-for DSM programs.

d) Please explain to what extent policy directions stated by Yukon Government in the climate change policy initiative "Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy" are binding on the Yukon Utilities Board. If these directions are not binding, please explain how the Yukon Utilities Board should consider those policy directions in its review of YEC's applied-for DSM programs.

e) Please explain why policy initiatives supported by Yukon Government should be funded by ratepayers through their utility bill, as opposed to through government supported initiatives such as taxation or other means. In addition, please provide YEC's view on how the two options might differently affect low-income households.

f) Please explain how YEC considered rates and rate base provisions of the Public Utilities Act in its proposal for demand-side management. In your response, please specifically identify how the DSM programs are the property of a public utility used or required to be used to provide service to the public.

g) On November 19, 2020, the Court of Appeal of Yukon heard an appeal regarding Board Order 2019-05 (in which the Board dismissed YEC's request to review Board Order 2018 10) in relation to DSM costs. What impact, if any, is there on the Board's consideration of the applied-for DSM costs in this proceeding given that the outcome of the Court of Appeal of Yukon's decision on the appeal remains outstanding?

h) Please explain YEC's management decision to include the DSM policy initiatives in the current application rather than in its next GRA? Please explain why these initiatives are required to be completed in 2021.

ANSWER:

(a) through **(f)**

Since the last rate application, the Yukon Government released a climate change strategy – "Our Clean Future: A Yukon strategy for climate change, energy and a green economy". More specifically, YG drafted the action below in the policy:

> 53. Direct the Yukon Utilities Board to allow Yukon's public utilities to pursue cost-effective capacity demand-side management measures.

This is a material change to how YEC approached DSM. The YG has clearly stated that DSM is a valid supply option for Yukon utilities and that they expect YEC to actively consider and implement prudent DSM programs. They also indicated their intention to direct the YUB to support cost-effective programs administered by YEC and AEY.

In keeping with action item number 53 the YG enacted OIC 2021-16.

OIC 2021/16 directs the Board to include in rates provision to recover costs that a public utility (i.e., YEC or AEY) reasonably incurs to provide or participate in a demand side management program.

Based on YG's DSM policy and also considering growth in electrical load on the system, Yukon Energy DSM planning was undertaken; this planning includes coordination with the Yukon government's DSM programs to meet the overall policy objectives in a cost effective manner.

DSM program costs of Yukon Energy have been approved by the Board in the past as deferred costs that are included in rate base, consistent with the rate and rate base provisions of the *Public Utilities Act ("PUA")*. The Board can continue to deal with these costs in the future in the same manner.

(g)

YEC notes the Court of Appeal ruled on this proceeding on February 5, 2021 and the appeal was dismissed. The Court of Appeal proceeding including the decision does not affect the 2021 GRA Application as none of the costs that were covered by the appeal are included in this Application.

(h)

As stated above, YG has publicly confirmed its support for utility-driven DSM programming and further they indicated that they expect YEC to undertake such programing. Based on YG's clear expectation (now confirmed by OIC 2021/16) and with the knowledge that a significant capacity shortfall exists on the Yukon integrated system, YEC believed it was timely and prudent to include these programming costs in the 2021 application.

REFERENCE: **Application, Section 5.3.1.2, page 5-23, line 14**

ISSUE: **Effect of DSM on Energy and Capacity Requirements**

QUOTE: "Since that determination the Yukon Government has put in place a Climate Change policy initiative called "Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy" which emphasizes the importance of DSM as a valuable resource to reduce the Yukon's energy and capacity requirements. As part of that policy the government fully expects YEC to pursue a cost-effective DSM program." (footnote removed)

QUESTION:

a) Please provide any analysis or research compiled by YEC, or its program partners, that supports the conclusion that DSM can reduce Yukon's energy and capacity requirements.

b) Please provide any analysis YEC, or its program partners, has carried out examining the effect of YEC's DSM projects to date on the energy and capacity requirements for YEC and the associated cost savings compared to the costs of the DSM programs.

c) Please comment on the potential effects on rates should DSM programs administered by YEC lead to a significant decline in energy sales. In particular, please provide YEC's view of whether it is possible for ratepayer-funded DSM programs to lead to increased rates as a result of declining energy sales.

d) Please provide the results of any analysis carried out by YEC, or its program partners, with respect to the ability of seasonal pricing to reduce peak energy and capacity demand. If YEC has not carried out any such analysis, please explain why.

ANSWER:

(a) and **(b)**

Yukon Energy in partnership with ATCO Electric Yukon and Yukon Government completed a DSM Program Portfolio which was filed with the Yukon Utilities Board as part of AEYs 2013-2015 GRA. This included a Conservation Potential Review, Market Characterization, Implementation Plan, and Evaluation Measurement and Verification Plan. The Conservation Potential Review was updated for Yukon Energy's 2016 Resource Plan. DSM programs were again shown to be a cost effective resource and were included in the recommended portfolio. These studies concluded the DSM can cost effectively reduce Yukon's energy and capacity requirements.

A portion of the residential programs presented in this portfolio were launched to the Yukon public. Progress reports and evaluations of the energy and capacity savings as well as cost effectiveness of these programs in accordance with the filed Evaluation Measurement and Verification Program were conducted and filed with the YUB. These reports and evaluations clearly demonstrated DSM as a cost-effective energy and capacity resource.

In Order 2014-06, the Board applied four standard cost-effectiveness measures for DSM costs (collectively, the "InCharge Programs Prudency Measures"), namely the total resource cost test (TRC), the program administration cost test (PAC), the rate-impact measure test (RIM), and the participant cost test (PCT).[1] Program elements of the residential non-government DSM portfolio that passed all four cost-effectiveness measures for 2014 and 2015 were approved by the Board.

Evidence provided by Yukon Energy in the 2017/18 GRA indicated that the Approved InCharge Programs met InCharge Programs Prudency Measures endorsed by the Board in Order 2014-06 and were rate neutral for ratepayers. Specifically, Approved InCharge Program development and delivery was reviewed in the 2017/18 Application at page 5-39 and 5-40. Figure 5-1 at page 5-40 provided a summary of energy savings and costs, updated to the end of 2016 which noted that the programs achieved an overall RIM ratio of 1.1 (1.0 shows the program is neutral from a utility rate impact perspective), and achieved a very high PCT ratio (3.0) and high PAC ratio (9.4), demonstrating that the

[1] See Order 2014-06, Appendix A at pp. 94, 100-101.

programs are very beneficial to program participants and to utilities. Table 5-1 also showed that the program achieved a high TRC ratio (3.1), showing that it also compares well against other electricity resource options.

Evidence provided by Yukon Energy in the 2017/18 GRA also showed that the Approved InCharge Programs elements were evaluated by a third party evaluation advisor in 2015 and 2016 which confirmed that the expenditures met or exceeded the above-noted InCharge Programs Prudency Measures key performance indicators. The following were specifically noted:

- The response to UCG-YEC-1-40 in that proceeding, provided the 2015 Interim Evaluation Report by ICF Marbek; and the 2015-16 Evaluation Report by ICF Marbek (actuals to end of July 2016).

- The evaluation reports were based on the Evaluation, Measurement and Verification Plan filed with the YUB as an attachment to YUB-YECL-26(a) during AEY's 2013-15 GRA[2].

- The energy savings and coincident peak demand reduction that have resulted from the Approved InCharge Program were outlined in Table 2 of both the 2015 and 2015/16 Evaluation reports.[3]

- The response to YUB-YEC-1-80 (d) and (e) in YEC's 2017-18 GRA noted that the cost benefit analysis provided by ICF Marbek was reviewed and approved by an independent evaluator (Econoler).

Reference to further supporting documentation that supports the conclusion that DSM can reduce Yukon's energy and capacity requirements are provided below:

- Demand Side Management Plan including Program Portfolio, Conservation Potential Review, Market Characterization and Working Group Guidelines. http://yukonutilitiesboard.yk.ca/pdf/YECL_2013-15_GRA_Part_2-_DSM_plan.May_27,_2013.pdf

[2] YEC 2017/18 GRA proceeding, UCG-YEC-1-49(a).
[3] YEC 2017/18 GRA proceeding, UCG-YEC-1-40(c).

- Program Implementation Plan http://yukonutilitiesboard.yk.ca/pdf/2013-08-08_YECL_Information_Responses.pdf

- Evaluation, Measurement and Verification Plan http://yukonutilitiesboard.yk.ca/pdf/2013-08-08_YECL_Information_Responses.pdf

- inCharge Annual Reports including Program Evaluation Reports http://yukonutilitiesboard.yk.ca/pdf/Reports/inCharge_Annual_Report_2017_FINAL.pdf
  http://yukonutilitiesboard.yk.ca/pdf/Reports/2016_DSM_Annual_Report.pdf

- 2016 Resource Plan http://yukonutilitiesboard.yk.ca/pdf/YEC_2017-18_GRA/Yukon_Energy_2016_Resource_Plan_Part_1.pdf
  http://yukonutilitiesboard.yk.ca/pdf/YEC_2017-18_GRA/Yukon_Energy_2016_Resource_Plan_Part_2.pdf

- Conservation Potential Review Update https://yukonenergy.ca/media/site_documents/Appendix_5.20_Updates_to_Yukon_Electricity_Conservation_and_Demand_Management_Potential_Review_(ICF_2016).pdf

(c)

The RIM test as reviewed in Board Order 2014-06 (see response to (a) and (b) above) recognizes and addresses the possibility that DSM programs may lead to significant decline in energy sales that result in increased rates. As reviewed in response to (a) and (b) above, Yukon Energy DSM programs were previously confirmed to pass the RIM test and were rate neutral for ratepayers.

YEC anticipates that the targets for its ongoing DSM programs will emphasize capacity-focused reductions rather than energy reductions. Capacity savings directly result in a reduced requirement for temporary diesel rental units. These savings, in combination with the fuel savings from any related energy savings, are expected to outweigh any potential rate impacts driven by the reduction of sales.

(d)

YEC is aware that seasonal pricing can be an effective tool to reduce peak energy and capacity demand. However, YEC has not proceeded with undertaking any detailed analysis or assessments regarding implementation of seasonal pricing as a DSM measure. As such, no analysis can be provided at this time.

While the 2017/18 GRA included forecast costs for a time-of-use rate structure and smart grid study to assess the potential for a time-of-use rate structure and associated smart grid – YEC did not proceed with undertaking this work. More specifically, in Order 2018-10 the Board found that "YEC has not provided information that persuades the Board that a study on smart grid and time-of-use rates is useful or needed. Accordingly, the Board directs YEC to remove any forecast expenditures and cost recovery related to this project in its compliance filing to this decision."

Seasonal or time of use rates would drive a need to consider impacts on cost of service (new rates/rate classes would require adjustments to COS study and alter results – including possibly seeking to distinguish "winter" costs from "summer" costs); and YEC would also need to consider the ability to implement a seasonal rate structure within rate policy environment established by OIC 1995/90 and OIC 2018-220.

REFERENCE: **Application, Tab 5, pages 5-1 to 5.6-1**

ISSUE: **Accuracy of Capital Project Forecasting**

PREAMBLE: The Board wishes to evaluate the accuracy of YEC's project cost and timeline forecasting and YEC's ability to control project costs.

QUESTION:

a) For all projects brought before the Board in YEC's 2008-09 GRA, 2012 GRA, 2016-17 GRA and 2017-18 GRA, please provide a table showing the original forecast cost and completion date provided to the Board and the final cost and completion date.

b) Based on the information provided in response to part (a), please comment on the accuracy of YEC's cost and timeline forecasts.

ANSWER:

(a)

Please see Table 1 that shows original forecast cost and completion dates for major projects (with forecast GRA cost more than $1 million) at the time projects were initially proposed to be included in rate base for the three YEC GRAs during this time period (2008/09 GRA, 2012/13 GRA and 2017/18 GRA), as well as actuals costs and completion dates for these projects. In preparing this response YEC focused on major projects as they represent most of the PP&E capital investments as well as providing the possibility for review in the time available for responding to these IRs. For example, for the 2021 test year about 91% of total PP&E capital spending is for major projects [91% for 2008 test year, 47% for 2009 test year, 77% for 2012 test year, 70% for 2013 test year, 64% average for 2017-2018 test years].

Please note that the cost information in column A is based on YEC's GRAs as requested and will vary from the forecasts included in Part 3 applications, where applicable.

The costs in columns A and C are before contributions.

Table 1: Major Projects Included in 2008/09, 2012/13 and 2017/18 GRAs [cost before contributions]

	Included in GRA		Actuals		
	Total Cost, $000	Completion Date	Total Cost, $000	Completion Date	Note
	A	B	C	D	E
2008/09 GRA [note 1]					
Carmacks Stewart/Minto Spur Transmission Line Phase I	38,383	2008	40,343	2008	2008/09 GRA, pages 5-3 and 5-7
FD1 Re-Build	1,565	2008	1,674	2010	2008/09 GRA, pages 5-11
P126 WD3 Re-build	1,100	2008	1,370	2009	2008/09 GRA, pages 5-12
Sub-total	**41,048**		**43,387**		
2012/13 GRA					
Mayo B - Construction	116,588	2011	116,477	2011	2012/13 GRA, pages 5-5 and 5-6
Carmacks Stewart Transmission Line Stage 2	41,912	2011	41,912	2011	2012/13 GRA, pages 5-4 and 5-5
Aishihik Third Turbine Construction	13,817	2011	14,007	2011	2012/13 GRA, pages 5-6 through 5-9 [note 2]
Mayo Hydro - Substation Enhancements	10,153	2012	10,302	2012	2012/13 GRA, pages 5-9 through 5-11
Aishihik Generation Station Redundancy	6,365	2012	5,918	2011	2012/13 GRA, pages 5-14 through 5-16
Enterprise System	3,236	2012	2,983	2012/2017	2012/13 GRA, pages 5-19 through 5-21 [note 3]
Mayo Head Gate Repairs	1,334	2012	2,017	2012	2012/13 GRA, pages 5-11 through 5-14
Whitehorse Spillway Improvements	1,246	2012	1,548	2014	2012/13 GRA, pages 5-16 through 5-18
sub total	**194,651**		**195,164**		
2017/18 GRA					
AH Elevator Shaft Structural Steel Rehabilitation	10,116	2017	10,279	2017	2017/18 GRA, pages 5-7 and 5-8
Aishihik Electrical & Control Upgrades	2,511	2018	2,507	2019	2017/18 GRA, pages 5-8 through 5-11
Communications Upgrade	1,003	Dec, 2018	1,152	2019	2017/18 GRA, pages 5-12 through 5-14
Hydro Unit #WH4 Overhaul	4,291	2017	3,008	2018	2017/18 GRA, pages 5-15 and 5-16
LNG Plant	41,933	2016	41,933	2016	2017/18 GRA, pages 5-22 through 5-26
MH2 Overhaul	1,657	2018	1,645	2018	2017/18 GRA, pages 5-16 through 5-18
Wareham Spillway Gate Hoist Replacement	2,700	2015	2,700	2015	2017/18 GRA, pages 5-21
Whistle Bend Supply / Takhini Upgrade	11,383	2015	11,537	2015	2017/18 GRA, pages 5-22
T&D - Breaker Replacements	1,350	2018	1,278	2018	2017/18 GRA, pages 5-18 and 5-19 [Note 4]
sub total	**76,946**		**76,039**		
Total All Three GRAs	**312,646**		**314,590**		

Notes:

1. 2008/09 GRA also included a project to purchase Minto diesels at a cost of $3.190 million. However, pursuant to the YUB's direction (para 207, Order 2009-08) the Minto diesels were removed from ratebase for the test years.
2. In 2012/13 GRA, page 5-9 YEC noted that "Yukon Energy is still attempting to resolve a number of issues including final deficiency work with the contractor which may impact costs but after the $5 million contribution from the Yukon Government, the present estimate of the net rate base cost is approximately $8.8 million." Please also see 2021 GRA, Appendix 5.1, page 5.1-8.
3. 2012/13 GRA, page 5-21 shows total projected cost at $3.24 million. On that page YEC noted that the timing and scope of subsequent roll-outs will be dependent in part on the work done in Roll-Out #1. The cost of $3.24 million included a portion of the project with $2.486 million cost to be completed in 2012 and additional spending of $0.750 million in 2012 and 2013 years. The project was partially completed in 2012 at a cost of $2.486 million and remaining work through 2017 at total cost at $0.495 million.
4. 2017/18 GRA included T&D - Breaker Replacements at a cost of $1.350 million. As reviewed on page 5-16 of the 2021 GRA Application replacement of 5 medium voltage (34.5kV) breakers in YEC substations S150(4) and S176(1) was completed with a cost of $0.798 million, including $0.688 million spending in 2018. Separately, replacement of 7 high voltage (138kV) breakers in YEC substations at Aishihik Faro, Riverside and Takhini with cost of $2.260 million was completed in 2019. The $1.278 million spending in column C reflects spending of $0.688 million for the first project and $0.479 million for the second project as shown in Table 5.2-1.

(b)

Table 1 shows varying outcomes for different projects, as would be expected. Overall, however, the capital cost and timeline forecasts in these three GRAs were reasonably accurate.

1. **Capital costs –** Overall, actual major project capital costs across the three GRAs were 100.6% of the capital costs included in the GRA rate base forecasts, i.e., actuals were very close to GRA forecast.
    a. Actual results as a percentage of forecast varied by GRA, from 105.7% for the 2008/09 GRA to 98.8% for the 2017/18 GRA.
    b. Results are affected by many projects already being completed or largely completed at the time of GRA filing. However, the largest project in the table (Mayo B) was also basically completed within the budget forecast before construction commenced. The spread in actual results as a percentage of forecast for different projects ranges from 70% (Hydro Unit #WH4 Overhaul) to 151% (Mayo Head Gate Repairs).

2. **Completion dates –** 13 of 20 (65%) of the major projects in Table 1 were completed on or before the forecast completion year in the GRA, and another (Enterprise System) had its major component completed on schedule and the balance completed at less than forecast cost; together, these 14 projects accounted for over 96% of the final completion costs for all projects in Table 1.

REFERENCE: **Application, Tab 5.2.1, pages 5-5, 5-7, 5-8, 5-11, 5-13, 5- 15 to 5-19 and 5-32**

ISSUE: **Costs for Capital Works Projects Greater Than $1 Million**

PREAMBLE: In this section of its application, YEC outlined the costs for Capital Works projects greater than $1 million as follows:

- For the LNG Third Engine Project, YEC indicated that it spent $3.156 million in 2017, $5.008 million in 2018 and $0.097 million in 2019.

- For the N-1 Capacity Shortage Whitehorse Thermal Rental Site Infrastructure Project, YEC indicated it spent $0.227 million in 2018 and $1.070 million in 2019.

- For the N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure Project, YEC indicated a forecast of $2.037 million in 2020.

- For the Mayo – McQuesten Transmission Line Upgrade Project, YEC indicated it spent $0.501 million in 2019, indicated a forecast of $20.000 million in 2020 (offset by a $15.274 million contribution) and indicated a forecast of $11.200 million in 2021 (offset by a $8.4 million contribution).

- For the McQuesten Substation Project, YEC indicated it spent $0.123 million in 2018 and $11.496 million in 2019 (offset by a $10.688 million contribution).

- For the Transmission Line Refurbishment Project, YEC indicated it spent $4.272 million in 2019.

- For the Transmission Line Refurbishment – L178 Project, YEC indicated a forecast of $1.3 million in 2021.

- For the Breaker Replacement Program Project, YEC indicated it spent $0.479 million in 2018 and $1.781 million in 2019.

- For the Replacement of the P125 Head Gate Project, YEC indicated it spent $0.093 million in 2019, indicated a forecast of $2.300 million in 2020 and indicated a forecast of $3.500 million in 2021.

- For the WH2 Uprate Project, YEC indicated it spend $3.044 million in 2019, indicated a forecast of $1.693 million in 2020 and indicated a forecast of $7.300 million in 2021.

- For the WH4 Uprate – Servomotor Replacement Project, YEC indicated it spent $0.052 million in 2018, $0.079 million in 2019, indicated a forecast of $0.400 million in 2020 and indicated a forecast of $1.000 million in 2021.

YEC stated it reflected these costs in Table 5.2.1 in its application, found from pages 5-32. It is not clear how YEC allocated these costs over the previous years and how it plans to allocate these costs in its forecasted years.

QUESTION:

a) Please provide a cost breakdown for the projects provided in the preamble. More specifically, provide the activities conducted (or the activities YEC forecasts to conduct) and the cost amount allocated to each activity.

ANSWER:

(a)

Please see the following tables that provides cost breakdown by major activities for each project listed in the preamble. Due to nature as well as the stage of the projects [actuals vs forecast] the key activities are not the same for all projects.

Please note that the following tables reflect updated costs for 2020 based on preliminary actuals and/or forecasts for 2021:

- Table 6: N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure reflects project preliminary actual costs. Please see response to CW-YEC-1-26 (b) that provides explanation for higher actual costs.

- Table 7: Mayo – McQuesten Transmission Line Upgrade Project reflects project preliminary actual costs for 2020 [$3.014 million lower than the forecast] and updated 2021 forecast [$0.422 million lower than the forecast in the application].

- Table 8: Replacement of the P125 Head Gate Project reflects project preliminary actual costs for 2020 [$0.342 million lower than the forecast] as well as change in scope for the project. The original scope of the project included work on WH1, WH2 and WH3 headgates with total project cost at $5.893 million, including about $3.5 million in 2021 for WH1 and WH3 headgates. YEC has now postponed work on WH2 and WH3 headgates to 2022 and 2023, respectively. The revised cost in Table 8 reflects removal of cost estimate for WH2 and WH3 headgates.

- Table 9: WH2 Uprate Project reflects project preliminary actual costs for 2020 [$0.827 million lower than the forecast] and updated 2021 forecast [$1.046 million higher than the forecast in the application].

- Table 10: WH4 Uprate – Servomotor Replacement Project reflects project preliminary actual costs for 2020 [$0.146 million lower than the forecast].

Yukon Energy will reflect updated projects costs in the compliance filing.

Please also note that McQuesten Substation Project was built by Victoria Gold Corporation and transferred to YEC, therefore, YEC does not have cost breakdown by activities.

Table 1: LNG Third Engine Project Cost Breakdown, $000

	Total Cost
Engineering & Construction Management	473.9
Engine Package & Transportation	5,710.2
Balance of Plant Installation	1,453.1
Commissioning	10.7
Owner Costs	265.2
Spare parts	347.5
Total	**8,261**

Table 2: N-1 Capacity Shortage Whitehorse Thermal Rental Site, $000

	Total Cost
Internal Labour	288.8
Other Internal Costs	18.2
Engineering	30.7
Materials	745.4
Contractors	214.7
Total	**1,298**

Table 3: Transmission Line Refurbishment Project, $000

	Total Cost
Materials	719.0
L170 Installation Contractor	1,006.1
L171 Installatoin Contractor	1,622.7
Construction Support	923.7
Total	**4,272**

Table 4: Transmission Line Refurbishment – L178 Project, $000

	Total Cost
Civil work	800.0
Installation	400.0
Materials	100.0
Total	**1,300**

Table 5: Breaker Replacement Program Project, $000

	Total Cost
AFUDC	16.2
Equipment	949.0
Installation	658.2
Labour	283.2
Owner's Engineer	299.2
YEC Internal	54.2
Total	**2,260**

Table 6: N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure, $000

	Total Cost
Engineering & Design	386.5
Materials	754.7
Installation & Construction	715.0
Internal Costs	417.7
Project Management	171.7
Total	**2,446**

Table 7: Mayo – McQuesten Transmission Line Upgrade Project, $000

	2019	2020	2021	Total Cost
Mayo-McQuesten Transmission Line				
Project Mgmt & Owner's Engineer	34	960	63	1,058
Surveying	13	157	43	212
Brushing & Access	0	2,674	0	2,674
Line Construction	87	8,239	2,324	10,650
Internal Costs	20	215	265	500
Subtotal	**154**	**12,245**	**2,695**	**15,094**
STATCOM				
Equipment	73	671	5,718	6,462
Project Mgmt & Owner's Engineer	45	597	709	1,351
Substation Construction	13	2,848	1,642	4,503
Internal Costs	10	226	14	250
First Nations Benefits	205	400	0	605
Subtotal	**347**	**4,741**	**8,083**	**13,171**
Total	**501**	**16,986**	**10,778**	**28,265**
Per 2021 GRA Application	501	20,000	11,200	**31,701**
Variance	0	-3,014	-422	-3,436

Table 8: Replacement of the P125 Head Gate Project, $000

	2019	2020	2021	Total Cost
Engineering, Project Mgmt & Internal Costs	93	94	50	237
Installation Contractor	0	1,865	0	1,865
Total	**93**	**1,958**	**50**	**2,102**
Per 2021 GRA Application	93	2,300	3,500	5,893
Variance	0	-342	-3,450	-3,792

Table 9: WH2 Uprate Project, $000

	2019	2020	2021	Total Cost
Owner's Engineer	167	213	732	1,112
Turbine & Generator	2,618	114	4,721	7,453
Internal Costs & Project mgmt	228	173	745	1,146
Balance of plant	32	366	436	834
Contingency & AFUDC	0	0	1,711	1,711
Total	**3,044**	**866**	**8,346**	**12,256**
Per 2021 GRA Application	3,044	1,693	7,300	12,038
Variance	-0	-827	1,046	218

Table 10: WH4 Uprate – Servomotor Replacement Project, $000

	2018	2019	2020	2021	Total Cost
Servomotor supplier	0	0	142	576	718
Owner's Engineer	0	0	47	83	130
Internal Costs & Project Mgmt	52	79	63	136	329
Balance of Plant	0	0	3	205	208
Total	**52**	**79**	**254**	**1,000**	**1,385**
Per 2021 GRA Application	52	79	400	1,000	1,531
Variance	0	0	-146	0	-146

REFERENCE: **Application, Tabs 5.2.1.1 and 5.2.1.2, pages 5-5, 5-7 and 5-8**

ISSUE: The LNG Third Engine, N-1 Capacity Shortage Whitehorse Thermal Rental Site Infrastructure and N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure projects.

QUOTE: From page 5-5 of the Application:

"The LNG Third Engine Project provides a third natural gas-fired generation unit of approximately 4.4 MW at the Whitehorse thermal plant to help address the existing dependable capacity shortfall in a cost effective manner. YEC 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 given the need to maintain reliable service, and permanent solutions (rather than relying on temporary options such as mobile diesel) are needed to address an ongoing and growing dependable capacity shortfall." (footnote removed)

From page 5-7 of the Application:

"The [N-1 Capacity Shortage Whitehorse Thermal Rental Site Infrastructure Project] involved the design of infrastructure to accommodate temporary rented thermal generators at Whitehorse substation to address the capacity shortfall projected under the N-1 for 2018/19 and 2019/20 winters.

In winter 2018/19 six temporarily rented 1.8 MW units were installed in the proximity of S150 Whitehorse Rapids Substation. The 2019 project included installation of two additional temporarily rented 1.8 MW units in the area between P126 Whitehorse Diesel and S150 Whitehorse Substation. The project scope included … installation support temporary seasonal diesel power generators to meet seasonal N-1 load requirements and assist with meeting winter system peaks. Total project cost was approximately $1.298 million."

From pages 5-7 to 5-8 of the Application:

"The [N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure] involves the design and installation of temporary rental site electrical infrastructure at Faro (870S) to ensure YEC can continue to meet its N 1 capacity planning requirements … The project is expected to be completed in 2020 at an estimated budget of $2.037 million. The project is on track for a mid-November 2020 in service date."

QUESTION:

a) Please provide the studies that were conducted showing the N-1 capacity criterion was being violated prior to the development of the LNG Third Engine, N-1 Capacity Shortage Whitehorse Thermal Rental Site Infrastructure and N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure projects.

b) Please provide the studies that were conducted to show that these projects met the N-1 capacity criterion.

c) Given that the LNG Third Engine Project was required as a permanent solution to meet the N-1 capacity criterion, please explain why YEC carried out the Whitehorse Thermal Rental Site Infrastructure and Faro Thermal Rental Site Infrastructure projects, which installed temporary infrastructure.

d) Given that the Whitehorse Thermal Rental Site Infrastructure and Faro Thermal Rental Site Infrastructure projects involve temporarily rented generators and temporary electrical infrastructure, please explain if YEC plans to implement a permanent solution in the future to meet the N-1 capacity criterion. For example, will the Battery Energy Storage System project discussed on page 5.1-5 of the Application replace the need for these projects?

e) Please provide an update on the Faro Thermal Rental Site Infrastructure Project, which had an in-service date of November 2020. Additionally, please indicate whether work was carried out by YEC staff or consultants. If external consultants were hired, please explain the competitive process that was followed.

ANSWER:

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

Section 2.4 of the Application provides details on the determination of the N-1 dependable capacity shortfall for 2021 and other years, including the criteria established in this regard in YEC's 2006 Resource Plan, updates carried out since that time, and the 2016 Resource Plan assessment of the N-1 capacity shortfall that emerged at that time and was forecast to grow until material new dependable capacity was developed. In January 2020, YEC experienced record peak demands which increased forecast capacity requirements.

As summarized at page 2-15 of the Application, under the N-1 dependable capacity criterion the N-1 capacity shortfall in 2021 without rented diesels is forecast at 25.75 MW after including the LNG Third Engine new dependable capacity of 4.2 MW. Provision of 27 MW of rented diesels using the referenced diesel rental infrastructure at Whitehorse and Faro is shown to result (in combination with the LNG Third Engine) with a surplus of dependable capacity of approximately 1.25 MW for 2021. In summary, both the LNG Third Engine and the rental diesels with related infrastructure were needed to meet the N-1 capacity criterion in 2021.

YEC's recent 10-Year Renewable Electricity Plan at Figure 17 and Table B3 provides a Base Case forecast of the substantial annual N-1 capacity shortfall absent diesel rentals that grows to 50 MW by 2035/36 with existing, committed and planned resources that include the Battery Energy Storage System, Diesel Replacement and DSM program projects. This updated resource plan includes proposed future renewable generation projects (i.e., Atlin Hydro Expansion Project and Tutshi- Moon Pumped Storage) that would provide permanent dependable capacity to remove this N-1 capacity shortfall (see summary at Table D1 of the plan). For a copy of this plan, please see Attachment 1 to CW-YEC-1-36(a). Even with this permanent solution, the diesel rental infrastructure will continue to enable back-up diesel rental capability if required.

(e)

The Faro rental site was commissioned and in service December 1, 2020.

The construction of the site was primarily carried out by YEC staff. Construction support was provided through existing vendor service contracts.

Engineering design and support was provided through an RFQ process, with the lowest price qualified bidder awarded the contract.

REFERENCE: **Application, Tab 5.2.1.3, pages 5-8 to 5-10**

ISSUE: **The Mayo-McQuesten Transmission Line Upgrade Project**

QUOTE: From page 5-8 of the Application:

"The Mayo – McQuesten Transmission Line (MMTL) project involves the construction of a new 138 kW framed transmission line from the Mayo to McQuesten substations as well as the installation of electronic voltage support equipment (Statcom) at Stewart Crossing South substation that will improve overall reliability and power quality in the system. The [Mayo – McQuesten Transmission Line Upgrade Project] transmission will initially be operated at 69 kV.

The existing 69 kV transmission line from Mayo to Keno constructed by the Northern Canada Power Commission (NCPC) in 1951 is at end of life and in need of replacement. The transmission line has experienced both reliability and power quality issues with an increasing number of outages on the line affecting customers on a system wide basis. Key requirements under the VGC Group PPA include development of the McQuesten Substation plus new transmission to replace the existing 69 kV facilities between at least Mayo and McQuesten by approximately summer of 2020." (footnote removed)

From page 5-9 of the Application:

"Later stages will proceed only when loads in the area justify increasing the operating voltage to 138 [kV], and when additional federal funding becomes available … Increased power transfer/ capacity will also support economic development in central Yukon, as well as connection of renewable energy sources such as hydro, wind and solar."

"Effects assessment and stakeholder engagement development activities for all project stages were undertaken in 2015 and 2016. As reported during the 2017-18 GRA, all project permits were in place, including the land use permit, access permits and highway permits. No

additional permitting was anticipated to be required." (footnote removed)

From page 5-10 of the Application:

"Decommissioning of the old 69 kV line is expected to occur between November 2020 and December 2020. Substation construction at Stewart Crossing commenced in August 2020 and is expected to be completed by June 2021. An order has been placed for the Statcom and it is in manufacturing. Statcom delivery is expected to occur by August 2021, with installation in September 2021 and commissioning completed by October 2021."

QUESTION:

a) Please provide the reliability criteria YEC utilizes in assessing the viability of its electric system (e.g. the thermal limit ratings and acceptable voltage range on transmission lines).

b) Please provide and explain the studies that were conducted to show that the existing 69 kilovolt (kV) transmission line had reliability and power quality issues. For example, did YEC carry out a contingency analysis that showed this line exhibited reliability criteria violations?

c) Please explain how often YEC carried out studies and assessed the reliability of the existing 69 kV transmission line in the past.

d) Please explain why YEC proposed to install STATCOM in this project. Were any other alternatives to STATCOM explored (e.g. static VAR compensators or synchronous condensers)? If other alternatives were explored, please provide the costs of these alternatives and the reasons these alternatives were dismissed.

e) Please provide the number and duration of outages experienced on the line in the last 10 years, on a per annum basis, and the costs incurred due to these outages.

f) Please provide and explain the studies that were conducted to show the Mayo-McQuesten Transmission Line Upgrade Project resolved reliability and power quality concerns.

g) Please explain if any other alternative solutions were proposed and explored. If applicable, please provide and explain the studies conducted on these alternatives and provide the costs of these alternatives.

h) Given that YEC plans to operate this new line initially at 69 kV and future load will need to justify an operating voltage of 138 kV, please explain why YEC considered it prudent to spend capital on infrastructure designed for 138 kV.

i) Please explain if there were any concerns brought up during stakeholder engagement sessions and if there are any outstanding concerns to date.

j) Please provide details on the selection process of contractors for this project, including how contracts were awarded for this project.

k) Based on the information provided in page 5-10 of the Application, please provide an update on the project. For example, did YEC decommission the old 69 kV line?

ANSWER:

(a)

Attachments 1 this response provides Transmission Line Design Criteria Stewart to Keno Transmission Project 138 kV Transmission Lines which is relevant to the MMTL Project. Attachment 2 provides YEC L170 Transmission Line – Clearance and Structural Evaluation Criteria" – this document defines YEC's evaluation criteria for all structures, and is also relevant to the MMTL project.

(b), **(c)** and **(e)**

As noted in Tab 5, Section 5.21.3 of the Application, a new line from Mayo to the Keno City region is required at this time to replace the end of life existing 69 kV line constructed in the 1950's. This line is in poor condition and there has been a significant degradation in

reliability. This was reviewed previously during the 2017 VGC Group PPA proceeding and the 2017/18 GRA[1], and is also supported by data collected from inspections.

In the early 1990s, Yukon Energy noted that the line was significantly deteriorated and needed to be rebuilt or abandoned due to safety and reliability concerns;[2] however, at the time a rebuild could not be justified due to the closure of UKHM. As an alternative, minimal capital improvements were undertaken at that time to maintain the line and ensure continued service to existing non-industrial customers;[3] and over the past 15+ years transmission line repairs have been required on an ongoing basis to address reliability concerns.

More specifically, the Stewart- Keno Transmission Line Project Proposal filed with YESAA in 2015 noted[4]:

> Transmission line repairs have been required over the past fifteen years to address ongoing reliability concerns. Line reliability has also become a more significant issue and line outages have increased, affecting customers on the Integrated Grid (including local customers as well as customers as far away as Dawson City and Whitehorse). For example, outages on the Mayo to Keno line have increased from 4 outages in 2012, to 6 outages in 2013, to 19 outages in 2014 to 20 outages (to the end of Q3 2015) – outages for 2015 are forecast to be 27. Further, in 2011, 35% (or 188 of 535) of the structures on L250 failed the test and treat assessment undertaken at that time and were considered unsafe to climb, limiting the maintenance work that can be safely undertaken on these structures. The

[1] See for example, YEC's 2017 VGG Group PPA Application, section 4.3; and 2017/18 GRA Section 5.3.1.1; and response to YUB-YEC-1-78.

[2] The Yukon Energy 1992 Resource Plan notes "This line was built in 1952 with untreated native poles, which have long since rotted at ground level. Virtually every pole on this line has been stubbed (a small pole attached at ground level) or cribbed (a rock filled culvert or container added) over the last forty years. The line was identified as a severe safety hazard for Company employees and the general public."

[3] In its 1992 Resource Plan, Yukon Energy noted that "it was recognized for many years, by both NCPC and YEC, that the Mayo-Elsa-Keno City transmission line urgently needed to be either re-built or abandoned." At the time, it was noted that "this project just could not continue to be deferred indefinitely," and "essential work had to be performed to ensure the safety of the line." The option of abandoning the transmission line was considered and discarded at the time for the following reasons: (1) Additional loads are also supplied from this line, via Keno City, CBC and NWTel tower sites, Silver Trail Lodge and a number of YTG Highways heat traces in culverts; and (2) The cost of diesel generation would be at least $250,000 per annum based on approximately 2.5 kWh consumption at 10 cents per kWh by UKHM.

[4] Stewart-Keno Transmission Line Project Proposal, Chapter 6, page 6-3.

remoteness of the line as well as terrain and access challenges also magnify the costs and difficulties involved in managing maintenance and reliability of this asset.

No power quality studies were performed for the existing 69kV transmission line due to the fact that the numerous outages were the assumed to be the cause of power quality issues experienced.

The following is noted regarding past inspections/ assessments for L250:

- A Line inspection was performed on L250 in 2002.
- A detailed Line inspection was performed on L250 in 2008.
- Wood pole test and treat was performed on the line on L250 in 2011.
- Outage statistics on L250 are updated as they occur.

Yukon Energy performs overhead line inspections and wood pole test and treat inspections to determine the condition of the line and poles. Outage reports are also reviewed annually to identify reliability issues.

See Table 1 below for a summary of the outages from 2011 to 2020 mid-year. Total cost to respond to outages (planned and unplanned) are about $320,900 (2012 to date) with an average annual cost of roughly $35,655. Additionally, capital investment in this line over the same period totaled $963,700.

Table 1: Number and Duration of Outages: 2011 to 2020

Year	Unplanned Outages	Planned Outages	Total Outages	Outage Hours
2011	8	0	8	16.19
2012	4	0	4	5.91
2013	6	0	6	3.78
2014	14	5	19	126.24
2015	23	7	30	105.1
2016	9	1	10	0.6
2017	14	0	14	8.2
2018	4	3	7	9.62
2019	20	0	20	14.42
2020	1	3	4	4.19

(d)

YEC explored three alternatives: the STATCOM (Static synchronous compensator); SVC (static VAR compensator); and the synchronous condenser.

The synchronous condenser was proposed as the best solution as it provided reactive power support while also being able to recover the system frequency with excursions below 64Hz in a large load loss such as Eagle Gold Mine. However, due to the associated costs the STATCOM was chosen as a compromise as its more responsive than the SVC solution.

See Table 2 below for further details.

Table 2: Stewart Crossing Potential FACTS Solutions

	STATCOM	SVC	Synchronous Condenser	BESS plus STATCOM
Pros	Fastest response for reactive power support.	The most economical solution for reactive power support.	Provides frequency stability enhancement in addition to reactive power support. This may avoid predicted and future review/changes for frequency protection relays or RASs.	Potentially addresses frequency issues.
Cons	There are no cons associated with the STATCOM solution, for providing the required reactive power support	It is considered as a harmonic source, and doesn't have a quick response time compared to the STATCOM (e.g. flicker).	No-load running losses; may require additional maintenance when compared with the STATCOM or SVC solution.	Not commercially available. Would require custom design and assembly.
Relative Budgetary Cost *	1.0	0.90 - 0.95	1.4 – 2.0	Unknown. Costs would need to be determined via communication with the potential suppliers.
Other Notes	For low inertia systems, the addition of a STATCOM (as a solution for the deficient reactive power support) is a fix for only one issue. However, the wide swing of frequency may impact the evaluation of the required reactive power support.	This technology is fading in popularity. A STATCOM would be the preferred solution for reactive power support.	Synchronous condensers (synchs) are the solution for both reactive power deficiency and frequency instability. Synchs will provide long term operational easiness. They will also reduce or eliminate the need for future frequency RASs. YEC personnel have O&M synchronous condenser experience.	This solution would require significant research/study, consultation/coordination with suppliers, etc. which would result in additional time and cost for the project. Ongoing costs associated with battery life would need to also be considered.

NOTE: * The above relative budgetary costs are provided based on Teshmont's in-house information. Supplier input was not obtained.

(f), **(g)** and **(h)**

As noted in part (b) a new line from Mayo to the Keno City region is required to replace the end of life existing 69 kV line constructed in the 1950's. This fundamental requirement necessitated the project as a key element of the PPA as approved by the Board.

Please see Attachment 1 to this response which provides the Chimax Inc Transmission Line preliminary design report; and Attachment 2 which provides the Chimax Inc Transmission Line Scope Extension Report which reviews overall project cost comparisons between Mono Pole and H-Frame transmission structures.

As reported on and reviewed during the VGC Group PPA proceeding, an assessment was also carried out to determine the transmission upgrades required to supply the proposed Eagle Gold facility (EG) from the Yukon Energy Corporation (YEC) power system while providing acceptable service and reliability to EG and existing YEC customers. This study confirmed the system upgrades required (as provided for in the PPA), and the STACOM requirement as part of the overall system improvements.

The decision to complete the design of the project using a 138 kV standard was made in March 2017 as a result of completion of the detailed design of the powerlines and substations and comparative pricing using 138 and 69 kV design standards. Table 3 below provides a cost comparison. Cost reductions shown in Table 3 are in comparison with the 138 kV H-frame design. For L180 line the cost reduction to use a 69 kV design compared to 138 k was less than 10% (between 3.8% and 9.4%).

Table 3: Preliminary Cost Estimates SKTP

	L180				L250		
Voltage	138kV		69kV		138kV	69kV	
Pole Framing	H-Frame	Mono Pole	Mono Pole		H-Frame	Mono Pole	
Tangent Insulator Type	Suspension	Braced Post	Braced Post	Post	Suspension	Braced Post	Post
Fiber Configuration	OPGW	OPGW	OPGW	OPGW	OPGW	ADSS	ADSS
No. Structure	162	218	255	255	118	175	175
No. Pole	354	230	266	266	227	178	178
Cost Item							
Procurement	$3,200,315.77	$3,317,249.23	$3,261,908.91	$2,838,233.03	$1,935,469.37	$1,842,557.06	$1,497,569.84
Construction	$6,515,800.56	$5,605,689.15	$5,839,587.50	$5,651,915.12	$4,090,160.91	$3,578,987.53	$3,447,030.38
Engineering Support	$68,790.00	$83,910.00	$93,900.00	$93,900.00	$56,910.00	$72,300.00	$72,300.00
Construction Management	$950,400.00	$950,400.00	$950,400.00	$950,400.00	$799,000.00	$799,000.00	$799,000.00
Additional Cost Provision	$281,029.86	$399,254.44	$447,979.30	$447,979.30	$159,717.42	$301,112.00	$301,112.00
Sub-Total	***$11,016,336.19***	***$10,356,502.82***	***$10,593,775.71***	***$9,982,427.45***	***$7,041,257.70***	***$6,593,956.59***	***$6,117,012.22***
Contingency (10%)	$1,101,633.62	$1,035,650.28	$1,059,377.57	$998,242.75	$704,125.77	$659,395.66	$611,701.22
Estimated Cost	**$12,117,969.81**	**$11,392,153.10**	**$11,653,153.28**	**$10,980,670.20**	**$7,745,383.47**	**$7,253,352.25**	**$6,728,713.44**
cost per km	$390,902.25	$367,488.81	$375,908.17	$354,215.17			
Comparison							
Cost Differences		($725,816.71)	($464,816.53)	($1,137,299.61)		($492,031.22)	($1,016,670.03)
% Reduction		-5.99%	-3.84%	-9.39%		-6.35%	-13.13%
Assumptions:							
All mono pole embedments are based on 10% pole length plus 6ft (from grade). Actual embedment requirement will vary, require additional engineering in final design.							
For 138kV mono pole, average pole span is approximately 150m (cable galloping governed)							
For 69kV mono pole, average pole span is approximately 120m (cable galloping governed)							
Remarks:							
The increased structure count and combined with higher Braced Post Insulator cost, the mono pole option with braced post insulator would not provide significant saving compared with H-Frame structure. The reduced 69kV span allow utilization of post insulator which can significantly reduce the overall cost.							

The decision to utilize a 138 H-frame design was based on the following factors:

1. For an increase in initial capital cost of between 4 % and 10% (for L-180 this would amount to between $0.5M and $1.0M) from 69 to 138 kV.

2. The benefits of prebuilding to a 138 kV standard are an increase in the ultimate line capacity of up to 400%.

3. The existing powerline is at its end of life and must be replaced in order to continue to serve existing customers in this region and new industrial customers.

4. It is not possible to upgrade a 69 kV line to 138 kV design at a later date cost effectively if at all.

5. The long term plan for any expansion to the Yukon's hydro grid is at the 138 kV voltage level or higher due to the small incremental capital cost between 69 kV and 138 kV.

6. Increase in reliability.

The selection of 138 kV vs 69 kV for this project was also addressed at some length during the VGC PPA proceeding. It was noted that the VGC Group PPA default transmission option defines a minimum priority development consistent with the SKTP planning to provide 138 kV capability to facilitate potential future load and/or renewable resource supply development in this region. Key features noted included the following:

- SKTP planning assessed transmission options, including 69 versus 138 kV options, and concluded that the mono pole option with braced post insulators at 69 kV would not provide significant cost savings compared with the proposed H-Frame structure and 138 kV when assessing costs for this new transmission.

- Further, proceeding to install a 69 kV transmission option with adequate upgrade limited only for VGC Group and Alexco would maintain existing service, but ignore the opportunity to strengthen and enhance the existing grid system to better support future development opportunities in the region.

- The example of the existing relatively new 69 kV from Stewart Crossing to Mayo highlights the significant added costs to come back in future (as per the full SKTP proposal) to increase the capability of transmission to 138 kV after a new 69 kV line has been installed.

It is expected that reliability will improve through replacing a 66 year old transmission line (built in the 1950's) that is at end of life with a new transmission line that is installed using today's line design standards.

Once the line is in service, reliability will be tracked.

(i)

Attachment 1 summarizes concerns raised by members of the public as part of the public engagement process to support the development of the Project Proposal for the Stewart-Keno Transmission Line Project and how these concerns were addressed.

During construction – the following stakeholder engagement occurred:

- Virtual meetings with FNNND Council, Village of Mayo and Selkirk Development Corporation (designate for Selkirk First Nation) to discuss status of the project, COVID-19 safety plans and to determine any concerns with proceeding with the project during COVID-19 (no concerns were raised about proceeding with the project during COVID-19 so long as YEC followed strict project and community COVID-19 safety plans).

- Weekly Project Updates to contacts at the FNNND, Selkirk First Nation, Village of Mayo, Selkirk Development Corporation and NND Development Corporation. These started in June 2020 and have continued since.

- Monthly Project Updates prepared for Village of Mayo Council, FNNND Council and Selkirk First Nation Council. Emailed to each government's designates beginning in June 2020 and have continued since.

- One Newspaper ad that ran in the Yukon News in June 2020 to advise Yukoners that the project was moving forward.

- Project Newsletters mailed to residents in Mayo, Keno and Pelly with updates about the project. Newsletters were distributed in June 2020, August 2020 and February 2021.

- A virtual public meeting hosted on June 11, 2020 to discuss the project. Less than five people attended.

- Project information is provided on YEC's website and in occasional social media posts.

YEC received a complaint about ruts that were left in a resident's driveway by one of YEC's contractors during construction. The complaint was addressed and repairs were made to the driveway.

The Department of Environment, Government of Yukon also engaged YEC to discuss a public complaint of construction-related disturbances to the Minto Creek Bridge Interpretive Trail area. Yukon Energy prepared a restoration plan for consideration by YG in this regard and expects to implement the restoration activities in the spring and summer of 2021 as it conducts other post-construction clean-up activities along the transmission line typical of such projects.

(j)

Contractors were selected through a competitive RFP process. Each of the contacts were evaluated based on technical ability, price and the ability to provide FN opportunities. Once the evaluation process was completed and successful bidder selected based on total score, contract negotiations began, were finalized and signed.

(k)

The L180 Transmission line will be completed and fully energized in March 2021. Upon energization of the new line, the old 69kV line will be decommissioned / removed with an anticipated end date of April 2021.

Chimax Inc.

TRANSMISSION LINE DESIGN CRITERIA

STEWART TO KENO TRANSMISSION PROJECT
138 kV TRANSMISSION LINES

Yukon Energy Corporation

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1.0 Project Overview

Yukon Energy Corporation (YEC) is proposing to construct a 138kV transmission line from Stewart Crossing South (SCS) substation to Keno City (KC) substation. The overall transmission line and associated substation construction or modification is grouped as SKTL project.

1.1 Project Descriptions

The proposed 138kV transmission line route originates and travels north from SCS substation (S251) generally parallel existing L175 138kV transmission line to a point north of Stewart Crossing North (SCN). At this point the route turns east and parallels the existing L176 69kV transmission line to Mayo substation (S249). The transmission line will turn northeast to parallel the existing L250 69kV transmission line to KC substation (S257). A new substation at McQuesten (S258) will be constructed north of Halfway Lakes to convert voltage from 138kV to 69kV. The transmission line from S258 to S257 will be constructed for 138kV and energized at 69kV.

The existing L176 and L250 69kV transmission right of way is 60m wide which should accommodate 2 (two) parallel transmission line circuits.

The preliminary design will assess deviations from the YEC primary proposed route due to land use conflicts, environmental restriction, construction and maintenance access, geological restriction, etc.

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2.0 Design Codes and Regulations

The design of the 138kV transmission line will be based on both deterministic approach as per CSA C22.3 No.1 (C22.3 No.1) "Overhead System" and reliability approach as per CSA C22.3 No.60826 (C22.3 No.60826) "Design Criteria of Overhead Transmission Lines".

The conditions outlined in CSA C22.3 No.1 are minimum design requirements for both transmission and distribution overhead lines.

CSA C22.3 No.60826 outlines additional extreme weather conditions and design requirements for transmission line voltage exceeding 70kV (phase – phase voltage) as recommended in CSA C22.3 No.1 Section 10.

YEC has specified the design of the SKTL transmission lines to comply with Alberta Electrical Utility Code (AEUC) in addition to CSA code requirements. Chimax will also review and incorporate the relevant information and guidelines outlined in the Alberta Electrical System Operator (AESO) ISO Rules Section 502.2 "Bulk Transmission Line Technical Requirements".

In addition to the Canadian overhead line design code, additional design codes and regulations will be followed for each transmission line component design. A full list of design codes and regulations is provided in Appendix B.

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3.0 Meteorological (Climate) Data

3.1 Site Descriptions

The closest meteorological locations outlined in both C22.3 No.1 and C22.3 No.60826 is Dawson City.

3.2 Deterministic Approach Weather Case

CSA C22.3 No.1 Section 7 outlines the minimum deterministic weather loads shall be applied to each line components. C22.3 No.1 Annex C Figure C.1 indicates that the Yukon falls under CSA Medium A Loading condition which does not represent local observed ice loading situations. The CSA Heavy Loading is used for the previous CSTL and proposed transmission lines. Parameters are given in C22.3 No.1 Table 30 and are listed as follows:

Table 3.1

Conditions	Temperature (°C)	Horizontal Wind Loading (N/m^2)	Radial Ice	
			Thickness (mm)	Ice Density (kg/m^3)
CSA Heavy	-20	400	12.5	900

3.3 Reliability Approach Weather Cases

CSA C22.3 No.60826 is the Canadian adaptation of IEC 60826 "Design criteria of overhead transmission lines", with implementation of appropriate Canadian variations and weather parameters. C22.3 No.60826 Table CA.1 listed 50 years return period (1/50) weather conditions for Canadian Locations. The mean annual maximum snow accumulation depths are provided in CSA C22.3 No.1 Table D.1. The ice, wind and snow depth parameters for the closest meteorological locations to the transmission line are listed below:

Table 3.2

Locations	Reference Average Minimum Temperature (°C)	Reference (1/50) Wind Speed (km/h)	Reference (1/50) Radial Ice		Mean Annual Maximum Snow Depth (m)
			Thickness (mm)	Ice Density (kg/m^3)	
Whitehorse (reference)	-43	85	10	900	0.4
Dawson City	-51	80	10	900	0.6

The ambient temperature for radial ice formation due to freezing precipitation is assumed at -10°C.

The reference wind and ice loading values given above are based on 1 in 50 year (1/50 return period) event.

3.3.1. Reference Ice Loadings

The reference ice loading listed in CSA C22.3 No.60826 does not reflect the occasionally observed rime ice condition on existing transmission line in Yukon. Additional ice loading of 51mm (2") rime ice (density of 350kg/m^3) has been included in the design of the proposed transmission line.

The cable diameter factor and structure height factor according to C22.3 No.60826 Section 6.3.4.1 will be adjusted accordingly in PLS-Cadd model for site specific design.

3.3.2. Reference Wind Loading

The 1 in 50 return period reference wind loading is recommended for the design of the transmission line for capital cost minimization.

3.3.3. Combined Wind and Low Temperature

As per requirement under CSA C22.3 No.60826 Section 6.2.4 for span typically less than 200m, combination of minimum temperature with wind shall be included for reliability design load scenario. The combination shall be verified for reference average minimum temperature with 60% of design wind speed. The design wind speed for combination with minimum temperature is recommended to be 1 in 50 return period.

3.3.4. Combined Ice and Wind Loadings

The requirement of combination of the ice with wind is defined in CSA C22.3 No.60826 Section 6.4. The section outlines two ice and wind combinations as follows:

- Reduced Ice with High Wind - 85% Reference Ice with 60% Reference Wind (normal combined ice and wind)
- High Ice with Average Wind - 130% Reference Ice with 40% Reference Wind (extreme combined ice and wind with spatial factor)

The recommended level of reliability for ice loading combined with wind loading shall be 1 in 50 return periods.

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4.0 Electrical Design Criteria

4.1 Code Clearances

4.1.1. Vertical and Horizontal External Clearances

4.1.1.1. Vertical Clearances

The minimum vertical ground clearance required for lowest cable is listed in C22.3 No.1 Table 2 (ground clearances), Table 3 (waterways), Table 9 (building, signs, fence, etc.) and Table 10 (bridges).

Segments of the proposed transmission lines are located at altitude between 1000 m to 1300 m above sea-level. According to C22.3 No.1 clause 5.3.1.1 (b), the required clearance shall be increased by 1% for each 100 m above of 1000 m. The designed high altitude clearance will be based on 3% increase of basic minimum clearance.

The minimum code specified clearance and recommended design values are summarized below:

Table 4.1 - 138kV (Maximum Voltage 155kV Ph-Ph) Vertical Ground Clearance

Clearance Descriptions	C22.3 No.1 Min. Clearance	Mean Annual Snow Depth	Survey Tolerance	Const. Tolerance	138kV Design Clearance	138kV High Altitude Clearance
	(m)	(m)	(m)	(m)	(m)	(m)
Ground Clearance (CSA C22.3 No.1 Table 2)						
Vehicular Clearance (Vehicle Height <4.15m)	5.5	0.6	0.3	0.3	6.7	6.9
Non-Vehicular Clearance (Pedestrian / ATV)	4.0	0.6	0.3	0.3	5.2	5.4
Railroad Crossings	8.4		0.3	0.3	9.0	9.3
Waterway Crossings (CSA C22.3 No.1 Table 3)						
Class 1 (Vessel H ≤ 4.0 m)	6.7		0.6		7.3	7.5
Class 2 (Vessel H ≤ 6.0 m)	8.7		0.6		9.3	9.6
Class 3 (Vessel H ≤ 8.0 m)	10.7		0.6		11.3	11.7
Class 4 (Vessel H ≤ 10.0 m)	12.7		0.6		13.3	13.7
Class 5 (Vessel H ≤ 12.0 m)	14.7		0.6		15.3	15.8
Class 6 (Vessel H ≤ 14.0 m)	16.7		0.6		17.3	17.8
Features (CSA C22.3 No.1 Table 9 & Table 10)						
Buildings	4.2	0.6	0.3	0.3	5.4	5.6
Signs, Fences, etc.	4.2		0.3	0.3	4.8	5.0
Bridges	3.4	0.6	0.3	0.3	4.6	4.8
Ground Clearance (AEUC 2013 Table 5)						
Non-Vehicular Clearance (Pedestrian / ATV < 3.6m)	5.0	0.6	0.3	0.3	6.2	6.4
High Load Clearance (Vehicle Height <5.3m)	6.7		0.3	0.3	7.3	7.5

The C22.3 No.1 vertical clearances between cable crossings not supported by same structure are listed in C22.3 No.1 Table 13.

In addition to C22.3 No.1 wire crossing specification, Local Distribution Companies (YEC & AEY) should be consulted at each crossing for specific requirement during the final design.

Table 4.2 - Aerial Cable Crossing Vertical Clearance

Upper Cables **Lower Cables**	**69kV (m)**	**138kV (m)**
Communication	0.9	1.2
Secondary (<750V)	0.8	1.1
Distribution (>750V & ≤34.5kV)	0.9	1.2
Sub-Transmission (>44kV & ≤69kV)	1.1	1.4
138kV to 138kV		1.5
Limit of Approach		2.5

The wire crossing of the 138kV transmission lines will be designed based on the highest specified clearance requirement.

4.1.1.2. Horizontal Clearances

The horizontal cable clearance is defined for cable under conductor Blowout Wind condition as specified in C22.3 No.1 Section 5.2.7 & A5.2.7. The horizontal clearance requirements are specified in C22.3 No.1 Table 6 (Railroad), Table 9 (building, signs, fence, etc.), Table 10 (bridges) and Table 35 (flashover for tree pruning).

Table 4.3 – 138kV Horizontal Electrical Ground Clearance

Clearance Descriptions	**C22.3 No.1 Min. Clearance**	**Survey Tolerance**	**138kV Design Clearance**
	(m)	**(m)**	**(m)**
Railroads (CSA C22.3 No.1 Table 6)			
Main Tracks	3.5	0.3	3.8
Sidings	2.9	0.3	3.2
Features (C22.3 No.1 Table 9, Table 10 & Table 35)			
Buildings	2.6	0.3	2.9
Signs, Fences, etc.	2.6	0.3	2.9
Bridges	2.2	0.3	2.5
Tree Pruning	0.97	0.3	1.3

The specified horizontal conductor clearances are specified for locations where vertical clearances are not achieved.

In addition to conductor electrical clearance, minimum structure clearances in proximity to adjacent features are also governed by appropriate national, provincial and local bylaws.

Table 4.4 – Structural Clearance to Adjacent Facilities

Clearance Descriptions	Min. Clearance (m)
Railroads (C22.3 No.1 Table 7)	
Railroad Tracks	
Main Tracks	2.5
Sidings	1.9
Road Clear Zone Requirement	
Edge of Road	7.0
Edge of Highway	9.0

4.1.2. Electrical Clearances to Structures

Electrical clearance from energized conductors and hardware depends on maximum system voltage and switching surge ratio of the transmission system.

The minimum electrical clearances between phase conductors to supporting structure for voltage greater than 50kV phase-ground (<69kV phase-phase) are outside of the voltage range specified in C22.3 No.1. American National Electrical Safety Code (NESC – IEEE C2) shall be used to determine the electrical clearances between energized live parts and support structure components. As per NESC clause 235E1 for 138kV transmission lines, Table 235-6 shall provide the minimum clearance requirements. In addition, CSA C22.3 No. 1 Table A.1 provides flashover to ground distance based on typical switching surge factor.

Table 4.5.1 – 138kV Electrical Clearances to Structures

Clearance Descriptions	Minimum Clearance (m)
NESC Table 235-6 (290 Pa [6 psf] wind @ 15°C)	
Surface of Structure	0.81
Anchor Guys	
Inline Parallel Guys	1.79
Bisect & Offset Guys	1.10
CSA C22.3 No. Table A.1	
Switching Surge Flashover	0.97
Additional Clearance Consideration (RUS 1724E-200 Table 7-1)	
At Rest - No Wind	1.27
Extreme Hourly Wind	0.33

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Table 4.5.2 – 138kV Electrical Design Clearances for Insulator Swing

Cable Conditions	Design Minimum Clearance (m)
Every Day Temperature	1.27
Blowout Wind (290 Pa wind @ 15°C)	0.97
-51°C	0.81
1/50 IEC Gust Wind	0.33

4.1.3. Lightning Performance and Shielding

The average structure height (ground to OPGW and OHGW) of the proposed transmission lines shall be below 92ft, the shielding angle of 30 degree, as per RUS 1724E-200 Table 8-3, was used for the determination of shieldwire and phase conductor separation.

Shielding angle of lightning protection by OPGW and OHGW shall be verified based on latest edition of IEEE Standard 1243 "Guide for Improving the Lightning Performance of Transmission Lines". The ground flash design should either be based on historical data (when available) or IEEE Std. 1243 equation (2) or equation (3).

4.1.4. Grounding

Pole and shieldwire grounding shall be installed at every structure location. Unattached grounding system resistivity shall be 100 ohms or below. Grounding study shall be performed in final design phase to estimate number of ground rod(s) at each ground connection.

4.1.5. Galloping Conductors

Conductor and shield wire separations will be assessed for ice and wind galloping under the following conditions;

Table 4.6 – Galloping Conditions

Conditions	Temperature (°C)	Horizontal Wind Loading (Pa) [psf]	Radial Ice	
			Thickness (mm)	Ice Density (kg/m^3)
Galloping Swing	-5	95.7 [2]		
Galloping Ice	-5	95.7 [2]	12.7	900

An additional separation of 0.3m shall be provided between galloping ellipses for design buffer.

4.2 Clearance Buffers

The proposed design clearance buffers has been listed in each of the clearance categories

4.3 Structure Spotting Criteria

The preferred standard design span for proposed 138kV transmission lines to be 150m to 180m based on phase separation requirement under galloping conditions and maintaining reasonable structure height during extreme ice loading conditions. The actual design spotting will be based on above

consideration with right of way constraint and adjacent utilities provided in topographical survey utilizing PLS-Cadd 3D TIN terrain model.

4.4 Ampacity Rating Criteria

The phase conductor ampacity calculations are performed based on IEEE Std. 738-2013. C22.3 No.1 Section 3 "Rated ampacity" which outlines the basic ambient and cable conditions to be used for the ampacity calculation.

The ampacity calculations based on parameters outlined in Table 4.4.1 for selected phase conductor cable 266.8MCM ACSR (Partridge) and 397.5MCM ACSR (Ibis) are performed using PLS-Cadd embedded IEEE 738-2013 module. The PLS-Cadd program generated ampacity calculation outputs are given in Appendix F. The calculated continuous and limited thermal ratings for a single conductor are summarized below:

Table 4.7 – IEEE Std. 738 Ampacity Calculations

Parameters	**CSA C22.3 No.1**	**AESO 502.2**
Ambient Temperature	40°C	40°C
Case 1 – Maximum Thermal Rating (Maximum Conductor Temperature)	100°C	100°C
Case 2 – Operating Temperature 40 MW (44.5 MVA) x 1.25 OL @138 kV	240 A	240 A
Case 3 –Design Thermal Rating (Design Conductor Temperature)	75°C	75°C
Wind Speed	0.61 m/s (2 ft/s)	0.61 m/s (2 ft/s)
Wind Angle to Conductor	90°	90°
Conductor Latitude	63.6°	63.6°
Conductor Elevation (above sea level)	800m	800m
Conductor Direction (maximum solar heat)	E-W	E-W
Emissivity	0.5	0.6
Solar Absorption Coefficient	0.5	0.8

Table 4.8 – Conductor Continuous and Limited Thermal Ratings

Cable Conditions	**CSA C22.3 No.1**	**AESO 502.2**
Case 1 – Maximum Thermal Rating		
266.6 MCM 27/6 ACSR (Partridge)	484 A	475 A
397.5 MCM 27/6 ACSR (Ibis)	624 A	612 A
Case 2 – Operating Temperature		
266.6 MCM 27/6 ACSR (Partridge)	59.0°C	62.7°C
397.5 MCM 27/6 ACSR (Ibis)	54.9°C	58.9°C
Case 3 – Design Thermal Rating		

266.6 MCM 27/6 ACSR (Partridge)	361 A (62 MW @138 kV) (31 MW @69 kV)	341 A (58 MW @138 kV) (29 MW @69 kV)
397.5 MCM 27/6 ACSR (Ibis)	463 A (79 MW @138 kV) (39 MW @69 kV)	434 A (74 MW @138 kV) (37 MW @69 kV)

Based on above ampacity and conductor temperature data for the proposed 138kV transmission lines, the design conductor sag shall be based on conductor temperature of 75°C.

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5.0 Structural Design Criteria

5.1 Conductor and Conductor Support Hardware

The conductor and conductor supporting hardware shall be design and selected to withstand the required loadings as per requirement outlined in this section.

5.1.1. Conductor Tension Limits

CSA C22.3 No.1-2006 and CSA C22.3 No.60826 design codes are based on maximum allowable design tensions under various loading conditions. However, the latest edition of CSA C22.3 No.1-2010 has been revised to recommended maximum initial catenary for phase conductor.

5.1.1.1. Tension Limit (% Ultimate Tensile Strength)

C22.3 No.1-2006 Table 34 and Table 35 outlined the tension limit of phase conductor and galvanized steel wire as lightning protection wires (Table 35 has not been modified in the 2010 edition).

Table 5.1 – CSA C22.3 No.1-2006 Allowable Cable Tension Limits

Loading Conditions	AAC, ACSR and Aluminum Alloys Phase Conductors	Galvanized Steel Wires
Maximum tension under appropriate loading conditions	60%	60%
Maximum recommended initial unloaded (initial) tension at mean temperature (EDT)	35%	20%
Maximum recommended final unloaded (creep) tension at mean temperature (EDT)	25%	15%

Strength factor for reliability design are listed in C22.3 No.60826 Section 7. The standard values for strength coefficient of variation is given in C22.3 No.60826 Table 18 and support design strength values for tangent / running and angle / dead end configurations are given in C22.3 No.60826 Canadian Section 7.3.3. The combined allowable material factors and equivalent tension limits are given below:

Table 5.2 – CSA C22.3 No.60826 Allowable Cable Material Factors

Conductor & Shieldwire	Cable Material Factor		Support Design Strength Factor	Combined Allowable Material Factor
	COV	Factor		
Intact Load	3%	0.962	0.80	0.77
Failure Load	3%	0.962	0.90	0.87

5.1.1.2. Maximum Initial Cable Catenary

CSA C22.3 No.1-2010 edition section 8.7.3 “Wire tension limits” has been revised to provide additional safety for fatigue damage of conductors due to aeolian vibration. C22.3 No.1 2010 Table 33 provides the recommended catenary parameter for different span lengths.

As per CSTL design requirement, the catenary parameter requirement is consistent with maximum 15% cable UTS under -50°C. These requirements did impact the structure height requirement but provide reliability where large ranges of temperature variation can occur.

5.1.1.3. Recommended Cable Design Criteria

In consideration of various governing factors for cable design criteria, the follow conditions and criteria are used for the design of conductor and OPGW / OHGW;

Table 5.4 – Recommended Cable Design Criteria

Design Conditions	Cable Condition	Conductor	OPGW / OHGW
C22.3 No.1 CSA Heavy	Loaded	50% UTS	50% UTS
C22.3 No. 60826 Extreme Ice	Loaded	60% UTS	60% UTS
C22.3 No. 60826 Gust Wind	Loaded	50% UTS	50% UTS
C22.3 No. 60826 Wind & Low Temp.	Loaded	60% UTS	60% UTS
C22.3 No. 60826 Ice & Wind (High Wind)	Loaded	60% UTS	60% UTS
C22.3 No. 60826 Ice & Wind (Low Wind)	Loaded	70% UTS	60% UTS
EDT	Initial	35% UTS	20% UTS
EDT	Creep	25% UTS	15% UTS
Catenary @ Mean Annual Min. Temp.	Initial	1500 m	1500 m
Min. Temperature (-50°C)	Creep	15% UTS	15% UTS

5.1.2. Insulators, Support Hardware and Conductor Accessories

Reliability design utilizes actual environmental loadings based on desired project return period to compare with reduced allowable material resistances.

The allowable material strength is dependent on material consistency and structure reliability requirement. Material strength factor for reliability design are listed in C22.3 No.60826 Section 7. The standard values for strength coefficient of variation is given in C22.3 No.60826 Table 18 and support design strength values for tangent / running and angle / dead end configurations are given in C22.3 No.60826 Canadian Section 7.3.3. The combined allowable material factors are summarized below;

Table 5.5 - CSA C22.3 No.60826 Cable and Hardware Material Factors

Materials	Material Factor		Running		Deadend	
	COV	Factor	Intact (0.9)	Failure (1.0)	Intact (0.8)	Failure (0.9)
Insulators	5%	0.936	0.84	0.94	0.75	0.84
Hardware	5%	0.936	0.84	0.94	0.75	0.84

Despite C22.3 No.60826 outlines the allowable strength factors for insulator and hardware, manufacturers of insulator and hardware recommended the allowable strength for these items shall be 50% of the design tensile strength. The selection of insulators and conductor attachment hardware shall be based on manufacturer design limits, with exception of the high ice with average wind (130% Ice & 40% Wind) combination, the maximum insulator and hardware usage shall be 0.75.

5.2 Guys and Hardware

CSA C22.3 No60826 clause 7.3.1 outlines the damage limit of steel guys and Table 18 provide material strength factor for grouted guy anchor design. The design of guy anchors shall be according to IEEE Std. 691 "IEEE Guide for Transmission Structure Foundation Design and Testing".

5.2.1. Guy Strand & Hardware

The maximum allowable guy cable and hardware tension shall be 0.75 (75%) ultimate tensile strength as per CSA C22.3 No.60826 Table 14.

5.2.2. Guy Anchors

The maximum design loadings for commercial available guy anchor shall be according to manufacturer recommended holding capacity. The material factor for grouted rock anchor shall be as follows;

Table 5.6 - CSA C22.3 No.60826 Allowable Rock Anchor Material Factors

Materials	Material Factor		Running		Deadend	
	COV	Factor	Intact (0.9)	Failure (1.0)	Intact (0.8)	Failure (0.9)
Grouted Rock Anchor	10%	0.872	0.78	0.87	0.70	0.78

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5.3 Structures

5.3.1. Load Factors

Deterministic approach is applied for designing transmission line components to withstand factored loads (vertical, transverse and longitudinal loads) under C22.3 No.1 conditions specific to the project area (see Table 3.1). The required overload factors are specified in C22.3 No.1 Section 7.4 to 7.9 and summarized in C22.3 No.1 Table 31.

Table 5.7 – CSA C22.3 No.1 Overload Factors for Limit State Design (Deterministic Approach)

Structure Type	Grade 2 Construction			Grade 1 Construction		
	Vertical	Trans.	Long.	Vertical	Trans.	Long.
Steel Components (crossarms, davit arms, braces, etc.)						
Tangent & Running Angle	1.15	1.10	1.00	1.30	1.20	1.10
Heavy Angle & Deadend	1.15	1.10	1.10	1.30	1.20	1.20
Wood Pole						
Tangent & Running Angle	1.50	1.30	1.00	2.00	1.90	1.20
Heavy Angle & Deadend	1.50	1.30	1.30	2.00	1.90	1.90

The allowable strengths for each transmission line structural component is calculated by PLS-Pole based on input material parameters, such as geometry, material yield strengths, mechanical properties of material type.

5.3.2. Strength Reduction Factors

The allowable material strength is dependent on material consistency and structure reliability requirement. Structural material strength coefficient of variation for steel component is given in C22.3 No.60826 Table 18 and support design strength values for tangent / running and angle / dead end configurations are given in C22.3 No.60826 Canadian Section 7.3.3. The combined allowable material factors are summarized below:

Table 5.8A - CSA C22.3 No.60826 Allowable Structural Material Factors

Materials	Material Factor		Running		Deadend	
	COV	Factor	Intact (0.9)	Failure (1.0)	Intact (0.8)	Failure (0.9)
Steel Component	5%	0.936	0.84	0.94	0.75	0.84
Wood Component	15%	0.808	0.73	0.80	0.65	0.73

5.4 Design Loads

The design load cases for the proposed 138kV transmission lines shall be based on the climatic data outlined in Section 3.

5.4.1.1. CSA Minimum Deterministic Load Case

The minimum design loads for the proposed transmission lines shall be CSA Heavy Condition as per Table 3.1.

5.4.1.2. Extreme Ice Load Cases

The maximum extreme ice loadings shall be designed for 1 in 50 years return period reference data.

5.4.1.3. Maximum Gust Wind Load Cases

The maximum gust wind loadings shall be designed for 1 in 50 years return period reference.

5.4.1.4. Combined Ice and Wind Load Cases

Both combination of ice with wind loading conditions will be evaluated according to Section 3..3.4.

5.4.1.5. Broken Wire and Unbalanced Ice Loads

For tangent and running angle structures, since the application of braced post insulator had limited longitudinal load capability, the unbalanced longitudinal loading conditions are not considered.

5.4.1.6. Containment Structures

All dead end angle structures and double dead end containment structures shall be designed to withstand complete one sided cable loadings in addition to standard configuration loadings under all climatic conditions.

5.4.1.7. Construction and Maintenance Loads

Construction and maintenance load requirements are specified in C22.3 No.60826 Section 6.5.

The lifting components (such as lifting vent if required) during structure erection shall have minimum safety factor of 1.5 for planned control operation.

The safety factor for cable tension shall be 2.0 during cable stringing operation with 50% of the applied tension added as longitudinal load on all running angle structures.

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5.5 Structure Design

The wood pole design shall be preformed using PLS-Pole wood pole structural add-on application module. The PLS-Pole model shall include wood pole, steel crossarm, steel cross braces, insulators, guy cables, etc.

Attachment loadings will be generated by PLS-Cadd line design application using Method 4 "Structure Loads" calculations. Additional longitudinal loads for maintenance and construction scenario under every day temperature will be applied manually in PLS-Pole application.

5.6 Foundation Design

Transmission pole structures in this project are direct-embedded poles and shall be designed to resist the overturning moment, shear and axial loads generated from the design of pole structures using L-Pile caisson foundation application.

5.6.1. Moment Foundations

5.6.1.1. Design Philosophy

For direct-embedded method, the pole embedment length below the ground line shall be determined using an allowable lateral displacement approach. Horizontal subgrade reaction along the embedded length is determined based on borehole record information as per the geotechnical investigation report. Pole structure shall be designed to withstand the structural loading specified in other sections of this criteria document, and shall also be qualified to sustain the corresponding geotechnical loading to ensure structural integrity.

5.6.1.2. Deflection Limits

Pole recoverable deflection at ground line is limited to 25mm due to actual loading under normal weather condition, and 40mm due to actual loading under extreme weather condition. The soil input parameters for L-Pile application, such as friction angle for granular material and undrain strength for cohesive material, are deduced from site geotechnical report.

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Appendix A – Site Location Plan

DRAFT

Appendix B – Code & Regulation List

DRAFT

Appendix C – Cables and Insulators Catalogue Information

DRAFT

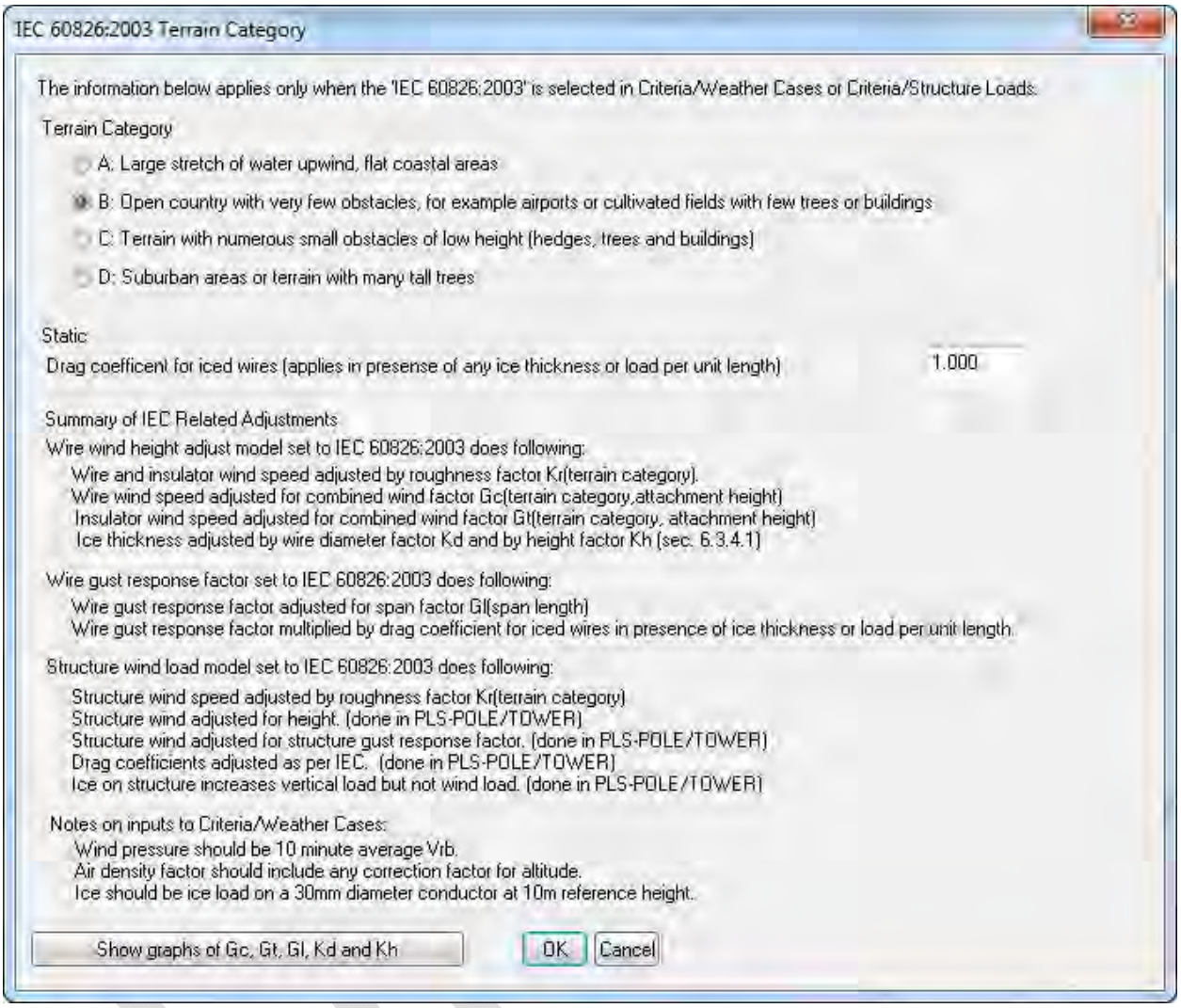
Appendix D – Climatic Data Reference Data

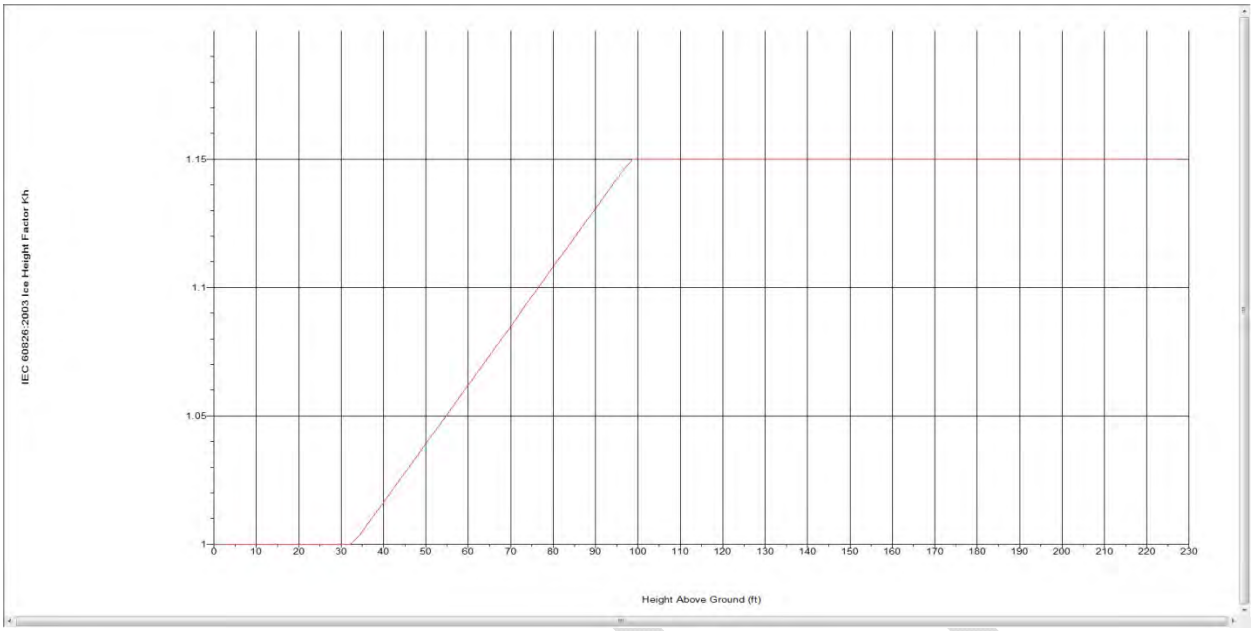
DRAFT

Appendix E – PLS-Cadd IEC 60826:03 Wind & Ice Adjustment Models

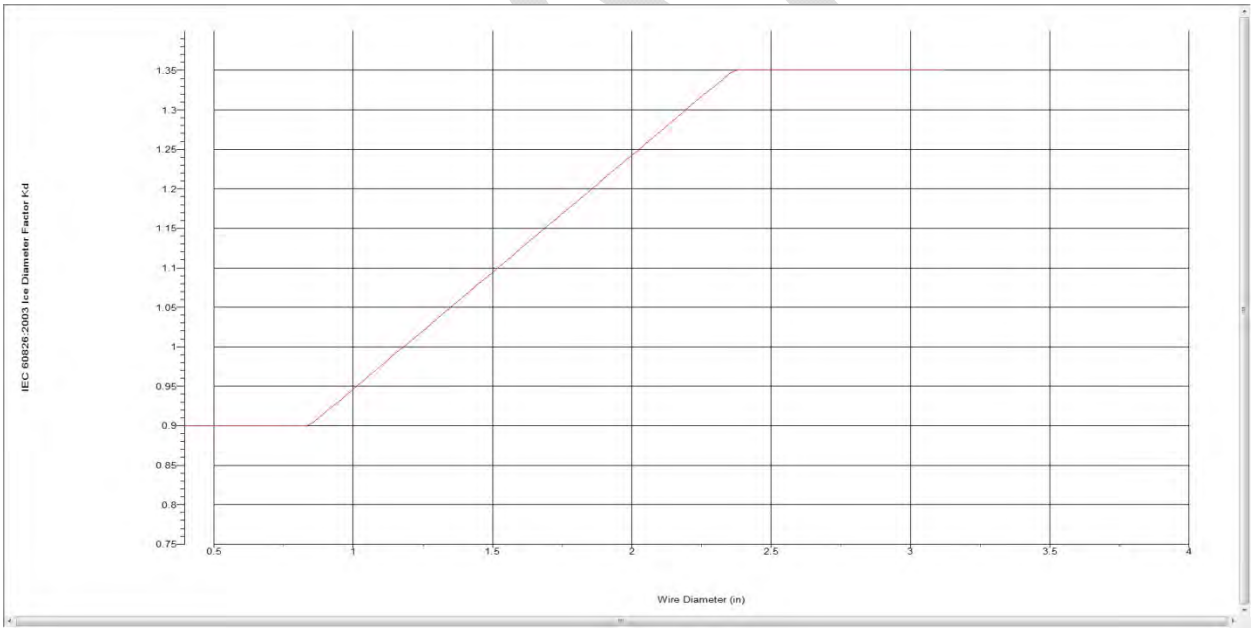
DRAFT

IEC 60826:2003 Design Code – Input Parameter Definitions

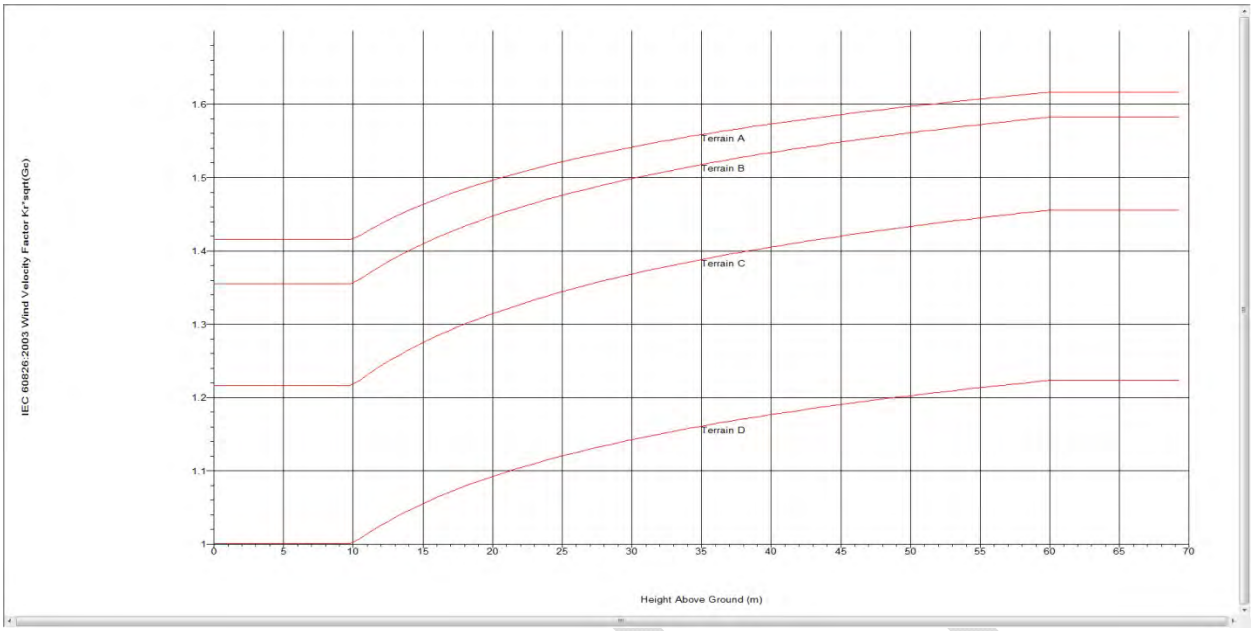




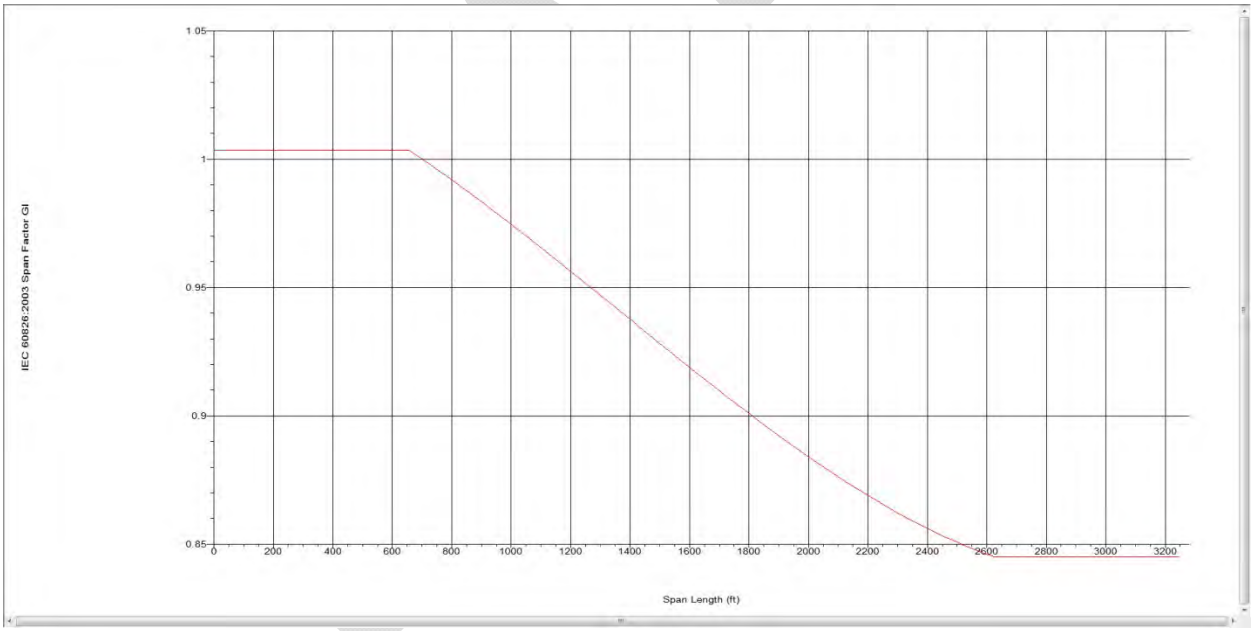
IEC Ice Height Factor (Kh) vs. Attachment Height



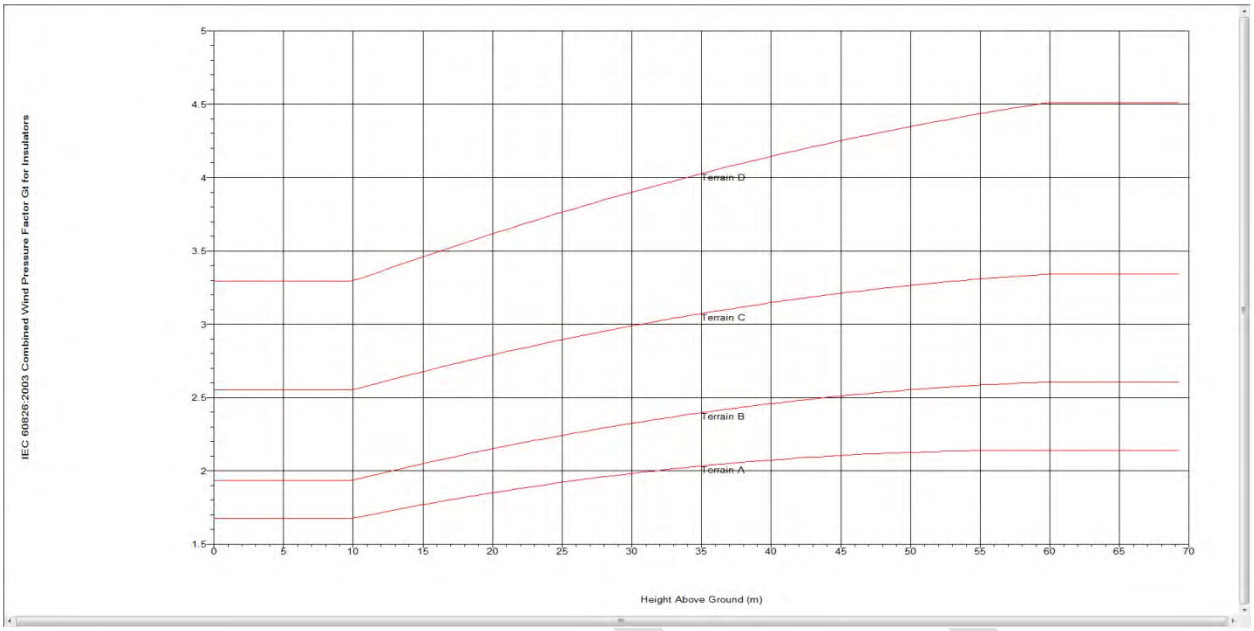
IEC Ice Diamter Factor (Kd) vs. Wire Diameter



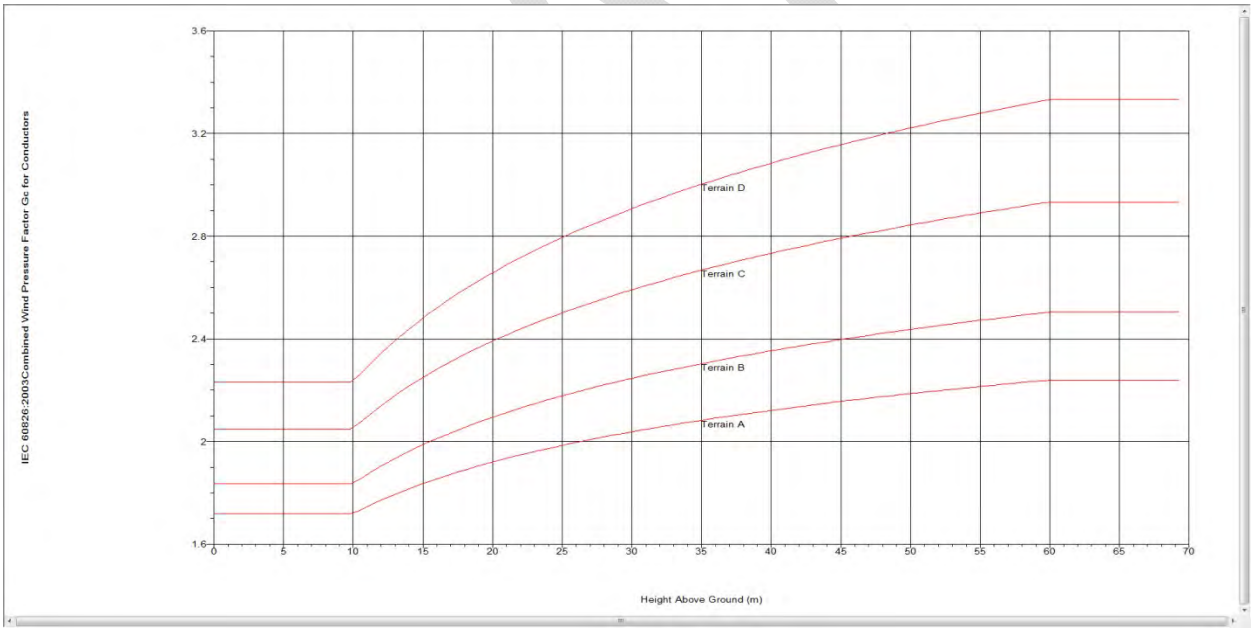
IEC Wind Velocity Factor (Kr*√Gc) vs. Attachment Height



IEC Span Factor (Gl) vs. Span



IEC Combined Wind Pressure Factor (Gt) for Insulators vs. Attachment Height



IEC Combined Wind Pressure Factor (Gc) for Conductors vs. Attachment Height

Appendix F – IEEE Std. 738 Ampacity Calculation Program Output

DRAFT

Chimax Inc.
Engineering Company

Evaluation Criteria

Re: ***YEC L170 Transmission Line – Clearance and Structural Evaluation Criteria***

1. General Description

The existing L170 138kV transmission line connects YEC Takhini switching station near Whitehorse and YEC Carmacks switching station at Carmacks. The L170 along with Carmacks to Stewart 138kV transmission lines (CSTL) (L173 Carmacks switching station to Minto Landing substation, L174 Minto Landing substation to Stewart Crossing South substation and L175 Stewart Crossing South substation to Stewart Crossing North switching station) provide the transmission grid tie between YEC southern operation area with northern operation area (Keno-Mayo-Dawson).

This document outlines the current governing design codes requirements for 138 kV transmission line clearance and structural criteria to be used in the evaluation of existing L170 structure compliance.

2. L170 Thermal Capacity & Conductor Temperature

The existing L170 has an operating capacity of 35MW with power factor of 0.93. The projected future capacity of L170 has been estimated to be 70MW. Based on power factor of 0.9, provide margin for flexibility, the calculated required ampacities are used in determination of the L170 conductor temperatures under different ambient temperatures and code reference conditions.

The CSTL 138kV transmission lines were designed with maximum conductor temperature of 75°C under both winter and summer conditions.

The phase conductor ampacity calculations are performed based on IEEE Std. 738-2013. The PLS-Cadd program generated ampacity calculation outputs are given in Appendix A.

Table 2.1 – IEEE Std. 738 Ampacity Calculations

Input Parameters	CSA C22.3 No.1	AESO 502.2	YEC Winter Operation	YEC Normal Operation	YEC Summer Operation
Ambient Temperature	40°C	40°C	10°C	15.6°C (60°F)	30°C
Wind Speed	0.61 m/s (2 ft/s)				
Wind Angle to Conductor	90°				
Conductor Latitude	61°				
Conductor Elevation (above sea level)	100m				
Conductor Direction (maximum solar heat)	E-W				
Emissivity	0.5	0.6	0.6	0.6	0.6
Solar Absorption Coefficient	0.5	0.8	0.8	0.8	0.8
Case 1 – Existing Thermal Loadings (35MW)	165 A				
Case 1 – Future Thermal Loadings (70MW)	330 A				
Case 3 – CSTL Design Conductor Temperature	75°C				

Table 2.2 – Conductor Continuous and Limited Thermal Ratings

Input Parameters	CSA C22.3 No.1	AESO 502.2	YEC Winter Operation	YEC Normal Operation	YEC Summer Operation
Ambient Temperature	40°C	40°C	10°C	15.6°C (60°F)	30°C
Case 1 – Conductor Temperature @ Existing Thermal Loadings (35MW)	54°C	57°C	28°C	33°C	48°C
Case 1 – Conductor Temperature @ Future Thermal Loadings (70MW)	71°C	75°C	44°C	50°C	65°C
Case 3 – Thermal Rating @ CSTL Design Conductor Temperature	358 A	337 A	500 A	474 A	399 A

3. Vertical Ground Clearance Criteria

In addition to compliance to CSA C22.3 No.1 "Overhead Systems", YEC is mandated to conform with Alberta Electrical Utility Code (AEUC) under Yukon regulation. The minimum code specified clearance and recommended design values are summarized below:

Table 3.1 - 138kV (Maximum Voltage 155kV Ph-Ph) Vertical Ground Clearance

Clearance Descriptions	Code Ref. Min. Clearance	Mean Annual Snow Depth	Survey Tolerance	Const. Tolerance	Summer Design Clearance	Winter Design Clearance
	(m)	(m)	(m)	(m)	(m)	(m)
Ground Clearance (CSA C22.3 No.1 Table 2)						
Vehicular Clearance (Vehicle Height <4.15m)	5.5	0.6	0.3	0.3	6.1	6.7
Non-Vehicular Clearance (Pedestrian / ATV)	4.0	0.6	0.3	0.3	4.6	5.2
Railroad Crossings	8.4		0.3	0.3	9.0	9.0
Waterway Crossings (CSA C22.3 No.1 Table 3)						
Class 1 (Vessel H ≤ 4.0 m)	6.7		0.6		7.3	7.3
Class 2 (Vessel H ≤ 6.0 m)	8.7		0.6		9.3	9.3
Class 3 (Vessel H ≤ 8.0 m)	10.7		0.6		11.3	11.3
Class 4 (Vessel H ≤ 10.0 m)	12.7		0.6		13.3	13.3
Class 5 (Vessel H ≤ 12.0 m)	14.7		0.6		15.3	15.3
Class 6 (Vessel H ≤ 14.0 m)	16.7		0.6		17.3	17.3
Features (CSA C22.3 No.1 Table 9 & Table 10)						
Buildings	4.2	0.6	0.3	0.3	4.8	5.4
Signs, Fences, etc.	4.2		0.3	0.3	4.8	4.8
Bridges	3.4	0.6	0.3	0.3	4.0	4.6
Ground Clearance (AEUC 2013 Table 5)						
Non-Vehicular Clearance (Pedestrian / ATV < 3.6m)	5.0	0.6	0.3	0.3	5.6	6.2
Vehicular Clearance (Vehicle Height <4.15m)	5.5	0.6	0.3	0.3	6.1	6.7
High Load Clearance (Vehicle Height <5.3m)	6.7	0.6	0.3	0.3	7.3	7.9

4. Structural Loadings

CSA C22.3 No.1 (Overhead Systems) Design Loadings

CSA C22.3 No.1 Section 7 outlines the minimum deterministic weather loads shall be applied to each line components. C22.3 No.1 Annex C Figure C.1 indicates that the Yukon falls under CSA Medium A Loading condition which does not represent local observed ice loading situations. The CSA Heavy Loading is used for the previous CSTL and proposed transmission lines.

Table 4.1 - C22.3 No.1 Table 30 Deterministic Weather Loads

Conditions	Temperature (°C)	Horizontal Wind Loading (N/m^2)	Radial Ice	
			Thickness (mm)	Ice Density (kg/m^3)
CSA Medium A	-20	400	6.5	900
CSA Heavy	-20	400	12.5	900

CSA C22.3 No.60826 (Overhead Transmission Lines) Design Loadings

CSA C22.3 No.60826 is the Canadian adaptation of IEC 60826 "Design criteria of overhead transmission lines", with implementation of appropriate Canadian variations and weather parameters. C22.3 No.60826 Table CA.1 listed 50 years return period (1/50) weather conditions for Canadian Locations. The mean annual maximum snow accumulation depths are provided in CSA C22.3 No.1 Table D.1. The ice, wind and snow depth parameters for the closest meteorological locations to the transmission line are listed below:

Table 4.2 - C22.3 No.60826 Table CA.1 Reliability Weather Reference Data

Locations	Reference Average Minimum Temperature (°C)	Reference (1/50) Wind Speed (km/h)	Reference (1/50) Radial Ice		Mean Annual Maximum Snow Depth (m)
			Thickness (mm)	Ice Density (kg/m^3)	
Whitehorse (reference)	-43	85	10	900	0.4
Dawson City	-51	80	10	900	0.6

The reference wind speed are based on 10 minutes average wind. Gust factor is applied in the PLS-Cadd program according the line configuration (typical factor of 1.6).

Ambient temperature for the corresponding wind and ice loadings are based on -10°C.

The reference ice loading listed in CSA C22.3 No.60826 does not reflect the occasionally observed rime ice condition on existing transmission line in Yukon. Additional ice loading of 51mm (2") rime ice (density of 350kg/m^3) has been proposed for the evaluation of transmission line structure.

Figure 4.1 – Extreme Rime Ice on L174 (2011)

Table 4.3 - Recommended Design Load Combinations

Conditions	Temperature (°C)	Horizontal Wind Loading (km/h) [Pa]	Radial Ice	
			Thickness (mm)	Ice Density (kg/m^3)
CSA Heavy	-20	25.5 [400]	12.7	900
IEC Ice	-10	--	12.7	900
IEC Wind	-10	85 [425]	--	--
IEC Wind & Low Temp.	-24	51 [161]	--	--
IEC Low Ice & High Wind	-10	51 [161]	10.8	900
Extreme Min. Temp.	-51	--	--	--
YEC Rime Ice	-30	--	-51	350

Gust and height factor applied in PLS-Cadd program according to code specification.

Based on available information, the existing L170 designs are based on the following load combinations.

Table 4.4 – Existing L170 (1968) Design Load Combinations

Conditions	**Temperature (°C) [°F]**	**Horizontal Wind Loading (Pa) [psf]**	**Radial Ice**	
			Thickness (mm) [in]	**Ice Density (kg/m^3)**
Extreme Ice	-18 [0°F]	--	25.4 [1]	900
CSA Ice & Wind	-18 [0°F]	383 [8]	12.7 [1/2]	900
Extreme Wind	-18 [0°F]	574 [12]	--	--
Extreme Min. Temp.	-37 [35°F]	--	--	--

5. Recommendations

For the evaluation of existing L170 structures and replacement structure design, the ground clearance should be based on projected future capacity of 70MW. The clearance criteria should be as follows:

Table 5.1 Recommended Clearance Criteria

Conditions	Conductor Condition			Clearance (m)	
	Temperature (°C)	Wind (Pa)	Ice (mm)	Along ROW	Cross / Along Highway
YEC Summer (30°C Ambient)	65	--	--	6.1	7.3
YEC Winter (10°C Ambient)	45	--	--	6.7	7.9
Rime Ice	-20	--	50 mm @350 kg/m^3	--	7.9

The structural evaluation of existing L170 structural components are recommended to comply with following loading criteria:

Table 5.2 Recommended Loading Criteria for Existing Structural Components

Conditions	Conductor Condition			Adjustment Factors	
	Temperature (°C)	Wind (Pa)	Ice (mm)	Wind Height Factor	Wind Gust Factor
CSA Heavy	-20	400	12.7 @900 kg/m^3	1	1
Extreme Ice	-20	--	25.4 @900 kg/m^3	1	1
IEC Wind	-10	425	--	IEC 60826	IEC 60826
Extreme Minimum Temp.	-51	--	--	1	1

The design of replacement structures shall conform to all loading listed in Table 5.2 and the following additional requirement:

Table 5.3 Additional Loading Criteria for Replacement Components

Conditions	Conductor Condition			Adjustment Factors	
	Temperature (°C)	Wind (Pa)	Ice (mm)	Wind Height Factor	Wind Gust Factor
IEC Wind & Low Temp.	-24	161	--	IEC 60826	IEC 60826
IEC Low Ice & High Wind	-10	161	10.8 @900 kg/m^3	IEC 60826	IEC 60826
Rime Ice	-20	--	50 mm @350 kg/m^3	1	1

Appendix A - IEEE Std. 738-2013 Calculation Outputs

```
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Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                       and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is      8.734 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m^2) - which was calculated)
Radiation cooling is     2.469 (Watt/m)
Convective cooling is   12.723 (Watt/m)

Given a constant ac current of 165.0 amperes,
The conductor surface temperature is 53.0 (deg C)
The conductor core temperature is 53.1 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))
```

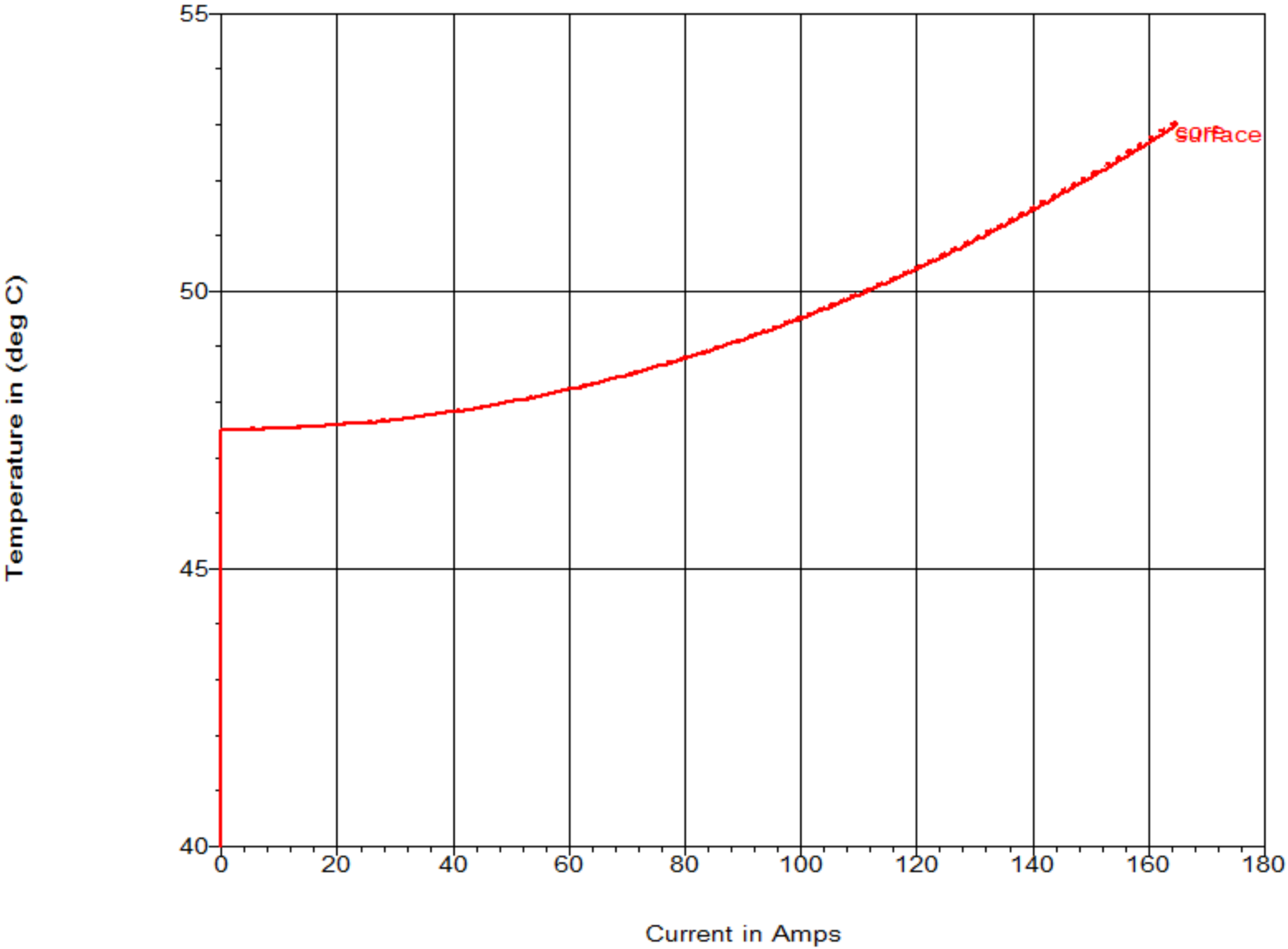
55
50
45
40
surface
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20
40
60
80
100
120
140
160
180
Current in Amps

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IEEE Std. 738-2012 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                       and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is      8.734 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m^2) - which was calculated)
Radiation cooling is     6.304 (Watt/m)
Convective cooling is   29.875 (Watt/m)

Given a constant ac current of 330.0 amperes,
The conductor surface temperature is 70.6 (deg C)
The conductor core temperature is 70.9 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))
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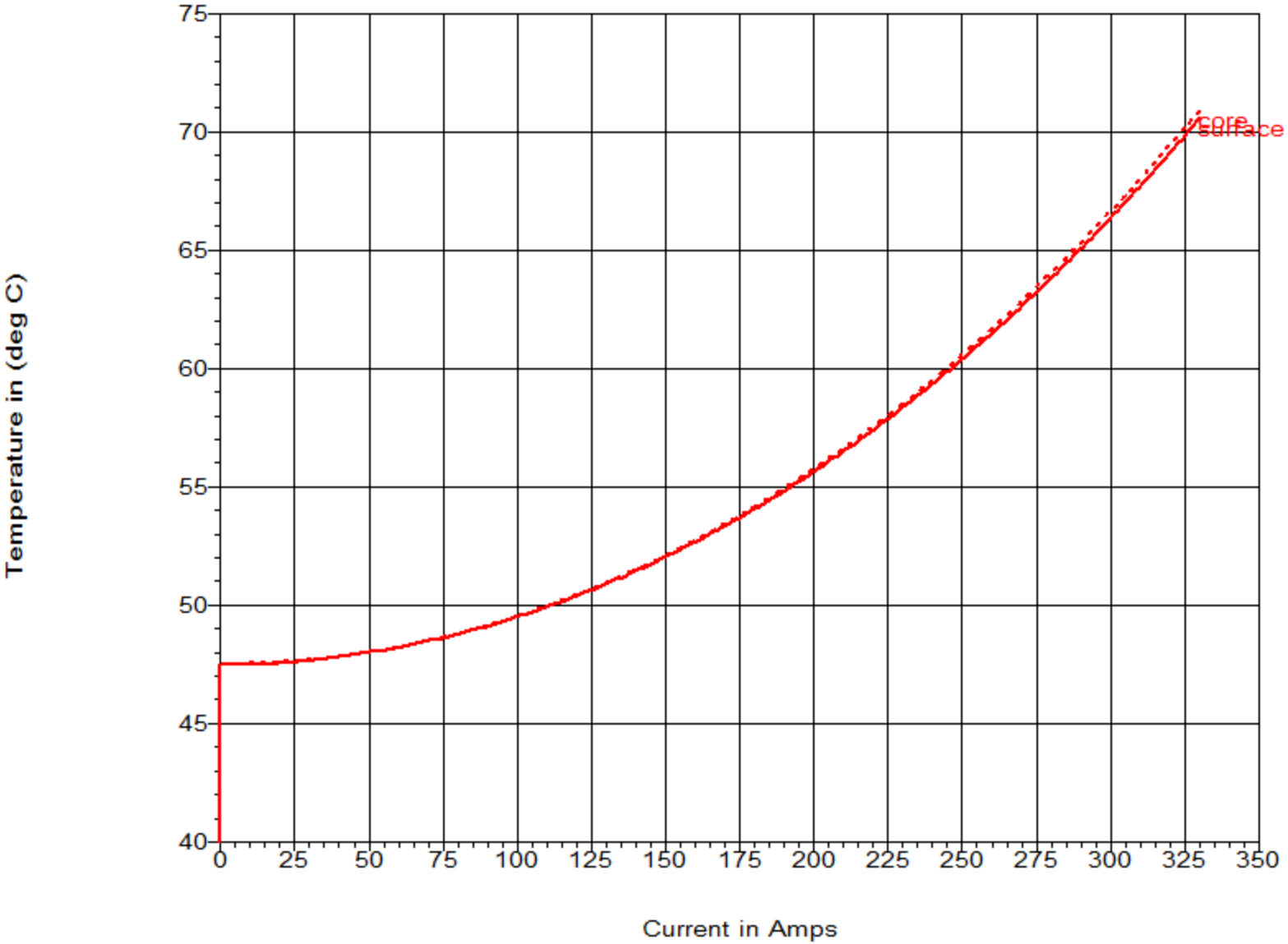
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70
65
60
55
50
45
40
0
25
50
75
100
125
150
175
200
225
250
275
300
325
350
Current in Amps
core
surface

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Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

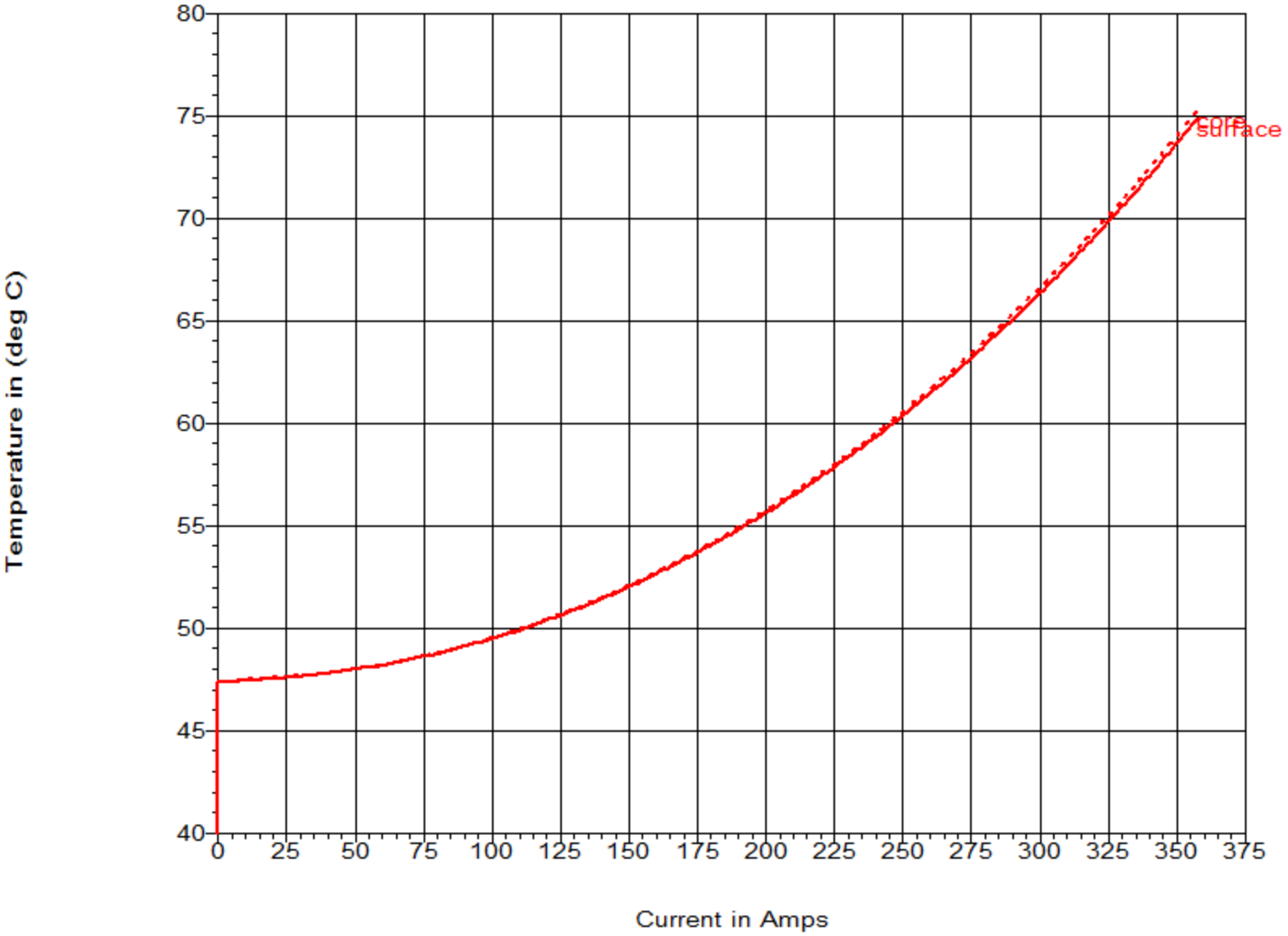
IEEE Std. 738-2012 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
  Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)
  and 0.2556 (Ohm/km) at 75.0 (deg C)
  Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is 8.734 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m^2) - which was calculated)
Radiation cooling is 7.366 (Watt/m)
Convective cooling is 34.188 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),
The steady-state thermal rating is 358.2 amperes


Temperature in (deg C)
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75
70
65
60
55
50
45
40
0
25
50
75
100
125
150
175
200
225
250
275
300
325
350
375
Current in Amps
coil
surface

```
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Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                       and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m^2) - which was calculated)
Radiation cooling is     3.934 (Watt/m)
Convective cooling is   16.582 (Watt/m)

Given a constant ac current of 165.0 amperes,
The conductor surface temperature is 57.0 (deg C)
The conductor core temperature is 57.0 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))
```
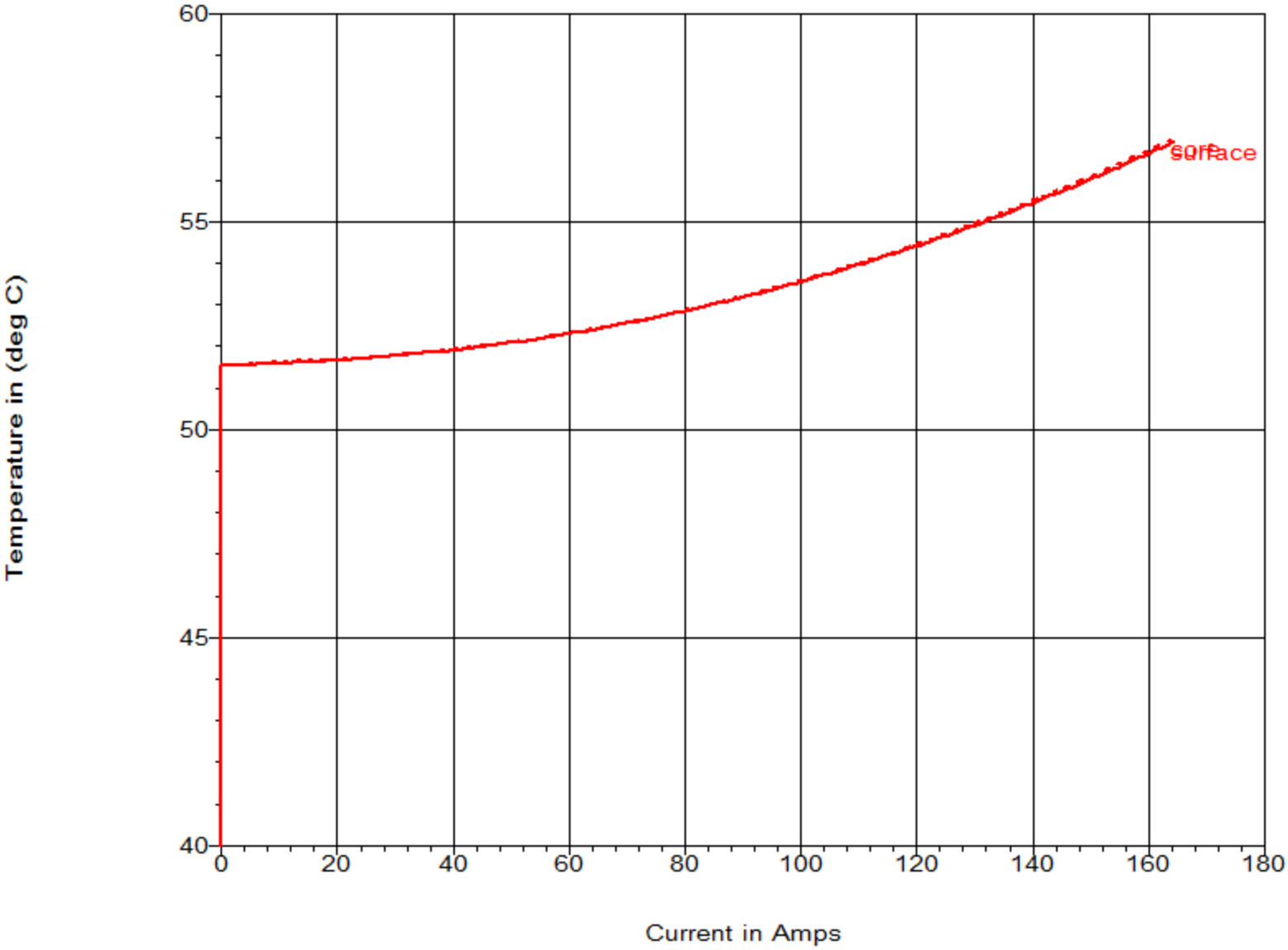
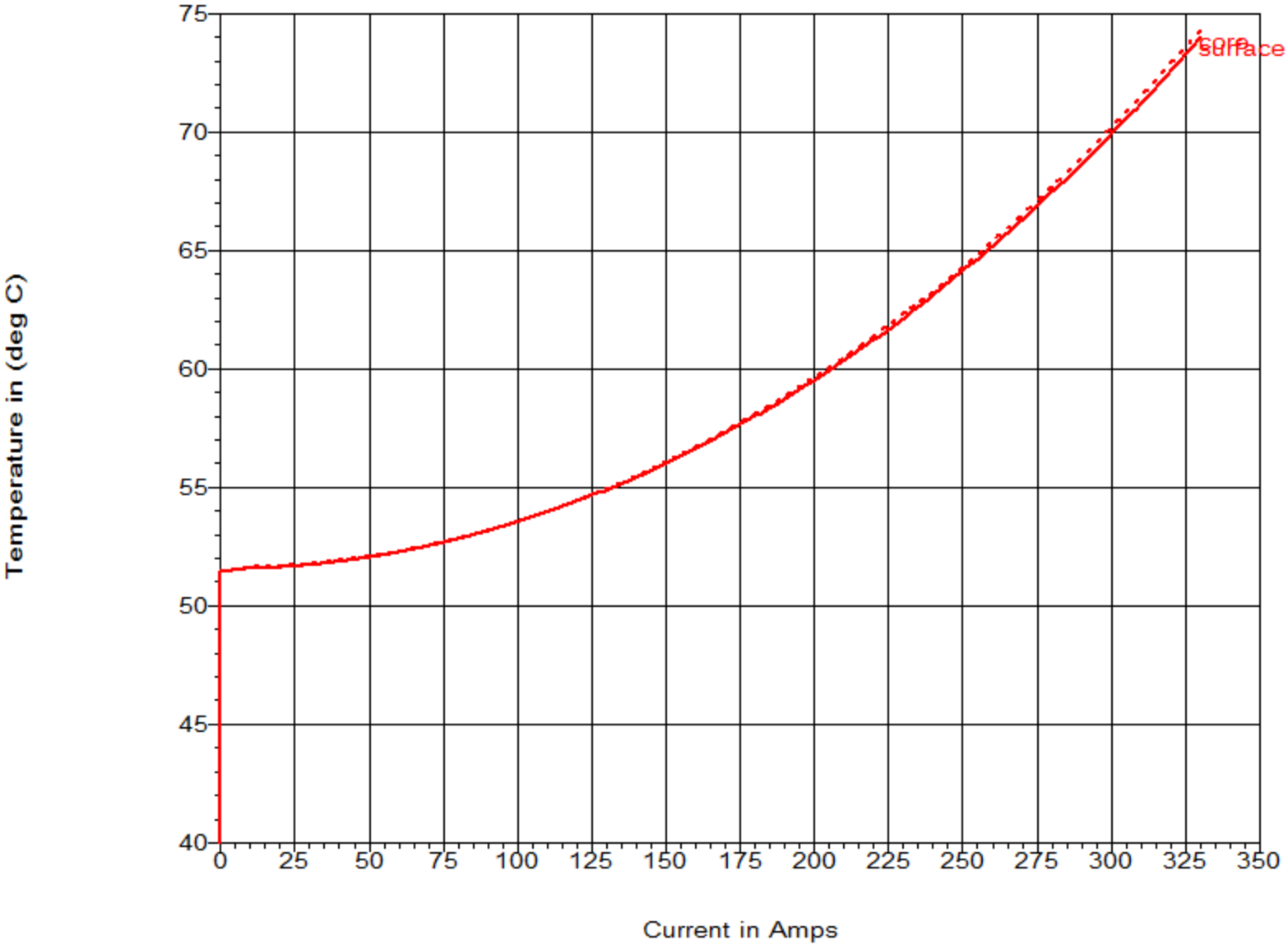


60
55
50
45
40
0
20
40
60
80
100
120
140
160
180
surface
Temperature in (deg C)
Current in Amps

```
PLS-CADD Version 14.40x64    3:04:34 PM Tuesday, October 17, 2017
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                       and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m^2) - which was calculated)
Radiation cooling is     8.540 (Watt/m)
Convective cooling is   33.191 (Watt/m)

Given a constant ac current of 330.0 amperes,
The conductor surface temperature is 74.0 (deg C)
The conductor core temperature is 74.3 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))
```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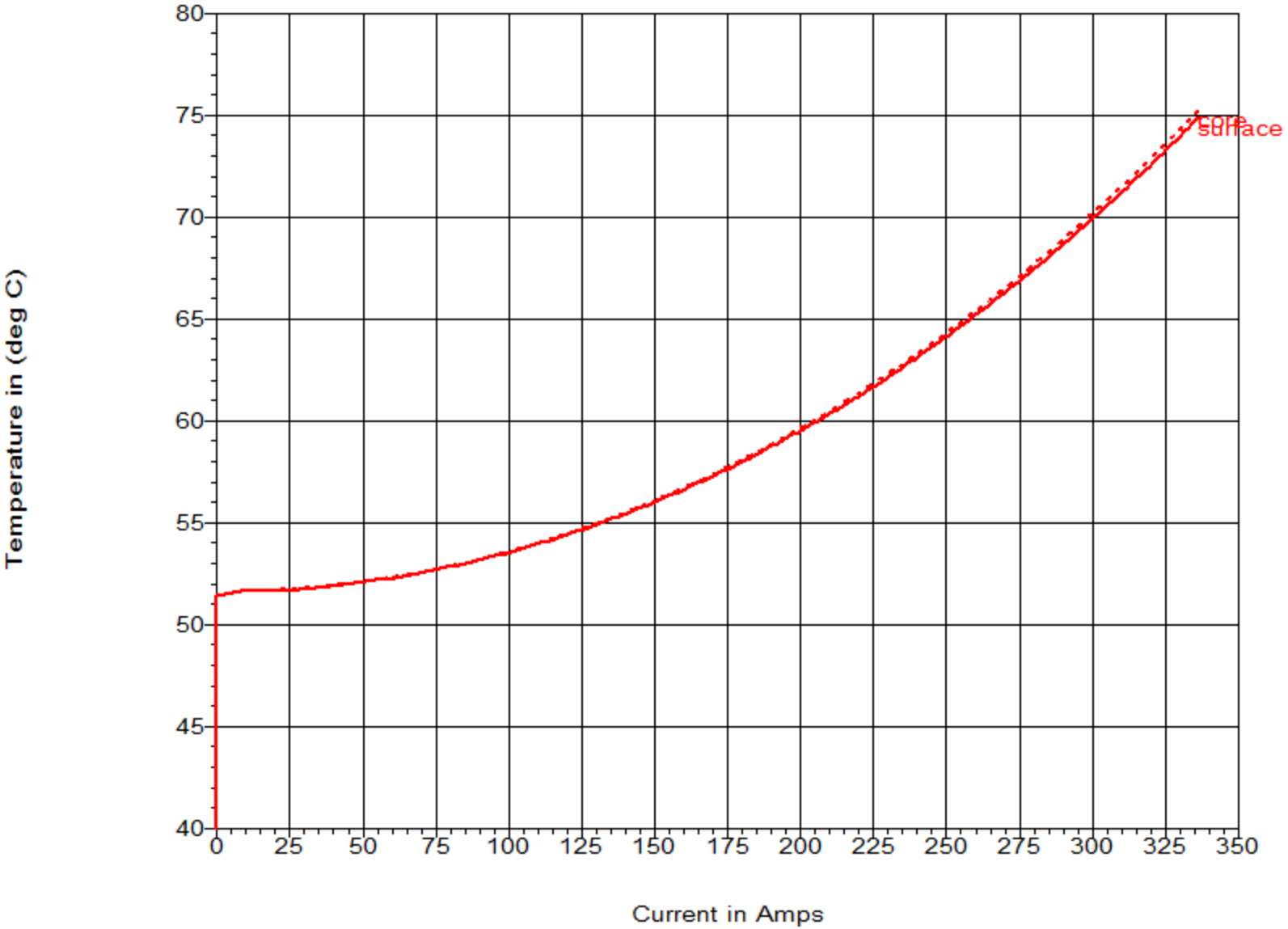
60
55
50
45
40
0
25
50
75
100
125
150
175
200
225
250
275
300
325
350
core
surface
Current in Amps

```
PLS-CADD Version 14.40x64    3:06:34 PM Tuesday, October 17, 2017
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                       and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m^2) - which was calculated)
Radiation cooling is     8.839 (Watt/m)
Convective cooling is   34.188 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),
The steady-state thermal rating is 337.1 amperes
```


Temperature in (deg C)
80
75
70
65
60
55
50
45
40
0
25
50
75
100
125
150
175
200
225
250
275
300
325
350
Current in Amps
core
surface

PLS-CADD Version 14.40x64 3:07:29 PM Tuesday, October 17, 2017
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

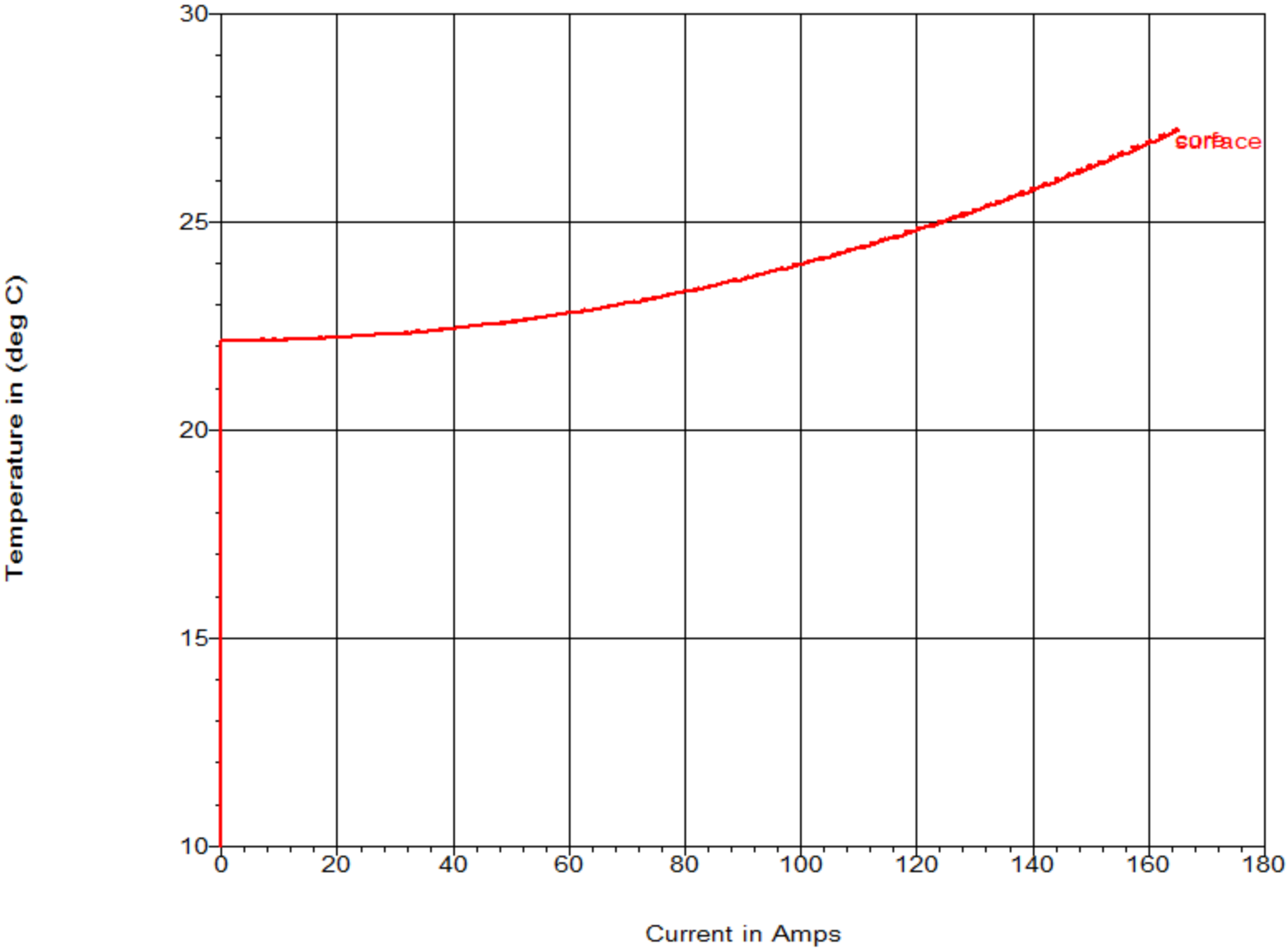
IEEE Std. 738-2012 method of calculation

Air temperature is 10.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

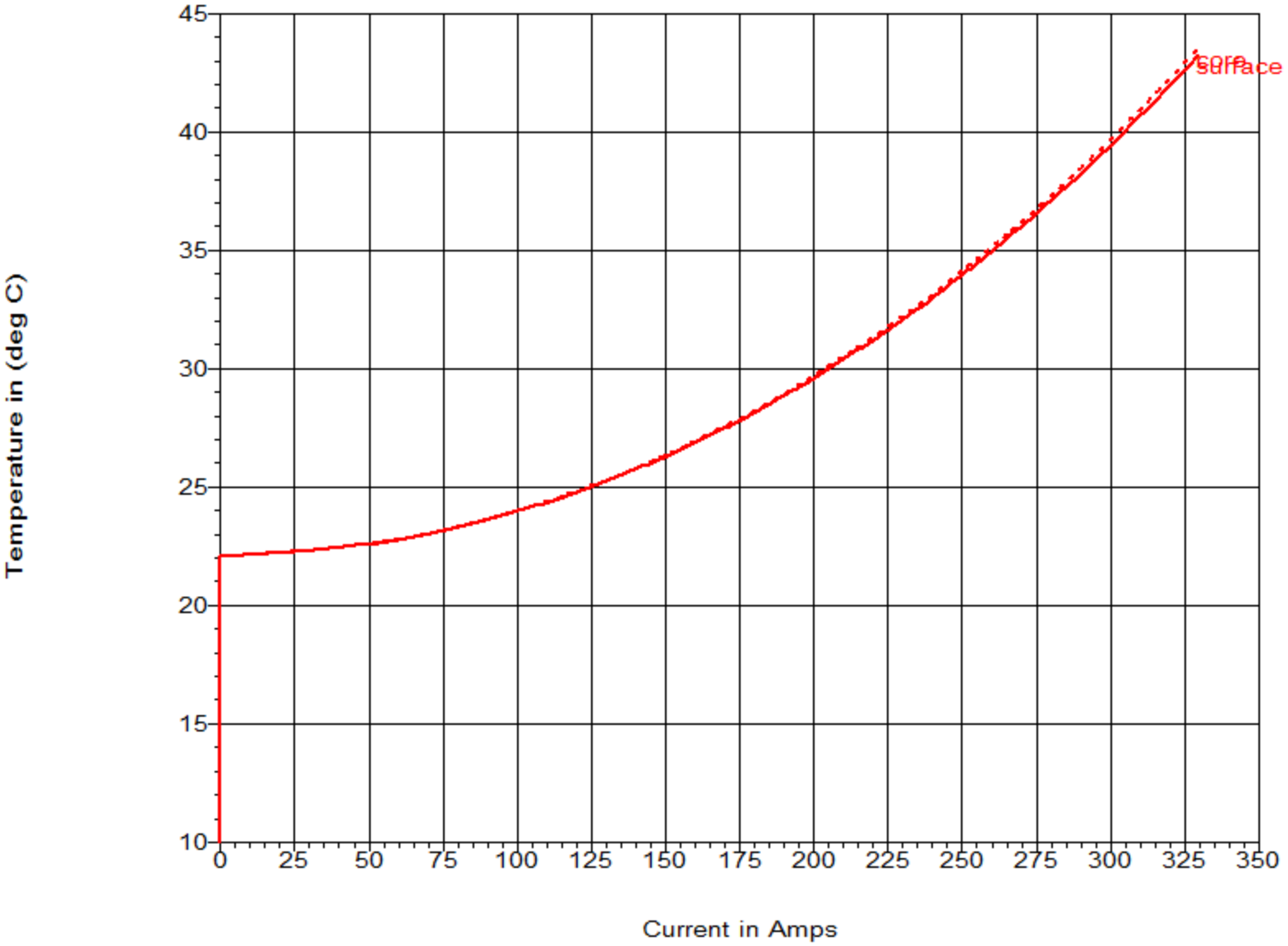
Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
  Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)
  and 0.2556 (Ohm/km) at 75.0 (deg C)
  Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m^2) - which was calculated)
Radiation cooling is 2.976 (Watt/m)
Convective cooling is 16.870 (Watt/m)

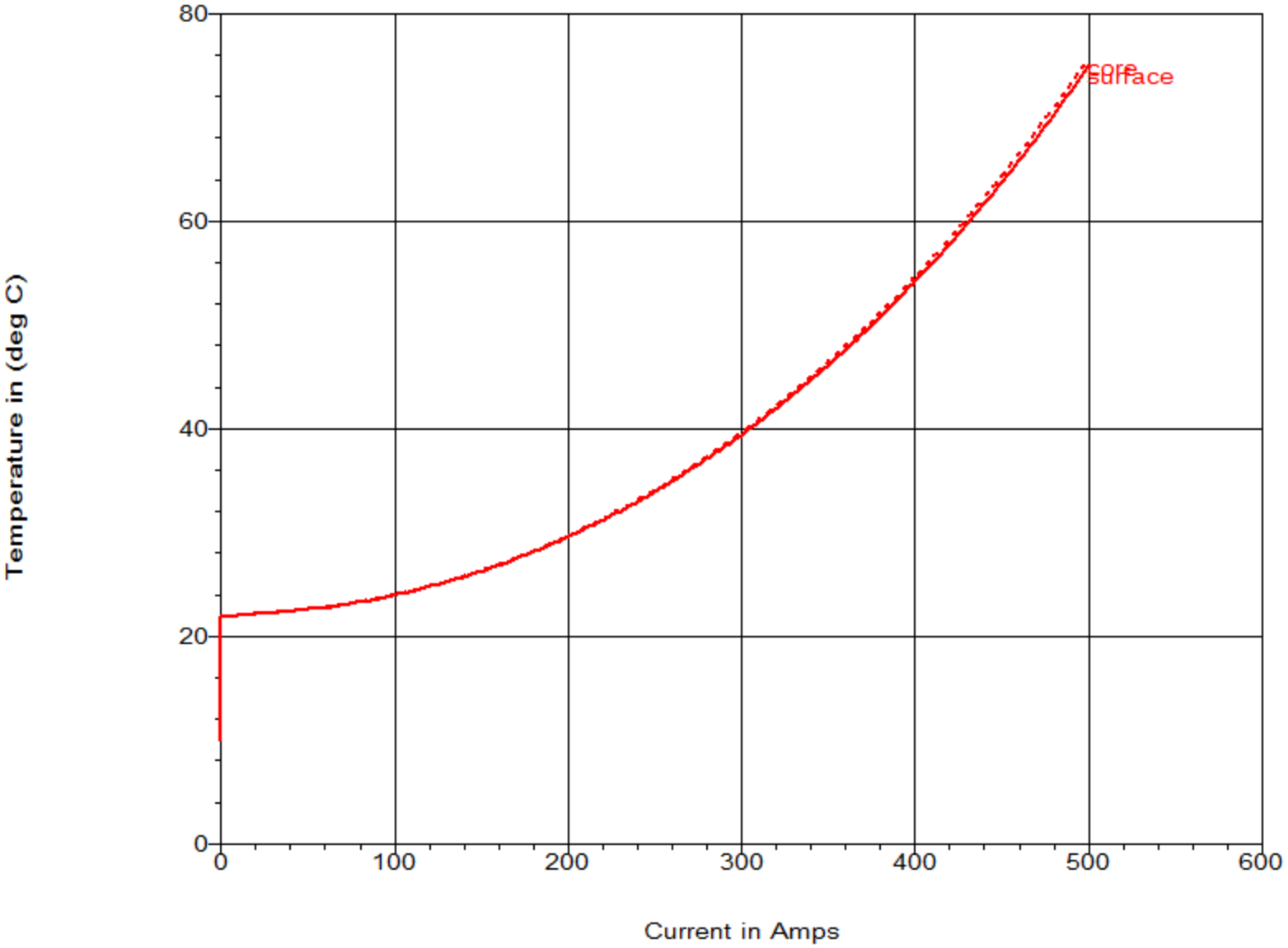
Given a constant ac current of 165.0 amperes,
The conductor surface temperature is 27.2 (deg C)
The conductor core temperature is 27.3 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))


30
25
20
15
10
0
20
40
60
80
100
120
140
160
180
surface
Temperature in (deg C)
Current in Amps

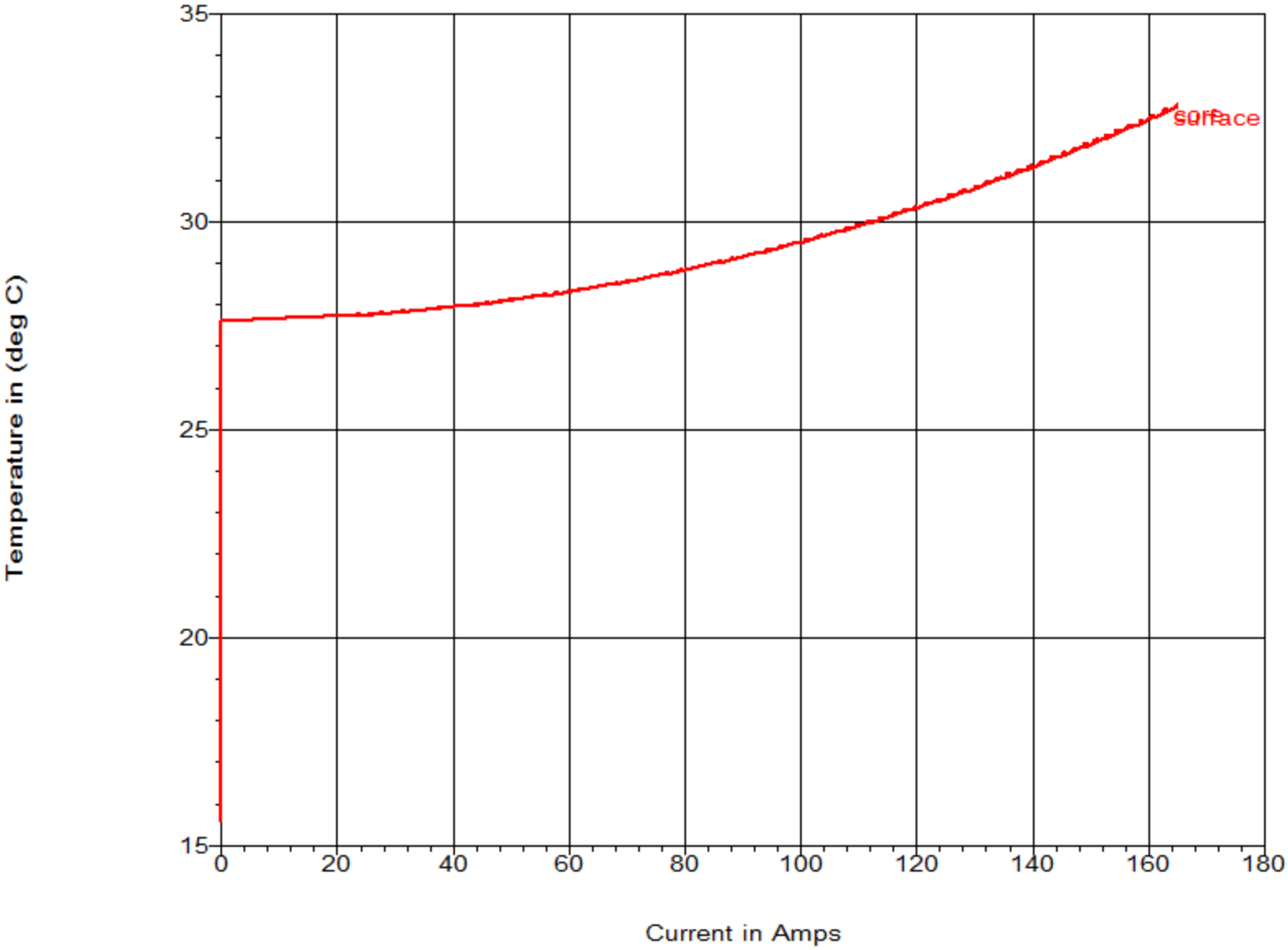
```
PLS-CADD Version 14.40x64    3:08:27 PM Tuesday, October 17, 2017
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 10.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                       and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m^2) - which was calculated)
Radiation cooling is     6.272 (Watt/m)
Convective cooling is   32.648 (Watt/m)

Given a constant ac current of 330.0 amperes,
The conductor surface temperature is 43.3 (deg C)
The conductor core temperature is 43.6 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))
```


Temperature in (deg C)
45
40
35
30
25
20
15
10
0
25
50
75
100
125
150
175
200
225
250
275
300
325
350
Current in Amps
core
surface

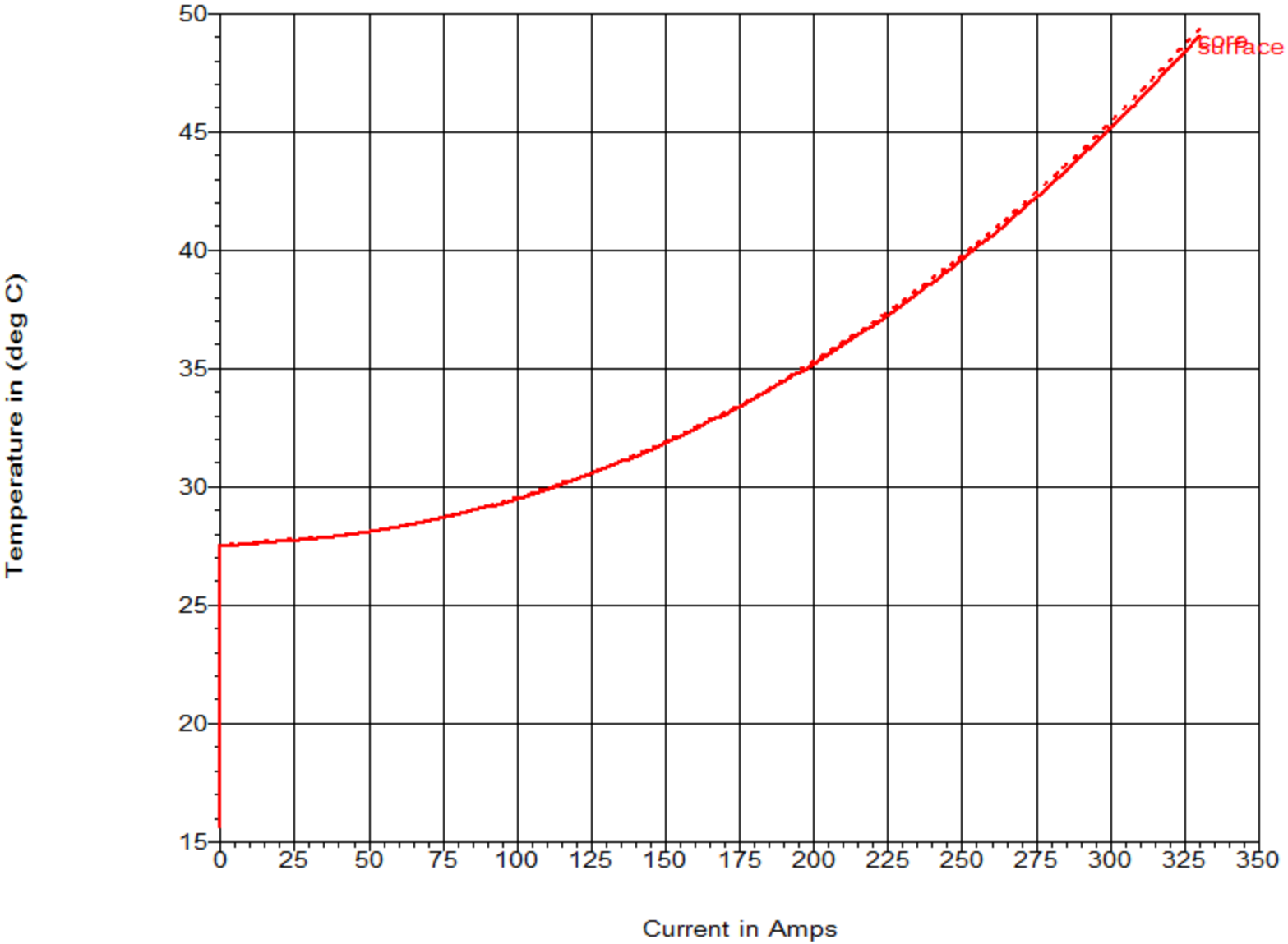
```
PLS-CADD Version 14.40x64    3:09:19 PM Tuesday, October 17, 2017
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 10.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                       and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m^2) - which was calculated)
Radiation cooling is    14.391 (Watt/m)
Convective cooling is   63.576 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),
The steady-state thermal rating is 500.1 amperes
```


Temperature in (deg C)
80
60
40
20
0
0
100
200
300
400
500
600
Current in Amps
core
surface

```
PLS-CADD Version 14.40x64    3:13:17 PM Tuesday, October 17, 2017
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 15.60 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                       and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m^2) - which was calculated)
Radiation cooling is     3.143 (Watt/m)
Convective cooling is   16.818 (Watt/m)

Given a constant ac current of 165.0 amperes,
The conductor surface temperature is 32.8 (deg C)
The conductor core temperature is 32.8 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))
```


35
30
25
20
15
0
20
40
60
80
100
120
140
160
180
surface
Temperature in (deg C)
Current in Amps

```
PLS-CADD Version 14.40x64    3:14:35 PM Tuesday, October 17, 2017
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 15.60 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                       and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m^2) - which was calculated)
Radiation cooling is     6.667 (Watt/m)
Convective cooling is   32.779 (Watt/m)

Given a constant ac current of 330.0 amperes,
The conductor surface temperature is 49.1 (deg C)
The conductor core temperature is 49.4 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))
```


Temperature in (deg C)
50
45
40
35
30
25
20
15
0
25
50
75
100
125
150
175
200
225
250
275
300
325
350
Current in Amps
core
surface

PLS-CADD Version 14.40x64 3:10:14 PM Tuesday, October 17, 2017
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

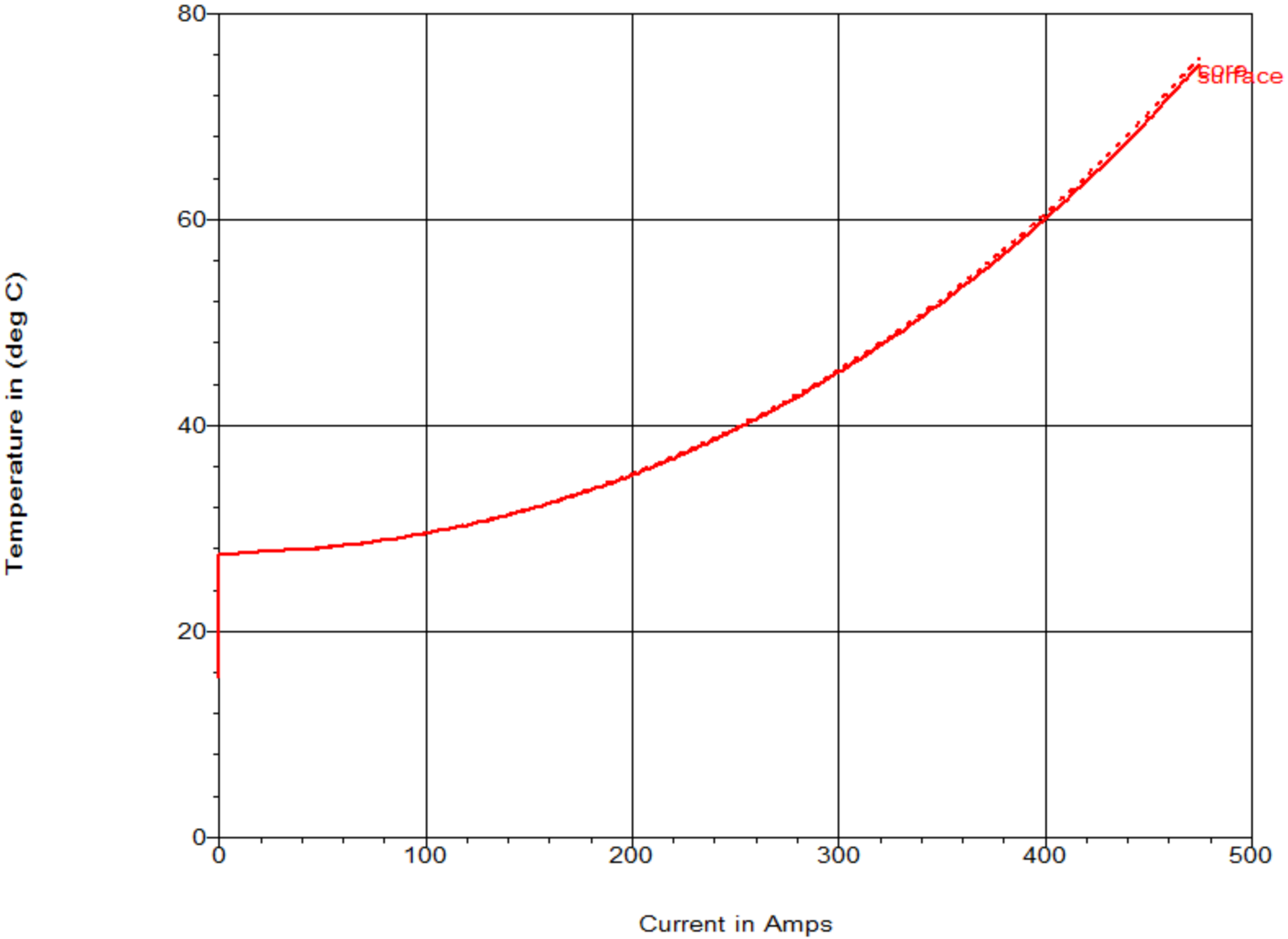
IEEE Std. 738-2012 method of calculation

Air temperature is 15.60 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

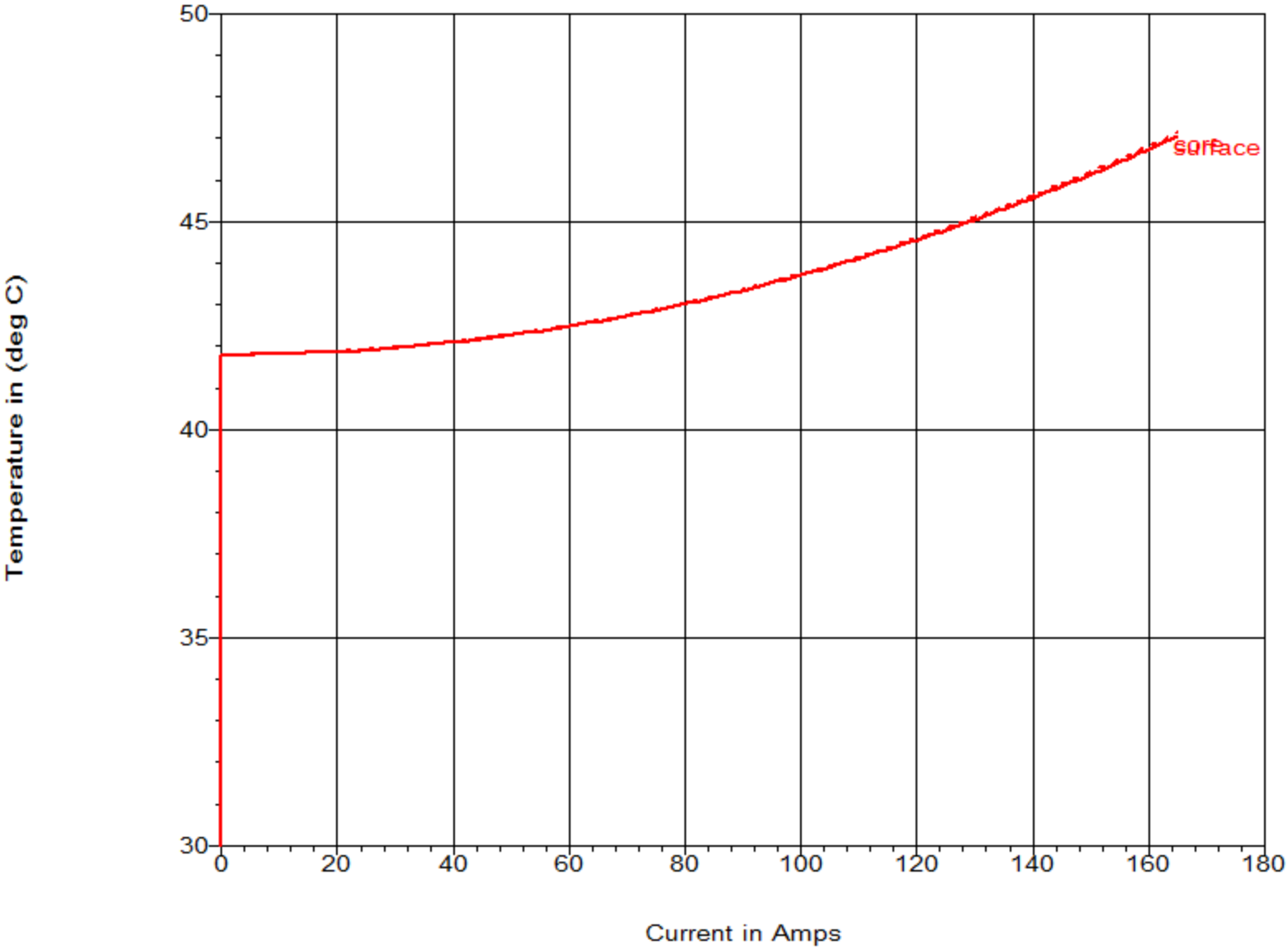
Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
  Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is 0.2136 (Ohm/km) at 25.0 (deg C)
  and 0.2556 (Ohm/km) at 75.0 (deg C)
  Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is 13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m^2) - which was calculated)
Radiation cooling is 13.479 (Watt/m)
Convective cooling is 58.082 (Watt/m)

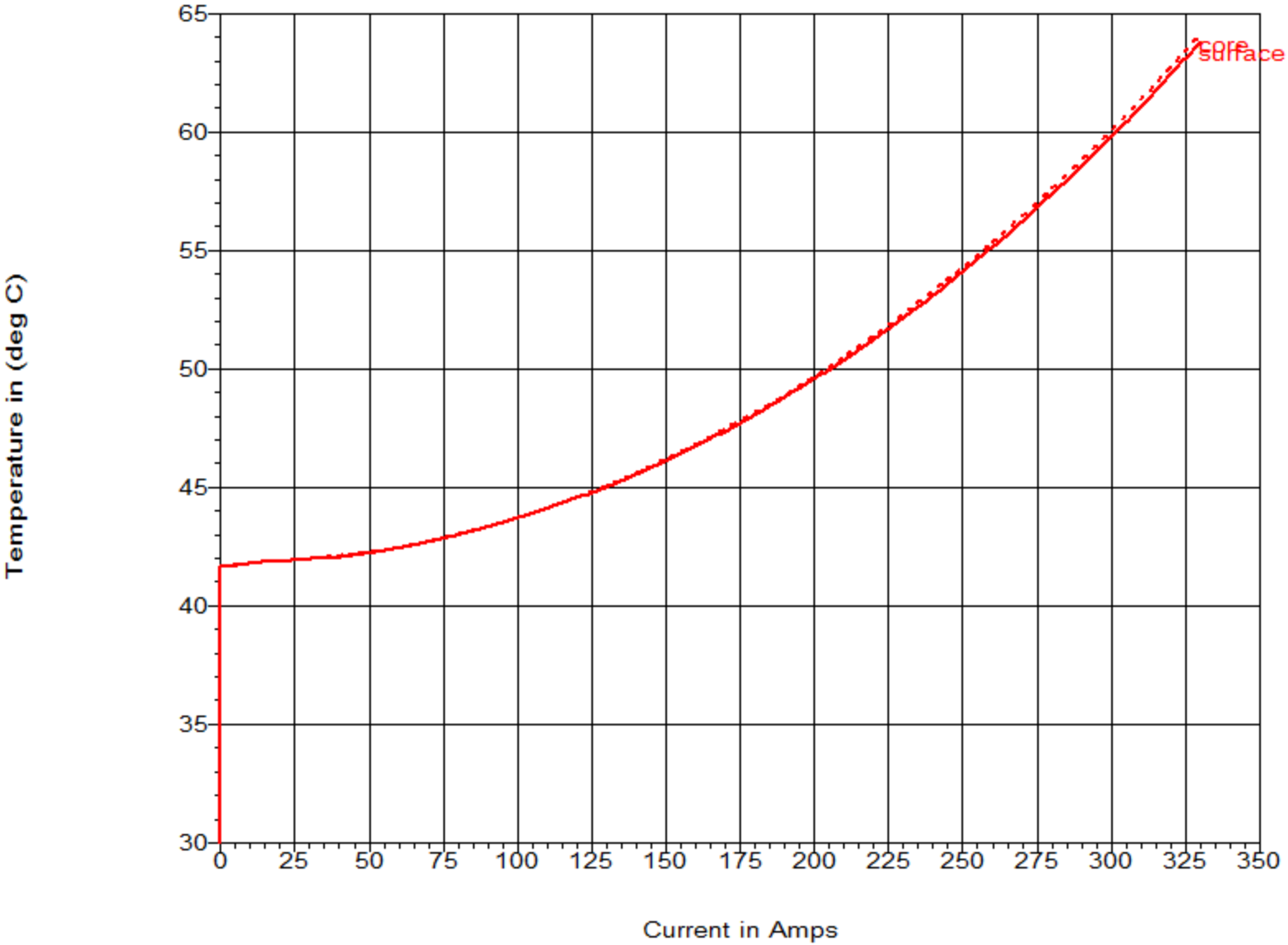
Given a maximum conductor temperature of 75.0 (deg C),
The steady-state thermal rating is 474.4 amperes


80
60
40
20
0
0
100
200
300
400
500
Temperature in (deg C)
Current in Amps
core
surface

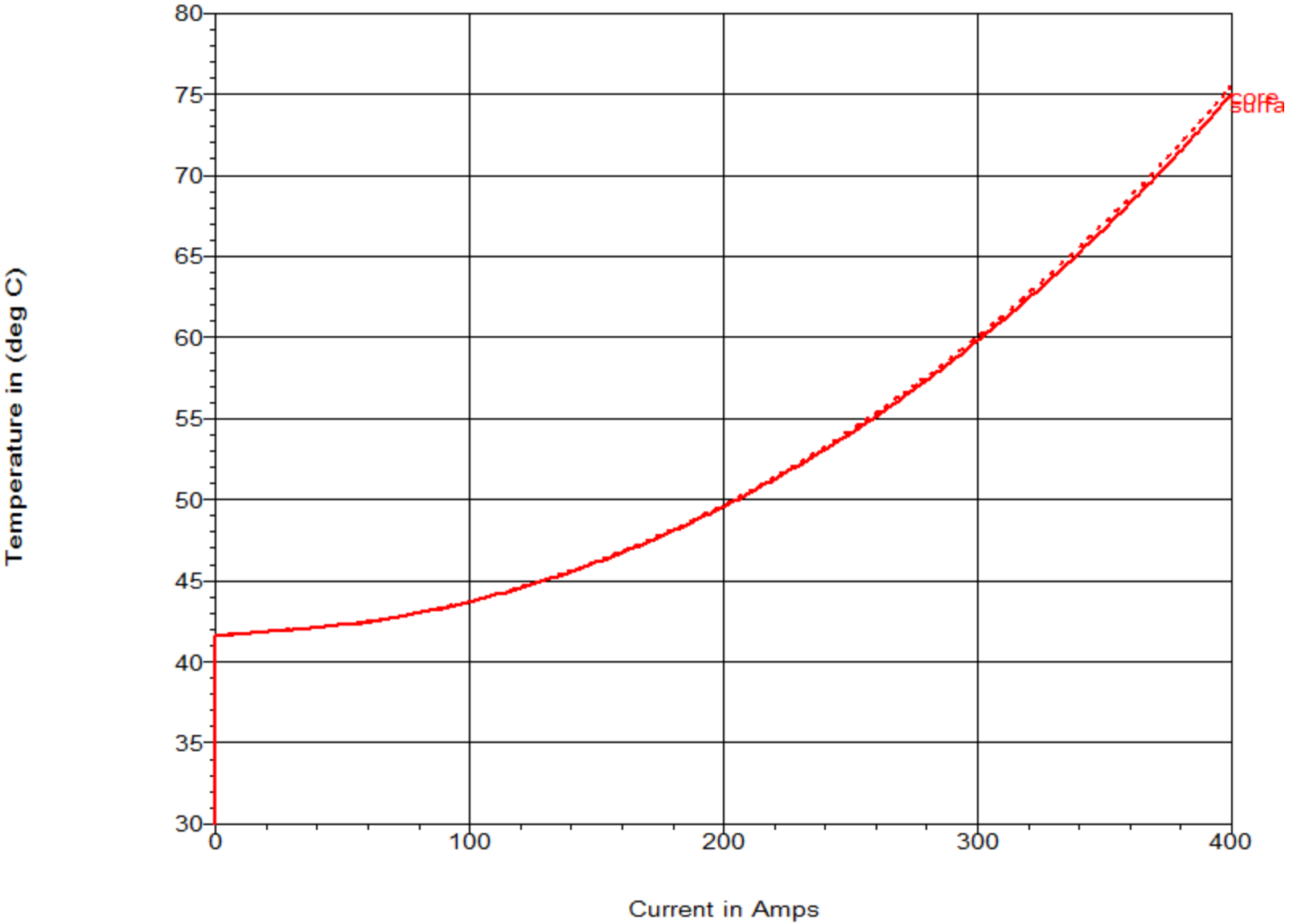
```
PLS-CADD Version 14.40x64    3:12:39 PM Tuesday, October 17, 2017
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 30.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                       and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m^2) - which was calculated)
Radiation cooling is     3.600 (Watt/m)
Convective cooling is   16.690 (Watt/m)

Given a constant ac current of 165.0 amperes,
The conductor surface temperature is 47.1 (deg C)
The conductor core temperature is 47.1 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))
```


50
45
40
35
30
0
20
40
60
80
100
120
140
160
180
surface
Temperature in (deg C)
Current in Amps

```
PLS-CADD Version 14.40x64    3:11:53 PM Tuesday, October 17, 2017
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 30.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                       and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m^2) - which was calculated)
Radiation cooling is     7.744 (Watt/m)
Convective cooling is   33.056 (Watt/m)

Given a constant ac current of 330.0 amperes,
The conductor surface temperature is 63.8 (deg C)
The conductor core temperature is 64.1 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))
```


Temperature in (deg C)
65
60
55
50
45
40
35
30
0
25
50
75
100
125
150
175
200
225
250
275
300
325
350
Current in Amps
core
surface

```
PLS-CADD Version 14.40x64    3:11:12 PM Tuesday, October 17, 2017
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2012 method of calculation

Air temperature is 30.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 1000 (m)
Conductor bearing is 248 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 11 hours (solar altitude is 51 deg. and solar azimuth is 158 deg.)
Conductor latitude is 61.0 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2017) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 0.000 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor AC resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                       and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     13.974 (Watt/m) (corresponds to Global Solar Radiation of 1071.190 (Watt/m^2) - which was calculated)
Radiation cooling is    10.878 (Watt/m)
Convective cooling is   43.973 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),
The steady-state thermal rating is 399.8 amperes
```


80
75
70
65
60
55
50
45
40
35
30
0
100
200
300
400
Temperature in (deg C)
Current in Amps
core
surfa

Appendix B – Canada Climate Normal Data

- Whitehorse
- Mayo

Climate Normals 1981-2010 Station Data

Metadata including Station Name, Province, Latitude, Longitude, Elevation, Climate ID, WMO ID, TC ID

STATION_NAME	PROVINCE	LATITUDE	LONGITUDE	ELEVATION	CLIMATE_ID	WMO_ID	TC_ID
WHITEHORSE A	YT	60°42'34.200" N	135°04'07.800" W	706.2 m	2101300	71964	YXY

Legend
A = WMO "3 and 5 rule" (i.e. no more than 3 consecutive and no more than 5 total missing for either temperature or precipitation)
B = At least 25 years
C = At least 20 years
D = At least 15 years

1981 to 2010 Canadian Climate Normals station data

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Temperature													
Daily Average (°C)	-15.2	-12.7	-6.3	1	7.3	12.3	14.3	12.6	7.2	0.5	-9.4	-12.5	-0.1
Standard Deviation	6.5	4.7	3.5	2.3	1.5	1.3	0.9	1.4	1.6	1.8	4.8	4.7	3.3
Daily Maximum (°C)	-11	-7.7	-0.7	6.6	13.5	19.1	20.6	18.5	12.1	4.2	-6	-8.5	5.1
Daily Minimum (°C)	-19.2	-17.6	-11.9	-4.6	1	5.6	8	6.7	2.1	-3.2	-12.9	-16.5	-5.2
Extreme Maximum (°C)	9	11.7	11.7	21.8	34.1	34.4	32.8	31.6	26.7	19.3	11.7	10.6	
Date (yyyy/dd)	1977/26	1968/27	1979/22	2002/30	1983/30	1969/14	1951/09	1999/05	1942/03	2003/03	1970/02	2004/23	
Extreme Minimum (°C)	-52.2	-51.2	-40.6	-29.4	-12.9	-2.8	-0.5	-4.4	-19.4	-31.1	-41	-47.8	
Date (yyyy/dd)	1947/31	1968/02	1972/08	1986/10	2002/03	1971/03	1984/19	1948/25	1983/27	1982/28	2006/27	1942/19	
Precipitation													
Rainfall (mm)	0.3	0	0	1.2	14.3	32.4	38.1	35.5	29	8.8	1	0.4	160.9
Snowfall (cm)	25.4	18.3	14.8	7.2	2	0	0	0.3	4.7	18.6	27	23.5	141.8
Precipitation (mm)	17.8	11.8	10.3	7	16.3	32.4	38.1	35.8	33.3	23.2	20.1	16.3	262.3
Average Snow Depth (cm)	22	27	23	8	0	0	0	0	0	2	10	15	9
Median Snow Depth (cm)	22	27	23	8	0	0	0	0	0	0	10	15	9
Snow Depth at Month-end (cm)	26	25	18	1	0	0	0	0	0	5	13	18	9
Extreme Daily Rainfall (mm)	3.4	0.8	0.8	4.4	12.6	44.9	23.2	30.7	24.6	18.3	9.4	4.2	
Date (yyyy/dd)	1981/03	1984/04	1944/15	1983/30	2000/26	1985/27	1991/27	1948/01	1983/04	1970/02	1949/03	1981/18	
Extreme Daily Snowfall (cm)	14	16.7	27.2	16.6	12.2	12.7	0	8.6	21.6	15	14.6	27	
Date (yyyy/dd)	1968/03	1982/09	1967/08	2006/14	1942/04	1972/01	1942/01	1974/22	1956/27	1999/23	1978/23	1980/25	
Extreme Daily Precipitation (mm)	9.5	10.4	10.4	15.8	12.6	44.9	23.2	30.7	25.2	23.6	11.4	18.7	
Date (yyyy/dd)	1994/17	1952/28	1962/07	2006/14	2000/26	1985/27	1991/27	1948/01	1986/23	1970/02	1955/06	1980/25	
Extreme Snow Depth (cm)	86	94	94	66	38	0	0	3	20	21	52	69	
Date (yyyy/dd)	1972/30	1972/16	1972/01	1967/13	1972/01	1955/01	1955/01	1969/11	1956/28	1982/31	1978/25	1980/29	
Wind													
Speed (km/h)	13.4	13.7	13.2	12.8	12.6	11.6	10.8	11.3	13.2	14.2	13.9	14.6	12.9
Most Frequent Direction	S	S	S	S	S	S	S	S	S	S	S	S	S
Maximum Hourly Speed (km/h)	72	68	64	60	64	56	63	52	72	63	68	72	72
Date (yyyy/dd)	1962/09	1957/15	1953/14	1966/09	1965/06	1965/16	1959/30	1998/29	1967/17	1961/28	1962/18	1954/17	1954/17
Direction of Maximum Hourly Speed	SE	S	S	N	S	SE	E	S	S	SE	SE	S	S
Maximum Gust Speed (km/h)	100	106	93	89	85	90	91	84	101	97	106	97	106
Date (yyyy/dd)	1965/17	1964/19	1965/10	1965/16	1965/02	1963/26	1982/07	1960/11	1967/18	1958/01	1962/18	1960/14	1962/18
Direction of Maximum Gust	S	S	SW	N	S	W	SE	SE	S	S	SE	SE	SE
Days with Winds >= 52 km/h	1.5	1.2	0.5	0.4	0.1	0.1	0.1	0.2	0.7	0.8	1.1	1.2	7.6
Days with Winds >= 63 km/h	0.2	0.3	0.1	0.1	0	0	0	0.1	0.1	0.1	0.1	0.1	1

1981 to 2010 Canadian Climate Normals station data (Frost-Free)

	Frost-Free:	Code					
Average Date of Last Spring Frost	5-Jun	C					
Average Date of First Fall Frost	25-Aug	C					
Average Length of Frost-Free Period	80 Days	C					
Probability of last temperature in spring of (	10%	25%	33%	50%	66%	75%	90%
Date	21-Jun	15-Jun	12-Jun	4-Jun	2-Jun	29-May	25-May
Probability of first temperature in fall of 0 °(	10%	25%	33%	50%	66%	75%	90%
Date	10-Aug	22-Aug	24-Aug	30-Aug	3-Sep	4-Sep	14-Sep
Probability of frost-free period equal to or l	10%	25%	33%	50%	66%	75%	90%
Days	60	66	73	85	91	95	102

Climate Normals 1981-2010 Station Data

Metadata including Station Name, Province, Latitude, Longitude, Elevation, Climate ID, WMO ID, TC ID

STATION_NAME	PROVINCE	LATITUDE	LONGITUDE	ELEVATION	CLIMATE_ID	WMO_ID	TC_ID
*MAYO A	YT	63°37'00.000" N	135°52'00.000" W	503.8 m	2100700	71965	YMA

* This station meets WMO standards for temperature and precipitation.

Legend
A = WMO "3 and 5 rule" (i.e. no more than 3 consecutive and no more than 5 total missing for either temperature or precipitation)
B = At least 25 years
C = At least 20 years
D = At least 15 years

1981 to 2010 Canadian Climate Normals station data

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Temperature													
Daily Average (°C)	-23.1	-17.9	-9.6	1	8.8	14.5	16.1	13.1	6.4	-2.7	-15.3	-19.9	-2.4
Standard Deviation	7.4	5.1	4.1	2.3	1.6	1.2	1	1.5	1.6	2.5	5.7	5.8	2.3
Daily Maximum (°C)	-18	-11.7	-2.9	7.2	15.2	21.4	22.8	19.5	12	1.2	-10.9	-14.7	3.4
Daily Minimum (°C)	-28.2	-24.1	-16.3	-5.2	2.2	7.5	9.4	6.7	0.9	-6.5	-19.7	-25.1	-8.2
Extreme Maximum (°C)	10.1	12.2	12.2	22.8	33.5	36.1	35.6	32.6	26.7	22.6	13.9	11.8	
Date (yyyy/dd)	1981/15	1968/27	1930/26	1976/29	1983/31	1969/14	1951/20	1999/06	1938/02	2003/03	1970/02	1999/23	
Extreme Minimum (°C)	-58.3	-62.2	-48.9	-41.1	-21.7	-3.9	-2.8	-10.6	-15.6	-36.7	-50.6	-57.8	
Date (yyyy/dd)	1947/28	1947/03	1951/05	1944/01	1964/11	2006/06	1928/23	1993/28	1946/28	1935/27	1950/26	1946/13	
Precipitation													
Rainfall (mm)	0.3	0	0.1	2.9	22.2	38.9	50.2	44.5	34.8	9.4	0.3	0.3	203.8
Snowfall (cm)	28.3	20.2	14.5	7.8	1	0.1	0	0.3	3.9	23	31.8	29.8	160.6
Precipitation (mm)	18.3	13	9.9	8.8	23.2	39	50.2	44.6	38.7	27	21.1	19.8	313.5
Average Snow Depth (cm)	31	38	34	15	0	0	0	0	0	3	14	23	13
Median Snow Depth (cm)	31	38	34	16	0	0	0	0	0	2	15	23	13
Snow Depth at Month-end (cm)	35	37	29	1	0	0	0	0	1	8	19	27	13
Extreme Daily Rainfall (mm)	4.2	0.3	14.5	20.3	25.4	34.6	29.2	31.8	23.6	12	6.6	5	
Date (yyyy/dd)	2009/20	1938/24	1947/17	1926/13	1939/26	2007/30	1976/14	1932/27	1959/19	1980/03	1947/22	1985/20	
Extreme Daily Snowfall (cm)	35.6	16.8	16	12.2	15	2.8	0	3.6	24.9	25.6	21	15.7	
Date (yyyy/dd)	1949/09	1974/07	1939/18	1964/01	1964/09	1992/07	1925/01	1984/28	1970/21	1982/25	2003/22	1958/15	
Extreme Daily Precipitation (mm)	35.6	16.5	16	21.6	25.4	34.6	29.2	31.8	23.6	22.4	16.3	15.7	
Date (yyyy/dd)	1949/09	1965/12	1939/18	1928/29	1939/26	2007/30	1976/14	1932/27	1959/19	1958/04	1966/04	1958/15	
Extreme Snow Depth (cm)	81	109	117	94	28	0	0	0	20	41	64	71	
Date (yyyy/dd)	2004/19	1967/24	1967/04	1967/01	1964/01	1934/18	1955/01	1955/01	1993/26	1982/26	1956/20	1958/31	
Wind													
Speed (km/h)	5	6.2	9.3	8.8	8	6.3	5.3	5.1	6.2	7.9	6.1	5.3	6.6
Most Frequent Direction	N	N	N	N	N	N	N	N	N	N	N	N	N
Maximum Hourly Speed (km/h)	42	43	42	56	42	64	42	50	43	72	43	50	72
Date (yyyy/dd)	1973/01	1979/02	1966/28	1965/18	1965/25	1961/12	1961/13	1984/26	1977/22	1962/27	1978/26	1998/26	1962/27
Direction of Maximum Hourly Speed	N	N	NE	NE	SW	S	W	N	N	S	N	N	S
Maximum Gust Speed (km/h)	69	74	65	126	70	117	65	74	65	67	67	61	126
Date (yyyy/dd)	1981/19	1986/26	1994/04	2002/20	1985/31	1998/14	1985/01	1998/02	1977/22	1989/07	1999/01	1980/14	2002/20
Direction of Maximum Gust	S	S	SE	W	E	E	W	S	N	S	SW	S	W

1981 to 2010 Canadian Climate Normals station data (Frost-Free)

	Frost-Free:	Code					
Average Date of Last Spring Frost	26-May	C					
Average Date of First Fall Frost	26-Aug	C					
Average Length of Frost-Free Period	91 Days	C					
Probability of last temperature in spring of 0	10%	25%	33%	50%	66%	75%	90%
Date	23-Jun	12-Jun	8-Jun	1-Jun	28-May	25-May	18-May
Probability of first temperature in fall of 0 °C	10%	25%	33%	50%	66%	75%	90%
Date	29-Jul	5-Aug	13-Aug	19-Aug	25-Aug	28-Aug	3-Sep
Probability of frost-free period equal to or le	10%	25%	33%	50%	66%	75%	90%
Days	47	62	65	72	85	90	104

Chimax Inc.

TRANSMISSION LINE PRELIMINARY DESIGN REPORT

STEWART TO KENO TRANSMISSION PROJECT
138 kV TRANSMISSION LINES

YUKON ENERGY

Yukon Energy Corporation

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PERMIT TO PRACTICE
CHIMAX INC.
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Date Mar 8, 2016
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Association of Professional Engineers of Yukon

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1.0 Project Overview

Yukon Energy Corporation (YEC) is proposing to construct a 138kV transmission line from Stewart Crossing South (SCS) substation to Keno City (KC) substation. The overall transmission line and associated substation construction or modification is grouped as SKTL project.

1.1 Project Descriptions

The proposed 138kV transmission line route originates and travels north from SCS substation (S251) generally parallel to the existing L175 138kV transmission line to a point north of Stewart Crossing North (SCN). At this point the route turns east and parallels the existing L176 69kV transmission line to Mayo substation (S249). The transmission line will turn northeast and parallel the existing L250 69kV transmission line to KC substation (S257). A new substation (S258) will be constructed north of Halfway Lakes to step down voltage from 138kV to 69kV. The transmission line from S258 to S257 will be constructed for 138kV and energized at 69kV.

The existing L176 and L250 69kV transmission right of way is 60m wide which should accommodate 2 (two) parallel transmission line circuits.

The preliminary design will assess deviations from the YEC primary proposed route due to land use conflicts, environmental restriction, construction and maintenance access, geological restriction, etc.

1.2 Design Codes and Regulations

The design of the 138kV transmission line will be based on both deterministic approach as per CSA C22.3 No.1 (C22.3 No.1) “Overhead System” and reliability approach as per CSA C22.3 No.60826 (C22.3 No.60826) “Design Criteria of Overhead Transmission Lines”.

The conditions outlined in CSA C22.3 No.1 are minimum design requirements for both transmission and distribution overhead lines.

CSA C22.3 No.60826 outlines additional extreme weather conditions and design requirements for transmission line voltage exceeding 70kV (phase – phase voltage) as recommended in CSA C22.3 No.1 Section 10.

YEC had specified the design of SKTL transmission lines to comply with Alberta Electrical Utility Code (AEUC) in addition to CSA code requirements. Chimax has also reviewed and incorporated the relevant information and guidelines outlined in the Alberta Electrical System Operator (AESO) ISO Rules Section 502.2 “Bulk Transmission Line Technical Requirements”.

The complete design criteria document (1513-DBM-0001) is provided in Appendix B.

2.0 SKTL Transmission Line Descriptions

2.1 L179 138kV TL – Stewart Crossing South Substation (S251) to Mayo Substation (S249)

The existing Stewart Crossing North substation is connected to Stewart Crossing South via L175 69kV H-frame configuration transmission line designed and built for 138kV operation and connected to Mayo substation (S249) via 69kV mono pole cross-arm transmission line. The proposed L179 138kV transmission line will run parallel to existing L175 and L176 transmission lines with nominal circuit separation of 20m.

The preliminary design of L179 is used to evaluate and finalize the proposed alignment for environmental permitting. The L179 design is also used as the baseline scenarios in comparing the fiber-optic cable configuration. The conductor size comparison between YEC current standard conductors are also performed during the preliminary design of L179.

2.2 L180 138kV TL – Mayo Substation (S249) to McQuesten Substation (S258)

The proposed L180 138kV transmission line will be replacing the existing L250 69kV transmission circuit line between Mayo substation and the proposed McQuesten substation. The existing L250 follows old highway alignments and crosses over the current highway in multiple locations while certain portions of the line are some distance from the highway right of way. The proposed L180 alignment will be parallel the existing L250 alignment with realignment to bring the new transmission line closer to the current highway alignment.

The proposed L180 is designed with H-Frame configuration with OPGW and shieldwire for fiber optic communication and lightning protection. As an alternative to supplying local service using 138kV potential transformer (P.T.) platform substation, mono framings with 25kV distribution underbuilt is also considered for cost comparison.

2.3 L250 69kV TL – McQuesten Substation (S258) to Keno Substation (S257)

The proposed L250 69kV transmission line rebuild will parallel the existing circuit to replace an existing aging mono pole line. The proposed transmission line will be designed and constructed for 138kV system and will be operating at 69kV.

Due to restricted right of way expansion around Keno City, the proposed transmission line will change from H-Frame configuration to mono pole configuration when the line exits Galena Hill and enters the Keno City boundary.

2.4 McQuesten Substation (S258 By-pass)

To improve reliability of the power supply to Keno City, an alternative emergency connection of L180 to Mayo 69kV system will be implemented. Existing L250 69kV transmission line structures at Mayo and structures adjacent to the new McQuesten substation will be modified to provide connections to by-pass McQuesten 138 / 69kV transformer and supply power to Keno City from Mayo substation.

3.0 Transmission Line - Design Parameter Comparisons

3.1 Fiber Optic Cable Configuration

On power lines, fiber communication is typically integrated into two types of applications: Optical Ground Wire conductor "OPGW" and All-Dielectric-Self-Supported conductor "ADSS".

OPGW offers the dual function of protection from lightning and short-circuit and of high capacity fiber communication. It has a high reliability because fibers are housed within the armor of the ground wire strands. OPGW installation and operation resembles those of conventional bare wires on power lines. Location of OPGW is at top of structure replacing the conventional ground wire.

ADSS is a fiber communication medium protected by a dielectric jacket typically installed below phase conductors. Challenges to ADSS are larger creep at heavy ice loading, limited strength for long span and vulnerability to UV and "tracking damages" due to surface gradient in very high voltage environment. Physical vertical clearance to ground and to conductors will still require an allowance of additional structure heights. When height is suitable, ADSS is best for retrofit situations and live line installations.

From a cost point of view, ADSS is cheaper than OPGW. This cost difference and its percentage shrinks when we include installation cost and as the fiber count increases. A final overall cost difference can be 10% or lower.

OPGW is recommended for new installation and its inherent added reliability while ADSS is recommended for short span, retrofit live line conditions.

3.2 Conductor Size Comparison

Standard YEC 138kV transmission line utilizes 266.8 MCM 26/7 ACSR (Partridge). Alternative conductor used in the YEC transmission network is 397.5 MCM 26/7 ACSR (Ibis). The Carmack to Stewart 138kV transmission line (CSTL) utilized 336.4 MCM 26/7 ACSR (Linnet) as long crossing spans conductors.

YEC has not reported any electro-magnetic field issues regarding operating 266.8 MCM ACSR on its 138kV transmission line. However, the minimum recommended conductor size for 138kV transmission line by US Rural Utilities Service (RUS) Design Manual is 336.4 MCM ACSR to minimize surface potential gradient.

For provision to future load growth and electro-magnetic field consideration, the larger YEC standard conductor 397.5 MCM ACSR has been used for structure loading calculations and cost estimations.

Based on Southwire standard published unit cost data, prior to volume discount and baseline currency exchange of 0.75, the unit conductor costs are estimated as follows:

Conductor	US$/km	CAD$/km
266.8 MCM ACSR (Partridge)	$4020.00	$5360.00
336.4 MCM ACSR (Linnet)	$4690.00	$6253.00
397.5 MCM ACSR (Ibis)	$5340.00	$7120.00

The conductor costs used in the transmission line cost estimates are based on volume discount of 0.8 to provide a conservative project estimate to allow for currency and metal index variations.

3.3 L180 Distribution Service Supplies

Existing distribution service supplies between Mayo and Halfway Lake utilize 69,000V/120V pole mount transformer at service locations. Future 138kV transmission voltage would require platform Potential Transformer PT substation(s) to provide distribution services. The standard estimated cost for a 138 kV PT substation is approximately $250,000.00 per location.

Alternatively, distribution underbuilt from Mayo to Halfway Lake has also been considered. This option would allow future supply of service along the transmission line route without high capital costs.

4.0 Basis of Cost Estimate

4.1 Final Design & Field Service Cost

The transmission line final design cost is estimated based on a unit cost of $6,000.00 per km to reflect the typical engineering hours required for lines of these lengths. If all 3 lines are to be designed under a single engineering contract, the unit rate should decrease by 20 to 25%.

In addition to the transmission line design cost, other field and permit costs should also be considered:

1. Environmental Assessment
2. Vegetation Clearing Permits
3. Crossing Permits (Roads and Water bodies)
4. Land Registrations

Since some of the transmission line alignments are different from the existing right of way, $200,000 has been included for land registration and other land matters.

Other field service costs have not been included in the transmission line estimates as these items will be considered as a YEC planning cost.

4.2 Transmission Corridor Preparations

4.2.1. Vegetation Clearings

The transmission line right of way (ROW) corridor widths are determined based on the preliminary line structure spotting and selected structure configurations. The 138kV H-frame structures with the standard span of 180m will require a minimum right of way of 25m. The 138kV mono pole structures with span of 100m will require a minimum right of way of 18m. These right of way widths are based on minimum electrical clearance.. Standard YEC 138kV right of way is typically cleared for 30m wide.

Vegetation clearing boundaries had been prepared based on the minimum requirements along with the required additional guy anchor clearings. Vegetation clearing areas are extracted as the base line requirements.

The proposed transmission lines are typically located 20m from the existing L176 and L250 transmission lines. Based on the existing transmission line ROW being cleared for 30m, the actual required clearing width could be reduced by 7.5m for H-frame and 4m for mono pole.

Due to geotechnical limitations, such as permafrost and wetland, the vegetation clearing operation is preferred to be performed during winter months. The unit cost associated with vegetation clearing for these transmission lines will be higher than typical due to this environment constraint.

The cost of vegetation clearing in CSTL was approximately $10,000 per hectare which included construction of access roads.

4.2.2. Access Road Entrance Preparation

Primarily, the proposed transmission line route follows the existing transmission line right of way with only a few locations where it has been realigned to parallel the existing highway.

Access road entrances will predominantly be the existing entrances with a limited number of new access points being proposed. Since the maintenance of the existing transmission line occurred regularly, there will be minimal entrance improvements required for construction.

4.2.3. Access Road Entrance Preparation

The cost of vegetation clearing in CSTL was an average of $10,000 per hectare which included access road entrance preparation. However, the final cost was reported by the contractor to be less than satisfactory. For SKTL, an estimate of $13,000 per hectare ($39,000/km) was used for the vegetation clearing and access entrance improvements. The estimated cost is conservative due to the geotechnical nature of the line route.

4.3 Material Procurements

Detailed conductor assembly and framing drawings of the proposed transmission line structures have been prepared for the preliminary design. The material costs are separated into 5 categories:

4.3.1. Insulator Assemblies

YEC prefers toughened glass insulator strings for the proposed transmission lines. Unit cost of the toughened glass insulator had been solicited from Sediver based on projected requirements.

Insulator Type	Attachment	Unit Cost
N70/146	Tangent & Running	$22.50 / disc
N12/146	Deadend	$25.00 / disc

The number of discs per insulator string varies from 7 to 10 dependent on the pollution level of the area. The preliminary design and cost estimates are based on 10 discs per string for conservative estimation.

Alternatively, polymer insulators were employed for mono pole structures. The costs of 138kV braced post insulators for tangent structures and strain insulators for running and deadend structures were based on actual project procurement costs of current transmission line construction projects.

Insulator Type	Attachment	Unit Cost
Braced Post	Tangent & Running	$415.00 / Assembly
Strain Insulator (UTS 30Kip)	Deadend	$78.00

Alternatively, other utilities have adopted using toughened glass suspension insulators for H-frame structures while employing polymer insulators for their deadend supports.

4.3.2. Cable Attachments

Conductor, shieldwire and OPGW attachment costs are calculated according to attachment drawings. Individual hardware cost is based on actual procurement costs of current transmission line construction projects.

4.3.3. Wood Poles

The preliminary design of the SKTL with H-frame and mono pole framing configurations resulted in poles ranging from 55ft CL3 to 115ft H2. The wood pole cost is based on data compiled from project procurements and quotations over the last two years. The wood pole costs range from $900.00 to $7,750.00 per pole.

4.3.4. Guying and Anchoring

Guying material costs are estimated based on standard helical anchor and log anchor with an average estimate of $1,500.00 per guy. Additional pole anchoring and guying material costs for swamp and bedrock are estimated based on a percentage of structures being located in these areas. The additional cost adder ranged from $1,500.00 to $3,500.00 per structure.

4.3.5. Miscellaneous Items

Additional miscellaneous items (such as aerial markers, structure markers, fiber optic splices etc.) are also included in the estimates.

4.4 Construction Cost

The construction cost of transmission line in Canada has been increasing during the last 5 years due to high demand in Alberta, Ontario and the Maritimes.

The average transmission line labor rate from several national transmission line contractors is approximately $105 per hour. Based on 10 hours work day, the adjusted labor rate used in the cost assessment is set at $125 per hour including expenses. Based on previous CSTL transmission line cost and labor hour information, the SKTL construction costs are calculated based on the hours required per structure type times the adjusted labor rate. The calculated unit installation cost for each structure type has also been compared with 2010 CSTL pricing with 5% annual inflation.

The conductor and OHGW/OPGW setup and stringing costs are based on CSTL unit costs with 5% annual escalation. The unit costs are as follows:

Cable Type	Unit Cost /km
Conductor	$17,000.00
3/8” EHS Steel OHGW	$13,000.00
OPGW	$20,000.00

The guy and anchor installation cost is based on assigned unit cost. The base cost is assigned using helical / log anchor materials and installation. Additional costs for rock anchor and swamp are based on estimated percentage of the lines.

4.5 Construction Project Management

The construction project management represents the owner engaged subcontractor for transmission line construction management and site inspection. The site service cost is based on the following factors:

- Anticipated duration (months) for vegetation clearing
- Anticipated duration (months) for line construction and demolition
- Construction schedule (hour/day and day/week)
- Number of site personnel required for each construction activities
- Unit cost per site personnel ($150.00/hour)
- Daily expense per site personnel ($600.00/day)
- Number of construction site offices

5.0 Recommendations & Conclusions

The transmission line cost estimates were calculated based on the preliminary line designs and cost parameters as outlined in the previous sections.

In additional to the estimated engineering services, environmental and permit supports, procurement and construction costs, a 15% contingency cost has been included to allow for changes in the final design, unforeseen issues and future escalation.

Per direction from YEC, there are no owner financing costs included in the transmission line cost estimates.

The individual transmission line cost breakdowns are listed in Appendix C. The transmission line estimated budgetary costs are summarized as follows:

Transmission Line	Item	Line Configuration	Base Estimate	15% Misc. Allowance
L179 S251 to S249 (54.2 km)	1A	138kV H-Frame with OPGW	$25,000K	$3,750K
	1B	138kV H-Frame with ADSS (no OHGW)	$23,885K	$3,583K
L180 S249 to S258 (31.1 km)	2A	138kV H-Frame with OPGW (Mono Poles at Restricted ROW Locations)	$13,423K	$2,014K
L250 S258 to S257 (20.2 km)	3A	138kV H-Frame with OPGW (Mono Poles at Restricted ROW Locations)	$9,660K	$1,449K

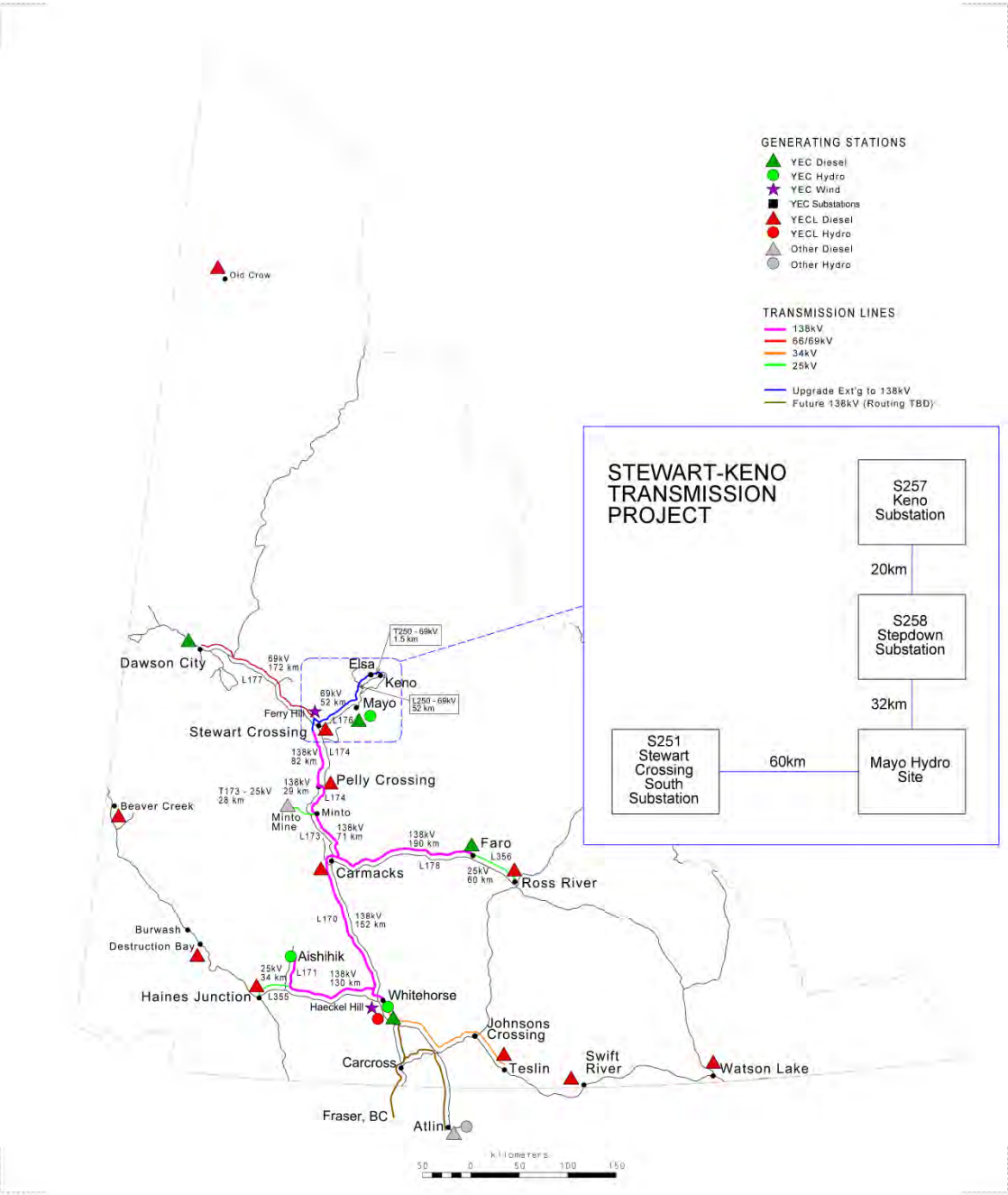
The cost differential between ADSS fibre optic and OPGW fibre optic configuration is mainly due to the additional shieldwire installation for the OPGW scenario. The OPGW configuration provides lightning protection for the transmission line in addition to fibre optic communication.

The overall project cost comparisons between Mono Pole and H-Frame transmission structures has been evaluated in the Extension Scope Report.

The estimated transmission line costs were calculated individually for each of the transmission line segments. For existing L250 replacement cost, please refer to Extension Scope Report for additional details.

Appendix A – Site Location Plan

Appendix A - GEOGRAPHICAL MAP OF THE PROPOSED TRANSMISSION LINE



Appendix B – Design Criteria Document

Chimax Inc.

TRANSMISSION LINE DESIGN CRITERIA

STEWART TO KENO TRANSMISSION PROJECT
138 kV TRANSMISSION LINES

Yukon Energy Corporation

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1.0 Project Overview

Yukon Energy Corporation (YEC) is proposing to construct a 138kV transmission line from Stewart Crossing South (SCS) substation to Keno City (KC) substation. The overall transmission line and associated substation construction or modification is grouped as SKTL project.

1.1 Project Descriptions

The proposed 138kV transmission line route originates and travels north from SCS substation (S251) generally parallel existing L175 138kV transmission line to a point north of Stewart Crossing North (SCN). At this point the route turns east and parallels the existing L176 69kV transmission line to Mayo substation (S249). The transmission line will turn northeast to parallel the existing L250 69kV transmission line to KC substation (S257). A new substation at McQuesten (S258) will be constructed north of Halfway Lakes to convert voltage from 138kV to 69kV. The transmission line from S258 to S257 will be constructed for 138kV and energized at 69kV.

The existing L176 and L250 69kV transmission right of way is 60m wide which should accommodate 2 (two) parallel transmission line circuits.

The preliminary design will assess deviations from the YEC primary proposed route due to land use conflicts, environmental restriction, construction and maintenance access, geological restriction, etc.

1.2 Design Codes and Regulations

The design of the 138kV transmission line will be based on both deterministic approach as per CSA C22.3 No.1 (C22.3 No.1) “Overhead System” and reliability approach as per CSA C22.3 No.60826 (C22.3 No.60826) “Design Criteria of Overhead Transmission Lines”.

The conditions outlined in CSA C22.3 No.1 are minimum design requirements for both transmission and distribution overhead lines.

CSA C22.3 No.60826 outlines additional extreme weather conditions and design requirements for transmission line voltage exceeding 70kV (phase – phase voltage) as recommended in CSA C22.3 No.1 Section 10.

YEC has specified the design of the SKTL transmission lines to comply with Alberta Electrical Utility Code (AEUC) in addition to CSA code requirements. Chimax will also review and incorporate the relevant information and guidelines outlined in the Alberta Electrical System Operator (AESO) ISO Rules Section 502.2 “Bulk Transmission Line Technical Requirements”.

In addition to the Canadian overhead line design code, additional design codes and regulations will be followed for each transmission line component design. A full list of design codes and regulations is provided in Appendix B.

2.0 Equipment and Material Descriptions

2.1 Cable Descriptions

The 138kV phase conductors, optical fiber cable and overhead grounding wire (OHGW).

2.1.1. 138kV Phase Conductor

The YEC standard phase conductor for the proposed 138 kV transmission lines is 266.8MCM 26/7 ACSR (Partridge). Alternatively, 397MCM 26/7 ACSR (Ibis) had also been used on few YEC transmission lines. Based on future load growth and cost estimate consideration, 397.5 MCM 26/7 ACSR (Ibis) was used as benchmark phase conductor. Comparison of structural requirement between the two conductors are also performed.

The general mechanical and electrical properties of 266.8 MCM 26/7 ACSR (Partridge) and 397.5 MCM 26/7 ACSR (Ibis) are listed in Table 2.1.1.

Table 2.1.1

Mechanical Properties								
Conductor	**Conductor Size**		**Stranding No. x Dia. (in)**		**O.D. (in)**	**Nominal Mass (lb/1000 ft)**	**Rated Strength**	
	MCM	**mm^2**	**Al**	**Steel**			**(lbf)**	**(kN)**
266.8 MCM ACSR (Partridge)	266.8	135.2	26x0.1013	7x0.0788	0.642	366.0	11300	50.3
397.5 MCM ACSR (Ibis)	397.5	201.4	26x0.1236	7x0.0961	0.783	545.0	16100	71.6
Electrical Properties								
Conductor	**Cross Section Area (in^2)**		**Resistance (ohms/ 1000ft)**			**GMD (ft)**	**Inductive Reactance (ohms/1000ft)**	**Capacitive Reactance (Mohms/1000ft)**
	Total	**Al**	**DC @20°C**	**AC @25°C**	**AC @75°C**			
266.8 MCM ACSR (Partridge)	0.2437	0.2095	0.0651	0.0665	0.0796	0.0217	0.0880	0.5673
397.5 MCM ACSR (Ibis)	0.3630	0.3123	0.0437	0.0447	0.0535	0.0265	0.0835	0.5361

2.1.2. Optical Fiber Cable

YEC will install optical fiber communication cable along proposed transmission line to improve existing protection and control communication. Standard installation of optical fiber cable on new transmission line will utilize optical grounding wire (OPGW). The current YEC 138kV transmission line standard does not utilize any lightning protection wire. Chimax has evaluated both optical cable communication underbuilt, all dielectric self-support (ADSS) and compared it to the OPGW configuration.

Table 2.1.2 – OPGW Properties

Electrical and Mechanical Properties							
OPGW Size	**Fibers (max)**	**Fault Current $(kA)^2s$**	**Cross Section Area (in^2)**	**O.D. (in)**	**Nominal Mass (lb/ft)**	**Rated Strength**	
						(lbf)	**(kN)**
SFPOC/SFSJ-J-10783	48	63	0.1474	0.496	0.356	18454	82.0

The final selection of OPGW will depended on the long-term forecast fault current levels and ground resistivity along the transmission line route.

Due to relative long span and restricted cable sag of ADSS cable required for the proposed transmission line, technical information is not available as standard information. Manufacturer had only confirmed the following parameters at this time.

Table 2.1.3 – ADSS Properties

Electrical and Mechanical Properties							
ADSS Size	**Fibers (max)**		**Cross Section Area (in^2)**	**O.D. (in)**	**Nominal Mass (lb/ft)**	**Rated Strength**	
						(lbf)	**(kN)**
OFS ADSS	48		0.2186	0.527	T.B.C.	T.B.C.	T.B.C.

Overhead Shield Wire (OHGW)

For H-Frame with two shieldwire configuration and lightning protection within 1 km of any station for other configuration, the overhead ground wire (OHGW) for the proposed transmission line will be based on existing shieldwire used in existing YEC transmission lines.

Table 2.3 – OHGW Properties

Mechanical Properties							
Cable Size	**Stranding No. x Dia. (in)**	**O.D. (in)**	**Cross Section Area (in^2)**	**Resistance (ohms/ 1000ft) @20°C**	**Nominal Mass (lb/1000ft)**	**Rated Strength**	
						(lbf)	**(kN)**
3/8" EHS Galv. Steel	7x0.1819	0.546	0.182	0.2264	524.9	27030	120.1

2.2 Insulator and Configuration

The preferred suspension insulators for standard 138kV H-Frame tangent and running angle structures shall be toughened glass suspension insulators. The Mono wood pole alternative shall employ a braced post insulator configuration for tangent structures.

The default deadend insulators shall be toughened glass strain insulators. Alternatively, polymeric strain insulator will be considered in the cost evaluation. (SaskPower standard H-Frame utilize glass insulators for suspension / running angle structures and polymer strain insulators for deadend application)

The electrical and mechanical properties of individual toughened glass insulators are given in Table 2.2.1.

Table 2.2.1 – Toughen Glass Suspension & Strain Insulator Properties

Mechanical & Electrical Properties							
Insulator Description	**Diameter (in) [mm]**	**Leakage Distance (in) [mm]**	**Tensile Strength (lbf) [kN]**	**Low Frequency Flashover**		**Critical Impulse Flashover**	
				Dry (kV)	**Wet (kV)**	**Positive (kV)**	**Negative (kV)**
Sediver N70/146	10 [255]	12 5/8 [320]	15000 [70]	80	50	125	130
Sediver N12/146	10 [255]	12 5/8 [320]	25000 [120]	80	50	125	130

The minimum insulation level for 138kV transmission line depends upon the critical impulse flashover and the pollution levels along the transmission line area. For 138kV transmission line, the maximum phase to phase voltage shall be 145kV and phase to ground voltage of 84kV. Table 2.2.2 summarized the insulation criteria and minimum insulator requirement for 138kV transmission line.

Table 2.2.2 – Minimum Insulator Requirement

	Pollution Level			
	Very Light	Light	Medium	Heavy
Critical Impulse Flashover (kV)	715			
No. of Insulators	6			
IEC 60815 Leakage Distance (mm/kV)	22.0	27.8	34.7	43.3
Minimum Leakage Distance (mm)	1848	2336	2915	3638
No. of Insulators	6	7.3	10	12
Recommended No. of Insulators	7	8	10	12

Typical recommended minimum leakage distance in manufacturer catalogue is based on 25mm/kV which will be 7 strings insulator and is consistent with existing YEC specification.

For the preliminary design of the SKTL, 8 strings insulator will be used for the majority of the 138kV H-Frame structures. For structures located on Galena Hill and Keno where pollution levels are expected to

be higher, 10 string insulators will be utilize. The preliminary designs and cost estimates will be based on 10 strings insulators to allow flexibility in final transmission line design.

The proposed polymer insulators electrical and mechanical properties are outlined in Table 2.2.3 and Table 2.2.4.

Table 2.2.3 – Polymer Suspension & Strain Insulator Properties

Mechanical & Electrical Properties							
Insulator Description	**Section Length (in) [mm]**	**Leakage Distance (in) [mm]**	**Tensile Strength (lbf) [kN]**	**Low Frequency Flashover**		**Critical Impulse Flashover**	
				Dry (kV)	**Wet (kV)**	**Positive (kV)**	**Negative (kV)**
NGK-Locke 251-SC410-YJ	60 [1525]	114.6 [2911]	25000 [111]	525	465	815	865
NGK-Locke 301-SC450-YJ	66.3 [1685]	125.8 [3195]	30000 [133]	570	505	890	940

Table 2.2.4 – Braced Post Insulator Properties

Mechanical Properties					
Insulator Description	**Maximum Design Loads**				**Dimensions**
	Vertical Load (lbf)	**Long. Load (lbf)**	**Tension Load (lbf)**	**Comp. Load (lbf)**	**Length (in) [mm]**
NGK-Locke HV-556	10000	1375	7500	7500	64.0 [1625]
Electrical Properties					
Insulator Description	**Leakage Distance (in) [mm]**	**Low Frequency Flashover**		**Critical Impulse Flashover**	
		Dry (kV)	**Wet (kV)**	**Positive (kV)**	**Negative (kV)**
NGK-Locke HV-556	148.8 [3780]	545	475	820	890

2.3 Structure Material and Configuration

The proposed 138kV transmission lines shall be YEC standard H-Frame structures along with alternative mono wood pole structures.

Currently, the baseline design will be based on wood poles H-Frame configuration utilizing toughened glass suspension insulator for tangent and light angle structures. Where right of way is restrictive, mono wood pole configuration will be used. The mono wood pole tangent and light angle shall be braced post triangular configuration with top and bottom phases on one side and middle phase on opposite side. Mono wood pole angle and dead end structures shall be vertically framed with guying.

As per previous Carmack to Stewart transmission line (CSTL), the minimum pole class shall be Class 3 to provide reliability and facilitation of pole climbing during maintenance.

2.4 Foundation Configuration

For H-Frame configuration, all wood poles shall be direct embedded with standard 10% pole length plus 0.610m (2ft) embedment. Additional foundation augmentation will be determined based on site requirement, such as side slope, swamps and weak soils.

For mono pole configuration, standard 10% pole length plus 0.610m will be used as baseline embedment and evaluated against site soil condition and ground line bending moment to ensure sufficient resistance will be achieved.

2.5 Conductor Hardware

All conductor hardware shall meet or exceed the specification outlined in CSA C83 “Communication and Power Line Hardware”. In addition, all current carrying connectors shall also meet the requirements outlined in CSA C57 “Electric Power Connectors for Use in Overhead Line Conductors”.

Baseline suspension clamp for proposed 138kV transmission lines shall be standard aluminum suspension clamp along with armor rod protection.

2.6 Vibration Protection

In addition to critical loading scenarios for phase conductor, the conductor tension is further limited to 15% UTS under -50°C extreme winter temperature to minimize vibration fatigue.

Stockbridge vibration damper will be installed on all phase conductors as well as for OHGW as required. Spiral vibration damper will be specified on all OPGW for vibration control to protect the fiber optic cable.

The preliminary vibration damper calculation will be performed using Preformed Line Product (PLP) Vortex Damper Design Application with design span and tension information.

3.0 Meteorological (Climate) Data

3.1 Site Descriptions

The closest meteorological locations outlined in both C22.3 No.1 and C22.3 No.60826 is Dawson City.

3.2 Deterministic Approach Weather Case

CSA C22.3 No.1 Section 7 outlines the minimum deterministic weather loads shall be applied to each line components. C22.3 No.1 Annex C Figure C.1 indicates that the Yukon falls under CSA Medium A Loading condition which does not represent local observed ice loading situations. The CSA Heavy Loading is used for the previous CSTL and proposed transmission lines. Parameters are given in C22.3 No.1 Table 30 and are listed as follows:

Table 3.1

Conditions	Temperature (°C)	Horizontal Wind Loading (N/m^2)	Radial Ice	
			Thickness (mm)	Ice Density (kg/m^3)
CSA Heavy	-20	400	12.5	900

3.3 Reliability Approach Weather Cases

CSA C22.3 No.60826 is the Canadian adaptation of IEC 60826 "Design criteria of overhead transmission lines", with implementation of appropriate Canadian variations and weather parameters. C22.3 No.60826 Table CA.1 listed 50 years return period (1/50) weather conditions for Canadian Locations. The mean annual maximum snow accumulation depths are provided in CSA C22.3 No.1 Table D.1. The ice, wind and snow depth parameters for the closest meteorological locations to the transmission line are listed below:

Table 3.2

Locations	Reference Average Minimum Temperature (°C)	Reference (1/50) Wind Speed (km/h)	Reference (1/50) Radial Ice		Mean Annual Maximum Snow Depth (m)
			Thickness (mm)	Ice Density (kg/m^3)	
Whitehorse (reference)	-43	85	10	900	0.4
Dawson City	-51	80	10	900	0.6

The ambient temperature for radial ice formation due to freezing precipitation is assumed at -10°C.

The reference wind and ice loading values given above are based on 1 in 50 year (1/50 return period) event.

3.3.1. Reference Ice Loadings

The reference ice loading listed in CSA C22.3 No.60826 does not reflect the occasionally observed rime ice condition on existing transmission line in Yukon. Additional ice loading of 51mm (2") rime ice (density of 350kg/m^3) has been included in the design of the proposed transmission line.

The cable diameter factor and structure height factor according to C22.3 No.60826 Section 6.3.4.1 will be adjusted accordingly in PLS-Cadd model for site specific design.

3.3.2. Reference Wind Loading

The 1 in 50 return period reference wind loading is recommended for the design of the transmission line for capital cost minimization.

3.3.3. Combined Wind and Low Temperature

As per requirement under CSA C22.3 No.60826 Section 6.2.4 for span typically less than 200m, combination of minimum temperature with wind shall be included for reliability design load scenario. The combination shall be verified for reference average minimum temperature with 60% of design wind speed. The design wind speed for combination with minimum temperature is recommended to be 1 in 50 return period.

3.3.4. Combined Ice and Wind Loadings

The requirement of combination of the ice with wind is defined in CSA C22.3 No.60826 Section 6.4. The section outlines two ice and wind combinations as follows:

- Reduced Ice with High Wind - 85% Reference Ice with 60% Reference Wind (normal combined ice and wind)
- High Ice with Average Wind - 130% Reference Ice with 40% Reference Wind (extreme combined ice and wind with spatial factor)

The recommended level of reliability for ice loading combined with wind loading shall be 1 in 50 return periods.

4.0 Electrical Design Criteria

4.1 Code Clearances

4.1.1. Vertical and Horizontal External Clearances

4.1.1.1. Vertical Clearances

The minimum vertical ground clearance required for lowest cable is listed in C22.3 No.1 Table 2 (ground clearances), Table 3 (waterways), Table 9 (building, signs, fence, etc.) and Table 10 (bridges).

Segments of the proposed transmission lines are located at altitude between 1000 m to 1300 m above sea-level. According to C22.3 No.1 clause 5.3.1.1 (b), the required clearance shall be increased by 1% for each 100 m above of 1000 m. The designed high altitude clearance will be based on 3% increase of basic minimum clearance.

The minimum code specified clearance and recommended design values are summarized below:

Table 4.1.1 - 138kV (Maximum Voltage 145kV) Vertical Ground Clearance

Clearance Descriptions	C22.3 No.1 Min. Clearance	Mean Annual Snow Depth	Survey Tolerance	Const. Tolerance	138kV Design Clearance	138kV High Altitude Clearance
	(m)	(m)	(m)	(m)	(m)	(m)
Ground Clearance (CSA C22.3 No.1 Table 2)						
Vehicular Clearance (Vehicle Height <4.15m)	5.5	0.6	0.3	0.3	6.7	6.9
Non-Vehicular Clearance (Pedestrian / ATV)	4.0	0.6	0.3	0.3	5.2	5.4
Railroad Crossings	8.4		0.3	0.3	9.0	9.3
Waterway Crossings (CSA C22.3 No.1 Table 3)						
Class 1 (Vessel H ≤ 4.0 m)	6.7		0.6		7.3	7.5
Class 2 (Vessel H ≤ 6.0 m)	8.7		0.6		9.3	9.6
Class 3 (Vessel H ≤ 8.0 m)	10.7		0.6		11.3	11.7
Class 4 (Vessel H ≤ 10.0 m)	12.7		0.6		13.3	13.7
Class 5 (Vessel H ≤ 12.0 m)	14.7		0.6		15.3	15.8
Class 6 (Vessel H ≤ 14.0 m)	16.7		0.6		17.3	17.8
Features (CSA C22.3 No.1 Table 9 & Table 10)						
Buildings	4.2	0.6	0.3	0.3	5.4	5.6
Signs, Fences, etc.	4.2		0.3	0.3	4.8	5.0
Bridges	3.4	0.6	0.3	0.3	4.6	4.8
Ground Clearance (AEUC 2013 Table 5)						
High Load Clearance (Vehicle Height <5.3m)	6.7	0.6	0.3	0.3	7.9	8.1

Table 4.2 - Communication Vertical Ground Clearance

Clearance Descriptions	C22.3 No.1 Min. Clearance	Mean Annual Snow Depth	Survey Tolerance	Const. Tolerance	Comm. Design Clearance
	(m)	(m)	(m)	(m)	(m)
Ground Clearance (CSA C22.3 No.1 Table 2)					
Vehicular Clearance (Vehicle Height <4.15m)	4.5	0.6	0.3	0.3	5.7
Non-Vehicular Clearance (Pedestrian / ATV)	2.5	0.6	0.3	0.3	3.7
Railroad Crossings	7.3		0.3	0.3	7.9
Waterway Crossings (CSA C22.3 No.1 Table 3)					
Class 1 (Vessel H ≤ 4.0 m)	5.0		0.6		5.6
Class 2 (Vessel H ≤ 6.0 m)	7.0		0.6		7.6
Class 3 (Vessel H ≤ 8.0 m)	9.0		0.6		9.6
Class 4 (Vessel H ≤ 10.0 m)	11.0		0.6		11.6
Class 5 (Vessel H ≤ 12.0 m)	13.0		0.6		13.6
Class 6 (Vessel H ≤ 14.0 m)	15.0		0.6		15.6
Features (CSA C22.3 No.1 Table 9 & Table 10)					
Buildings	0.1	0.6	0.3	0.3	1.3
Signs, Fences, etc.	0.1		0.3	0.3	0.7
Bridges	2.5	0.6	0.3	0.3	3.7
Ground Clearance (AEUC 2013 Table 5)					
High Load Clearance (Vehicle Height <5.3m)	5.6	0.6	0.3	0.3	6.8

The C22.3 No.1 vertical clearances between cable crossings not supported by same structure are listed in C22.3 No.1 Table 13.

In addition to C22.3 No.1 wire crossing specification, Local Distribution Companies (YEC & AEY) should be consulted at each crossing for specific requirement during the final design.

Table 4.2 - Aerial Cable Crossing Vertical Clearance

Upper Cables **Lower Cables**	**69kV (m)**	**138kV (m)**
Communication	0.9	1.2
Secondary (<750V)	0.8	1.1
Distribution (>750V & ≤34.5kV)	0.9	1.2
Sub-Transmission (>44kV & ≤69kV)	1.1	1.4
138kV to 138kV		1.5
Typical LDC Clearance (Communication to 44kV Cables)		2.5

The wire crossing of the 138kV transmission lines will be designed based on the highest specified clearance requirement.

4.1.1.2. Horizontal Clearances

The horizontal cable clearance is defined for cable under conductor Blowout Wind condition as specified in C22.3 No.1 Section 5.2.7 & A5.2.7. The horizontal clearance requirements are specified in C22.3 No.1 Table 6 (Railroad), Table 9 (building, signs, fence, etc.), Table 10 (bridges) and Table 35 (flashover for tree pruning).

Table 4.3 – 138kV Horizontal Electrical Ground Clearance

Clearance Descriptions	**C22.3 No.1 Min. Clearance**	**Survey Tolerance**	**138kV Design Clearance**
	(m)	**(m)**	**(m)**
Railroads (CSA C22.3 No.1 Table 6)			
Main Tracks	3.5	0.3	3.8
Sidings	2.9	0.3	3.2
Features (C22.3 No.1 Table 9, Table 10 & Table 35)			
Buildings	2.6	0.3	2.9
Signs, Fences, etc.	2.6	0.3	2.9
Bridges	2.2	0.3	2.5
Tree Pruning	0.97	0.3	1.3

The specified horizontal conductor clearances are specified for locations where vertical clearances are not achieved.

In addition to conductor electrical clearance, minimum structure clearances in proximity to adjacent features are also governed by appropriate national, provincial and local bylaws.

Table 4.4 – Structural Clearance to Adjacent Facilities

Clearance Descriptions	**Min. Clearance (m)**
Railroads (C22.3 No.1 Table 7)	
Railroad Tracks	
Main Tracks	2.5
Sidings	1.9
Road Clear Zone Requirement	
Edge of Road	5.0 or 6.0 depended on Road Classification

4.1.2. Electrical Clearances to Structures

Electrical clearance from energized conductors and hardware depends on maximum system voltage and switching surge ratio of the transmission system.

The minimum electrical clearances between phase conductors to supporting structure for voltage greater than 50kV phase-ground (<69kV phase-phase) are outside of the voltage range specified in C22.3 No.1. American National Electrical Safety Code (NESC – IEEE C2) shall be used to determine the electrical clearances between energized live parts and support structure components. As per NESC clause 235E1 for 138kV transmission lines, Table 235-6 shall provide the minimum clearance requirements. In addition, CSA C22.3 No. 1 Table A.1 provides flashover to ground distance based on typical switching surge factor.

Table 4.5 – 138kV Electrical Clearances to Structures

Clearance Descriptions	**Minimum Clearance (m)**
NESC Table 235-6 (290 Pa [6 psf] wind @ 15°C)	
Surface of Structure (joint-use)	0.76
Anchor Guys	
Inline Parallel Guys	1.59
Bisect & Offset Guys	0.96
CSA C22.3 No. Table A.1	
Switching Surge Flashover	0.97
Additional Clearance Consideration (RUS 1724E-200 Table 7-1)	
At Rest - No Wind	1.22
Extreme Hourly Wind	0.31

4.1.3. Lightning Performance and Shielding

The average structure height (ground to OPGW and OHGW) of the proposed transmission lines shall be below 92ft, the shielding angle of 30 degree, as per RUS 1724E-200 Table 8-3, was used for the determination of shieldwire and phase conductor separation.

Shielding angle of lightning protection by OPGW and OHGW shall be verified based on latest edition of IEEE Standard 1243 "Guide for Improving the Lightning Performance of Transmission Lines". The ground flash design should either be based on historical data (when available) or IEEE Std. 1243 equation (2) or equation (3).

4.1.4. Grounding

Pole and shieldwire grounding shall be installed at every structure location. Unattached grounding system resistivity shall be 25ohms or below. Grounding study shall be performed in final design phase to estimate number of ground rod(s) at each ground connection.

4.1.5. Galloping Conductors

Conductor and shield wire separations will be assessed for ice and wind galloping under the following conditions;

Table 4.6 – Galloping Conditions

Conditions	Temperature (°C)	Horizontal Wind Loading (Pa) [psf]	Radial Ice	
			Thickness (mm)	Ice Density (kg/m^3)
Galloping Swing	-5	95.7 [2]		
Galloping Ice	-5	95.7 [2]	12.7	900

An additional separation of 0.3m shall be provided between galloping ellipses for design buffer.

4.2 Clearance Buffers

The proposed design clearance buffers has been listed in each of the clearance categories

4.3 Structure Spotting Criteria

The preferred standard design span for proposed 138kV transmission lines to be 150m to 180m based on phase separation requirement under galloping conditions and maintaining reasonable structure height during extreme ice loading conditions. The actual design spotting will be based on above consideration with right of way constraint and adjacent utilities provided in topographical survey utilizing PLS-Cadd 3D TIN terrain model.

4.4 Ampacity Rating Criteria

The phase conductor ampacity calculations are performed based on IEEE Std. 738-2013. C22.3 No.1 Section 3 "Rated ampacity" which outlines the basic ambient and cable conditions to be used for the ampacity calculation.

The ampacity calculations based on parameters outlined in Table 4.4.1 for selected phase conductor cable 266.8MCM ACSR (Partridge) and 397.5MCM ACSR (Ibis) are performed using PLS-Cadd embedded IEEE 738-2013 module. The PLS-Cadd program generated ampacity calculation outputs are given in Appendix F. The calculated continuous and limited thermal ratings for a single conductor are summarized below:

Table 4.7 – IEEE Std. 738 Ampacity Calculations

Parameters	**CSA C22.3 No.1**	**AESO 502.2**
Ambient Temperature	40°C	40°C
Case 1 – Maximum Thermal Rating (Maximum Conductor Temperature)	100°C	100°C
Case 2 – Operating Temperature 40 MW (44.5 MVA) x 1.25 OL @138 kV	240 A	240 A
Case 3 –Design Thermal Rating (Design Conductor Temperature)	75°C	75°C
Wind Speed	0.61 m/s (2 ft/s)	0.61 m/s (2 ft/s)
Wind Angle to Conductor	90°	90°
Conductor Latitude	63.6°	63.6°
Conductor Elevation (above sea level)	800m	800m
Conductor Direction (maximum solar heat)	E-W	E-W
Emissivity	0.5	0.6
Solar Absorption Coefficient	0.5	0.8

Table 4.8 – Conductor Continuous and Limited Thermal Ratings

Cable Conditions	**CSA C22.3 No.1**	**AESO 502.2**
Case 1 – Maximum Thermal Rating		
266.6 MCM 27/6 ACSR (Partridge)	484 A	475 A
397.5 MCM 27/6 ACSR (Ibis)	624 A	612 A
Case 2 – Operating Temperature		
266.6 MCM 27/6 ACSR (Partridge)	59.0°C	62.7°C
397.5 MCM 27/6 ACSR (Ibis)	54.9°C	58.9°C
Case 3 – Design Thermal Rating		
266.6 MCM 27/6 ACSR (Partridge)	361 A (62 MW @138 kV) (31 MW @69 kV)	341 A (58 MW @138 kV) (29 MW @69 kV)
397.5 MCM 27/6 ACSR (Ibis)	463 A (79 MW @138 kV) (39 MW @69 kV)	434 A (74 MW @138 kV) (37 MW @69 kV)

Based on above ampacity and conductor temperature data for the proposed 138kV transmission lines, the design conductor sag shall be based on conductor temperature of 75°C.

5.0 Structural Design Criteria

5.1 Conductor and Conductor Support Hardware

The conductor and conductor supporting hardware shall be design and selected to withstand the required loadings as per requirement outlined in this section.

5.1.1. Conductor Tension Limits

CSA C22.3 No.1-2006 and CSA C22.3 No.60826 design codes are based on maximum allowable design tensions under various loading conditions. However, the latest edition of CSA C22.3 No.1-2010 has been revised to recommended maximum initial catenary for phase conductor.

5.1.1.1. Tension Limit (% Ultimate Tensile Strength)

C22.3 No.1-2006 Table 34 and Table 35 outlined the tension limit of phase conductor and galvanized steel wire as lightning protection wires (Table 35 has not been modified in the 2010 edition).

Table 5.1 – CSA C22.3 No.1-2006 Allowable Cable Tension Limits

Loading Conditions	AAC, ACSR and Aluminum Alloys Phase Conductors	Galvanized Steel Wires
Maximum tension under appropriate loading conditions	60%	60%
Maximum recommended initial unloaded (initial) tension at mean temperature (EDT)	35%	20%
Maximum recommended final unloaded (creep) tension at mean temperature (EDT)	25%	15%

Strength factor for reliability design are listed in C22.3 No.60826 Section 7. The standard values for strength coefficient of variation is given in C22.3 No.60826 Table 18 and support design strength values for tangent / running and angle / dead end configurations are given in C22.3 No.60826 Canadian Section 7.3.3. The combined allowable material factors and equivalent tension limits are given below:

Table 5.2 – CSA C22.3 No.60826 Allowable Cable Material Factors

Conductor & Shieldwire	Cable Material Factor		Support Design Strength Factor	Combined Allowable Material Factor
	COV	Factor		
Intact Load	3%	0.962	0.80	0.77
Failure Load	3%	0.962	0.90	0.87

5.1.1.2. Maximum Initial Cable Catenary

CSA C22.3 No.1-2010 edition section 8.7.3 “Wire tension limits” has been revised to provide additional safety for fatigue damage of conductors due to aeolian vibration. C22.3 No.1 2010 Table 33 provides the recommended catenary parameter for different span lengths.

As per CSTL design requirement, the catenary parameter requirement is consistent with maximum 15% cable UTS under -50°C. These requirements did impact the structure height requirement but provide reliability where large ranges of temperature variation can occur.

5.1.1.3. Recommended Cable Design Criteria

In consideration of various governing factors for cable design criteria, the follow conditions and criteria are used for the design of conductor and OPGW / OHGW;

Table 5.4 – Recommended Cable Design Criteria

Design Conditions	Cable Condition	Conductor	OPGW / OHGW
C22.3 No.1 CSA Heavy	Loaded	60% UTS	60% UTS
C22.3 No. 60826 Extreme Ice	Loaded	60% UTS	60% UTS
C22.3 No. 60826 Gust Wind	Loaded	50% UTS	50% UTS
C22.3 No. 60826 Wind & Low Temp.	Loaded	60% UTS	60% UTS
C22.3 No. 60826 Ice & Wind (High Wind)	Loaded	60% UTS	60% UTS
C22.3 No. 60826 Ice & Wind (Low Wind)	Loaded	70% UTS	60% UTS
EDT	Initial	35% UTS	20% UTS
EDT	Creep	25% UTS	15% UTS
Catenary @ Mean Annual Min. Temp.	Initial	1500 m	1500 m
Min. Temperature (-50°C)	Creep	15% UTS	15% UTS

5.1.2. Insulators, Support Hardware and Conductor Accessories

Reliability design utilizes actual environmental loadings based on desired project return period to compare with reduced allowable material resistances.

The allowable material strength is dependent on material consistency and structure reliability requirement. Material strength factor for reliability design are listed in C22.3 No.60826 Section 7. The standard values for strength coefficient of variation is given in C22.3 No.60826 Table 18 and support design strength values for tangent / running and angle / dead end configurations are given in C22.3 No.60826 Canadian Section 7.3.3. The combined allowable material factors are summarized below;

Table 5.5 - CSA C22.3 No.60826 Cable and Hardware Material Factors

Materials	Material Factor		Running		Deadend	
	COV	Factor	Intact (0.9)	Failure (1.0)	Intact (0.8)	Failure (0.9)
Insulators	5%	0.936	0.84	0.94	0.75	0.84
Hardware	5%	0.936	0.84	0.94	0.75	0.84

Despite C22.3 No.60826 outlines the allowable strength factors for insulator and hardware, manufacturers of insulator and hardware recommended the allowable strength for these items shall be 50% of the design tensile strength. The selection of insulators and conductor attachment hardware shall be based on manufacturer design limits, with exception of the high ice with average wind (130% Ice & 40% Wind) combination, the maximum insulator and hardware usage shall be 0.75.

5.2 Guys and Hardware

CSA C22.3 No60826 clause 7.3.1 outlines the damage limit of steel guys and Table 18 provide material strength factor for grouted guy anchor design. The design of guy anchors shall be according to IEEE Std. 691 "IEEE Guide for Transmission Structure Foundation Design and Testing".

5.2.1. Guy Strand & Hardware

The maximum allowable guy cable and hardware tension shall be 0.75 (75%) ultimate tensile strength as per CSA C22.3 No.60826 Table 14.

5.2.2. Guy Anchors

The maximum design loadings for commercial available guy anchor shall be according to manufacturer recommended holding capacity. The material factor for grouted rock anchor shall be as follows;

Table 5.6 - CSA C22.3 No.60826 Allowable Rock Anchor Material Factors

Materials	Material Factor		Running		Deadend	
	COV	Factor	Intact (0.9)	Failure (1.0)	Intact (0.8)	Failure (0.9)
Grouted Rock Anchor	10%	0.872	0.78	0.87	0.70	0.78

5.3 Structures

5.3.1. Load Factors

Deterministic approach is applied for designing transmission line components to withstand factored loads (vertical, transverse and longitudinal loads) under C22.3 No.1 conditions specific to the project area (see Table 3.1). The required overload factors are specified in C22.3 No.1 Section 7.4 to 7.9 and summarized in C22.3 No.1 Table 31.

Table 5.7 – CSA C22.3 No.1 Overload Factors for Limit State Design (Deterministic Approach)

Structure Type	Grade 2 Construction			Grade 1 Construction		
	Vertical	Trans.	Long.	Vertical	Trans.	Long.
Steel Components (crossarms, davit arms, braces, etc.)						
Tangent & Running Angle	1.15	1.10	1.00	1.30	1.20	1.10
Heavy Angle & Deadend	1.15	1.10	1.10	1.30	1.20	1.20
Wood Pole						
Tangent & Running Angle	1.50	1.30	1.00	2.00	1.90	1.20
Heavy Angle & Deadend	1.50	1.30	1.30	2.00	1.90	1.90

The allowable strengths for each transmission line structural component is calculated by PLS-Pole based on input material parameters, such as geometry, material yield strengths, mechanical properties of material type.

5.3.2. Strength Reduction Factors

The allowable material strength is dependent on material consistency and structure reliability requirement. Structural material strength coefficient of variation for steel component is given in C22.3 No.60826 Table 18 and support design strength values for tangent / running and angle / dead end configurations are given in C22.3 No.60826 Canadian Section 7.3.3. The combined allowable material factors are summarized below:

Table 5.8A - CSA C22.3 No.60826 Allowable Structural Material Factors

Materials	Material Factor		Running		Deadend	
	COV	Factor	Intact (0.9)	Failure (1.0)	Intact (0.8)	Failure (0.9)
Steel Component	5%	0.936	0.84	0.94	0.75	0.84
Wood Component	15%	0.808	0.73	0.80	0.65	0.73

5.4 Design Loads

The design load cases for the proposed 138kV transmission lines shall be based on the climatic data outlined in Section 3.

5.4.1.1. CSA Minimum Deterministic Load Case

The minimum design loads for the proposed transmission lines shall be CSA Heavy Condition as per Table 3.1.

5.4.1.2. Extreme Ice Load Cases

The maximum extreme ice loadings shall be designed for 1 in 50 years return period reference data.

5.4.1.3. Maximum Gust Wind Load Cases

The maximum gust wind loadings shall be designed for 1 in 50 years return period reference.

5.4.1.4. Combined Ice and Wind Load Cases

Both combination of ice with wind loading conditions will be evaluated according to Section 3..3.4.

5.4.1.5. Broken Wire and Unbalanced Ice Loads

For tangent and running angle structures, since the application of braced post insulator had limited longitudinal load capability, the unbalanced longitudinal loading conditions are not considered.

5.4.1.6. Containment Structures

All dead end angle structures and double dead end containment structures shall be designed to withstand complete one sided cable loadings in addition to standard configuration loadings under all climatic conditions.

5.4.1.7. Construction and Maintenance Loads

Construction and maintenance load requirements are specified in C22.3 No.60826 Section 6.5.

The lifting components (such as lifting vent if required) during structure erection shall have minimum safety factor of 1.5 for planned control operation.

The safety factor for cable tension shall be 2.0 during cable stringing operation with 50% of the applied tension added as longitudinal load on all running angle structures.

5.5 Structure Design

The wood pole design shall be preformed using PLS-Pole wood pole structural add-on application module. The PLS-Pole model shall include wood pole, steel crossarm, steel cross braces, insulators, guy cables, etc.

Attachment loadings will be generated by PLS-Cadd line design application using Method 4 "Structure Loads" calculations. Additional longitudinal loads for maintenance and construction scenario under every day temperature will be applied manually in PLS-Pole application.

5.6 Foundation Design

Transmission pole structures in this project are direct-embedded poles and shall be designed to resist the overturning moment, shear and axial loads generated from the design of pole structures using L-Pile caisson foundation application.

5.6.1. Moment Foundations

5.6.1.1. Design Philosophy

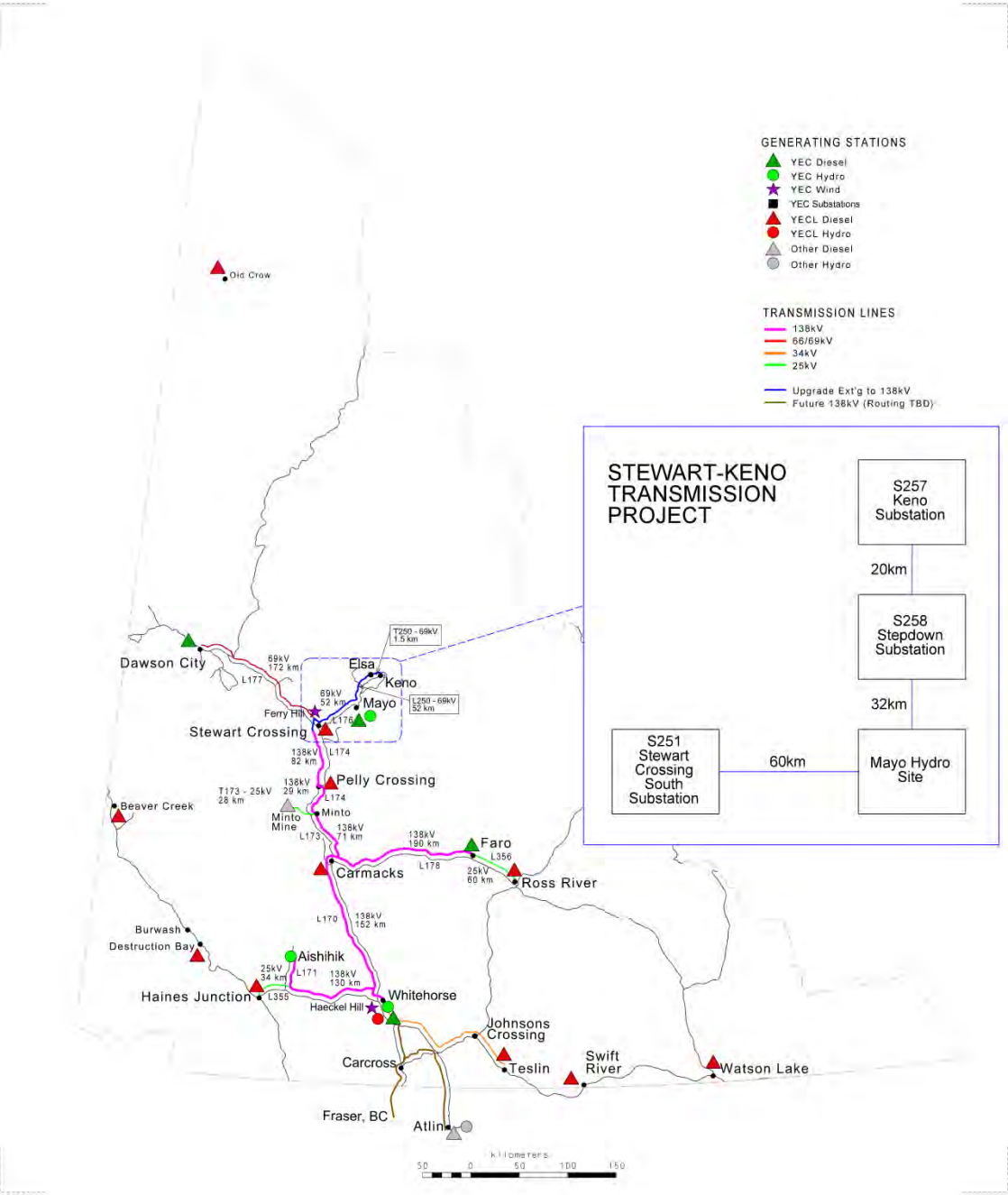
For direct-embedded method, the pole embedment length below the ground line shall be determined using an allowable lateral displacement approach. Horizontal subgrade reaction along the embedded length is determined based on borehole record information as per the geotechnical investigation report. Pole structure shall be designed to withstand the structural loading specified in other sections of this criteria document, and shall also be qualified to sustain the corresponding geotechnical loading to ensure structural integrity.

5.6.1.2. Deflection Limits

Pole recoverable deflection at ground line is limited to 25mm due to actual loading under normal weather condition, and 40mm due to actual loading under extreme weather condition. The soil input parameters for L-Pile application, such as friction angle for granular material and undrain strength for cohesive material, are deduced from site geotechnical report.

Appendix A – Site Location Plan

Appendix A - GEOGRAPHICAL MAP OF THE PROPOSED TRANSMISSION LINE



Appendix B – Code & Regulation List

Chimax Inc.
Engineering Company

Code & Regulations

Re: ***Transmission & Distribution Line Design – Code & Specifications***

This document listed the Design Code & Specifications for transmission and distribution overhead line design.

Design Specifications

- CAN/CSA C22.3 No. 1-10 "Overhead Systems"
- CAN/CSA C22.3 No. 1-06 "Overhead Systems"
- CAN/CSA C22.3 No. 60826-10 "Design Criteria for Overhead Transmission Lines"
- CAN/CSA C22.3 No. 61936-1:08 "Power Installations Exceeding 1 kV A.C."
- IEEE Std. 738-2012 "IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors"
- National Electrical Safety Code (NESC C2-2012), 22st Edition 2012

Supplementary Specifications

- CAN/CSA C22.1-15 "Canadian Electrical Code, Part 1"
- Ontario Electrical Safety Code (OESC), 25th Edition 2012
- Alberta Electrical Utility Code (AEUC), 4th Edition 2013
- CAN/CSA M421-11 "Use of Electricity in Mines"
- CAN/CSA C22.3 No. 3-1998 "Electrical Coordination"
- CAN/CSA C22.3 No. 4-1974 "Control of Electrochemical Corrosion of Underground Metallic Structures"
- CAN/CSA C22.3 No. 5.1-93 "Recommended Practices for Electrical Protection – Electric Contact Between Overhead Supply and Communication Lines"
- CAN/CSA C22.3 No. 6-13 "Principles and Practices of Electrical Coordination Between Pipelines and Electric Supply Lines"
- CAN/CSA C22.3 No. 7-10 "Underground Systems"
- CAN/CSA C22.3 No. 9-08 "Interconnection of Distributed Resources and Electricity Supply Systems"
- ASCE/SEI 74-09 "Guidelines for Electrical Transmission Line Structural Loading"
- ASCE/SEI 48-11 "Design of Steel Transmission Pole Structures"
- ASCE/SEI 10-97 "Design of Latticed Steel Transmission Structures"
- IEEE Std. 524-2003 "IEEE Guide to the Installation of Overhead Transmission Line Conductors"
- IEEE Std. 691-2001 "IEEE Guide for Transmission Structure Foundation Design and Testing"
- IEEE Std. 951-1996 "IEEE Guide to the Assembly and Erection of Metal Transmission Structures"
- IEEE Std. 977-2010 "IEEE Guide to Installation of Foundations for Transmission Line Structures"
- IEEE Std. 1243-1997 "IEEE Guide for Improving the Lightning Performance of Transmission Lines"
- IEEE Std. 1441-2004 "IEEE Guide for Inspection of Overhead Transmission Line Construction"

Design Manual

- RUS Bulletin 1724E-200 “Design Manual for High Voltage Transmission Lines”
- RUS Bulletin 1724E-205 “Design Guide “Embedment Depths for Concrete and Steel Poles”
- RUS Bulletin 1724E-224 “Electric Transmission Guide Specifications and Drawings for Steel Pole Construction – 34.5 to 230 kV”
- RUS Bulletin 1724E-226 “Electric Transmission Guide Specifications and Drawings for Concrete Pole Construction – 34.5 to 230 kV”
- RUS Bulletin 1728F-810 “Electric Transmission Specifications and Drawings for 34.5 Through 69 kV”
- RUS Bulletin 1728F-811 “Electric Transmission Specifications and Drawings for 115 Through 230 kV”
- RUS Bulletin 1724E-104 “Reduced Size Neutral Conductors for Overhead Rural Distribution Lines”
- RUS Bulletin 1724E-150 “Unguyed Distribution Poles – Strength Requirements”
- RUS Bulletin 1724E-151 “Mechanical Loading on Distribution Crossarms”
- RUS Bulletin 1724E-152 “The Mechanics of Overhead Distribution Line Conductors”
- RUS Bulletin 1724E-153 “Electrical Distribution Line Guys and Anchors”
- RUS Bulletin 1724E-154 “Distribution Conductor Clearances and Span Limitations”
- RUS Bulletin 1728F-803 “Specifications and Drawings for 24.9/14.4 kV Line Construction”
- RUS Bulletin 1728F-804 “Specifications and Drawings for 12.47/7.2 kV Line Construction”
- Chance “Encyclopedia of Anchoring”
- Chance “Encyclopedia of Grounding”

Cable Specifications

- CAN/CSA G12-92 "Zinc-Coated Steel Wire Strand"
- ASTM A363-03 "Standard Specification for Zinc-Coated (Galvanized) Steel Overhead Wire Strand"
- ASTM A475-03 "Standard Specification for Zinc-Coated Steel Wire Strand"
- CAN/CSA C61089:03 "Round Wire Concentric Lay Overhead electrical Stranded Conductors"
- CAN/CSA C49.2-1975 "Compact Aluminum Conductors Steel Reinforced"
- CAN/CSA C68.3-97 "Shielded and Concentric Neutral Power Cables Rated 5 – 46 kV"

Insulator Specifications

- CAN/CSA C411.1-10 "AC Suspension Insulators"
- CAN/CSA C411.4-10 "Composite Suspension Insulators for Overhead Lines > 75 kV"
- CAN/CSA C411.5-10 "Dead-end/Suspension Composite Insulators for Overhead Lines ≤ 75 kV"
- CAN/CSA C411.6-11 "Line Post Composite Insulators for Overhead Distribution Lines ≤ 75 kV"
- CAN/CSA C411.7-11 "Composite Insulators for Guy Wires"
- IEC/TS 60815-2 "Selection and dimensioning of high-voltage insulators intended for use in polluted conditions – Part 2: Ceramic and glass insulators for a.c. systems"
- IEC/TS 60815-3 "Selection and dimensioning of high-voltage insulators intended for use in polluted conditions – Part 3: Polymer insulators for a.c. systems"
- ANSI C29.2-1992 "Wet-Process Porcelain and Toughened Glass – Suspension Type"
- ANSI C29.7-1996 "Wet-Process Porcelain Insulators – High Voltage Line-Post Type"
- ANSI C29.4-1989 "Wet-Process Porcelain Insulators – Strain Type"
- ANSI C29.9-1983 "Wet-Process Porcelain Insulators – Apparatus, Post-Type"
- ANSI C29.12-1997 "For Insulators – Composite – Suspension Type"
- ANSI C29.13-2000 "For Insulators – Composite – Distribution Deadend Type"
- ANSI C29.17-2002 "For Insulators – Composite – Line Post Type"
- ANSI C29.18-2003 "For Insulators – Composite – Distribution Line Post Type"
- RUS Bulletin 1724E-220 "Procurement and Application Guide for Non-Ceramic Composite Insulators, Voltage Class 34.5 kV and Above"

Material Specifications

- CAN/CSA O15-15 “Wood Utility Poles and Reinforcing Stubs”
- CAN/CSA O80 Series-08 “Wood Preservation”
- CAN/CSA A14-07 “Concrete Poles”
- CAN/CSA C57-98 “Electric Power Connectors for Use in Overhead Line Conductors”
- CAN/CSA C83-96 “Communication and Power Line Hardware”
- RUS Bulletin 1724E-204 “Guide Specification for Steel Single Pole and H-Frame Structures”
- RUS Bulletin 1724E-206 “Guide Specification for Spun, Prestressed Concrete Poles and Concrete Pole Structures”
- RUS Bulletin 1724E-214 “Guide Specification for Standard Class Steel Transmission Poles”
- RUS Bulletin 1724E-216 “Guide Specification for Standard Class Spun, Prestressed Concrete Transmission Poles”
- RUS Bulletin 1728F-700 “Specification for Wood Poles, Stubs and Anchor Logs”
- RUS Bulletin 1728H-701 “Specification for Wood Crossarms (Solid and Laminated), Transmission Timbers and Pole Keys”
- RUS Bulletin 1728H-702 “Specification for Quality Control and Inspection of Timber Products”
- ASTM A370-09a “Standard Test Methods and definitions for Mechanical Testing of Steel Products”
- ASTM A354-07a “ Standard Specification for Quenched and Tempered Alloy Steel Bolts, Studs, and Other Externally Threaded Fasteners”
- ASTM A490-09 “Standard Specification for Structural Bolts, Alloy Steel, Heat Treated, 150 ksi Minimum Tensile Strength”
- ASTM A320/A320M-08 “Standard Specification for Alloy-Steel and Stainless Steel Bolting Materials for Low Temperature Service”
- ASTM A572/A572M-07 “Standard Specification for High-Strength Low-Alloy Columbium-Vanadium Structural Steel”

Appendix C – Cables and Insulators Catalogue Information

TransPowr® ACSR Bare Overhead Conductor to CAN/CSA C61089

Aluminum Conductor Steel-Reinforced Concentric-Lay-Stranded

ACSR, ALUMINUM CONDUCTOR, STEEL-REINFORCED, CONCENTRIC-LAY-STRANDED (MECHANICAL PROPERTIES)

	CONDUCTOR SIZE		STRANDING NO. X DIA. INCHES		CROSS-SECTION SQ. INCHES		O.D.		APPROX. WEIGHT LB/1000 FT (2)			PERCENT BY MASS		RATED STRENGTH		STANDARD PACKAGES (3)		
CODE WORD (1)	AWG OR kcmil	mm²	AL	STEEL	TOTAL	AL	INCHES	mm	TOTAL	AL	STEEL	AL	STEEL	LB	kN	REEL DESIG.	WT kg	LENGTH M
Turkey	6	13.3	6x0.0661	1x0.0661	0.0240	0.0206	0.198	5.04	36.1	24.5	11.6	67.90	32.10	1160	5.16	NR 30.22	268	4980
																COIL	88	1646
Swan	4	21.1	6x0.0834	1x0.0834	0.0382	0.0328	0.250	6.36	57.4	38.9	18.4	67.89	32.11	1830	8.14	NR 36.22	401	4700
																COIL	100	1169
Swanate	4	21.1	7x0.0772	1x0.1029	0.0411	0.0328	0.257	6.54	67.0	38.9	28.0	58.13	41.87	2300	10.2	RW 40.18	544	5459
																NR 30.22	272	2729
																COIL	109	1091
Sparrow	2	33.6	6x0.1052	1x0.1052	0.0608	0.0522	0.316	8.01	91.2	61.9	29.3	67.87	32.13	2800	12.5	RW 48.24	803	5910
																NR 36.22	401	2955
																NR 30.22	268	1970
																COIL	100	735
Sparate	2	33.6	7x0.0974	1x0.1299	0.0654	0.0522	0.325	8.24	106.6	61.9	44.7	58.08	41.92	3510	15.6	RW 48.24	544	3429
																NR 30.22	272	1714
																COIL	109	686
Robin	1	42.4	6x0.1181	1x0.1181	0.0767	0.0657	0.354	9.00	115.0	78.1	36.9	67.88	32.12	3480	15.5	RW 48.24	801	4681
																NR 36.22	401	2341
																NR 30.22	268	1560
																COIL	100	582
Raven	1/0	53.5	6x0.1327	1x0.1327	0.0968	0.0830	0.398	10.1	145.1	98.5	46.6	67.87	32.13	4250	18.9	RW 48.24	803	3715
																NR 36.22	401	1858
																NR 30.22	268	1237
																COIL	100	462
Quail	2/0	67.4	6x0.1489	1x0.1489	0.1219	0.1045	0.447	11.3	182.9	124.2	58.7	67.89	32.11	5280	23.5	RW 48.24	803	2947
																NR 36.22	401	1474
																NR 30.22	268	981
Pigeon	3/0	85.0	6x0.1672	1x0.1672	0.1537	0.1317	0.502	12.7	230.6	156.5	74.0	67.89	32.11	6660	29.6	RW 48.24	801	2338
																NR 36.22	401	1169
																NR 30.22	268	780
Penguin	4/0	107.2	6x0.1878	1x0.1878	0.1939	0.1662	0.563	14.3	290.8	197.4	93.4	67.88	32.12	8400	37.4	RW 48.24	803	1853
																NR 36.22	401	927
																NR 30.22	268	617
Owl	266.8	135.2	6x0.2109	7x0.0703	0.2368	0.2096	0.633	16.1	341.0	249	92	73.01	26.99	9500	42.3	RM 68.38	2237	4407
																RW 60.32	1118	2204
																RW 48.24	559	1102
Waxwing	266.8	135.2	18x0.1217	1x0.1217	0.2210	0.2094	0.609	15.5	289.0	250	39	86.43	13.57	7000	31.1	RM 68.38	1882	4377
																RW 66.36	1882	4377
																RW 50.32	941	2188
Spoonbill	266.8	135.2	22x0.1101	7x0.0612	0.2300	0.2095	0.624	15.9	320.0	250	70	78.20	21.80	8800	39.1	RM 68.38	1275	2668
																RW 60.32	1275	2668
																RW 50.32	851	1778
Scaup	266.8	135.2	24x0.1054	7x0.0703	0.2366	0.2094	0.633	16.1	342.0	250	92	73.11	26.89	10100	44.9	RM 68.38	1481	2902
																RW 66.36	1481	2902
																RW 60.32	989	1935
Partridge	266.8	135.2	26x0.1013	7x0.0788	0.2437	0.2095	0.642	16.3	366.0	250	116	68.42	31.58	11300	50.3	RW 60.32	1719	3148

(1) Code words shown denote ACSR with regular-strength Class A galvanized steel core (S1A). See the Options section to find the appropriate code word modifier designation for alternative design options.
(2) Due to rounding, total values may be slightly greater or slightly less than the sum of the component values.
(3) Weights shown are for conductor only and do not include the reel. Normal length and shipping tolerances apply.
Dimensions and weights not designated minimum or maximum are nominal values and subject to manufacturing tolerances. In this context, weight means mass.

TransPowr® ACSR Bare Overhead Conductor to CAN/CSA C61089

Aluminum Conductor Steel-Reinforced Concentric-Lay-Stranded

ACSR, ALUMINUM CONDUCTOR, STEEL-REINFORCED, CONCENTRIC-LAY-STRANDED (ELECTRICAL PROPERTIES)

CODE WORD (4)	CONDUCTOR SIZE AWG OR kcmil	CONDUCTOR SIZE mm²	STRANDING NO. X DIA. INCHES AL	STRANDING NO. X DIA. INCHES STEEL	CROSS-SECTION SQ. INCHES TOTAL	CROSS-SECTION SQ. INCHES AL	O.D. INCHES	O.D. mm	RESISTANCE (5) OHMS/1000 FT DC @ 20°C	RESISTANCE (5) OHMS/1000 FT AC @ 25°C	RESISTANCE (5) OHMS/1000 FT AC @ 75°C	AMPACITY 75°C (6)	GEOMETRIC MEAN RADIUS FT	INDUCTIVE REACTANCE OHM/1000 FT (7)	CAPACITIVE REACTANCE MEGAOHM 1000 FT (7)
Turkey	6	13.3	6x0.0661	1x0.0661	0.0240	0.0206	0.198	5.04	0.658	0.671	0.804	95	0.0064	0.1163	0.7512
Swan	4	21.1	6x0.0834	1x0.0834	0.0382	0.0328	0.250	6.36	0.414	0.422	0.505	125	0.0080	0.1109	0.7148
Swanate	4	21.1	7x0.0772	1x0.1029	0.0411	0.0328	0.257	6.54	0.414	0.422	0.505	125	0.0085	0.1096	0.7104
Sparrow	2	33.6	6x0.1052	1x0.1052	0.0608	0.0522	0.316	8.01	0.260	0.265	0.318	165	0.0101	0.1056	0.6785
Sparate	2	33.6	7x0.0974	1x0.1299	0.0654	0.0522	0.325	8.24	0.260	0.265	0.318	165	0.0107	0.1043	0.6741
Robin	1	42.4	6x0.1181	1x0.1181	0.0767	0.0657	0.354	9.00	0.206	0.210	0.252	190	0.0113	0.1029	0.6603
Raven	1/0	53.5	6x0.1327	1x0.1327	0.0968	0.0830	0.398	10.1	0.163	0.167	0.200	220	0.0127	0.1003	0.6421
Quail	2/0	67.4	6x0.1489	1x0.1489	0.1219	0.1045	0.447	11.3	0.130	0.132	0.158	250	0.0143	0.0976	0.6240
Pigeon	3/0	85.0	6x0.1672	1x0.1672	0.1537	0.1317	0.502	12.7	0.103	0.105	0.126	285	0.0161	0.0950	0.6059
Penguin	4/0	107.2	6x0.1878	1x0.1878	0.1939	0.1662	0.563	14.3	0.0816	0.0833	0.100	325	0.0180	0.0923	0.5877
Owl	266.8	135.1876	6x0.2109	7x0.0703	0.2368	0.2096	0.633	16.1	0.0647	0.0661	0.0791	385	0.0202	0.0896	0.5695
Waxwing	266.8	135.2	18x0.1217	1x0.1217	0.2210	0.2094	0.609	15.5	0.0649	0.0664	0.0794	410	0.0197	0.0903	0.5756
Spoonbill	266.8	135.2	22x0.1101	7x0.0612	0.2300	0.2095	0.624	15.9	0.0650	0.0664	0.0795	410	0.0207	0.0891	0.5717
Scaup	266.8	135.2	24x0.1054	7x0.0703	0.2366	0.2094	0.633	16.1	0.0650	0.0664	0.0795	415	0.0212	0.0886	0.5695
Partridge	266.8	135.2	26x0.1013	7x0.0788	0.2437	0.2095	0.642	16.3	0.0651	0.0665	0.0796	415	0.0217	0.0880	0.5673

(4) Code words shown denote ACSR with regular-strength Class A galvanized steel core (S1A). See the Options section to find the appropriate code word modifier designation for alternative design options.
(5) Based on a conductivity of 61.0% IACS at 20°C for aluminum and ignores the effects of the steel core. To convert to ohms/mile, multiply by 5.28. To convert to ohms/km, multiply by 3.281.
(6) Based on a conductor temperature of 75°C at 60 Hz and the following conditions: 32°C ambient temperature, 1.98 ft/sec (0.6 m/s) crosswind (90° to conductor), 0.5 coefficient of emissivity, 0.5 coefficient of absorbtivity, 42° northern latitude, sea level elevation, 90° azimuth of line (East-West), clear atmosphere, and a date and time of noon on July 1 (resulting in 95.0 W/ft² of solar and sky radiated heat). Actual ampacity will differ based on local conditions. For specific ampacities, please contact your General Cable sales representative.
(7) Values for inductive reactance and capacitive reactance are expressed in terms of a 1 ft radius (30.48 cm). To convert the Geometric Mean Radius (GMR) to cm, divide the value by 0.03821. To convert inductive reactance to ohm/km, multiply the value by 3.281. To convert capacitive reactance to ohm/km, divide the value by 3.281.

BICC BRAND

General Cable

TransPowr® ACSR Bare Overhead Conductor to CAN/CSA C61089

Aluminum Conductor Steel-Reinforced Concentric-Lay-Stranded

ACSR, ALUMINUM CONDUCTOR, STEEL-REINFORCED, CONCENTRIC-LAY-STRANDED (MECHANICAL PROPERTIES)

	CONDUCTOR SIZE		STRANDING NO. X DIA. INCHES		CROSS-SECTION SQ. INCHES		O.D.		APPROX. WEIGHT LB/1000 FT (2)			PERCENT BY MASS		RATED STRENGTH		STANDARD PACKAGES (3)		
CODE WORD (1)	AWG OR kcmil	mm²	AL	STEEL	TOTAL	AL	INCHES	mm	TOTAL	AL	STEEL	AL	STEEL	LB	kN	REEL DESIG.	WT kg	LENGTH M
Junco	266.8	135.2	30x0.0943	7x0.0943	0.2584	0.2095	0.660	16.8	416.0	250	166	60.20	39.80	13700	60.9	RM 68.38	2254	3624
																RW 66.36	2254	3624
Phoebe	300.0	152.0	18x0.1291	1x0.1291	0.2487	0.2356	0.646	16.4	325.0	281	44	86.41	13.59	7900	35.1	RW 66.36	1887	3901
																RW 60.32	943	1951
Piper	300.0	152.0	30x0.1000	7x0.1000	0.2906	0.2356	0.700	17.8	468.0	282	186	60.20	39.80	15200	67.6	RMT 84.36	3392	4870
																RW 60.32	1696	2435
Ostrich	300.0	152.0	26x0.1074	7x0.0835	0.2739	0.2355	0.680	17.3	411.0	282	130	68.45	31.55	12700	56.5	RW 60.32	1717	2801
Merlin	336.4	170.5	18x0.1367	1x0.1367	0.2789	0.2642	0.684	17.4	364.0	315	49	86.42	13.58	8900	39.6	RM 68.38	1885	3472
																RW 66.36	1885	3472
																RW 50.32	943	1736
Woodcock	336.4	170.5	22x0.1237	7x0.0687	0.2903	0.2644	0.701	17.8	403.0	315	88	78.21	21.79	10900	48.5	RMT 84.36	2549	4230
																RW 60.32	1275	2115
Widgeon	336.4	170.5	24x0.1184	7x0.0789	0.2985	0.2642	0.710	18.0	431.0	315	116	73.13	26.87	12300	54.7	RMT 84.36	2971	4611
																RW 60.32	1486	2306
Linnet	336.4	170.5	26x0.1137	7x0.0884	0.3072	0.2643	0.720	18.3	461.0	316	145	68.46	31.54	14000	62.3	RMT 84.36	3438	4995
																RW 60.32	1717	2498
Oriole	336.4	170.5	30x0.1059	7x0.1059	0.3259	0.2642	0.741	18.8	525.0	316	209	60.20	39.80	17100	76.1	RMT 84.36	3383	4319
																RM 60.32	1692	2159
Chickadee	397.5	201.4	18x0.1486	1x0.1486	0.3295	0.3122	0.743	18.9	431.0	372	58	86.42	13.58	10200	45.4	RM 68.38	1882	2935
																RW 66.36	1882	2935
																RW 50.32	941	1468
Stork	397.5	201.4	22x0.1344	7x0.0747	0.3428	0.3121	0.762	19.3	477.0	373	104	78.20	21.80	12900	57.4	RMT 84.36	2542	3575
																RW 60.32	1272	1788
Brant	397.5	201.4	24x0.1287	7x0.0858	0.3527	0.3122	0.772	19.6	510.0	373	137	73.11	26.89	14600	64.9	RMT 84.36	2964	3898
																RW 60.32	1483	1949
Ibis	397.5	201.4	26x0.1236	7x0.0961	0.3630	0.3123	0.783	19.9	545.0	373	172	68.46	31.54	16100	71.6	RMT 84.36	3436	4227
																RW 60.32	1717	2114
Lark	397.5	201.4	30x0.1151	7x0.1151	0.3850	0.3121	0.806	20.5	620.0	373	247	60.21	39.79	20000	89.0	RM 68.38	2252	2432
																RW 66.36	2252	2432
Pelican	477.0	241.7	18x0.1628	1x0.1628	0.3955	0.3747	0.814	20.7	517.0	447	70	86.42	13.58	12300	54.7	RM 68.38	1882	2447
																RW 66.36	1882	2447
																RW 50.32	941	1224
Toucan	477.0	241.7	22x0.1472	7x0.0818	0.4112	0.3744	0.834	21.2	572.0	447	125	78.21	21.79	15500	68.9	RMT 84.36	2549	2984
																RW 60.32	1275	1492
Flicker	477.0	241.7	24x0.1410	7x0.0940	0.4233	0.3747	0.846	21.5	612.0	447	165	73.11	26.89	17300	77.0	RMT 84.36	2964	3249
																RW 60.32	1481	1625
Hawk	477.0	241.7	26x0.1354	7x0.1053	0.4357	0.3747	0.858	21.8	654.0	448	206	68.45	31.55	19300	85.8	RMT 84.36	3429	3523
																RW 60.32	1715	1762
Hen	477.0	241.7	30x0.1261	7x0.1261	0.4621	0.3747	0.883	22.4	744.0	448	296	60.20	39.80	23200	103	RM 68.38	2250	2027
																RW 66.36	2250	2027
Heron	500.0	253.4	30x0.1291	7x0.1291	0.4843	0.3927	0.904	23.0	780.0	469	310	60.20	39.80	24300	108.1	RM 68.38	2250	1934
Osprey	556.5	282.0	18x0.1758	1x0.1758	0.4612	0.4369	0.879	22.3	603.0	521	82	86.43	13.57	14300	63.6	RM 68.38	1885	2100
																RW 66.36	1885	2100
																RW 50.32	941	1050

(1) Code words shown denote ACSR with regular-strength Class A galvanized steel core (S1A). See the Options section to find the appropriate code word modifier designation for alternative design options.
(2) Due to rounding, total values may be slightly greater or slightly less than the sum of the component values.
(3) Weights shown are for conductor only and do not include the reel. Normal length and shipping tolerances apply.
Dimensions and weights not designated minimum or maximum are nominal values and subject to manufacturing tolerances. In this context, weight means mass.

General Cable

BICC BRAND

TransPowr® ACSR Bare Overhead Conductor to CAN/CSA C61089

Aluminum Conductor Steel-Reinforced Concentric-Lay-Stranded

ACSR, ALUMINUM CONDUCTOR, STEEL-REINFORCED, CONCENTRIC-LAY-STRANDED (ELECTRICAL PROPERTIES)

CODE WORD (4)	CONDUCTOR SIZE AWG OR kcmil	CONDUCTOR SIZE mm²	STRANDING NO. X DIA. INCHES AL	STRANDING NO. X DIA. INCHES STEEL	CROSS-SECTION SQ. INCHES TOTAL	CROSS-SECTION SQ. INCHES AL	O.D. INCHES	O.D. mm	RESISTANCE (5) OHMS/1000 FT DC @ 20°C	RESISTANCE (5) OHMS/1000 FT AC @ 25°C	RESISTANCE (5) OHMS/1000 FT AC @ 75°C	AMPACITY 75°C (6)	GEOMETRIC MEAN RADIUS FT	INDUCTIVE REACTANCE OHM/1000 FT (7)	CAPACITIVE REACTANCE MEGAOHM 1000 FT (7)
Junco	266.8	135.2	30x0.0943	7x0.0943	0.2584	0.2095	0.660	16.8	0.0651	0.0665	0.0796	415	0.0227	0.0870	0.5629
Phoebe	300.0	152.0	18x0.1291	1x0.1291	0.2487	0.2356	0.646	16.4	0.0577	0.0591	0.0707	440	0.0209	0.0889	0.5664
Piper	300.0	152.0	30x0.1000	7x0.1000	0.2906	0.2356	0.700	17.8	0.0579	0.0591	0.0708	450	0.0241	0.0856	0.5537
Ostrich	300.0	152.0	26x0.1074	7x0.0835	0.2739	0.2355	0.680	17.3	0.0579	0.0592	0.0708	445	0.0230	0.0867	0.5582
Merlin	336.4	170.5	18x0.1367	1x0.1367	0.2789	0.2642	0.684	17.4	0.0515	0.0527	0.0631	475	0.0221	0.0876	0.5574
Woodcock	336.4	170.5	22x0.1237	7x0.0687	0.2903	0.2644	0.701	17.8	0.0516	0.0527	0.0631	475	0.0232	0.0865	0.5535
Widgeon	336.4	170.5	24x0.1184	7x0.0789	0.2985	0.2642	0.710	18.0	0.0516	0.0527	0.0631	475	0.0238	0.0859	0.5514
Linnet	336.4	170.5	26x0.1137	7x0.0884	0.3072	0.2643	0.720	18.3	0.0516	0.0528	0.0632	480	0.0244	0.0854	0.5492
Oriole	336.4	170.5	30x0.1059	7x0.1059	0.3259	0.2642	0.741	18.8	0.0516	0.0528	0.0632	480	0.0255	0.0843	0.5447
Chickadee	397.5	201.4	18x0.1486	1x0.1486	0.3295	0.3122	0.743	18.9	0.0436	0.0447	0.0534	525	0.0240	0.0857	0.5443
Stork	397.5	201.4	22x0.1344	7x0.0747	0.3428	0.3121	0.762	19.3	0.0436	0.0447	0.0535	530	0.0252	0.0846	0.5404
Brant	397.5	201.4	24x0.1287	7x0.0858	0.3527	0.3122	0.772	19.6	0.0436	0.0447	0.0534	530	0.0259	0.0840	0.5383
Ibis	397.5	201.4	26x0.1236	7x0.0961	0.3630	0.3123	0.783	19.9	0.0437	0.0447	0.0535	530	0.0265	0.0835	0.5361
Lark	397.5	201.4	30x0.1151	7x0.1151	0.3850	0.3121	0.806	20.5	0.0437	0.0447	0.0535	535	0.0277	0.0824	0.5316
Pelican	477.0	241.7	18x0.1628	1x0.1628	0.3955	0.3747	0.814	20.7	0.0363	0.0373	0.0446	590	0.0263	0.0836	0.5301
Toucan	477.0	241.7	22x0.1472	7x0.0818	0.4112	0.3744	0.834	21.2	0.0364	0.0373	0.0446	590	0.0276	0.0825	0.5262
Flicker	477.0	241.7	24x0.1410	7x0.0940	0.4233	0.3747	0.846	21.5	0.0364	0.0373	0.0446	595	0.0283	0.0819	0.5240
Hawk	477.0	241.7	26x0.1354	7x0.1053	0.4357	0.3747	0.858	21.8	0.0364	0.0373	0.0446	595	0.0290	0.0814	0.5218
Hen	477.0	241.7	30x0.1261	7x0.1261	0.4621	0.3747	0.883	22.4	0.0364	0.0373	0.0446	600	0.0304	0.0803	0.5174
Heron	500.0	253.4	30x0.1291	7x0.1291	0.4843	0.3927	0.904	23.0	0.0347	0.0356	0.0425	620	0.0311	0.0797	0.5137
Osprey	556.5	282.0	18x0.1758	1x0.1758	0.4612	0.4369	0.879	22.3	0.0311	0.0320	0.0383	645	0.0284	0.0818	0.5180

(4) Code words shown denote ACSR with regular-strength Class A galvanized steel core (S1A). See the Options section to find the appropriate code word modifier designation for alternative design options.
(5) Based on a conductivity of 61.0% IACS at 20°C for aluminum and ignores the effects of the steel core. To convert to ohms/mile, multiply by 5.28. To convert to ohms/km, multiply by 3.281.
(6) Based on a conductor temperature of 75°C at 60 Hz and the following conditions: 32°C ambient temperature, 1.98 ft/sec (0.6 m/s) crosswind (90° to conductor), 0.5 coefficient of emissivity, 0.5 coefficient of absorbtivity, 42° northern latitude, sea level elevation, 90° azimuth of line (East-West), clear atmosphere, and a date and time of noon on July 1 (resulting in 95.0 W/ft² of solar and sky radiated heat). Actual ampacity will differ based on local conditions. For specific ampacities, please contact your General Cable sales representative.
(7) Values for inductive reactance and capacitive reactance are expressed in terms of a 1 ft radius (30.48 cm). To convert the Geometric Mean Radius (GMR) to cm, divide the value by 0.03821. To convert inductive reactance to ohm/km, multiply the value by 3.281. To convert capacitive reactance to ohm/km, divide the value by 3.281.

BICC BRAND

General Cable

OPGW Design

Ref: SFPOC/SFSJ-J-10783

Cable: 36/48 SMF OPGW

Key Design Data – Complete Cable:

Nominal Cross Sectional area	**mm²**	**91**
Center-Stainless Steel Tube –No./Dia.	**mm**	**1/3.4**
Center-Aluminum tube–No./Dia.	**mm**	**1/6.2**
L1- Aluminum Clad Steel Wires –No./Dia.(20%)	**mm**	**3/3.2**
L1- Aluminum Clad Steel Wires –No./Dia.(27%)	**mm**	**6/3.2**
Lay Direction-Outer Layer		**LEFT HAND**

General Design Data (For Information Only)

Overall Diameter	**mm**	**12.60±1%**
Ultimate Conductor Tensile Strength	**kgf**	**8371**
Max. Working Tension	**%**	**60**
Approximate Total Mass	**kg/km**	**517**
Electrical Resistance at 20^0C	**Ω/km**	**0.5935**
Modulus of Elasticity	**N/mm²**	**130,154**
Coefficient of Linear Expansion	**x10^{-6}/^{0}C**	**14.2**
Short Circuit Current Capacity(Ambient=40^0C)	**kA²S**	**63.0**
Minimum bending diameter	**mm**	**1000**
Operating temperature range	**^{0}C**	**-40~+85**

Optical Data

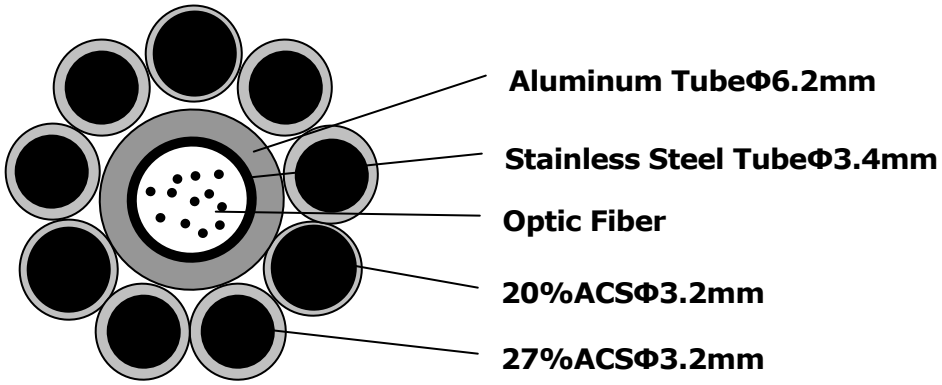
Optical Fibre Type	**-**	**Single Mode G.652D**
Fiber Manufacturer	**-**	**OFS**
Mode Field Diameter-1310nm	**μm**	**9.2±0.4**
Mode Field Diameter-1550nm	**μm**	**10.4±0.5**
Cladding Diameter	**μm**	**125.0±0.7**
Core-Clad Concentricity	**μm**	**≤ 0.5**
Cladding Non-Circularity	**%**	**≤ 1.0**
Coating Diameter	**μm**	**235-245**
Coating-Cladding Concentricity	**μm**	**<12**
Attenuation Coefficient-1310nm	**dB/km**	**≤0.35**
Attenuation Coefficient-1550nm	**dB/km**	**≤0.22**
Cable Cut-Off Wavelength	**nm**	**≤1260**
Zero Dispersion Wavelength	**nm**	**1302-1322**

OPGW Design

Ref: SFPOC/SFSJ-J-10783

Cable: 36/48 SMF OPGW

OPGW Cross section Drawing



Color Coding:

Fiber 1 to Fiber 12: Blue, Orange Green, Brown, Slate, White, Red, Natural, Yellow, Violet, Rose, Aqua.

Fiber 13 to Fiber 24: same base color but with one black ring mark at regular intervals.

Fiber 25 to Fiber 36: same base color but with two black ring marks at regular intervals.

Fiber 37 to Fiber 48: same base color but with three black ring marks at regular intervals.

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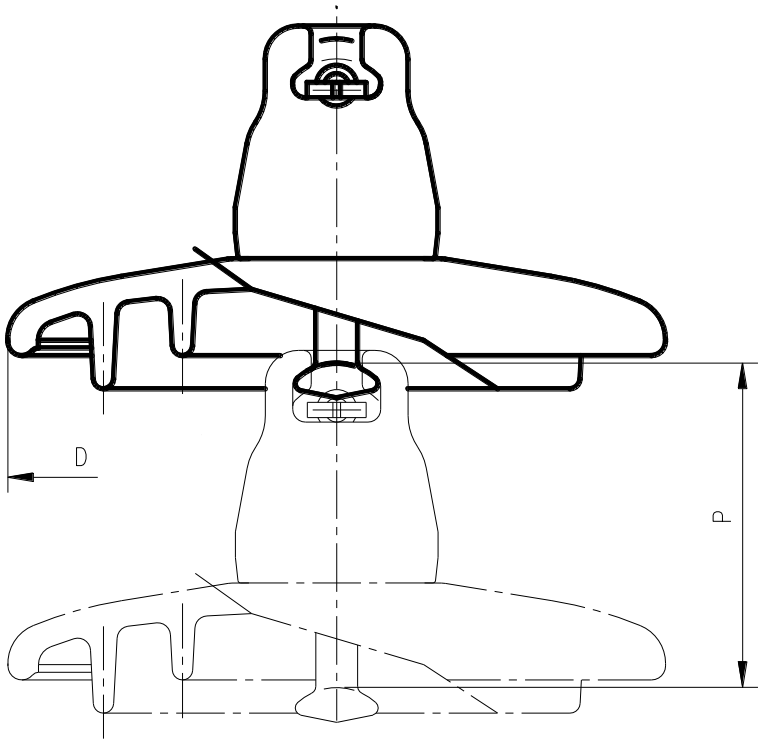

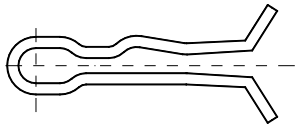

DIMENSIONS

	According to CSA-C411.1 & ANSI C29-2	
Diameter of shell (D)	10 in	255 mm
Spacing (P)	5 3/4 in	146 mm
Creepage distance	12 5/8 in	320 mm
Coupling according to CSA-C411.1 & ANSI C29-2	Type:CS-3 & Class: 52.3 Type:B	
Approximate net weight	8.8 lbs	4 kg

ELECTRICAL PERFORMANCES

Tested as per CSA-C411.1 & ANSI C29.2

Low frequency	
Dry flashover voltage	80 kV
Wet flashover voltage	50 kV
Critical impulse flashover voltage	
Positive	125 kV
Negative	130 kV
Low frequency puncture voltage	130 kV
Radio interference test voltage rms	10 kV
Maxi radio interference - 1 MHz	50 µV

MECHANICAL PERFORMANCES

According to CSA-C411.1 & ANSI C29.2

Combined mechanical and electrical strength	15000 lbs	70 kN
Tension proof	7500 lbs	35 kN
Mechanical impact strength	400 in.lbs	45 N.m

COMPONENT PARTS

Dielectric shell : TOUGHENED GLASS
Cap : HOT DIP GALVANIZED CAST IRON
Pin : HOT DIP GALVANIZED FORGED STEEL
Cotter key : STAINLESS STEEL
Cement : ALUMINOUS, hot cured

SEDIVER®
® Registered trade mark

INSULATOR TYPE	**N 70/146**	Date 2012-11-20
		Approved
SEVES Spa Via R. Giuliani 360 50141 Firenze Italy		Drawing no ENG 4975A1D9
		issue : -

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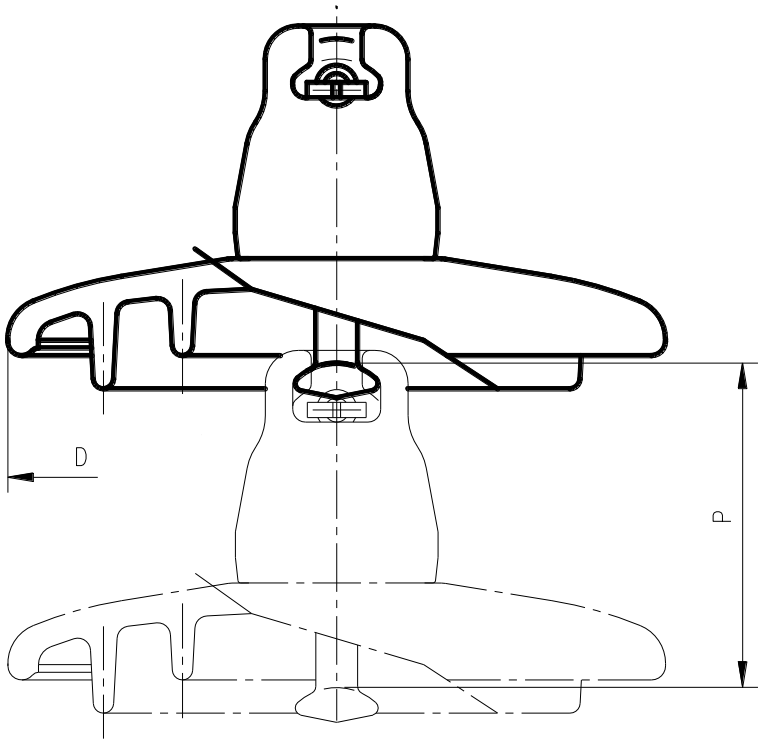
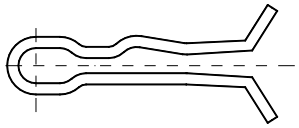




DIMENSIONS

	According to CSA-C411.1 & ANSI C29-2	
Diameter of shell (D)	10 in	255 mm
Spacing (P)	5 3/4 in	146 mm
Creepage distance	12 5/8 in	320 mm
Coupling according to CSA-C411.1 & ANSI C29-2	Type:CS-5 & Class:52.5 Type:J	
Approximate net weight	8.8 lbs	4 kg

ELECTRICAL PERFORMANCES

Tested as per CSA-C411.1 & ANSI C29.2

Low frequency	
Dry flashover voltage	80 kV
Wet flashover voltage	50 kV
Critical impulse flashover voltage	
Positive	125 kV
Negative	130 kV
Low frequency puncture voltage	130 kV
Radio interference test voltage rms	10 kV
Maxi radio interference - 1 MHz	50 µV

MECHANICAL PERFORMANCES

According to CSA-C411.1 & ANSI C29.2

Combined mechanical and electrical strength	25000 lbs	120 kN
Tension proof	12500 lbs	60 kN
Mechanical impact strength	400 in.lbs	45 N.m

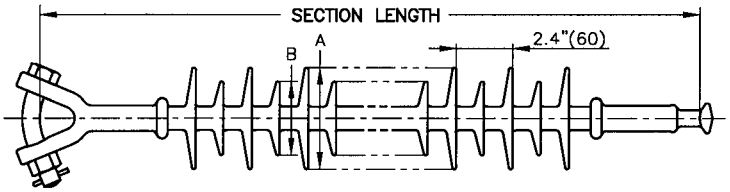
COMPONENT PARTS

Dielectric shell : TOUGHENED GLASS
Cap : HOT DIP GALVANIZED CAST IRON
Pin : HOT DIP GALVANIZED FORGED STEEL
Cotter key : STAINLESS STEEL
Cement : ALUMINOUS, hot cured

SEDIVER®
® Registered trade mark

INSULATOR TYPE	**N 12/146**	Date 2012-11-20
		Approved
SEVES Spa Via R. Giuliani 360 50141 Firenze Italy		Drawing no ENG 4975A241
		issue : -

ANSI 25kip / SC, SS, SL Shed Series



Shed Type	Shed Diameter	
	A	B
"SC" Normal	ø3.0″ (ø76mm)	ø3.0″ (ø76mm)
"SS" Alternating	ø4.2″ (ø106mm)	ø3.0″ (ø76mm)
"SL" Alternating	ø5.2″ (ø132mm)	ø4.0″ (ø102mm)

Typical System Voltage (kV)	Catalog No.	No. of Sheds	Section Length YJ *inch* (mm)	Section Length SJ *inch* (mm)	Section Length EJ *inch* (mm)	Leakage Distance *inch* (mm)	Arcing Distance *inch* (mm)	Low Frequency Flashover Dry kV	Low Frequency Flashover Wet kV	Critical Impulse Flashover Positive kV	Critical Impulse Flashover Negative kV	Approx. Weight *lbs.* (kg)
69	251-SC210-YJ	21	*36.0* (915)	*35.4* (900)	*36.4* (925)	*58.7* (1491)	*26.5* (674)	305	270	450	480	*7.1* (3.2)
	251-SS210-YJ					*71.5* (1816)	*27.1* (688)	310	275	460	490	*8.1* (3.7)
	251-SL210-YJ					*92.8* (2356)	*27.9* (708)	320	280	470	505	*10.1* (4.6)
69	251-SC250-YJ	25	*40.7* (1035)	*40.2* (1020)	*41.1* (1045)	*69.9* (1775)	*31.2* (794)	350	310	525	560	*7.6* (3.5)
	251-SS250-YJ					*85.0* (2159)	*31.8* (808)	355	310	535	565	*8.9* (4.0)
	251-SL250-YJ					*110.3* (2802)	*32.6* (828)	360	320	545	580	*11.3* (5.1)
69/115	251-SC280-YJ	28	*44.3* (1125)	*43.7* (1110)	*44.7* (1135)	*78.3* (1988)	*34.8* (884)	380	340	580	615	*8.1* (3.7)
	251-SS280-YJ					*94.5* (2401)	*35.1* (892)	385	340	585	620	*9.4* (4.3)
	251-SL280-YJ					*122.9* (3122)	*35.8* (909)	390	345	595	630	*12.1* (5.5)
69/115	251-SC310-YJ	31	*47.8* (1215)	*47.2* (1200)	*48.1* (1225)	*86.7* (2201)	*38.3* (974)	415	365	635	675	*8.5* (3.9)
	251-SS310-YJ					*105.2* (2673)	*38.9* (988)	420	370	645	680	*10.1* (4.6)
	251-SL310-YJ					*136.7* (3471)	*39.7* (1008)	430	380	655	695	*13.0* (5.9)
115/138	251-SC350-YJ	35	*52.6* (1335)	*52.0* (1320)	*53.0* (1345)	*97.8* (2485)	*43.1* (1094)	460	405	705	750	*9.1* (4.1)
	251-SS350-YJ					*118.7* (3016)	*43.6* (1108)	465	410	715	760	*10.8* (4.9)
	251-SL350-YJ					*154.2* (3917)	*44.4* (1128)	470	420	730	770	*14.2* (6.4)
138	251-SC390-YJ	39	*57.3* (1455)	*56.7* (1440)	*57.7* (1465)	*109.0* (2769)	*47.8* (1214)	505	445	780	825	*9.6* (4.4)
	251-SS390-YJ					*132.2* (3359)	*48.4* (1228)	510	450	790	835	*11.6* (5.3)
	251-SL390-YJ					*171.8* (4363)	*49.1* (1248)	515	460	800	850	*15.3* (6.9)
138	251-SC410-YJ	41	*59.6* (1515)	*59.1* (1500)	*60.0* (1525)	*114.6* (2911)	*50.2* (1274)	525	465	815	865	*9.9* (4.5)
	251-SS410-YJ					*139.0* (3531)	*50.7* (1288)	530	470	825	875	*11.9* (5.4)
	251-SL410-YJ					*180.6* (4586)	*51.5* (1308)	540	480	840	885	*15.9* (7.2)
138/161	251-SC450-YJ	45	*64.4* (1635)	*63.8* (1620)	*64.8* (1645)	*125.8* (3195)	*54.9* (1394)	570	505	890	940	*10.5* (4.8)
	251-SS450-YJ					*152.5* (3874)	*55.4* (1408)	575	510	900	950	*12.7* (5.8)
	251-SL450-YJ					*198.1* (5032)	*56.2* (1428)	580	520	910	965	*17.0* (7.7)
161	251-SC500-YJ	50	*70.3* (1785)	*69.7* (1770)	*70.7* (1795)	*139.8* (3550)	*60.8* (1544)	625	555	980	1040	*11.2* (5.1)
	251-SS500-YJ					*168.8* (4288)	*61.1* (1552)	625	560	985	1045	*13.6* (6.2)
	251-SL500-YJ					*219.5* (5575)	*61.8* (1569)	635	565	995	1055	*18.4* (8.3)
161	251-SC550-YJ	55	*76.2* (1935)	*75.6* (1920)	*76.8* (1950)	*153.7* (3905)	*66.7* (1695)	680	605	1075	1135	*11.9* (5.4)
	251-SS550-YJ					*186.3* (4731)	*67.3* (1709)	685	610	1080	1145	*14.6* (6.6)
	251-SL550-YJ					*242.0* (6147)	*68.1* (1729)	690	615	1095	1155	*19.9* (9.0)

25kip Other End Fitting Combination Section Length Adjustment Table, **Base Coupling: Eye-Ball (EJ)**	inch				
Eye/Eye (EE)	+1.4	Clevis/Eye (CE)	+0.4	Clevis/Clevis (CC)	-0.6
Clevis/Ball (CJ)	-1.0	Y-Clevis/Y-Clevis (YY)	+0.5	Y-Clevis/Tongue (YT)	+0.5
Y-Clevis/Eye (YE)	+0.9	Y-Clevis/Socket (YS)	-0.1	Clevis/Tongue (CT)	0

Typical System Voltage (kV)	Catalog No.	No. of Sheds	Section Length YJ *inch* (mm)	SJ *inch* (mm)	EJ *inch* (mm)	Leakage Distance *inch* (mm)	Arcing Distance *inch* (mm)	Low Frequency Flashover Dry kV	Low Frequency Flashover Wet kV	Critical Impulse Flashover Positive kV	Critical Impulse Flashover Negative kV	Approx. Weight *lbs.* (kg)
161/230	251-SC590-YJ	59	*80.9* (2055)	*80.3* (2040)	*81.5* (2070)	*164.9* (4189)	*71.4* (1815)	725	645	1145	1210	*12.5* (5.7)
	251-SS590-YJ					*199.8* (5074)	*72.0* (1829)	730	650	1155	1220	*15.4* (7.0)
	251-SL590-YJ					*259.6* (6593)	*72.8* (1849)	735	655	1170	1235	*21.0* (9.5)
230	251-SC640-YJ	64	*86.8* (2205)	*86.2* (2190)	*87.4* (2220)	*178.9* (4544)	*77.4* (1965)	780	695	1240	1310	*13.2* (6.0)
	251-SS640-YJ					*216.1* (5488)	*77.7* (1973)	780	700	1245	1315	*16.3* (7.4)
	251-SL640-YJ					*280.9* (7136)	*78.3* (1990)	785	705	1255	1325	*22.4* (10.2)
230	251-SC690-YJ	69	*92.7* (2355)	*92.1* (2340)	*93.3* (2370)	*192.9* (4899)	*83.3* (2115)	835	745	1330	1405	*13.9* (6.3)
	251-SS690-YJ					*233.5* (5932)	*83.8* (2129)	840	750	1340	1415	*17.3* (7.9)
	251-SL690-YJ					*303.5* (7708)	*84.6* (2149)	845	755	1350	1425	*23.9* (10.8)
230/345	251-SC740-YJ	74	*98.6* (2505)	*98.0* (2490)	*99.2* (2520)	*206.9* (5254)	*89.2* (2265)	890	795	1420	1500	*14.6* (6.6)
	251-SS740-YJ					*249.8* (6346)	*89.5* (2273)	890	795	1425	1505	*18.2* (8.3)
	251-SL740-YJ					*324.8* (8251)	*90.2* (2290)	895	805	1435	1515	*25.3* (11.5)
230/345	251-SC780-YJ	78	*103.3* (2625)	*102.8* (2610)	*103.9* (2640)	*218.0* (5538)	*93.9* (2385)	930	835	1495	1575	*15.2* (6.9)
	251-SS780-YJ					*263.3* (6689)	*94.2* (2393)	935	835	1500	1580	*19.0* (8.6)
	251-SL780-YJ					*342.4* (8697)	*94.9* (2410)	940	845	1510	1595	*26.4* (12.0)
345	251-SC810-YJ	81	*106.9* (2715)	*106.3* (2700)	*107.5* (2730)	*226.4* (5751)	*97.5* (2475)	965	865	1550	1635	*15.6* (7.1)
	251-SS810-YJ					*274.0* (6961)	*98.0* (2489)	970	870	1560	1645	*19.6* (8.9)
	251-SL810-YJ					*356.1* (9046)	*98.8* (2509)	975	875	1570	1655	*27.3* (12.4)
345	251-SC860-YJ	86	*112.8* (2865)	*112.2* (2850)	*113.4* (2880)	*240.4* (6106)	*103.4* (2626)	1010	905	1640	1730	*16.4* (7.4)
	251-SS860-YJ					*290.3* (7375)	*103.7* (2634)	1010	905	1645	1735	*20.5* (9.3)
	251-SL860-YJ					*377.5* (9589)	*104.4* (2651)	1015	910	1655	1745	*28.7* (13.0)
345	251-SC910-YJ	91	*118.7* (3015)	*118.3* (3005)	*119.3* (3030)	*254.4* (6461)	*109.3* (2776)	1050	940	1735	1825	*17.1* (7.7)
	251-SS910-YJ					*307.8* (7818)	*109.8* (2790)	1050	940	1740	1835	*21.5* (9.8)
	251-SL910-YJ					*400.0* (10161)	*110.6* (2810)	1055	945	1755	1850	*30.2* (13.7)
345	251-SC1000-YJ	100	*129.3* (3285)	*128.9* (3275)	*129.9* (3300)	*279.5* (7100)	*119.9* (3046)	1115	1000	1900	2000	*18.4* (8.3)
	251-SS1000-YJ					*337.6* (8575)	*120.2* (3054)	1115	1000	1905	2005	*23.2* (10.5)
	251-SL1000-YJ					*439.0* (11150)	*120.9* (3071)	1120	1005	1915	2015	*32.7* (14.8)
345/500	251-SC1090-YJ	109	*140.0* (3555)	*139.6* (3545)	*140.6* (3570)	*304.7* (7739)	*130.6* (3316)	1180	1055	2065	2170	*19.6* (8.9)
	251-SS1090-YJ					*368.6* (9362)	*131.1* (3330)	1185	1060	2070	2180	*24.9* (11.3)
	251-SL1090-YJ					*479.1* (12168)	*131.9* (3350)	1185	1065	2085	2195	*35.3* (16.0)

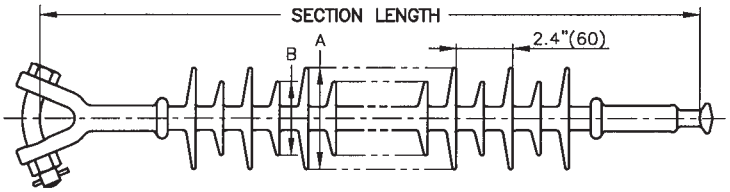
Approx. Weight is for Y-clevis & Ball unless otherwise specified.

Test methods and criteria are in accordance with ANSI C29.11 and ANSI C29.12.

All tables show the typical products. Please contact NLPI for other dimensions and end fitting combinations.

Electrical values exceeding the capacity (AC FOV>1200kV, L.I. FOV>3000kV) are presumed by the extrapolation of values obtained from short string unit.

ANSI 30kip / SC, SS, SL Shed Series



Shed Type	Shed Diameter	
	A	B
"SC" Normal	ø3.0 (ø76mm)	ø3.0 (ø76mm)
"SS" Alternating	ø4.2 (ø106mm)	ø3.0 (ø76mm)
"SL" Alternating	ø5.2" (ø132mm)	ø4.0 (ø102mm)

Typical System Voltage (kV)	Catalog No.	No. of Sheds	Section Length YJ *inch* (mm)	SJ *inch* (mm)	EJ *inch* (mm)	Leakage Distance *inch* (mm)	Arcing Distance *inch* (mm)	Low Frequency Flashover Dry kV	Low Frequency Flashover Wet kV	Critical Impulse Flashover Positive kV	Critical Impulse Flashover Negative kV	Approx. Weight *lbs.* (kg)
69	301-SC210-YJ	21	*37.8* (960)	*36.8* (935)	*38.0* (965)	*58.7* (1491)	*26.5* (674)	305	270	450	480	*7.7* (3.5)
	301-SS210-YJ					*71.5* (1816)	*27.1* (688)	310	275	460	490	*8.8* (4.0)
	301-SL210-YJ					*92.8* (2356)	*27.9* (708)	320	280	470	505	*10.8* (4.9)
69	301-SC250-YJ	25	*42.5* (1080)	*41.5* (1055)	*42.7* (1085)	*69.9* (1775)	*31.2* (794)	350	310	525	560	*8.3* (3.8)
	301-SS250-YJ					*85.0* (2159)	*31.8* (808)	355	310	535	565	*9.7* (4.4)
	301-SL250-YJ					*110.3* (2802)	*32.6* (828)	360	320	545	580	*11.9* (5.4)
69/115	301-SC280-YJ	28	*46.1* (1170)	*45.1* (1145)	*46.3* (1175)	*78.3* (1988)	*34.8* (884)	380	340	580	615	*8.8* (4.0)
	301-SS280-YJ					*94.5* (2401)	*35.1* (892)	385	340	585	620	*10.1* (4.6)
	301-SL280-YJ					*122.9* (3122)	*35.8* (909)	390	345	595	630	*12.8* (5.8)
69/115	301-SC310-YJ	31	*49.6* (1260)	*48.6* (1235)	*49.8* (1265)	*86.7* (2201)	*38.3* (974)	415	365	635	675	*9.3* (4.2)
	301-SS310-YJ					*105.2* (2673)	*38.9* (988)	420	370	645	680	*10.8* (4.9)
	301-SL310-YJ					*136.7* (3471)	*39.7* (1008)	430	380	655	695	*13.7* (6.2)
115/138	301-SC350-YJ	35	*54.3* (1380)	*53.3* (1355)	*54.5* (1385)	*97.8* (2485)	*43.1* (1094)	460	405	705	750	*9.7* (4.4)
	301-SS350-YJ					*118.7* (3016)	*43.6* (1108)	465	410	715	760	*11.5* (5.2)
	301-SL350-YJ					*154.2* (3917)	*44.4* (1128)	470	420	730	770	*14.8* (6.7)
138	301-SC390-YJ	39	*59.1* (1500)	*58.1* (1475)	*59.3* (1505)	*109.0* (2769)	*47.8* (1214)	505	445	780	825	*10.4* (4.7)
	301-SS390-YJ					*132.2* (3359)	*48.4* (1228)	510	450	790	835	*12.3* (5.6)
	301-SL390-YJ					*171.8* (4363)	*49.1* (1248)	515	460	800	850	*16.1* (7.3)
138/161	301-SC450-YJ	45	*66.1* (1680)	*65.2* (1655)	*66.3* (1685)	*125.8* (3195)	*54.9* (1394)	570	505	890	940	*11.2* (5.1)
	301-SS450-YJ					*152.5* (3874)	*55.4* (1408)	575	510	900	950	*13.5* (6.1)
	301-SL450-YJ					*198.1* (5032)	*56.2* (1428)	580	520	910	965	*17.6* (8.0)
161	301-SC500-YJ	50	*72.0* (1830)	*71.1* (1805)	*72.2* (1835)	*139.8* (3550)	*60.8* (1544)	625	555	980	1040	*11.9* (5.4)
	301-SS500-YJ					*168.8* (4288)	*61.1* (1552)	625	560	985	1045	*14.3* (6.5)
	301-SL500-YJ					*219.5* (5575)	*61.8* (1569)	635	565	995	1055	*19.2* (8.7)
161	301-SC550-YJ	55	*78.0* (1980)	*77.0* (1955)	*78.1* (1985)	*153.7* (3905)	*66.7* (1695)	680	605	1075	1135	*12.6* (5.7)
	301-SS550-YJ					*186.3* (4731)	*67.3* (1709)	685	610	1080	1145	*15.4* (7.0)
	301-SL550-YJ					*242.0* (6147)	*68.1* (1729)	690	615	1095	1155	*20.5* (9.3)
161/230	301-SC590-YJ	59	*82.7* (2100)	*81.7* (2075)	*82.9* (2105)	*164.9* (4189)	*71.4* (1815)	725	645	1145	1210	*13.2* (6.0)
	301-SS590-YJ					*199.8* (5074)	*72.0* (1829)	730	650	1155	1220	*16.1* (7.3)
	301-SL590-YJ					*259.6* (6593)	*72.8* (1849)	735	655	1170	1235	*21.8* (9.9)

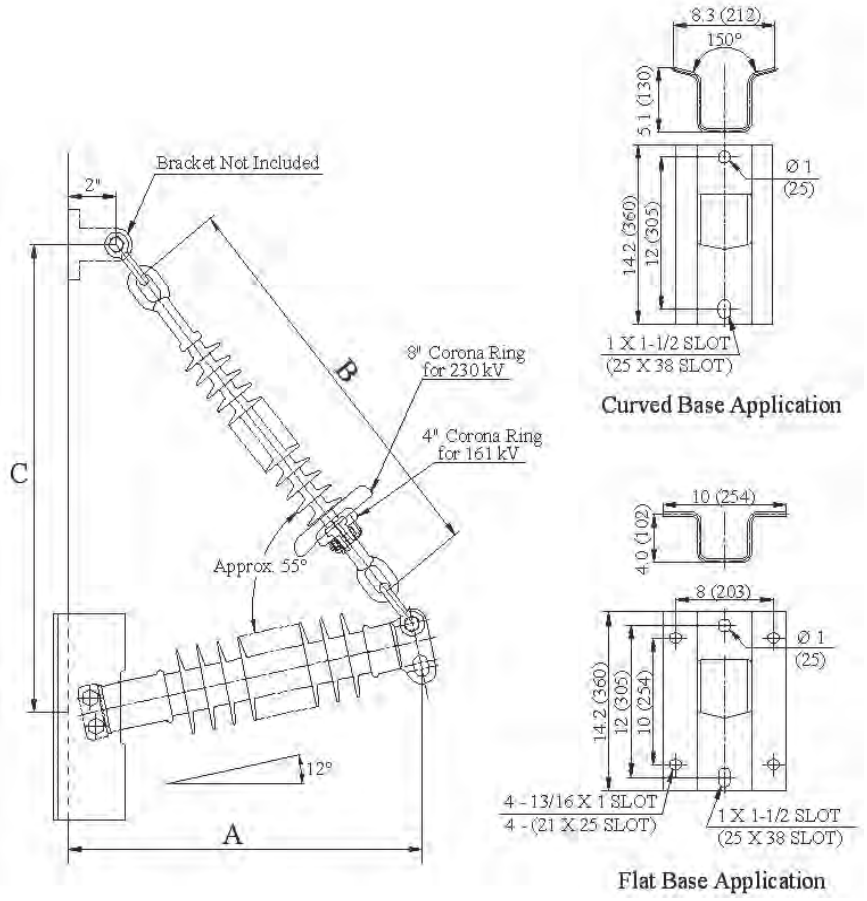
30kip Other End Fitting Combination Section Length Adjustment Table, **Base Coupling: Eye-Ball (EJ)** Inch			
Eye/Eye (EE)	+1.5	Y-Clevis/Y-Clevis (YY)	+1.1
Y-Clevis/Eye (YE)	+1.3	Y-Clevis/Socket (YS)	+0.1

Please contact NLPI for additional end fittings and combinations, including Clevis and Tongue hardware.

Typical System Voltage (kV)	Catalog No.	No. of Sheds	Section Length			Leakage Distance	Arcing Distance	Low Frequency Flashover		Critical Impulse Flashover		Approx. Weight
			YJ *inch* (mm)	SJ *inch* (mm)	EJ *inch* (mm)	*inch* (mm)	*inch* (mm)	Dry kV	Wet kV	Positive kV	Negative kV	*lbs.* (kg)
230	301-SC640-YJ	64	*88.6* (2250)	*87.6* (2225)	*88.8* (2255)	*178.9* (4544)	*77.4* (1965)	780	695	1240	1310	*13.9* (6.3)
	301-SS640-YJ					*216.1* (5488)	*77.7* (1973)	780	700	1245	1315	*17.0* (7.7)
	301-SL640-YJ					*280.9* (7136)	*78.3* (1990)	785	705	1255	1325	*23.2* (10.5)
230	301-SC690-YJ	69	*94.5* (2400)	*93.5* (2375)	*94.7* (2405)	*192.9* (4899)	*83.3* (2115)	835	745	1330	1405	*14.6* (6.6)
	301-SS690-YJ					*233.5* (5932)	*83.8* (2129)	840	750	1340	1415	*18.1* (8.2)
	301-SL690-YJ					*303.5* (7708)	*84.6* (2149)	845	755	1350	1425	*24.7* (11.2)
230/345	301-SC730-YJ	73	*99.2* (2520)	*98.2* (2495)	*99.4* (2525)	*204.1* (5183)	*88.0* (2235)	875	785	1405	1480	*15.2* (6.9)
	301-SS730-YJ					*247.0* (6275)	*88.5* (2249)	880	790	1410	1490	*18.7* (8.5)
	301-SL730-YJ					*321.0* (8154)	*89.3* (2269)	890	795	1425	1500	*25.8* (11.7)
345	301-SC810-YJ	81	*108.7* (2760)	*107.7* (2735)	*108.9* (2765)	*226.4* (5751)	*97.5* (2475)	965	865	1550	1635	*16.3* (7.4)
	301-SS810-YJ					*274.0* (6961)	*98.0* (2489)	970	870	1560	1645	*20.3* (9.2)
	301-SL810-YJ					*356.1* (9046)	*98.8* (2509)	975	875	1570	1655	*28.0* (12.7)
345	301-SC910-YJ	91	*120.5* (3060)	*119.5* (3035)	*120.7* (3065)	*254.4* (6461)	*109.3* (2776)	1050	940	1735	1825	*17.9* (8.1)
	301-SS910-YJ					*307.8* (7818)	*109.8* (2790)	1050	940	1740	1835	*22.3* (10.1)
	301-SL910-YJ					*400.0* (10161)	*110.6* (2810)	1055	945	1755	1850	*30.9* (14.0)
345	301-SC1000-YJ	100	*131.1* (3330)	*130.1* (3305)	*131.3* (3335)	*279.5* (7100)	*119.9* (3046)	1115	1000	1900	2000	*19.2* (8.7)
	301-SS1000-YJ					*337.6* (8575)	*120.2* (3054)	1115	1000	1905	2005	*23.8* (10.8)
	301-SL1000-YJ					*439.0* (11150)	*120.9* (3071)	1120	1005	1915	2015	*33.5* (15.2)
345/500	301-SC1090-YJ	109	*141.7* (3600)	*140.7* (3575)	*141.9* (3605)	*304.7* (7739)	*130.6* (3316)	1180	1055	2065	2170	*20.3* (9.2)
	301-SS1090-YJ					*368.6* (9362)	*131.1* (3330)	1185	1060	2070	2180	*25.6* (11.6)
	301-SL1090-YJ					*479.1* (12168)	*131.9* (3350)	1185	1065	2085	2195	*36.2* (16.4)
500	301-SC1170-YJ	117	*151.2* (3840)	*150.2* (3815)	*151.4* (3845)	*327.0* (8307)	*140.0* (3556)	1235	1105	2210	2325	*21.6* (9.8)
	301-SS1170-YJ					*395.6* (10048)	*140.6* (3570)	1235	1110	2220	2335	*27.1* (12.3)
	301-SL1170-YJ					*514.2* (13060)	*141.4* (3590)	1240	1110	2230	2350	*38.4* (17.4)
500	301-SC1310-YJ	131	*167.7* (4260)	*166.7* (4235)	*168.1* (4270)	*366.2* (9301)	*156.6* (3977)	1325	1185	2465	2595	*23.6* (10.7)
	301-SS1310-YJ					*442.8* (11248)	*157.1* (3991)	1325	1190	2475	2605	*29.8* (13.5)
	301-SL1310-YJ					*575.6* (14621)	*157.9* (4011)	1330	1190	2485	2615	*42.3* (19.2)
500/765	301-SC1410-YJ	141	*179.7* (4565)	*178.5* (4535)	*179.9* (4570)	*394.1* (10011)	*168.4* (4277)	1385	1240	2650	2785	*24.9* (11.3)
	301-SS1410-YJ					*476.6* (12106)	*168.9* (4291)	1390	1245	2660	2795	*31.8* (14.4)
	301-SL1410-YJ					*619.5* (15736)	*169.7* (4311)	1390	1245	2670	2810	*45.2* (20.5)
765	301-SC1530-YJ	153	*193.9* (4925)	*192.7* (4895)	*194.1* (4930)	*427.7* (10863)	*182.6* (4638)	1455	1305	2870	3020	*26.7* (12.1)
	301-SS1530-YJ					*517.1* (13135)	*183.1* (4652)	1455	1305	2875	3025	*34.2* (15.5)
	301-SL1530-YJ					*672.2* (17074)	*183.9* (4672)	1460	1310	2890	3040	*48.7* (22.1)

NGK-Locke Polymer Insulators, Inc.

2.5" (63mm) CORE
BRACED LINE POST (BLP) ASSEMBLY



System Voltage, kV	Catalog No.	Component Catalog No.[1]		Arcing Distance, in.(mm)	Leakage Distance, in.(mm)[2]	Dimension			Low Frequency Flashover		Critical Impulse Flashover		Design Loads, lbs.[3,4]			
						A in. (mm)	B in. (mm)	C in. (mm)	Dry kV	Wet kV	Pos. kV	Neg. kV	Vertical	Tension	Compression	Longitudinal
115	HV-554	Strut	L2-SN321-13	46.5 (1181)	132.3 (3360)	58.2 (1478)	69.8 (1772)	64.1 (1628)	495	435	730	800	10000	7500	7500	1530
		Stay	251-SC480-EE													
138	HV-556	Strut	L2-SN361-13	52.4 (1331)	148.8 (3780)	64.0 (1625)	78.0 (1982)	71.3 (1810)	545	475	820	890	10000	7500	7500	1375
		Stay	251-SC550-EE													
161	HV-558	Strut	L2-SN431-13	62.0 (1575)	177.8 (4515)	74.1 (1881)	92.2 (2343)	83.4 (2118)	620	545	960	1040	10000	7500	7500	1165
		Stay	251-SC670-EE-04													
230	HV-560	Strut	L2-SN581-13	81.8 (2078)	239.8 (6090)	95.7 (2432)	121.8 (3093)	108.1 (2745)	765	670	1255	1350	8450	7500	7500	880
		Stay	251-SC920-EE-08													

1) Refer to individual product catalogs for details of the components.
2) The leakage distance is the lesser value of the strut and stay.
3) Design loads are for single loads in the specified direction.
4) Design load values do not consider the supporting structure strength.

The catalog numbers listed above use a bendable curved base. A flat base option is also available upon request.
Application of corona ring(s) depends on requirements.
For more detailed information please contact our local sales representative.

Appendix D – Climatic Data Reference Data

Location	Elevation (m)	Latitude	Longitude	Minimum temperature (°C)*	Reference wind speed† (km/h)	Reference ice thickness‡ (mm)	Wet snow thickness§ (mm)
Prince Edward Island							
Charlottetown	5	46.23	–63.13	–22	112	30	—
Souris	5	46.35	–62.25	–21	114	30	—
Summerside	10	46.40	–63.78	–22	114	30	—
Tignish	10	46.95	–64.03	–22	122	30	—
Newfoundland and Labrador							
Argentia	15	47.30	–53.98	–14	130	35	—
Bonavista	15	48.65	–53.12	–16	140	40	—
Buchans	255	48.82	–56.87	–27	115	24	—
Cape Harrison	5	54.78	–57.95	–31	130	35	—
Cape Race	5	46.65	–53.07	–13	154	45	—
Channel–Port aux Basques	5	47.57	–59.15	–15	133	32	—
Corner Brook	35	48.95	–57.95	–18	111	24	—
Gander	125	48.98	–54.59	–20	117	30	—
Grand Bank	5	47.10	–55.77	–15	130	35	—
Grand Falls	60	48.93	–55.67	–29	100	28	—
Happy Valley–Goose Bay	15	53.32	–60.37	–32	98	20	—
Labrador City	550	52.95	–66.92	–38	95	15	—
St. Anthony	10	51.37	–55.58	–27	138	30	—
St. John's	65	47.57	–52.72	–16	138	42	—
Stephenville	25	48.55	–58.58	–18	114	24	—
Twin Falls	425	53.50	–64.53	–37	95	17	—
Wabana	75	47.63	–52.95	–17	130	40	—
Wabush	550	52.92	–66.87	–38	95	15	—
Yukon							
Aishihik	920	61.60	–137.52	–46	85	10	—
Dawson	330	64.07	–139.42	–51	80	10	—
Destruction Bay	815	61.25	–138.80	–45	117	10	—
Faro	670	62.23	–133.36	–47	80	10	—
Haines Junction	600	60.78	–137.54	–47	87	10	—
Snag	595	62.40	–140.37	–53	80	10	—
Teslin	690	60.17	–132.72	–44	80	10	—
Watson Lake	685	60.13	–128.71	–48	80	10	—
Whitehorse	655	60.72	–135.05	–43	85	10	—
Northwest Territories							
Aklavik	5	68.23	–135.01	–44	100	10	—
Echo Bay / Port Radium	195	66.05	–117.88	–44	99	10	—
Fort Good Hope	100	66.29	–128.63	–45	89	10	—
Fort McPherson	25	67.43	–134.88	–46	90	10	—
Fort Providence	150	61.35	–117.65	–43	80	10	—
Fort Resolution	160	61.19	–113.67	–42	93	10	—
Fort Simpson	120	61.93	–121.35	–44	80	10	—
Fort Smith	205	60.00	–111.88	–43	80	10	—
Hay River	45	60.85	–115.73	–41	89	10	—
Inuvik	45	68.35	–133.72	–45	100	10	—
Mould Bay	5	76.23	–119.33	–46	114	10	—
Norman Wells	65	65.28	–126.85	–45	89	10	—

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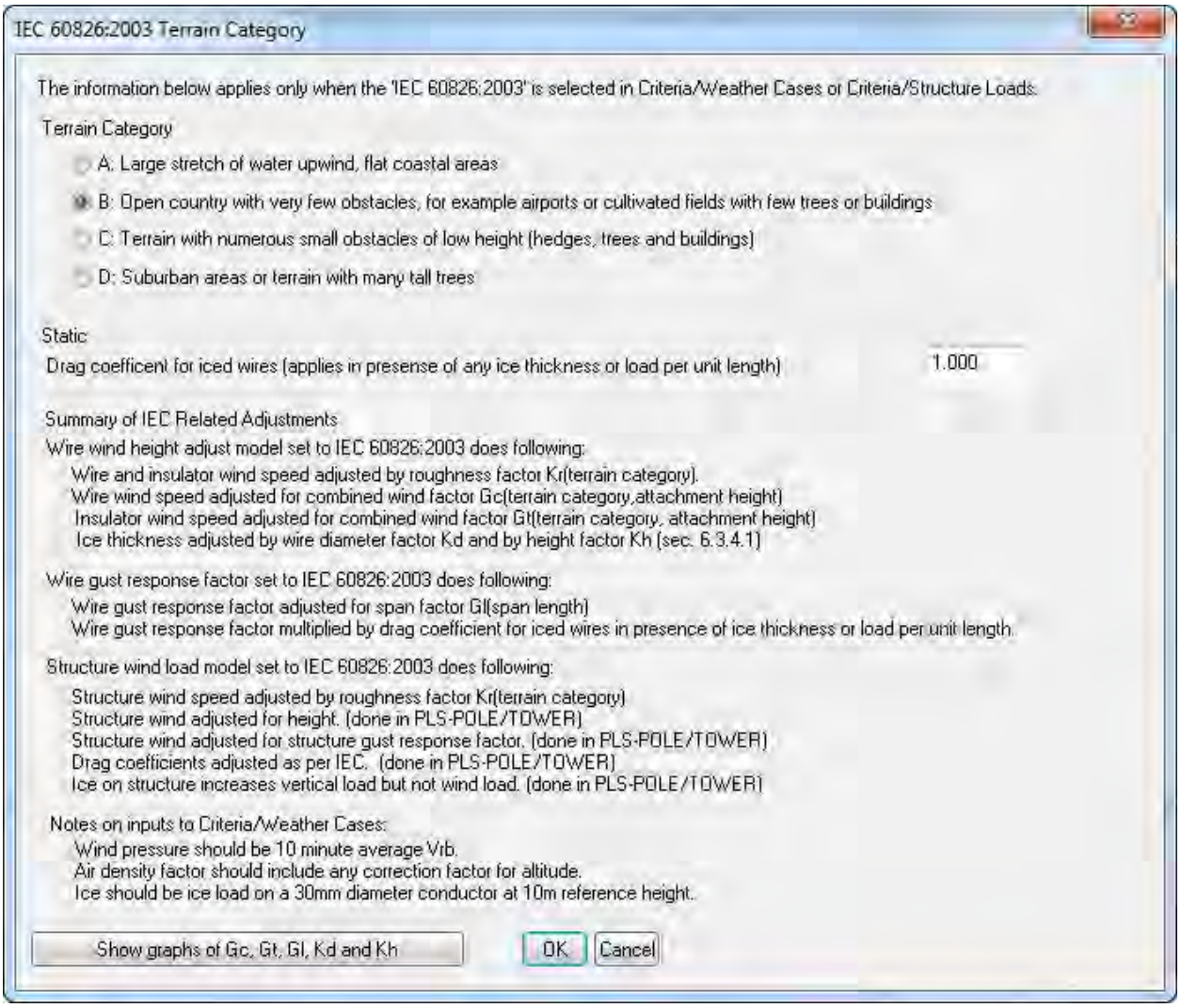
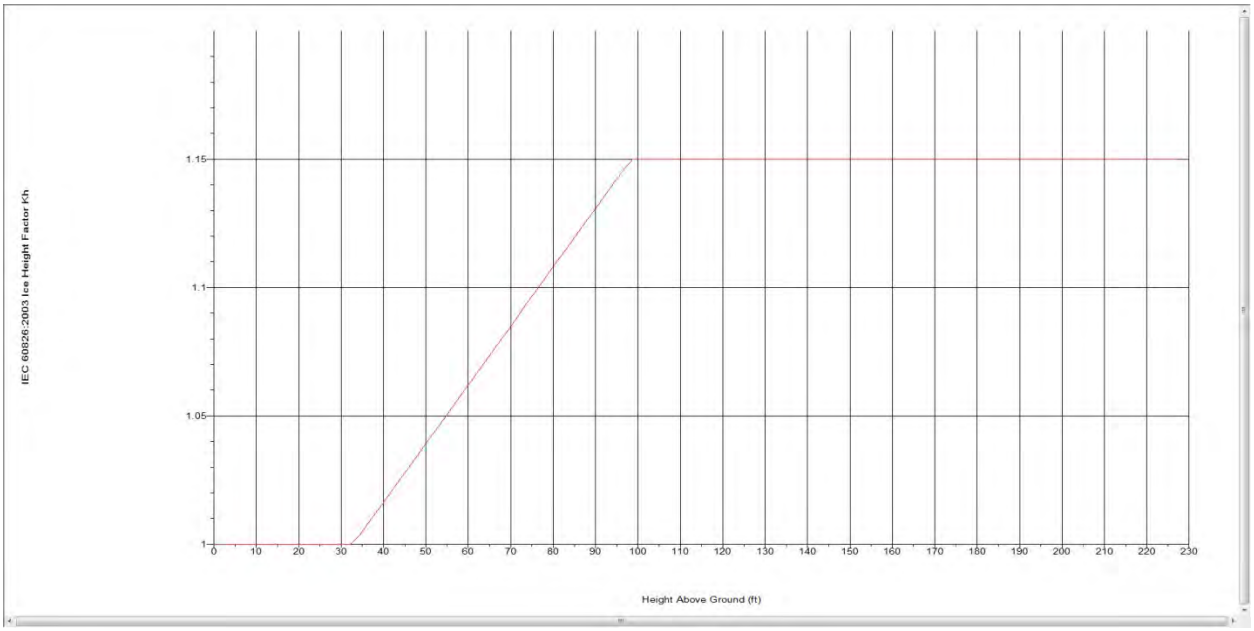
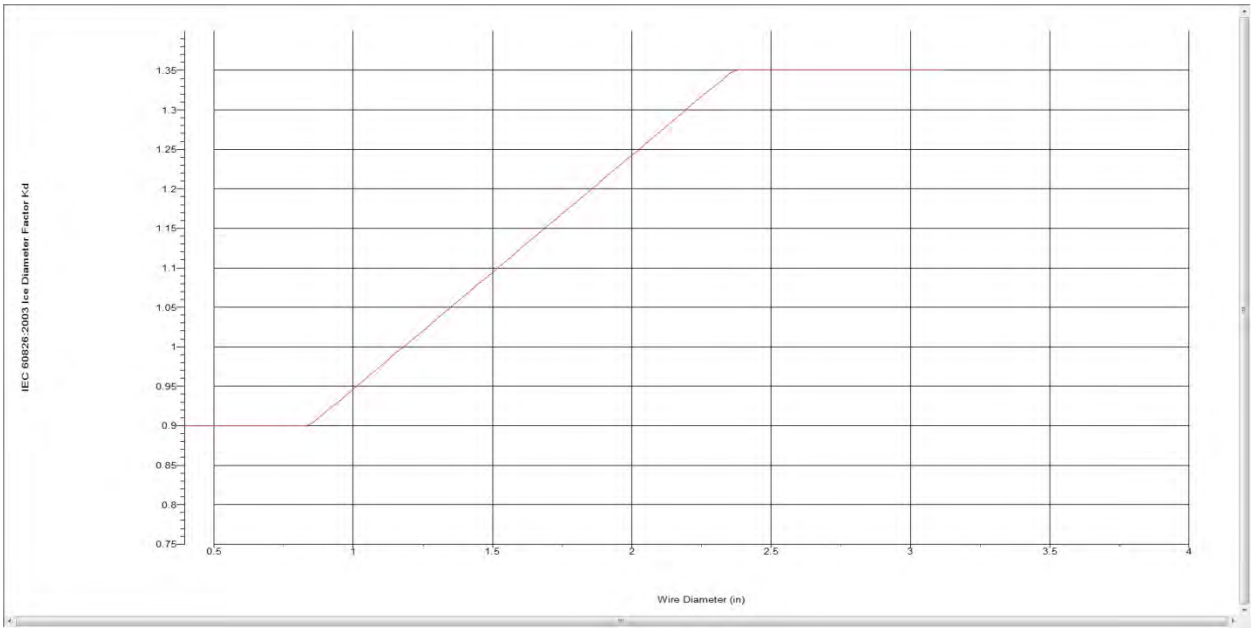
Appendix E – PLS-Cadd IEC 60826:03 Wind & Ice Adjustment Models

IEC 60826:2003 Design Code – Input Parameter Definitions

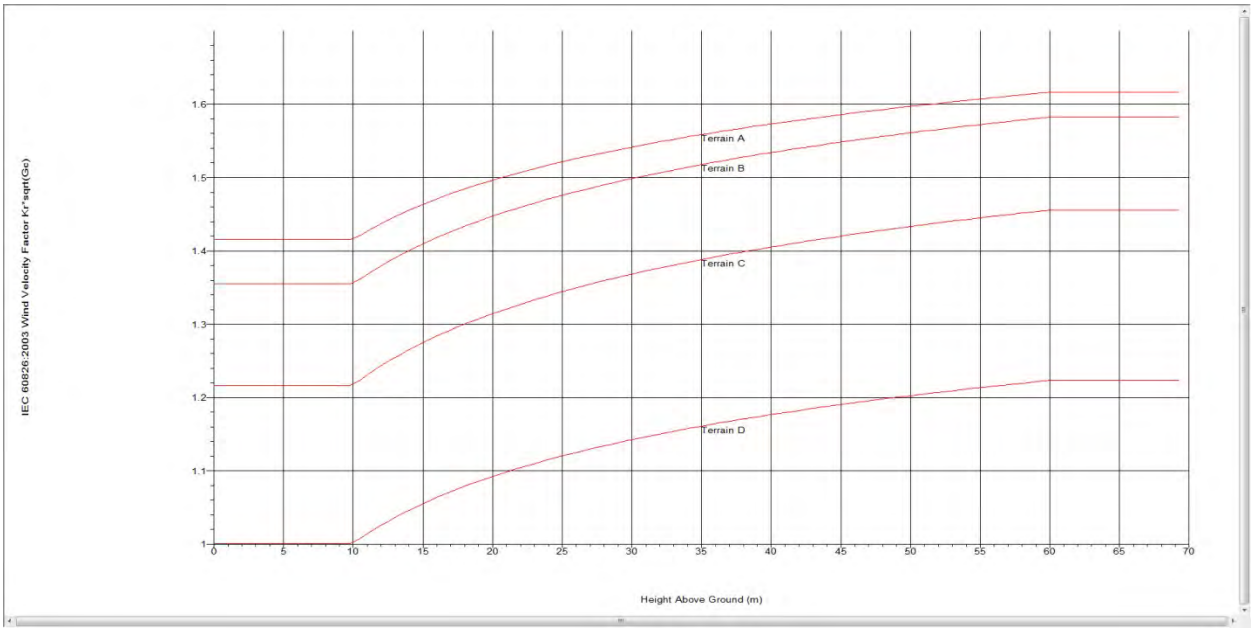




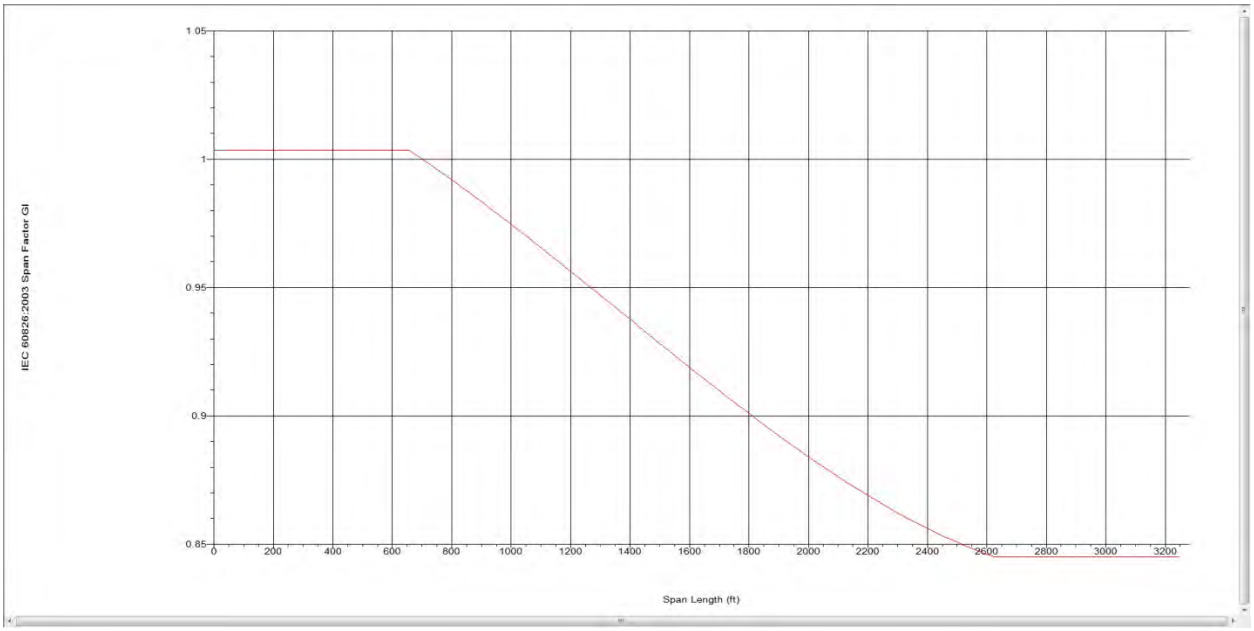
IEC Ice Height Factor (Kh) vs. Attachment Height



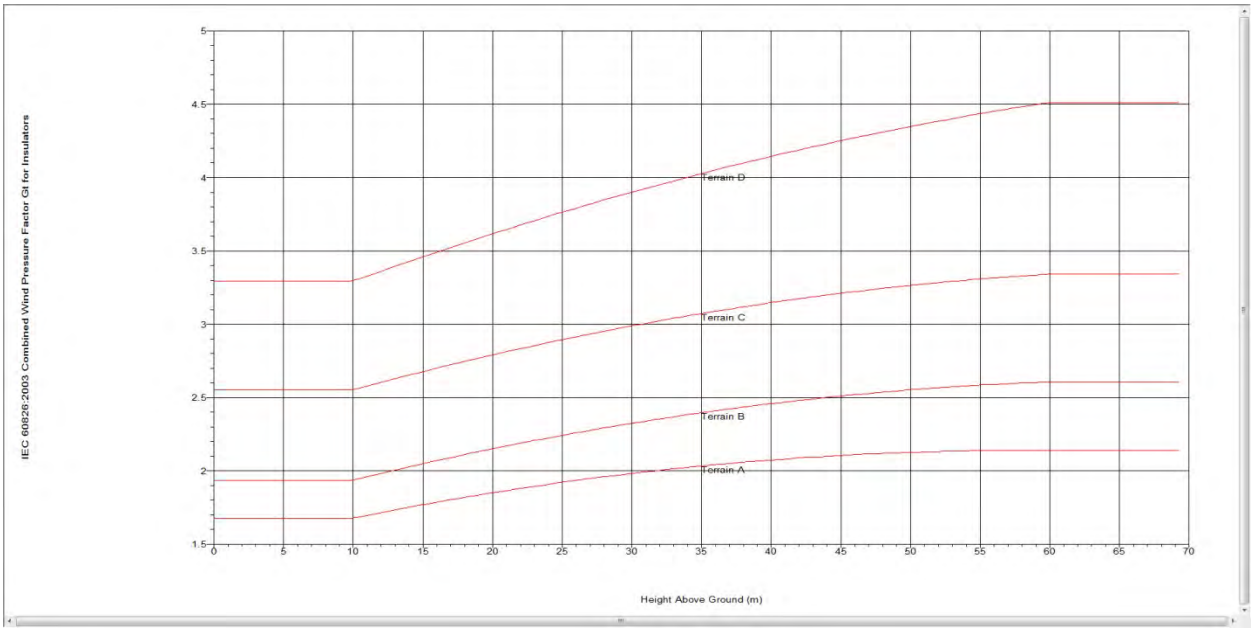
IEC Ice Diamter Factor (Kd) vs. Wire Diameter



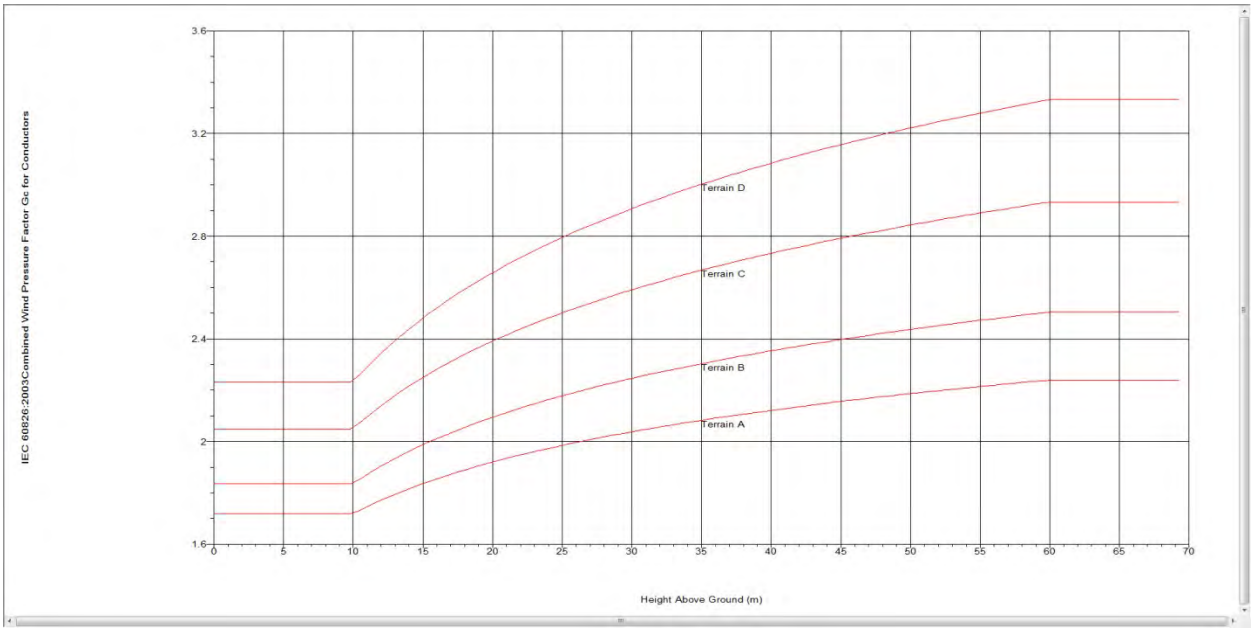
IEC Wind Velocity Factor (Kr*√Gc) vs. Attachment Height



IEC Span Factor (Gl) vs. Span



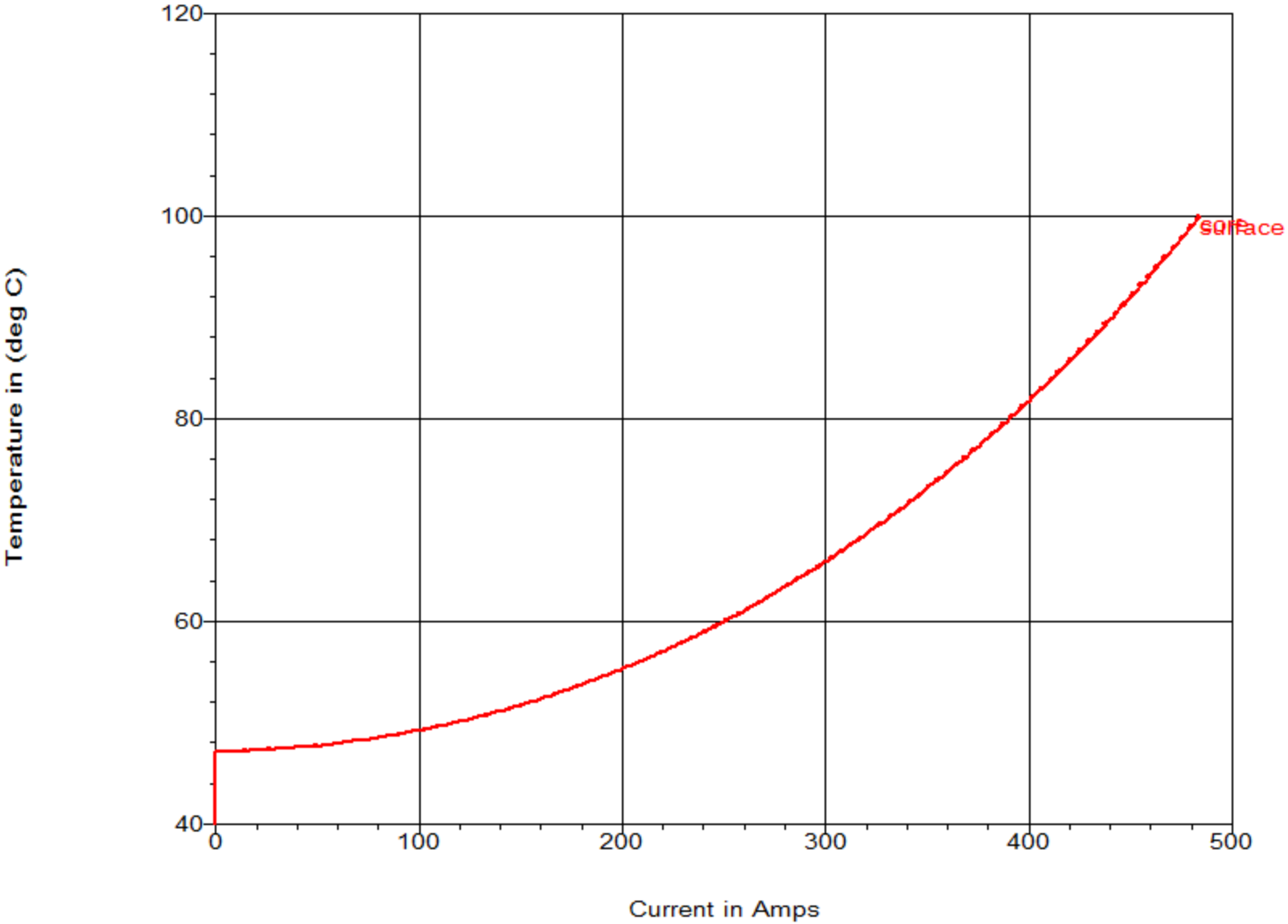
IEC Combined Wind Pressure Factor (Gt) for Insulators vs. Attachment Height



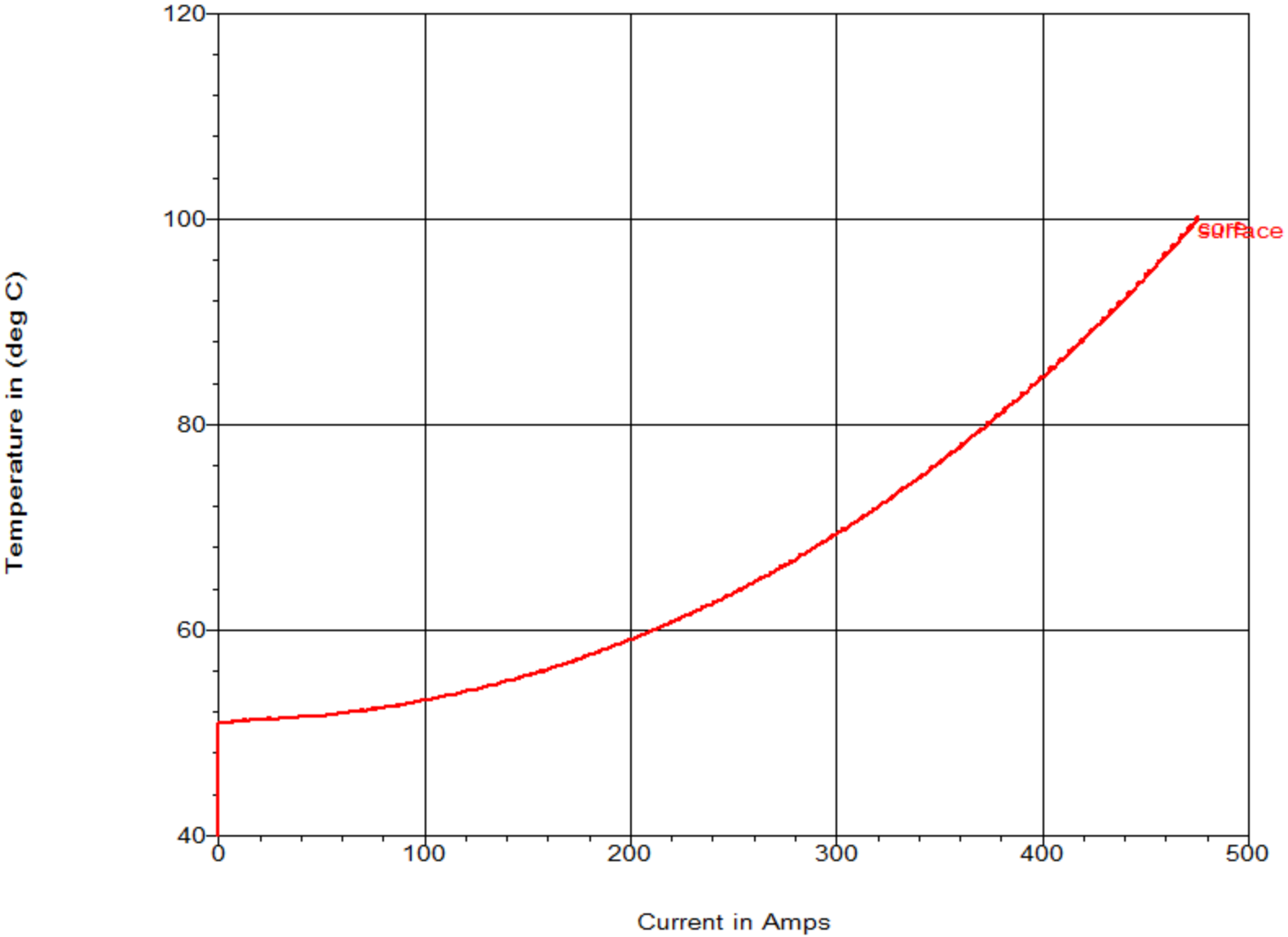
IEC Combined Wind Pressure Factor (Gc) for Conductors vs. Attachment Height

Appendix F – IEEE Std. 738 Ampacity Calculation Program Output

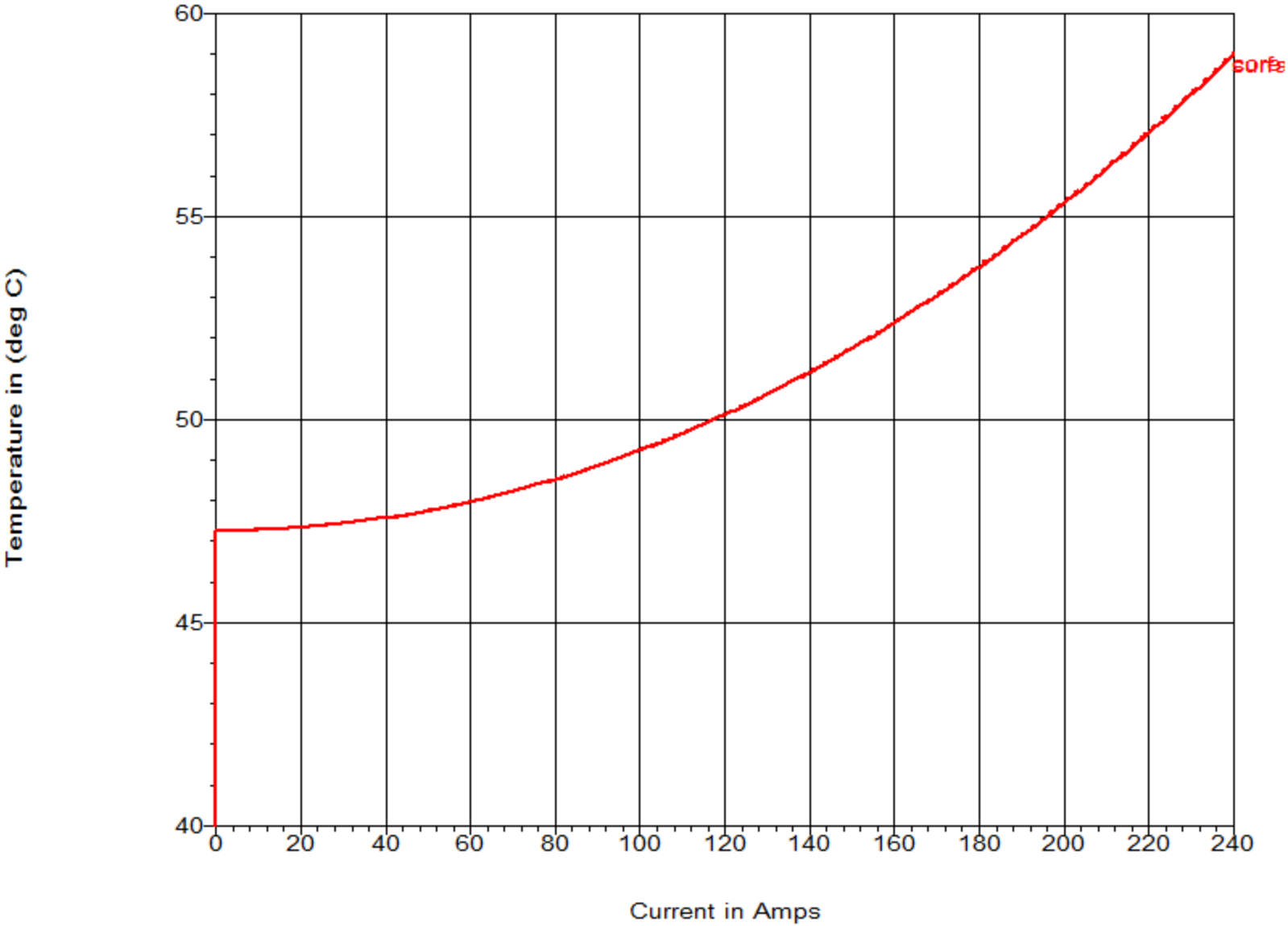
```
PLS-CADD Version 13.20x64    3:50:27 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                    and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is      8.539 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m^2) - which was calculated)
Radiation cooling is    14.183 (Watt/m)
Convective cooling is   59.286 (Watt/m)

Given a maximum conductor temperature of 100.0 (deg C),
The steady-state thermal rating is 484.4 amperes
```


120
100
80
60
40
0
100
200
300
400
500
surface
Temperature in (deg C)
Current in Amps

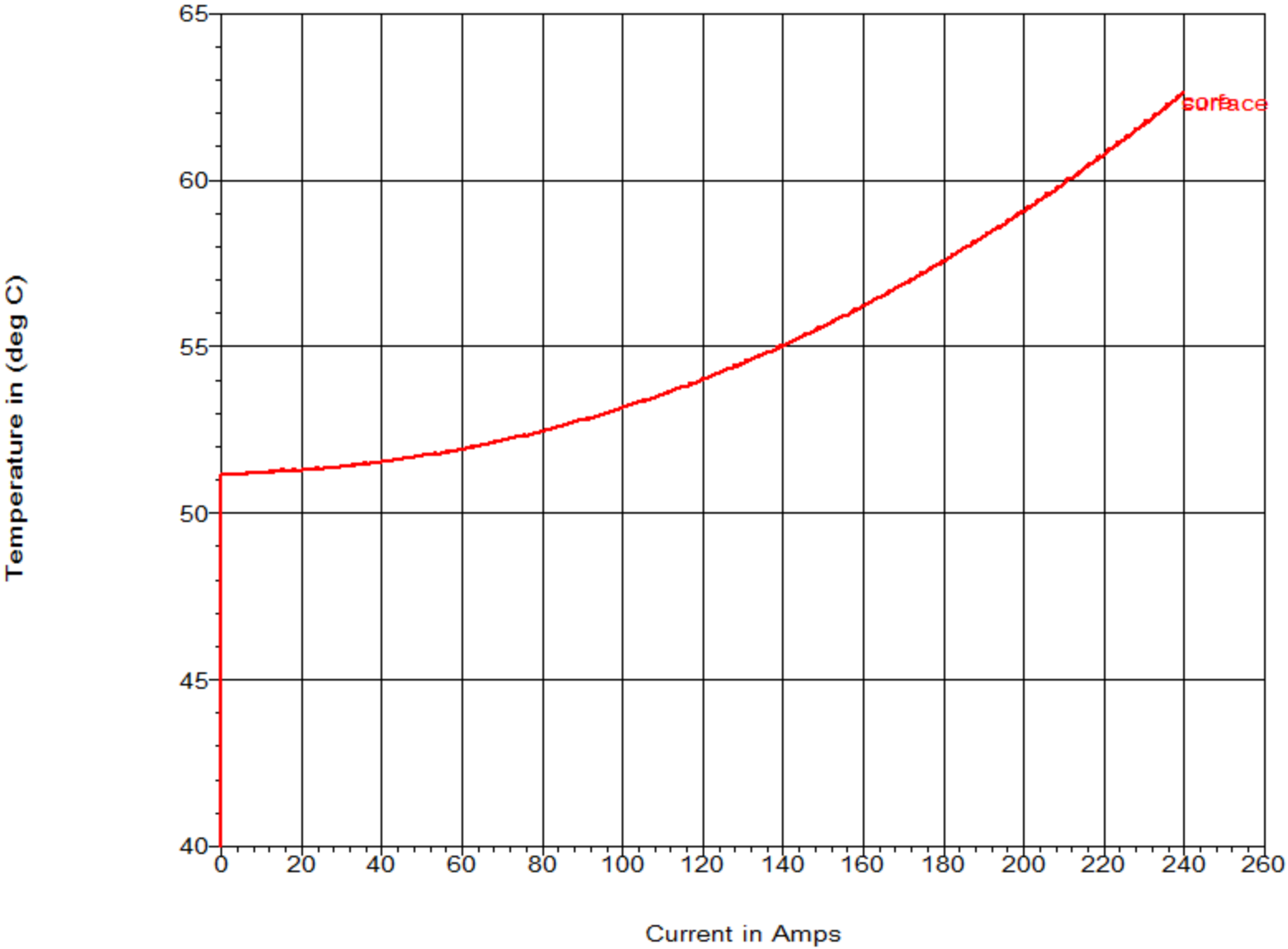
```
PLS-CADD Version 13.20x64    3:51:07 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                    and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     13.662 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m^2) - which was calculated)
Radiation cooling is    17.020 (Watt/m)
Convective cooling is   59.286 (Watt/m)

Given a maximum conductor temperature of 100.0 (deg C),
The steady-state thermal rating is 475.8 amperes
```


120
100
80
60
40
0
100
200
300
400
500
surface
Temperature in (deg C)
Current in Amps

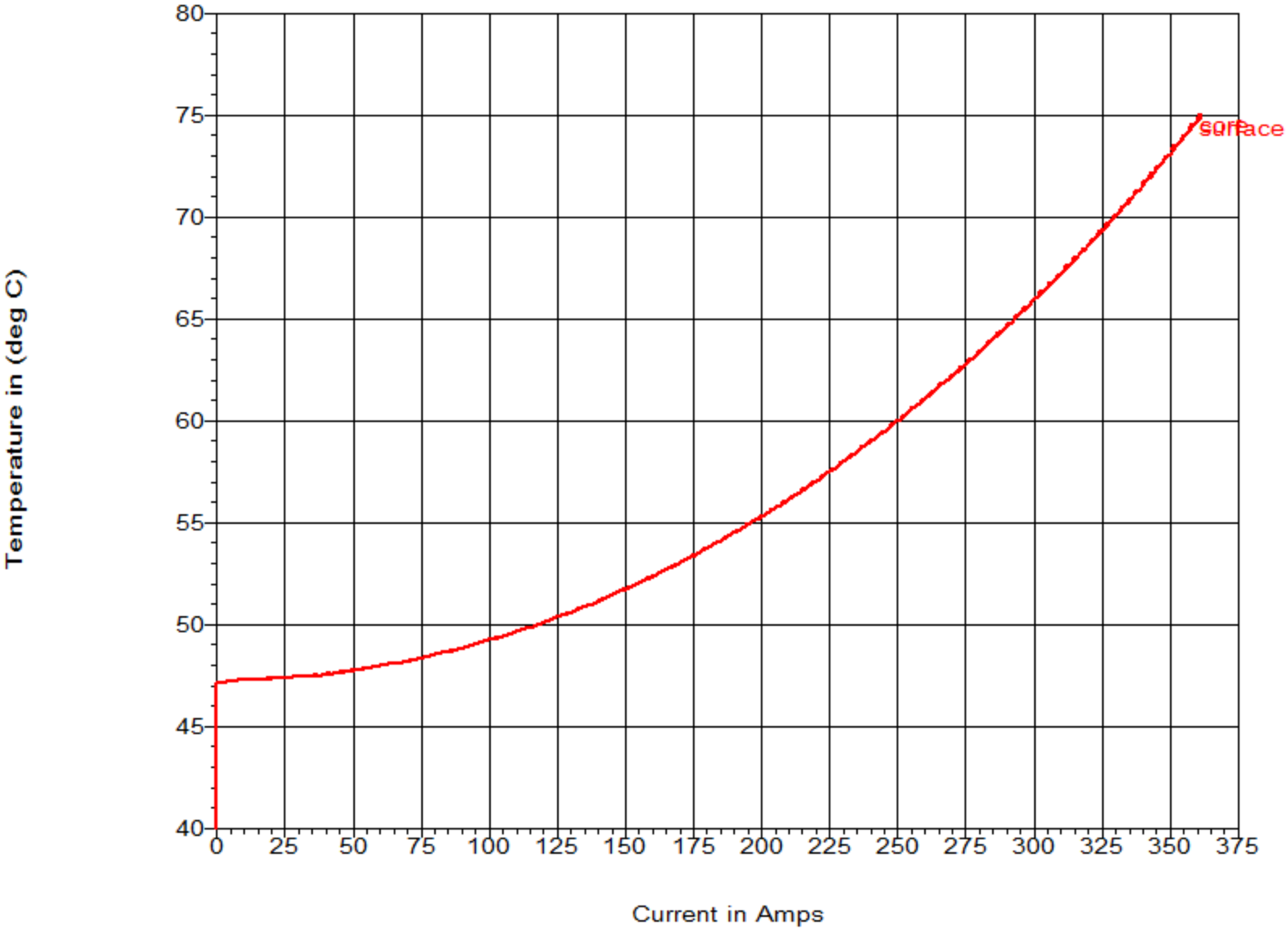
```
PLS-CADD Version 13.20x64    3:48:23 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                    and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is      8.539 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m^2) - which was calculated)
Radiation cooling is     3.704 (Watt/m)
Convective cooling is   18.779 (Watt/m)

Given a constant ac current of 240.0 amperes,
The conductor surface temperature is 59.0 (deg C)
The conductor core temperature is 59.0 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))
```


60
55
50
45
40
0
20
40
60
80
100
120
140
160
180
200
220
240
Temperature in (deg C)
Current in Amps

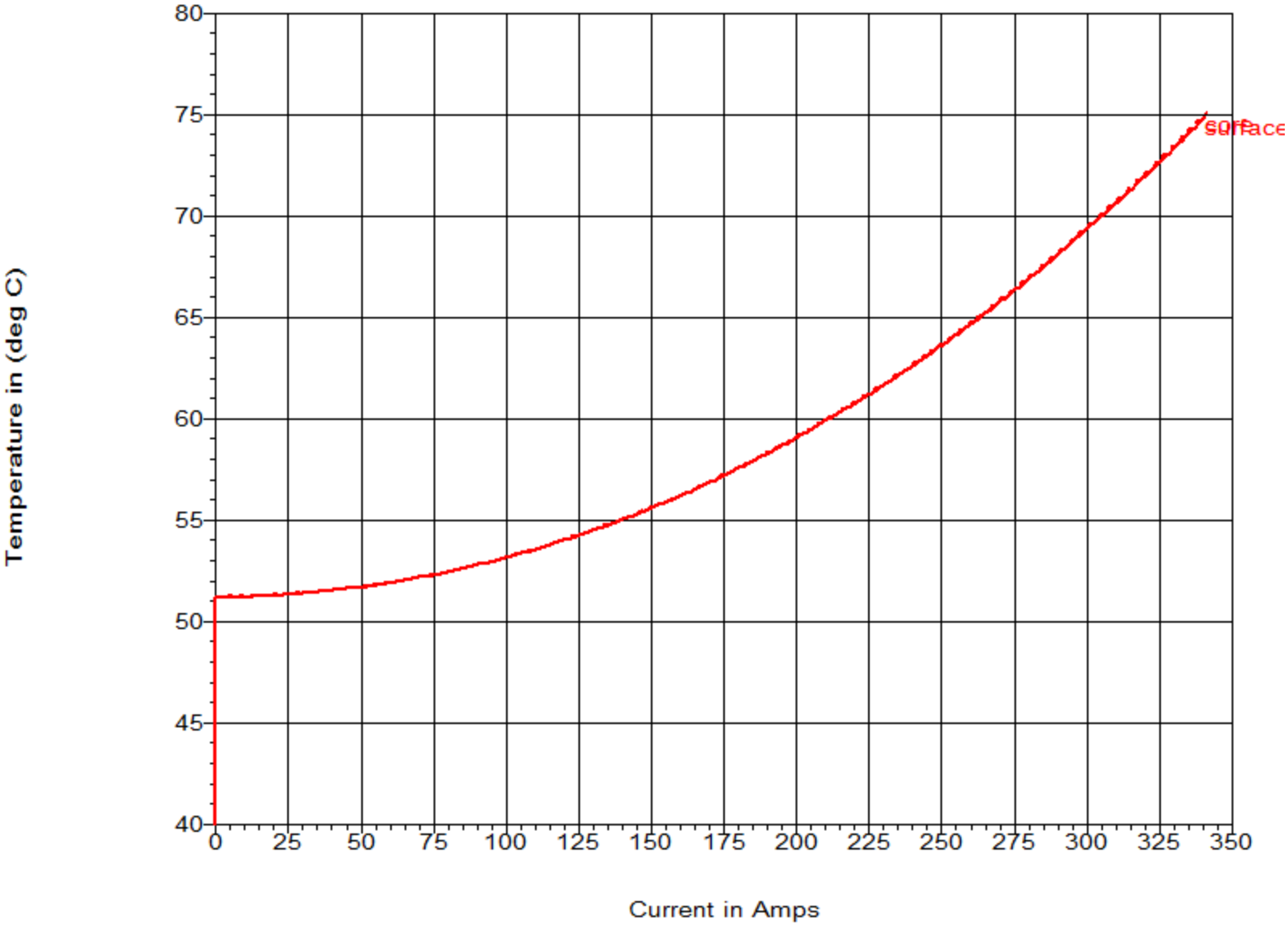
```
PLS-CADD Version 13.20x64    3:55:40 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                    and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     13.662 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m^2) - which was calculated)
Radiation cooling is     5.393 (Watt/m)
Convective cooling is   22.393 (Watt/m)

Given a constant ac current of 240.0 amperes,
The conductor surface temperature is 62.6 (deg C)
The conductor core temperature is 62.7 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))
```


65
60
55
50
45
40
0
20
40
60
80
100
120
140
160
180
200
220
240
260
surface
Temperature in (deg C)
Current in Amps

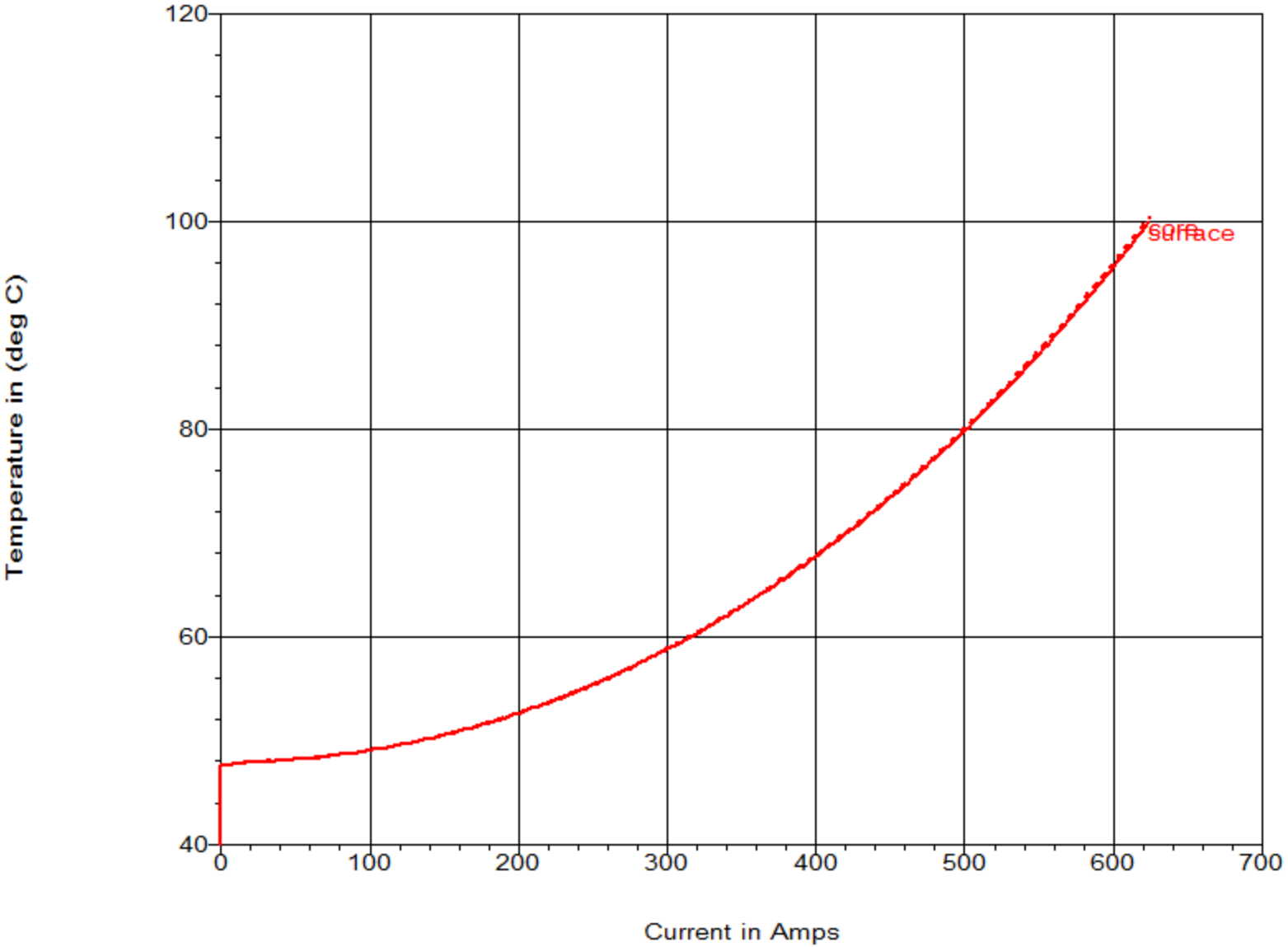
```
PLS-CADD Version 13.20x64    3:44:35 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                    and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is      8.539 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m^2) - which was calculated)
Radiation cooling is     7.366 (Watt/m)
Convective cooling is   34.610 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),
The steady-state thermal rating is 361.7 amperes
```


Temperature in (deg C)
80
75
70
65
60
55
50
45
40
0
25
50
75
100
125
150
175
200
225
250
275
300
325
350
375
surface
Current in Amps

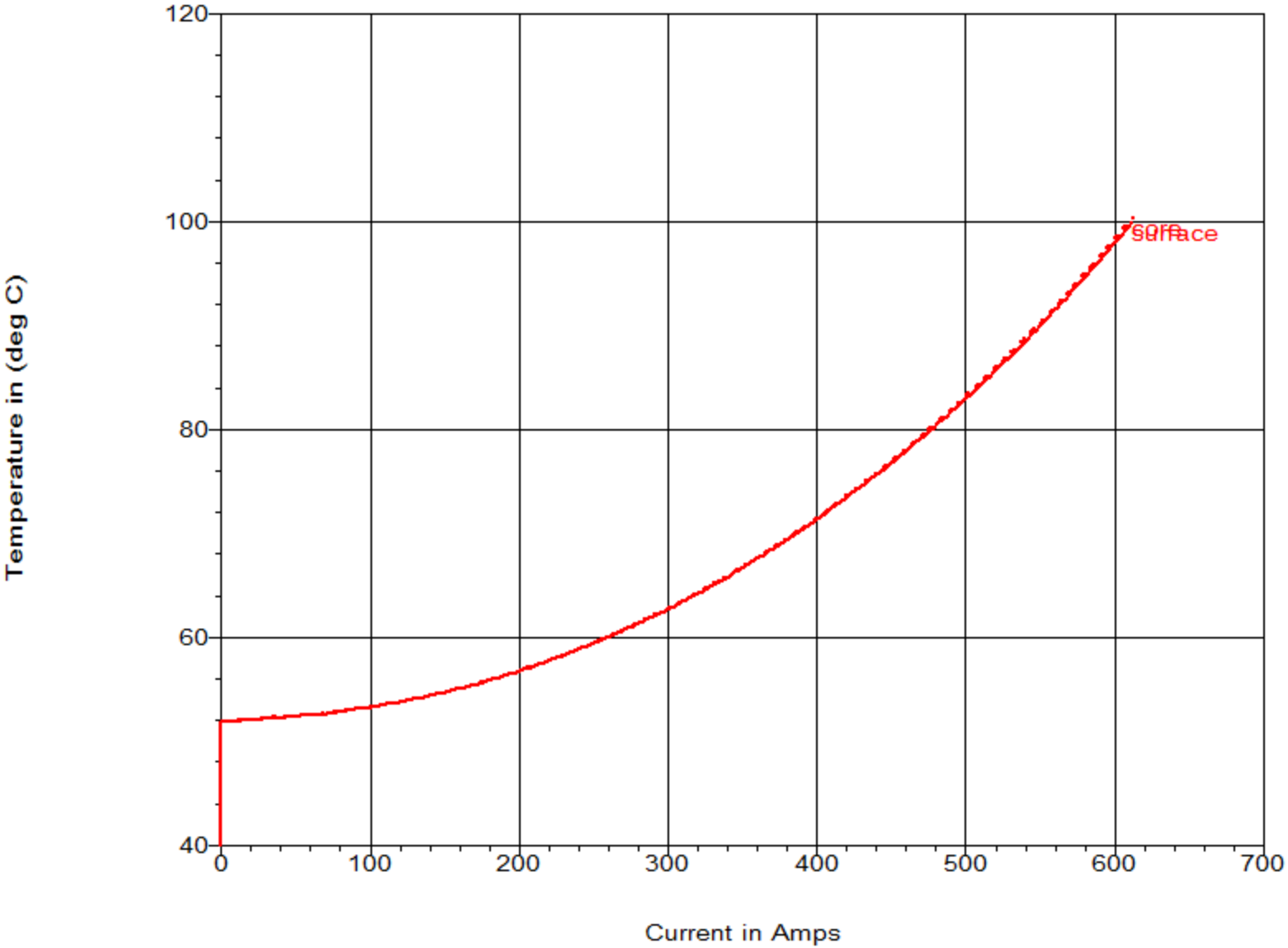
```
PLS-CADD Version 13.20x64    3:47:38 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 266.8 kcmil 26/7 Strands PARTRIDGE ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.631 (cm)
CORE STRANDS:
       Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is     0.2136 (Ohm/km) at  25.0 (deg C)
                    and     0.2556 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     13.662 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m^2) - which was calculated)
Radiation cooling is     8.839 (Watt/m)
Convective cooling is   34.610 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),
The steady-state thermal rating is 341.4 amperes
```


Temperature in (deg C)
80
75
70
65
60
55
50
45
40
0
25
50
75
100
125
150
175
200
225
250
275
300
325
350
Current in Amps
surface

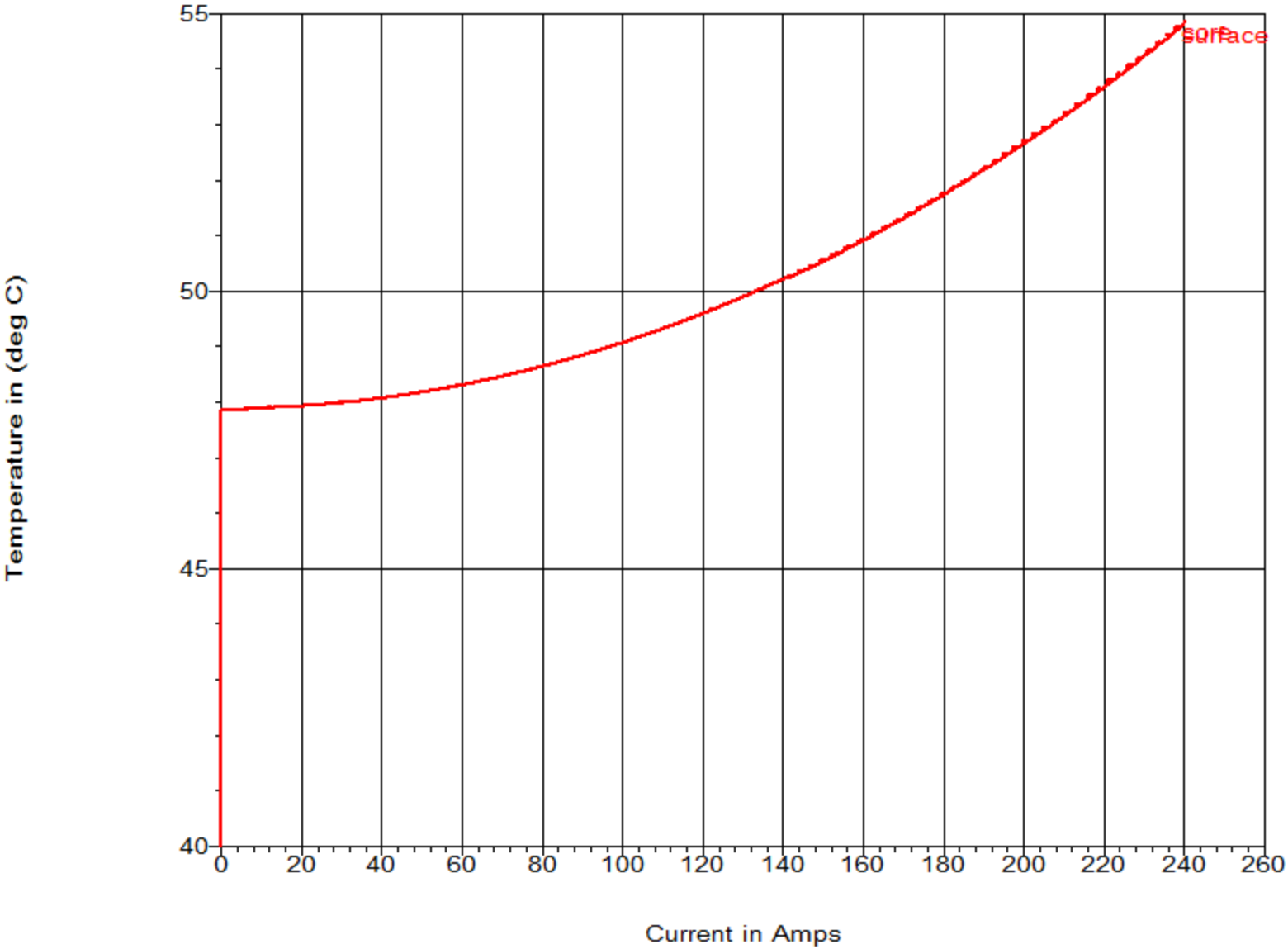
```
PLS-CADD Version 13.20x64    3:52:40 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 397.5 kcmil 26/7 Strands IBIS ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.989 (cm)
CORE STRANDS:
       Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is     0.1436 (Ohm/km) at  25.0 (deg C)
                    and     0.1717 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is     10.414 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m^2) - which was calculated)
Radiation cooling is    17.298 (Watt/m)
Convective cooling is   65.540 (Watt/m)

Given a maximum conductor temperature of 100.0 (deg C),
The steady-state thermal rating is 624.1 amperes
```


120
100
80
60
40
0
100
200
300
400
500
600
700
surface
Temperature in (deg C)
Current in Amps

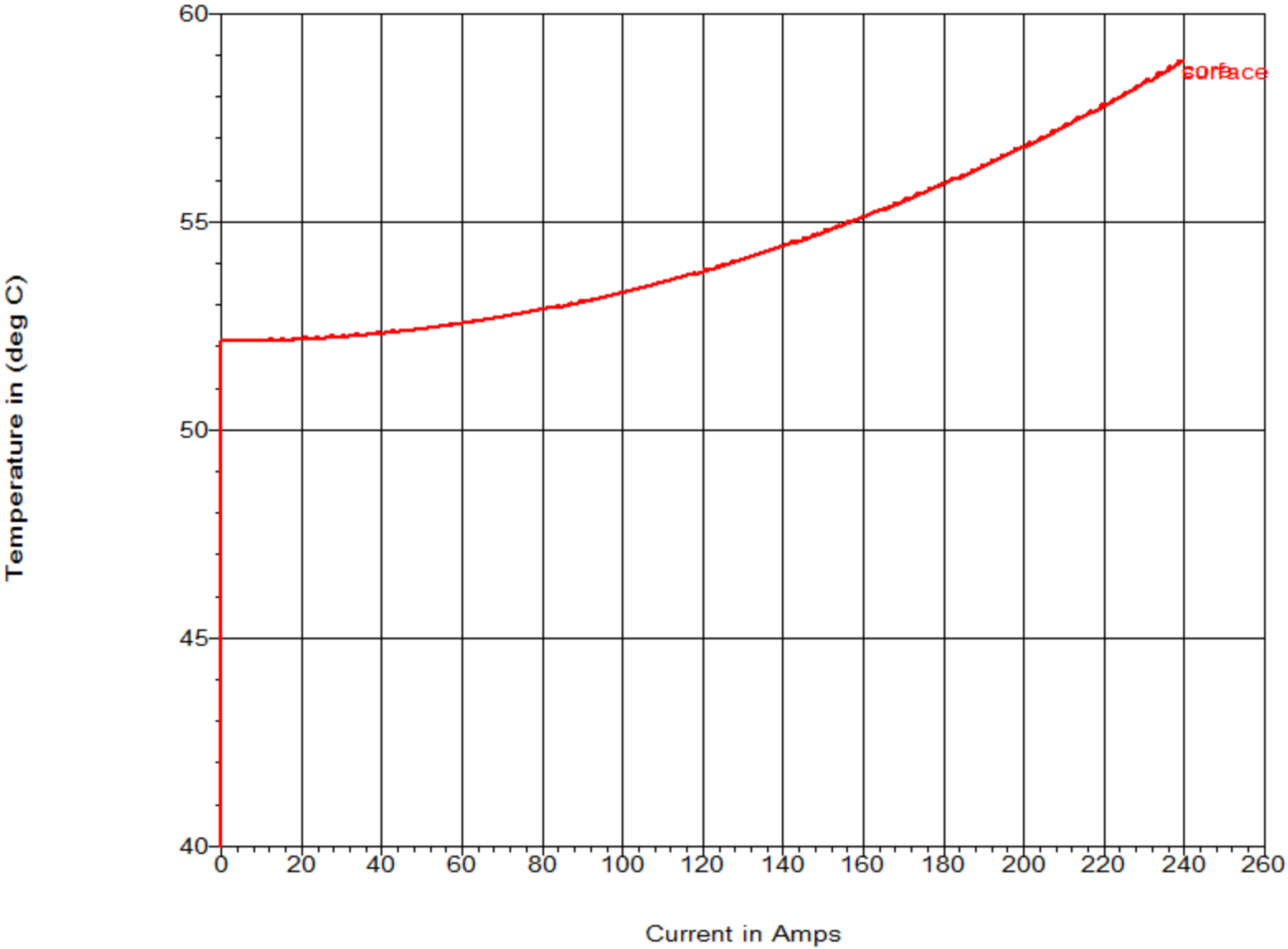
```
PLS-CADD Version 13.20x64    4:06:41 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 397.5 kcmil 26/7 Strands IBIS ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.989 (cm)
CORE STRANDS:
       Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is     0.1436 (Ohm/km) at  25.0 (deg C)
                    and     0.1717 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     16.663 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m^2) - which was calculated)
Radiation cooling is    20.758 (Watt/m)
Convective cooling is   65.540 (Watt/m)

Given a maximum conductor temperature of 100.0 (deg C),
The steady-state thermal rating is 612.0 amperes
```


120
100
80
60
40
0
100
200
300
400
500
600
700
Temperature in (deg C)
Current in Amps
surface

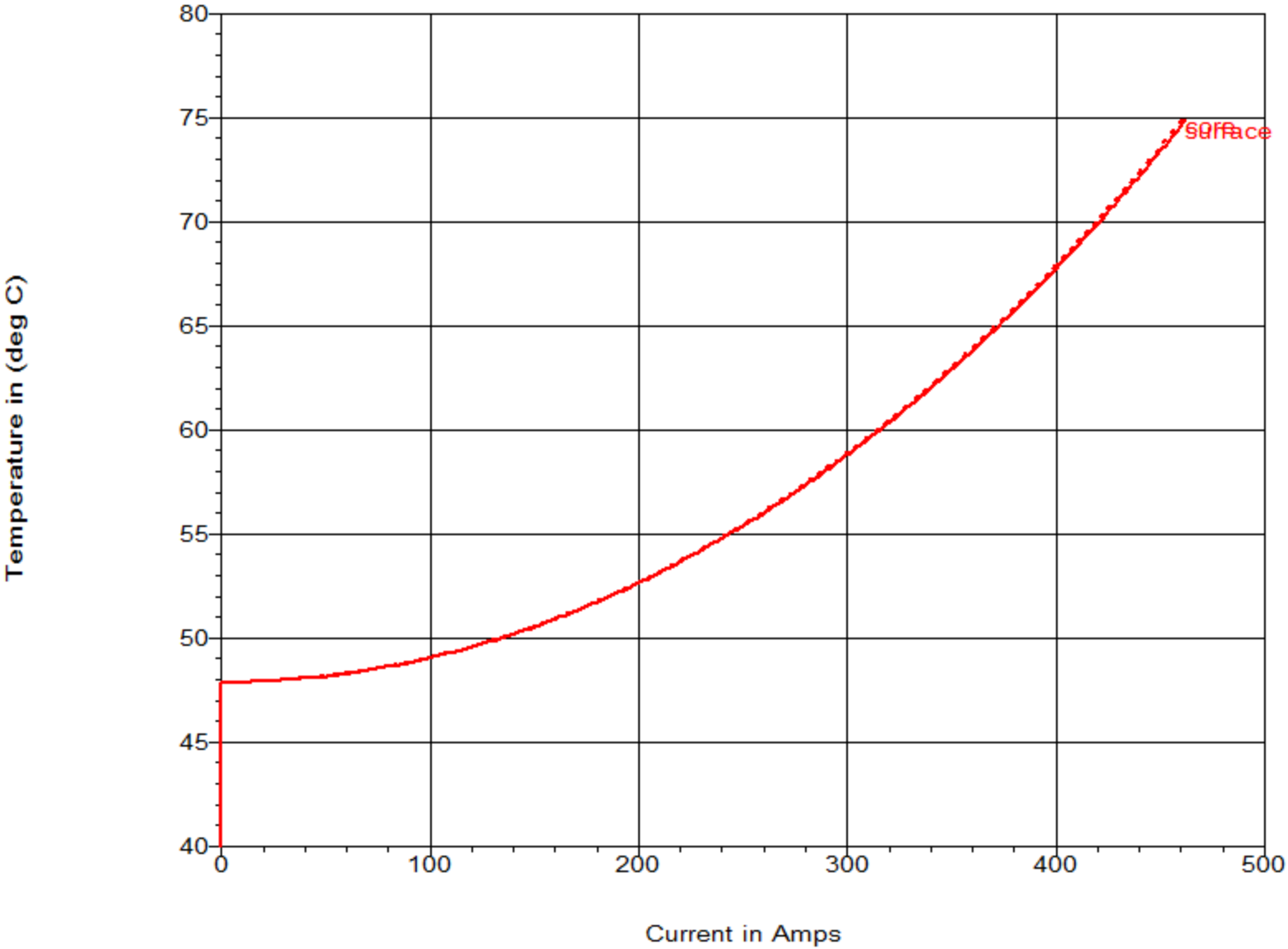
```
PLS-CADD Version 13.20x64    4:07:12 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 397.5 kcmil 26/7 Strands IBIS ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.989 (cm)
CORE STRANDS:
       Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is     0.1436 (Ohm/km) at  25.0 (deg C)
                    and     0.1717 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is     10.414 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m^2) - which was calculated)
Radiation cooling is     3.455 (Watt/m)
Convective cooling is   16.203 (Watt/m)

Given a constant ac current of 240.0 amperes,
The conductor surface temperature is 54.8 (deg C)
The conductor core temperature is 54.9 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))
```


55
50
45
40
surface
Temperature in (deg C)
0
20
40
60
80
100
120
140
160
180
200
220
240
260
Current in Amps

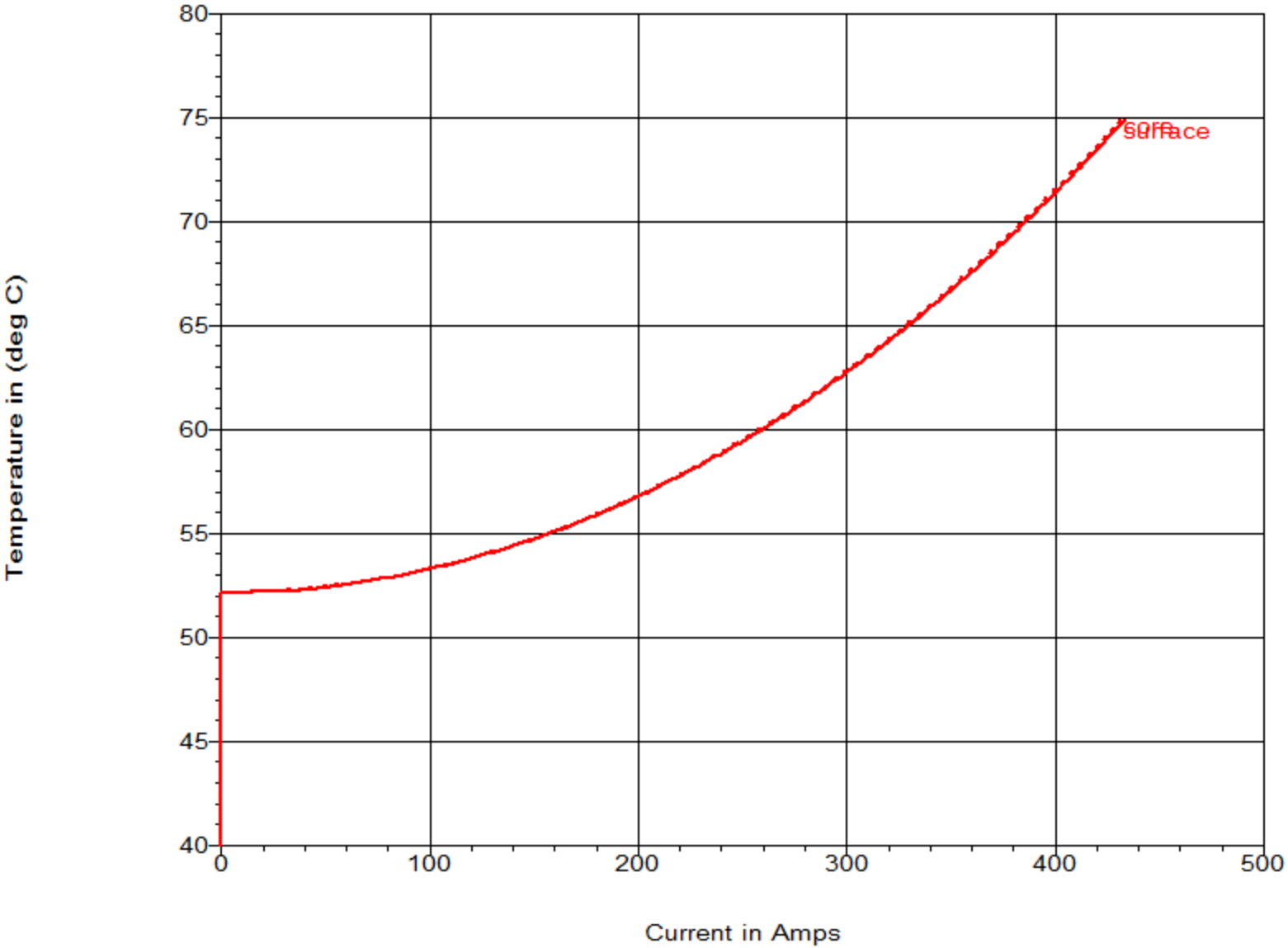
```
PLS-CADD Version 13.20x64    4:07:52 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 397.5 kcmil 26/7 Strands IBIS ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.989 (cm)
CORE STRANDS:
       Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is     0.1436 (Ohm/km) at  25.0 (deg C)
                    and     0.1717 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     16.663 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m^2) - which was calculated)
Radiation cooling is     5.387 (Watt/m)
Convective cooling is   20.648 (Watt/m)

Given a constant ac current of 240.0 amperes,
The conductor surface temperature is 58.9 (deg C)
The conductor core temperature is 58.9 (deg C) (based on radial thermal conductivity of 2.00 (W/m-K))
```


60
55
50
45
40
surface
Temperature in (deg C)
0
20
40
60
80
100
120
140
160
180
200
220
240
260
Current in Amps

```
PLS-CADD Version 13.20x64    3:51:58 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 397.5 kcmil 26/7 Strands IBIS ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.989 (cm)
CORE STRANDS:
       Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is     0.1436 (Ohm/km) at  25.0 (deg C)
                    and     0.1717 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.5 and solar absorptivity is 0.5

Solar heat input is     10.414 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m^2) - which was calculated)
Radiation cooling is     8.984 (Watt/m)
Convective cooling is   38.264 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),
The steady-state thermal rating is 463.0 amperes
```


80
75
70
65
60
55
50
45
40
0
100
200
300
400
500
surface
Temperature in (deg C)
Current in Amps

```
PLS-CADD Version 13.20x64    4:05:57 PM Thursday, July 23, 2015
Chimax Inc.
Project Name: 'c:\project\cable ampacity.DON'

IEEE Std. 738-2013 method of calculation

Air temperature is 40.00 (deg C)
Wind speed is 0.61 (m/s)
Angle between wind and conductor is 90 (deg)
Conductor elevation above sea level is 800 (m)
Conductor bearing is 270 (deg) (perpendicular to solar azimuth for maximum solar heating)
Sun time is 12 hours (solar altitude is 50 deg. and solar azimuth is 180 deg.)
Conductor latitude is 63.6 (deg)
Atmosphere is CLEAR
Day of year is 172 (corresponds to June 21 in year 2015) (day of the year with most solar heating)

Conductor description: 397.5 kcmil 26/7 Strands IBIS ACSR - Adapted from 1970's Publicly Available Data
Conductor diameter is 1.989 (cm)
CORE STRANDS:
       Diameter is 10.363 (mm)
Radial Thermal Conductivity is 2.00 (W/m-K)
Conductor resistance is     0.1436 (Ohm/km) at  25.0 (deg C)
                    and     0.1717 (Ohm/km) at  75.0 (deg C)
       Conductor resistance is computed using average of core and surface temperatures.
Emissivity is 0.6 and solar absorptivity is 0.8

Solar heat input is     16.663 (Watt/m) (corresponds to Global Solar Radiation of 1047.273 (Watt/m^2) - which was calculated)
Radiation cooling is    10.780 (Watt/m)
Convective cooling is   38.264 (Watt/m)

Given a maximum conductor temperature of 75.0 (deg C),
The steady-state thermal rating is 434.1 amperes
```


80
75
70
65
60
55
50
45
40
0
100
200
300
400
500
surface
Temperature in (deg C)
Current in Amps

Appendix C – Transmission Line Cost Data

1A L179 138kV H-Frame with OPGW

1B L179 138kV H-Frame with ADSS

2A L180 138kV H-Frame with OPGW

3A L250 138kV H-Frame with OPGW

YEC - SKTL 10-Feb-16
138kV L179 Stewart Crossing South to Mayo (H-Frame with OPGW) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L179 H-Frame with OPGW**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	193.0	km	$1,100,100.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	65.0	km	$243,750.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	65.0	km	$162,500.00
1.2	Structure Framing			
1.2A	Insulator			$330,336.00
1.2B	Hardware			$694,564.00
1.2C	Structural Steel	155,060	kg	$682,264.00
1.2D	Poles	819	ea	$1,515,800.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	15	ea	$22,500.00
1.2G	Aerial Marker	39	ea	$5,850.00
1.2H	Structure Marker	389	ea	$5,835.00
1.2J	Phase Marker	78	ea	$2,340.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	548	set	$383,600.00
1.3B	Imported Backfill	39	ea	$116,700.00
1.3C	Bed Rock Install Adder	78	ea	$116,700.00
1.3D	Swamp & Bog Adder	156	ea	$544,600.00
A	**Total Procurement Cost**			**$5,927,439.00**
2.0	***Construction Labour***	**L179 H-Frame with OPGW**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	58.3	km	$204,050.00
2.1B	Survey (Construction)	389.0	ea	$544,600.00
2.1C	Clearing	174.9	ha	$2,273,700.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	98	ea	$83,300.00
2.2B	Structure Installation	389	ea	$5,372,500.00
2.2C	Guy & Anchor Installation	548	set	$865,500.00
2.2D	Imported Backfill	39	ea	$272,300.00
2.2E	Bed Rock Install Adder	78	ea	$194,500.00
2.2F	Swamp & Bog Adder	156	ea	$1,089,200.00
2.2G	Conductor Stringing	175	km	$2,973,300.00
2.2H	OPGW Stringing	58	km	$1,166,000.00
2.2J	OHGW Stringing	58	km	$757,900.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	15	ea	$120,000.00
2.2M	Aerial Marker	39	ea	$7,800.00
2.2N	Structure Marker	389	ea	$50,570.00
2.2P	Phase Marker	78	ea	$10,140.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$15,985,360.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	58	km	$349,800.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$349,800.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	12	mth	$230,000
4.3	Personnel Cost	37	man-mth	$1,683,500
4.4	Personnel Expense	37	man-mth	$673,400
D	**Total Construction Management Cost**			**$2,736,900.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	0	ha	$0.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$0.00**

	L179 H-Frame with OPGW	
Sub-Total Cost		**$24,999,499.00**
Misc. Items	15%	**$3,749,924.85**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$28,749,423.85**

YEC - SKTL 10-Feb-16
138kV L179 Stewart Crossing South to Mayo (H-Frame with ADSS) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***		**L179 H-Frame with ADSS**	
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	193.0	km	$1,100,100.00
1.1B	ADSS	65.0	km	$201,500.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	3.5	km	$8,750.00
1.2	Structure Framing			
1.2A	Insulator			$328,443.00
1.2B	Hardware			$632,685.00
1.2C	Structural Steel	157,583	kg	$693,365.20
1.2D	Poles	823	ea	$1,498,200.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	15	ea	$22,500.00
1.2G	Aerial Marker	39	ea	$5,850.00
1.2H	Structure Marker	389	ea	$5,835.00
1.2J	Phase Marker	78	ea	$2,340.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	372	set	$260,400.00
1.3B	Imported Backfill	39	ea	$116,700.00
1.3C	Bed Rock Install Adder	78	ea	$116,700.00
1.3D	Swamp & Bog Adder	156	ea	$544,600.00
A	**Total Procurement Cost**			**$5,537,968.20**
2.0	***Construction Labour***		**L179 H-Frame with ADSS**	
2.1	Site Preparation			
2.1A	Survey (Right of Way)	58.3	km	$204,050.00
2.1B	Survey (Construction)	389.0	ea	$544,600.00
2.1C	Clearing	174.9	ha	$2,273,700.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	98	ea	$83,300.00
2.2B	Structure Installation	389	ea	$5,378,750.00
2.2C	Guy & Anchor Installation	372	set	$846,000.00
2.2D	Imported Backfill	39	ea	$272,300.00
2.2E	Bed Rock Install Adder	78	ea	$194,500.00
2.2F	Swamp & Bog Adder	156	ea	$1,089,200.00
2.2G	Conductor Stringing	175	km	$2,973,300.00
2.2H	ADSS Stringing	58	km	$1,166,000.00
2.2J	OHGW Stringing	4	km	$45,500.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	15	ea	$120,000.00
2.2M	Aerial Marker	39	ea	$7,800.00
2.2N	Structure Marker	389	ea	$50,570.00
2.2P	Phase Marker	78	ea	$10,140.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$15,259,710.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	58	km	$349,800.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$349,800.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	12	mth	$230,000
4.3	Personnel Cost	37	man-mth	$1,683,500
4.4	Personnel Expense	37	man-mth	$673,400
D	**Total Construction Management Cost**			**$2,736,900.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	0	ha	$0.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$0.00**

	L179 H-Frame with ADSS	
Sub-Total Cost		**$23,884,378.20**
Misc. Items	15%	**$3,582,656.73**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$27,467,034.93**

YEC - SKTL 28-Jan-16
138kV L180 Mayo to McQueston (H-Frame with OPGW) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***		**L180 H-Frame with OPGW**	
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	103.0	km	$587,100.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	35.0	km	$131,250.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	35.0	km	$87,500.00
1.2	Structure Framing			
1.2A	Insulator			$153,765.00
1.2B	Hardware			$331,835.00
1.2C	Structural Steel	77,324	kg	$340,225.60
1.2D	Poles	406	ea	$744,000.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	19	ea	$2,850.00
1.2H	Structure Marker	187	ea	$2,805.00
1.2J	Phase Marker	38	ea	$1,140.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	265	set	$185,500.00
1.3B	Imported Backfill	19	ea	$56,100.00
1.3C	Bed Rock Install Adder	37	ea	$56,100.00
1.3D	Swamp & Bog Adder	75	ea	$261,800.00
A	**Total Procurement Cost**			**$2,956,970.60**
2.0	***Construction Labour***		**L180 H-Frame with OPGW**	
2.1	Site Preparation			
2.1A	Survey (Right of Way)	31.1	km	$108,850.00
2.1B	Survey (Construction)	187.0	ea	$261,800.00
2.1C	Clearing	93.3	ha	$1,212,900.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	47	ea	$39,950.00
2.2B	Structure Installation	187	ea	$2,618,750.00
2.2C	Guy & Anchor Installation	265	set	$745,500.00
2.2D	Imported Backfill	19	ea	$130,900.00
2.2E	Bed Rock Install Adder	37	ea	$93,500.00
2.2F	Swamp & Bog Adder	75	ea	$523,600.00
2.2G	Conductor Stringing	93	km	$1,586,100.00
2.2H	OPGW Stringing	31	km	$622,000.00
2.2J	OHGW Stringing	31	km	$404,300.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	19	ea	$3,800.00
2.2N	Structure Marker	187	ea	$24,310.00
2.2P	Phase Marker	38	ea	$4,940.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$8,461,200.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	31	km	$186,600.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$186,600.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	7	mth	$130,000
4.3	Personnel Cost	21	man-mth	$955,500
4.4	Personnel Expense	21	man-mth	$382,200
D	**Total Construction Management Cost**			**$1,617,700.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	1	ha	$200,000.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$200,000.00**

	L180 H-Frame with OPGW	
Sub-Total Cost		**$13,422,470.60**
Misc. Items	15%	**$2,013,370.59**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$15,435,841.19**

YEC - SKTL 28-Jan-16
69kV L250 McQueston to Keno (H-Frame with OPGW) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***		**L250 H-Frame with OPGW**	
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	67.0	km	$381,900.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	23.0	km	$86,250.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	21.0	km	$52,500.00
1.2	Structure Framing			
1.2A	Insulator			$125,664.00
1.2B	Hardware			$224,786.00
1.2C	Structural Steel	50,492	kg	$222,164.80
1.2D	Poles	279	ea	$492,950.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	15	ea	$2,250.00
1.2H	Structure Marker	143	ea	$2,145.00
1.2J	Phase Marker	29	ea	$870.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	137	set	$95,900.00
1.3B	Imported Backfill	14	ea	$42,900.00
1.3C	Bed Rock Install Adder	29	ea	$42,900.00
1.3D	Swamp & Bog Adder	57	ea	$200,200.00
A	**Total Procurement Cost**			**$1,988,379.80**
2.0	***Construction Labour***		**L250 H-Frame with OPGW**	
2.1	Site Preparation			
2.1A	Survey (Right of Way)	20.2	km	$70,700.00
2.1B	Survey (Construction)	143.0	ea	$200,200.00
2.1C	Clearing	60.6	ha	$787,800.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	36	ea	$30,600.00
2.2B	Structure Installation	143	ea	$1,830,625.00
2.2C	Guy & Anchor Installation	137	set	$987,000.00
2.2D	Imported Backfill	14	ea	$100,100.00
2.2E	Bed Rock Install Adder	29	ea	$71,500.00
2.2F	Swamp & Bog Adder	57	ea	$400,400.00
2.2G	Conductor Stringing	61	km	$1,030,200.00
2.2H	OPGW Stringing	20	km	$404,000.00
2.2J	OHGW Stringing	20	km	$262,600.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	15	ea	$3,000.00
2.2N	Structure Marker	143	ea	$18,590.00
2.2P	Phase Marker	29	ea	$3,770.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$6,281,085.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	20	km	$121,200.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$121,200.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	5	mth	$100,000
4.3	Personnel Cost	16	man-mth	$728,000
4.4	Personnel Expense	16	man-mth	$291,200
D	**Total Construction Management Cost**			**$1,269,200.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	0	ha	$0.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$0.00**

	L250 H-Frame with OPGW		
	Sub-Total Cost		**$9,659,864.80**
	Misc. Items	15%	**$1,448,979.72**
	Owner's Cost (Cost of Financing)	0%	**$0.00**
	Total Cost of Transmission Line		**$11,108,844.52**

Construction Cost Comparison

Line Configuration	Procurement & Construction				Construction Unit Cost / km			
	L179	L180	L250	Total	L179 58.3	L180 31.1	L250 20.2	Combined 109.6
H-Frame (Preferred Configuration - More Reliable)								
H-Frame (with OPGW & OHGW)	$21,912,799.00	$11,418,170.60	$8,269,464.80	$41,600,434.40	$375,862.76	$367,143.75	$409,379.45	$379,566.01

For L250 within Keno City boundary - Mono Poles are used in all scenario due to reduced ROW.

L179 Fibre-Optic Configuration Comparison

L179 Line Configuration	Procurement & Construction	
	L179	L179 58.3
H-Frame (No OHGW with ADSS)	$20,797,678.20	$356,735.48
H-Frame (OHGW & ADSS)	$21,912,799.00	$375,862.76

SKTL Project Cost	H-Frame OHGW &OPGW
Project Component	
Conductor & Stringing	$7,658,700.00
OPGW / OHGW & Stringing	$4,380,550.00
Structures - Material & Labour	$23,896,584.40
Subtotal - Structures & Conductor	***$35,935,834.40***
Survey	$1,390,200.00
Clearing & Access	$4,274,400.00
Subtotal - Procurement & Construction	***$41,600,434.40***
Construction Management	$5,623,800.00
Construction Support	$2,192,000.00
Transmission Line Construction Costs	***$49,416,234.40***
Contingency - 15% of T/L Costs	$7,412,435.16
Planning Costs	
Environmental Assessment & Permits	$720,000.00
Preliminary Engineering - T/L	$340,000.00
Preliminary Engineering - S/S	$250,000.00
Communications	$150,000.00
Project Management	$180,000.00
Plan & Permitting	***$1,640,000.00***
Land Acquisition	
Legal & Consulation Cost	$200,000.00
Land Easement Cost	$0.00
FN Project Agreement	$0.00
Land Cost / FN Agreements	***$200,000.00***
Detail Enginnering -T/L	
Confirmation Survey for Design	$0.00
Environmental Assessment	$0.00
Vegetation Clearing Permit	$0.00
Transmission Engineering Design	$657,600.00
Crossing Permits	$0.00
Detail Enginnering -T/L	***$657,600.00***
Planning, Permitting & Engineering	***$2,497,600.00***
Contingency - 15% of PPE Costs	$374,640.00
Total Cost	**$59,700,909.56**
Cost / km	$544,716.33

Chimax Inc.

TRANSMISSION LINE
Extension Scope Report

STEWART TO KENO TRANSMISSION PROJECT
138 kV TRANSMISSION LINES

Yukon Energy Corporation

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February 12, 2016 (Rev-0)

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1.0 Project Overview

Yukon Energy Corporation (YEC) is proposing to construct a 138kV transmission line from Stewart Crossing South (SCS) substation to Keno City (KC) substation. The overall transmission line and associated substation construction or modification is grouped as SKTL project.

Chimax Inc. had developed the transmission line cost estimations for the three segments of the SKTL transmission lines. The preliminary design report was produced in early January 2016.

The preliminary SKTL cost estimates for transmission lines and substations are approximately $86 million which substantially higher than conceptual cost estimation of the project.

The transmission line L250 between Mayo to Keno City had already past the end of life and required constant replacement maintenances.

An extension scope had been requested by YEC to provide cost estimations of rebuilding existing L250 to 138kV standard between Mayo to Keno City and operate at 69kV until further customer loads warrant 138kV operation.

1.1 Extension Scope Descriptions

The extension scope is to provide a cost breakdown of the rebuild of existing L250 based on transmission line alignments determined in the original scope with addition configuration scenarios:

I. Mono Pole with Braced Post Insulators (Like as Like Replacement)
   a. 138kV Mono Pole without shieldwire (OPGW or OHGW)
   b. 138kV Mono Pole with shieldwire provision (future OPGW or OHGW)
   c. 138kV Mono Pole with OHGW installed (lightning protection)
   d. 138kV Mono Pole with OPGW installed (lightning protection & fiber communication)

II. H-Frame with Suspension Insulators (Preferred Configuration)
   a. 138kV H-Frame without shieldwire (Identical to CSTL)
   b. 138kV H-Frame with shieldwire provision (future OPGW or OHGW)
   c. 138kV H-Frame with 2xOHGW (lightning protection)
   d. 138kV H-Frame with 1xOHGW & 1xOPGW (lightning protection & fiber communication)

Chimax Inc. will also review and assess YEC cost adjustments applied in their project cost workbook.

A high-level assessment of the incremental cost increase for provision to provide space for future distribution underbuilt below 138kV transmission line between Mayo to Minto Bridge.

2.0 Configuration Comparison & Benefits

2.1 Mono Pole Configuration

Mono Pole 138kV transmission line with braced post insulators has been utilized widely where transmission right of way is limited. The standard transmission post insulators are limited by the cantilever capacities and often restrict the transmission span to 120m or less depending on the loading criteria. Braced post insulators transfer majority of the vertical loading to the strut suspension insulator, where the design span can range from 150m to 250m.

The 72kV mono pole compared to 138kV mono pole will be slightly reduces the pole height requirement due to reduce phase to phase separation and lower ground clearance requirement. The braced poet insulator cost for 72kV will also be slightly lower compared to 138kV braced post insulator. The class of wood pole will predominantly identical. All other material and construction cost remain identical. The overall cost reduction is approximately 2 to 5% of the 138kV transmission line cost.

The critical consideration of Mono Pole transmission structures is the soil properties. Self-supported Mono Pole structures will exert substantial bending moment at the ground line, therefore available soil resistance will become the controlling factor in the design and cost process.

2.2 H-Frame Configuration

H-frame transmission line structures had been in used for many years. The advantage of H-frame structure is the reduced requirement for soil resistance. H-frame tangent structures with cross braces and guyed angle structures have majority of the ground line reactions as vertical down and uplift forces with minimal bending moments. This configuration is more suitable in poor soil conditions and transmission line can be designed with minimal geotechnical data during design stage.

The disadvantage of H-frame structures compared with Mono Pole structures is the additional right of way requirement in order to accommodate the required configuration. In general, H-frame structures will require additional 5m to 10m extra width compared to Mono Poles.

2.3 Shieldwire (OHGW or OPGW)

Despite YEC not implementing shieldwire requirement in past transmission lines, the requirement of shieldwire above 69kV had been implemented in many other Provincial regulations, including Alberta AESO ISO rules.

The performance of shieldwire for lightning protection depends on the local lightning frequency, shielding angle of the lightning protection and soil ground resistivity.

As per information provided by YEC, service outage resulted from lightning strike on existing L250 has been increasing. Implementation of shieldwire in the rebuild of L250 should be considered.

3.0 Cost Adjustment to Initial Preliminary SKTL Design Estimation

3.1 Structure Procurement and Construction Cost

Based on YEC final billing information on CSTL 2 construction cost, Chimax had performed a comparison analysis to verify the structure procurement construction based on 2015 values. The cost comparison is based on identical structures having shieldwire protection. The comparison is attached in Appendix A.

The unit cost of steel for the SKTL cost estimation has been reduced from initial $2.50 per lbs to $2.00 per lbs. The initial unit cost is based on the upper market cost, while the adjusted cost will be medium to low market cost range.

The comparison has shown the SKTL estimated structure costs are in general agreement with the inflation adjusted CSTL 2 project with difference of approximately 8%.

3.2 EPCM Cost Adjustment

Chimax had review the adjustment to the EPCM cost for each line segment.

The reduction in number of site office from 2 to 1 is acceptable. The previous CSTL and CSTL 2 project did not actually utilized proper site office.

The adjustment of construction period is generally acceptable while keeping 4 EPCM personnel during the construction. This should in general provide sufficient funding budget for the EPCM contract.

3.3 Final Design & Field Services

Several permitting and legal items have been removed in the YEC cost estimations.

- Environmental Assessment
- Vegetation Clearing Permits
- Crossing Permits
- Legal & Consultation Cost
- Land Easement Cost

Chimax initially included the above items in the cost estimates to ensure the associated cost is accounted. The relocation of the above item costs from the project budget to operating budget is acceptable.

The engineering cost is based on engineering company performing final design for the SKTL without previous knowledge of YEC standards and project managements.

3.4 Survey Cost for Engineering Design

Chimax have included a confirmation survey cost of $150,000 for each segment of transmission line. The confirmation survey can be performed ahead of final design or during final design prior to construction. The requirement of confirmation survey will be depended on the engineering company performing the final design of the transmission line. Chimax have no objection in remove the survey cost from the transmission line budget.

4.0 Existing L250 Replacement Costs

The L250 replacement cost comparisons outlined below are for procurement and construction (PC) cost, while all other indirect cost are excluded since they will remain same for different configurations.

The PC costs for the different configurations are summarized in Appendix B.

4.1 Like as Like Replacement

Chimax has further revised the new L180 and L250 designs with Mono Pole configurations to provide the budgetary cost for Like as Like replacement.

Line Configuration	PC Cost	Incremental Increase	Cost / km
Base Case - Mono Pole (no shieldwire provision)	$16,814,524.00		$327,729.00
Option 1 – Mono Pole (shieldwire provision)	$16,900,224.00	$85,700.00	$329,439.00
Option 2 – Mono Pole (OHGW Installed)	$17,765,524.00	$865,300.00	$346,307.00
Option 3 – Mono Pole (OPGW Installed)	$18,197,124.00	$431,600.00	$354,720.00

Based on lightning outage data from L250, the Like as Like scenario without shieldwire provision is highly not recommended. The incremental cost increase of $85,700.00 to allow L250 replacement to have future provision of shieldwire protection should be considered as the baseline scenario.

The implementation of OHGW during initial replacement construction will cost approximately $865,000, while installing the OHGW at the later date would likely cost additional $300,000 due to contractor mobilization, administration and construction management.

The incremental increase of installing OPGW instead of OHGW depends on YEC future system planning and protection & control protocol. The installation of OPGW will only be justified if fiber-optic communications between YEC assets are planned.

4.2 H-Frame Replacement

The H-Frame comparison costs are based on original preliminary design with re-alignment at Minto Bridge area due to land application. Incremental cost comparisons have also been performed for H-frame structures.

Line Configuration	PC Cost	Incremental Increase	Cost / km
H-Frame (CSTL 2) (no shieldwire provision)	$17,437,607.00		$339,914.00
Option 1 – H-Frame (shieldwire provision)	$17,609,425.00	$171,818.00	$343,264.00
Option 2 – H-Frame (2xOHGW Installed)	$19,251,035.00	$1,641,610.00	$375,264.00
Option 3 – H-Frame (OHGW & OPGW Installed)	$19,687,635.00	$436,600.00	$383,775.00

4.3 Cost Comparison Mono Pole Versus H-Frame

The following cost comparison is based on replacing existing L250 with structures having OHGW protection.

PC Costs	H-Frame (Option 2)	Mono Pole (Option 2)	Differential
L250 Replacement	$19,251,035.00	$17,765,524.00	$1,485,511.00
Cost / km	$375,264.00	$346,307.00	$28,957.00

Despite the overall costs for H-frame configuration are higher compared with Mono Pole configuration, the reliability of H-frame structures are much better due to less dependency on soil conditions, better distribution of loads along the structures and minimal structure deflection during extreme climate conditions.

4.4 High-Level Cost Estimation for 3 Phases Distribution Underbuilt

High level design review had been performed in order to provide the cost increment for provision to allow 3 phases distribution underbuilt below L180 between Mayo substation and Minto Bridge (Mease Farms).

The mono pole tangent structures have increased height by 5 ft to 10 ft in length and class of pole increased from Class 1 to H1. The resulting incremental cost increase is approximately $30,000.00 per km without distribution hardware. For approximately 8 km between Mayo to Minto Bridge, the estimated cost increase is approximately $240,000.00 for pole procurement.

In general, the incremental cost to have provision below transmission line will be less than building independent distribution line for same distance. Additional electrical studies should be performed regarding induction between transmission and distribution circuit to ensure the underbuilt will have acceptable power quality.

5.0 Recommendations & Conclusions

For transmission line in Yukon where soil conditions are generally loose gravel, wet swamp and permafrost in many areas, the H-frame configuration is recommended for long term reliability.

For transmission line designed for future 138kV operating voltage, lightning protection should be included in the structure designs.

Installation of shieldwire at later date would cost additional $300,000.00 compared to installing shieldwire at the time of replacement construction. It is recommended to include shieldwire installation in the project budget.

Appendix A – CSTL 2 & SKTL Structure Cost Comparison

Steel Crossarm Unit Cost $2.00 $/lbs Adjusted from $2.50 to $2.00 per lbs

Guys & Anchors	CSTP 2 Cost Materials	Labour
Down Guy G011	$139.21	$222.05
V-Down Guy G02	$420.47	$310.87
Log Anchor	$263.60	$1,332.29

Structure Type	CSTP 2 Framing	SKTP Framing	Pole	No. Guys		CSTP 2 Cost				Adjmt to 2015	Adjusted CSTP 2 to 2015					SKTP Prelim. Cost					Differential	
				G01	G02	Framing		Guys & Anchors			Framing		Guys & Anchors		Total	Framing		Guys & Anchors		Total	Diff. Cost	% Increase
						Materials	Labour	Materials	Labour		Materials	Labour	Materials	Labour		Materials	Labour	Materials	Labour			
H-Frame Tangent	0924-P2121	L179-B-T221	DF-3-60			$5,034.96	$9,580.50			115.93%	$5,836.90	$11,106.43			$16,943.32	$5,773.20	$12,500.00			$18,273.20	$1,329.88	7.8%
			DF-3-65			$5,364.23	$9,580.50			115.93%	$6,218.61	$11,106.43			$17,325.04	$6,173.20	$12,500.00			$18,673.20	$1,348.16	7.8%
			DF-3-70			$5,723.61	$9,963.73			115.93%	$6,635.23	$11,550.69			$18,185.93	$6,573.20	$12,500.00			$19,073.20	$887.27	4.9%
			DF-2-75			$7,073.94	$9,963.73			115.93%	$8,200.64	$11,550.69			$19,751.33	$7,973.20	$12,500.00			$20,473.20	$721.87	3.7%
			DF-2-80			$8,298.50	$9,963.73			115.93%	$9,620.24	$11,550.69			$21,170.93	$8,573.20	$12,500.00			$21,073.20	-$97.73	-0.5%
H-Frame 15-30° Light Angle	0924-P2122	L179-B-T223	DF-3-65	4		$7,078.20	$15,223.90	$1,611.24	$6,217.36	115.93%	$8,205.57	$17,648.67	$1,867.87	$7,207.62	$34,929.74	$7,834.40	$18,750.00	$2,800.00	$6,000.00	$35,384.40	$454.66	1.3%
H-Frame 30-60° Medium Angle	0924-P2123	L179-B-T224	DF-3-70	1	3	$7,978.39	$15,223.90	$3,245.82	$10,480.69	115.93%	$9,249.14	$17,648.67	$3,762.79	$12,149.99	$42,810.60	$10,248.40	$18,750.00	$4,900.00	$10,500.00	$44,398.40	$1,587.80	3.7%
H-Frame 60-90° Heavy Angle	0924-P2124	L179-B-T226	DF-3-60	11		$9,951.41	$17,212.15	$4,430.91	$17,097.74	115.93%	$11,536.41	$19,953.60	$5,136.64	$19,820.97	$56,447.62	$13,448.40	$21,875.00	$7,700.00	$16,500.00	$59,523.40	$3,075.78	5.4%
			DF-3-75	11		$13,009.88	$17,900.64	$4,430.91	$17,097.74	115.93%	$15,082.02	$20,751.75	$5,136.64	$19,820.97	$60,791.37	$15,248.40	$21,875.00	$7,700.00	$16,500.00	$61,323.40	$532.03	0.9%

Appendix B – L250 Replacement Configuration Comparison

Construction Cost Comparison

Line Configuration	Procurement & Construction					Construction Unit Cost / km		
	L180	L250	Total	Diff	Incremental Cable Increase	L180 31.1	L250 20.2	Combined 51.3
H-Frame (Preferred Configuration - More Reliable)								
H-Frame (no OPGW Provision)	$10,028,874.00	$7,408,733.40	$17,437,607.40			$322,471.83	$366,768.98	$339,914.37
H-Frame (OPGW Provision)	$10,143,310.60	$7,466,114.80	$17,609,425.40	$171,818.00		$326,151.47	$369,609.64	$343,263.65
H-Frame (with 2xOHGW)	$11,156,720.60	$8,094,314.80	$19,251,035.40	$1,813,428.00	$1,641,610.00	$358,737.00	$400,708.65	$375,263.85
H-Frame (with OPGW & OHGW)	$11,418,170.60	$8,269,464.80	$19,687,635.40	$2,250,028.00	$436,600.00	$367,143.75	$409,379.45	$383,774.57
Mono Pole (Alternative - Reduce ROW)								
Mono Pole (no OPGW Provision)	$9,844,459.60	$6,957,465.00	$16,801,924.60			$316,542.11	$344,428.96	$327,522.90
Mono Pole (OPGW Provision)	$9,903,659.60	$6,983,965.00	$16,887,624.60	$85,700.00		$318,445.65	$345,740.84	$329,193.46
Mono Pole (with OHGW)	$10,440,859.60	$7,324,665.00	$17,765,524.60	$963,600.00	$877,900.00	$335,718.96	$362,607.18	$346,306.52
Mono Pole (with OPGW)	$10,702,309.60	$7,494,815.00	$18,197,124.60	$1,395,200.00	$431,600.00	$344,125.71	$371,030.45	$354,719.78

For L250 within Keno City boundary - Mono Poles are used in all scenario due to reduced ROW.

L250 Replacement Cost	H-Frame				Mono Pole			
	No OPGW Provision	OPGW Provision	2xOHGW	OPGW & OHGW	No OPGW Provision	OPGW Provision	OHGW	OPGW
Project Component								
Conductor & Stringing	$3,585,300.00	$3,585,300.00	$3,585,300.00	$3,585,300.00	$3,585,300.00	$3,585,300.00	$3,585,300.00	$3,585,300.00
OPGW / OHGW & Stringing	$124,000.00	$124,000.00	$1,613,800.00	$2,050,400.00	$62,000.00	$62,000.00	$811,900.00	$1,243,500.00
Structures - Material & Labour	$11,086,057.40	$11,257,875.40	$11,409,685.40	$11,409,685.40	$10,418,574.60	$10,504,274.60	$10,632,274.60	$10,632,274.60
Subtotal - Structures & Conductor	***$14,795,357.40***	***$14,967,175.40***	***$16,608,785.40***	***$17,045,385.40***	***$14,065,874.60***	***$14,151,574.60***	***$15,029,474.60***	***$15,461,074.60***
Survey	$641,550.00	$641,550.00	$641,550.00	$641,550.00	$735,350.00	$735,350.00	$735,350.00	$735,350.00
Clearing & Access	$2,000,700.00	$2,000,700.00	$2,000,700.00	$2,000,700.00	$2,000,700.00	$2,000,700.00	$2,000,700.00	$2,000,700.00
Susbtotal - Procurement & Construction	***$17,437,607.40***	***$17,609,425.40***	***$19,251,035.40***	***$19,687,635.40***	***$16,801,924.60***	***$16,887,624.60***	***$17,765,524.60***	***$18,197,124.60***
Construction Management	$2,886,900.00	$2,886,900.00	$2,886,900.00	$2,886,900.00	$2,886,900.00	$2,886,900.00	$2,886,900.00	$2,886,900.00
Construction Support	$1,026,000.00	$1,026,000.00	$1,026,000.00	$1,026,000.00	$1,026,000.00	$1,026,000.00	$1,026,000.00	$1,026,000.00
Transmission Line Construction Costs	***$21,350,507.40***	***$21,522,325.40***	***$23,163,935.40***	***$23,600,535.40***	***$20,714,824.60***	***$20,800,524.60***	***$21,678,424.60***	***$22,110,024.60***
Contingency - 15% of T/L Costs	$3,202,576.11	$3,228,348.81	$3,474,590.31	$3,540,080.31	$3,107,223.69	$3,120,078.69	$3,251,763.69	$3,316,503.69
Planning Costs								
Environmental Assessment & Permits	$720,000.00	$720,000.00	$720,000.00	$720,000.00	$720,000.00	$720,000.00	$720,000.00	$720,000.00
Preliminary Engineering - T/L	$340,000.00	$340,000.00	$340,000.00	$340,000.00	$340,000.00	$340,000.00	$340,000.00	$340,000.00
Preliminary Engineering - S/S	$250,000.00	$250,000.00	$250,000.00	$250,000.00	$250,000.00	$250,000.00	$250,000.00	$250,000.00
Communications	$150,000.00	$150,000.00	$150,000.00	$150,000.00	$150,000.00	$150,000.00	$150,000.00	$150,000.00
Project Management	$180,000.00	$180,000.00	$180,000.00	$180,000.00	$180,000.00	$180,000.00	$180,000.00	$180,000.00
Plan & Permitting	***$1,640,000.00***	***$1,640,000.00***	***$1,640,000.00***	***$1,640,000.00***	***$1,640,000.00***	***$1,640,000.00***	***$1,640,000.00***	***$1,640,000.00***
Land Acquisition								
Legal & Consulation Cost	$200,000.00	$200,000.00	$200,000.00	$200,000.00	$200,000.00	$200,000.00	$200,000.00	$200,000.00
Land Easement Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FN Project Agreement	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Land Cost / FN Agreements	***$200,000.00***	***$200,000.00***	***$200,000.00***	***$200,000.00***	***$200,000.00***	***$200,000.00***	***$200,000.00***	***$200,000.00***
Detail Enginnering -T/L								
Confirmation Survey for Design	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Environmental Assessment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Vegetation Clearing Permit	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transmission Engineering Design	$307,800.00	$307,800.00	$307,800.00	$307,800.00	$307,800.00	$307,800.00	$307,800.00	$307,800.00
Crossing Permits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Detail Enginnering -T/L	***$307,800.00***	***$307,800.00***	***$307,800.00***	***$307,800.00***	***$307,800.00***	***$307,800.00***	***$307,800.00***	***$307,800.00***
Planning, Permitting & Engineering	***$2,147,800.00***	***$2,147,800.00***	***$2,147,800.00***	***$2,147,800.00***	***$2,147,800.00***	***$2,147,800.00***	***$2,147,800.00***	***$2,147,800.00***
Contingency - 15% of PPE Costs	$322,170.00	$322,170.00	$322,170.00	$322,170.00	$322,170.00	$322,170.00	$322,170.00	$322,170.00
Total Cost	**$27,023,053.51**	**$27,220,644.21**	**$29,108,495.71**	**$29,610,585.71**	**$26,292,018.29**	**$26,390,573.29**	**$27,400,158.29**	**$27,896,498.29**
Cost / km	$526,765.18	$530,616.85	$567,417.07	$577,204.40	$512,514.98	$514,436.13	$534,116.15	$543,791.39

YEC - SKTL 28-Jan-16

138kV L180 Mayo to McQueston (H-Frame with No OPGW Provision) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L180 H-Frame with No OPGW Provision**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	103.0	km	$587,100.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	0.0	km	$0.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	4.0	km	$10,000.00
1.2	Structure Framing			
1.2A	Insulator			$155,295.00
1.2B	Hardware			$236,195.00
1.2C	Structural Steel	78,310	kg	$344,564.00
1.2D	Poles	408	ea	$616,000.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	19	ea	$2,850.00
1.2H	Structure Marker	187	ea	$2,805.00
1.2J	Phase Marker	38	ea	$1,140.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	277	set	$193,900.00
1.3B	Imported Backfill	19	ea	$56,100.00
1.3C	Bed Rock Install Adder	37	ea	$56,100.00
1.3D	Swamp & Bog Adder	75	ea	$261,800.00
A	**Total Procurement Cost**			**$2,538,849.00**
2.0	***Construction Labour***	**L180 H-Frame with No OPGW Provision**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	31.1	km	$108,850.00
2.1B	Survey (Construction)	187.0	ea	$261,800.00
2.1C	Clearing	93.3	ha	$1,212,900.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	47	ea	$39,950.00
2.2B	Structure Installation	187	ea	$2,621,875.00
2.2C	Guy & Anchor Installation	277	set	$745,500.00
2.2D	Imported Backfill	19	ea	$130,900.00
2.2E	Bed Rock Install Adder	37	ea	$93,500.00
2.2F	Swamp & Bog Adder	75	ea	$523,600.00
2.2G	Conductor Stringing	93	km	$1,586,100.00
2.2H	OPGW Stringing	0	km	$0.00
2.2J	OHGW Stringing	4	km	$52,000.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	19	ea	$3,800.00
2.2N	Structure Marker	187	ea	$24,310.00
2.2P	Phase Marker	38	ea	$4,940.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$7,490,025.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	31	km	$186,600.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$186,600.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	7	mth	$130,000
4.3	Personnel Cost	21	man-mth	$955,500
4.4	Personnel Expense	21	man-mth	$382,200
D	**Total Construction Management Cost**			**$1,617,700.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	1	ha	$200,000.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$200,000.00**

	L180 H-Frame with No OPGW Provision	
Sub-Total Cost		**$12,033,174.00**
Misc. Items	15%	**$1,804,976.10**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$13,838,150.10**

YEC - SKTL 28-Jan-16

69kV L250 McQueston to Keno (H-Frame with No OPGW Provision) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L250 H-Frame with No OPGW Provision**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	67.0	km	$381,900.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	0.0	km	$0.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	4.0	km	$10,000.00
1.2	Structure Framing			
1.2A	Insulator			$118,956.00
1.2B	Hardware			$153,094.00
1.2C	Structural Steel	50,661	kg	$222,908.40
1.2D	Poles	279	ea	$492,950.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	15	ea	$2,250.00
1.2H	Structure Marker	143	ea	$2,145.00
1.2J	Phase Marker	29	ea	$870.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	99	set	$69,300.00
1.3B	Imported Backfill	14	ea	$42,900.00
1.3C	Bed Rock Install Adder	29	ea	$42,900.00
1.3D	Swamp & Bog Adder	57	ea	$200,200.00
A	**Total Procurement Cost**			**$1,755,373.40**
2.0	***Construction Labour***	**L250 H-Frame with No OPGW Provision**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	20.2	km	$70,700.00
2.1B	Survey (Construction)	143.0	ea	$200,200.00
2.1C	Clearing	60.6	ha	$787,800.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	36	ea	$30,600.00
2.2B	Structure Installation	143	ea	$1,817,500.00
2.2C	Guy & Anchor Installation	99	set	$987,000.00
2.2D	Imported Backfill	14	ea	$100,100.00
2.2E	Bed Rock Install Adder	29	ea	$71,500.00
2.2F	Swamp & Bog Adder	57	ea	$400,400.00
2.2G	Conductor Stringing	61	km	$1,030,200.00
2.2H	OPGW Stringing	0	km	$0.00
2.2J	OHGW Stringing	4	km	$52,000.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	15	ea	$3,000.00
2.2N	Structure Marker	143	ea	$18,590.00
2.2P	Phase Marker	29	ea	$3,770.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$5,653,360.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	20	km	$121,200.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$121,200.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	5	mth	$100,000
4.3	Personnel Cost	16	man-mth	$728,000
4.4	Personnel Expense	16	man-mth	$291,200
D	**Total Construction Management Cost**			**$1,269,200.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	0	ha	$0.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$0.00**

	L250 H-Frame with No OPGW Provision	
Sub-Total Cost		**$8,799,133.40**
Misc. Items	15%	**$1,319,870.01**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$10,119,003.41**

YEC - SKTL 28-Jan-16

138kV L180 Mayo to McQueston (H-Frame with OPGW Provision) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L180 H-Frame with OPGW Provision**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	103.0	km	$587,100.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	0.0	km	$0.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	4.0	km	$10,000.00
1.2	Structure Framing			
1.2A	Insulator			$153,765.00
1.2B	Hardware			$240,025.00
1.2C	Structural Steel	77,324	kg	$340,225.60
1.2D	Poles	406	ea	$744,000.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	19	ea	$2,850.00
1.2H	Structure Marker	187	ea	$2,805.00
1.2J	Phase Marker	38	ea	$1,140.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	265	set	$185,500.00
1.3B	Imported Backfill	19	ea	$56,100.00
1.3C	Bed Rock Install Adder	37	ea	$56,100.00
1.3D	Swamp & Bog Adder	75	ea	$261,800.00
A	**Total Procurement Cost**			**$2,656,410.60**
2.0	***Construction Labour***	**L180 H-Frame with OPGW Provision**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	31.1	km	$108,850.00
2.1B	Survey (Construction)	187.0	ea	$261,800.00
2.1C	Clearing	93.3	ha	$1,212,900.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	47	ea	$39,950.00
2.2B	Structure Installation	187	ea	$2,618,750.00
2.2C	Guy & Anchor Installation	265	set	$745,500.00
2.2D	Imported Backfill	19	ea	$130,900.00
2.2E	Bed Rock Install Adder	37	ea	$93,500.00
2.2F	Swamp & Bog Adder	75	ea	$523,600.00
2.2G	Conductor Stringing	93	km	$1,586,100.00
2.2H	OPGW Stringing	0	km	$0.00
2.2J	OHGW Stringing	4	km	$52,000.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	19	ea	$3,800.00
2.2N	Structure Marker	187	ea	$24,310.00
2.2P	Phase Marker	38	ea	$4,940.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$7,486,900.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	31	km	$186,600.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$186,600.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	7	mth	$130,000
4.3	Personnel Cost	21	man-mth	$955,500
4.4	Personnel Expense	21	man-mth	$382,200
D	**Total Construction Management Cost**			**$1,617,700.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	1	ha	$200,000.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$200,000.00**

	L180 H-Frame with OPGW Provision	
Sub-Total Cost		**$12,147,610.60**
Misc. Items	15%	**$1,822,141.59**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$13,969,752.19**

YEC - SKTL 28-Jan-16

69kV L250 McQueston to Keno (H-Frame with OPGW Provision) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L250 H-Frame with OPGW Provision**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	67.0	km	$381,900.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	0.0	km	$0.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	4.0	km	$10,000.00
1.2	Structure Framing			
1.2A	Insulator			$125,664.00
1.2B	Hardware			$164,786.00
1.2C	Structural Steel	50,492	kg	$222,164.80
1.2D	Poles	279	ea	$492,950.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	15	ea	$2,250.00
1.2H	Structure Marker	143	ea	$2,145.00
1.2J	Phase Marker	29	ea	$870.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	137	set	$95,900.00
1.3B	Imported Backfill	14	ea	$42,900.00
1.3C	Bed Rock Install Adder	29	ea	$42,900.00
1.3D	Swamp & Bog Adder	57	ea	$200,200.00
A	**Total Procurement Cost**			**$1,799,629.80**
2.0	***Construction Labour***	**L250 H-Frame with OPGW Provision**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	20.2	km	$70,700.00
2.1B	Survey (Construction)	143.0	ea	$200,200.00
2.1C	Clearing	60.6	ha	$787,800.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	36	ea	$30,600.00
2.2B	Structure Installation	143	ea	$1,830,625.00
2.2C	Guy & Anchor Installation	137	set	$987,000.00
2.2D	Imported Backfill	14	ea	$100,100.00
2.2E	Bed Rock Install Adder	29	ea	$71,500.00
2.2F	Swamp & Bog Adder	57	ea	$400,400.00
2.2G	Conductor Stringing	61	km	$1,030,200.00
2.2H	OPGW Stringing	0	km	$0.00
2.2J	OHGW Stringing	4	km	$52,000.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	15	ea	$3,000.00
2.2N	Structure Marker	143	ea	$18,590.00
2.2P	Phase Marker	29	ea	$3,770.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$5,666,485.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	20	km	$121,200.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$121,200.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	5	mth	$100,000
4.3	Personnel Cost	16	man-mth	$728,000
4.4	Personnel Expense	16	man-mth	$291,200
D	**Total Construction Management Cost**			**$1,269,200.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	0	ha	$0.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$0.00**

	L250 H-Frame with OPGW Provision	
Sub-Total Cost		**$8,856,514.80**
Misc. Items	15%	**$1,328,477.22**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$10,184,992.02**

YEC - SKTL 28-Jan-16
138kV L180 Mayo to McQueston (H-Frame with 2xOHGW) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L180 H-Frame with 2xOHGW**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	103.0	km	$587,100.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	0.0	km	$0.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	70.0	km	$175,000.00
1.2	Structure Framing			
1.2A	Insulator			$153,765.00
1.2B	Hardware			$331,835.00
1.2C	Structural Steel	77,324	kg	$340,225.60
1.2D	Poles	406	ea	$744,000.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	19	ea	$2,850.00
1.2H	Structure Marker	187	ea	$2,805.00
1.2J	Phase Marker	38	ea	$1,140.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	265	set	$185,500.00
1.3B	Imported Backfill	19	ea	$56,100.00
1.3C	Bed Rock Install Adder	37	ea	$56,100.00
1.3D	Swamp & Bog Adder	75	ea	$261,800.00
A	**Total Procurement Cost**			**$2,913,220.60**
2.0	***Construction Labour***	**L180 H-Frame with 2xOHGW**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	31.1	km	$108,850.00
2.1B	Survey (Construction)	187.0	ea	$261,800.00
2.1C	Clearing	93.3	ha	$1,212,900.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	47	ea	$39,950.00
2.2B	Structure Installation	187	ea	$2,618,750.00
2.2C	Guy & Anchor Installation	265	set	$745,500.00
2.2D	Imported Backfill	19	ea	$130,900.00
2.2E	Bed Rock Install Adder	37	ea	$93,500.00
2.2F	Swamp & Bog Adder	75	ea	$523,600.00
2.2G	Conductor Stringing	93	km	$1,586,100.00
2.2H	OPGW Stringing	0	km	$0.00
2.2J	OHGW Stringing	62	km	$808,600.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	19	ea	$3,800.00
2.2N	Structure Marker	187	ea	$24,310.00
2.2P	Phase Marker	38	ea	$4,940.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$8,243,500.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	31	km	$186,600.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$186,600.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	7	mth	$130,000
4.3	Personnel Cost	21	man-mth	$955,500
4.4	Personnel Expense	21	man-mth	$382,200
D	**Total Construction Management Cost**			**$1,617,700.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	1	ha	$200,000.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$200,000.00**

	L180 H-Frame with 2xOHGW	
Sub-Total Cost		**$13,161,020.60**
Misc. Items	15%	**$1,974,153.09**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$15,135,173.69**

YEC - SKTL 28-Jan-16
69kV L250 McQueston to Keno (H-Frame with OHGW) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L250 H-Frame with OHGW**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	67.0	km	$381,900.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	0.0	km	$0.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	42.0	km	$105,000.00
1.2	Structure Framing			
1.2A	Insulator			$125,664.00
1.2B	Hardware			$224,786.00
1.2C	Structural Steel	50,492	kg	$222,164.80
1.2D	Poles	279	ea	$492,950.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	15	ea	$2,250.00
1.2H	Structure Marker	143	ea	$2,145.00
1.2J	Phase Marker	29	ea	$870.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	137	set	$95,900.00
1.3B	Imported Backfill	14	ea	$42,900.00
1.3C	Bed Rock Install Adder	29	ea	$42,900.00
1.3D	Swamp & Bog Adder	57	ea	$200,200.00
A	**Total Procurement Cost**			**$1,954,629.80**
2.0	***Construction Labour***	**L250 H-Frame with OHGW**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	20.2	km	$70,700.00
2.1B	Survey (Construction)	143.0	ea	$200,200.00
2.1C	Clearing	60.6	ha	$787,800.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	36	ea	$30,600.00
2.2B	Structure Installation	143	ea	$1,830,625.00
2.2C	Guy & Anchor Installation	137	set	$987,000.00
2.2D	Imported Backfill	14	ea	$100,100.00
2.2E	Bed Rock Install Adder	29	ea	$71,500.00
2.2F	Swamp & Bog Adder	57	ea	$400,400.00
2.2G	Conductor Stringing	61	km	$1,030,200.00
2.2H	OPGW Stringing	0	km	$0.00
2.2J	OHGW Stringing	40	km	$525,200.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	15	ea	$3,000.00
2.2N	Structure Marker	143	ea	$18,590.00
2.2P	Phase Marker	29	ea	$3,770.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$6,139,685.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	20	km	$121,200.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$121,200.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	5	mth	$100,000
4.3	Personnel Cost	16	man-mth	$728,000
4.4	Personnel Expense	16	man-mth	$291,200
D	**Total Construction Management Cost**			**$1,269,200.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	0	ha	$0.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$0.00**

	L250 H-Frame with OHGW	
Sub-Total Cost		**$9,484,714.80**
Misc. Items	15%	**$1,422,707.22**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$10,907,422.02**

YEC - SKTL 28-Jan-16

138kV L180 Mayo to McQueston (H-Frame with OPGW) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L180 H-Frame with OPGW**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	103.0	km	$587,100.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	35.0	km	$131,250.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	35.0	km	$87,500.00
1.2	Structure Framing			
1.2A	Insulator			$153,765.00
1.2B	Hardware			$331,835.00
1.2C	Structural Steel	77,324	kg	$340,225.60
1.2D	Poles	406	ea	$744,000.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	19	ea	$2,850.00
1.2H	Structure Marker	187	ea	$2,805.00
1.2J	Phase Marker	38	ea	$1,140.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	265	set	$185,500.00
1.3B	Imported Backfill	19	ea	$56,100.00
1.3C	Bed Rock Install Adder	37	ea	$56,100.00
1.3D	Swamp & Bog Adder	75	ea	$261,800.00
A	**Total Procurement Cost**			**$2,956,970.60**
2.0	***Construction Labour***	**L180 H-Frame with OPGW**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	31.1	km	$108,850.00
2.1B	Survey (Construction)	187.0	ea	$261,800.00
2.1C	Clearing	93.3	ha	$1,212,900.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	47	ea	$39,950.00
2.2B	Structure Installation	187	ea	$2,618,750.00
2.2C	Guy & Anchor Installation	265	set	$745,500.00
2.2D	Imported Backfill	19	ea	$130,900.00
2.2E	Bed Rock Install Adder	37	ea	$93,500.00
2.2F	Swamp & Bog Adder	75	ea	$523,600.00
2.2G	Conductor Stringing	93	km	$1,586,100.00
2.2H	OPGW Stringing	31	km	$622,000.00
2.2J	OHGW Stringing	31	km	$404,300.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	19	ea	$3,800.00
2.2N	Structure Marker	187	ea	$24,310.00
2.2P	Phase Marker	38	ea	$4,940.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$8,461,200.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	31	km	$186,600.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$186,600.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	7	mth	$130,000
4.3	Personnel Cost	21	man-mth	$955,500
4.4	Personnel Expense	21	man-mth	$382,200
D	**Total Construction Management Cost**			**$1,617,700.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	1	ha	$200,000.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$200,000.00**

	L180 H-Frame with OPGW	
Sub-Total Cost		**$13,422,470.60**
Misc. Items	15%	**$2,013,370.59**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$15,435,841.19**

YEC - SKTL 28-Jan-16
69kV L250 McQueston to Keno (H-Frame with OPGW) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L250 H-Frame with OPGW**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	67.0	km	$381,900.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	23.0	km	$86,250.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	21.0	km	$52,500.00
1.2	Structure Framing			
1.2A	Insulator			$125,664.00
1.2B	Hardware			$224,786.00
1.2C	Structural Steel	50,492	kg	$222,164.80
1.2D	Poles	279	ea	$492,950.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	15	ea	$2,250.00
1.2H	Structure Marker	143	ea	$2,145.00
1.2J	Phase Marker	29	ea	$870.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	137	set	$95,900.00
1.3B	Imported Backfill	14	ea	$42,900.00
1.3C	Bed Rock Install Adder	29	ea	$42,900.00
1.3D	Swamp & Bog Adder	57	ea	$200,200.00
A	**Total Procurement Cost**			**$1,988,379.80**
2.0	***Construction Labour***	**L250 H-Frame with OPGW**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	20.2	km	$70,700.00
2.1B	Survey (Construction)	143.0	ea	$200,200.00
2.1C	Clearing	60.6	ha	$787,800.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	36	ea	$30,600.00
2.2B	Structure Installation	143	ea	$1,830,625.00
2.2C	Guy & Anchor Installation	137	set	$987,000.00
2.2D	Imported Backfill	14	ea	$100,100.00
2.2E	Bed Rock Install Adder	29	ea	$71,500.00
2.2F	Swamp & Bog Adder	57	ea	$400,400.00
2.2G	Conductor Stringing	61	km	$1,030,200.00
2.2H	OPGW Stringing	20	km	$404,000.00
2.2J	OHGW Stringing	20	km	$262,600.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	15	ea	$3,000.00
2.2N	Structure Marker	143	ea	$18,590.00
2.2P	Phase Marker	29	ea	$3,770.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$6,281,085.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	20	km	$121,200.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$121,200.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	5	mth	$100,000
4.3	Personnel Cost	16	man-mth	$728,000
4.4	Personnel Expense	16	man-mth	$291,200
D	**Total Construction Management Cost**			**$1,269,200.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	0	ha	$0.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$0.00**

	L250 H-Frame with OPGW	
Sub-Total Cost		**$9,659,864.80**
Misc. Items	15%	**$1,448,979.72**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$11,108,844.52**

YEC - SKTL 28-Jan-16

138kV L180 Mayo to McQueston (Mono Pole with No OPGW Provision) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L180 Mono Pole No OPGW Provision**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	103.0	km	$587,100.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	0.0	km	$0.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	2.0	km	$5,000.00
1.2	Structure Framing			
1.2A	Insulator			$367,023.00
1.2B	Hardware			$202,877.00
1.2C	Structural Steel	934	kg	$4,109.60
1.2D	Poles	238	ea	$694,000.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	24	ea	$3,600.00
1.2H	Structure Marker	234	ea	$3,510.00
1.2J	Phase Marker	47	ea	$1,410.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	192	set	$134,400.00
1.3B	Imported Backfill	23	ea	$70,200.00
1.3C	Bed Rock Install Adder	47	ea	$70,200.00
1.3D	Swamp & Bog Adder	94	ea	$327,600.00
A	**Total Procurement Cost**			**$2,486,029.60**
2.0	***Construction Labour***	**L180 Mono Pole No OPGW Provision**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	31.1	km	$108,850.00
2.1B	Survey (Construction)	234.0	ea	$327,600.00
2.1C	Clearing	93.3	ha	$1,212,900.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	59	ea	$50,150.00
2.2B	Structure Installation	234	ea	$2,002,500.00
2.2C	Guy & Anchor Installation	192	set	$987,000.00
2.2D	Imported Backfill	23	ea	$163,800.00
2.2E	Bed Rock Install Adder	47	ea	$117,000.00
2.2F	Swamp & Bog Adder	94	ea	$655,200.00
2.2G	Conductor Stringing	93	km	$1,586,100.00
2.2H	OPGW Stringing	0	km	$0.00
2.2J	OHGW Stringing	2	km	$26,000.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	24	ea	$4,800.00
2.2N	Structure Marker	234	ea	$30,420.00
2.2P	Phase Marker	47	ea	$6,110.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$7,358,430.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	31	km	$186,600.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$186,600.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	7	mth	$130,000
4.3	Personnel Cost	21	man-mth	$955,500
4.4	Personnel Expense	21	man-mth	$382,200
D	**Total Construction Management Cost**			**$1,617,700.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	1	ha	$200,000.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$200,000.00**

	L180 Mono Pole with No OPGW Provision		
	Sub-Total Cost		**$11,848,759.60**
	Misc. Items	15%	**$1,777,313.94**
	Owner's Cost (Cost of Financing)	0%	**$0.00**
	Total Cost of Transmission Line		**$13,626,073.54**

YEC - SKTL 28-Jan-16

69kV L250 McQueston to Keno (Mono Pole with No OPGW Provision) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L250 Mono Pole with No OPGW Provision**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	67.0	km	$381,900.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	0.0	km	$0.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	2.0	km	$5,000.00
1.2	Structure Framing			
1.2A	Insulator			$252,462.00
1.2B	Hardware			$130,438.00
1.2C	Structural Steel	0	kg	$0.00
1.2D	Poles	163	ea	$476,000.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	17	ea	$2,550.00
1.2H	Structure Marker	163	ea	$2,445.00
1.2J	Phase Marker	33	ea	$990.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	104	set	$72,800.00
1.3B	Imported Backfill	16	ea	$48,900.00
1.3C	Bed Rock Install Adder	33	ea	$48,900.00
1.3D	Swamp & Bog Adder	65	ea	$228,200.00
A	**Total Procurement Cost**			**$1,665,585.00**
2.0	***Construction Labour***	**L250 Mono Pole with No OPGW Provision**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	20.2	km	$70,700.00
2.1B	Survey (Construction)	163.0	ea	$228,200.00
2.1C	Clearing	60.6	ha	$787,800.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	41	ea	$34,850.00
2.2B	Structure Installation	163	ea	$1,366,250.00
2.2C	Guy & Anchor Installation	104	set	$987,000.00
2.2D	Imported Backfill	16	ea	$114,100.00
2.2E	Bed Rock Install Adder	33	ea	$81,500.00
2.2F	Swamp & Bog Adder	65	ea	$456,400.00
2.2G	Conductor Stringing	61	km	$1,030,200.00
2.2H	OPGW Stringing	0	km	$0.00
2.2J	OHGW Stringing	2	km	$26,000.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	17	ea	$3,400.00
2.2N	Structure Marker	163	ea	$21,190.00
2.2P	Phase Marker	33	ea	$4,290.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$5,291,880.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	20	km	$121,200.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$121,200.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	5	mth	$100,000
4.3	Personnel Cost	16	man-mth	$728,000
4.4	Personnel Expense	16	man-mth	$291,200
D	**Total Construction Management Cost**			**$1,269,200.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	0	ha	$0.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$0.00**

	L250 Mono Pole with No OPGW Provision	
Sub-Total Cost		**$8,347,865.00**
Misc. Items	15%	**$1,252,179.75**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$9,600,044.75**

YEC - SKTL 28-Jan-16

138kV L180 Mayo to McQueston (Mono Pole with OPGW Provision) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L180 Mono Pole with OPGW Provision**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	103.0	km	$587,100.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	0.0	km	$0.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	2.0	km	$5,000.00
1.2	Structure Framing			
1.2A	Insulator			$367,023.00
1.2B	Hardware			$202,877.00
1.2C	Structural Steel	934	kg	$4,109.60
1.2D	Poles	238	ea	$753,200.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	24	ea	$3,600.00
1.2H	Structure Marker	234	ea	$3,510.00
1.2J	Phase Marker	47	ea	$1,410.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	192	set	$134,400.00
1.3B	Imported Backfill	23	ea	$70,200.00
1.3C	Bed Rock Install Adder	47	ea	$70,200.00
1.3D	Swamp & Bog Adder	94	ea	$327,600.00
A	**Total Procurement Cost**			**$2,545,229.60**
2.0	***Construction Labour***	**L180 Mono Pole with OPGW Provision**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	31.1	km	$108,850.00
2.1B	Survey (Construction)	234.0	ea	$327,600.00
2.1C	Clearing	93.3	ha	$1,212,900.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	59	ea	$50,150.00
2.2B	Structure Installation	234	ea	$2,002,500.00
2.2C	Guy & Anchor Installation	192	set	$987,000.00
2.2D	Imported Backfill	23	ea	$163,800.00
2.2E	Bed Rock Install Adder	47	ea	$117,000.00
2.2F	Swamp & Bog Adder	94	ea	$655,200.00
2.2G	Conductor Stringing	93	km	$1,586,100.00
2.2H	OPGW Stringing	0	km	$0.00
2.2J	OHGW Stringing	2	km	$26,000.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	24	ea	$4,800.00
2.2N	Structure Marker	234	ea	$30,420.00
2.2P	Phase Marker	47	ea	$6,110.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$7,358,430.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	31	km	$186,600.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$186,600.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	7	mth	$130,000
4.3	Personnel Cost	21	man-mth	$955,500
4.4	Personnel Expense	21	man-mth	$382,200
D	**Total Construction Management Cost**			**$1,617,700.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	1	ha	$200,000.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$200,000.00**

	L180 Mono Pole with OPGW Provision	
Sub-Total Cost		**$11,907,959.60**
Misc. Items	15%	**$1,786,193.94**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$13,694,153.54**

YEC - SKTL 28-Jan-16

69kV L250 McQueston to Keno (Mono Pole with OPGW Provision) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L250 Mono Pole with OPGW Provision**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	67.0	km	$381,900.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	0.0	km	$0.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	2.0	km	$5,000.00
1.2	Structure Framing			
1.2A	Insulator			$252,462.00
1.2B	Hardware			$130,438.00
1.2C	Structural Steel	0	kg	$0.00
1.2D	Poles	163	ea	$502,500.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	17	ea	$2,550.00
1.2H	Structure Marker	163	ea	$2,445.00
1.2J	Phase Marker	33	ea	$990.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	104	set	$72,800.00
1.3B	Imported Backfill	16	ea	$48,900.00
1.3C	Bed Rock Install Adder	33	ea	$48,900.00
1.3D	Swamp & Bog Adder	65	ea	$228,200.00
A	**Total Procurement Cost**			**$1,692,085.00**
2.0	***Construction Labour***	**L250 Mono Pole with OPGW Provision**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	20.2	km	$70,700.00
2.1B	Survey (Construction)	163.0	ea	$228,200.00
2.1C	Clearing	60.6	ha	$787,800.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	41	ea	$34,850.00
2.2B	Structure Installation	163	ea	$1,366,250.00
2.2C	Guy & Anchor Installation	104	set	$987,000.00
2.2D	Imported Backfill	16	ea	$114,100.00
2.2E	Bed Rock Install Adder	33	ea	$81,500.00
2.2F	Swamp & Bog Adder	65	ea	$456,400.00
2.2G	Conductor Stringing	61	km	$1,030,200.00
2.2H	OPGW Stringing	0	km	$0.00
2.2J	OHGW Stringing	2	km	$26,000.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	17	ea	$3,400.00
2.2N	Structure Marker	163	ea	$21,190.00
2.2P	Phase Marker	33	ea	$4,290.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$5,291,880.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	20	km	$121,200.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$121,200.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	5	mth	$100,000
4.3	Personnel Cost	16	man-mth	$728,000
4.4	Personnel Expense	16	man-mth	$291,200
D	**Total Construction Management Cost**			**$1,269,200.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	0	ha	$0.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$0.00**

	L250 Mono Pole with OPGW Provision	
Sub-Total Cost		**$8,374,365.00**
Misc. Items	15%	**$1,256,154.75**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$9,630,519.75**

YEC - SKTL 28-Jan-16
138kV L180 Mayo to McQueston (Mono Pole with OHGW) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L180 Mono Pole with OHGW**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	103.0	km	$587,100.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	0.0	km	$0.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	35.0	km	$87,500.00
1.2	Structure Framing			
1.2A	Insulator			$367,023.00
1.2B	Hardware			$279,277.00
1.2C	Structural Steel	934	kg	$4,109.60
1.2D	Poles	238	ea	$753,200.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	24	ea	$3,600.00
1.2H	Structure Marker	234	ea	$3,510.00
1.2J	Phase Marker	47	ea	$1,410.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	192	set	$134,400.00
1.3B	Imported Backfill	23	ea	$70,200.00
1.3C	Bed Rock Install Adder	47	ea	$70,200.00
1.3D	Swamp & Bog Adder	94	ea	$327,600.00
A	**Total Procurement Cost**			**$2,704,129.60**
2.0	***Construction Labour***	**L180 Mono Pole with OHGW**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	31.1	km	$108,850.00
2.1B	Survey (Construction)	234.0	ea	$327,600.00
2.1C	Clearing	93.3	ha	$1,212,900.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	59	ea	$50,150.00
2.2B	Structure Installation	234	ea	$2,002,500.00
2.2C	Guy & Anchor Installation	192	set	$987,000.00
2.2D	Imported Backfill	23	ea	$163,800.00
2.2E	Bed Rock Install Adder	47	ea	$117,000.00
2.2F	Swamp & Bog Adder	94	ea	$655,200.00
2.2G	Conductor Stringing	93	km	$1,586,100.00
2.2H	OPGW Stringing	0	km	$0.00
2.2J	OHGW Stringing	31	km	$404,300.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	24	ea	$4,800.00
2.2N	Structure Marker	234	ea	$30,420.00
2.2P	Phase Marker	47	ea	$6,110.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$7,736,730.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	31	km	$186,600.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$186,600.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	7	mth	$130,000
4.3	Personnel Cost	21	man-mth	$955,500
4.4	Personnel Expense	21	man-mth	$382,200
D	**Total Construction Management Cost**			**$1,617,700.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	1	ha	$200,000.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$200,000.00**

	L180 Mono Pole with OHGW	
Sub-Total Cost		**$12,445,159.60**
Misc. Items	15%	**$1,866,773.94**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$14,311,933.54**

YEC - SKTL 28-Jan-16

69kV L250 McQueston to Keno (Mono Pole with OHGW) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L250 Mono Pole with OHGW**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	67.0	km	$381,900.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	0.0	km	$0.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	23.0	km	$57,500.00
1.2	Structure Framing			
1.2A	Insulator			$252,462.00
1.2B	Hardware			$182,038.00
1.2C	Structural Steel	0	kg	$0.00
1.2D	Poles	163	ea	$502,500.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	17	ea	$2,550.00
1.2H	Structure Marker	163	ea	$2,445.00
1.2J	Phase Marker	33	ea	$990.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	104	set	$72,800.00
1.3B	Imported Backfill	16	ea	$48,900.00
1.3C	Bed Rock Install Adder	33	ea	$48,900.00
1.3D	Swamp & Bog Adder	65	ea	$228,200.00
A	**Total Procurement Cost**			**$1,796,185.00**
2.0	***Construction Labour***	**L250 Mono Pole with OHGW**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	20.2	km	$70,700.00
2.1B	Survey (Construction)	163.0	ea	$228,200.00
2.1C	Clearing	60.6	ha	$787,800.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	41	ea	$34,850.00
2.2B	Structure Installation	163	ea	$1,366,250.00
2.2C	Guy & Anchor Installation	104	set	$987,000.00
2.2D	Imported Backfill	16	ea	$114,100.00
2.2E	Bed Rock Install Adder	33	ea	$81,500.00
2.2F	Swamp & Bog Adder	65	ea	$456,400.00
2.2G	Conductor Stringing	61	km	$1,030,200.00
2.2H	OPGW Stringing	0	km	$0.00
2.2J	OHGW Stringing	20	km	$262,600.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	17	ea	$3,400.00
2.2N	Structure Marker	163	ea	$21,190.00
2.2P	Phase Marker	33	ea	$4,290.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$5,528,480.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	20	km	$121,200.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$121,200.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	5	mth	$100,000
4.3	Personnel Cost	16	man-mth	$728,000
4.4	Personnel Expense	16	man-mth	$291,200
D	**Total Construction Management Cost**			**$1,269,200.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	0	ha	$0.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$0.00**

	L250 Mono Pole with OHGW	
Sub-Total Cost		**$8,715,065.00**
Misc. Items	15%	**$1,307,259.75**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$10,022,324.75**

YEC - SKTL 28-Jan-16

138kV L180 Mayo to McQueston (Mono Pole with OPGW) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L180 Mono Pole with OPGW**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	103.0	km	$587,100.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	35.0	km	$131,250.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	0.0	km	$0.00
1.2	Structure Framing			
1.2A	Insulator			$367,023.00
1.2B	Hardware			$279,277.00
1.2C	Structural Steel	934	kg	$4,109.60
1.2D	Poles	238	ea	$753,200.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	24	ea	$3,600.00
1.2H	Structure Marker	234	ea	$3,510.00
1.2J	Phase Marker	47	ea	$1,410.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	192	set	$134,400.00
1.3B	Imported Backfill	23	ea	$70,200.00
1.3C	Bed Rock Install Adder	47	ea	$70,200.00
1.3D	Swamp & Bog Adder	94	ea	$327,600.00
A	**Total Procurement Cost**			**$2,747,879.60**
2.0	***Construction Labour***	**L180 Mono Pole with OPGW**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	31.1	km	$108,850.00
2.1B	Survey (Construction)	234.0	ea	$327,600.00
2.1C	Clearing	93.3	ha	$1,212,900.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	59	ea	$50,150.00
2.2B	Structure Installation	234	ea	$2,002,500.00
2.2C	Guy & Anchor Installation	192	set	$987,000.00
2.2D	Imported Backfill	23	ea	$163,800.00
2.2E	Bed Rock Install Adder	47	ea	$117,000.00
2.2F	Swamp & Bog Adder	94	ea	$655,200.00
2.2G	Conductor Stringing	93	km	$1,586,100.00
2.2H	OPGW Stringing	31	km	$622,000.00
2.2J	OHGW Stringing	0	km	$0.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	24	ea	$4,800.00
2.2N	Structure Marker	234	ea	$30,420.00
2.2P	Phase Marker	47	ea	$6,110.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$7,954,430.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	31	km	$186,600.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$186,600.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	7	mth	$130,000
4.3	Personnel Cost	21	man-mth	$955,500
4.4	Personnel Expense	21	man-mth	$382,200
D	**Total Construction Management Cost**			**$1,617,700.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	1	ha	$200,000.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$200,000.00**

	L180 Mono Pole with OPGW	
Sub-Total Cost		**$12,706,609.60**
Misc. Items	15%	**$1,905,991.44**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$14,612,601.04**

YEC - SKTL 28-Jan-16

69kV L250 McQueston to Keno (Mono Pole with OPGW) Rev. 1

Item	Descirptions	Quantity	Unit	Cost
1.0	***Procurement***	**L250 Mono Pole with OPGW**		
1.1	Cables			
1.1A	Conductor (397.5 MCM ACSR Ibis)	67.0	km	$381,900.00
1.1B	OPGW (SFPOC /SFSJ-J-10783 48SMF)	23.0	km	$86,250.00
1.1C	OHGW (3/8" EHS Galvanized Steel)	0.0	km	$0.00
1.2	Structure Framing			
1.2A	Insulator			$252,462.00
1.2B	Hardware			$182,038.00
1.2C	Structural Steel	0	kg	$0.00
1.2D	Poles	163	ea	$502,500.00
1.2E	Vibration Damper / Spacer	0	set	$0.00
1.2F	Fiber Optic Splicing	10	ea	$15,000.00
1.2G	Aerial Marker	17	ea	$2,550.00
1.2H	Structure Marker	163	ea	$2,445.00
1.2J	Phase Marker	33	ea	$990.00
1.3	Structure Anchoring			
1.3A	Guy & Anchor	104	set	$72,800.00
1.3B	Imported Backfill	16	ea	$48,900.00
1.3C	Bed Rock Install Adder	33	ea	$48,900.00
1.3D	Swamp & Bog Adder	65	ea	$228,200.00
A	**Total Procurement Cost**			**$1,824,935.00**
2.0	***Construction Labour***	**L250 Mono Pole with OPGW**		
2.1	Site Preparation			
2.1A	Survey (Right of Way)	20.2	km	$70,700.00
2.1B	Survey (Construction)	163.0	ea	$228,200.00
2.1C	Clearing	60.6	ha	$787,800.00
2.2	Transmission Line Construction			
2.2A	Soil Probe Testing	41	ea	$34,850.00
2.2B	Structure Installation	163	ea	$1,366,250.00
2.2C	Guy & Anchor Installation	104	set	$987,000.00
2.2D	Imported Backfill	16	ea	$114,100.00
2.2E	Bed Rock Install Adder	33	ea	$81,500.00
2.2F	Swamp & Bog Adder	65	ea	$456,400.00
2.2G	Conductor Stringing	61	km	$1,030,200.00
2.2H	OPGW Stringing	20	km	$404,000.00
2.2J	OHGW Stringing	0	km	$0.00
2.2K	Vibration Damper / Spacer	0	set	$0.00
2.2L	Fiber Optic Splicing	10	ea	$80,000.00
2.2M	Aerial Marker	17	ea	$3,400.00
2.2N	Structure Marker	163	ea	$21,190.00
2.2P	Phase Marker	33	ea	$4,290.00
2.3	Mobilization / Demobilization			
2.3A	Surveyor	0	u	$0.00
2.3B	Clearing Contractor	0	u	$0.00
2.3C	Construction Contractors	0	u	$0.00
B	**Total Construction Cost**			**$5,669,880.00**
3.0	***Detail Engineering***			
3.1	Confirmation Survey for Design	0	u	$0.00
3.2	Environmental Assessment	0	km	$0.00
3.3	Vegetation Clearing Permit	0	km	$0.00
3.4	Transmission Engineering Design	20	km	$121,200.00
3.5	Crossing Permits	0	ea	$0.00
C	**Total Engineering Cost**			**$121,200.00**
4.0	***Construction Management***			
4.1	Mobilization	2	ea	$150,000
4.2	Site Office Expense	5	mth	$100,000
4.3	Personnel Cost	16	man-mth	$728,000
4.4	Personnel Expense	16	man-mth	$291,200
D	**Total Construction Management Cost**			**$1,269,200.00**
5.0	***Land Acquisition***			
5.1	Legal & Consultation Cost	0	ha	$0.00
5.2	Land Easement Cost	0	ha	$0.00
E	**Land Cost**			**$0.00**

	L250 Mono Pole with OPGW	
Sub-Total Cost		**$8,885,215.00**
Misc. Items	15%	**$1,332,782.25**
Owner's Cost (Cost of Financing)	0%	**$0.00**
Total Cost of Transmission Line		**$10,217,997.25**

Table Error! No text of specified style in document.**-1:**
Interests and Concerns Raised by Members of the Public and Areas where Feedback from Public Engagement Activities was considered in the Environmental and Socio-economic Assessment Process

Issue	Interest/Concern Raised	Response
Project Description and Transmission Line Route	New line segment between Mayo and Keno City should limit frequency of crossing over the highway.	This was a consideration in the routing of the new transmission line between Mayo and Keno City. See Chapter 6, Section 6.3.3.
	New line should avoid crossing properties as it enters Keno City substation (Mayo to Keno City Line Segment).	See Chapter 6, Section 6.3.3.
	Concern regarding the potential for the new line to encroach on existing private property as distance between existing centre line and private property line is limited.	See mitigation discussed in Chapter 7, Section 7.3.3.2 (Private and Commercial Land Use).
	Special care and attention was requested for a buried water line near McGuinty Creek along the proposed route.	See mitigation discussed in Chapter 7, Section 7.3.3.2 (Private and Commercial Land Use).
	Concern regarding avoidance of historic signage and engine on Alexco parcel near Keno City.	See mitigation discussed in Chapter 7, Section 7.3.3.2 (Private and Commercial Land Use). See also Chapter 6, section 6.3.3.
	Interest in the types of poles being used to replace the line segment between Mayo and Keno City.	An H-Frame configuration is planned with use of mono-pole or double circuit design provided in specific areas to mitigate adverse impacts on private property or other interests.
Substations	Interest in the potential locations for the substations.	Project Description, Chapter 6, Section 6.3.3.1 describes alternatives locations for substation.

Issue	Interest/Concern Raised	Response
Safety and Reliability	New line should limit the frequency and duration of power outages for customers (Mayo to Keno City Line Segment).	See Chapter 6, Project Description. The Project will improve the transmission grid infrastructure in central Yukon between Stewart Crossing and Keno City, and reinforce and strengthen the grid between Stewart Crossing and Mayo ensuring continued safe and reliable service.
	Concern regarding power outages during line construction.	In the event that substantial power outages are anticipated, generators will be put in place to reduce impacts of outages to hours (not days).
	Concern regarding potential for stray electricity coming off the new line given it will be operated at a higher voltage.	Due to the size of the line this concern is not an issue.
Transformer Upgrades	Concern regarding replacement of existing transformers that were considered insufficient to meet existing power needs of two customers along the route northeast of Mayo.	The Project will also provide updated transformer infrastructure for service to specific properties near the Minto Bridge and Halfway Lakes.
	Interest in new opportunities to access grid power and associated costs.	The cost of a new transformer and distribution line is borne by the customer. However, the Yukon Government's Rural Electrification Program may provide some financing assistance. A 69kV step-down transformer may cost between $100,000 and $150,000 (a 138 kV step-down transformer would cost slightly more). Ten distribution poles (100 m apart) would cost on the order of $15,000.

Issue	Interest/Concern Raised	Response
Project Costs	Concern regarding how the Project will be funded; and impact of Project costs and potential cost over-runs on ratepayers.	Funding by the Yukon Government through Yukon Development Corporation (YDC), rather than by Yukon Energy, will allow the system improvement to be completed without any adverse cost impacts on electrical rates. Yukon Energy does not have any specific information regarding how the Yukon Government or YDC plans to finance the Project at this time, but understands a number of funding options are being considered.
	Concern regarding extreme cost of the Project when there are only a handful of customers in Keno; suggestion to decommission the line and turn on the diesels in the communities. Suggestion that money could be used more strategically.	See Chapter 6, Section 6.3.3. Moving existing customers from grid generation to thermal (diesel) generation is not consistent with the goals of Yukon government's Energy Strategy for Yukon or the Climate Change Action Plan. Removal of the line would also likely limit potential future industrial growth in this area of longstanding mining activity, which could have an adverse impact on potential economic growth in Yukon. It would also limit future renewable generation development in this area for connection to the Yukon grid.
	Concern over how the government is funding the Project.	Yukon Energy understands that the government is considering a number of funding options.

Issue	Interest/Concern Raised	Response
	Concern over building public infrastructure to potentially support uncertain and future private development. Suggest that mining companies should pay for their own infrastructure. Concern regarding the high cost of substations for industrial purposes.	See Chapter 6, Section 6.3. The Project will 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, ensuring continued safe and reliable service and facilitating future economic development within the territory. See also discussion in Chapter 5, Section 5.4 which outlines the current industrial customer investment policy as approved by the YUB. This reduces the risk of adverse cost impacts to other utility ratepayers from new capital costs needed to connect a new major industrial customer and focuses on maximizing potential industrial customer investment to new transmission facilities developed to extend service to them as well as to retain direct assignment of annual capital-related transmission costs for existing facilities, where appropriate.
Employment Opportunities	Queries regarding who would be hired to do line work.	Line work will be put out to competitive and open tender.
	Interest in construction employment opportunities, including local contractors (brushing, clearing, substation crews).	Line work will be put out to competitive and open tender. Brushing contracts have been tendered separately in the past. Yukon Energy would like to understand the capacity of local residents have for this type of work in order to maximize Project benefits to local residents and Yukoners in general.
	Interest in environmental contracts.	There are not likely to be any other environmental contracts at this time; however, Yukon Energy is pursuing potential heritage work.
	Interest in local economic benefits. YEC should have a policy that supports using local companies and businesses for their infrastructure projects and should consider local businesses during tender process.	Yukon Energy will endeavour as part of the remaining project planning, procurement and construction stages to maximize benefits to local businesses.

Issue	Interest/Concern Raised	Response
	Interest in the location of construction camps and potential opportunities for local businesses.	Decisions have not yet been made regarding the number of camps or camp locations. Camp location would very likely be located on private property.
Consultation	Interest in consultation/engagement process and how individuals could participate in the planning and assessment process so that their views could be discussed.	See discussion included in Section 4.3 and Section 4.4 of this Chapter regarding methods of communication for the public engagement process.
Project Schedule	Interest in overall Project schedule (YESAB submissions, construction, operation).	See Chapter 6, Section 6.5 for overall Project schedule.
Biophysical Environment	Concern regarding important small mammal habitat area.	See Chapter 7, Section 7.2.3.3.
	Interest in impact collisions related to migratory birds.	See Chapter 7, Section 7.2.3.4.
	Request to avoid Community Ecological Monitoring Plots.	See Chapter 7, Section 7.3.3.2.
	Include a vegetative buffer between roadway and transmission line.	See mitigation discussion in Chapter 7. A vegetative buffer is being provided to the extent feasible.
	Concern over past construction practises regarding waste materials and garbage along the ROW.	There will be environmental monitoring and adequate oversight. Yukon Energy will ensure its EMS is applied.
	Concern regarding ground disturbance along the ROW including permafrost melting, soil erosion and drainage.	See mitigation measures described in Chapter 7. Ground disturbance will be minimized through avoidance of poor terrain, where possible, and other mitigation measures as described in Chapter 7.
Heritage	Concern over heritage or historic sites of value along the proposed route.	See Chapter 7, Section 7.3.3.5. A Heritage Resources Impact Assessment has been completed. Yukon Energy's Heritage and Culture EWP will be followed during construction.

Issue	Interest/Concern Raised	Response
Timber Salvage	NND and local community residents (Mayo and Keno City) noted importance of access to fuel wood.	The Timber Salvage Plan has been prepared as part of the submission.
	Queries regarding whether hand clearing or machinery would be used.	See Chapter 7 and Timber Salvage Plan provided as Appendix 6C. In areas of low salvageable timber and extensive permafrost the wood will likely be mulched and left as ground cover. In conventional terrain areas it will be slashed and burned.
	Interest in access to usable salvaged poles.	Yukon Energy will offer opportunities for salvage/use of decommissioned poles where appropriate.
Future Development	Concern over whether Mayo will still be serviced with new infrastructure if mining activities become productive in the future.	Mayo will still be serviced with new infrastructure if mining activities become productive in the future.
	Interest in renewable energy projects, specifically the potential power from future wind projects on Ferry Hill to be fed into the system.	Consideration, via data collection, is being given to the feasibility of the Ferry Hill power source. See also Chapter 6, Section 6.3. The proposed improvements to the integrated system will extend Yukon's existing 138 kV grid from Stewart Crossing to Mayo and the Keno City area, addressing continued reliability concerns, and also facilitating connection to the integrated grid of potential future customers and sources of renewable energy in this region that require a higher voltage power line with greater capacity.
	Interest in fibre optic cable providing faster internet speeds being included in this Project.	See Project Description provided in Chapter 6. Fibre optic cable will be for utility usage only.

REFERENCE: **Application, Tab 5.2.1.4, page 5-13**

ISSUE: **McQuesten Substation Project**

QUOTE: "Total cost estimated for the McQuesten Substation during the VGC PPA proceeding were $8.529 million (assuming no need for a Step Down transformer)…"

"YEC has received an asset contribution from VGC Group valued at $10.688 million, and has incurred a net cost of $0.931 million (related to added facilities to enable future 138 kV service operation if required)." (footnote removed)

QUESTION:

a) Please explain in what circumstances YEC would require a step-down transformer in this substation and the likelihood of such a transformer in the near future.

b) Please explain the assets included in the $10.688 million contribution amount and whether this amount will equate to future 138 kV service operation, if required.

ANSWER:

(a)

YEC would require a step down transformer if the line from Stewart Crossing substation to McQuesten substation was energized at 138kV. The likelihood of installing the step down transformer is unknown at this time.

(b)

The assets included in the $10.688 million asset contribution from VCG Group include substation assets and all related ancillary components that VGC Group was responsible for funding, i.e., all capital costs related to the McQuesten Substation development except for costs to enable operation at 138 kV voltage. Accordingly, this amount is not related to future 138 kV service operation, if required.

The VGC Group PPA provides for VGC Group to recover from YEC the incremental fees, costs and expenses associated with the McQuesten Substation, as initially developed, being able to operate at 138 kV voltage ("YEC McQuesten Substation Costs" as specified in Schedule B of the VGC Group PPA). YEC McQuesten Substation Costs as included in Schedule B of the VGC Group PPA are summarized in the Table below, and are YEC's net cost related to this facility.

Table B-2: YEC McQuesten Substation Costs

S258 McQuesten & S249 Mayo		YEC
Construction	**$**	**605,931**
Supervision	$	36,000
Site Prep (Civil works)	$	325,350
Foundations	$	174,081
Structure and Bus Work	$	8,000
Electrical / Telecontrol / Telecom	$	62,500
Material	**$**	**240,036**
Switch Yard	$	132,770
Major Equipment	$	87,266
Delivery	$	20,000
Commissioning	**$**	-
On-site		
Owner's Costs	**$**	-
Overall owner's costs		
Subtotal	**$**	**845,967**
Contingency (10%)	**$**	**84,597**
TOTAL	**$**	**930,563**

REFERENCE: **Application, Tab 5.2.1.5, pages 5-13 to 5-14**

ISSUE: **Transmission Line Refurbishment Project**

QUOTE: "YEC's 138 kV Whitehorse-Aishihik-Faro (WAF) transmission system was constructed in the late 1960's and early 1970's, and plays a critical role linking key hydro generation sources to load centres in Whitehorse and on the northern grid. Recent studies as well as a detailed line assessment in 2017 indicated that key components of the WAF system were at end of life, in poor condition, and required replacement."

"Specifically, certain components of these lines had begun to exhibit higher failure rates. Based on these events, YEC commissioned external asset assessments of the key backbone lines on the integrated system as noted above. These assessments indicated that a large number of cross arms and insulators are at end of life with a high risk of failure." (footnote removed)

QUESTION:

a) Please provide and explain the studies (including the detailed line assessment conducted in 2017) that were conducted to show that key components of the WAF transmission system were at end of life, in poor condition and required replacement. For example, what reliability criteria were violated, and were contingency analyses performed?

b) Please explain how often YEC carried out studies and assessed the reliability of the WAF transmission system in the past.

c) Please explain which components of the system began exhibiting higher failure rates and whether this system experienced any outages. If so, please provide the number and duration of outages experienced in the last 10 years, on a per annum basis, and the costs incurred due to these outages.

ANSWER:

(a)

The requested studies are provided in the following attachments:

Attachment 1 provides the "Transmission Line Overhead Facilities Condition Assessment Technical Specification and Project Management Requirements." The document defines the requirements for inspection and condition assessment of Yukon Energy Corporation's (YEC) overhead transmission line assets and notes as follows in the Overview:

> The intent of transmission line inspection and condition assessment is to ensure that sufficient information is available to support ongoing operations and maintenance of these assets, plan for maintenance upgrades in the future, and address immediate maintenance issues that may affect reliability or availability. In general, the transmission line inspection will assess the present condition of each structure and piece of hardware associated with the line, as well as noting possible foundation, clearance, and vegetation issues related to the line. The line patrol will also involve identifying original structure location relative to its replacement structure. A photo record of each structure and associated foundation and of every defect recorded will be part of the inspection and assessment work. Inspection crews are required to install missing structure tags in the field as necessary, the structure tags will be supplied by YEC.
>
> Following collection of field data, the inspection results, record of defects and repair priorities is to be summarized in the supplied excel worksheet.

The excel worksheet is provided as **Attachment 2**.

Other studies undertaken that show that key components of the WAF transmission study were at end of life, in poor condition or required replacement are summarized below. Generally, cross-arms, insulation and the shell thickness of the poles were the main components of concern.

- **Attachment 3** provides the Powertech Labs Inc. assessment of "Failure Analysis and Condition Assessment Tests on Suspension Insulators from Yukon Energy 138 kV Transmission Line". As noted in the report, 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. The Powertech report notes in summary that "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."

- **Attachment 4** provides PowerTech "Condition Assessment and Evaluation of Type ASX Cross Arms". A condition assessment and evaluation of in-service crossarms from a 138 kV transmission line operated by Yukon Energy was performed by Powertech Labs, to determine the remaining load carrying capacity of the crossarms, and whether they still meet both historical and upgraded modern design load requirements. The crossarms were from angled tangent structures, in which the angle of the crossarms is approximating that of the sloping terrain. The report noted that "Given the high probability of not meeting design vertical loads and the age of the crossarms (close to 50 years old), as well as evidence of failure in service, it is recommended that the replacement of these crossarms should be initiated to mitigate the risk of failure in service". The following priorities were suggested:
    - Long spans should be given priority for replacement over short spans;
    - Crossing structures should be given priority over non-crossing structures; and
    - For all spans, those structures in which knots and checks are noted around connection points should be given priority over structures in which these features are not seen.

- **Attachment 5** provides "Condition Assessment and Evaluation of 138 kV Wood Cross Arms". Wood crossarms utilized in single crossarm H-frame structures from an existing 138 kV transmission line were supplied by Yukon Energy Corporation for full scale mechanical testing and flexural testing. The crossarms of the transmission line are scheduled to be replaced by steel crossarms, the testing was undertaken to assess the existing structural integrity of the crossarms and their serviceability with respect to updated design criteria for the line, and gauge the

immediacy of the replacement program. The report notes, “Based on the test results, it can be stated that the existing single wood crossarms do not meet the updated design criteria for the line. The design criteria itself takes into account load factors in combination with worst case climate load scenarios. From the reliabilities obtained against the unfactored design load, it is seen that the probability of any immediate failures of existing crossarms is low.” It was recommended that the replacement program of steel crossarms begin as soon as operational practicability dictates, and be guided as follows:

- Long spans should be given priority for replacement over short spans;
- Crossing structures should be given priority over non-crossing structures;
- For all spans, those structures in which knots and checks are noted around connection points should be given priority over structures in which these features are not seen.

(b)

YEC established the first Test and Treat in 2009. Tests and treat is a process that determines the pole shell thickness above and below grade, treats cavities and eliminates insect infestations. Detailed line assessments occur on the various transmission lines at approximately 10-year intervals. The first was in 2003, and the latest was in 2018.

(c)

Cross-arms, insulation and the shell thickness of the poles were the main components of concern. For further details see Attachments 3, 4 and 5 to part (a) of this response.

Please see Table 1 below for number and duration of outages on L170 and L171 over the past 10 years. Outage data is not available for L172.

Total costs related to outages are as follows:

- L170 total cost to respond to outages (planned and unplanned) are $313,500, with an average annual cost (2012-2020) of $34,800; additionally, capital investment in this line over the same period totaled $7,064,600;

- L171 total cost to respond to outages (planned and unplanned) are $100,500, with an average annual cost (2012-2020) of $11,200; additionally, capital investment in this line over the same period totaled $3,718,600; and

- L172 total cost to respond to outages (planned and unplanned) are $25,400, with an average annual cost (2012-2020) of $2,800; additionally, capital investment in this line over the same period totaled $321,000.

Table 1: Number and Duration of Outages L170: 2011 to 2020

2011-2020 L170 Planned and Unplanned Line Outages				
Year	**Unplanned Outages**	**Planned Outages**	**Total Outages**	**Outage Hours**
2011	3	0	3	5.23
2012	1	0	1	0.31
2013	3	0	3	1.35
2014	3	5	8	5.35
2015	4	1	5	4.95
2016	6	0	6	5.14
2017	5	11	16	10.13
2018	2	1	3	3.67
2019	2	2	4	9.73
2020	5	5	5	23.46

Table 2: Number and Duration of Outages L171: 2011 to 2020

2011-2020 L171 Planned and Unplanned Line Outages				
Year	**Unplanned Outages**	**Planned Outages**	**Total Outages**	**Outage Hours**
2011	2	0	2	0.74
2012	0	0	0	0
2013	0	0	0	0
2014	0	3	3	0.2
2015	0	3	3	0.83
2016	1	0	1	1.47
2017	1	4	5	36.67
2018	2	1	3	181.75
2019	2	1	3	382.87
2020	1	0	1	0.3

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Transmission Line Overhead Facilities Condition Assessment

Technical Specification and Project Management Requirements

REVISION LOG:

Revision #	Revision Date	Amendment
0	2016-Sep-09th	Release for Detailed Line Assessment – (RFP 2016-044)
1	2016-Oct-06th	Release for Detailed Line Assessment – L171 (Field Work)
2	2016-Dec-16th	Remove GPS requirements for Detailed Line Assessment 2017

1. OVERVIEW

This document defines the requirements for inspection and condition assessment of Yukon Energy Corporation's (YEC) overhead transmission line assets.

The intent of transmission line inspection and condition assessment is to ensure that sufficient information is available to support ongoing operations and maintenance of these assets, plan for maintenance upgrades in the future, and address immediate maintenance issues that may affect reliability or availability. In general, the transmission line inspection will assess the present condition of each structure and piece of hardware associated with the line, as well as noting possible foundation, clearance, and vegetation issues related to the line. The line patrol will also involve identifying original structure location relative to its replacement structure. A photo record of each structure and associated foundation and of every defect recorded will be part of the inspection and assessment work. Inspection crews are required to install missing structure tags in the field as necessary, the structure tags will be supplied by YEC.

Following collection of field data, the inspection results, record of defects and repair priorities is to be summarized in the supplied excel worksheet. All data including hard and soft copies of all field inspection check sheets, line assessment summary spreadsheets, notes, tailboards and photo record (soft-copy only) are to be returned to YEC following completion of the transmission line inspection.

1.1. LINE GENERAL INFORMATION

YEC's 138kV transmission line network consists primarily of wood pole H-Frame type transmission structures. Some of the newer lines and replacement structures make use of steel crossarms and steel cross-braces. Insulation is a mix of porcelain dating to 1968, toughened glass, and composite.

1.1.1. L171 (Aishishik Generation - Takhini Substation)

L171 is a 129km transmission line built in 1976 to connect Aishihik power generation to Whitehorse. L171 is comprised of ~611 structures.

L172 (Riverside Substation – Takhini Substation)

L172 was part of the L170 original line built from Whitehorse (Riverside) to Faro Mining community in 1970. Later, Takhini substation was built and the L170 structures #1 - #112 became their own line, L172. L172 is 25km long, with ~112 structures.

L169 (L172 tap – McIntyre Substation)

L169 was built to connect the 138kV L172 to McIntyre Substation in 1980. L169 is 6.5 km long with ~30 structures.

1.1.2. L170 (Takhini Substation – Carmacks Airport Sub)

L170 is 152 km transmission line built in 1970, and has maintained its Line designation from the original build to the Carmacks area. L170 is comprised of ~723 structures.

1.1.3. L178 (Carmacks Airport Sub – Faro Mine)

L178 was part of the L170 original line built from Whitehorse (Riverside) to Faro Mining community in 1970. L178 is 190km from Carmacks Airport Sub to the Faro Mine and is comprised of ~832 structures.

1.2. GROUND PATROL SCOPE OF WORK

The scope of work for this assessment project consists of the following aspects:

1. Complete ground patrol and structure condition assessment and accurate recording of field data. Assess urgency of associated maintenance actions.
2. Produce photographic record of each structure, structure foundation, and all visible defects.
3. Note and photo record vegetation along Right of Way (ROW).
4. Install missing structure tags where required.
5. Provide all equipment and supplies required to perform the assessment in a safe, professional manner including: quads; trailers; vehicles; fuel; hand tools; binoculars; GPS enabled camera; computers; safety and communications equipment; food; accommodations, and so on. (YEC will supply structure tag kit).
6. Project management, tracking, and reporting of progress.
7. Support YEC QA/QC process and checks.
8. Compile results into final report including line assessment summary spreadsheet and provide to YEC.

1.3. YUKON ENERGY RESPONSIBILITIES

1. Supply plan and profile drawings of the line to be inspected.
2. Supply number tags and plates for replacement of missing structure tags.
3. Co-ordination of pre-job safety review between the Contractor and YEC personnel.
4. Perform contractor orientation and QA/QC checks to ensure quality of returned data matches specification and expectations.
5. Responsive support from YEC SCC to track and support daily operations (daily check-in and check-out).

2. FACILITIES INSPECTION PATROL REQUIREMENTS

2.1. STRUCTURE CONDITION ASSESSMENT

A structure by structure ground patrol, on foot where difficult terrain prevents ATV access, examination of each structure on the line (including PT-Substation structural components and take off structures from main substations) is the primary goal of this project.

Each aspect of the structure is to be identified, inspected, and the condition recorded. Any associated visual defects and deficiencies are to be identified and recorded. Each deficiency is to be categorized on a YEC defined maintenance priority scale, reflecting the urgency of need for repair.

2.1.1. Structure (STR)

Each structure is to be visually inspected to establish the general condition of the structure framing. The structure type is to be identified and recorded. General structure straightness and condition is to be noted and recorded.

Each component shall be visually inspected for condition and defect, including poles, cross-arms, insulators, hardware, armor-rod, conductor, guys and anchors.

2.1.2. Poles (POL)

Pole height, class, species, date stamp, general external condition, evidence of ant infestation and any external visual damage including burns, woodpecker holes and mechanical damage are to be identified, noted and recorded as part of the patrol finding.

Internal testing of poles is not included as part of the scope of the patrol inspection. Separate inspection program will determine the pole structural adequacy.

2.1.3. Foundation (FDN)

The condition of structure foundations is to be examined, the type of foundation is to be recorded, and visual deficiencies such as leaning structures, inadequate backfill, sloughing, soft-rot and other problems are to be identified, noted and recorded.

2.1.4. Guys and Anchors (G&A)

The number, type, configuration, general condition of the guy and anchor shall be noted and recorded. Visual damage of the guy wire and hardware shall be noted and categorized for maintenance priority. Anchor surface condition shall be inspected to determine the state of the anchor performance. Any anchor deficiency shall be noted, recorded and categorized for maintenance priority.

2.1.5. Cross Arm (XRM)

Type of cross arm, steel or wood, general external condition, visual damage including cracks, burns, bow, bend, twist, sloping grain, rust are to be identified, noted and recorded as part of the patrol finding. Cross arms before road or trail crossings are to be noted with key words ‘ road crossing’ in the comment section.

2.1.6. Cross Brace (XBR)

Type of cross brace, steel or wood, general external condition, visual damage including cracks, bow, twist, grain, rust are to be identified, noted and recorded as part of the patrol finding.

2.1.7. Insulators (INS)

The colour (grey or brown) and type (ceramic or composite) of the insulators on each structure are to be noted during the inspection patrol, as this will date the age of the insulator. The condition of the insulator and any defects including staining, rust, cement bulging, burn marks, chips, cracks, misalignment, defective pins, etc, are to be identified, noted and recorded as part of the inspection.

2.1.8. Vibration Damper (VIB)

The type and number of vibration damper on each span shall be noted and recorded as part of the inspection.

2.1.9. Aerial Marker (AMK)

The type and number of aerial marker, general condition, visual damage including gun shot, broken marker, colour fading are to be identified, noted and recorded as part of the inspection.

2.1.10. Conductor and Shield Wire (C&S)

The condition of conductor between structures is to be visually assessed and any visible damage, such as loose or broken strands, bird caging, gunshot damage or other types of damage is to be recorded. Any damage to overhead shield wire, where it exists (typically only near substations) should be noted as well. The presence of in-line splices is to be noted as part of the inspection, and the key words ‘auto sleeve’ added to the comment field.

A span of conductor will be identified by the name of the structure behind it. For example the span between structures L170-455 and L170-456 is to be recorded as span L170-455.

2.1.11. Grounding and Bonding (G&B)

The condition of grounding wires and connections are to be visually assessed. Any missing connections, broken wires, missing guards, signs of tracking or burning are to be noted.

Bonding of hardware in presence of shield wire or metal cross arm is to be inspected for any visible damage, loose or missing connections.

2.1.12. Hardware (HDW)

All hardware and attachments are to be inspected in detail. Any deficiencies, including damaged, worn, missing, decayed, loose, miss-aligned or incorrectly installed items are to be identified, noted and recorded. Deficiencies are to be categorized on a YEC defined relative priority scale, reflecting the urgency of need for repair.

2.1.13. Vegetation on Right of Way (VEG)

Vegetation in the span following the structure (in the direction of the structure with the next highest number) is to be assessed, and the average height estimated. Any trees in danger of falling on the Line will be noted.

2.1.14. General Comments (GRL)

Any access issues to the structure should be recorded here.

2.2. EQUIPMENT CONDITION CODES AND MAINTENANCE PRIORITY CODES

All deficiencies noted are to be categorized as to equipment condition as well as the maintenance priority. Condition and Priority Codes are defined on a YEC defined priority scale reflecting the relative urgency for repair.

Equipment Data Collection Codes[1], Equipment Condition Codes, and Maintenance Priority Codes are supplied in the Appendix.

The Condition (general) and Maintenance Priority Codes to be assigned to deficiencies found in the field are summarized in the table below.

2.2.1. YEC Transmission Line Condition Codes (General Summary)

YEC has supplied specific equipment condition codes for each aspect of a transmission in the Appendix.

In general, condition codes are assigned as per the following pattern.

G	Good Condition – No Visible Defects (Will Last Next 10 Years) No maintenance necessary. Re-inspect at next cycle (Priority Code of 5).
F	Fair Condition – Visible Defects Not Critical. Requires Maintenance, Adjustment, Repair at next opportunity, or Ongoing Monitoring (Priority Code of 4 or 5 would be appropriate depending on the defect).
P	Poor Condition – Replace or Repair Required. Priority Code of 1, 2, or 3 would be appropriate depending on the defect.
M	Missing – Replace Missing Item (Priority Code of 1, 2 or 3 would be appropriate depending on the missing component).
O	Other Condition – Specify.
N/A	Not Applicable

[1] Abbreviations used to identify different types of each structure aspect found in Appendix A.

2.2.2. YEC Transmission Line Maintenance Priority Codes

1 Indicates a very serious system reliability or public safety problem. Repairs or modifications should be made immediately (probably within 1 to 2 days). Contact YEC T&D Leadhand as soon as possible (ASAP).

2 Indicates a reliability or safety problem which is serious enough it should be rectified in the not too distant future (possibly within 3 months). Condition is serious enough that it would probably be dealt with prior to the next scheduled routine maintenance.

3 Indicates a concern which should be corrected, but is minor enough that it could be rectified as part of a planned maintenance program (possibly within the next 1 to 5 years).

4 Indicates a concern which is minor enough it would only be corrected if convenient to do so. Corrections would only be made if other work were being done in the same area or on the same pole.

5 Indicates a comment which is recorded for information only – no corrective action is required.

2.3. NOTE AND RECORD VEGETATION GROWTH IN THE ROW DURING GROUND PATROL

The Contractor is to document and record in general terms the predominant type and height of vegetation in the cleared ROW for each span (e.g. mixed willow / poplar to 3m). The intent is for YEC to confirm brushing plans in the coming years, and to manage any danger tree or clearance issues which have arisen between clearing cycles. The Contractor is to make note of any danger trees (or potential danger trees) threatening the transmission line. Digital photos are to be taken to support the observations of general vegetation condition and danger trees.

2.4. REPLACE MISSING STRUCTURE TAGS DURING GROUND PATROL

The Contractor will be required to re-install missing structure tags with a YEC Supplied structure tag kit during the ground patrol.

2.5. PHOTO RECORD

For each structure, a baseline of four digital photos is required, showing the entire structure and foundation from each quadrant; Front, Left, Back and Right side. Example; L170-000963-FRNT, L170-000963-LEFT, L170-000963-BACK, L170-000963-RGHT.

For ground patrol, additional images will be taken to show specific details of the structure to illustrate any concerns or deficiency, if necessary.

The Contractor will be required to supply his own photographic equipment for this project. Photos taken must have an accurate time/date stamp and GPS location Data inserted in the picture by the camera. The digital images shall be in JPEG format. Images shall have a minimum resolution of 3 megapixels.

Two copies of the photo record shall be provided to YEC in a photo directory on separate USB keys. Photos are to be saved with proper orientation, such that no further rotation is needed. Photos shall be titled in accordance with the following system:

- L170-xxxxxx-aaa-xx
  - L170 indicates line number
  - xxxxxx indicates structure number (Six characters required: Leading zeros are needed for effective database sorting e.g. S91 is not acceptable; S000091 is acceptable).
  - aaa-xx 3 digit alpha code to indicate which aspect of the structure;

STR - Structure	INS - Insulator	G&B - Grounding and
POL - Pole	VIB - Vibration Damper	Bounding Defect
FDN - Foundation	AMK - Aerial Marker	HDW – Hardware
G&A - Guy & Anchor	C&S – Conductor &	VEG – Vegetation
XRM - Cross-Arm	Shield Wire	GRL - General Comments
XBR - Cross-Brace		

and 2 digit numeric code for different images of the same detail.

- Examples
  - L170-000963-STR-01.JPG Line 170, Structure 963, Structure defect image 01
  - L170-000963-FDN-01.JPG Line 170, Structure 963, Foundation defect img 01
  - L171-0062_7-XRM-01.JPG Line 171, Structure 62/7, Cross Arm defect img 01

3. FINAL REPORT

A draft of the final report detailing the condition of the transmission line is to be submitted within 10 working days of the completion of the transmission line assessment. Upon YEC's approval of the draft, the final hard copy of the report shall be submitted to YEC within 10 working days.

YEC retains rights to all field and summary data, photos and records collected during the course of inspection.

The final report will consist of the following;

- A summary describing the general condition of the line and significant findings or discussion of difficulties encountered.
- Hard copies of the field inspection check sheets, sorted by line and structure.
- Hard copies of daily tailboards by field crew, in chronological order.
- A base excel line assessment summary spreadsheet complete with all assessment information[2]. This spreadsheet will be, sorted by structure number, containing all the findings and notes of the field assessment, including:
  - Inspection data, condition codes and related comments.
  - Defects noted, related priority code, and photo reference.
  - Structure photo references (minimum 4).
  - Notes regarding minor maintenance work performed in the field (eg. structure tags).
  - Height of vegetation growth for each span.
  - Location of old structure relative to existing, where structure has been replaced.
  - Road crossings spans.
- Summary of structure issues which require attention, sorted by priority.
- Separate summary of issues, sorted by aspect category (first) and then by priority.

[2] Format supplied by YEC and is intended for conversion to a database by YEC.

- The complete photographic record of the line, by structure, including photos of all defects (soft-copy only).

The Contractor is responsible for all computer hardware and software required to record data and compile the line assessment summary spreadsheet, as well as the integrity of all data until the project is complete and all reports have been submitted to, and accepted by, YEC. During the project, data backups, security, and storage are the responsibility of the Contractor.

Two hard copies of the final report are to be submitted to YEC in separate binders, with sections logically separated by tabs. Two soft copies of the final report are to be submitted on separate USB keys in both PDF and native formats. These submissions are to include copies of field inspection check sheet forms and copies of daily tailboards and weekly progress updates. Two soft copies of the Photo Record on separate USB memory sticks will be submitted to YEC. Hard copy photo prints of structures and defects are not required.

The Contractor will submit a draft report to YEC for review prior to publishing the final report. YEC will review the draft report and advise the Contractor, within 7 working days, whether the report is acceptable or whether deficiencies exist. If changes are needed, the Contractor shall remedy any deficiencies and re-submit the final report within a further 10 working days.

4. PROJECT MANAGEMENT, SAFETY PLANNING, AND GENERAL INFORMATION

4.1.

The YEC project manager will implement the following Q/A Q/C checks with the contractor's cooperation, to ensure returned data accurately captures the condition of equipment in the field, and that expectations between YEC, the contractor, and the inspection team are aligned.

1. Prior to Field inspection, YEC will review the inspection specification and expectations with the inspection field team. This will occur immediately following safety and environmental orientation at the project kick-off with the contractor.
2. Field Audit on Day 1 Week 1: YEC will accompany the contractor on the entire first day of field inspection and oversee the quality of data collection as performed by the contractor meets YEC expectations.
3. Field Audit on Day 3 Week 1: The contractor will complete inspections on the second day without YEC oversight. YEC will randomly select at minimum one structure from the second day of inspection for field audit to confirm the quality of collected data.
4. The contractor is to return to YEC all inspection data collected over the course of a week by the end of day Sunday. This is to support field inspection, and is not to be considered as the final report or complete inspection data package deliverable to be supplied at the end of the project.
5. Field Audit Week 2: The contractor will submit weekly field data for YEC review at the end of the first week of inspection. YEC will randomly select a structure from Week 1 inspection for field audit to confirm the quality of collected data.
6. Field Audit Week 3: The contractor will submit weekly field data for YEC review at the end of the second week of inspection. YEC will randomly select a structure from the week prior inspection for field audit to confirm the quality of collected data. YEC will confirm tailboards with the crew in the field.
7. Field Audit on returned data: Once the contractor has processed the first batch of field data into the summary spreadsheet, YEC will select a structure from the data set and perform a field audit to confirm the summary spreadsheet condition data matches the structure in the field.
8. Ongoing Q/A Q/C checks: Every two weeks for the duration of the project, YEC will perform at least one structure inspection audit to compare contractor collected data with a field structure.

4.2. ACCESS

YEC will supply known, existing access points, which YEC uses for planned maintenance activities. However, for inspection purposes without heavy equipment (e.g ATV or foot

access), any publicly accessible access point may be used. The exception is private property or First Nations Settlement Land Parcels.

Crossing of private property land parcels without the landowners' permission is not permitted. It is incumbent on the Contractor to pre-arrange access over private land where it may be necessary.

First Nations Settlement Land is to be respected as private property. YEC will engage the first nation and work to arrange for access across settlement land parcels for the Contractor before field work begins, and may require the Contractor's input in this regard. YEC advises that the FN may impose access restrictions.

Access roads may not be modified or altered, nor may new accesses be created.

YEC will provide maps showing line plan view, which will identify the transmission line route and structure locations, road ROW, known access points for YEC maintenance purposes, private surveyed land parcels and First Nation settlement land.

Regardless of land title or ownership, YEC expects that the crew performing field work will act in a professional manner, not leave behind litter or waste, and treat land and residents living near or along the transmission line with respect.

Access to substations (some PT Substations are fenced) is not expected. If needed, access arrangements shall be made with YEC System Control Center (SCC).

4.3. DAILY CHECK-IN AND CHECK-OUT

The Contractor will be required to check-in with the YEC System Control Centre (SCC) at the beginning of each day, indicating the section of line that is planned to be patrolled during that day, and the hours of work planned.

The Contractor will be required to check-out with SCC at the end of each working day.

4.4. PROJECT TRACKING

The Contractor shall supply a weekly project update to the YEC project manager overseeing inspection. The weekly report is due by the end of day Sunday, and will include:

- Project report of structures inspected in the past week
- Field data from the previous weeks inspection work, to support and facilitate YEC QA/QC checks.
- Structures/sections scheduled for inspection in the week ahead.
- Notable difficulties encountered.
- Notable deficiencies and critical defects encountered requiring immediate attention.
- Any change to forecast completion date as a result of progress to date.

4.5. CRITICAL DEFECTS

The YEC Lead-hand T&D is to be called as quickly as possible and notified of critical field issues found during the ground patrol which require immediate attention to avoid failure of the line.

In all circumstances, the initial call to YEC Lead-hand T&D is to be followed up with an email within five working days. The email will indicate;

- Where: Line and structure number
- When: The problem was first noticed
- What: Nature of the problem
- Photograph

4.6. SAFETY PLANNING / COMMUNICATIONS

The Contractor is required to develop and present to YEC before beginning field work, a comprehensive safety plan for their work including: Tailboards and job plans, communications equipment, emergency contact information, MSDS sheets where applicable, PPE and safety equipment, and training appropriate to the work being done.

The inspection Contractor is required to comply with all YEC Health, Safety and Environmental requirements and policies, Yukon OH&S requirements, environmental regulation and reporting requirements, as well as any additional H&S requirements as deemed necessary by the Contractor as part of the Contractor's Health and Safety Plan.

All field personnel are required to complete YEC Health, Safety, and Environmental orientations prior to beginning field work. Environmental portion includes awareness of bird nesting habits and fish bearing streams.

A joint safety review / orientation meeting between YEC, the Contractor, and all workers involved in the project, will be conducted by the YEC project manager before any field work is carried out. Radio communication with YEC repeaters is not reliable along all sections of transmission line. It is suggested that the Contractor not plan to depend on the YEC radio repeater network for communications during this project.

The Contractor will make provision to supply their own satellite phone for each crew in the field for the duration of the field work. The YEC System Control Centre must be able to contact the field crew(s) while they are working in the field. When working on YEC property/ROW, SCC should be the first line of contact for the Contractor in an emergency.

Appendix A - Abbreviations For Transmission Line Master Inspection Form

Structure Information (STR)

Structure Number Sxxxxxx

L170, L172, L178 - Structure Type:

A / AX	Tangent Structure 0° to 3°
B	Angle Structure 3° to 12° 30’
BS	Angle Structure 3° to 12° 30’ for Side Slope Locations
C	Angle Structure (Str. 1244) Angle 12° 48’ Left
CS	Permanent Structure (Str. 1208) Angle 12° 48’ Left
D	Angle Structure 30° to 60°
DS	Angle Structure 30° to 60° for Side Slope Locations
E	Angle Structure 0° to 90°
ES	Angle Structure 0° to 90° for Side Slope Locations
F	Transposition Structures
G	Uplift Structure Tangent 0° to 3°
AG / AGX	Tangent Structure 0° to 3° with OHGW
EG	Angle Structure Deadend 0° to 90° with OHGW
AXS	Tangent Structure for Sloping Locations (Snowshed structures)

L171 – Structure Type:

Type H	Tangent Structure: 0° - 1°
Type HG	Tangent Structure: 1° - 3°
Type HW	Tangent Structure with OHG (Unguyed Structures)
Type HWG	Tangent Structure with OHG (with Side Guys 1° to 3° line angle)
Type HWX	Tangent Structure with OHG (with longitudinal guys – dead end of OHG)
Type T	Transposition Structure
Type 3A	Angle Structure: 3° - 15°
Type 3AS	Sidehill Tangent Structure
Type 3B	Angle Structure: 15° - 30°
Type 3C	Angle Structure: 30° - 45°
Type 3D0	Dead End Angle Structure: 0° to 1°
Type 3D10	Dead End Angle Structure: 1° to 10°
Type 3D90	Dead End Angle Structure: 10° to 90°
Type 3DW10S	Dead End Structures with OHGW: 0° - 10° Slack Span
Type 3DW90S	Dead End Structures with OHGW: 10° to 90° Slack Span
Type 3DW90	Dead End Structures with OHGW: 10° to 90°

Number Tag:

G	Number Tag in Good Condition
P	Number Tag in Poor Condition (replace during inspection)
M	Number Tag Missing (replace during inspection)

Structure Straightness

G	Structure Straightness in Good Condition
LT	Structure Leaning in Transverse Direction (Left or Right) e.g. structure leaning sideway perpendicular to line
LL	Structure Leaning in Longitudinal Direction (Forward or Back) e.g. structure leaning toward either ahead or back along the line

Wood Pole (POL)

Pole Class and Height

L	Left Pole (As seen when looking down the Line[3])
C	Center Pole
R	Right Pole

1/80 Denote Class 1 80ft pole

Species (Code according to CSA O15-2015 Clause 6.5.3)

Cedar		
	WC	Western Red Cedar
Fir		
	DF	Douglas Fir
Pine		
	LP	Lodgepole Pine
	RP	Red Pine
	SP	Southern Yellow Pine

Date Stamp 68 (for 1968)

Pole Condition

E	Pole in Excellent Condition (Like New)
G	Pole in Good Condition – No Visible Defects (Will Last Next 10 Years) e.g. light weathering, light cracking along wood grains
F	Pole in Fair Condition – Specify Visible Defects (Require Maintenance) e.g. moderate to heavy weathering, minor groundline rotting, deep cracks along wood grains, minor insect / animal damage, small woodpecker hole, etc.
P	Pole in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. severe groundline rotting, cracks perpendicular to wood grains, large woodpecker hole with opening larger than 4 inches, etc.
O	Other Condition – Specify

POL Maintenance Comments

In addition to noting the pole condition;

- Note bird nests on pole tops.
- Record distance and direction to old Pole stubs from existing, where structure has been replaced.
- Record quantity and size of Wood Pecker Holes (WPH) openings
  Size: - Small <2”
  - Medium 2-4”
  - Large >4”

[3] As seen while facing the structure being inspected, with your back towards lower number structures. Looking toward the end of the line with the highest structure number.

Pole Foundation (FDN)

Foundation Type

D	Direct buried - no stub
S1D	Direct buried - one stub
S2D	Direct buried - two stubs
S3D	Direct buried - three stubs
TC	Timber crib filled with rocks - no stub
S1TC	Timber crib filled with rocks - one stub
C	Culvert filled with rocks - no stub
S1C	Culvert filled with rocks - one stub

Ground Type

SO	Soil
SW	Swamp
R	Rock

Foundation Condition

S	Foundation Stable
U	Foundation Unstable (Require Maintenance) e.g. pole base sinking (tilted structure), large void surrounding pole, pole base heaving, water pond surrounding pole base, etc.

Guys & Anchors (G&A)

Configuration g/a number of guys / number of anchors

Guy & Anchor Condition

NA	Not Available (Not Require As Per Framing)
G	Guy & Anchor in Good Condition – No Visible Defects
F	Guy & Anchor in Fair Condition – No Visible Defects (Adjustment Performed During Inspection) e.g. guy tension adjustment, preform snapped shut, etc.
P	Guy & Anchor in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. bended anchor rod, anchor out of alignment with guy wire, broken anchor or wire, anchor movement (shifted/pulled/exposed), significant corrosion, etc.
M	Guy & Anchor Missing (Require Replacement)
O	Other Condition – Specify

Cross arm (XRM)

Cross arm Type

ST	Steel Cross arm
WD	Wood Cross arm

Cross arm (Wood) Condition

E	Cross arm in Excellent Condition (Like New)
G	Cross arm in Good Condition – No Visible Defects (Will Last Next 10 Years) e.g. light weathering.
F	Cross arm in Fair Condition – Specify Visible Defects (Require Maintenance) e.g. moderate to heavy weathering, lightly bowed or twisted, bird nesting, etc.
P	Cross arm in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. broken, split, surface rot, deep cracking along wood grains, cracks perpendicular to wood grains, wood grain of cross arm sloped (not parallel to arm), excessive knots, heavily bowed or twisted, burned, etc.
O	Other Condition – Specify

Cross arm (Steel) Condition

E	Cross arm in Excellent Condition (Like New)
G	Cross arm in Good Condition – No Visible Defects (Will Last Next 10 Years) e.g. light weathering (discoloration)
F	Cross arm in Fair Condition – Specify Visible Defects (Require Maintenance) e.g. minor rusting on attachment holes, lightly bowed or twisted, burned, etc.
P	Cross arm in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. bended, damaged, rusting along entire cross arm, heavily bowed or twisted, etc.
O	Other Condition – Specify

XRM Maintenance Comments

In addition to noting the cross arm condition;

- Use key words ‘road crossing’ where next span crosses road or trail.
- Where the structure has multiple cross arms, record condition and maintenance priority code based on the worst cross arm condition in both the ‘Front’ and ‘Back’ sets. Use comment field to record condition of remaining cross arms.

Cross Brace (XBR)

Cross Brace Type

ST	Steel Cross Brace
WD	Wood Cross Brace

Cross Brace (Wood) Condition

E	Cross Brace in Excellent Condition (Like New)
G	Cross Brace in Good Condition – No Visible Defects (Will Last Next 10 Years) e.g. light weathering.
F	Cross Brace in Fair Condition – Specify Visible Defects (Require Maintenance) e.g. moderate to heavy weathering, lightly bowed or twisted, bird nesting, etc.
P	Cross Brace in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. broken, split, surface rot, deep cracking along wood grains, cracks perpendicular to wood grains, sloping grain, heavily bowed or twisted, burned, etc.
O	Other Condition – Specify

Cross Brace (Steel) Condition

E	Cross Brace in Excellent Condition (Like New)
G	Cross Brace in Good Condition – No Visible Defects (Will Last Next 10 Years) e.g. light weathering (discoloration)
F	Cross Brace in Fair Condition – Specify Visible Defects (Require Maintenance) e.g. minor rusting on attachment holes, lightly bowed or twisted, burned, etc.
P	Cross Brace in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. bended, damaged, rusting along entire brace, heavily bowed or twisted, etc.
O	Other Condition – Specify

Insulators (INS)

Insulator Type

BP	Brown Porcelain
GP	Grey Porcelain
TG	Toughen Glass
EP	Epoxy / Composite
MX	Mixed

Fitting Type

BS	Ball-Socket End Fittings
CT	Clevis-Tongue End Fittings

Count i Number of Insulator Units

Insulator Visible Condition (Porcelain / Glass)

- G — Insulators in Good Condition – No Visible Defects (Will Last Next 10 Years)
- F — Insulators in Fair Condition – Specify Visible Defects (Require Maintenance)
  e.g. light pollution contamination, minor rust stains on skirt, light rust on caps, foreign object lodged, etc.
- P — Insulators in Poor Condition – Specify Visible Defects (Recommend Replacement)
  e.g. heavy pollution, moderate to severe rust on caps, tracking or flash marks, gunshot damage, chipped or cracked bell skirt, shattered or missing bell skirt, rusty pin, crushed socket, insulator not hanging straight, burn marks, bulged porcelain, etc.
- O — Other Condition – Specify

Insulator Visible Condition (Polymer)

- G — Insulators in Good Condition – No Visible Defects (Will Last Next 10 Years)
- F — Insulators in Fair Condition – Specify Visible Defects (Require Maintenance)
  e.g. light pollution contamination, minor rust stains on skirt, etc.
- P — Insulators in Poor Condition – Specify Visible Defects (Recommend Replacement)
  e.g. heavy pollution, tracking or flash marks, gunshot damage, broken skirt (missing pieces of skirt), moderate to heavy rusting of end fittings, etc.
- O — Other Condition – Specify

Vibration Damper (VIB)

Vibration Damper v/Type Number Per Phase on Each Span / Damper Type

Vibration Type

SB	Stockbridge Dampers – two small weights suspended by short cable.
HX	Helix Spiral Dampers – pre-form grip section, followed by widening spirals.

Aerial Marker (AMK)

Marker Condition

NR	Not Required
G	Aerial Marker in Good Condition – No Visible Defects (Will Last Next 10 Years)
P	Aerial Marker in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. broken aerial marker, severe color fading, gunshot damage, etc.
M	Aerial Marker Missing (Require Replacement)

Conductor & Shield Wire (C&S)

Cable Condition

G	Cables in Good Condition – No Visible Defects (Will Last Next 10 Years)
F	Cables in Fair Condition – Specify Visible Defects (Require Maintenance) e.g. bird cage, minor outer strands breakage, etc.
P	Cables in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. severe strand breakage, burned, severe corrosion, etc.
O	Other Condition – Specify

C&S Maintenance Comments

In addition to noting the conductor and shield wire condition;

- Use key words ‘auto sleeve’ where next span has splice in conductors.

Grounding & Bonding (G&B)

G&B Condition

G	Ground and Bond Wires in Good Condition – No Visible Defects (Will Last Next 10 Years)
F	Ground and Bond Wires in Fair Condition - Specify Visible Defects (Require Maintenance) e.g. light discoloration at contact point, loose connections, damaged guard, etc.
P	Hardware in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. moderate to heavy discoloration, severe wearing (reduce effective thickness), broken connections, signs of tracking, burn marks on pole, etc.
O	Other Condition – Specify

Hardware (HDW)

Hardware Condition

G	Hardware in Good Condition – No Visible Defects (Will Last Next 10 Years)
F	Hardware in Fair Condition – Specify Visible Defects (Require Maintenance) e.g. light rusting at contact point, loose hardware, etc.
P	Hardware in Poor Condition – Specify Visible Defects (Recommend Replacement) e.g. moderate to heavy rusting, severe wearing (reduce effective thickness), deformation, missing hardware, missing retaining cotter pin, etc.
O	Other Condition – Specify

Right of Way Vegetation (VEG)

Species

P/A	Poplar / Aspen
B	Birch
W	Willow
S/P	Spruce / Pine
O	Other – Specify

Vegetation Density

LD	Low Density – Maintenance Vehicle Can Travel Along
MD	Medium Density – ATV Can Travel Along Easily
HD	High Density – ATV Can Travel Along with Difficulty

Vegetation Height h ft Highest vegetation along ROW

Clearance Concern

N	No Vegetation Clearance Issue (Within Next 10 Years)
Y	Vegetation Clearance Violation (Within Next 10 Years)

Danger Tree

N	Not Present
Y	Danger Tree Present

Danger Tree Height d ft Danger Tree Height

Vegetation Comments List Vegetation Concern on Each Line

Priority

1	Indicates a very serious system reliability or public safety problem. Repairs or modifications should be made immediately (probably within 1 to 2 days). Contact YEC T&D Leadhand as soon as possible (ASAP).
2	Indicates a reliability or safety problem which is serious enough it should be rectified in the not too distant future (possibly within 3 months). Condition is serious enough that it would probably be dealt with prior to the next scheduled routine maintenance.
3	Indicates a concern which should be corrected, but is minor enough that it could be rectified as part of a planned maintenance program (possibly within the next 1 to 5 years).
4	Indicates a concern which is minor enough it would only be corrected if convenient to do so. Corrections would only be made if other work were being done in the same area or on the same pole.
5	Indicates a comment which is recorded for information only – no corrective action is required.

General (GRL)

GRL Additional Comments

- Record any issues with structure access.

Structure Maintenance Concern

Maintenance Comments List Individual Defect on Each Line

Photo Number Reference Photo for Each Individual Defect

Aspect **Category**

STR	Structure Defect	VIB	Vibration Damper Defect
POL	Wood Pole Defect	AMK	Aerial Marker Defect
FDN	Foundation Defect	C&S	Conductor & Shield Wire Defect
G&A	Guy & Anchor Defect	G&B	Grounding & Bonding Defect
XRM	Cross arm Defect	HDW	Hardware Defect
XBR	Cross Brace Defect	VEG	Vegetation in Right of Way
INS	Insulator Defect	GRL	General – Any Additional Notes

Priority

1	Indicates a very serious system reliability or public safety problem. Repairs or modifications should be made immediately (probably within 1 to 2 days). Contact YEC T&D Leadhand as soon as possible (ASAP).
2	Indicates a reliability or safety problem which is serious enough it should be rectified in the not too distant future (possibly within 3 months). Condition is serious enough that it would probably be dealt with prior to the next scheduled routine maintenance.
3	Indicates a concern which should be corrected, but is minor enough that it could be rectified as part of a planned maintenance program (possibly within the next 1 to 5 years).
4	Indicates a concern which is minor enough it would only be corrected if convenient to do so. Corrections would only be made if other work were being done in the same area or on the same pole.
5	Indicates a comment which is recorded for information only – no corrective action is required.

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	Inpsctn Lead	Inspctn Second	Inspctn Date	STR Framing Type	STR No.	STR Straight-ness	STR Maint. Priority	STR Maintenance Comment	STR Deficiency Photo	POL Loc.	POL Class	POL Size	POL Species	POL Date Stamp	POL Cond.	POL Maint. Priority	POL Maintenance Comment	POL Deficiency Photo	FDN Loc	FDN Type	FDN Ground Type	FDN Ground Cond.	FDN Maintenance	FDN Maintenance Comment	FDN Deficiency Photo	G&A # of Guys	G&A # of Anchor	G&A Cond.	G&A Maint. Priority	G&A Maintenance Comment	G&A Deficiency Photo	XRM Loc.	XRM Type	XRM Cond.
113	Jake O'Brien	Chad Harvey	2017-06-15	EG	G	G	5		L170000113	L	1	65	DF	1974	G	5			L	D	SO	S	5			2	2	F	4	Faded guy guards		F	WD	P
113	Jake O'Brien	Chad Harvey	2017-06-15							C	1	60	DF	1974	G	5			C	D	SO	S	5			2	2	F	4	Missing guy guards	L170000113(6)	B	WD	F
113	Jake O'Brien	Chad Harvey	2017-06-15							R	1	65	DF	1974	G	5			R	D	SO	S	5			2	2	F	4	Faded guy guards				
114	Jake O'Brien	Chad Harvey	2017-06-15	AG	G	G	5		L170000114	L	2	65	WC	2014	E	5			L	D	SO	S	5			1	1	G	5			F	ST	E
114	Jake O'Brien	Chad Harvey	2017-06-15							R	2	65	WC	2014	E	5			R	D	SO	S	5			1	1	G	5					
114	Jake O'Brien	Chad Harvey	2017-06-15																														
115	Jake O'Brien	Chad Harvey	2017-06-15	A	G	LL	5	Leaning back 14"	L170000115	L	4	65	DF	1968	G	5			L	D	SO	S	5									F	WD	G
115	Jake O'Brien	Chad Harvey	2017-06-15							R	4	65	DF	1968	G	5			R	D	SO	S	5											
115	Jake O'Brien	Chad Harvey	2017-06-15																														
116	Jake O'Brien	Chad Harvey	2017-06-15	A	G	G	5		L170000116	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	P
116	Jake O'Brien	Chad Harvey	2017-06-15							R	4	60	DF	1968	G	5			R	D	SO	S	5											
116	Jake O'Brien	Chad Harvey	2017-06-15																														
117	Jake O'Brien	Chad Harvey	2017-06-15	A	G	LT	5	Leaning back 12"	L170000117	L	4	65	DF	1968	G	5			L	D	SO	S	5			1	1	F	5	Faded guy guard	L1700000117(10)	F	WD	P
117	Jake O'Brien	Chad Harvey	2017-06-15							R	4	65	DF	1968	G	5			R	D	SO	S	5			1	1	F	5	Faded guy guard	L1700000117(11)			
117	Jake O'Brien	Chad Harvey	2017-06-15																														
118	Jake O'Brien	Chad Harvey	2017-06-16	F	M	M	5	Replaced number sign	L170000118	L	4	65	DF	1968	G	5			L	D	SO	S	5									F	WD	F
118	Jake O'Brien	Chad Harvey	2017-06-16							R	4	65	DF	1968	G	5			R	D	SO	S	5									B	WD	F
118	Jake O'Brien	Chad Harvey	2017-06-16																														
119	Jake O'Brien	Chad Harvey	2017-06-16	F	G	LL	5	Right pole leaning ahead 12"	L170000119	L	4	65	DF	1968	G	5			L	D	SO	S	5									F	WD	G
119	Jake O'Brien	Chad Harvey	2017-06-16							R	4	65	DF	1968	G	5			R	D	SO	S	5									B	WD	F
119	Jake O'Brien	Chad Harvey	2017-06-16																														
120	Jake O'Brien	Chad Harvey	2017-06-16	A	G	LL	5	Left pole leaning back 6"	L170000120	L	3	55	WC	2015	E	5			L	D	SO	S	5									F	ST	E
120	Jake O'Brien	Chad Harvey	2017-06-16							R	3	55	WC	2015	E	5			R	D	SO	S	5											
120	Jake O'Brien	Chad Harvey	2017-06-16																														
121	Jake O'Brien	Chad Harvey	2017-06-16	A	G	G	5		L170000121	L	3	65	WC	2014	G	5			L	D	SO	S	5									F	ST	E
121	Jake O'Brien	Chad Harvey	2017-06-16							R	3	65	WC	2014	G	5			R	D	SO	S	5											
121	Jake O'Brien	Chad Harvey	2017-06-16																														
122	Jake O'Brien	Chad Harvey	2017-06-16	A	G	G	5		L170000122	L	4	65	DF	1968	G	5			L	D	SO	S	5									F	WD	G
122	Jake O'Brien	Chad Harvey	2017-06-16							R	4	65	DF	1968	F	4	Checking throughout	L170000122(4)	R	D	SO	S	5											
122	Jake O'Brien	Chad Harvey	2017-06-16																														
123	Jake O'Brien	Chad Harvey	2017-06-16	A	G	LL	5	Left pole leaning 6" ahead	L170000123	L	4	65	DF	1968	F	5			L	D	SO	S	5									F	WD	F
123	Jake O'Brien	Chad Harvey	2017-06-16							R	4	65	DF	1968	F	5			R	D	SO	S	5											
123	Jake O'Brien	Chad Harvey	2017-06-16																														
124	Jake O'Brien	Chad Harvey	2017-06-16	A	G	G	5		L170000124	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	F
124	Jake O'Brien	Chad Harvey	2017-06-16							R	4	60	DF	1968	P	3	Wood shavings at base of pole	L170000124(5)	R	D	SO	S	5											
124	Jake O'Brien	Chad Harvey	2017-06-16																														
125	Jake O'Brien	Chad Harvey	2017-06-16	A	G	LL	5	Str leaning back 14-18"	L170000125	L	4	65	DF	1968	P	3	Insect damage / wood shavings at	L170000125(5)	L	D	SO	S	5									F	WD	G
125	Jake O'Brien	Chad Harvey	2017-06-16							R	4	65	DF	1968	G	5			R	D	SO	S	5											
125	Jake O'Brien	Chad Harvey	2017-06-16																														
126	Jake O'Brien	Chad Harvey	2017-06-16	A	G	G	5		L170000126	L	4	65	DF	1968	G	5			L	D	SO	S	5									F	WD	F
126	Jake O'Brien	Chad Harvey	2017-06-16							R	3	65	DF	1968	G	5			R	D	SO	S	5											
126	Jake O'Brien	Chad Harvey	2017-06-16																														
127	Jake O'Brien	Chad Harvey	2017-06-16	A	G	LL	5	Leaning back 10" (right pole)	L170000127	N/A					G	5			L	D	SO	S	5									F	WD	F

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Structure Number	Inpsctn Lead	Inspctn Second	Inspctn Date	STR Framing Type	STR No.	STR Straight-ness	STR Maint. Priority	STR Maintenance Comment	STR Deficiency Photo	POL Loc.	POL Class	POL Size	POL Species	POL Date Stamp	POL Cond.	POL Maint. Priority	POL Maintenance Comment	POL Deficiency Photo	FDN Loc	FDN Type	FDN Ground Type	FDN Ground Cond.	FDN Maintenance	FDN Maintenance Comment	FDN Deficiency Photo	G&A # of Guys	G&A # of Anchor	G&A Cond.	G&A Maint. Priority	G&A Maintenance Comment	G&A Deficiency Photo	XRM Loc.	XRM Type	XRM Cond.
127	Jake O'Brien	Chad Harvey	2017-06-16							N/A					G	5			R	D	SO	S	5										
127	Jake O'Brien	Chad Harvey	2017-06-16																														
128	Jake O'Brien	Chad Harvey	2017-06-16	A	G	G	5		L170000128	L	3	55	WC	2014	E	5			L	D	SO	S	5								F	ST	E
128	Jake O'Brien	Chad Harvey	2017-06-16							R	3	55	WC	2014	E	5	2 3/4" Woodpecker holes 6-8" AGL		R	D	SO	S	5										
128	Jake O'Brien	Chad Harvey	2017-06-16																														
129	Jake O'Brien	Chad Harvey	2017-06-16	A	G	G	5		L170000129	L	2	60	WC	2015	E	5			L	D	SO	S	5								F	ST	E
129	Jake O'Brien	Chad Harvey	2017-06-16							R	2	60	WC	2015	E	5			R	D	SO	S	5										
129	Jake O'Brien	Chad Harvey	2017-06-16																														
130	Jake O'Brien	Chad Harvey	2017-06-16	A	G	G	5		L170000130	L	3	55	WC	2015	E	5			L	D	SO	S	5								F	ST	E
130	Jake O'Brien	Chad Harvey	2017-06-16							R	3	55	WC	2015	E	5			R	D	SO	S	5										
130	Jake O'Brien	Chad Harvey	2017-06-16																														
131	Jake O'Brien	Chad Harvey	2017-06-16	A	G	G	5		L170000131	N/A					G	5			L	D	SO	S	5								F	WD	G
131	Jake O'Brien	Chad Harvey	2017-06-16							N/A					G	5			R	D	SO	S	5										
131	Jake O'Brien	Chad Harvey	2017-06-16																														
132	Jake O'Brien	Chad Harvey	2017-06-16	A	G	G	5		L170000132	L	3	55	WC	2015	E	5			L	D	SO	S	5								F	ST	E
132	Jake O'Brien	Chad Harvey	2017-06-16							R	3	55	WC	2015	E	5			R	D	SO	S	5										
132	Jake O'Brien	Chad Harvey	2017-06-16																														
133	Jake O'Brien	Chad Harvey	2017-06-16	F	G	G	5		L170000133	L	4	65	DF	1968	G	5			L	D	SO	S	5								F	WD	F
133	Jake O'Brien	Chad Harvey	2017-06-16							R	4	65	DF	1968	G	5			R	D	SO	S	5								B	WD	F
133	Jake O'Brien	Chad Harvey	2017-06-16																														
134	Jake O'Brien	Chad Harvey	2017-06-16	F	G	G	5		L170000134	N/A					G	5			L	D	SO	S	5								F	WD	G
134	Jake O'Brien	Chad Harvey	2017-06-16							N/A					G	5			R	D	SO	S	5										
134	Jake O'Brien	Chad Harvey	2017-06-16																														
135	Jake O'Brien		2017-06-16	A	G	G	5		L170000135	L	3	55	WC	2014	E	5			L	D	SO	S	5	Old stubs 10' back							F	ST	E
135	Jake O'Brien		2017-06-16							R	3	55	WC	2014	E	5			R	D	SO	S	5	Old stubs 10' back									
135	Jake O'Brien		2017-06-16																														
136	Jake O'Brien		2017-06-16	A	G	G	5		L170000136	L	3	55	DF	1968	G	5			L	D	SO	S	5								F	WD	P
136	Jake O'Brien		2017-06-16							R	3	55	DF	1968	G	5			R	D	SO	S	5										
136	Jake O'Brien		2017-06-16																														
137	Jake O'Brien		2017-06-16	A	G	G	5		L170000137	L	3	55	WC	2015	E	5			L	D	SO	S	5	Old stub 8' ahe	000137(5)						F	ST	E
137	Jake O'Brien		2017-06-16							R	3	55	WC	2015	E	5			R	D	SO	S	5	Old stub 8' ahe	000137(6)								
137	Jake O'Brien		2017-06-16																														
138	Jake O'Brien		2017-06-16	A	G	G	5		L170000138	L	3	55	WC	2014	E	5			L	D	SO	S	5								F	ST	E
138	Jake O'Brien		2017-06-16							R	3	55	WC	2014	E	5			R	D	SO	S	5										
138	Jake O'Brien		2017-06-16																														
139	Jake O'Brien		2017-06-16	A	G	G	5		L170000139	L	4	50	DF	1968	G	5			L	D	SO	S	5								F	WD	P
139	Jake O'Brien		2017-06-16							R	4	50	DF	1968	G	5			R	D	SO	S	5										
139	Jake O'Brien		2017-06-16																														
140	Jake O'Brien		2017-06-16	A	G	G	5		L170000140	L	3	55	WC	2014	E	5			L	D	SO	S	5								F	ST	E
140	Jake O'Brien		2017-06-16							R	3	55	WC	2014	E	5			R	D	SO	S	5										
140	Jake O'Brien		2017-06-16																														
141	Jake O'Brien		2017-06-16	A	G	G	5		L170000141	L	3	55	WC	2014	E	5			L	D	SO	S	5								F	ST	E
141	Jake O'Brien		2017-06-16							R	3	55	WC	2014	E	5			R	D	SO	S	5										
141	Jake O'Brien		2017-06-16																														
142	Jake O'Brien		2017-06-16	A	G	G	5		L170000142	L	3	55	WC	2014	E	5			L	D	SO	S	5								F	ST	E
142	Jake O'Brien		2017-06-16							R	3	55	WC	2014	E	5			R	D	SO	S	5										
142	Jake O'Brien		2017-06-16																														
143	Jake O'Brien		2017-06-16	A	G	G	5		L170000143	L	3	55	WC	2015	E	5			L	D	SO	S	5	Old stub stub 8	000143(5)						F	ST	E
143	Jake O'Brien		2017-06-16							R	3	55	WC	2015	E	5			R	D	SO	S	5	Old pole stub 8	000143(5)								
143	Jake O'Brien		2017-06-16																														
144	Jake O'Brien		2017-06-16	A	M	G	5		L170000144	L	3	55	WC	2014	E	5			L	D	SO	S	5	Old pole stubs	000144(6)						F	ST	E
144	Jake O'Brien		2017-06-16							R	3	55	WC	2014	E	5			R	D	SO	S	5	Old pole stubs	000144(5)								
144	Jake O'Brien		2017-06-16																														
145	Jake O'Brien		2017-06-16	A	G	G	5		L170000145	L	3	55	WC	2014	E	5			L	D	SO	S	5	Old stub stub 8	000145(6)						F	ST	E
145	Jake O'Brien		2017-06-16							R	3	55	WC	2014	E	5			R	D	SO	S	5	Old pole stub 8	000145(5)								
145	Jake O'Brien		2017-06-16																														

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146	Jake O'Brien		2017-06-16	A	M	G	5		L170000146	L	3	55	WC	2014	E	5			L	D	SO	S	5	Old stub stub 8	000146(4)							F	ST	E
146	Jake O'Brien		2017-06-16							R	3	55	WC	2014	E	5			R	D	SO	S	5	Old pole stub 8	000146(5)									
146	Jake O'Brien		2017-06-16																															
147	Jake O'Brien		2017-06-16	A	M	G	5		L170000147	L	3	55	WC	2014	E	5			L	D	SO	S	5	Old stub stub 8	000147(5)							F	ST	E
147	Jake O'Brien		2017-06-16							R	3	55	WC	2014	E	5			R	D	SO	S	5	Old pole stub 8	000147(6)									
147	Jake O'Brien		2017-06-16																															
148	Jake O'Brien		2017-06-16	F	M	G	5		L170000148	L	2	65	WC	2014	E	5			L	D	SO	S	5	Old stub stub 8	000148(6)							F	WD	E
148	Jake O'Brien		2017-06-16							R	2	65	WC	2014	E	5			R	D	SO	S	5	Old pole stub 8	000148(5)							B	WD	E
148	Jake O'Brien		2017-06-16																															
149	Jake O'Brien		2017-06-16	F	M	G	5		L170000149	L	2	65	WC	2014	E	5			L	D	SO	S	5	Old stub stub 8	000149(5)							F	WD	E
149	Jake O'Brien		2017-06-16							R	2	65	WC	2014	E	5			R	D	SO	S	5	Old pole stub 8	000149(6)							B	WD	E
149	Jake O'Brien		2017-06-16																															
150	Jake O'Brien		2017-06-16	E	G	G	5		L170000150	L	4	55	DF	1968	G	5			L	D	SO	S	5			2	2	F	5	Faded guy guard	L170000150(6)	F	WD	G
150	Jake O'Brien		2017-06-16							C	4	55	DF	1968	G	5			C	D	SO	S	5			2	2	F	5	Faded guy guard	L170000150(7)	B	WD	G
150	Jake O'Brien		2017-06-16							R	4	55	DF	1968	G	5			R	D	SO	S	5			2	2	F	5	Faded guy guard	L170000150(8)			
151	Jake O'Brien		2017-06-16	A	G	G	5		L170000151	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
151	Jake O'Brien		2017-06-16							R	4	55	DF	1968	G	5			R	D	SO	S	5											
151	Jake O'Brien		2017-06-16																															
152	Jake O'Brien		2017-06-16	A	G	G	5		L170000152	L	3	55	WC	2014	E	5			L	D	SO	S	5	Old stub stub 8	000152(5)							F	ST	E
152	Jake O'Brien		2017-06-16							R	3	55	WC	2014	E	5			R	D	SO	S	5	Old pole stub 8	000152(6)									
152	Jake O'Brien		2017-06-16																															
153	Jake O'Brien		2017-06-16	A	G	G	5		L170000153	L	3	55	WC	2014	E	5			L	D	SO	S	5	Old stub stub 8	000153(5)							F	ST	E
153	Jake O'Brien		2017-06-16							R	3	55	WC	2014	E	5			R	D	SO	S	5	Old pole stub 8	000153(6)									
153	Jake O'Brien		2017-06-16																															
154	Jake O'Brien		2017-06-16	A	G	LL	5	Left pole leaning back 12"	L170000154	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	F
154	Jake O'Brien		2017-06-16							R	4	50	DF	1968	G	5			R	D	SO	S	5											
154	Jake O'Brien		2017-06-16																															
155	Jake O'Brien		2017-06-16	A	G	LL	5	Left pole leaning back 12"	L170000155	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
155	Jake O'Brien		2017-06-16							R	4	50	DF	1968	G	5			R	D	SO	S	5											
155	Jake O'Brien		2017-06-16																															
156	Jake O'Brien		2017-06-16	A	G	G	5	Ant dust	L170000156	L	N/A			1967	P	3	Ant dust at GL	L170000156(7)	L	D	SO	S	5									F	WD	G
156	Jake O'Brien		2017-06-16							R	N/A			1967	G	5			R	D	SO	S	5											
156	Jake O'Brien		2017-06-16																															
157	Jake O'Brien		2017-06-16	A	G	G	5		L170000157	L	3	55	WC	2014	E	5			L	D	SO	S	5	Old stub stub 8	000157(5)							F	ST	E
157	Jake O'Brien		2017-06-16							R	3	55	WC	2014	E	5			R	D	SO	S	5	Old pole stub 8	000157(6)									
157	Jake O'Brien		2017-06-16																															
158	Jake O'Brien		2017-06-16	A	G	G	5		L170000158	L	N/A				G	5			L	D	SO	S	5									F	WD	G
158	Jake O'Brien		2017-06-16							R	N/A				G	5			R	D	SO	S	5											
158	Jake O'Brien		2017-06-16																															
159	Jake O'Brien		2017-06-16	A	G	G	5		L170000159	L	N/A				G	5			L	D	SO	S	5									F	WD	P
159	Jake O'Brien		2017-06-16							R	N/A				G	5			R	D	SO	S	5											
159	Jake O'Brien		2017-06-16																															
160	Jake O'Brien		2017-06-16	A	G	LT	5	Structure leaning right 12"	L170000160	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	G
160	Jake O'Brien		2017-06-16							R	4	60	DF	1968	G	5			R	D	SO	S	5											
160	Jake O'Brien		2017-06-16																															
161	Jake O'Brien		2017-06-16	A	G	G	5		L170000161	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
161	Jake O'Brien		2017-06-16							R	4	55	DF	1968	G	5			R	D	SO	S	5											
161	Jake O'Brien		2017-06-16																															
162	Jake O'Brien		2017-06-16	A	G	LL	5	Left pole leaning ahead 20"	L170000162	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
162	Jake O'Brien		2017-06-16							R	4	55	DF	1968	P	3	Ant damage at GL	L170000162(8)	R	D	SO	S	5											
162	Jake O'Brien		2017-06-16																															
163	Jake O'Brien	Chad Harvey	2017-06-17	A	G	G	5		L170000163	L	4	65	DF	1968	G	5			L	D	SO	S	5									F	WD	F
163	Jake O'Brien	Chad Harvey	2017-06-17							R	4	65	DF	1968	F	4	Checking throughout	L170000163(3)	R	D	SO	S	5											
163	Jake O'Brien	Chad Harvey	2017-06-17																															
164	Jake O'Brien	Chad Harvey	2017-06-17	EG	G	G	5		L170000164	L	4	60	DF	1968	F	4	Weathered, checking	L170000164(5)	L	D	SO	S	5			2	2	G	5	Faded guy guards	L170000164(7)	F	WD	F
164	Jake O'Brien	Chad Harvey	2017-06-17							C	4	60	DF	1968	F	4	Weathered, checking	L170000164(5)	C	D	SO	S	5			2	2	G	5	Faded guy guards	L170000164(7)	B	WD	F

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164	Jake O'Brien	Chad Harvey	2017-06-17							R	4	60	DF	1968	F	4	Weathered, checking	L170000164(5)	R	D	SO	S	5			3	3	G	5	Faded guy guards	L170000164(7)			
165	Jake O'Brien	Chad Harvey	2017-06-17	A	G	G	5		L170000165	L	4	60	DF	1968	F	4	Weathered, checking	L170000165(4)	L	D	R	S	5									F	WD	F
165	Jake O'Brien	Chad Harvey	2017-06-17							R	4	60	DF	1968	F	4	Weathered, checking	L170000165(4)	R	D	R	S	5									B	WD	F
165	Jake O'Brien	Chad Harvey	2017-06-17																														
166	Jake O'Brien	Chad Harvey	2017-06-17	A	G	G	5		L170000166	L	3	55	WC	2015	E	5			L	D	SO	S	5									F	ST	E
166	Jake O'Brien	Chad Harvey	2017-06-17							R	3	55	WC	2015	E	5			R	D	SO	S	5											
166	Jake O'Brien	Chad Harvey	2017-06-17																														
167	Jake O'Brien	Chad Harvey	2017-06-17	E	G	G	5		L170000167	L	4	45	DF	1968	G	5	Checking		L	D	R	S	5			2	2	G	5	Faded / missing guy guard	L170000167(6)	F	WD	G
167	Jake O'Brien	Chad Harvey	2017-06-17							C	4	45	DF	1968	G	5	Checking		C	D	R	S	5			2	2	G	5	Faded / missing guy guard	L170000167(6)	B	WD	G
167	Jake O'Brien	Chad Harvey	2017-06-17							R	4	45	DF	1968	G	5	Checking		R	D	R	S	5			2	2	G	5	Faded / missing guy guard				
168	Jake O'Brien	Chad Harvey	2017-06-17	E	G	G	5		L170000168	L	4	60	DF	1968	P	3	Cut damage 12' AGL	L170000168(6)	L	D	SO	S	5			2	2	F	4	Faded / missing guy guard		F	WD	G
168	Jake O'Brien	Chad Harvey	2017-06-17							C	4	60	DF	1968	F	4	Weathered, checking	L170000168(3)	C	D	SO	S	5			2	2	F	4	Faded / missing guy guard		B	WD	G
168	Jake O'Brien	Chad Harvey	2017-06-17							R	4	60	DF	1968	F	4	Weathered, checking	L170000168(3)	R	D	SO	S	5			2	2	F	4	Faded				
169	Jake O'Brien	Chad Harvey	2017-06-17	A	G	G	5		L170000169	L	N/A				G	5	Birdhouse 8' AGL		L	D	SO	S	5									F	WD	G
169	Jake O'Brien	Chad Harvey	2017-06-17							R	N/A				G	5	Checking	L170000169(6)	R	D	SO	S	5											
169	Jake O'Brien	Chad Harvey	2017-06-17																														
170	Jake O'Brien	Chad Harvey	2017-06-17	F	G	G	5		L170000170	L	3	65	WC	2014	E	5			L	D	SO	S	5									F	ST	G
170	Jake O'Brien	Chad Harvey	2017-06-17							R	3	65	WC	2014	G	5			R	D	SO	S	5									B	ST	G
170	Jake O'Brien	Chad Harvey	2017-06-17																														
171	Jake O'Brien	Chad Harvey	2017-06-17	F	G	LL	5	Left pole leaning ahead 10"	L170000171	L	N/A				F	4	Weathered, checking	L170000171(4)	L	D	SO	S	5									F	WD	F
171	Jake O'Brien	Chad Harvey	2017-06-17							R	N/A				F	4	Weathered, checking	L170000171(4)	R	D	SO	S	5									B	WD	F
171	Jake O'Brien	Chad Harvey	2017-06-17																														
172	Jake O'Brien	Chad Harvey	2017-06-17	EG	G	LL	5	Str is leaning 12" back	L170000172	L	N/A				G	5			L	D	SO	S	5			1	1	G	4	Loose bridle guy hook bolt	L170000172(6)	F	WD	F
172	Jake O'Brien	Chad Harvey	2017-06-17							R	N/A				G	5			R	D	SO	S	5			1	1	G	4	Loose bridle guy hook bolt	L170000172(6)	B	WD	F
172	Jake O'Brien	Chad Harvey	2017-06-17																														
173	Jake O'Brien	Chad Harvey	2017-06-17	A	G	G	5		L170000173	L	N/A				G	5			L	D	SO	S	5									F	WD	P
173	Jake O'Brien	Chad Harvey	2017-06-17							R	N/A				G	5			R	D	SO	S	5									B	WD	P
173	Jake O'Brien	Chad Harvey	2017-06-17																														
174	Jake O'Brien	Chad Harvey	2017-06-17	E	G	G	5		L170000174	L	N/A				P	3			L	D	SO	S	5									F	WD	P
174	Jake O'Brien	Chad Harvey	2017-06-17							C	4	N/A		1968	P	3	Insect damage	L170000174(7)	C	D	SO	S	5									B	WD	P
174	Jake O'Brien	Chad Harvey	2017-06-17							R	4	55	DF	1968	F	4	Checking	L170000174(8)	R	D	SO	S	5			1	1	G	4	Faded guy guard	L170000174(9)			
175	Jake O'Brien	Chad Harvey	2017-06-17	A	G	G	5		L170000175	L	3	55	WC	2014	E	5			L	D	SO	S	5									F	ST	E
175	Jake O'Brien	Chad Harvey	2017-06-17							R	3	55	WC	2014	E	5			R	D	SO	S	5											
175	Jake O'Brien	Chad Harvey	2017-06-17																														
176	Jake O'Brien	Chad Harvey	2017-06-17	A	G	G	5		L170000176	L	4	55	DF	1968	F	4	Checking	L170000176(6)	L	D	SO	S	5									F	WD	F
176	Jake O'Brien	Chad Harvey	2017-06-17							R	4	55	DF	1968	P	3	Insect damage	L170000176(5)	R	D	SO	S	5											
176	Jake O'Brien	Chad Harvey	2017-06-17																														
177	Jake O'Brien	Chad Harvey	2017-06-17	A	G	G	5		L170000177	L	N/A				F	5	Checking	L170000177(4)	L	D	SO	S	5									F	WD	P
177	Jake O'Brien	Chad Harvey	2017-06-17							R	N/A				F	5	Checking / weathered	L170000177(4)	R	D	SO	S	5											
177	Jake O'Brien	Chad Harvey	2017-06-17																														
178	Jake O'Brien	Chad Harvey	2017-06-17	A	G	G	5		L170000178	L	4	65	DF	1968	F	5	Checking	L170000178(5)	L	D	SO	S	5									F	WD	P
178	Jake O'Brien	Chad Harvey	2017-06-17							R	4	65	DF	1968	F	5	Checking	L170000178(5)	R	D	SO	S	5											
178	Jake O'Brien	Chad Harvey	2017-06-17																														
179	Jake O'Brien	Chad Harvey	2017-06-17	F	M	G	5		L170000179	L	N/A				F	5	Checking	L170000179(4)	L	D	SO	S	5									F	WD	P
179	Jake O'Brien	Chad Harvey	2017-06-17							R	N/A				F	5	Checking	L170000179(4)	R	D	SO	S	5									B	WD	P
179	Jake O'Brien	Chad Harvey	2017-06-17																														
180	Jake O'Brien	Chad Harvey	2017-06-17	F	G	G	5		L170000180	L	4	65	DF	1968	F	5	Checking	L170000180(4)	L	D	SO	S	5									F	WD	F
180	Jake O'Brien	Chad Harvey	2017-06-17							R	4	65	DF	1968	F	5	Checking	L170000180(4)	R	D	SO	S	5									B	WD	F
180	Jake O'Brien	Chad Harvey	2017-06-17																														
181	Jake O'Brien	Chad Harvey	2017-06-17	EG	G	G	5		L170000181	L	4	50	DF	1968	G	5			L	D	SO	S	5			1	1	G	4	Faded guy guard	L170000181(5)	F	WD	G
181	Jake O'Brien	Chad Harvey	2017-06-17							R	4	50	DF	1968	G	5			R	D	SO	S	5			1	1	G	4	Faded guy guard	L170000181(6)			
181	Jake O'Brien	Chad Harvey	2017-06-17																														
182	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000182	L	3	55	WC	2014	E	5			L	D	SO	S	5									F	ST	E
182	Jake O'Brien	Chad Harvey	2017-06-18							R	3	55	WC	2014	E	5			R	D	SO	S	5											
182	Jake O'Brien	Chad Harvey	2017-06-18																														
183	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000183	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	G

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183	Jake O'Brien	Chad Harvey	2017-06-18							R	4	60	DF	1968	G	5			R	D	SO	S	5										
183	Jake O'Brien	Chad Harvey	2017-06-18																														
183	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000183	L	4	60	DF	1968	G	5			L	D	SO	S	5								F	WD	G
183	Jake O'Brien	Chad Harvey	2017-06-18							R	4	60	DF	1968	G	5			R	D	SO	S	5										
183	Jake O'Brien	Chad Harvey	2017-06-18																														
184	Jake O'Brien	Chad Harvey	2017-06-18	A	G	LD	5	Str is leaning 10" left	L170000184	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G
184	Jake O'Brien	Chad Harvey	2017-06-18							R	4	55	DF	1968	G	5			R	D	SO	S	5										
184	Jake O'Brien	Chad Harvey	2017-06-18																														
185	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000185	L	3	55	WC	2014	E	5			L	D	SO	S	5								F	ST	E
185	Jake O'Brien	Chad Harvey	2017-06-18							R	3	55	WC	2014	E	5			R	D	SO	S	5										
185	Jake O'Brien	Chad Harvey	2017-06-18																														
186	Jake O'Brien	Chad Harvey	2017-06-18	EG	G	LD	5	Str is leaning left 10"	L170000186	L	N/A				G	5	Barbed wire around butt of pole	L170000186(6)	L	D	SO	S	5			1	1	F	4	Faded guy guard	L170000186(5)	F	WD	G
186	Jake O'Brien	Chad Harvey	2017-06-18							R	N/A				G	5	Barbed wire around butt of pole	L170000186(7)	R	D	SO	S	5			1	1	F	4	Faded guy guard		B	WD	G
186	Jake O'Brien	Chad Harvey	2017-06-18																														
187	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000187	L	3	85	DF	1968	G	5			L	D	SO	S	5								F	WD	F
187	Jake O'Brien	Chad Harvey	2017-06-18							R	3	85	DF	1968	G	5			R	D	SO	S	5										
187	Jake O'Brien	Chad Harvey	2017-06-18																														
188	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000188	L	N/A				G	5			L	D	SO	S	5								F	WD	G
188	Jake O'Brien	Chad Harvey	2017-06-18							R	4	50	DF	1968	G	5			R	D	SO	S	5										
188	Jake O'Brien	Chad Harvey	2017-06-18																														
189	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000189	L	N/A				G	5			L	D	SO	S	5								F	WD	G
189	Jake O'Brien	Chad Harvey	2017-06-18							R	N/A				G	5			R	D	SO	S	5										
189	Jake O'Brien	Chad Harvey	2017-06-18																														
190	Jake O'Brien	Chad Harvey	2017-06-18	E	G	G	5		L170000190	L	4	50	DF	1968	G	5			L	D	SO	S	5			2	2	G	4	Faded	L170000190(5)	F	WD	G
190	Jake O'Brien	Chad Harvey	2017-06-18							C	4	50	DF	1968	G	5			C	D	SO	S	5			2	2	G	4	Faded, missing	L170000190(6)	B	WD	G
190	Jake O'Brien	Chad Harvey	2017-06-18							R	4	50	DF	1968	G	5			R	D	SO	S	5			2	2	G	4	Faded, missing	L170000190(7)			
191	Jake O'Brien		2017-06-17	A	M	G	5		L170000191	L	3	55	WC	2014	E	5			L	D	SO	S	5	Old pole butt 8	000191(5)						F	ST	E
191	Jake O'Brien		2017-06-17							R	3	55	WC	2014	E	5			R	D	SO	S	5	Old pole butt 8	000191(7)								
191	Jake O'Brien		2017-06-17																														
192	Jake O'Brien		2017-06-17	A	G	G	5		L170000192	L	3	55	WC	2014	E	5			L	D	SO	S	5	Old pole butt 8	000192(5)						F	ST	E
192	Jake O'Brien		2017-06-17							R	3	55	WC	2014	E	5			R	D	SO	S	5	Old pole butt 8	000192(6)								
192	Jake O'Brien		2017-06-17																														
193	Jake O'Brien		2017-06-17	EG	G	G	5		L170000193	L	4	55	DF	1968	G	5			L	D	SO	S	5			2	2	F	5	Faded guy guards	L170000194(6)	F	WD	G
193	Jake O'Brien		2017-06-17							C	4	55	DF	1968	G	5			C	D	SO	S	5			2	2	F	5	Faded guy guards		B	WD	G
193	Jake O'Brien		2017-06-17							R	4	55	DF	1968	G	5			R	D	SO	S	5			2	2	F	5	Faded guy guards				
194	Jake O'Brien		2017-06-17	A	G	G	5		L170000194	L	3	55	WC	2014	E	5			L	D	SO	S	5	Old pole butt 1	000194(5)						F	ST	E
194	Jake O'Brien		2017-06-17							R	3	55	WC	2014	E	5			R	D	SO	S	5	Old pole butt 1	000194(6)								
194	Jake O'Brien		2017-06-17																														
195	Jake O'Brien		2017-06-17	A	G	LT	5	Structure leaning left 12"	L170000195	L	N/A				G	5			L	D	SO	S	5								F	WD	P
195	Jake O'Brien		2017-06-17							R	N/A				G	5			R	D	SO	S	5										
195	Jake O'Brien		2017-06-17																														
196	Jake O'Brien		2017-06-17	F	G	G	5		L170000196	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	F
196	Jake O'Brien		2017-06-17							R	4	55	DF	1968	G	5			R	D	SO	S	5								B	WD	F
196	Jake O'Brien		2017-06-17																														
197	Jake O'Brien		2017-06-17	F	G	G	5		L170000197	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G
197	Jake O'Brien		2017-06-17							R	4	55	DF	1968	G	5			R	D	SO	S	5								B	WD	G
197	Jake O'Brien		2017-06-17																														
198	Jake O'Brien		2017-06-17	G	G	G	5		L170000198	L	4	65	DF	1968	G	5			L	D	SO	S	5			1	1	F	4	Guy guard missing and ben	L170000198(5)	F	WD	F
198	Jake O'Brien		2017-06-17							R	4	65	DF	1968	G	5			R	D	SO	S	5			1	1	G	5			B	WD	P
198	Jake O'Brien		2017-06-17																														
199	Jake O'Brien		2017-06-17	AX	G	G	5		L170000199	L	4	50	DF	1968	G	5			L	D	SO	S	5								F	WD	G
199	Jake O'Brien		2017-06-17							R	4	50	DF	1968	G	5			R	D	SO	S	5										
199	Jake O'Brien		2017-06-17																														
200	Jake O'Brien		2017-06-17	A	F	G	5	Ahead upper sign faded	L170000200	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G
200	Jake O'Brien		2017-06-17							R	4	55	DF	1968	G	5			R	D	SO	S	5										
200	Jake O'Brien		2017-06-17																														

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201	Jake O'Brien		2017-06-17	A	G	G	5		L170000201	L	3	55	WC	2014	E	5			L	D	SO	S	5	Old pole butts	1000201(5)							F	ST	E
201	Jake O'Brien		2017-06-17							R	3	55	WC	2014	E	5			R	D	SO	S	5	Old pole butts	1000201(6)									
201	Jake O'Brien		2017-06-17																															
202	Jake O'Brien		2017-06-17	E	G	G	5		L170000202	L	4	55	DF	2014	G	5			L	D	SO	S	5			1	1	F	5	Guy guard missing	L170000202(6)	F	WD	F
202	Jake O'Brien		2017-06-17							C	4	55	DF	2014	G	5			C	D	SO	S	5			1	1	F	5	Guy guard faded	L170000202(5)	B	WD	G
202	Jake O'Brien		2017-06-17							R	4	55	DF	2014	G	5			R	D	SO	S	5			1	1	F	5	Guy guard faded	L170000202(5)			
203	Jake O'Brien		2017-06-17	A	G	LL	5		L170000203	L	N/A				G	5			L	D	SO	S	5									F	WD	G
203	Jake O'Brien		2017-06-17							R	N/A				G	5			R	D	SO	S	5											
203	Jake O'Brien		2017-06-17																															
204	Jake O'Brien		2017-06-17	A	G	G	5		L170000204	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
204	Jake O'Brien		2017-06-17							R	4	55	DF	1968	G	5			R	D	SO	S	5											
204	Jake O'Brien		2017-06-17																															
205	Jake O'Brien		2017-06-17	A	M	G	5		L170000205	L	3	55	WC	2014	E	5			L	D	SO	S	5	Old pole butt	1000205(5)							F	ST	E
205	Jake O'Brien		2017-06-17							R	3	55	WC	2014	E	5			R	D	SO	S	5	Old pole butt	1000205(6)									
205	Jake O'Brien		2017-06-17																															
206	Jake O'Brien		2017-06-17	A	M	G	5		L170000206	L	3	55	WC	2014	E	5			L	D	SO	S	5	Old pole butt	1000206(5)							F	ST	E
206	Jake O'Brien		2017-06-17							R	3	55	WC	2014	E	5			R	D	SO	S	5	Old pole butt	1000206(6)									
206	Jake O'Brien		2017-06-17																															
207	Jake O'Brien		2017-06-17	A	G	G	5		L170000207	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
207	Jake O'Brien		2017-06-17							R	4	55	DF	1968	G	5			R	D	SO	S	5											
207	Jake O'Brien		2017-06-17																															
208	Jake O'Brien		2017-06-17	A	M	G	5		L170000208	L	3	65	WC	2014	E	5			L	D	SO	S	5	Old pole butt	1000208(5)							F	ST	E
208	Jake O'Brien		2017-06-17							R	3	65	WC	2014	E	5			R	D	SO	S	5	Old pole butt	1000208(6)									
208	Jake O'Brien		2017-06-17																															
209	Jake O'Brien		2017-06-17	F	G	G	5		L170000209	L	4	55	DF	1968	F	5	1 Sm WPH @ top brace bolt	L170000209(5)	L	D	SO	S	5									F	WD	P
209	Jake O'Brien		2017-06-17							R	4	55	DF	1968	G	5			R	D	SO	S	5									B	WD	G
209	Jake O'Brien		2017-06-17																															
210	Jake O'Brien		2017-06-17	F	G	LL	5	Left pole leaning ahead 20" / top sign fa	L170000210	L	N/A				G	5			L	D	SO	S	5									F	WD	G
210	Jake O'Brien		2017-06-17							R	N/A				G	5			R	D	SO	S	5									B	WD	F
210	Jake O'Brien		2017-06-17																															
211	Jake O'Brien		2017-06-19	G	G	G	5		L170000211	L	4	65	DF	1968	F	5	2 med WPH between brace	L170000211(6)	L	D	SO	S	5									F	WD	F
211	Jake O'Brien		2017-06-19							R	4	65	DF	1968	G	5			R	D	SO	S	5											
211	Jake O'Brien		2017-06-19																															
212	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000212	L	N/A				G	5			L	D	SO	S	5									F	WD	G
212	Jake O'Brien	Chad Harvey	2017-06-18							R	N/A				G	5			R	D	SO	S	5											
212	Jake O'Brien	Chad Harvey	2017-06-18																															
213	Jake O'Brien	Chad Harvey	2017-06-18	A	G	LL	5	Left pole leaning ahead 12", right pole l	L170000213	L	4	65	DF	1968	G	5	One small WPH at bottom sway bc	L170000213(6)	L	D	SO	S	5			1	1	G	4	Missing guy guard	L170000213(5)	F	WD	G
213	Jake O'Brien	Chad Harvey	2017-06-18							R	4	65	DF	1968	G	5			R	D	SO	S	5			1	1	G	4	Missing guy guard	L170000213(5)			
213	Jake O'Brien	Chad Harvey	2017-06-18																															
214	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000214	L	N/A				G	5			L	D	SO	S	5									F	WD	G
214	Jake O'Brien	Chad Harvey	2017-06-18							R	N/A				G	5			R	D	SO	S	5											
214	Jake O'Brien	Chad Harvey	2017-06-18																															
215	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000215	L	3	55	WC	2014	E	5			L	D	SO	S	5									F	ST	E
215	Jake O'Brien	Chad Harvey	2017-06-18							R	3	55	WC	2014	E	5			R	D	SO	S	5											
215	Jake O'Brien	Chad Harvey	2017-06-18																															
216	Jake O'Brien	Chad Harvey	2017-06-18	E	G	G	5		L170000216	L	4	60	DF	1968	G	5			L	D	SO	S	5			1	1	G	4	Missing guy guard	L170000216(6)	F	WD	G
216	Jake O'Brien	Chad Harvey	2017-06-18							C	4	60	DF	1968	G	5			C	D	SO	S	5			1	1	G	4	Missing guy guard / guy ru	L170000216(7)	B	WD	G
216	Jake O'Brien	Chad Harvey	2017-06-18							R	4	55	DF	1968	G	5			R	D	SO	S	5			1	1	G	4	Missing guy guard	L170000216(5)			
217	Jake O'Brien	Chad Harvey	2017-06-18	H DE	G	G	5		L170000217	L	N/A				G	5			L	D	SO	S	5			1	1	G	4	Missing guy guard	L170000217(2)	F	WD	G
217	Jake O'Brien	Chad Harvey	2017-06-18							R	N/A				G	5			R	D	SO	S	5			1	1	G	4	Missing guy guard	L170000217(5)			
217	Jake O'Brien	Chad Harvey	2017-06-18																															
218	Jake O'Brien	Chad Harvey	2017-06-18	E	G	G	5		L170000218	L	N/A				G	5			L	D	SO	S	5									F	WD	G
218	Jake O'Brien	Chad Harvey	2017-06-18							C	N/A				G	5			C	D	SO	S	5									B	WD	G
218	Jake O'Brien	Chad Harvey	2017-06-18							R	N/A				G	5			R	D	SO	S	5			1	1	G	4	Missing guy guard	L170000218(5)			
219	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000219	L	N/A				G	5			L	D	SO	S	5									F	WD	G
219	Jake O'Brien	Chad Harvey	2017-06-18							R	N/A				G	5			R	D	SO	S	5											

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219	Jake O'Brien	Chad Harvey	2017-06-18																															
220	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000220	L	N/A				G	5			L	D	SO	S	5									F	WD	F
220	Jake O'Brien	Chad Harvey	2017-06-18							R	N/A				G	5			R	D	SO	S	5											
220	Jake O'Brien	Chad Harvey	2017-06-18																															
221	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000221	L	N/A				G	5			L	D	SO	S	5									F	WD	F
221	Jake O'Brien	Chad Harvey	2017-06-18							R	N/A				G	5			R	D	SO	S	5											
221	Jake O'Brien	Chad Harvey	2017-06-18																															
222	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000222	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	ST	F
222	Jake O'Brien	Chad Harvey	2017-06-18							R	4	55	DF	1968	G	5			R	D	SO	S	5											
222	Jake O'Brien	Chad Harvey	2017-06-18																															
223	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000223	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
223	Jake O'Brien	Chad Harvey	2017-06-18							R	4	55	DF	1968	G	5			R	D	SO	S	5											
223	Jake O'Brien	Chad Harvey	2017-06-18																															
224	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000224	L	N/A				G	5			L	D	SO	S	5									F	WD	F
224	Jake O'Brien	Chad Harvey	2017-06-18							R	N/A				G	5			R	D	SO	S	5											
224	Jake O'Brien	Chad Harvey	2017-06-18																															
225	Jake O'Brien	Chad Harvey	2017-06-18	A	M	LL/LD	5	Str is leaning ahead 3' and right 2'	L170000225	L	N/A				G	5			L	C	SW	U	5		L170000225(6)	1	1	G	5			F	WD	G
225	Jake O'Brien	Chad Harvey	2017-06-18							R	N/A				G	5			R	C	SW	U	5		L170000225(5)	1	1	P	4	Loose/missing guy guard	L170000225(7)			
225	Jake O'Brien	Chad Harvey	2017-06-18																															
226	Jake O'Brien	Chad Harvey	2017-06-18	A	G	G	5		L170000226	L	3	55	WC	2005	G	5	One WPH 6' AGL	L170000226(5)	L	D	SW	U	4	Gains are 8' Ag	L000226(9)	3	3	G	5			F	WD	G
226	Jake O'Brien	Chad Harvey	2017-06-18							R	3	55	WC	2005	F	4	8 WPH 3 large, 3 med 3 small at 10	L170000226(6)	R	D	SW	U	4	Gain is 8' AGL,	L000226(9)	3	3	G	5					
226	Jake O'Brien	Chad Harvey	2017-06-18																															
227	Jake O'Brien	Chad Harvey	2017-06-18	A	G	LL	5		L170000227	L	N/A				G	5	5 Small WPH 8-20' AGL	L170000227(8)	L	D	SW	S	5			2	1	P	4	Anchor head is 4' AGL	L170000227(5)	F	WD	G
227	Jake O'Brien	Chad Harvey	2017-06-18							R	N/A				G	5	1 Med, 1 small WPH 8-20 AGL	L170000227(9)	R	D	SW	S	5			2	2	P	4	Anchor head is 4' AGL	L170000227(7)			
227	Jake O'Brien	Chad Harvey	2017-06-18																															
228	Jake O'Brien	Chad Harvey	2017-06-19	A	G	LD	5	Str is leaning left 12"	L170000228	L	N/A				G	5	1 small WPH at 12' AGL	L170000228(4)	L	C	SW	U	5	Culvert sinking	L000228(5)	1	1	G	4	Missing guy guard / loose	L170000228(7)	F	WD	G
228	Jake O'Brien	Chad Harvey	2017-06-19							C	N/A				G	5			R	C	SW	U	5	Culvert sinking	L000228(6)	1	1	G	4	Missing guy guard	L170000228(8)			
228	Jake O'Brien	Chad Harvey	2017-06-19																															
229	Jake O'Brien	Chad Harvey	2017-06-19	A	G	LL	5	Str leaning ahead 12"	L170000229	L	4	60	DF	1968	G	5	1 Small WPH at 20' AGL light WP d	L170000229(8)	L	D	SW	S	5									F	WD	F
229	Jake O'Brien	Chad Harvey	2017-06-19							R	4	60	DF	1968	G	5	1 Small WPH 15' AGL	L170000229(7)	R	C	SW	U	5	Culvert sinking	L000229(5)									
229	Jake O'Brien	Chad Harvey	2017-06-19																															
230	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000230	L	2	70	WC	2003	G	5			L	D	SO	S	5									F	ST	E
230	Jake O'Brien	Chad Harvey	2017-06-19							R	2	70	WC	2002	G	5			R	D	SO	S	5											
230	Jake O'Brien	Chad Harvey	2017-06-19																															
231	Jake O'Brien	Chad Harvey	2017-06-19	H DE	G	LD	5	Str is leaning 10" right	L170000231	L	4	60	DF	1968	G	5			L	D	SO	S	5			1	1	G	4	Missing guy guard	L170000231(7)	F	WD	F
231	Jake O'Brien	Chad Harvey	2017-06-19							R	4	60	DF	1968	G	5	3 Small WPH mid pole	L170000231(5)	R	D	SO	S	5			1	1	G	4	Missing guy guard	L170000231(6)	B	WD	F
231	Jake O'Brien	Chad Harvey	2017-06-19																															
232	Jake O'Brien	Chad Harvey	2017-06-19	A	G	LL	5	Left pole leaning ahead 6", right pole le	L170000232	L	N/A				G	5			L	D	SW	S	5									F	WD	P
232	Jake O'Brien	Chad Harvey	2017-06-19							R	N/A				G	5			R	D	SW	S	5											
232	Jake O'Brien	Chad Harvey	2017-06-19																															
233	Jake O'Brien	Chad Harvey	2017-06-19	A	G	LD	5	Str leaning left 10"	L170000233	L	N/A				G	5	5 small WPH bottom half of pole	L170000233(5)	L	D	SO	S	5									F	WD	G
233	Jake O'Brien	Chad Harvey	2017-06-19							R	N/A				G	5	1 Small WPH 20' AGL	L170000233(6)	R	D	SO	S	5											
233	Jake O'Brien	Chad Harvey	2017-06-19																															
234	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000234	L	N/A				G	5			L	D	SO	S	5									F	WD	G
234	Jake O'Brien	Chad Harvey	2017-06-19							R	N/A				G	5			R	D	SO	S	5											
234	Jake O'Brien	Chad Harvey	2017-06-19																															
235	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000235	L	N/A				G	5			L	D	SO	S	5									F	WD	F
235	Jake O'Brien	Chad Harvey	2017-06-19							R	N/A				G	5			R	D	SO	S	5											
235	Jake O'Brien	Chad Harvey	2017-06-19																															
236	Jake O'Brien	Chad Harvey	2017-06-19	H DE	G	G	5		L170000236	L	2	45	WC	2014	E	5			L	D	SO	S	5									F	WD	E
236	Jake O'Brien	Chad Harvey	2017-06-19							R	2	45	WC	2014	E	5			R	D	SO	S	5									B	WD	E
236	Jake O'Brien	Chad Harvey	2017-06-19																															
237	Jake O'Brien	Chad Harvey	2017-06-19	A	M	G	5		L170000237	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	F
237	Jake O'Brien	Chad Harvey	2017-06-19							R	4	50	DF	1968	G	5			R	D	SO	S	5											
237	Jake O'Brien	Chad Harvey	2017-06-19																															
238	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000238	L	N/A				G	5			L	D	SO	S	5									F	WD	F

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238	Jake O'Brien	Chad Harvey	2017-06-19							R	N/A				G	5			R	D	SO	S	5									B	WD	F
238	Jake O'Brien	Chad Harvey	2017-06-19																															
239	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000239	L	2	50	WC	2010	E	5			L	D	SO	S	5									F	ST	E
239	Jake O'Brien	Chad Harvey	2017-06-19							R	2	50	WC	2010	E	5			R	D	SO	S	5											
239	Jake O'Brien	Chad Harvey	2017-06-19																															
240	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000240	L	3	55	WC	2014	E	5			L	D	SO	S	5									F	ST	E
240	Jake O'Brien	Chad Harvey	2017-06-19							R	3	55	WC	2011	E	5			R	D	SO	S	5											
240	Jake O'Brien	Chad Harvey	2017-06-19																															
241	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000241	L	3	55	WC	2014	E	5			L	D	SO	S	5									F	ST	E
241	Jake O'Brien	Chad Harvey	2017-06-19							R	3	55	WC	2014	E	5			R	D	SO	S	5											
241	Jake O'Brien	Chad Harvey	2017-06-19																															
242	Jake O'Brien	Chad Harvey	2017-06-19	A	G	LL	5	Str leaning back 6"	L170000242	L	N/A		DF	1968	G	5			L	D	SO	S	5									F	WD	F
242	Jake O'Brien	Chad Harvey	2017-06-19							R	N/A		DF	1968	G	5			R	D	SO	S	5											
242	Jake O'Brien	Chad Harvey	2017-06-19																															
243	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000243	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
243	Jake O'Brien	Chad Harvey	2017-06-19							R	4	55	DF	1968	G	5			R	D	SO	S	5											
243	Jake O'Brien	Chad Harvey	2017-06-19																															
244	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000244	L	3	45	LP	2014	E	5			L	D	SO	S	5									F	ST	E
244	Jake O'Brien	Chad Harvey	2017-06-19							R	3	45	LP	2014	E	5			R	D	SO	S	5											
244	Jake O'Brien	Chad Harvey	2017-06-19																															
245	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000245	L	N/A				G	5			L	D	SO	S	5									F	WD	G
245	Jake O'Brien	Chad Harvey	2017-06-19							R	N/A				G	5			R	D	SO	S	5											
245	Jake O'Brien	Chad Harvey	2017-06-19																															
246	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000246	L	N/A				G	5			L	D	SO	S	5									F	WD	G
246	Jake O'Brien	Chad Harvey	2017-06-19							R	N/A				G	5			R	D	SO	S	5											
246	Jake O'Brien	Chad Harvey	2017-06-19																															
247	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000247	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
247	Jake O'Brien	Chad Harvey	2017-06-19							R	3	55	WC	2016	E	5			R	D	SO	S	5											
247	Jake O'Brien	Chad Harvey	2017-06-19																															
248	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000248	L	N/A				F	4	Pole top is splitting	L170000248(5)	L	D	SO	S	5									F	WD	P
248	Jake O'Brien	Chad Harvey	2017-06-19							R	N/A				G	5			R	D	SO	S	5											
248	Jake O'Brien	Chad Harvey	2017-06-19																															
249	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000249	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
249	Jake O'Brien	Chad Harvey	2017-06-19							R	3	55	WC	2016	E	5			R	D	SO	S	5											
249	Jake O'Brien	Chad Harvey	2017-06-19																															
250	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000250	L	N/A				G	5			L	D	SO	S	5									F	WD	F
250	Jake O'Brien	Chad Harvey	2017-06-19							R	N/A				G	5			C	D	SO	S	5											
250	Jake O'Brien	Chad Harvey	2017-06-19																															
251	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000251	L	3	55	WC	2015	E	5			L	D	SO	S	5									F	ST	E
251	Jake O'Brien	Chad Harvey	2017-06-19							R	3	55	WC	2015	E	5			R	D	SO	S	5											
251	Jake O'Brien	Chad Harvey	2017-06-19																															
252	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000252	L	N/A				G	5			L	D	SO	S	5									F	WD	F
252	Jake O'Brien	Chad Harvey	2017-06-19							R	N/A				G	5			R	D	SO	S	5											
252	Jake O'Brien	Chad Harvey	2017-06-19																															
253	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000253	L	N/A				G	5			L	D	SO	S	5									F	WD	F
253	Jake O'Brien	Chad Harvey	2017-06-19							R	N/A				G	5			R	D	SO	S	5											
253	Jake O'Brien	Chad Harvey	2017-06-19																															
254	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000254	L	N/A				G	5			L	D	SO	S	5									F	WD	G
254	Jake O'Brien	Chad Harvey	2017-06-19							R	N/A				G	5			R	D	SO	S	5											
254	Jake O'Brien	Chad Harvey	2017-06-19																															
255	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000255	L	3	55	WC	2014	E	5			L	D	SO	S	5									F	ST	E
255	Jake O'Brien	Chad Harvey	2017-06-19							R	3	55	WC	2014	E	5			R	D	SO	S	5											
255	Jake O'Brien	Chad Harvey	2017-06-19																															
256	Jake O'Brien	Chad Harvey	2017-06-19	A	G	G	5		L170000256	L	3	55	WC	2014	E	5			L	D	SO	S	5									F	ST	E
256	Jake O'Brien	Chad Harvey	2017-06-19							R	3	55	WC	2014	E	5			R	D	SO	S	5											
256	Jake O'Brien	Chad Harvey	2017-06-19																															

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257	Jake O'Brien	Chad Harvey	2017-06-19	EG	M	G	5		L170000257	L	3	60	WC	2016	E	5			L	D	SO	S	5			3	3	G	5			F	WD	E
257	Jake O'Brien	Chad Harvey	2017-06-19							C	3	60	WC	2016	E	5			C	D	SO	S	5			2	2	G	5			B	WD	E
257	Jake O'Brien	Chad Harvey	2017-06-19							R	3	60	WC	2016	E	5			R	D	SO	S	5			2	2	G	5					
258	Jake O'Brien		2017-06-19	A	G	G	5		L170000258	L	3	55	WC	2013	P	3	Ant dust at GL	L170000258(8)	L	D	SO	S	5									F	ST	E
258	Jake O'Brien		2017-06-19							C	3	55	WC	2014	E	5			R	D	SO	S	5											
258	Jake O'Brien		2017-06-19																														
259	Jake O'Brien		2017-06-19	A	G	G	5		L170000259	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
259	Jake O'Brien		2017-06-19							R	4	55	DF	1968	G	5			R	D	SO	S	5											
259	Jake O'Brien		2017-06-19																														
260	Jake O'Brien		2017-06-19	A	G	G	5		L170000260	L	2	60	WC	2002	G	5	1 Sm WPH at top	L170000260(5)	L	D	SO	S	5	Old pole butts	L000260(6)							F	ST	E
260	Jake O'Brien		2017-06-19							R	2	60	WC	2003	E	5			R	D	SO	S	5	Old pole butts	L000260(7)									
260	Jake O'Brien		2017-06-19																														
261	Jake O'Brien		2017-06-19	A	G	G	5		L170000261	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
261	Jake O'Brien		2017-06-19							R	4	50	DF	1968	P	3	Ant dust and active ants	L170000261(8)	R	D	SO	S	5											
261	Jake O'Brien		2017-06-19																														
262	Jake O'Brien		2017-06-19	A	M	G	5		L170000262	L	3	55	WC	2014	G	5	Sm WPH 4' AgL	L170000262(5)	L	D	RO	S	5	Old pole butt 8	000262(6)							F	ST	E
262	Jake O'Brien		2017-06-19							C	3	55	WC	2014	E	5			R	D	RO	S	5	Old pole butt 8	000262(7)									
262	Jake O'Brien		2017-06-19																														
263	Jake O'Brien		2017-06-19	A	G	G	5		L170000263	L	4	55	DF	1968	G	5			L	D	RO	S	5									F	WD	G
263	Jake O'Brien		2017-06-19							R	4	55	DF	1968	G	5			R	D	RO	S	5											
263	Jake O'Brien		2017-06-19																														
264	Jake O'Brien		2017-06-19	A	G	G	5		L170000264	L	3	60	WC	2016	E	5			L	D	SO	S	5	Old pole butts	8000264(5)							F	ST	E
264	Jake O'Brien		2017-06-19							R	3	60	WC	2016	E	5			R	D	SO	S	5	Old pole butts	8000264(6)									
264	Jake O'Brien		2017-06-19																														
265	Jake O'Brien		2017-06-19	A	G	G	5		L170000265	L	3	60	WC	2016	E	5			L	D	SO	S	5									F	ST	E
265	Jake O'Brien		2017-06-19							R	3	60	WC	2016	E	5			R	D	SO	S	5											
265	Jake O'Brien		2017-06-19																														
266	Jake O'Brien		2017-06-19	A	G	G	5		L170000266	L	3	55	WC	2016	E	5			L	D	SO	S	5	Old pole butts	8000266(5)							F	ST	E
266	Jake O'Brien		2017-06-19							R	3	55	WC	2016	E	5			R	D	SO	S	5	Old pole butts	8000266(6)									
266	Jake O'Brien		2017-06-19																														
267	Jake O'Brien		2017-06-19	A	G	G	5		L170000267	L	3	50	WC	2016	E	5			L	D	SO	S	5									F	ST	E
267	Jake O'Brien		2017-06-19							R	3	50	WC	2016	E	5			R	D	SO	S	5											
267	Jake O'Brien		2017-06-19																														
268	Jake O'Brien		2017-06-19	A	G	G	5		L170000268	L	3	50	WC	2016	E	5			L	D	SO	S	5	Old pole butts	8000268(5)							F	ST	E
268	Jake O'Brien		2017-06-19							R	3	50	WC	2016	E	5			R	D	SO	S	5	Old pole butts	8000268(6)									
268	Jake O'Brien		2017-06-19																														
269	Jake O'Brien		2017-06-19	A	G	LL	5	Right pole leaning ahead 18"	L170000269	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
269	Jake O'Brien		2017-06-19							R	4	55	DF	1968	F	5	Checking throughout	L70000269(10)	R	D	SO	S	5											
269	Jake O'Brien		2017-06-19																														
270	Jake O'Brien		2017-06-19	A	G	G	5	Ahead top sign faded	L170000270	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	P
270	Jake O'Brien		2017-06-19							R	4	50	DF	1968	G	5			R	D	SO	S	5											
270	Jake O'Brien		2017-06-19																														
271	Jake O'Brien		2017-06-19	A	G	G	5		L170000271	L	4	45	DF	1968	G	5			L	D	SO	S	5									F	WD	P
271	Jake O'Brien		2017-06-19							R	4	40	DF	1968	G	5			R	D	SO	S	5											
271	Jake O'Brien		2017-06-19																														
272	Jake O'Brien		2017-06-19	A	G	G	5		L170000272	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	P
272	Jake O'Brien		2017-06-19							R	4	50	DF	1968	F	5	Checking throughout	L170000272(6)	R	D	SO	S	5											
272	Jake O'Brien		2017-06-19																														
273	Jake O'Brien		2017-06-19	A	G	G	5		L170000273	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
273	Jake O'Brien		2017-06-19							R	4	50	DF	1968	F	5	Outer shell damage throughout	L170000273(8)	R	D	SO	S	5											
273	Jake O'Brien		2017-06-19																														
274	Jake O'Brien		2017-06-19	A	G	G	5		L170000274	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
274	Jake O'Brien		2017-06-19							R	4	55	DF	1968	F	5	Sm WPH 20' AgL	L170000274(8)	R	D	SO	S	5											
274	Jake O'Brien		2017-06-19																														
275	Jake O'Brien		2017-06-19	A	G	G	5		L170000275	L	3	50	WC	2014	E	5			L	D	SO	S	5									F	ST	E
275	Jake O'Brien		2017-06-19							R	3	50	WC	2014	E	5			R	D	SO	S	5											

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275	Jake O'Brien		2017-06-19																														
276	Jake O'Brien		2017-06-19	A	G	G	5		L170000276	L	2	50	WC	2015	E	5			L	D	SO	S	5									F	ST	E
276	Jake O'Brien		2017-06-19							R	2	50	WC	2015	E	5			R	D	SO	S	5											
276	Jake O'Brien		2017-06-19																														
277	Jake O'Brien		2017-06-19	A	G	LL	5	Str leaning back 12"	L170000277	L	4	55	DF	1968	F	5	1 sm WPH 8' AGL 2 med WPH 18' a	170000277(10)	L	D	SO	S	5									F	WD	G
277	Jake O'Brien		2017-06-19							R	4	55	DF	1968	F	5	2 Sm WPH 10' and 18' AGL and 1 S	170000277(6)	R	D	SO	S	5											
277	Jake O'Brien		2017-06-19																														
278	Jake O'Brien		2017-06-19	A	G	G	5		L170000278	L	4	60	DF	1968	F	5	3 Sm WPH 20-26' AGL	170000278(8)	L	D	SO	S	5									F	WD	G
278	Jake O'Brien		2017-06-19							R	4	60	DF	1968	F	5	5 med WPH from 12-22' AGL	170000278(7)	R	D	SO	S	5											
278	Jake O'Brien		2017-06-19																														
279	Jake O'Brien		2017-06-19	A	G	G	5		L170000279	L	4	60	DF	1968	F	5	2 Sm WPH 18-20' AGL	170000279(5)	L	D	SO	S	5									F	WD	G
279	Jake O'Brien		2017-06-19							C	4	60	DF	1968	F	5	1 sm WPH 22' AGL	170000279(6)	R	D	SO	S	5											
279	Jake O'Brien		2017-06-19																														
280	Jake O'Brien		2017-06-19	A	G	G	5	Back top sign missing numbers	L170000280	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
280	Jake O'Brien		2017-06-19							R	4	55	DF	1968	F	5	4 Sm WPH 10-16' AGL	170000280(8)	R	D	SO	S	5											
280	Jake O'Brien		2017-06-19																														
281	Jake O'Brien		2017-06-19	G	G	G	5		L170000281	L	4	55	DF	1968	F	5	1 sm WPH 20' AGL	170000281(5)	L	D	SO	S	5			1	1	G	5			F	WD	G
281	Jake O'Brien		2017-06-19							R	4	55	DF	1968	F	5	1 med WPH 20' AGL	170000281(6)	R	D	SO	S	5			1	1	G	5					
281	Jake O'Brien		2017-06-19																														
282	Jake O'Brien		2017-06-19	A	G	G	5		L170000282	L	4	50	DF	1968	F	4	Heavy checking throughout	170000282(8)	L	D	RO	S	5									F	WD	P
282	Jake O'Brien		2017-06-19							R	4	50	DF	1968	G	5			R	D	RO	S	5											
282	Jake O'Brien		2017-06-19																														
283	Jake O'Brien		2017-06-19	A	M	G	5		L170000283	L	3	60	WC	2016	E	5			L	D	RO	S	5									F	ST	E
283	Jake O'Brien		2017-06-19							R	3	60	WC	2016	E	5			R	D	RO	S	5											
283	Jake O'Brien		2017-06-19																														
284	Jake O'Brien		2017-06-19	A	G	G	5		L170000284	L	2	50	WC	2015	E	5			L	D	RO	S	5	Old pole butt 8	000284(5)							F	ST	E
284	Jake O'Brien		2017-06-19							R	2	50	WC	2015	E	5			R	D	RO	S	5	Old pole butt 8	000284(6)									
284	Jake O'Brien		2017-06-19																														
285	Jake O'Brien		2017-06-19	A	G	G	5		L170000285	L	N/A				F	5	3 Med WPH 18-25' AGL, checking a	170000285(10)	L	D	SO	S	5									F	WD	G
285	Jake O'Brien		2017-06-19							R	N/A				F	5	5 Sm WPH 15-20' AGL	170000285(8)	R	D	SO	S	5											
285	Jake O'Brien		2017-06-19																														
286	Jake O'Brien		2017-06-19	A	G	G	5		L170000286	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	F
286	Jake O'Brien		2017-06-19							R	4	50	DF	1968	G	5			R	D	SO	S	5											
286	Jake O'Brien		2017-06-19																														
287	Jake O'Brien		2017-06-19	A	G	G	5		L170000287	L	4	55	DF	1968	F	5	3 Med WPH 10-15' AgL	170000287(9)	L	D	SO	S	5									F	WD	P
287	Jake O'Brien		2017-06-19							R	4	55	DF	1968	G	5			R	D	SO	S	5											
287	Jake O'Brien		2017-06-19																														
288	Jake O'Brien		2017-06-19	A	G	G	5		L170000288	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	P
288	Jake O'Brien		2017-06-19							R	4	50	DF	1968	F	5	1 med WPH 2' blow bottom brace	170000288(9)	R	D	SO	S	5											
288	Jake O'Brien		2017-06-19																														
289	Jake O'Brien		2017-06-19	A	G	G	5		L170000289	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
289	Jake O'Brien		2017-06-19							R	4	55	DF	1968	G	5			R	D	SO	S	5											
289	Jake O'Brien		2017-06-19																														
290	Jake O'Brien		2017-06-19	D	G	G	5	Top signs faded	L170000290	L	4	65	DF	1968	G	5			L	D	SO	S	5									F	WD	F
290	Jake O'Brien		2017-06-19							C	4	65	DF	1968	G	5			C	D	SO	S	5									B	WD	G
290	Jake O'Brien		2017-06-19							R	4	60	DF	1968	G	5			R	D	SO	S	5			1	1	F	3	Guy guard missing	L170000290(5)			
291	Jake O'Brien		2017-06-19	A	G	G	5		L170000291	L	3	60	WC	2016	E	5			L	D	SO	S	5	Old pole stub 8	000291(5)							F	ST	E
291	Jake O'Brien		2017-06-19							R	3	60	WC	2016	E	5			R	D	SO	S	5	Old pole stub 8	000291(6)									
291	Jake O'Brien		2017-06-19																														
292	Jake O'Brien		2017-06-19	A	G	G	5		L170000292	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	P
292	Jake O'Brien		2017-06-19							R	4	60	DF	1968	G	5			R	D	SO	S	5											
292	Jake O'Brien		2017-06-19																														
293	Jake O'Brien		2017-06-20	A	G	G	5		L170000293	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
293	Jake O'Brien		2017-06-20							R	4	55	DF	1968	G	5			R	D	SO	S	5											
293	Jake O'Brien		2017-06-20																														
294	Jake O'Brien		2017-06-20	A	G	G	5		L170000294	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G

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294	Jake O'Brien		2017-06-20							R	4	55	DF	1968	G	5	1 Small WPH at 20' AGL	.170000294(7)	R	D	SO	S	5										
294	Jake O'Brien		2017-06-20																														
295	Jake O'Brien		2017-06-20	F	G	G	5		L170000295	L	4	65	DF	1968	G	5			L	D	SO	S	5								F	WD	G
295	Jake O'Brien		2017-06-20							R	4	65	DF	1968	G	5			R	D	SO	S	5								B	WD	G
295	Jake O'Brien		2017-06-20																														
296	Jake O'Brien		2017-06-20	F	M	G	5		L170000296	L	4	65	DF	1968	G	5			L	D	SO	S	5								F	WD	G
296	Jake O'Brien		2017-06-20							R	4	65	DF	1968	G	5			R	D	SO	S	5								B	WD	G
296	Jake O'Brien		2017-06-20																														
297	Jake O'Brien		2017-06-20	A	G	LD	5	Str is leaning 12" right	L170000297	L	4	60	DF	1968	G	5			L	D	SO	S	5								F	WD	P
297	Jake O'Brien		2017-06-20							R	4	60	DF	1968	G	5			R	D	SO	S	5										
297	Jake O'Brien		2017-06-20																														
298	Jake O'Brien		2017-06-20	A	G	LD	5	Str leaning 10" right	L170000298	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	P
298	Jake O'Brien		2017-06-20							R	4	55	DF	1968	G	5	1 med WPH top sway	.170000298(5)	R	D	SO	S	5										
298	Jake O'Brien		2017-06-20																														
299	Jake O'Brien		2017-06-20	A	G	G	5		L170000299	L	N/A				G	5	1 Small WPH at 12' AGL	.170000299(5)	L	D	SO	S	5								F	WD	F
299	Jake O'Brien		2017-06-20							R	N/A				G	5	3 small WPH at 15-30' AGL	.710000299(6)	R	D	SO	S	5										
299	Jake O'Brien		2017-06-20																														
300	Jake O'Brien		2017-06-20	A	G	G	5		L170000300	L	N/A				G	5			L	D	SO	S	5								F	WD	G
300	Jake O'Brien		2017-06-20							R	N/A				G	5			R	D	SO	S	5										
300	Jake O'Brien		2017-06-20																														
301	Jake O'Brien		2017-06-20	A	G	G	5		L170000301	L	4	50	DF	1968	G	5			L	D	SO	S	5								F	WD	F
301	Jake O'Brien		2017-06-20							R	4	50	DF	1968	G	5			C	D	SO	S	5										
301	Jake O'Brien		2017-06-20																														
302	Jake O'Brien		2017-06-20	A	G	LL	5	Str leaning back 12"	L170000302	L	N/A				G	5			L	D	SO	S	5								F	WD	G
302	Jake O'Brien		2017-06-20							R	N/A				G	5			R	D	SO	S	5										
302	Jake O'Brien		2017-06-20																														
303	Jake O'Brien		2017-06-20	A	G	G	5		L170000303	L	N/A				G	5			L	D	SO	S	5								F	WD	P
303	Jake O'Brien		2017-06-20							R	N/A				G	5			R	D	SO	S	5										
303	Jake O'Brien		2017-06-20																														
304	Jake O'Brien		2017-06-20	A	G	G	5		L170000304	L	N/A				G	5			L	D	SO	S	5								F	WD	G
304	Jake O'Brien		2017-06-20							R	N/A				G	5			R	D	SO	S	5										
304	Jake O'Brien		2017-06-20																														
305	Jake O'Brien		2017-06-20	A	G	LL	5	Right pole leaning back 10"	L170000305	L	4	50	DF	1968	G	5			L	D	SO	S	5								F	WD	P
305	Jake O'Brien		2017-06-20							R	4	50	DF	1968	G	5			R	D	SO	S	5										
305	Jake O'Brien		2017-06-20																														
306	Jake O'Brien		2017-06-20	A	M	G	5		L170000306	L	4	50	DF	1968	G	5	1 Small WPH at 12' AGL	.170000306(6)	L	D	SO	S	5								F	WD	F
306	Jake O'Brien		2017-06-20							R	4	50	DF	1968	G	5	3 small WPH at 6-12' AGL	.170000306(5)	R	D	SO	S	5										
306	Jake O'Brien		2017-06-20																														
307	Jake O'Brien		2017-06-20	A	G	G	5		L170000307	L	4	50	DF	1968	G	5			L	D	SO	S	5								F	WD	F
307	Jake O'Brien		2017-06-20							R	4	50	DF	1968	G	5			R	D	SO	S	5										
307	Jake O'Brien		2017-06-20																														
308	Jake O'Brien		2017-06-20	A	G	G	5		L170000308	L	N/A				G	5			L	D	SO	S	5								F	WD	F
308	Jake O'Brien		2017-06-20							R	N/A				G	5			R	D	SO	S	5										
308	Jake O'Brien		2017-06-20																														
309	Jake O'Brien		2017-06-20	A	G	G	5		L170000309	L	N/A				G	5			L	D	SO	S	5								F	WD	F
309	Jake O'Brien		2017-06-20							C	N/A				G	5			R	D	SO	S	5										
309	Jake O'Brien		2017-06-20																														
310	Jake O'Brien		2017-06-20	A	G	G	5		L170000310	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	P
310	Jake O'Brien		2017-06-20							R	4	55	DF	1968	G	5			R	D	SO	S	5										
310	Jake O'Brien		2017-06-20																														
311	Jake O'Brien		2017-06-20	A	G	G	5		L170000311	L	N/A				G	5			L	D	SO	S	5								F	WD	G
311	Jake O'Brien		2017-06-20							R	N/A				G	5			R	D	SO	S	5										
311	Jake O'Brien		2017-06-20																														
312	Jake O'Brien		2017-06-20	A	G	G	5		L170000312	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	F
312	Jake O'Brien		2017-06-20							R	4	50	DF	1968	G	5			R	D	SO	S	5										
312	Jake O'Brien		2017-06-20																														

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Structure Number	Inpsctn Lead	Inspctn Second	Inspctn Date	STR Framing Type	STR No.	STR Straight-ness	STR Maint. Priority	STR Maintenance Comment	STR Deficiency Photo	POL Loc.	POL Class	POL Size	POL Species	POL Date Stamp	POL Cond.	POL Maint. Priority	POL Maintenance Comment	POL Deficiency Photo	FDN Loc	FDN Type	FDN Ground Type	FDN Ground Cond.	FDN Maintenance	FDN Maintenance Comment	FDN Deficiency Photo	G&A # of Guys	G&A # of Anchor	G&A Cond.	G&A Maint. Priority	G&A Maintenance Comment	G&A Deficiency Photo	XRM Loc.	XRM Type	XRM Cond.
313	Jake O'Brien		2017-06-20	A	G	G	5		L170000313	L	4	50	DF	1968	G	5	3 Small WPH at 8-15' AGL	L170000313(5)	L	D	SO	S	5									F	WD	P
313	Jake O'Brien		2017-06-20							C	4	50	DF	1968	G	5			R	D	SO	S	5											
313	Jake O'Brien		2017-06-20																														
314	Jake O'Brien		2017-06-20	A	G	G	5		L170000314	L	4	60	DF	1968	G	5	Pole top starting to split 6 small W	L170000314(6)	L	D	SO	S	5									F	WD	G
314	Jake O'Brien		2017-06-20							R	4	60	DF	1968	G	5	Pole top starting to split 6 small W	L170000314(3)	R	D	SO	S	5											
314	Jake O'Brien		2017-06-20																														
315	Jake O'Brien		2017-06-20	A	G	G	5		L170000315	L	4	60	DF	1968	G	5	4 small WPH at 12-17' AGL	L170000315(6)	L	D	SO	S	5			1	1	G	5	Missing guy guard	L170000315(7)	F	WD	P
315	Jake O'Brien		2017-06-20							R	4	60	DF	1968	G	5	1 Small WPH at 12' AGL	L170000315(6)	R	D	SO	S	5			1	1	G	5	Missing guy guard	L170000315(7)			
315	Jake O'Brien		2017-06-20																														
316	Jake O'Brien		2017-06-20	B	M	G	5		L170000316	L	N/A				G	5			L	D	SO	S	5									F	WD	F
316	Jake O'Brien		2017-06-20							C	N/A				G	5			C	D	SO	S	5									B	WD	F
316	Jake O'Brien		2017-06-20							R	N/A				G	5	1 Small WPH at 15' AGL	L170000316(6)	R	D	SO	S	5			1	1	G	5	Missing guy guard	L170000316(5)			
317	Jake O'Brien		2017-06-20	A	G	G	5		L170000317	L	4	65	DF	1968	G	5			L	D	SO	S	5									F	WD	G
317	Jake O'Brien		2017-06-20							R	4	60	DF	1968	G	5			R	D	SO	S	5											
317	Jake O'Brien		2017-06-20																														
318	Jake O'Brien		2017-06-20	H DE	G	G	5		L170000318	L	3	55	WC	2015	E	5			L	D	SO	S	5			1	1	G	5			F	WD	E
318	Jake O'Brien		2017-06-20							R	3	55	WC	2015	E	5			R	D	SO	S	5			1	1	G	5					
318	Jake O'Brien		2017-06-20																														
319	Jake O'Brien		2017-06-20	H DE	G	LD	5	Str is leaning left 12"	L170000319	L	4	50	DF	1968	G	5			L	D	SO	S	5			1	1	G	5	Missing guy guard	L170000319(5)	F	WD	F
319	Jake O'Brien		2017-06-20							R	4	50	DF	1968	G	5			R	D	SO	S	5			1	1	G	5	Missing guy guard	L170000319(6)	B	WD	F
319	Jake O'Brien		2017-06-20																														
320	Jake O'Brien		2017-06-20	A	G	G	5		L170000320	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	G
320	Jake O'Brien		2017-06-20							R	4	60	DF	1968	G	5			R	D	SO	S	5											
320	Jake O'Brien		2017-06-20																														
321	Jake O'Brien		2017-06-20	A	G	G	5		L170000321	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	G
321	Jake O'Brien		2017-06-20							R	4	60	DF	1968	G	5	4 Small WPH at 10-20' AGL	L170000321(5)	R	D	SO	S	5											
321	Jake O'Brien		2017-06-20																														
322	Jake O'Brien		2017-06-20	A	M	LL	5	Str leaning ahead 12-18"	L170000322	L	4	60	DF	1968	G	5	2 small WPH 15-20' Agl	L170000322(7)	L	D	SO	S	5									F	WD	P
322	Jake O'Brien		2017-06-20							R	4	60	DF	1968	G	5			R	D	SO	S	5											
322	Jake O'Brien		2017-06-20																														
323	Jake O'Brien		2017-06-20	A	G	G	5		L170000323	L	4	N/A	DF	1968	F	5	3 Small, 2 med, 1 large WPH 10-18	L170000323(9)	L	D	SO	S	5									F	WD	P
323	Jake O'Brien		2017-06-20							R	4	N/A	DF	1968	G	5			R	D	SO	S	5											
323	Jake O'Brien		2017-06-20																														
324	Jake O'Brien		2017-06-20	A	G	LL	5		L170000324	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	P
324	Jake O'Brien		2017-06-20							R	4	50	DF	1968	F	5	2 Sm WPH 18' AgL	L170000324(9)	R	D	SO	S	5											
324	Jake O'Brien		2017-06-20																														
325	Jake O'Brien		2017-06-20	A	G	LL	5		L170000325	L	4	50	DF	1968	G	5			L	D	SO	U	4	Bank eroding	000325(8)							F	WD	F
325	Jake O'Brien		2017-06-20							R	4	55	DF	1968	G	5			R	D	SO	S	5											
325	Jake O'Brien		2017-06-20																														
326	Jake O'Brien		2017-06-20	A	M	G	5		L170000326	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
326	Jake O'Brien		2017-06-20							R	4	55	DF	1968	G	5			R	D	SO	S	5											
326	Jake O'Brien		2017-06-20																														
327	Jake O'Brien		2017-06-20	B	G	G	5		L170000327	L	3	50	DF	1968	F	5	Outer shell damage from GL to 15'	L170000327(7)	L	D	SO	S	5			1	1	F	3	Guy guard missing	L170000327(5)	F	WD	G
327	Jake O'Brien		2017-06-20							R	3	50	DF	1968	F	5			R	D	SO	S	5			1	1	G	5					
327	Jake O'Brien		2017-06-20																														
328	Jake O'Brien		2017-06-20	B	G	G	5		L170000328	L	N/A			1968	G	5			L	D	SO	S	5			1	1	G	5			F	WD	P
328	Jake O'Brien		2017-06-20							R	N/A			1968	G	5			C	D	SO	S	5			1	1	F	3	Guy guard missing	L170000328(8)			
328	Jake O'Brien		2017-06-20																														
329	Jake O'Brien		2017-06-20	A	G	G	5		L170000329	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
329	Jake O'Brien		2017-06-20							R	4	50	DF	1968	P	3	Old ant dust at GL	L170000329(5)	R	D	SO	S	5											
329	Jake O'Brien		2017-06-20																														
330	Jake O'Brien		2017-06-20	BS	F	LL	5	Centre pole leaning back 12", ahead up	L170000330	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	G
330	Jake O'Brien		2017-06-20							C	4	55	DF	1968	F	5			C	D	SO	S	5									B	WD	G
330	Jake O'Brien		2017-06-20							R	4	50	DF	1968	F	5	Sm WPH at top of pole	L170000330(6)	R	D	SO	S	5			1	1	F	3	Guy guard missing	L170000330(5)			
331	Jake O'Brien		2017-06-20	AX	G	LL	5	Left pole ahead 10", right pole back 10"	L170000331	L	4	50	DF	1968	G	5			L	D	SO	S	5			1	1	F	3	Guy guard missing	170000331(10)	F	WD	G
331	Jake O'Brien		2017-06-20							R	4	50	DF	1968	G	5			R	D	SO	S	5											

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331	Jake O'Brien		2017-06-20																														
332	Jake O'Brien		2017-06-20	A	G	G	5		L170000332	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
332	Jake O'Brien		2017-06-20							R	4	50	DF	1968	G	5			R	D	SO	S	5											
332	Jake O'Brien		2017-06-20																														
333	Jake O'Brien		2017-06-20	A	M	G	5		L170000333	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	P
333	Jake O'Brien		2017-06-20							R	4	60	DF	1968	F	3	Active ants and dust at GL	L70000333(10)	R	D	SO	S	5											
333	Jake O'Brien		2017-06-20																														
334	Jake O'Brien		2017-06-20	A	G	G	5		L170000334	L	4	55	DF	1968	G	5			L	D	SO	S	5			1	1	F	3	Guy guard missing and tail	L170000334(11)	F	WD	P
334	Jake O'Brien		2017-06-20							R	4	55	DF	1968	G	5			R	D	SO	S	5			1		G	5					
334	Jake O'Brien		2017-06-20																														
335	Jake O'Brien		2017-06-20	A	G	G	5		L170000335	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	P
335	Jake O'Brien		2017-06-20							R	4	60	DF	1968	G	5			R	D	SO	S	5											
335	Jake O'Brien		2017-06-20																														
336	Jake O'Brien		2017-06-20	H DE	M	G	5		L170000336	L	4	50	DF	1968	G	5			L	D	SO	S	5			1	1	F	3	Guy guard missing	L170000336(5)	F	WD	P
336	Jake O'Brien		2017-06-20							R	4	50	DF	1968	G	5			R	D	SO	S	5			1	1	F	3	Guy guard missing	L170000336(6)	B	WD	G
336	Jake O'Brien		2017-06-20																														
337	Jake O'Brien		2017-06-20	A	G	G	5		L170000337	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
337	Jake O'Brien		2017-06-20							R	4	55	DF	1968	G	5			R	D	SO	S	5											
337	Jake O'Brien		2017-06-20																														
338	Jake O'Brien		2017-06-20	A	G	G	5		L170000338	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
338	Jake O'Brien		2017-06-20							R	4	55	DF	1968	F	5	2 Sm WPH 20-24' AGL	L170000338(5)	R	D	SO	S	5											
338	Jake O'Brien		2017-06-20																														
339	Jake O'Brien		2017-06-20	A	M	G	5		L170000339	L	N/A				F	5	3 sm WPH 10-16' AGL	L70000339(11)	L	D	SO	S	5									F	WD	P
339	Jake O'Brien		2017-06-20							R	N/A				F	5	5 sm WPH 12-18' AGL	L70000339(12)	R	D	SO	S	5											
339	Jake O'Brien		2017-06-20																														
340	Jake O'Brien		2017-06-20	F	G	G	5		L170000340	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
340	Jake O'Brien		2017-06-20							C	4	50	DF	1968	F	5	1 Sm WPH 16' AGL	L170000340(4)	R	D	SO	S	5									B	WD	G
340	Jake O'Brien		2017-06-20																														
341	Jake O'Brien		2017-06-20	F	M	G	5		L170000341	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	P
341	Jake O'Brien		2017-06-20							R	4	50	DF	1968	G	5			R	D	SO	S	5									B	WD	G
341	Jake O'Brien		2017-06-20																														
342	Jake O'Brien		2017-06-20	A	G	G	5		L170000342	L	4	50	DF	1968	G	5			L	D	SO	S	5											
342	Jake O'Brien		2017-06-20							R	4	50	DF	1968	F	5	2 Sm WPH 12' AGL	L170000342(5)	R	D	SO	S	5											
342	Jake O'Brien		2017-06-20																														
343	Jake O'Brien		2017-06-20	A	G	G	5		L170000343	L	4	55	DF	1968	F	5	1 Med WPH 12' AGL and moderate	L70000343(13)	L	D	SO	S	5									F	WD	P
343	Jake O'Brien		2017-06-20							R	4	55	DF	1968	F	5	1 med WPH 10' AGL	L170000343(7)	C	D	SO	S	5											
343	Jake O'Brien		2017-06-20																														
344	Jake O'Brien		2017-06-20	AX	M	G	5		L170000344	L	4	65	DF	1968	G	5			L	D	SO	S	5			1		G	5			F	WD	G
344	Jake O'Brien		2017-06-20							R	4	60	DF	1968	G	5			R	D	SO	S	5			1	1	F	3	Guy guard missing and tail	L170000344(6)			
344	Jake O'Brien		2017-06-20																														
345	Jake O'Brien	Chad Harvey	2017-06-21	BS	G	G	5		L170000345	L	4	65	DF	1968	G	5	2 Small WPH 12-15' AGL	L170000345(5)	L	D	SO	S	5									F	WD	G
345	Jake O'Brien	Chad Harvey	2017-06-21							C	4	65	DF	1968	G	5			R	D	SO	S	5									B	WD	G
345	Jake O'Brien	Chad Harvey	2017-06-21							R	4	65	DF	1968	G	5										1	1	G	5	Missing guy guard	L170000345(6)			
346	Jake O'Brien	Chad Harvey	2017-06-21	A	M	G	5		L170000346	L	N/A				G	5			L	D	SO	S	5									F	WD	G
346	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5											
346	Jake O'Brien	Chad Harvey	2017-06-21																														
347	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000347	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	P
347	Jake O'Brien	Chad Harvey	2017-06-21							R	4	50	DF	1968	G	5			R	D	SO	S	5											
347	Jake O'Brien	Chad Harvey	2017-06-21																														
348	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000348	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	F
348	Jake O'Brien	Chad Harvey	2017-06-21							R	4	60	DF	1968	G	5			R	D	SO	S	5											
348	Jake O'Brien	Chad Harvey	2017-06-21																														
349	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000349	L	N/A				G	5			L	D	SO	S	5									F	WD	G
349	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5											
349	Jake O'Brien	Chad Harvey	2017-06-21																														
350	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000350	L	N/A				G	5			L	D	SO	S	5									F	WD	F

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350	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5										
350	Jake O'Brien	Chad Harvey	2017-06-21																														
351	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000351	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	G
351	Jake O'Brien	Chad Harvey	2017-06-21							R	4	55	DF	1968	G	5			R	D	SO	S	5										
351	Jake O'Brien	Chad Harvey	2017-06-21																														
352	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000352	L	N/A				G	5			L	D	SO	S	5									F	WD	G
352	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5										
352	Jake O'Brien	Chad Harvey	2017-06-21																														
353	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000353	L	N/A				G	5			L	D	SO	S	5									F	WD	P
353	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5										
353	Jake O'Brien	Chad Harvey	2017-06-21																														
354	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000354	L	N/A				G	5			L	D	SO	S	5									F	WD	P
354	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5										
354	Jake O'Brien	Chad Harvey	2017-06-21																														
355	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000355	L	N/A				G	5			L	D	SO	S	5									F	WD	F
355	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5										
355	Jake O'Brien	Chad Harvey	2017-06-21																														
356	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000356	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	F
356	Jake O'Brien	Chad Harvey	2017-06-21							R	4	50	DF	1968	G	5			R	D	SO	S	5										
356	Jake O'Brien	Chad Harvey	2017-06-21																														
357	Jake O'Brien	Chad Harvey	2017-06-21	A	G	LD	5	Str is leaning 14" left	L170000357	L	N/A				G	5			L	D	SO	S	5									F	WD	F
357	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5										
357	Jake O'Brien	Chad Harvey	2017-06-21																														
358	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000358	L	N/A				G	5	Burn damage	L170000358(6)	L	D	SO	S	5									F	WD	F
358	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5	Burn damage, 3 sm WPH 10-20' AG	L170000358(5)	R	D	SO	S	5										
358	Jake O'Brien	Chad Harvey	2017-06-21																														
359	Jake O'Brien	Chad Harvey	2017-06-21	A	G	LL/LD	5	Str is leaning 6" left and ahead	L170000359	L	N/A				G	5	2 Small WPH 4' below bottom swa	L170000359(5)	L	D	SO	S	5									F	WD	G
359	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5										
359	Jake O'Brien	Chad Harvey	2017-06-21																														
360	Jake O'Brien	Chad Harvey	2017-06-21	B	G	G	5		L170000360	L	N/A				G	5			L	D	SO	S	5			1	1	G	5	Missing guy guard	L170000360(5)	F	WD	G
360	Jake O'Brien	Chad Harvey	2017-06-21							C	N/A				G	5			C	D	SO	S	5			1	1	G	5	Missing guy guard	L170000360(5)	B	WD	G
360	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5	Burn damage	000360(5)	1	1	G	5	Missing guy guard	L170000360(5)			
361	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000361	L	N/A				G	5			L	D	SO	S	5									F	WD	F
361	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5	1 Small WPH at 12' AGL	L170000361(5)	R	D	SO	S	5										
361	Jake O'Brien	Chad Harvey	2017-06-21																														
362	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000362	L	N/A				G	5			L	D	SO	S	5									F	WD	P
362	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5										
362	Jake O'Brien	Chad Harvey	2017-06-21																														
363	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000363	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
363	Jake O'Brien	Chad Harvey	2017-06-21							R	4	55	DF	1968	G	5			R	D	SO	S	5										
363	Jake O'Brien	Chad Harvey	2017-06-21																														
364	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000364	L	N/A				G	5			L	D	SO	S	5									F	WD	G
364	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5										
364	Jake O'Brien	Chad Harvey	2017-06-21																														
365	Jake O'Brien	Chad Harvey	2017-06-21	F	G	G	5		L170000365	L	N/A				G	5	Burn damage	L170000365(4)	L	D	SO	S	5									F	WD	G
365	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5	1 small WPH at bottom sway, burn	L170000365(5)	R	D	SO	S	5									B	WD	G
365	Jake O'Brien	Chad Harvey	2017-06-21																														
366	Jake O'Brien	Chad Harvey	2017-06-21	F	G	G	5		L170000366	L	N/A				G	5			L	D	SO	S	5									F	WD	F
366	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5									B	WD	F
366	Jake O'Brien	Chad Harvey	2017-06-21																														
367	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000367	L	N/A				G	5			L	D	SO	S	5									F	WD	P
367	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5										
367	Jake O'Brien	Chad Harvey	2017-06-21																														
368	Jake O'Brien	Chad Harvey	2017-06-21	E	G	G	5		L170000368	L	N/A				G	5			L	D	SO	S	5			1	1	G	4	Missing guy guard	L170000368(5)	F	WD	F
368	Jake O'Brien	Chad Harvey	2017-06-21							C	N/A				G	5			C	D	SO	S	5									B	WD	F
368	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5										

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369	Jake O'Brien	Chad Harvey	2017-06-21	E	G	G	5		L170000369	L	4	65	DF	1968	G	5			L	D	SO	S	5			1	1	G	4	Missing guy guard	L170000369(6)	F	WD	P
369	Jake O'Brien	Chad Harvey	2017-06-21							C	4	60	DF	1968	G	5			C	D	SO	S	5									B	WD	F
369	Jake O'Brien	Chad Harvey	2017-06-21							R	4	60	DF	1968	G	5			R	D	SO	S	5											
370	Jake O'Brien	Chad Harvey	2017-06-23	A	G	G	5		L170000370	L	N/A				G	5			L	D	SO	S	5									F	WD	G
370	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5			R	D	SO	S	5											
370	Jake O'Brien	Chad Harvey	2017-06-23																															
371	Jake O'Brien	Chad Harvey	2017-06-23	A	G	LD	5	Str leaning left 6"	L170000371	L	N/A				G	5			L	D	SO	S	5									F	WD	P
371	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				P	3	Carpenter ant damage, ants seen i	L170000371(5)	R	D	SO	S	5											
371	Jake O'Brien	Chad Harvey	2017-06-23																															
372	Jake O'Brien	Chad Harvey	2017-06-23	H DE	G	LD	5	Str is leaning left 12"	L170000372	L	4	55	DF	1968	G	5			L	C	SO	U	5	Culvert tilted	000372(3)							F	WD	G
372	Jake O'Brien	Chad Harvey	2017-06-23							R	4	55	DF	1968	G	5			R	C	SO	U	5	Culvert tilted	000372(6)							B	WD	G
372	Jake O'Brien	Chad Harvey	2017-06-23																															
373	Jake O'Brien	Chad Harvey	2017-06-23	H DE	G	G	5		L170000373	L	N/A				F	3	Extensive burn damage in checking	L170000373(6)								1	1	G	5	Missing guy guard	L170000373(7)	F	WD	G
373	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5	Burn damage	L170000373(5)								1	1	G	5	Missing guy guard	L170000373(8)			
373	Jake O'Brien	Chad Harvey	2017-06-23																															
374	Jake O'Brien	Chad Harvey	2017-06-23	A	G	G	5		L170000374	L	N/A				G	5			L	D	SO	S	5									F	WD	G
374	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5			R	D	SO	S	5											
374	Jake O'Brien	Chad Harvey	2017-06-23																															
375	Jake O'Brien	Chad Harvey	2017-06-23	A	G	LL	5	Left pole leaning ahead 12"	L170000375	L	N/A				G	5			L	D	SO	S	5									F	WD	G
375	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5			R	D	SO	S	5											
375	Jake O'Brien	Chad Harvey	2017-06-23																															
376	Jake O'Brien	Chad Harvey	2017-06-23	A	G	LL	5	Right pole leaning back 6"	L170000376	L	N/A				G	5			L	D	SO	S	5									F	WD	G
376	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5			R	D	SO	S	5											
376	Jake O'Brien	Chad Harvey	2017-06-23																															
377	Jake O'Brien	Chad Harvey	2017-06-23	A	G	LL/LD	5	Right pole leaning 12" right and 12" bac	L170000377	L	N/A				G	5			L	D	SO	S	5									F	WD	F
377	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5			R	D	SO	S	5											
377	Jake O'Brien	Chad Harvey	2017-06-23																															
378	Jake O'Brien	Chad Harvey	2017-06-23	H DE	G	G	5		L170000378	L	4	65	DF	1968	G	5			L	D	SO	S	5			1	1	F	4	Guy guard missing	L170000378(6)	F	WD	G
378	Jake O'Brien	Chad Harvey	2017-06-23							R	4	65	DF	1968	G	5			R	D	SO	S	5			1	1	F	4	Guy guard missing	L170000378(5)	B	WD	G
378	Jake O'Brien	Chad Harvey	2017-06-23																															
379	Jake O'Brien	Chad Harvey	2017-06-23	A	G	G	5		L170000379	L	N/A				G	5			L	D	SO	S	5									F	WD	G
379	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5			R	D	SO	S	5											
379	Jake O'Brien	Chad Harvey	2017-06-23																															
380	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000380	L	4	65	DF	1968	G	5			L	D	SO	S	5									F	WD	G
380	Jake O'Brien	Chad Harvey	2017-06-21							R	4	65	DF	1968	F	5	Light shell damage at top xbrace b	L170000380(5)	R	D	SO	S	5											
380	Jake O'Brien	Chad Harvey	2017-06-21																															
381	Jake O'Brien	Chad Harvey	2017-06-21	H DE	G	G	5		L170000381	L	N/A				G	5			L	D	SO	S	5			1	1	F	3	Guy guards missing	L170000381(7)	F	WD	P
381	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5			1	1	F	3	Guy guards missing	L170000381(8)	B	WD	G
381	Jake O'Brien	Chad Harvey	2017-06-21																															
382	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000382	L	3	65	DF	1968	P	3	Active ants and ant dust	L70000382(10)	L	D	SO	S	5									F	WD	P
382	Jake O'Brien	Chad Harvey	2017-06-21							R	3	65	DF	1968	G	5			R	D	SO	S	5											
382	Jake O'Brien	Chad Harvey	2017-06-21																															
383	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000383	L	N/A				F	5	Outer shell burn damage at GL-4' A	L170000383(8)	L	D	SO	S	5									F	WD	G
383	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				F	5	Outer shell burn damage at GL-8' A	L170000383(9)	R	D	SO	S	5											
383	Jake O'Brien	Chad Harvey	2017-06-21																															
384	Jake O'Brien	Chad Harvey	2017-06-21	A	G	LL	5	Right pole leaning back 20"	L170000384	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	P
384	Jake O'Brien	Chad Harvey	2017-06-21							R	4	55	DF	1968	G	5			R	D	SO	S	5									B	WD	G
384	Jake O'Brien	Chad Harvey	2017-06-21																															
385	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000385	L	N/A				G	5			L	D	SO	S	5									F	WD	G
385	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			C	D	SO	S	5											
385	Jake O'Brien	Chad Harvey	2017-06-21																															
386	Jake O'Brien	Chad Harvey	2017-06-21	A	G	LT	5	Structure leaning left 12"	L170000386	L	N/A				F	5	Burn damage on outer shell from G	L170000386(6)	L	D	SO	S	5									F	WD	G
386	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				F	5	Burn damage on outer shell from G	L170000386(7)	R	D	SO	S	5											
386	Jake O'Brien	Chad Harvey	2017-06-21																															
387	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000387	L	3	60	DF	1968	G	5	Light burn damage at GL	L170000387(8)	L	D	SO	S	5									F	WD	P
387	Jake O'Brien	Chad Harvey	2017-06-21							R	4	55	DF	1968	G	5			R	D	SO	S	5											
387	Jake O'Brien	Chad Harvey	2017-06-21																															

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388	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000388	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
388	Jake O'Brien	Chad Harvey	2017-06-21							R	4	50	DF	1968	G	5			R	D	SO	S	5											
388	Jake O'Brien	Chad Harvey	2017-06-21																														
389	Jake O'Brien	Chad Harvey	2017-06-21	F	G	G	5		L170000389	L	N/A				F	5	Light burn damage from GL - 12' A	L170000389(6)	L	D	SO	S	5									F	WD	G
389	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5									B	WD	G
389	Jake O'Brien	Chad Harvey	2017-06-21																														
390	Jake O'Brien	Chad Harvey	2017-06-21	F	G	G	5		L170000390	L	4	60	DF	1968	G	5																F	WD	G
390	Jake O'Brien	Chad Harvey	2017-06-21							R	4	60	DF	1968	G	5																B	WD	P
390	Jake O'Brien	Chad Harvey	2017-06-21																														
391	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000391	L	N/A				G	5			L	D	SO	S	5									F	WD	G
391	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5											
391	Jake O'Brien	Chad Harvey	2017-06-21																														
392	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000392	L	N/A				F	5	Checking throughout	L170000392(9)	L	D	SO	S	5									F	WD	P
392	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	SO	S	5											
392	Jake O'Brien	Chad Harvey	2017-06-21																														
393	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000393	L	N/A				G	5			L	D	SO	S	5									F	WD	P
393	Jake O'Brien	Chad Harvey	2017-06-21							C	N/A				G	5			R	D	SO	S	5											
393	Jake O'Brien	Chad Harvey	2017-06-21																														
394	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000394	L	N/A				G	5			L	D	SO	S	5									F	WD	F
394	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				F	5	Light burn damage from GL to 10' A	L170000394(6)	R	D	SO	S	5											
394	Jake O'Brien	Chad Harvey	2017-06-21																														
395	Jake O'Brien	Chad Harvey	2017-06-21	D	G	G	5		L170000395	L	3	60	DF	1968	G	5			L	D	SO	S	5			2	2	G	5			F	WD	E
395	Jake O'Brien	Chad Harvey	2017-06-21							C	3	60	DF	1968	G	5			C	D	SO	S	5			2	2	G	5			B	WD	G
395	Jake O'Brien	Chad Harvey	2017-06-21							R	3	60	DF	1968	G	5			R	D	SO	S	5			2	2	G	5					
396	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000396	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
396	Jake O'Brien	Chad Harvey	2017-06-21							R	4	50	DF	1968	G	5			R	D	SO	S	5											
396	Jake O'Brien	Chad Harvey	2017-06-21																														
397	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000397	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	P
397	Jake O'Brien	Chad Harvey	2017-06-21							C	4	50	DF	1968	G	5			R	D	SO	S	5											
397	Jake O'Brien	Chad Harvey	2017-06-21																														
398A	Jake O'Brien	Chad Harvey	2017-06-21	A		G	5		L170000398A	L	3	65	WC	2014	E	5			L	D	SO	S	5									F	ST	E
398A	Jake O'Brien	Chad Harvey	2017-06-21							R	3	65	WC	2014	E	5			R	D	SO	S	5											
398A	Jake O'Brien	Chad Harvey	2017-06-21																														
398	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000398	L	3	55	WC	2016	E	5			L	D	SO	S	5	Old pole butt 8	000398(5)							F	ST	E
398	Jake O'Brien	Chad Harvey	2017-06-21							R	3	55	WC	2016	E	5			R	D	SO	S	5	Old pole butt 8	000398(6)									
398	Jake O'Brien	Chad Harvey	2017-06-21																														
399	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000399	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	P
399	Jake O'Brien	Chad Harvey	2017-06-21							R	4	60	DF	1968	G	5			R	D	SO	S	5											
399	Jake O'Brien	Chad Harvey	2017-06-21																														
400	Jake O'Brien	Chad Harvey	2017-06-21	A	G	LL	5		L170000400	L	3	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
400	Jake O'Brien	Chad Harvey	2017-06-21							R	3	55	DF	1968	G	5			R	D	SO	S	5											
400	Jake O'Brien	Chad Harvey	2017-06-21																														
401	Jake O'Brien	Chad Harvey	2017-06-21	A	G	LL	5	Left pole leaning ahead 20"	L170000401	L	4	60	DF	1968	F	3	Pole top splitting needs split bolt	L170000401(6)	L	D	SO	S	5									F	WD	F
401	Jake O'Brien	Chad Harvey	2017-06-21							R	4	55	DF	1968	G	5			R	D	SO	S	5									B	WD	G
401	Jake O'Brien	Chad Harvey	2017-06-21																														
402	Jake O'Brien	Chad Harvey	2017-06-21	A	G	G	5		L170000402	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
402	Jake O'Brien	Chad Harvey	2017-06-21							R	4	55	DF	1968	G	5			R	D	SO	S	5											
402	Jake O'Brien	Chad Harvey	2017-06-21																														
403	Jake O'Brien	Chad Harvey	2017-06-21	A	G	LT	5	Str leaning left 14"	L170000403	L	3	60	DF	1968	G	5			L	D	SO	S	5			1	1	F	4	Guy is loose	L170000403(5)	F	WD	G
403	Jake O'Brien	Chad Harvey	2017-06-21							R	3	60	DF	1968	G	5			R	D	SO	S	5			1	1							
403	Jake O'Brien	Chad Harvey	2017-06-21																														
404	Jake O'Brien	Chad Harvey	2017-06-21	A	G	LL, LT	5	Left pole leaning ahead 20", str leaning	L170000404	L	N/A				G	5			L	D	RO	S	5									F	WD	P
404	Jake O'Brien	Chad Harvey	2017-06-21							R	N/A				G	5			R	D	RO	S	5											
404	Jake O'Brien	Chad Harvey	2017-06-21																														
405	Jake O'Brien	Chad Harvey	2017-06-23	A	G	LL	5	Right pole leaning back 12"	L170000405	L	N/A				G	5			L	D	SO	S	5									F	WD	F
405	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5			R	D	SO	S	5											

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405	Jake O'Brien	Chad Harvey	2017-06-23																														
406	Jake O'Brien	Chad Harvey	2017-06-23	A	G	G	5		L170000406	L	N/A				G	5			L	D	RO	S	5									F	WD	P
406	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5			R	D	RO	S	5									B	WD	G
406	Jake O'Brien	Chad Harvey	2017-06-23																														
407	Jake O'Brien	Chad Harvey	2017-06-23	H DE	G	LL	5	Left pole leaning ahead 10"	L170000407	L	N/A				G	5			L	C	SO	S	5			1	1	G	5			F	WD	G
407	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5			R	D	SO	S	5	Back filled with rocks		1	1	G	5	Bridle guy loose	L170000407(3)	B	WD	G
407	Jake O'Brien	Chad Harvey	2017-06-23																														
408	Jake O'Brien	Chad Harvey	2017-06-23	A	G	LL	5	Str leaning ahead 8"	L170000408	L	4	55	DF	1966	G	5			L	D	SO	S	5									F	WD	G
408	Jake O'Brien	Chad Harvey	2017-06-23							R	4	55	DF	1968	G	5	One small WPH 22' AGL	L170000408(5)	R	D	SO	S	5											
408	Jake O'Brien	Chad Harvey	2017-06-23																														
409	Jake O'Brien	Chad Harvey	2017-06-23	A	G	G	5		L170000409	L	3	55	WC	2016	E	5			L	C	RO	S	5									F	ST	E
409	Jake O'Brien	Chad Harvey	2017-06-23							R	3	55	WC	2016	E	5			R	C	RO	S	5											
409	Jake O'Brien	Chad Harvey	2017-06-23																														
410	Jake O'Brien	Chad Harvey	2017-06-23	A	G	G	5		L170000410	L	N/A				G	5			L	D	RO	S	5									F	WD	G
410	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5			R	D	RO	S	5											
410	Jake O'Brien	Chad Harvey	2017-06-23																														
411	Jake O'Brien	Chad Harvey	2017-06-23	E	G	G	5		L170000411	L	4	60	DF	1968	G	5			L	D	SO	S	5			1	1	G	5			F	WD	G
411	Jake O'Brien	Chad Harvey	2017-06-23							C	4	60	DF	1968	G	5			C	D	SO	S	5			2	2	G	5			B	WD	G
411	Jake O'Brien	Chad Harvey	2017-06-23							R	4	60	DF	1968	G	5			R	D	SO	S	5			1	1	G	5					
412	Jake O'Brien	Chad Harvey	2017-06-23	A	G	LD	5	Str leaning 10" left	L170000412	L	3	60	DF	1968	G	5			L	D	SO	S	5									F	WD	F
412	Jake O'Brien	Chad Harvey	2017-06-23							R	3	60	DF	1968	G	5			R	D	SO	S	5											
412	Jake O'Brien	Chad Harvey	2017-06-23																														
413	Jake O'Brien	Chad Harvey	2017-06-23	E	G	G	5		L170000413	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	F
413	Jake O'Brien	Chad Harvey	2017-06-23							R	4	50	DF	1968	G	5			R	D	SO	S	5									B	WD	F
413	Jake O'Brien	Chad Harvey	2017-06-23																														
414	Jake O'Brien	Chad Harvey	2017-06-23	F	G	LD	5	Str is leaning 18" left	L170000414	L	N/A				G	5			L	C	SO	S	5									F	WD	F
414	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5			R	D	SO	S	5									B	WD	F
414	Jake O'Brien	Chad Harvey	2017-06-23																														
415	Jake O'Brien	Chad Harvey	2017-06-23	A	G	G	5		L170000415	L	4	45	DF	1968	G	5			L	D	SO	S	5									F	WD	P
415	Jake O'Brien	Chad Harvey	2017-06-23							R	4	45	DF	1968	G	5			R	D	SO	S	5											
415	Jake O'Brien	Chad Harvey	2017-06-23																														
416	Jake O'Brien	Chad Harvey	2017-06-23	A	G	G	5		L170000416	L	N/A				G	5			L	S2D	SO	S	5			1	1	F	5	Anchor head is 3' out of gro	L170000416(5)	F	WD	G
416	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				F	4	Pole top splitting recommend insta	L170000416(6)	R	S2D	SO	S	5											
416	Jake O'Brien	Chad Harvey	2017-06-23																														
417	Jake O'Brien	Chad Harvey	2017-06-23	A	G	G	5		L170000417	L	3	55	DF	1968	G	5	3 Small WPH 18-25' AGL	L170000417(6)	L	D	SO	S	5									F	WD	G
417	Jake O'Brien	Chad Harvey	2017-06-23							R	3	55	DF	1968	G	5			R	D	SO	S	5											
417	Jake O'Brien	Chad Harvey	2017-06-23																														
418	Jake O'Brien	Chad Harvey	2017-06-23	A	G	G	5		L170000418	L	N/A				F	5	Checking	L170000418(5)	L	D	SO	S	5									F	WD	G
418	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5			R	D	SO	S	5											
418	Jake O'Brien	Chad Harvey	2017-06-23																														
419	Jake O'Brien	Chad Harvey	2017-06-23	A	G	G	5		L170000419	L	N/A				G	5	2 Small WPH at 12-15' AGL	L170000419(6)	L	D	SO	S	5									F	WD	G
419	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5	6 Small WPH at 12-20' AGL	L170000419(5)	R	D	SO	S	5											
419	Jake O'Brien	Chad Harvey	2017-06-23																														
420	Jake O'Brien	Chad Harvey	2017-06-23	A	G	G	5		L170000420	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
420	Jake O'Brien	Chad Harvey	2017-06-23							R	4	55	DF	1968	G	5			R	D	SO	S	5											
420	Jake O'Brien	Chad Harvey	2017-06-23																														
421	Jake O'Brien	Chad Harvey	2017-06-23	A	G	G	5		L170000421	L	N/A				G	5			L	D	SO	S	5									F	WD	P
421	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5			R	D	SO	S	5											
421	Jake O'Brien	Chad Harvey	2017-06-23																														
422	Jake O'Brien	Chad Harvey	2017-06-23	E	G	G	5		L170000422	L	4	50	DF	1968	G	5			L	D	SO	S	5			1	1	G	5			F	WD	G
422	Jake O'Brien	Chad Harvey	2017-06-23							C	4	50	DF	1968	G	5			C	D	SO	S	5			2	2	G	5			B	WD	G
422	Jake O'Brien	Chad Harvey	2017-06-23							R	4	50	DF	1968	G	5			R	D	SO	S	5			1	1	G	5					
423	Jake O'Brien	Chad Harvey	2017-06-23	A	G	G	5		L170000423	L	3	60	DF	1968	G	5			L	D	SO	S	5									F	WD	F
423	Jake O'Brien	Chad Harvey	2017-06-23							R	3	60	DF	1968	G	5	Checking	L170000423(1)	R	D	SO	S	5											
423	Jake O'Brien	Chad Harvey	2017-06-23																														
424	Jake O'Brien	Chad Harvey	2017-06-23	A	G	LD	5	Str is leaning 6" left	L170000424	L	N/A				G	5			L	D	SO	S	5									F	WD	F

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424	Jake O'Brien	Chad Harvey	2017-06-23							R	N/A				G	5			R	D	SO	S	5										
424	Jake O'Brien	Chad Harvey	2017-06-23																														
425	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000425	L	N/A				G	5			L	D	SO	S	5								F	WD	P
425	Jake O'Brien	Chad Harvey	2017-06-24							R	N/A				G	5			R	D	SO	S	5										
425	Jake O'Brien	Chad Harvey	2017-06-24																														
426	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000426	L	N/A				G	5			L	D	SO	S	5								F	WD	G
426	Jake O'Brien	Chad Harvey	2017-06-24							R	N/A				G	5			R	D	SO	S	5										
426	Jake O'Brien	Chad Harvey	2017-06-24																														
427	Jake O'Brien	Chad Harvey	2017-06-24	A	G	LL	5	Right pole leaning ahead 6"	L170000427	L	3	55	WC	2016	E	5			L	D	SO	S	5								F	ST	E
427	Jake O'Brien	Chad Harvey	2017-06-24							R	3	55	WC	2016	E	5			C	D	SO	S	5										
427	Jake O'Brien	Chad Harvey	2017-06-24																														
428	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000428	L	N/A				G	5			L	D	SO	S	5								F	WD	G
428	Jake O'Brien	Chad Harvey	2017-06-24							R	N/A				G	5			R	D	SO	S	5										
428	Jake O'Brien	Chad Harvey	2017-06-24																														
429	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000429	L	4	50	DF	1968	G	5			L	D	SO	S	5								F	WD	P
429	Jake O'Brien	Chad Harvey	2017-06-24							R	4	50	DF	1968	G	5			R	D	SO	S	5										
429	Jake O'Brien	Chad Harvey	2017-06-24																														
430	Jake O'Brien	Chad Harvey	2017-06-24	A	G	LL	5	Left pole leaning ahead 12"	L170000430	L	4	65	DF	1968	G	5			L	D	SO	S	5								F	WD	P
430	Jake O'Brien	Chad Harvey	2017-06-24							R	4	65	DF	1968	G	5			R	D	SO	S	5										
430	Jake O'Brien	Chad Harvey	2017-06-24																														
431	Jake O'Brien	Chad Harvey	2017-06-24	H DE	G	LL	5	Str leaning ahead 8"	L170000431	L	4	55	DF	1968	G	5			L	D	SO	S	5			1	1	G	4	Installed partial guy guard	L170000431(9)	F	WD	P
431	Jake O'Brien	Chad Harvey	2017-06-24							R	4	55	DF	1968	G	5			R	D	SO	S	5			1	1	G	4	Installed partial guy guard	170000431(10)	B	WD	F
431	Jake O'Brien	Chad Harvey	2017-06-24																														
432	Jake O'Brien	Chad Harvey	2017-06-24	A	G	LL	5	Right pole leaning ahead 10"	L170000432	L	N/A				G	5			L	D	SO	S	5								F	WD	G
432	Jake O'Brien	Chad Harvey	2017-06-24							R	N/A				G	5			R	D	SO	S	5										
432	Jake O'Brien	Chad Harvey	2017-06-24																														
433	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000433	L	2	55	WC	1998	G	5			L	D	SO	S	5								F	WD	P
433	Jake O'Brien	Chad Harvey	2017-06-24							R	2	55	WC	1998	G	5			R	D	SO	S	5										
433	Jake O'Brien	Chad Harvey	2017-06-24																														
434	Jake O'Brien	Chad Harvey	2017-06-24	A	G	LL	5	Left pole leaning ahead 12" right pole le	L170000434	L	N/A				G	5			L	D	SO	S	5								F	WD	G
434	Jake O'Brien	Chad Harvey	2017-06-24							R	N/A				G	5			R	D	SO	S	5										
434	Jake O'Brien	Chad Harvey	2017-06-24																														
435	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000435	L	N/A				G	5			L	D	SO	S	5								F	WD	P
435	Jake O'Brien	Chad Harvey	2017-06-24							R	N/A				G	5			R	D	SO	S	5										
435	Jake O'Brien	Chad Harvey	2017-06-24																														
436	Jake O'Brien	Chad Harvey	2017-06-24	A	G	LL	5	Left pole leaning ahead 14"	L170000436	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	P
436	Jake O'Brien	Chad Harvey	2017-06-24							R	4	55	DF	1968	G	5			R	D	SO	S	5										
436	Jake O'Brien	Chad Harvey	2017-06-24																														
437	Jake O'Brien	Chad Harvey	2017-06-24	H DE	G	G	5		L170000437	L	3	55	WC	2016	E	5			L	D	SO	S	5			1	1	G	5			F	WD	E
437	Jake O'Brien	Chad Harvey	2017-06-24							R	3	55	WC	2016	E	5			R	D	SO	S	5			1	1	G	5					
437	Jake O'Brien	Chad Harvey	2017-06-24																														
438	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000438	L	4	45	DF	1968	G	5			L	D	SO	S	5								F	WD	P
438	Jake O'Brien	Chad Harvey	2017-06-24							R	4	45	DF	1968	G	5			R	D	SO	S	5										
438	Jake O'Brien	Chad Harvey	2017-06-24																														
439	Jake O'Brien	Chad Harvey	2017-06-24	A	G	LL	5	Left pole leaning ahead 6" right pole lea	L170000439	L	N/A				G	5			L	D	SO	S	5								F	WD	F
439	Jake O'Brien	Chad Harvey	2017-06-24							R	N/A				G	5			R	D	SO	S	5										
439	Jake O'Brien	Chad Harvey	2017-06-24																														
440	Jake O'Brien	Chad Harvey	2017-06-24	A	G	LL	5	Left pole leaning ahead 12"	L170000440	L	4	45	DF	1968	G	5			L	D	SO	S	5								F	WD	P
440	Jake O'Brien	Chad Harvey	2017-06-24							C	4	45	DF	1968	G	5			R	D	SO	S	5										
440	Jake O'Brien	Chad Harvey	2017-06-24																														
441	Jake O'Brien	Chad Harvey	2017-06-24	A	G	LD	5	Left pole leaning 10" left	L170000441	L	N/A				F	4	Pole top splitting recommend insta	170000441(6)	L	D	SO	S	5								F	WD	F
441	Jake O'Brien	Chad Harvey	2017-06-24							R	N/A				G	5			R	D	SO	S	5										
441	Jake O'Brien	Chad Harvey	2017-06-24																														
442	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000442	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G
442	Jake O'Brien	Chad Harvey	2017-06-24							R	4	55	DF	1968	G	5			R	D	SO	S	5										
442	Jake O'Brien	Chad Harvey	2017-06-24																														

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443	Jake O'Brien	Chad Harvey	2017-06-24	E	G	G	5		L170000443	L	N/A				G	5			L	D	SO	S	5			1	1	G	5	Missing guy guards	L170000443(5)	F	WD	G
443	Jake O'Brien	Chad Harvey	2017-06-24							C	N/A				G	5			C	D	SO	S	5			2	2	G	5	Missing guy guards	L170000443(5)	B	WD	G
443	Jake O'Brien	Chad Harvey	2017-06-24							R	N/A				G	5			R	D	SO	S	5			1	1	G	5	Missing guy guards	L170000443(6)			
444	Jake O'Brien	Chad Harvey	2017-06-24	DE	G	G	5		L170000444	L	4	50	DF	1968	G	5			L	D	SO	S	5			3	3	G	4	Missing guy guards	L170000444(4)	F	WD	G
444	Jake O'Brien	Chad Harvey	2017-06-24							C	4	50	DF	1968	G	5			C	D	SO	S	5			2	2	G	4	Missing guy guards	L170000444(4)	B	WD	G
444	Jake O'Brien	Chad Harvey	2017-06-24							R	4	50	DF	1968	F	4	Pole top is splitting, recommend in	L170000444(5)	R	D	SO	S	5			2	2	G	4	Missing guy guards	L170000444(4)			
445	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000445	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
445	Jake O'Brien	Chad Harvey	2017-06-24							R	3	55	WC	2016	E	5			R	D	SO	S	5											
445	Jake O'Brien	Chad Harvey	2017-06-24																															
446	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000446	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
446	Jake O'Brien	Chad Harvey	2017-06-24							R	3	55	WC	2016	P	2	1 large WPH at 6' AGL, opens up in	L170000446(8)	R	D	SO	S	5											
446	Jake O'Brien	Chad Harvey	2017-06-24																															
447	Jake O'Brien	Chad Harvey	2017-06-24	A	M	LD	5	Str leaning right 8"	L170000447	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
447	Jake O'Brien	Chad Harvey	2017-06-24							R	3	55	WC	2016	E	5			R	D	SO	S	5											
447	Jake O'Brien	Chad Harvey	2017-06-24																															
448	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000448	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
448	Jake O'Brien	Chad Harvey	2017-06-24							R	4	55	DF	1968	G	5			R	D	SO	S	5											
448	Jake O'Brien	Chad Harvey	2017-06-24																															
449	Jake O'Brien	Chad Harvey	2017-06-24	A	G	LL	5	Str leaning ahead 8"	L170000449	L	N/A				G	5			L	D	SO	S	5									F	WD	P
449	Jake O'Brien	Chad Harvey	2017-06-24							R	N/A				G	5			R	D	SO	S	5											
449	Jake O'Brien	Chad Harvey	2017-06-24																															
450	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000450	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
450	Jake O'Brien	Chad Harvey	2017-06-24							R	3	55	WC	2016	E	5			R	D	SO	S	5											
450	Jake O'Brien	Chad Harvey	2017-06-24																															
451	Jake O'Brien	Chad Harvey	2017-06-24	A	G	LD	5	Str leaning 6" right	L170000451	L	N/A				G	5	2 Small WPH upper pole	L170000451(5)	L	D	SO	S	5									F	WD	G
451	Jake O'Brien	Chad Harvey	2017-06-24							R	N/A				G	5			R	D	SO	S	5											
451	Jake O'Brien	Chad Harvey	2017-06-24																															
452	Jake O'Brien	Chad Harvey	2017-06-24	A	G	LD	5	Str leaning 6" right	L170000452	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	F
452	Jake O'Brien	Chad Harvey	2017-06-24							R	4	50	DF	1968	G	5			R	D	SO	S	5											
452	Jake O'Brien	Chad Harvey	2017-06-24																															
453	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000453	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
453	Jake O'Brien	Chad Harvey	2017-06-24							R	4	55	DF	1968	G	5			R	D	SO	S	5											
453	Jake O'Brien	Chad Harvey	2017-06-24																															
454	Jake O'Brien	Chad Harvey	2017-06-24	E	G	G	5		L170000454	L	3	60	WC	2016	E	5	1 Small WPH at 4' AGL		L	D	SO	S	5			1	1	G	5			F	WD	E
454	Jake O'Brien	Chad Harvey	2017-06-24							C	3	60	WC	2016	E	5	1 Small WPH at gain tag		C	D	SO	S	5			2	2	G	5			B	WD	E
454	Jake O'Brien	Chad Harvey	2017-06-24							R	3	60	WC	2016	E	5	1 Med WPH at gain tag		R	D	SO	S	5			1	1	G	5					
455	Jake O'Brien	Chad Harvey	2017-06-24	A	G	LL	5	Left pole leaning ahead 6"	L170000455	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	P
455	Jake O'Brien	Chad Harvey	2017-06-24							R	4	50	DF	1968	G	5			R	D	SO	S	5											
455	Jake O'Brien	Chad Harvey	2017-06-24																															
456	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000456	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
456	Jake O'Brien	Chad Harvey	2017-06-24							R	4	55	DF	1968	G	5			R	D	SO	S	5											
456	Jake O'Brien	Chad Harvey	2017-06-24																															
457	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000457	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
457	Jake O'Brien	Chad Harvey	2017-06-24							R	4	55	DF	1968	G	5			R	D	SO	S	5											
457	Jake O'Brien	Chad Harvey	2017-06-24																															
458	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000458	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
458	Jake O'Brien	Chad Harvey	2017-06-24							R	3	55	WC	2016	E	5			R	D	SO	S	5											
458	Jake O'Brien	Chad Harvey	2017-06-24																															
459	Jake O'Brien	Chad Harvey	2017-06-24	A	G	G	5		L170000459	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
459	Jake O'Brien	Chad Harvey	2017-06-24							R	3	55	WC	2016	E	5			R	D	SO	S	5											
459	Jake O'Brien	Chad Harvey	2017-06-24																															
460	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000460	L	3	60	WC	2016	E	5	1 Small WPH at 4' AGL	L170000460(5)	L	D	SO	S	5									F	ST	E
460	Jake O'Brien	Chad Harvey	2017-06-25							R	3	60	WC	2016	E	5			R	D	SO	S	5											
460	Jake O'Brien	Chad Harvey	2017-06-25																															
461	Jake O'Brien	Chad Harvey	2017-06-25	F	G	G	5		L170000461	L	N/A				G	5			L	D	SO	S	5									F	WD	G
461	Jake O'Brien	Chad Harvey	2017-06-25							R	N/A				G	5	1 Small WPH at pole top	L170000461(5)	R	D	SO	S	5									B	WD	G

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461	Jake O'Brien	Chad Harvey	2017-06-25																														
462	Jake O'Brien	Chad Harvey	2017-06-25	F	G	G	5		L170000462	L	3	65	WC	2016	E	5			L	D	SO	S	5									F	WD	E
462	Jake O'Brien	Chad Harvey	2017-06-25							R	3	65	WC	2016	E	5	5 Small WPH mid pole	L170000462(6)	R	D	SO	S	5									B	WD	E
462	Jake O'Brien	Chad Harvey	2017-06-25																														
463	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000463	L	N/A				F	5	Weathered pole top	L170000463(7)	L	D	SO	S	5									F	WD	P
463	Jake O'Brien	Chad Harvey	2017-06-25							R	N/A				F	5	Weathered pole top	L170000463(7)	R	D	SO	S	5											
463	Jake O'Brien	Chad Harvey	2017-06-25																														
464	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000464	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
464	Jake O'Brien	Chad Harvey	2017-06-25							R	4	55	DF	1968	G	5			R	D	SO	S	5											
464	Jake O'Brien	Chad Harvey	2017-06-25																														
465	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000465	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
465	Jake O'Brien	Chad Harvey	2017-06-25							R	4	55	DF	1968	G	5			R	D	SO	S	5											
465	Jake O'Brien	Chad Harvey	2017-06-25																														
466	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000466	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
466	Jake O'Brien	Chad Harvey	2017-06-25							R	3	55	WC	2016	E	5			R	D	SO	S	5											
466	Jake O'Brien	Chad Harvey	2017-06-25																														
467	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000467	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
467	Jake O'Brien	Chad Harvey	2017-06-25							R	3	55	WC	2016	E	5			R	D	SO	S	5			1	1	G	5					
467	Jake O'Brien	Chad Harvey	2017-06-25																														
468	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000468	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
468	Jake O'Brien	Chad Harvey	2017-06-25							R	3	55	WC	2016	E	5			R	D	SO	S	5											
468	Jake O'Brien	Chad Harvey	2017-06-25																														
469	Jake O'Brien	Chad Harvey	2017-06-25	A	G	LD	5	Left pole leaning 6" left	L170000469	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
469	Jake O'Brien	Chad Harvey	2017-06-25							R	3	55	WC	2016	E	5			R	D	SO	S	5											
469	Jake O'Brien	Chad Harvey	2017-06-25																														
470	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000470	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
470	Jake O'Brien	Chad Harvey	2017-06-25							R	3	55	WC	2016	E	5			R	D	SO	S	5			1	1	G	5					
470	Jake O'Brien	Chad Harvey	2017-06-25																														
471	Jake O'Brien	Chad Harvey	2017-06-25	A	G	LD	5	Str is leaning 8" right	L170000471	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	E
471	Jake O'Brien	Chad Harvey	2017-06-25							R	4	55	DF	1968	G	5			R	D	SO	S	5											
471	Jake O'Brien	Chad Harvey	2017-06-25																														
472	Jake O'Brien	Chad Harvey	2017-06-25	H DE	G	LD	5		L170000472	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
472	Jake O'Brien	Chad Harvey	2017-06-25							R	3	55	WC	2016	E	5			R	D	SO	S	5											
472	Jake O'Brien	Chad Harvey	2017-06-25																														
473	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000473	L	N/A				G	5			L	D	SO	S	5									F	WD	F
473	Jake O'Brien	Chad Harvey	2017-06-25							R	N/A				F	4	Pole top is splitting	L170000473(7)	R	D	SO	S	5											
473	Jake O'Brien	Chad Harvey	2017-06-25																														
474	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000474	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
474	Jake O'Brien	Chad Harvey	2017-06-25							R	3	55	WC	2016	E	5			R	D	SO	S	5			1	1	G	5					
474	Jake O'Brien	Chad Harvey	2017-06-25																														
475	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000475	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
475	Jake O'Brien	Chad Harvey	2017-06-25							R	3	55	WC	2016	E	5			R	D	SO	S	5											
475	Jake O'Brien	Chad Harvey	2017-06-25																														
476	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000476	L	3	55	WC	2016	E	5			L	D	SO	S	5									F	ST	E
476	Jake O'Brien	Chad Harvey	2017-06-25							R	3	55	WC	2016	E	5			R	D	SO	S	5											
476	Jake O'Brien	Chad Harvey	2017-06-25																														
477	Jake O'Brien	Chad Harvey	2017-06-25	E	G	G	5		L170000477	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	F
477	Jake O'Brien	Chad Harvey	2017-06-25							C	4	50	DF	1968	G	5			R	D	SO	S	5									B	WD	F
477	Jake O'Brien	Chad Harvey	2017-06-25							R	4	50	DF	1968	G	5										1	1	G	5	Missing guy guard on stub	L170000477(5)			
478	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000478	L	N/A				G	5			L	D	SO	S	5									F	WD	G
478	Jake O'Brien	Chad Harvey	2017-06-25							R	N/A				G	5			R	D	SO	S	5											
478	Jake O'Brien	Chad Harvey	2017-06-25																														
479	Jake O'Brien	Chad Harvey	2017-06-25	F	G	G	5		L170000479	L	3	60	WC	2016	E	5			L	D	SO	S	5									F	WD	E
479	Jake O'Brien	Chad Harvey	2017-06-25							R	3	60	WC	2016	E	5			R	D	SO	S	5									B	WD	E
479	Jake O'Brien	Chad Harvey	2017-06-25																														
480	Jake O'Brien	Chad Harvey	2017-06-25	F	G	LD	5	Str leaning 8" right	L170000480	L	4	65	DF	1968	G	5			L	D	SO	S	5									F	WD	G

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480	Jake O'Brien	Chad Harvey	2017-06-25							R	4	65	DF	1968	G	5	4 small WPH from 20' AGL to pole	L170000480(7)	R	D	SO	S	5									B	WD	G
480	Jake O'Brien	Chad Harvey	2017-06-25																														
481	Jake O'Brien	Chad Harvey	2017-06-25	H DE S	G	LL/LD	5	Str is leaning 8" right and 6" ahead	L170000481	L	2	65	WC	2000	G	5	1 med WPH at 22' AGL	L170000481(5)	L	D	SO	S	5			2	2	G	5			F	WD	G
481	Jake O'Brien	Chad Harvey	2017-06-25							R	2	65	WC	2000	G	5	WP damage in checking at 15' AGL	L170000481(6)	R	D	SO	S	5			2	2	G	5			B	WD	G
481	Jake O'Brien	Chad Harvey	2017-06-25																														
482	Jake O'Brien	Chad Harvey	2017-06-25	A	G	LD	5	Str leaning 16" right	L170000482	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
482	Jake O'Brien	Chad Harvey	2017-06-25							R	4	55	DF	1968	G	5			R	D	SO	S	5											
482	Jake O'Brien	Chad Harvey	2017-06-25																														
483	Jake O'Brien	Chad Harvey	2017-06-25	A	G	LD	5	Str leaning 8" right	L170000483	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
483	Jake O'Brien	Chad Harvey	2017-06-25							R	4	55	DF	1968	G	5			R	D	SO	S	5											
483	Jake O'Brien	Chad Harvey	2017-06-25																														
484	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000484	L	3	55	WC	2014	P	2	Large WPH with bird living inside 4	L710000484(6)	L	D	SO	S	5									F	ST	E
484	Jake O'Brien	Chad Harvey	2017-06-25							R	3	55	WC	2014	E	5			R	D	SO	S	5											
484	Jake O'Brien	Chad Harvey	2017-06-25																														
485	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000485	L	3	55	WC	2014	E	5			L	D	SO	S	5									F	ST	E
485	Jake O'Brien	Chad Harvey	2017-06-25							R	3	55	WC	2014	E	5			C	D	SO	S	5											
485	Jake O'Brien	Chad Harvey	2017-06-25																														
486	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000486	L	2	55	LP	2014	E	5			L	D	SO	S	5									F	ST	E
486	Jake O'Brien	Chad Harvey	2017-06-25							R	2	55	LP	2014	E	5			R	D	SO	S	5											
486	Jake O'Brien	Chad Harvey	2017-06-25																														
487	Jake O'Brien	Chad Harvey	2017-06-25	A	G	LD	5	Str leaning 6" right	L170000487	L	N/A				G	5			L	D	SO	S	5									F	WD	P
487	Jake O'Brien	Chad Harvey	2017-06-25							R	N/A				G	5			R	D	SO	S	5											
487	Jake O'Brien	Chad Harvey	2017-06-25																														
488	Jake O'Brien	Chad Harvey	2017-06-25	A	G	LD	5	Str leaning 6" right	L170000488	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
488	Jake O'Brien	Chad Harvey	2017-06-25							R	4	50	DF	1968	G	5			R	D	SO	S	5											
488	Jake O'Brien	Chad Harvey	2017-06-25																														
489	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000489	L	N/A				G	5			L	D	SO	S	5									F	WD	P
489	Jake O'Brien	Chad Harvey	2017-06-25							R	N/A				G	5			R	D	SO	S	5											
489	Jake O'Brien	Chad Harvey	2017-06-25																														
490	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000490	L	2	55	LP	2014	E	5			L	D	SO	S	5									F	ST	E
490	Jake O'Brien	Chad Harvey	2017-06-25							R	2	55	LP	2014	E	5			R	D	SO	S	5											
490	Jake O'Brien	Chad Harvey	2017-06-25																														
491	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000491	L	2	60	WC	2013	E	5			L	D	SO	S	5									F	ST	E
491	Jake O'Brien	Chad Harvey	2017-06-25							R	2	60	WC	2015	E	5			R	D	SO	S	5											
491	Jake O'Brien	Chad Harvey	2017-06-25																														
492	Jake O'Brien	Chad Harvey	2017-06-25	E	G	G	5		L170000492	L	3	65	WC	2016	E	5			L	D	SO	S	5									F	ST	E
492	Jake O'Brien	Chad Harvey	2017-06-25							C	3	65	WC	2016	E	5			C	D	SO	S	5											
492	Jake O'Brien	Chad Harvey	2017-06-25							R	3	65	WC	2016	E	5			R	D	SO	S	5			2	2	G	5					
493	Jake O'Brien	Chad Harvey	2017-06-25	A	G	LL/LD	5	Right pole leaning 8" right, and 8" back	L170000493	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
493	Jake O'Brien	Chad Harvey	2017-06-25							C	4	55	DF	1968	G	5			R	D	SO	S	5											
493	Jake O'Brien	Chad Harvey	2017-06-25																														
494	Jake O'Brien	Chad Harvey	2017-06-25	A	G	LL/LD	5	Str leaning 10" left 6" back	L170000494	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
494	Jake O'Brien	Chad Harvey	2017-06-25							R	4	50	DF	1968	G	5			R	D	SO	S	5											
494	Jake O'Brien	Chad Harvey	2017-06-25																														
495	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000495	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
495	Jake O'Brien	Chad Harvey	2017-06-25							R	4	50	DF	1968	G	5			R	D	SO	S	5											
495	Jake O'Brien	Chad Harvey	2017-06-25																														
496	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000496	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
496	Jake O'Brien	Chad Harvey	2017-06-25							R	4	50	DF	1968	G	5			R	D	SO	S	5											
496	Jake O'Brien	Chad Harvey	2017-06-25																														
497	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000497	L	3	55	WC	2015	E	5			L	D	SO	S	5									F	ST	E
497	Jake O'Brien	Chad Harvey	2017-06-25							C	3	55	WC	2015	E	5			R	D	SO	S	5											
497	Jake O'Brien	Chad Harvey	2017-06-25																														
498	Jake O'Brien	Chad Harvey	2017-06-25	A	G	LL/LD	5	Left pole leaning 6" right and back, right	L170000498	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
498	Jake O'Brien	Chad Harvey	2017-06-25							R	4	50	DF	1968	G	5			R	D	SO	S	5											
498	Jake O'Brien	Chad Harvey	2017-06-25																														

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499	Jake O'Brien	Chad Harvey	2017-06-25	A	G	G	5		L170000499	L	4	45	DF	1968	G	5			L	D	SO	S	5									F	WD	G
499	Jake O'Brien	Chad Harvey	2017-06-25							R	4	45	DF	1968	G	5			R	D	SO	S	5											
499	Jake O'Brien	Chad Harvey	2017-06-25																														
500	Jake O'Brien	Chad Harvey	2017-06-26	A	G	LD	5	Str leaning 6" right	L170000500	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
500	Jake O'Brien	Chad Harvey	2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5											
500	Jake O'Brien	Chad Harvey	2017-06-26																														
501	Jake O'Brien	Chad Harvey	2017-06-26	A	G	G	5		L170000501	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
501	Jake O'Brien	Chad Harvey	2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5											
501	Jake O'Brien	Chad Harvey	2017-06-26																														
502	Jake O'Brien	Chad Harvey	2017-06-26	A	G	G	5		L170000502	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
502	Jake O'Brien	Chad Harvey	2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5											
502	Jake O'Brien	Chad Harvey	2017-06-26																														
503	Jake O'Brien	Chad Harvey	2017-06-26	E	G	G	5		L170000503	L	3	60	WC	2016	E	5			L	D	SO	S	5			1	1	G	5			F	WD	E
503	Jake O'Brien	Chad Harvey	2017-06-26							C	3	60	WC	2016	E	5	1 Small WPH at 15' AgL	L170000503(5)	C	D	SO	S	5			2	2	G	5			B	WD	E
503	Jake O'Brien	Chad Harvey	2017-06-26							R	3	60	WC	2016	E	5			R	D	SO	S	5			1	1	G	5					
504	Jake O'Brien	Chad Harvey	2017-06-26	A	G	LL	5	Left pole leaning back 10"	L170000504	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
504	Jake O'Brien	Chad Harvey	2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5											
504	Jake O'Brien	Chad Harvey	2017-06-26																														
505	Jake O'Brien	Chad Harvey	2017-06-26	A	G	G	5		L170000505	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
505	Jake O'Brien	Chad Harvey	2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5											
505	Jake O'Brien	Chad Harvey	2017-06-26																														
506	Jake O'Brien	Chad Harvey	2017-06-26	H DE	G	G	5		L170000506	L	4	55	DF	1968	F	4	1 Large WPH at pole top 11 small t	L170000506(9)	L	D	SO	S	5			1	1	G	4	Missing guy guard	L170000506(5)	F	WD	G
506	Jake O'Brien	Chad Harvey	2017-06-26							R	4	55	DF	1968	F	4	2 Med WPH mid pole	L70000506(10)	R	D	SO	S	5			1	1	G	4	Missing guy guard	L170000506(6)	B	WD	G
506	Jake O'Brien	Chad Harvey	2017-06-26																														
507	Jake O'Brien	Chad Harvey	2017-06-26	A	G	G	5		L170000507	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
507	Jake O'Brien	Chad Harvey	2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5									B	WD	F
507	Jake O'Brien	Chad Harvey	2017-06-26																														
508	Jake O'Brien	Chad Harvey	2017-06-26	H DE	G	G	5		L170000508	L	4	50	DF	1968	G	5			L	D	SO	S	5			1	1	G	5			F	WD	G
508	Jake O'Brien	Chad Harvey	2017-06-26							R	4	50	DF	1968	G	5			R	D	SO	S	5			1	1	G	5			B	WD	G
508	Jake O'Brien	Chad Harvey	2017-06-26																														
509	Jake O'Brien	Chad Harvey	2017-06-26	A	G	G	5		L170000509	L	3	60	WC	2016	E	5			L	D	SO	S	5									F	ST	E
509	Jake O'Brien	Chad Harvey	2017-06-26							R	3	60	WC	2016	E	5			R	D	SO	S	5											
509	Jake O'Brien	Chad Harvey	2017-06-26																														
510	Jake O'Brien	Chad Harvey	2017-06-26	A	G	G	5		L170000510	L	2	60	WC	2016	E	5			L	D	SO	S	5									F	ST	E
510	Jake O'Brien	Chad Harvey	2017-06-26							R	2	60	WC	2016	E	5			R	D	SO	S	5											
510	Jake O'Brien	Chad Harvey	2017-06-26																														
511	Jake O'Brien	Chad Harvey	2017-06-26	A	G	G	5		L170000511	L	2	60	WC	2016	E	5			L	C	RO	S	5									F	ST	E
511	Jake O'Brien	Chad Harvey	2017-06-26							R	2	60	WC	2016	E	5			R	C	RO	S	5											
511	Jake O'Brien	Chad Harvey	2017-06-26																														
512	Jake O'Brien	Chad Harvey	2017-06-26	A	G	G	5		L170000512	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
512	Jake O'Brien	Chad Harvey	2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5											
512	Jake O'Brien	Chad Harvey	2017-06-26																														
513	Jake O'Brien	Chad Harvey	2017-06-26	A	G	G	5		L170000513	L	N/A				G	5			L	D	SO	S	5									F	WD	G
513	Jake O'Brien	Chad Harvey	2017-06-26							R	N/A				G	5			R	D	SO	S	5											
513	Jake O'Brien	Chad Harvey	2017-06-26																														
514	Jake O'Brien	Chad Harvey	2017-06-26	AXS	G	G	5		L170000514	L	4	55	DF	1968	G	5			L	D	RO	S	5									F	WD	F
514	Jake O'Brien	Chad Harvey	2017-06-26							R	4	50	DF	1968	G	5			R	D	RO	S	5									B	WD	F
514	Jake O'Brien	Chad Harvey	2017-06-26																														
515	Jake O'Brien	Chad Harvey	2017-06-26	AXS	G	G	5		L170000515	L	N/A				G	5	5 small WPH at 20' Agl	L170000515(5)	L	D	SO	S	5									F	WD	G
515	Jake O'Brien	Chad Harvey	2017-06-26							R	N/A				G	5	2 Small WPH at pole top	L170000515(6)	R	D	SO	S	5									B	WD	G
515	Jake O'Brien	Chad Harvey	2017-06-26																														
516	Jake O'Brien	Chad Harvey	2017-06-26	E	G	G	5		L170000516	L	N/A				G	5			L	D	SO	S	5			1	1	G	4	Missing guy guards		F	WD	G
516	Jake O'Brien	Chad Harvey	2017-06-26							C	N/A				G	5			C	D	SO	S	5			2	2	G	4	Missing guy guards		B	WD	G
516	Jake O'Brien	Chad Harvey	2017-06-26							R	N/A				F	4	1 Large WPH mid pole	L710000516(5)	R	D	SO	S	5			1	1	G	4	Missing guy guards				
517	Jake O'Brien	Chad Harvey	2017-06-26	A	G	G	5		L170000517	L	4	65	DF	1968	G	5			L	D	SO	S	5									F	WD	F
517	Jake O'Brien	Chad Harvey	2017-06-26							R	4	65	DF	1968	G	5			R	D	SO	S	5											

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517	Jake O'Brien	Chad Harvey	2017-06-26																														
518	Jake O'Brien	Chad Harvey	2017-06-26	A	G	G	5		L170000518	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	P
518	Jake O'Brien	Chad Harvey	2017-06-26							R	4	60	DF	1968	P	3	1 Large WPH at arm	L170000518(5)	R	D	SO	S	5											
518	Jake O'Brien	Chad Harvey	2017-06-26																														
519	Jake O'Brien	Chad Harvey	2017-06-26	A	G	G	5		L170000519	L	4	65	DF	1968	G	4	Pole top splitting, recommend installing anti split		L	D	SO	S	5									F	WD	G
519	Jake O'Brien	Chad Harvey	2017-06-26							R	4	65	DF	1968	G	5			R	D	SO	S	5											
519	Jake O'Brien	Chad Harvey	2017-06-26																														
520	Jake O'Brien	Chad Harvey	2017-06-26	A	G	G	5		L170000520	L	N/A				F	4	1 med WPH at bottom sway	L170000520(5)	L	D	SO	S	5									F	WD	F
520	Jake O'Brien	Chad Harvey	2017-06-26							R	N/A				G	5			R	D	SO	S	5									B	WD	F
520	Jake O'Brien	Chad Harvey	2017-06-26																														
521	Jake O'Brien	Chad Harvey	2017-06-26	H DE	G	G	5		L170000521	L	3	50	WC	2016	E	5			L	D	SO	S	5			1	1	G	4	Missing guy guards	L170000521(5)	F	WD	E
521	Jake O'Brien	Chad Harvey	2017-06-26							R	3	50	WC	2016	E	5			R	D	SO	S	5			1	1	G	4	Missing guy guards	L170000521(6)	B	WD	E
521	Jake O'Brien	Chad Harvey	2017-06-26																														
522	Jake O'Brien	Chad Harvey	2017-06-26	AXS	G	LL	5	Left pole leaning back 6"	L170000522	L	N/A				G	5			L	D	SO	S	5									F	WD	G
522	Jake O'Brien	Chad Harvey	2017-06-26							R	N/A				G	5			R	D	SO	S	5									B	WD	F
522	Jake O'Brien	Chad Harvey	2017-06-26																														
523	Jake O'Brien	Chad Harvey	2017-06-26	AXS	G	LL/LD	5	Str leaning left 12" left pole leaning ahe	L170000523	L	N/A				G	5			L	D	SO	S	5									F	WD	G
523	Jake O'Brien	Chad Harvey	2017-06-26							R	N/A				G	5			R	D	SO	S	5									B	WD	F
523	Jake O'Brien	Chad Harvey	2017-06-26																														
524	Jake O'Brien	Chad Harvey	2017-06-26	H DE	G	G	5		L170000524	L	3	50	WC	2016	E	5			L	D	SO	S	5			1	1	G	4	Loose		F	WD	E
524	Jake O'Brien	Chad Harvey	2017-06-26							R	3	50	WC	2016	E	5			R	D	SO	S	5			1	1	G	4	Loose				
524	Jake O'Brien	Chad Harvey	2017-06-26																														
525	Jake O'Brien	Chad Harvey	2017-06-26	F	G	G	5		L170000525	L	N/A				G	5	1 Small WPH mid pole	L170000525(8)	L	D	SO	S	5									F	WD	G
525	Jake O'Brien	Chad Harvey	2017-06-26							R	N/A				F	4	5 Small WPH mid pole 1 med WPH	L170000525(7)	R	D	SO	S	5									B	WD	G
525	Jake O'Brien	Chad Harvey	2017-06-26																														
526	Jake O'Brien	Chad Harvey	2017-06-26	F	G	G	5		L170000526	L	4	65	DF	1968	G	5	2 Med WPH mid pole, 1 small WPH	L170000526(5)	L	D	SO	S	5									F	WD	G
526	Jake O'Brien	Chad Harvey	2017-06-26							R	4	65	DF	1968	G	5			R	D	SO	S	5									B	WD	G
526	Jake O'Brien	Chad Harvey	2017-06-26																														
527	Jake O'Brien	Chad Harvey	2017-06-26	A	G	LL	5	Str leaning ahead 12"	L170000527	L	4	60	DF	1968	G	5	1 small WPH mid pole	L170000527(7)	L	D	SO	S	5									F	WD	G
527	Jake O'Brien	Chad Harvey	2017-06-26							R	4	60	DF	1968	G	5	2 large WPH mid pole 1 small WPH	L170000527(6)	R	D	SO	S	5											
527	Jake O'Brien	Chad Harvey	2017-06-26																														
528	Jake O'Brien	Chad Harvey	2017-06-26	H DE	G	LD	5	Left pole leaning 8" left	L170000528	L	N/A				G	5			L	D	SO	S	5			1	1	G	5	Missing guy guard	L170000528(5)	F	WD	G
528	Jake O'Brien	Chad Harvey	2017-06-26							R	N/A				G	5			R	D	SO	S	5			1	1	G	5	Missing guy guard	L170000528(6)	B	WD	G
528	Jake O'Brien	Chad Harvey	2017-06-26																														
529	Jake O'Brien	Chad Harvey	2017-06-26	E	G	G	5		L170000529	L	4	50	DF	1968	G	5			L	D	SO	S	5			1	1	G	5	Missing guy guard	L170000529(5)	F	WD	G
529	Jake O'Brien	Chad Harvey	2017-06-26							C	4	50	DF	1968	G	5			C	D	SO	S	5			2	2	G	5	Missing guy guard	L170000529(5)	B	WD	G
529	Jake O'Brien	Chad Harvey	2017-06-26							R	4	50	DF	1968	G	5			R	D	SO	S	5			1	1	G	5	Missing guy guard	L170000529(5)			
530	Jake O'Brien	Chad Harvey	2017-06-26	A	G	G	5		L170000530	L	N/A				G	5			L	D	SO	S	5									F	WD	G
530	Jake O'Brien	Chad Harvey	2017-06-26							R	N/A				G	5			R	D	SO	S	5											
530	Jake O'Brien	Chad Harvey	2017-06-26																														
531	Jake O'Brien	Chad Harvey	2017-06-26	AXS	G	G	5		L170000531	L	N/A				G	5	Insect damage	L170000531(5)	L	D	SO	S	5									F	WD	F
531	Jake O'Brien	Chad Harvey	2017-06-26							R	N/A				G	5			R	D	SO	S	5									B	WD	P
531	Jake O'Brien	Chad Harvey	2017-06-26																														
532	Jake O'Brien	Chad Harvey	2017-06-26	AXS	G	LD	5	Str leaning 6" left	L170000532	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
532	Jake O'Brien	Chad Harvey	2017-06-26							R	4	50	DF	1968	F	4	Checking from 6' AGL to pole top r	L170000532(5)	R	D	SO	S	5									B	WD	P
532	Jake O'Brien	Chad Harvey	2017-06-26																														
533	Jake O'Brien	Chad Harvey	2017-06-27	AXS	G	LL	5	Str leaning ahead 8"	L170000533	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
533	Jake O'Brien	Chad Harvey	2017-06-27							R	4	50	DF	1968	G	5			R	D	SO	S	5									B	WD	G
533	Jake O'Brien	Chad Harvey	2017-06-27																														
534	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000534	L	2	55	WC	1998	G	5			L	D	SO	S	5									F	WD	P
534	Jake O'Brien	Chad Harvey	2017-06-27							R	2	55	WC	1998	G	5			R	D	SO	S	5											
534	Jake O'Brien	Chad Harvey	2017-06-27																														
534	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000534	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	G
534	Jake O'Brien	Chad Harvey	2017-06-27							R	4	60	DF	1968	F	4	2 Med WPH mid pole 1 large WPH	L170000534(6)	R	D	SO	S	5											
534	Jake O'Brien	Chad Harvey	2017-06-27																														
535	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000535	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	F

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535	Jake O'Brien	Chad Harvey	2017-06-27							R	4	50	DF	1968	G	5			R	D	SO	S	5										
535	Jake O'Brien	Chad Harvey	2017-06-27																														
536	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000536	L	N/A				G	5			L	D	SO	S	5								F	WD	P
536	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				G	5			R	D	SO	S	5										
536	Jake O'Brien	Chad Harvey	2017-06-27																														
537	Jake O'Brien	Chad Harvey	2017-06-27	A	G	LL	5	Str leaning ahead 10"	L170000537	L	4	50	DF	1968	G	5			L	D	SO	S	5								F	WD	F
537	Jake O'Brien	Chad Harvey	2017-06-27							R	4	50	DF	1968	G	5			R	D	SO	S	5										
537	Jake O'Brien	Chad Harvey	2017-06-27																														
538	Jake O'Brien	Chad Harvey	2017-06-27	A	G	LL	5		L170000538	L	N/A				G	5			L	D	SO	S	5								F	WD	F
538	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				G	5			R	D	SO	S	5										
538	Jake O'Brien	Chad Harvey	2017-06-27																														
539	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000539	L	N/A				G	5			L	D	SO	S	5								F	WD	G
539	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				G	5			R	D	SO	S	5										
539	Jake O'Brien	Chad Harvey	2017-06-27																														
540	Jake O'Brien	Chad Harvey	2017-06-27	E	G	G	5		L170000540	L	4	55	DF	1968	G	5			L	D	SO	S	5			1	1	G	4	Missing guy guard		F	WD	G
540	Jake O'Brien	Chad Harvey	2017-06-27							C	4	55	DF	1968	G	5			C	D	SO	S	5										
540	Jake O'Brien	Chad Harvey	2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5										
541	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000541	L	4	55	DF	1968	G	5	2 Med WPH midpole to pole top at	L170000541(5)	L	D	SO	S	5								F	WD	G
541	Jake O'Brien	Chad Harvey	2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5										
541	Jake O'Brien	Chad Harvey	2017-06-27																														
542	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000542	L	4	50	DF	1968	G	5			L	D	SO	S	5								F	WD	G
542	Jake O'Brien	Chad Harvey	2017-06-27							R	4	50	DF	1968	G	5			R	D	SO	S	5										
542	Jake O'Brien	Chad Harvey	2017-06-27																														
543	Jake O'Brien	Chad Harvey	2017-06-27	F	G	G	5		L170000543	L	N/A				F	4	3 Med WPH mid pole, 2 Small WPH	L170000543(6)	L	D	SO	S	5								F	WD	G
543	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				F	4	1 med WPH mid pole	L170000543(7)	R	D	SO	S	5								B	WD	G
543	Jake O'Brien	Chad Harvey	2017-06-27																														
544	Jake O'Brien	Chad Harvey	2017-06-27	F	G	G	5		L170000544	L	N/A				G	4	WPH 2 med, 1 small mid pole and	L170000544(6)	L	D	SO	S	5								F	WD	G
544	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				P	3	WPH: 2 med at 20' AGL, 1 small at	L170000544(10)	R	D	SO	S	5								B	WD	G
544	Jake O'Brien	Chad Harvey	2017-06-27																														
545	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000545	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G
545	Jake O'Brien	Chad Harvey	2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5										
545	Jake O'Brien	Chad Harvey	2017-06-27																														
546	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000546	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G
546	Jake O'Brien	Chad Harvey	2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5										
546	Jake O'Brien	Chad Harvey	2017-06-27																														
547	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000547	L	4	60	DF	1968	F	4	WPH: 4 Large, 4 med, 2 small throu	L170000547(8)	L	D	SO	S	5								F	WD	G
547	Jake O'Brien	Chad Harvey	2017-06-27							R	4	60	DF	1968	F	4	WPH: 2 med, 1 small, mid pole	L70000547(10)	R	D	SO	S	5										
547	Jake O'Brien	Chad Harvey	2017-06-27																														
548	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000548	L	3	55	DF	1968	G	5	1 sm WPH mid pole	l170000548(5)	L	D	SO	S	5								F	WD	G
548	Jake O'Brien	Chad Harvey	2017-06-27							R	3	55	DF	1968	G	5			R	D	SO	S	5										
548	Jake O'Brien	Chad Harvey	2017-06-27																														
549	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000549	L	N/A				G	4	WPH: 1 med at pole top, 1 small at	L170000549(6)	L	D	SO	S	5								F	WD	P
549	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				F	4	3 Large WPH 6' AGL	L170000549(7)	R	D	SO	S	5										
549	Jake O'Brien	Chad Harvey	2017-06-27																														
550	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000550	L	4	50	DF	1968	G	5	2 Small WPH mid pole and pole to	L170000550(6)	L	D	SO	S	5								F	WD	G
550	Jake O'Brien	Chad Harvey	2017-06-27							R	4	50	DF	1968	G	5			R	D	SO	S	5										
550	Jake O'Brien	Chad Harvey	2017-06-27																														
551	Jake O'Brien	Chad Harvey	2017-06-27	A	G	LD	5	Str is leaning 6" left	L170000551	L	4	50	DF	1968	G	5	1 sm WPH at pole top	L170000551(5)	L	D	SO	S	5								F	WD	G
551	Jake O'Brien	Chad Harvey	2017-06-27							R	4	50	DF	1968	G	5			R	D	SO	S	5										
551	Jake O'Brien	Chad Harvey	2017-06-27																														
552	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000552	L	4	50	DF	1968	G	5	2 Small WPH mid pole and pole to	L170000552(6)	L	D	SO	S	5								F	WD	P
552	Jake O'Brien	Chad Harvey	2017-06-27							R	4	50	DF	1968	G	5	1 Small WPH at bottom sway	L170000552(7)	R	D	SO	S	5										
552	Jake O'Brien	Chad Harvey	2017-06-27																														
553	Jake O'Brien	Chad Harvey	2017-06-27	E	G	G	5		L170000553	L	N/A				G	5	1 Small WPH at pole top	L170000553(7)	L	D	SO	S	5								F	WD	G
553	Jake O'Brien	Chad Harvey	2017-06-27							C	N/A				P	2	1 large and 1 small SPH at same ele	L170000553(6)	R	D	SO	S	5								B	WD	G
553	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				G	5	1 Med SPH 8' AGL	L170000553(8)								1	1	G	4	Missing guy guard	L170000553(9)			

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554	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000554	L	N/A				G	5	2 Med WPH mid pole and at groun	L170000554(7)	L	D	SO	S	5			1	1	G	4	Missing guy guard	L170000554(5)	F	WD	G
554	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				G	5			R	D	SO	S	5			1	1	G	4	Missing guy guard	L170000554(5)			
554	Jake O'Brien	Chad Harvey	2017-06-27																														
555	Jake O'Brien	Chad Harvey	2017-06-27	A	M	LL	5	Str leaning ahead 10"	L170000555	L	N/A				P	2	2 Major WP damage 6' below pole	L170000555(8)	L	D	SO	S	5									F	WD	G
555	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				G	5	1 small WPH at bottom sway		R	D	SO	S	5											
555	Jake O'Brien	Chad Harvey	2017-06-27																														
556	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000556	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
556	Jake O'Brien	Chad Harvey	2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5											
556	Jake O'Brien	Chad Harvey	2017-06-27																														
557	Jake O'Brien	Chad Harvey	2017-06-27	A	G	LL	5	Str leaning ahead 10"	L170000557	L	N/A				G	5			L	D	SO	S	5									F	WD	G
557	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				G	5			R	D	SO	S	5											
557	Jake O'Brien	Chad Harvey	2017-06-27																														
558	Jake O'Brien	Chad Harvey	2017-06-27	AXS	G	LD	5	Str leaning 6" left	L170000558	L	N/A				G	5			L	D	RO	S	5									F	WD	F
558	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				G	5			C	D	RO	S	5											
558	Jake O'Brien	Chad Harvey	2017-06-27																R	D	RO	S	5											
559	Jake O'Brien	Chad Harvey	2017-06-27	AXS	G	G	5		L170000559	L	N/A				G	5	3 Small WPH mid pole	170000559(10)	L	D	SO	S	5									F	WD	F
559	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				G	5	WPH 6 small, 2 med, 1 large throu	L170000559(8)	R	D	SO	S	5									B	WD	F
559	Jake O'Brien	Chad Harvey	2017-06-27																														
560	Jake O'Brien	Chad Harvey	2017-06-27	F	G	G	5		L170000560	L	N/A				G	5			L	D	SO	S	5									F	WD	G
560	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				G	5			R	D	SO	S	5									B	WD	G
560	Jake O'Brien	Chad Harvey	2017-06-27																														
561	Jake O'Brien	Chad Harvey	2017-06-27	F	G	G	5		L170000561	L	4	60	WC	1968	G	5	WPH 3 small, 1 med mid pole	L170000561(8)	L	D	SO	S	5									F	WD	G
561	Jake O'Brien	Chad Harvey	2017-06-27							R	4	60	WC	1968	G	5	1 Med WPH upper pole	L170000561(7)	R	D	SO	S	5									B	WD	G
561	Jake O'Brien	Chad Harvey	2017-06-27																														
562	Jake O'Brien	Chad Harvey	2017-06-27	E	G	LL	5	Right pole leaning back 10"	L170000562	L	4	50	DF	1968	G	5			L	D	SO	S	5			1	1	G	4	Missing guy guards	L170000562(5)	F	WD	F
562	Jake O'Brien	Chad Harvey	2017-06-27							C	4	50	DF	1968	G	5			C	D	SO	S	5			2	2	G	4	Missing guy guards	L170000562(5)			
562	Jake O'Brien	Chad Harvey	2017-06-27							R	4	50	DF	1968	G	5			R	D	SO	S	5			1	1	G	4	Missing guy guards	L170000562(5)			
563	Jake O'Brien	Chad Harvey	2017-06-27	A	G	G	5		L170000563	L	N/A				G	5			L	D	SO	S	5									F	WD	F
563	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				G	5			R	D	SO	S	5											
563	Jake O'Brien	Chad Harvey	2017-06-27																														
564	Jake O'Brien	Chad Harvey	2017-06-27	E	G	G	5		L170000564	L	N/A				G	5			L	D	SO	S	5			2	2	G	4	Guy guard missing	L170000564(6)	F	WD	G
564	Jake O'Brien	Chad Harvey	2017-06-27							C	N/A				G	5			C	D	SO	S	5			2	2	G	4	Guy guard missing	L170000564(6)			
564	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				G	5			R	D	SO	S	5			2	2	G	4	Guy guard missing	L170000564(6)			
565	Jake O'Brien	Chad Harvey	2017-06-27	AXS	G	LT	5	Leaning 1' left	L170000565	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
565	Jake O'Brien	Chad Harvey	2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5											
565	Jake O'Brien	Chad Harvey	2017-06-27																														
566	Jake O'Brien	Chad Harvey	2017-06-27	AXS	G	LT	5	Structure leaning 12" left	L170000566	L	3	65	DF	1968	G	5			L	D	SO	S	5									F	WD	F
566	Jake O'Brien	Chad Harvey	2017-06-27							R	3	65	DF	1968	F	3	4 Med WPH mid section	L170000566(6)	R	D	SO	S	5									B	WD	P
566	Jake O'Brien	Chad Harvey	2017-06-27																														
567	Jake O'Brien	Chad Harvey	2017-06-27	A	G	LL	5	Structure leaning ahead 18"	L170000567	L	N/A				G	5	2 Med WPH middle	L170000567(6)	L	D	SO	S	5									F	WD	G
567	Jake O'Brien	Chad Harvey	2017-06-27							R	N/A				G	5	1 Med WPH middle	L170000567(5)	R	D	SO	S	5											
567	Jake O'Brien	Chad Harvey	2017-06-27																														
568	Jake O'Brien	Chad Harvey	2017-06-27	H DE	G	LL	5	Leaning ahead 16"	L170000568	L	4	55	DF	1968	G	5			L	D	SO	S	5			1	1	F	5	Missing guy guards	L170000568(6)	F	WD	G
568	Jake O'Brien	Chad Harvey	2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5			1	1	F	5	Missing guy guards				
568	Jake O'Brien	Chad Harvey	2017-06-27																														
569	Jake O'Brien	Chad Harvey	2017-06-27	H DE	G	LL	5	Str leaning ahead 8"	L170000569	L	4		DF	1968	G	4	Med WPH 7' AGL	L170000569(7)	L	D	SO	S	5			1	1	F	5	Missing guy guards	L170000569(8)	F	WD	F
569	Jake O'Brien	Chad Harvey	2017-06-27							R	4		DF	1968	G	5			R	D	SO	S	5			1	1	F	5	Missing guy guards	L170000569(9)	B	WD	P
569	Jake O'Brien	Chad Harvey	2017-06-27																														
570	Jake O'Brien	Chad Harvey	2017-06-28	A	G	G	5	Pole top number sign faded	L170000570	L	N/A				G	5			L	D	SO	S	5									F	WD	G
570	Jake O'Brien	Chad Harvey	2017-06-28							R	N/A				G	5			R	D	SO	S	5											
570	Jake O'Brien	Chad Harvey	2017-06-28																														
571	Jake O'Brien	Chad Harvey	2017-06-28	A	G	G	5		L170000571	L	N/A				G	5			L	D	SO	S	5									F	WD	F
571	Jake O'Brien	Chad Harvey	2017-06-28							R	N/A				G	5			R	D	SO	S	5											
571	Jake O'Brien	Chad Harvey	2017-06-28																														
572	Jake O'Brien	Chad Harvey	2017-06-28	A	G	LL	5	Leaning ahead 8"	L170000572	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
572	Jake O'Brien	Chad Harvey	2017-06-28							R	4	55	DF	1968	G	5			R	D	SO	S	5											

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572	Jake O'Brien	Chad Harvey	2017-06-28																														
573	Jake O'Brien	Chad Harvey	2017-06-28	A	G	LL	5		L170000573	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
573	Jake O'Brien	Chad Harvey	2017-06-28							R	4	55	DF	1968	G	5			R	D	SO	S	5											
573	Jake O'Brien	Chad Harvey	2017-06-28																														
574	Jake O'Brien	Chad Harvey	2017-06-28	A	G	G	5		L170000574	L	N/A				G	5			L	D	SO	S	5									F	WD	F
574	Jake O'Brien	Chad Harvey	2017-06-28							R	N/A				G	5			R	D	SO	S	5											
574	Jake O'Brien	Chad Harvey	2017-06-28																														
575	Jake O'Brien	Chad Harvey	2017-06-28	H DE	G	G	5		L170000575	L	4	50	DF	1968	G	5			L	D	SO	S	5			1	1	G	5			F	WD	G
575	Jake O'Brien	Chad Harvey	2017-06-28							R	4	50	DF	1968	G	5			R	D	SO	S	5			1	1	G	5			B	WD	G
575	Jake O'Brien	Chad Harvey	2017-06-28																														
576	Jake O'Brien	Chad Harvey	2017-06-28	A	G	G	5		L170000576	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
576	Jake O'Brien	Chad Harvey	2017-06-28							R	4	55	DF	1968	G	5			R	D	SO	S	5											
576	Jake O'Brien	Chad Harvey	2017-06-28																														
577	Jake O'Brien	Chad Harvey	2017-06-28	E	G	G	5	Left pole leaning ahead 3'	L170000577	L	4	55	DF	1968	G	5			L	D	SO	S	5			1	1	G	5			F	WD	G
577	Jake O'Brien	Chad Harvey	2017-06-28							C	4	55	DF	1968	G	5			C	D	SO	S	5			2	2	G	5					
577	Jake O'Brien	Chad Harvey	2017-06-28							R	4	55	DF	1968	G	5			R	D	SO	S	5			1	1	G	5	Missing guy guards				
578	Jake O'Brien	Chad Harvey	2017-06-28	A	G	G	5		L170000578	L	N/A				G	5	2 small WPH holes midtop	L170000578(9)	L	D	SO	S	5									F	WD	P
578	Jake O'Brien	Chad Harvey	2017-06-28							R	N/A				G	5	1 Small WPH upper pole	L170000578(10)	R	D	SO	S	5											
578	Jake O'Brien	Chad Harvey	2017-06-28																														
579	Jake O'Brien	Chad Harvey	2017-06-28	A	G	G	5		L170000579	L	2	45	LP	2006	G	5			L	D	SO	S	5	Old pole butts	L000579(6)							F	WD	F
579	Jake O'Brien	Chad Harvey	2017-06-28							R	2	45	LP	2006	G	5			R	D	SO	S	5	Old pole butts 6' ahead										
579	Jake O'Brien	Chad Harvey	2017-06-28																														
580	Jake O'Brien		2017-06-26	A	G	G	5	Ahead top sign faded	L170000580	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
580	Jake O'Brien		2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5											
580	Jake O'Brien		2017-06-26																														
581	Jake O'Brien		2017-06-26	A	G	G	5	Str leaning back 10"	L170000581	L	N/A				F	5	1 Med WPH 15' AGL	L170000581(8)	L	D	SO	S	5									F	WD	P
581	Jake O'Brien		2017-06-26							R	N/A				G	5			R	D	SO	S	5											
581	Jake O'Brien		2017-06-26																														
582	Jake O'Brien		2017-06-26	A	G	G	5		L170000582	L	4	40	DF	1968	G	5			L	D	SO	S	5									F	WD	G
582	Jake O'Brien		2017-06-26							R	4	40	DF	1968	G	5			R	D	SO	S	5											
582	Jake O'Brien		2017-06-26																														
583	Jake O'Brien		2017-06-26	A	M	G	5		L170000583	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
583	Jake O'Brien		2017-06-26							R	4	55	DF	1968	F	5	Checking at top of pole needs a sp	L170000583(5)	R	D	SO	S	5											
583	Jake O'Brien		2017-06-26																														
584	Jake O'Brien		2017-06-26	A	G	LL	5	Str leaning ahead 20"	L170000584	L	4	60	DF	1968	F	5	Medium woodpecker hole at top o	L170000584(5)	L	D	SO	S	5									F	WD	P
584	Jake O'Brien		2017-06-26							R	4	60	DF	1968	G	5			R	D	SO	S	5											
584	Jake O'Brien		2017-06-26																														
585	Jake O'Brien		2017-06-26	A	G	G	5		L170000585	L	4	50	WC	1968	G	5			L	D	SO	S	5									F	WD	P
585	Jake O'Brien		2017-06-26							R	4	50	WC	1968	F	5	Woodpecker small 4' from top	L170000585(5)	R	D	SO	S	5											
585	Jake O'Brien		2017-06-26																														
586	Jake O'Brien		2017-06-26	A	G	G	5		L170000586	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	P
586	Jake O'Brien		2017-06-26							R	4	50	DF	1968	G	5			R	D	SO	S	5											
586	Jake O'Brien		2017-06-26																														
587	Jake O'Brien		2017-06-26	A	G	G	5		L170000587	L	3	55	WC	2015	E	5			L	D	SO	S	5	Old pole butt	L000587(6)							F	ST	E
587	Jake O'Brien		2017-06-26							R	3	55	WC	2015	G	5	Checking from GL 20'	L170000587(8)	R	D	SO	S	5	Old pole butt	L000587(5)									
587	Jake O'Brien		2017-06-26																														
588	Jake O'Brien		2017-06-26	A	G	G	5		L170000588	L	N/A				G	5			L	D	SO	S	5									F	WD	P
588	Jake O'Brien		2017-06-26							R	N/A				G	5			R	D	SO	S	5											
588	Jake O'Brien		2017-06-26																														
589	Jake O'Brien		2017-06-26	A	G	G	5		L170000589	L	2	70	WC	2014	F	5	2 med WPH 20' AGL	L170000589(7)	L	D	SO	S	5	Old pole butts	L000589(5)							F	ST	E
589	Jake O'Brien		2017-06-26							R	2	70	WC	2014	E	5			R	D	SO	S	5	Old pole butts	L000589(6)									
589	Jake O'Brien		2017-06-26																														
590	Jake O'Brien		2017-06-26	A	G	G	5		L170000590	L	2	55	LP	2014	E	5	Pole butts back 8'	L170000590(5)	L	D	SO	S	5									F	ST	E
590	Jake O'Brien		2017-06-26							R	2	55	LP	2014	E	5	Pole butts back 8'	L170000590(6)	R	D	SO	S	5											
590	Jake O'Brien		2017-06-26																														
591	Jake O'Brien		2017-06-26	A	G	G	5		L170000591	L	2	55	LP	2014	E	5			L	D	SO	S	5									F	ST	E

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591	Jake O'Brien		2017-06-26							R	2	55	WC	2014	E	5			R	D	SO	S	5										
591	Jake O'Brien		2017-06-26																														
592	Jake O'Brien		2017-06-26	A	G	G	5		L170000592	L	3	65	WC	2014	E	5			L	D	SO	S	5	10' back old po	000592(7)							F	ST	E
592	Jake O'Brien		2017-06-26							R	3	65	WC	2014	E	5			R	D	SO	S	5										
592	Jake O'Brien		2017-06-26																														
593	Jake O'Brien		2017-06-26	A	G	G	5		L170000593	L	1	60	WC	2015	F	5	Med WPH 1' below arm, large WPI	L170000593(8)	L	D	SO	S	5	Old pole butts 6	000593(5)							F	ST	E
593	Jake O'Brien		2017-06-26							R	1	60	WC	2015	G	5			R	D	SO	S	5	Old pole butts 6	000593(6)									
593	Jake O'Brien		2017-06-26																														
594	Jake O'Brien		2017-06-26	A	G	G	5		L170000594	L	2	55	WC	2013	F	5	Small WPH 4-10' from top	L170000594(6)	L	D	SO	S	5	Old pole butts 8	000594(6)							F	ST	E
594	Jake O'Brien		2017-06-26							R	2	55	WC	2013	E	5			R	D	SO	S	5	Old pole butts 8	000594(7)									
594	Jake O'Brien		2017-06-26																														
595	Jake O'Brien		2017-06-26	E	G	G	5		L170000595	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
595	Jake O'Brien		2017-06-26							C	4	55	DF	1968	G	5			C	D	SO	S	5									B	WD	P
595	Jake O'Brien		2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5			1	1	G	5					
596	Jake O'Brien		2017-06-26	A	G	G	5		L170000596	L	3	55	WC	2015	F	5	Large WPH very top	L170000596(5)	L	D	SO	S	5									F	ST	E
596	Jake O'Brien		2017-06-26							R	3	55	WC	2015	G	5			R	D	SO	S	5										
596	Jake O'Brien		2017-06-26																														
597	Jake O'Brien		2017-06-26	A	G	G	5		L170000597	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
597	Jake O'Brien		2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5										
597	Jake O'Brien		2017-06-26																														
598	Jake O'Brien		2017-06-26	A	G	G	5		L170000598	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	P
598	Jake O'Brien		2017-06-26							R	4	50	DF	1968	G	5			R	D	SO	S	5										
598	Jake O'Brien		2017-06-26																														
599	Jake O'Brien		2017-06-26	A	G	G	5		L170000599	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
599	Jake O'Brien		2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5										
599	Jake O'Brien		2017-06-26																														
600	Jake O'Brien		2017-06-26	A	G	G	5	Ahead top sign faded	L170000600	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
600	Jake O'Brien		2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5										
600	Jake O'Brien		2017-06-26																														
601	Jake O'Brien		2017-06-26	F	G	G	5		L170000601	L	3	65	WC	2016	F	5	Large WPH 6' AGL 2 Large PH 28' A	L170000601(6)	L	D	SO	S	5	Old pole butts 8	000601(8)							F	WD	E
601	Jake O'Brien		2017-06-26							R	3	65	WC	2016	E	5			R	D	SO	S	5	Old pole butts 8	000601(8)									
601	Jake O'Brien		2017-06-26																														
602	Jake O'Brien		2017-06-26	F	G	G	5		L170000602	L	3	65	WC	2016	E	5			L	D	SO	S	5	Old pole butts 4' back								F	WD	E
602	Jake O'Brien		2017-06-26							R	3	65	WC	2016	F	5	Large WPH 6' AGL small WPH 8' AG	L170000602(8)	R	D	SO	S	5	Old pole butts 4' back										
602	Jake O'Brien		2017-06-26																														
603	Jake O'Brien		2017-06-26	A	G	G	5		L170000603	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
603	Jake O'Brien		2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5										
603	Jake O'Brien		2017-06-26																														
604	Jake O'Brien		2017-06-26	A	G	G	5		L170000604	L	N/A				G	5			L	D	SO	S	5									F	WD	P
604	Jake O'Brien		2017-06-26							R	N/A				F	5	WPH 35' AGL	L170000604(5)	R	D	SO	S	5											
604	Jake O'Brien		2017-06-26																														
605	Jake O'Brien		2017-06-26	A	G	G	5		L170000605	L	3	55	WC	2015	E	5			L	D	SO	S	5	Pole butts back	000605(6)							F	ST	E
605	Jake O'Brien		2017-06-26							R	3	55	WC	2015	E	5			R	D	SO	S	5	Pole butts back 7'										
605	Jake O'Brien		2017-06-26																														
606	Jake O'Brien		2017-06-26	A	G	G	5		L170000606	L	N/A				G	5			L	D	SO	S	5									F	WD	G
606	Jake O'Brien		2017-06-26							R	N/A				G	5			R	D	SO	S	5										
606	Jake O'Brien		2017-06-26																														
607	Jake O'Brien		2017-06-26	A	G	G	5		L170000607	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
607	Jake O'Brien		2017-06-26							R	4	55	DF	1968	F	5	2 large WPH between brace bolt, 1	L170000607(6)	R	D	SO	S	5											
607	Jake O'Brien		2017-06-26																														
608	Jake O'Brien		2017-06-26	A	G	G	5		L170000608	L	3	55	WC	2015	F	5	Top damaged	L170000608(5)	L	D	SO	S	5									F	ST	E
608	Jake O'Brien		2017-06-26							R	3	55	WC	2015	F	5	WPH 5' AGL light in knot hole	L170000608(6)	R	D	SO	S	5											
608	Jake O'Brien		2017-06-26																														
609	Jake O'Brien		2017-06-26	A	G	G	5		L170000609	L	3	55	WC	2015	G	5	Large WPH 15' AGL, light WP dama	L170000609(9)	L	D	SO	S	5	Old pole butts 8	000609(5)							F	ST	E
609	Jake O'Brien		2017-06-26							R	3	55	WC	2015	G	5			R	D	SO	S	5	Old pole butts 8	000609(6)									
609	Jake O'Brien		2017-06-26																														

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610	Jake O'Brien		2017-06-26	A	G	G	5		L170000610	L	N/A				G	5			L	D	SO	S	5									F	WD	G
610	Jake O'Brien		2017-06-26							R	N/A				G	5			R	D	SO	S	5											
610	Jake O'Brien		2017-06-26																														
611	Jake O'Brien		2017-06-26	A	G	G	5		L170000611	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
611	Jake O'Brien		2017-06-26							R	4	55	DF	1968	F	5	Light shell damage 18' AGL	L170000611(5)	R	D	SO	S	5											
611	Jake O'Brien		2017-06-26																														
612	Jake O'Brien		2017-06-26	A	M	G	5		L170000612	L	3	65	WC	2016	G	5			L	D	SO	S	5									F	ST	E
612	Jake O'Brien		2017-06-26							R	3	65	WC	2016	G	5			R	D	SO	S	5											
612	Jake O'Brien		2017-06-26																														
613	Jake O'Brien		2017-06-26	A	G	G	5		L170000613	L	4	65	DF	1968	G	5			L	D	SO	S	5									F	WD	P
613	Jake O'Brien		2017-06-26							R	4	65	DF	1968	F	5	Heavy checking throughout	700000613(10)	R	D	SO	S	5											
613	Jake O'Brien		2017-06-26																														
614	Jake O'Brien		2017-06-26	A	G	G	5		L170000614	L	N/A				G	5			L	D	SO	S	5									F	WD	P
614	Jake O'Brien		2017-06-26							R	N/A				G	5			R	D	SO	S	5											
614	Jake O'Brien		2017-06-26																														
615	Jake O'Brien		2017-06-26	A	G	G	5		L170000615	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	G
615	Jake O'Brien		2017-06-26							R	4	60	DF	1968	F	5	2 large WPH 25-35' AGL, med WPH	L70000615(10)	R	D	SO	S	5											
615	Jake O'Brien		2017-06-26																														
616	Jake O'Brien		2017-06-26	A	G	G	5		L170000616	L	N/A				G	5			L	D	SO	S	5									F	WD	F
616	Jake O'Brien		2017-06-26							R	N/A				G	5			R	D	SO	S	5											
616	Jake O'Brien		2017-06-26																														
617	Jake O'Brien		2017-06-26	A	G	G	5		L170000617	L	N/A				F	5	LL 10" Large woodpecker damage	L170000617(8)	L	D	SO	S	5									F	WD	G
617	Jake O'Brien		2017-06-26							R	N/A				G	5			R	D	SO	S	5											
617	Jake O'Brien		2017-06-26																														
618	Jake O'Brien		2017-06-26	F	G	G	5		L170000618	L	N/A				F	5	3 Med WPH 10-14' AGL	L170000618(6)	L	D	SO	S	5									F	WD	G
618	Jake O'Brien		2017-06-26							R	N/A				F	5	7 Med WPH throughout	L170000618(9)	R	D	SO	S	5											
618	Jake O'Brien		2017-06-26																														
619	Jake O'Brien		2017-06-26	F	G	G	5		L170000619	L	4	65	DF	1968	F	5	Large WPH 18" from top	L170000619(6)	L	D	SO	S	5									F	WD	P
619	Jake O'Brien		2017-06-26							R	4	65	DF	1968	G	5			R	D	SO	S	5											
619	Jake O'Brien		2017-06-26																														
620	Jake O'Brien		2017-06-26	A	M	G	5	Upper back sign missing number	L170000620	L	4	60	DF	1968	F	4	Large WPH 15' from top	L170000620(7)	L	D	SO	S	5									F	WD	G
620	Jake O'Brien		2017-06-26							R	4	60	DF	1968	G	5			R	D	SO	S	5											
620	Jake O'Brien		2017-06-26																														
621	Jake O'Brien		2017-06-27	A	G	G	5		L170000621	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
621	Jake O'Brien		2017-06-27							R	4	55	DF	1968	P	3	Ant dust ground level	L170000621(8)	R	D	SO	S	5											
621	Jake O'Brien		2017-06-27																														
622	Jake O'Brien		2017-06-27	A	G	G	5		L170000622	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
622	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5											
622	Jake O'Brien		2017-06-27																														
623	Jake O'Brien		2017-06-27	A	G	G	5		L170000623	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
623	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5											
623	Jake O'Brien		2017-06-27																														
624	Jake O'Brien		2017-06-27	A	G	G	5		L170000624	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	E
624	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5											
624	Jake O'Brien		2017-06-27																														
625	Jake O'Brien		2017-06-27	A	G	G	5		L170000625	L	N/A				G	5			L	D	SO	S	5									F	WD	P
625	Jake O'Brien		2017-06-27							R	N/A				G	5			R	D	SO	S	5											
625	Jake O'Brien		2017-06-27																														
626	Jake O'Brien		2017-06-27	A	G	G	5		L170000626	L	4	55	DF	1968	F	5	Small WPH hole 30' AGL	L170000626(7)	L	D	SO	S	5									F	WD	P
626	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5											
626	Jake O'Brien		2017-06-27																														
627	Jake O'Brien		2017-06-27	A	G	G	5		L170000627	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
627	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5											
627	Jake O'Brien		2017-06-27																														
628	Jake O'Brien		2017-06-27	A	G	LL	5	Structure leaning back 24"	L170000628	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
628	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5											

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628	Jake O'Brien		2017-06-27																														
629	Jake O'Brien		2017-06-27	A	G	G	5		L170000629	L	4	55	DF	1968	F	5	Small WP damage from GL to 6' AG	L170000629(7)	L	D	SO	S	5								F	WD	F
629	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5										
629	Jake O'Brien		2017-06-27																														
630	Jake O'Brien		2017-06-27	E	G	G	5		L170000630	L	4	55	DF	1968	G	5			L	D	SO	S	5			1	1	F	3	Missing guy guard	L170000630(8)	F	WD	F
630	Jake O'Brien		2017-06-27							C	4	55	DF	1968	G	5			C	D	SO	S	5								B	WD	F
630	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5										
631	Jake O'Brien		2017-06-27	A	G	G	5		L170000631	L	N/A		DF	1968	G	5			L	D	SO	S	5								F	WD	G
631	Jake O'Brien		2017-06-27							R	N/A		DF	1968	G	5			R	D	SO	S	5										
631	Jake O'Brien		2017-06-27																														
632	Jake O'Brien		2017-06-27	A	G	LL	5	Structure leaning back 10" (right pole)	L170000632	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G
632	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5										
632	Jake O'Brien		2017-06-27																														
633	Jake O'Brien		2017-06-27	A	G	G	5		L170000633	L	4	60	DF	1968	G	5			L	D	SO	S	5								F	WD	G
633	Jake O'Brien		2017-06-27							R	4	60	DF	1968	G	5			R	D	SO	S	5										
633	Jake O'Brien		2017-06-27																														
634	Jake O'Brien		2017-06-27	A	G	G	5		L170000634	L	4	N/A	DF	1968	G	5			L	D	SO	S	5								F	WD	G
634	Jake O'Brien		2017-06-27							R	4	N/A	DF	1968	G	5			R	D	SO	S	5										
634	Jake O'Brien		2017-06-27																														
635	Jake O'Brien		2017-06-27	A	G	G	5		L170000635	L	4	N/A	DF	1968	G	5			L	D	SO	S	5								F	WD	P
635	Jake O'Brien		2017-06-27							R	4	N/A	DF	1968	G	5			R	D	SO	S	5										
635	Jake O'Brien		2017-06-27																														
636	Jake O'Brien		2017-06-27	A	G	G	5		L170000636	L	4	N/A		1968	G	5			L	D	SO	S	5								F	WD	P
636	Jake O'Brien		2017-06-27							R	4	N/A		1968	G	5			R	D	SO	S	5										
636	Jake O'Brien		2017-06-27																														
637	Jake O'Brien		2017-06-27	A	G	G	5		L170000637	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	F
637	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5										
637	Jake O'Brien		2017-06-27																														
638	Jake O'Brien		2017-06-27	A	G	G	5		L170000638	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	P
638	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5										
638	Jake O'Brien		2017-06-27																														
639	Jake O'Brien		2017-06-27	A	G	G	5		L170000639	L	N/A				G	5			L	D	SO	S	5								F	WD	F
639	Jake O'Brien		2017-06-27							R	N/A				G	5			R	D	SO	S	5										
639	Jake O'Brien		2017-06-27																														
640	Jake O'Brien		2017-06-27	A	G	LT	5	Str leaning to the right 20"	L170000640	L	N/A				G	5			L	D	SO	S	5								F	WD	G
640	Jake O'Brien		2017-06-27							R	N/A				G	5			R	D	SO	S	5										
640	Jake O'Brien		2017-06-27																														
641	Jake O'Brien		2017-06-27	A	G	G	5		L170000641	L	4	55	DF	1968	G	5	Light WP damage top of left pole, t	L170000641(7)	L	D	SO	S	5								F	WD	P
641	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5										
641	Jake O'Brien		2017-06-27																														
642	Jake O'Brien		2017-06-27	A	G	LL	5	Left pole leaning back 1', right pole lean	L170000642	L	N/A		DF	1968	F	5	WPH Damage, checking between x	L70000642(16)	L	D	SO	S	5			1	1	F	3	Guy guard broken	L170000642(7)	F	WD	G
642	Jake O'Brien		2017-06-27							R	N/A		DF	1968	P	3	2 Small WPH 6-8' AGL, 4 large WPH	L70000642(14)	R	D	SO	S	5			1	1	F	3	Missing guy guard	L170000642(5)			
642	Jake O'Brien		2017-06-27																														
643	Jake O'Brien		2017-06-27	F	M	LT	5	Pulled ahead 18"	L170000643	L	N/A				G	5			L	D	SO	S	5								F	WD	P
643	Jake O'Brien		2017-06-27							R	N/A				F	5	2 Large 3 med WPH from bottom a	L170000643(6)	R	D	SO	S	5										
643	Jake O'Brien		2017-06-27																														
644	Jake O'Brien		2017-06-27	A	G	LT/LL	5	Str leaning right 3', back 14"	L170000644	L	4	65	DF	1968	F	5	Small WPH top pole, and mid smal	L170000644(7)	L	C	SO	S	5								F	WD	G
644	Jake O'Brien		2017-06-27							R	4	65	DF	1968	G	5			R	C	SO	S	5										
644	Jake O'Brien		2017-06-27																														
645	Jake O'Brien		2017-06-27	A	G	LL	5	Str leaning 10-12" ahead	L170000645	L	4	55	DF	1967	G	5			L	D	SO	S	5								F	WD	F
645	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5										
645	Jake O'Brien		2017-06-27																														
646	Jake O'Brien		2017-06-27	AXS	G	LL	5	Left pole 10" ahead	L170000646	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G
646	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5										
646	Jake O'Brien		2017-06-27																														
647	Jake O'Brien		2017-06-27	AXS	G	G	5		L170000647	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G

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647	Jake O'Brien		2017-06-27							R	4	55	DF	1968	P	2	5 Med WPH 1 large WPH upper sec	L170000647(6)	R	D	SO	S	5										
647	Jake O'Brien		2017-06-27																														
648	Jake O'Brien		2017-06-27	AXS	G	G	5		L170000648	L	N/A				G	5			L	D	SO	S	5								F	WD	G
648	Jake O'Brien		2017-06-27							R	N/A				G	5			R	D	SO	S	5										
648	Jake O'Brien		2017-06-27																														
649	Jake O'Brien		2017-06-27	AXS	G	G	5		L170000649	L	4	50	DF	1968	F	5	Small WPH top section	L170000649(7)	L	D	SO	S	5								F	WD	G
649	Jake O'Brien		2017-06-27							R	4	50	DF	1968	F	5	Damage 1' above top brace bolt ap	L170000649(6)	R	D	SO	S	5										
649	Jake O'Brien		2017-06-27																														
650	Jake O'Brien		2017-06-27	AXS	G	G	5	Upper ahead sign faded	L170000650	L	4	55	DF	1967	G	5			L	D	SO	S	5								F	WD	G
650	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5										
650	Jake O'Brien		2017-06-27																														
651	Jake O'Brien		2017-06-26	A	G	LL	5	Structure leaning back 14"	L170000651	L	N/A				P	3	2 med, large WPH top section, 2 la	L170000651(15)	L	D	SO	S	5								F	WD	P
651	Jake O'Brien		2017-06-26							R	N/A				P	4	3 Large WPH 1 med top section, 3	L170000651(16)	R	D	SO	S	5										
651	Jake O'Brien		2017-06-26																														
652	Jake O'Brien		2017-06-26	AXS	G	G	5		L170000652	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G
652	Jake O'Brien		2017-06-26							R	4	55	DF	1968	P	3	3 Large 1 medium top of pole	L170000652(6)	R	D	SO	S	5										
652	Jake O'Brien		2017-06-26																														
653	Jake O'Brien		2017-06-26	AXS	G	LL	5	Leaning ahead 20"	L170000653	L	N/A				F	5	5 Small WPH top section of pole	L170000653(6)	L	D	SO	S	5								F	WD	G
653	Jake O'Brien		2017-06-26							R	N/A				G	5			R	D	SO	S	5										
653	Jake O'Brien		2017-06-26																														
654	Jake O'Brien		2017-06-26	AXS	G	LL	5	Str leaning ahead 18"	L170000654	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G
654	Jake O'Brien		2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5										
654	Jake O'Brien		2017-06-26																														
655	Jake O'Brien		2017-06-26	H DE	G	G	5		L170000655	L	4	50	DF	1968	G	5			L	D	SO	S	5								F	WD	G
655	Jake O'Brien		2017-06-26							R	4	50	DF	1968	F	5	3 Small 1 med mid section, 3 med	L170000655(7)	C	D	SO	S	5			1	1	M	2	Broken anchor rod	L170000655(8)			
655	Jake O'Brien		2017-06-26																R	D	SO	S	5			1	1	F	3	Guy guard missing	L170000655(9)			
656	Jake O'Brien		2017-06-26	A	G	G	5		L170000656	L	4	50	DF	1968	G	5			L	D	SO	S	5								F	WD	P
656	Jake O'Brien		2017-06-26							R	4	50	DF	1968	G	5			R	D	SO	S	5										
656	Jake O'Brien		2017-06-26																														
657	Jake O'Brien		2017-06-26	A	G	G	5		L170000657	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G
657	Jake O'Brien		2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5										
657	Jake O'Brien		2017-06-26																														
658	Jake O'Brien		2017-06-26	A	G	G	5		L170000658	L	4	50	DF	1968	G	5			L	D	SO	S	5								F	WD	P
658	Jake O'Brien		2017-06-26							R	4	50	DF	1968	G	5			R	D	SO	S	5										
658	Jake O'Brien		2017-06-26																														
659	Jake O'Brien		2017-06-26	E	G	G	5		L170000659	L	4	55	DF	1968	G	5			L	D	SO	S	5			1	1	F	3	Guy guards missing	L170000659(5)	F	WD	G
659	Jake O'Brien		2017-06-26							C	4	55	DF	1968	G	5			C	D	SO	S	5			2	2	F	3	Guy guards missing	L170000659(5)	B	WD	F
659	Jake O'Brien		2017-06-26							R	4	55	DF	1968	F	5	Med size WPH, small WPH and ligh	L170000659(8)	R	D	SO	S	5			1	1	F	3	Guy guards missing	L170000659(5)			
660	Jake O'Brien		2017-06-26	AXS	G	G	5	Ahead top sign faded	L170000660	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	P
660	Jake O'Brien		2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5								B	WD	G
660	Jake O'Brien		2017-06-26																														
661	Jake O'Brien		2017-06-26	AXS	G	G	5		L170000661	L	N/A				G	5			L	D	SO	S	5								F	WD	P
661	Jake O'Brien		2017-06-26							R	N/A				G	5			R	D	SO	S	5								B	WD	G
661	Jake O'Brien		2017-06-26																														
662	Jake O'Brien		2017-06-26	AXS	G	G	5		L170000662	L	4	45	DF	1968	F	5	2 Med WPH top section mid sectio	L170000662(7)	L	D	SO	S	5								F	WD	G
662	Jake O'Brien		2017-06-26							R	4	45	DF	1968	G	5			R	D	SO	S	5								B	WD	G
662	Jake O'Brien		2017-06-26																														
663	Jake O'Brien		2017-06-26	AXS	G	G	5		L170000663	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G
663	Jake O'Brien		2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5								B	WD	G
663	Jake O'Brien		2017-06-26																														
664	Jake O'Brien		2017-06-26	F	M	G	5		L170000664	L	N/A				G	5			L	D	SO	S	5								F	WD	G
664	Jake O'Brien		2017-06-26							R	N/A				F	5	Mid section 3 sm WPH top section	L170000665(7)	R	D	SO	S	5								B	WD	P
664	Jake O'Brien		2017-06-26																														
665	Jake O'Brien		2017-06-26	F	G	LL	5	Right pole leaning back 1'	L170000665	L	4	65	DF	1968	G	5			L	D	SO	S	5								F	WD	P
665	Jake O'Brien		2017-06-26							R	4	60	DF	1968	F	4	Large WPH upper section, small W	L170000665(10)	R	D	SO	S	5								B	WD	P
665	Jake O'Brien		2017-06-26																														

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Structure Number	Inpsctn Lead	Inspctn Second	Inspctn Date	STR Framing Type	STR No.	STR Straight-ness	STR Maint. Priority	STR Maintenance Comment	STR Deficiency Photo	POL Loc.	POL Class	POL Size	POL Species	POL Date Stamp	POL Cond.	POL Maint. Priority	POL Maintenance Comment	POL Deficiency Photo	FDN Loc	FDN Type	FDN Ground Type	FDN Ground Cond.	FDN Maintenance	FDN Maintenance Comment	FDN Deficiency Photo	G&A # of Guys	G&A # of Anchor	G&A Cond.	G&A Maint. Priority	G&A Maintenance Comment	G&A Deficiency Photo	XRM Loc.	XRM Type	XRM Cond.
666	Jake O'Brien		2017-06-26	H DE	G	G	5	Left pole leaning ahead 18"	L170000666	L	N/A				G	5			L	D	SO	S	5			1	1	F	3	Guy guards missing and ro	170000666(11)	F	WD	G
666	Jake O'Brien		2017-06-26							R	N/A				F	5	2 Med WPH mid section, 1 med 3 s	170000666(6)	R	D	SO	S	5			1	1	F	3	Guy guards missing and ro	170000666(10)	B	WD	F
666	Jake O'Brien		2017-06-26																														
667	Jake O'Brien		2017-06-26	A	G	LL	5	Right pole leaning back 8-12"	L170000667	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
667	Jake O'Brien		2017-06-26							R	4	50	DF	1968	G	5			R	D	SO	S	5											
667	Jake O'Brien		2017-06-26																														
668	Jake O'Brien		2017-06-26	A	G	G	5		L170000668	L	N/A				G	5			L	D	SO	S	5									F	WD	P
668	Jake O'Brien		2017-06-26							R	N/A				G	5			R	D	SO	S	5											
668	Jake O'Brien		2017-06-26																														
669	Jake O'Brien		2017-06-26	A	G	G	5		L170000669	L	N/A				G	5			L	D	SO	S	5									F	WD	F
669	Jake O'Brien		2017-06-26							R	N/A				G	5	Ant dust in checking GL-6' AGL	170000669(8)	R	D	SO	S	5											
669	Jake O'Brien		2017-06-26																														
670	Jake O'Brien		2017-06-26	A	G	G	5		L170000670	L	N/A				G	5			L	D	SO	S	5									F	WD	P
670	Jake O'Brien		2017-06-26							R	N/A				G	5			R	D	SO	S	5											
670	Jake O'Brien		2017-06-26																														
671	Jake O'Brien		2017-06-26	A	G	G	5		L170000671	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
671	Jake O'Brien		2017-06-26							R	4	50	DF	1968	G	5			R	D	SO	S	5											
671	Jake O'Brien		2017-06-26																														
672	Jake O'Brien		2017-06-26	A	G	G	5		L170000672	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
672	Jake O'Brien		2017-06-26							R	4	50	DF	1968	G	5			R	D	SO	S	5											
672	Jake O'Brien		2017-06-26																														
673	Jake O'Brien		2017-06-26	E	G	G	5		L170000673	L	4	50	DF	1968	G	5	Top 3 small WPH	170000673(7)	L	D	SO	S	5			1	1	F	3	Guy guards missing	L170000673(8)	F	WD	G
673	Jake O'Brien		2017-06-26							C	4	50	DF	1968	G	5			C	D	SO	S	5			2	2	F	3	Guy guards missing	L170000673(8)	B	WD	G
673	Jake O'Brien		2017-06-26							R	4	50	DF	1968	G	5	1 Medium top section WPH, 1 sma	170000673(6)	R	D	SO	S	5			1	1	F	3	Guy guards missing	L170000673(8)			
674	Jake O'Brien		2017-06-26	A	G	G	5		L170000674	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	P
674	Jake O'Brien		2017-06-26							R	4	60	DF	1968	P	3	Mid section has 2 med and 3 sm W	70000674(10)	R	D	SO	S	5											
674	Jake O'Brien		2017-06-26																														
675	Jake O'Brien		2017-06-26	A	G	G	5		L170000675	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
675	Jake O'Brien		2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5											
675	Jake O'Brien		2017-06-26																														
676	Jake O'Brien		2017-06-26	A	G	LL	5		L170000676	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
676	Jake O'Brien		2017-06-26							R	4	50	DF	1968	G	5			R	D	SO	S	5											
676	Jake O'Brien		2017-06-26																														
677	Jake O'Brien		2017-06-26	A	G	G	5		L170000677	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
677	Jake O'Brien		2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5											
677	Jake O'Brien		2017-06-26																														
678	Jake O'Brien		2017-06-26	A	G	G	5		L170000678	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
678	Jake O'Brien		2017-06-26							R	4	55	DF	1968	F	5	Lower section small WPH	170000678(7)	R	D	SO	S	5											
678	Jake O'Brien		2017-06-26																														
679	Jake O'Brien		2017-06-26	A	G	G	5		L170000679	L	4	55	DF	1968	F	5	2 Small WPH lower section	170000679(6)	L	D	SO	S	5									F	WD	G
679	Jake O'Brien		2017-06-26							R	4	55	DF	1968	G	5			R	D	SO	S	5											
679	Jake O'Brien		2017-06-26																														
680	Jake O'Brien		2017-06-26	A	G	G	5	Back upper sign faded (unreadable)	L170000680	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
680	Jake O'Brien		2017-06-26							R	4	55	DF	1968	F	5	1 Small WPH lower section	170000680(5)	R	D	SO	S	5											
680	Jake O'Brien		2017-06-26																														
681	Jake O'Brien		2017-06-27	F	G	G	5		L170000681	L	4	65	DF	1968	F	5	2 Large WPH mid section	170000681(9)	L	D	SO	S	5									F	WD	G
681	Jake O'Brien		2017-06-27							R	4	65	DF	1968	G	3			R	D	SO	S	5									B	WD	G
681	Jake O'Brien		2017-06-27																														
682	Jake O'Brien		2017-06-27	F	G	G	5		L170000682	L	4	65	DF	1968	G	5			L	D	SO	S	5									F	WD	G
682	Jake O'Brien		2017-06-27							R	4	65	DF	1968	G	5			R	D	SO	S	5											
682	Jake O'Brien		2017-06-27																														
683	Jake O'Brien		2017-06-27	A	G	G	5		L170000683	L	4	55	DF	1968	G	5			L	D	SO	S	5			1	1	F	3	Missing guy guards	L170000683(6)	F	WD	G
683	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5			1	1	F	3	Missing guy guards	L170000683(5)			
683	Jake O'Brien		2017-06-27																														
684	Jake O'Brien		2017-06-27	A	G	LT	5	Str leaning 24" to the right	L170000684	L	N/A				G	5			L	D	SW	S	5			1	1	F	3	Guy guard missing		F	WD	G
684	Jake O'Brien		2017-06-27							R	N/A				G	5			R	D	SW	S	5			1	1	G	5					

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684	Jake O'Brien		2017-06-27																														
685	Jake O'Brien		2017-06-27	A	G	LT	5	Structure leaning ahead 20"	L170000685	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	F
685	Jake O'Brien		2017-06-27							R	4	50	DF	1968	G	5			R	D	SO	S	5											
685	Jake O'Brien		2017-06-27																														
686	Jake O'Brien		2017-06-27	A	G	G	5		L170000686	L	N/A				G	5			L	D	SO	S	5								F	WD	G
686	Jake O'Brien		2017-06-27							R	N/A				G	5			R	D	SO	S	5										
686	Jake O'Brien		2017-06-27																														
687	Jake O'Brien		2017-06-27	A	M	G	5		L170000687	L	4	N/A		1968	G	5			L	D	SO	S	5								F	WD	P
687	Jake O'Brien		2017-06-27							R	4	N/A		1968	G	5			R	D	SO	S	5										
687	Jake O'Brien		2017-06-27																														
688	Jake O'Brien		2017-06-27	A	M	G	5		L170000688	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	P
688	Jake O'Brien		2017-06-27							R	4	55	DF	1968	G	5			R	D	SO	S	5										
688	Jake O'Brien		2017-06-27																														
689	Jake O'Brien		2017-06-27	A	M	G	5		L170000689	L	N/A				G	5			L	C	SO	U	3	Culvert close to	000689(7)						F	WD	G
689	Jake O'Brien		2017-06-27							R	N/A				G	5			R	C	SO	S	5										
689	Jake O'Brien		2017-06-27																														
690	Jake O'Brien		2017-06-27	A	G	G	5		L170000690	L	N/A				G	5			L	C	SO	S	5								F	WD	P
690	Jake O'Brien		2017-06-27							R	N/A				G	5			R	C	SO	S	5										
690	Jake O'Brien		2017-06-27																														
691	Jake O'Brien		2017-07-07	B	G	G	5		L170000691	L	4	50	DF	1968	G	5			L	D	SO	S	5								F	WD	P
691	Jake O'Brien		2017-07-07							C	4	50	DF	1968	P	3	Large WPH midpole	170000691(7)	C	D	SO	S	5								B	WD	G
691	Jake O'Brien		2017-07-07							R	4	50	DF	1968	P	3	Heavy checking at top	170000691(9)	R	D	SO	S	5			1	1	F	3	Needs guy guard	1710000691(8)			
692	Jake O'Brien		2017-07-07	H DE	G	G	5		L170000692	L	N/A				P	3	11 large WPH from GL to mid secti	170000692(10)	L	D	RO	S	5			1	1	P	4	Has been removed for road	170000692(11)	F	WD	G
692	Jake O'Brien		2017-07-07							R	N/A				F	5	1 Med WPH lower mid section	170000692(5)	R	D	RO	S	5			1	1	F	4	needs guy guard	170000692(12)			
692	Jake O'Brien		2017-07-07																														
693	Jake O'Brien		2017-07-07	AXS	G	G	5		L170000693	L	N/A				F	5	1 Med WPH lower section	170000693(6)	L	D	SO	S	5								F	WD	G
693	Jake O'Brien		2017-07-07							R	N/A				G	5			R	D	SO	S	5										
693	Jake O'Brien		2017-07-07																														
694	Jake O'Brien		2017-07-07	AXS	G	LL	5	Leaning ahead 20"	L170000694	L	N/A				G	5			L	D	RO	S	5								F	WD	P
694	Jake O'Brien		2017-07-07							R	N/A				G	5			R	D	RO	S	5								B	WD	P
694	Jake O'Brien		2017-07-07																														
695	Jake O'Brien		2017-07-07	A	G	G	5		L170000695	L	4	55	DF	1968	P	3	2 Sm WPH mid section and 1 med	170000695(12)	L	D	SO	S	5								F	WD	P
695	Jake O'Brien		2017-07-07							R	4	50	DF	1968	G	5			R	D	SO	S	5										
695	Jake O'Brien		2017-07-07																														
696	Jake O'Brien		2017-07-07	H DE	G	G	5		L170000696	L	4	55	DF	1968	P	3	Heavy checking throughout	170000696(14)	L	D	SO	S	5			1	1	F	3	Guy guard missing	L170000696(7)	F	WD	P
696	Jake O'Brien		2017-07-07							R	4	45	DF	1968	G	5			R	D	SO	S	5			1	1	F	3	Guy guard missing light be	L170000696(7)	B	WD	P
696	Jake O'Brien		2017-07-07																														
697	Jake O'Brien		2017-07-07	A	G	G	5		L170000697	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G
697	Jake O'Brien		2017-07-07							R	4	55	DF	1968	G	5			R	D	SO	S	5										
697	Jake O'Brien		2017-07-07																														
698	Jake O'Brien		2017-07-07	A	M	LL	5	Leaning ahead 18"	L170000698	L	4	55	DF	1968	F	4	1 Med WPH mid section, 3 large W	170000698(9)	L	D	RO	S	5								F	WD	P
698	Jake O'Brien		2017-07-07							R	4	55	DF	1968	G	5			R	D	RO	S	5										
698	Jake O'Brien		2017-07-07																														
699	Jake O'Brien		2017-07-07	AXS	M	LL	5	Leaning ahead 20"	L170000699	L	4	55	DF	1968	F	5	1 Sm WPH mid sec	170000699(6)	L	D	SO	S	5								F	WD	E
699	Jake O'Brien		2017-07-07							R	4	55	DF	1968	G	5			R	D	SO	S	5								B	WD	E
699	Jake O'Brien		2017-07-07																														
700	Jake O'Brien		2017-07-07	F	G	G	5		L170000700	L	N/A				F	4	1 Large WPH top sec, 2 sm WPH m	170000700(9)	L	D	SO	S	5								F	WD	G
700	Jake O'Brien		2017-07-07							R	N/A				P	3	1 Med WPH top sec and 1 large ne	70000700(11)	R	D	SO	S	5								B	WD	G
700	Jake O'Brien		2017-07-07																														
701	Jake O'Brien		2017-07-07	F	G	LL	5	Leaning ahead 30"	L170000701	L	N/A				F	5	3 Large WPH top sec and 1 sm WPI	170000701(13)	L	D	RO	S	5								F	WD	F
701	Jake O'Brien		2017-07-07							R	N/A				G	5			R	D	RO	S	5								B	WD	P
701	Jake O'Brien		2017-07-07																														
702	Jake O'Brien		2017-07-07	H DE	G	G	5		L170000702	L	N/A				F	5	4 sm WPH top sec, 1 med and 2 sm	170000702(13)	L	D	RO	S	5			1	1	F	3	Guy guards missing	170000702(14)	F	WD	G
702	Jake O'Brien		2017-07-07							R	N/A				P	4	1 Large WPH top sec and 3 large W	170000702(9)	R	D	RO	S	5			1	1	F	3	Guy guards missing	170000702(10)	B	WD	P
702	Jake O'Brien		2017-07-07																														
703	Jake O'Brien		2017-07-07	A	M	G	5		L170000703	L	N/A				P	4	3 sm WPH 2 Large WPH mid sec an	170000703(12)	L	D	SO	S	5								F	WD	G

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703	Jake O'Brien		2017-07-07							R	N/A				P	3	3 Large WPH mid sec, and 4 lg WPH	L170000703(10)	R	D	SO	S	5									B	WD	P
703	Jake O'Brien		2017-07-07																														
704	Jake O'Brien		2017-07-07	A	M	LL	5	Leaning ahead 20"	L170000704	L	N/A				F	5	2 Sm WPH top sec, 2 sm WPH mid	L170000704(7)	L	D	SO	S	5									F	WD	G
704	Jake O'Brien		2017-07-07							R	N/A				G	5			R	D	SO	S	5											
704	Jake O'Brien		2017-07-07																														
705	Jake O'Brien		2017-07-07	H DE	M	G	5		L170000705	L	4	50	DF	1968	G	5			L	D	SO	S	5			1	1	F	3	Guy guards missing	L170000705(8)	F	WD	G
705	Jake O'Brien		2017-07-07							R	4	50	DF	1968	G	5			R	D	SO	S	5			1	1	F	3	Guy guards missing	L170000705(9)	B	WD	G
705	Jake O'Brien		2017-07-07																														
706	Jake O'Brien		2017-07-07	A	G	G	5		L170000706	L	4	45	DF	1968	G	5			L	D	SO	S	5									F	WD	F
706	Jake O'Brien		2017-07-07							R	4	45	DF	1968	G	5			R	D	SO	S	5											
706	Jake O'Brien		2017-07-07																														
707	Jake O'Brien		2017-07-07	A	G	G	5		L170000707	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
707	Jake O'Brien		2017-07-07							R	4	55	DF	1968	G	5			R	D	SO	S	5											
707	Jake O'Brien		2017-07-07																														
708	Jake O'Brien		2017-07-07	A	M	G	5		L170000708	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
708	Jake O'Brien		2017-07-07							R	4	55	DF	1968	G	5			R	D	SO	S	5									B	WD	G
708	Jake O'Brien		2017-07-07																														
709	Jake O'Brien		2017-07-07	A	G	G	5		L170000709	L	N/A				G	5			L	D	SO	S	5									F	WD	G
709	Jake O'Brien		2017-07-07							R	N/A				F	5	1 Large 2 med WPH in lower sec	L170000709(6)	R	D	SO	S	5											
709	Jake O'Brien		2017-07-07																														
710	Jake O'Brien		2017-07-07	A	G	G	5	Top sign faded and back missing numbe	L170000710	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
710	Jake O'Brien		2017-07-07							R	4	55	DF	1968	F	5	1 Med WPH lower section	L170000710(7)	R	D	SO	S	5											
710	Jake O'Brien		2017-07-07																														
711	Jake O'Brien		2017-07-07	A	G	G	5		L170000711	L	4	55	DF	1968	F	5	Light checking from GL to 20' AGL	L170000711(5)	L	D	SO	S	5									F	WD	G
711	Jake O'Brien		2017-07-07							R	4	55	DF	1968	G	5			R	D	SO	S	5											
711	Jake O'Brien		2017-07-07																														
712	Jake O'Brien		2017-08-01	A	G	G	5		L170000712	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
712	Jake O'Brien		2017-08-01							R	4	55	DF	1968	G	5			R	D	SO	S	5											
712	Jake O'Brien		2017-08-01																														
713	Jake O'Brien		2017-08-01	A	G	G	5		L170000713	L	3	60	WC	2017	E	5			L	D	SO	S	5									F	WD	E
713	Jake O'Brien		2017-08-01							C	3	60	WC	2017	E	5			C	D	SO	S	5									B	WD	E
713	Jake O'Brien		2017-08-01							R	3	60	WC	2017	E	5			R	D	SO	S	5			2	2	G	5					
714	Jake O'Brien		2017-08-01	H DE	M	G	5		L170000714	L	4	50	DF	1968	G	5			L	D	SO	S	5			1	1	F	3	Guy guards missing	L170000714(6)	F	WD	G
714	Jake O'Brien		2017-08-01							R	4	50	DF	1968	G	5			R	D	SO	S	5			1	1	F	3	Guy guards missing	L170000714(5)			
714	Jake O'Brien		2017-08-01																														
715	Jake O'Brien		2017-08-01	A	G	LL	5	Str leaning ahead 16"	L170000715	L	4	50	DF	1968	F	5	3 med WPH mid section and 1 larg	L170000715(6)	L	D	SO	S	5									F	WD	G
715	Jake O'Brien		2017-08-01							R	4	50	DF	1968	G	5			R	D	SO	S	5											
715	Jake O'Brien		2017-08-01																														
716	Jake O'Brien		2017-08-01	AXS	P	LL	5	Left pole leaning ahead 12"	L170000716	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
716	Jake O'Brien		2017-08-01							R	4	55	DF	1968	G	5			R	D	SO	S	5											
716	Jake O'Brien		2017-08-01																														
717	Jake O'Brien		2017-08-01	AXS	G	G	5		L170000717	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
717	Jake O'Brien		2017-08-01							R	4	55	DF	1968	G	5			R	D	SO	S	5									B	WD	P
717	Jake O'Brien		2017-08-01																														
718	Jake O'Brien		2017-08-01	A	G	G	5		L170000718	L	4	45	DF	1968	G	5			L	D	SO	S	5									F	WD	G
718	Jake O'Brien		2017-08-01							R	4	45	DF	1968	G	5			R	D	SO	S	5											
718	Jake O'Brien		2017-08-01																														
719	Jake O'Brien	Chad Harvey	2017-07-16	F	G	G	5		L170000719	L	N/A				G	5			L	D	SO	S	5									F	WD	G
719	Jake O'Brien	Chad Harvey	2017-07-16							R	N/A				F	4	WPH Holes: 2 med at mid pole, 2 l	L170000719(6)	R	D	SO	S	5									B	WD	F
719	Jake O'Brien	Chad Harvey	2017-07-16																														
720	Jake O'Brien	Chad Harvey	2017-07-16	F	G	LL	5	Str leaning ahead 2-3 feet	L170000720	L	N/A				G	5			L	D	SO	S	5									F	WD	G
720	Jake O'Brien	Chad Harvey	2017-07-16							R	N/A				G	5			R	D	SO	S	5									B	WD	G
720	Jake O'Brien	Chad Harvey	2017-07-16																														
721	Jake O'Brien	Chad Harvey	2017-07-16	H DE	G	G	5		L170000721	L	4	55	DF	1968	G	5			L	D	SO	S	5			1	1	G	4	Missing guy guard	L170000721(3)	F	WD	F
721	Jake O'Brien	Chad Harvey	2017-07-16							R	4	55	DF	1968	G	5			R	D	SO	S	5			1	1	G	4	Missing guy guard	L170000721(3)	B	WD	F
721	Jake O'Brien	Chad Harvey	2017-07-16																														

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722	Jake O'Brien	Chad Harvey	2017-07-16	A	M	LD	5	Str leaning 6" left	L170000722	L	3	65	WC	2014	G	5			L	C	SO	S	5									F	ST	G
722	Jake O'Brien	Chad Harvey	2017-07-16							R	3	65	WC	2014	G	5			R	C	SO	S	5											
722	Jake O'Brien	Chad Harvey	2017-07-16																															
723	Jake O'Brien	Chad Harvey	2017-07-16	A	G	G	5		L170000723	L	3	65	DF	2008	G	5			L	D	SO	S	5									F	ST	G
723	Jake O'Brien	Chad Harvey	2017-07-16							R	3	65	WC	2015	G	5			R	D	SO	S	5											
723	Jake O'Brien	Chad Harvey	2017-07-16																															
724	Jake O'Brien	Chad Harvey	2017-07-16	A	G	G	5	Old str butts 6' ahead	L170000724	L	3	65	WC	2015	G	5			L	D	SO	S	5									F	WD	G
724	Jake O'Brien	Chad Harvey	2017-07-16							R	3	65	WC	2015	G	5			R	D	SO	S	5											
724	Jake O'Brien	Chad Harvey	2017-07-16																															
725	Jake O'Brien	Chad Harvey	2017-07-16	A	G	G	5		L170000725	L	3	55	WC	2015	G	5			L	D	SO	S	5									F	ST	G
725	Jake O'Brien	Chad Harvey	2017-07-16							R	3	55	WC	2015	G	5			R	D	SO	S	5											
725	Jake O'Brien	Chad Harvey	2017-07-16																															
726	Jake O'Brien	Chad Harvey	2017-07-16	EG	G	G	5		L170000726	L	N/A				G	5			L	D	SO	S	5			3	3	F	4	Damaged side guy wire, ma	L170000726(8)	F	WD	G
726	Jake O'Brien	Chad Harvey	2017-07-16							C	N/A				G	5			C	D	SO	S	5			2	2	G	5	Missing guy guards	L170000726(5)	B	WD	G
726	Jake O'Brien	Chad Harvey	2017-07-16							R	N/A				G	5			R	D	SO	S	5			2	2	G	5	Missing guy guards	L170000726(5)			
727	Jake O'Brien	Chad Harvey	2017-07-16	A	G	G	5		L170000727	L	3	55	WC	2015	G	5			L	D	SO	S	5									F	ST	G
727	Jake O'Brien	Chad Harvey	2017-07-16							C	3	55	WC	2015	G	5			R	D	SO	S	5											
727	Jake O'Brien	Chad Harvey	2017-07-16							R	3	55	WC	2015	G	5																		
728	Jake O'Brien	Chad Harvey	2017-07-16	H DE	G	G	5		L170000728	L	N/A				G	5			L	D	SO	S	5			1	1	G	4	Missing guy guard	L170000728(5)	F	WD	G
728	Jake O'Brien	Chad Harvey	2017-07-16							R	N/A				G	5			R	D	SO	S	5			1	1	G	4	Missing guy guard	L170000728(6)	B	WD	G
728	Jake O'Brien	Chad Harvey	2017-07-16																															
729	Jake O'Brien	Chad Harvey	2017-07-16	A	G	G	5		L170000729	L	3	55	WC	2015	G	5			L	C	SO	S	5									F	ST	G
729	Jake O'Brien	Chad Harvey	2017-07-16							R	3	55	WC	2015	G	5			R	C	SO	S	5											
729	Jake O'Brien	Chad Harvey	2017-07-16																															
730	Jake O'Brien	Chad Harvey	2017-07-16	A	M	G	5		L170000730	L	2	60	WC	2015	G	5			L	D	SO	S	5	1 Med WPH mi	000730(5)							F	ST	G
730	Jake O'Brien	Chad Harvey	2017-07-16							R	1	60	WC	2015	G	5			R	D	SO	S	5											
730	Jake O'Brien	Chad Harvey	2017-07-16																															
731	Jake O'Brien	Chad Harvey	2017-07-16	H DE	G	G	5		L170000731	L	N/A				G	5			L	D	SO	S	5			1	1	G	4	Missing guy guard	L170000731(5)	F	WD	G
731	Jake O'Brien	Chad Harvey	2017-07-16							R	N/A				G	5			R	D	SO	S	5			1	1	G	4	Missing guy guard	L170000731(6)	B	WD	G
731	Jake O'Brien	Chad Harvey	2017-07-16																															
732	Jake O'Brien	Chad Harvey	2017-07-16	A	G	G	5		L170000732	L	3	65	WC	2015	G	5	1 Small WPH mid pole	L170000732(7)	L	D	SO	U	2	Extensive bank	000732(9)							F	ST	G
732	Jake O'Brien	Chad Harvey	2017-07-16							R	3	65	WC	2015	G	5	2 Small WPH mid pole 1 med WPH	L170000732(6)	R	D	SO	S	5											
732	Jake O'Brien	Chad Harvey	2017-07-16																															
733	Jake O'Brien	Chad Harvey	2017-07-16	A	G	G	5		L170000733	L	2	60	WC	2003	G	5	1 Small WPH mid pole	L170000733(6)	L	D	SO	S	5									F	ST	G
733	Jake O'Brien	Chad Harvey	2017-07-16							R	2	60	WC	2013	G	5			R	D	SO	S	5											
733	Jake O'Brien	Chad Harvey	2017-07-16																															
734	Jake O'Brien	Chad Harvey	2017-07-16	A	G	G	5		L170000734	L	N/A				G	5			L	D	SO	S	5			1	1	F	4	Light rust, missing guy gua	L170000734(5)	F	WD	G
734	Jake O'Brien	Chad Harvey	2017-07-16							R	N/A				F	4	WPH 8 small 3 med throughout po	L170000734(7)	R	D	SO	S	5			1	1	G	5	Missing guy guard				
734	Jake O'Brien	Chad Harvey	2017-07-16																															
735	Jake O'Brien	Chad Harvey	2017-07-16	A	G	G	5		L170000735	L	N/A				G	4	Pole top splitting, needs anti split bolt installed		L	D	SO	S	5									F	WD	G
735	Jake O'Brien	Chad Harvey	2017-07-16							R	N/A				G	5			R	D	SO	S	5											
735	Jake O'Brien	Chad Harvey	2017-07-16																															
736	Jake O'Brien	Chad Harvey	2017-07-16	H DE	G	G	5		L170000736	L	3	55	DF	1968	G	5			L	D	SO	S	5			1	1	G	4	Missing guy guards	L170000736(5)	F	WD	G
736	Jake O'Brien	Chad Harvey	2017-07-16							R	3	55	DF	1968	G	5			R	D	SO	S	5			1	1	G	4	Missing guy guards	L170000736(6)	B	WD	G
736	Jake O'Brien	Chad Harvey	2017-07-16																															
737	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000737	L	2	55	WC	N/A	G	5			L	D	SO	S	5			1	1	G	5			F	WD	G
737	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A	55	N/A		G	5	1 Medium WPH mid section 1 sma	L170000737(6)	R	D	SO	S	5											
737	Jake O'Brien	Chad Harvey	2017-07-29																															
738	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000738	L	3	55	DF	2002	G	5			L	D	SO	S	5									F	WD	G
738	Jake O'Brien	Chad Harvey	2017-07-29							R	2	60	DF	2002	G	5			R	D	SO	S	5			1	1	G	5					
738	Jake O'Brien	Chad Harvey	2017-07-29																															
739	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000739	L	3	65	WC	2015	G	5			L	D	SW	S	5			3	3	G	4			F	ST	G
739	Jake O'Brien	Chad Harvey	2017-07-29							R	2	65	WC	2008	G	5			R	D	SO	S	5			3	3	G	4					
739	Jake O'Brien	Chad Harvey	2017-07-29																															
740	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000740	L	N/A				G	5			L	D	SO	S	5									F	WD	G
740	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A				G	5			R	D	SO	S	5											

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740	Jake O'Brien	Chad Harvey	2017-07-29																														
741	Jake O'Brien	Chad Harvey	2017-07-29	A	G	LL	5	Left pole leaning ahead 16"	L170000741	L	N/A				F	5	14 small WPH medium lower sectio	L170000741(7)	L	D	SO	S	5									F	WD	G
741	Jake O'Brien	Chad Harvey	2017-07-29							R	4	55	DF	1968	F	5	3 small WPH mid section	L170000741(5)	R	D	SO	S	5											
741	Jake O'Brien	Chad Harvey	2017-07-29																														
742	Jake O'Brien	Chad Harvey	2017-07-29	E	G	LL	5	Leaning back 10" centre pole	L170000742	L	N/A				G	5			L	D	SO	S	5									F	WD	G
742	Jake O'Brien	Chad Harvey	2017-07-29							C	N/A				G	5			C	D	SO	S	5									B	WD	G
742	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A				G	5			R	D	SO	S	5			1	1	O	3	Missing guy guard	L170000742(5)			
743	Jake O'Brien	Chad Harvey	2017-07-29	A	G	LL	5		L170000743	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
743	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A		DF	1968	G	5			R	D	SO	S	5											
743	Jake O'Brien	Chad Harvey	2017-07-29																														
744	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000744	L	4	45	DF	1968	G	4			L	D	SO	S	5									F	WD	G
744	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A				G	5	5 Small WPH 1 med, 1 large throug	L170000744(7)	R	D	SO	S	5											
744	Jake O'Brien	Chad Harvey	2017-07-29																														
745	Jake O'Brien	Chad Harvey	2017-07-29	H DE	G	G	5		L170000745	L	3	55	WC	2016	G	5			L	D	SO	S	5			1	1	O	3	Missing guy guard	L170000745(5)	F	WD	G
745	Jake O'Brien	Chad Harvey	2017-07-29							R	3	55	WC	2016	G	5			R	D	SO	S	5			1	1	O	3	Missing guy guard	L170000745(5)	B	WD	G
745	Jake O'Brien	Chad Harvey	2017-07-29																														
746	Jake O'Brien	Chad Harvey	2017-07-29	AX	G	G	5	Left pole leaning ahead 16"	L170000746	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	P
746	Jake O'Brien	Chad Harvey	2017-07-29							R	4	55	DF	1968	G	5			R	D	SO	S	5									B	WD	G
746	Jake O'Brien	Chad Harvey	2017-07-29																														
747	Jake O'Brien	Chad Harvey	2017-07-29	AX	G	LT/LL	5	Left pole leaning 8" left and ahead	L170000747	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
747	Jake O'Brien	Chad Harvey	2017-07-29							R	4	50	DF	1968	G	5			R	D	SO	S	5									B	WD	G
747	Jake O'Brien	Chad Harvey	2017-07-29																														
748	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000748	L	N/A	50	DF	1968	P	3	Ant dust from GL to 10' AGL	L170000748(5)	L	D	SO	S	5									F	WD	G
748	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A				G	5			R	D	SO	S	5											
748	Jake O'Brien	Chad Harvey	2017-07-29																														
749	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000749	L	N/A				G	5			L	D	SO	S	5									F	WD	G
749	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A				G	5			R	D	SO	S	5											
749	Jake O'Brien	Chad Harvey	2017-07-29																														
750	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000750	L	3	65	WC	2016	G	5			L	D	SO	S	5									F	ST	G
750	Jake O'Brien	Chad Harvey	2017-07-29							R	3	65	WC	2016	G	5			R	D	SO	S	5											
750	Jake O'Brien	Chad Harvey	2017-07-29																														
751	Jake O'Brien	Chad Harvey	2017-07-29	A	G	LL	5	Right pole leaning back 18"	L170000751	L	2	55	WC	2007	G	5	Small WPH top	L170000751(5)	L	D	SW	S	5	Has stabilizer on ground p		3	3	G	5			F	WD	G
751	Jake O'Brien	Chad Harvey	2017-07-29							R	2	55	WC	2007	G	5			R	D	SW	S	5			3	3	G	5	Lose guy hardware	L170000751(6)			
751	Jake O'Brien	Chad Harvey	2017-07-29																														
752	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000752	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
752	Jake O'Brien	Chad Harvey	2017-07-29							R	4	55	DF	1968	G	5			R	D	SO	S	5											
752	Jake O'Brien	Chad Harvey	2017-07-29																														
753	Jake O'Brien	Chad Harvey	2017-07-29	A	G	LT	5		L170000753	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
753	Jake O'Brien	Chad Harvey	2017-07-29							R	4	55	DF	1968	G	5			R	D	SO	S	5											
753	Jake O'Brien	Chad Harvey	2017-07-29																														
754	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000754	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	G
754	Jake O'Brien	Chad Harvey	2017-07-29							R	4	60	DF	1968	G	5			R	D	SO	S	5											
754	Jake O'Brien	Chad Harvey	2017-07-29																														
754A	Jake O'Brien	Chad Harvey	2017-07-29	H DE	G	G	5		L170000754A	L	2	55	WC	2009	G	5			L	D	SO	S	5			2	2	G	5			F	WD	G
754A	Jake O'Brien	Chad Harvey	2017-07-29							R	2	55	WC	2011	G	5			R	D	SO	S	5			2	2	G	5			B	WD	G
754A	Jake O'Brien	Chad Harvey	2017-07-29																														
755	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000755	L	3	60	WC	2017	G	5			L	D	SO	S	5									F	ST	G
755	Jake O'Brien	Chad Harvey	2017-07-29							R	3	60	WC	2017	G	5			R	D	SO	S	5											
755	Jake O'Brien	Chad Harvey	2017-07-29																														
756	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000756	L	N/A				G	5			L	D	SO	S	5									F	WD	F
756	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A			1967	G	5			R	D	SO	S	5											
756	Jake O'Brien	Chad Harvey	2017-07-29																														
757	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000757	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
757	Jake O'Brien	Chad Harvey	2017-07-29							R	4	55	DF	1968	G	5			R	D	SO	S	5											
757	Jake O'Brien	Chad Harvey	2017-07-29																														
758	Jake O'Brien	Chad Harvey	2017-07-16	A	G	G	5		L170000758	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F

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758	Jake O'Brien	Chad Harvey	2017-07-16							R	4	55	DF	1968	G	5			R	D	SO	S	5										
758	Jake O'Brien	Chad Harvey	2017-07-16																														
759	Jake O'Brien	Chad Harvey	2017-07-16	A	G	G	5		L170000759	L	N/A				P	3	Ant dust in checking from GL - 7' A	L170000759(5)	L	D	SO	S	5								F	WD	G
759	Jake O'Brien	Chad Harvey	2017-07-16							R	N/A				P	3	Ant dust in checking 4-8' AGL	L170000759(6)	R	D	SO	S	5										
759	Jake O'Brien	Chad Harvey	2017-07-16																														
760	Jake O'Brien	Chad Harvey	2017-07-16	A	G	LT	5		L170000760	L	N/A				G	5			L	D	SO	S	5								F	WD	F
760	Jake O'Brien	Chad Harvey	2017-07-16							R	N/A				G	5			R	D	SO	S	5										
760	Jake O'Brien	Chad Harvey	2017-07-16																														
761	Jake O'Brien	Chad Harvey	2017-07-16	A	G	G	5		L170000761	L	2	55	DF	1968	G	5	3 Small WPH mid to upper	L170000761(5)	L	D	SO	S	5								F	WD	F
761	Jake O'Brien	Chad Harvey	2017-07-16							R	2	55	DF	1968	G	5			R	D	SO	S	5										
761	Jake O'Brien	Chad Harvey	2017-07-16																														
762	Jake O'Brien	Chad Harvey	2017-07-16	A	G	G	5		L170000762	L	3	60	WC	2017	G	5			L	D	SO	S	5								F	ST	G
762	Jake O'Brien	Chad Harvey	2017-07-16							R	3	60	WC	2017	G	5			R	D	SO	S	5										
762	Jake O'Brien	Chad Harvey	2017-07-16																														
763	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000763	L	N/A				P	2	3 Large WPH pole top	L170000763(5)	L	D	SO	S	5								F	WD	P
763	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A				G	5			R	D	SO	S	5										
763	Jake O'Brien	Chad Harvey	2017-07-29																														
764	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000764	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	F
764	Jake O'Brien	Chad Harvey	2017-07-29							R	4	55	DF	1968	G	5			R	D	SO	S	5										
764	Jake O'Brien	Chad Harvey	2017-07-29																														
765	Jake O'Brien	Chad Harvey	2017-07-29	H DE	G	G	5	Structure leaning back 1'	L170000765	L	4	55	DF	1968	F	5	5 small WPH in mid section	L170000765(7)	L	D	SW	S	5								F	WD	P
765	Jake O'Brien	Chad Harvey	2017-07-29							R	4	55	DF	1968	G	5	1 Small WPH in mid pole	L170000765(8)	R	D	SW	S	5								F	WD	G
765	Jake O'Brien	Chad Harvey	2017-07-29																														
766	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000766	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	F
766	Jake O'Brien	Chad Harvey	2017-07-29							R	4	55	DF	1968	G	5	1 Med WPH, 3 small WPH	L170000766(6)	R	D	SO	S	5										
766	Jake O'Brien	Chad Harvey	2017-07-29																														
767	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000767	L	N/A				G	5			L	D	SO	S	5								F	WD	G
767	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A				G	5			R	D	SO	S	5										
767	Jake O'Brien	Chad Harvey	2017-07-29																														
768	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5	Right pole back 2' left pole back 16"	L170000768	L	4	60	WC	1968	G	5	16 Small WPH	L170000768(8)	L	D	SO	S	5								F	WD	G
768	Jake O'Brien	Chad Harvey	2017-07-29							R	4	60	WC	1968	G	5	16 Small WPH	L170000768(6)	R	D	SO	S	5										
768	Jake O'Brien	Chad Harvey	2017-07-29																														
769	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000769	L	4	50	DF	1968	G	5			L	D	SO	S	5								F	WD	G
769	Jake O'Brien	Chad Harvey	2017-07-29							R	4	45	DF	1968	G	5			R	D	SO	S	5										
769	Jake O'Brien	Chad Harvey	2017-07-29																														
770	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000770	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G
770	Jake O'Brien	Chad Harvey	2017-07-29							R	4	50	DF	1968	G	5			R	D	SO	S	5										
770	Jake O'Brien	Chad Harvey	2017-07-29																														
771	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000771	L	N/A				G	5			L	D	SO	S	5								F	WD	G
771	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A				G	5			R	D	SO	S	5										
771	Jake O'Brien	Chad Harvey	2017-07-29																														
772	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000772	L	4	55	DF	1968	G	5			L	D	SO	S	5								F	WD	G
772	Jake O'Brien	Chad Harvey	2017-07-29							R	4	55	DF	1968	G	5			R	D	SO	S	5										
772	Jake O'Brien	Chad Harvey	2017-07-29																														
773	Jake O'Brien	Chad Harvey	2017-07-29	AXS	G	G	5		L170000773	L	N/A				G	5			L	D	SO	S	5								F	WD	F
773	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A				G	5			R	D	SO	S	5								F	WD	F
773	Jake O'Brien	Chad Harvey	2017-07-29																														
774	Jake O'Brien	Chad Harvey	2017-07-29	F	G	G	5		L170000774	L	N/A				P	5	4 small WPH damage	L170000774(7)	L	D	SO	S	5								F	WD	G
774	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A				G	5			R	D	SO	S	5								B	WD	P
774	Jake O'Brien	Chad Harvey	2017-07-29																														
775	Jake O'Brien	Chad Harvey	2017-07-29	F	G	G	5		L170000775	L	4	60	DF	1968	F	5	1 Large WPH top section	L170000775(6)	L	D	SO	S	5								F	WD	G
775	Jake O'Brien	Chad Harvey	2017-07-29							R	4	55	DF	1968	G	5			R	D	SO	S	5								F	WD	G
775	Jake O'Brien	Chad Harvey	2017-07-29																														
776	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000776	L	4	N/A		1968	G	5			L	D	SO	S	5								F	WD	F
776	Jake O'Brien	Chad Harvey	2017-07-29							R	4	N/A		1968	G	5			R	D	SO	S	5										
776	Jake O'Brien	Chad Harvey	2017-07-29																														

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777	Jake O'Brien	Chad Harvey	2017-07-29	A	M	G	5		L170000777	L	4	60	DF	1968	F	5	Small WPH mid pole	L170000777(5)	L	D	SO	S	5									F	WD	G
777	Jake O'Brien	Chad Harvey	2017-07-29							R	4	55	DF	1968	G	5			R	D	SO	S	5											
777	Jake O'Brien	Chad Harvey	2017-07-29																															
778	Jake O'Brien	Chad Harvey	2017-07-29	A	G	LT	5	Structure leaning ahead 8"	L170000778	L	N/A				G	5			L	D	SO	S	5									F	WD	F
778	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A				G	5			R	D	SO	S	5											
778	Jake O'Brien	Chad Harvey	2017-07-29																															
779	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000779	L	4	65	WC	1968	G	5			L	D	SO	S	5									F	WD	G
779	Jake O'Brien	Chad Harvey	2017-07-29							R	4	65	WC	1968	G	5			R	D	SO	S	5											
779	Jake O'Brien	Chad Harvey	2017-07-29																															
780	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000780	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	F
780	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A				P	3	Ant dust in checking 2'-7' AGL	L170000780(6)	R	D	SO	S	5											
780	Jake O'Brien	Chad Harvey	2017-07-29																															
781	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000781	L	N/A				G	5			L	D	SO	S	5									F	WD	F
781	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A				G	5			R	D	SO	S	5											
781	Jake O'Brien	Chad Harvey	2017-07-29																															
782	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000782	L	N/A	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
782	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A	55	DF	1968	G	5			R	D	SO	S	5											
782	Jake O'Brien	Chad Harvey	2017-07-29																															
783	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000783	L	N/A				F	5	2 Medium WPH upper section	L170000783(6)	L	D	SO	S	5									F	WD	G
783	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A				G	5			R	D	SO	S	5											
783	Jake O'Brien	Chad Harvey	2017-07-29																															
784	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000784	L	4	50	DF	1968	P	3	Ant dust in checking from GL-20' A	L170000784(5)	L	D	SO	S	5									F	WD	G
784	Jake O'Brien	Chad Harvey	2017-07-29							R	4	45	DF	1968	G	5			R	D	SO	S	5											
784	Jake O'Brien	Chad Harvey	2017-07-29																															
785	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000785	L	N/A				F	5			L	D	SO	S	5									F	WD	F
785	Jake O'Brien	Chad Harvey	2017-07-29							R	N/A				P	3	Ant dust in checking from GL-6' Agl		R	D	SO	S	5											
785	Jake O'Brien	Chad Harvey	2017-07-29																															
786	Jake O'Brien	Chad Harvey	2017-07-29	A	G	G	5		L170000786	L	4	60	WC	1968	P	2	2 Small PWH, ant dust GL-7' AGL	L170000786(7)	L	D	SO	S	5									F	WD	G
786	Jake O'Brien	Chad Harvey	2017-07-29							R	4	60	WC	1968	P	3	Ant dust GL-15' AGL	L170000786(6)	R	D	SO	S	5											
786	Jake O'Brien	Chad Harvey	2017-07-29																															
787	Jake O'Brien	Chad Harvey	2017-07-30	E	G	G	5		L170000787	L	4	60	WC	1968	G	5			L	D	SO	S	5			3	3	G	5	Missing guy guards	L170000787(5)	F	WD	G
787	Jake O'Brien	Chad Harvey	2017-07-30							C	4	60	WC	1968	G	5			C	D	SO	S	5			2	2	G	5	Missing guy guards	L170000787(5)			
787	Jake O'Brien	Chad Harvey	2017-07-30							R	4	60	wc	1968	F	5	3 medium WPH mid pole	L170000787(7)	R	D	SO	S	5			1	1	G	5	Missing guy guards	L170000787(5)			
788	Jake O'Brien	Chad Harvey	2017-07-30	AXS	G	G	5		L170000788	L	N/A				G	5			L	D	SO	S	5									F	WD	F
788	Jake O'Brien	Chad Harvey	2017-07-30							R	4	55	DF	1968	G	5			R	D	SO	S	5									B	WD	F
788	Jake O'Brien	Chad Harvey	2017-07-30																															
789	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000789	L	N/A				G	5			L	D	SO	S	5									F	WD	G
789	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5			R	D	SO	S	5											
789	Jake O'Brien	Chad Harvey	2017-07-30																															
790	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000790	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	G
790	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5			R	D	SO	S	5											
790	Jake O'Brien	Chad Harvey	2017-07-30																															
791	Jake O'Brien	Chad Harvey	2017-07-30	A	G	LL	5	Right poole leaning 16" right	L170000791	L	N/A				G	5			L	D	SO	S	5									F	WD	P
791	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5			R	D	SO	S	5											
791	Jake O'Brien	Chad Harvey	2017-07-30																															
792	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000792	L	N/A				G	5			L	D	SO	S	5									F	WD	F
792	Jake O'Brien	Chad Harvey	2017-07-30							R	4	50	N/A	1968	G	5			R	D	SO	S	5											
792	Jake O'Brien	Chad Harvey	2017-07-30																															
793	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000793	L	N/A				G	5			L	D	SO	S	5									F	WD	G
793	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5			R	D	SO	S	5											
793	Jake O'Brien	Chad Harvey	2017-07-30																															
794	Jake O'Brien	Chad Harvey	2017-07-30	A	G	LT/LL	5	Structure leaning left 1'	L170000794	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	G
794	Jake O'Brien	Chad Harvey	2017-07-30							R	4	50	DF	1968	G	5	Leaning back 1'	L170000794(4)	R	D	SO	S	5											
794	Jake O'Brien	Chad Harvey	2017-07-30																															
795	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000795	L	4	60	WC	1968	G	5			L	D	SO	S	5									F	WD	G
795	Jake O'Brien	Chad Harvey	2017-07-30							R	4	55	WC	1968	G	5			R	D	SO	S	5											

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795	Jake O'Brien	Chad Harvey	2017-07-30																														
796	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000796	L	4	55	DF	1968	G	5			L	D	SO	S	5									F	WD	F
796	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5			R	D	SO	S	5											
796	Jake O'Brien	Chad Harvey	2017-07-30																														
797	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000797	L	4	60	WC	1968	F	4	6 small WPH mid to top, 1 large W	L170000797(6)	L	D	SO	S	5									F	WD	G
797	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				P	3	Ant dust in checking (heavy) from	L170000797(7)	C	D	SO	S	5											
797	Jake O'Brien	Chad Harvey	2017-07-30																														
798	Jake O'Brien	Chad Harvey	2017-07-30	A	G	LL	5	Leaning left 1'	L170000798	L	N/A				G	5			L	D	SO	S	5									F	WD	F
798	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5	Ant dust in checking GL-3' AGL		R	D	SO	S	5											
798	Jake O'Brien	Chad Harvey	2017-07-30																														
799	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000799	L	N/A				G	5			L	D	SO	S	5			1	1	G	5	Missing guy guards		F	WD	G
799	Jake O'Brien	Chad Harvey	2017-07-30							C	N/A				G	5			C	D	SO	S	5			2	2	G	5	Missing guy guards		B	WD	G
799	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				P	3	Ant dust in checking from GL-7' AG	L170000799(5)	R	D	SO	S	5			1	1	G	5	Missing guy guards				
800	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000800	L	N/A				G	5			L	D	SO	S	5									F	WD	G
800	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5			R	D	SO	S	5											
800	Jake O'Brien	Chad Harvey	2017-07-30																														
801	Jake O'Brien	Chad Harvey	2017-07-30	A	G	LT	5	Structure leaning back 8"	L170000801										L	D	SO	S	5									F	WD	G
801	Jake O'Brien	Chad Harvey	2017-07-30																R	D	SO	S	5											
801	Jake O'Brien	Chad Harvey	2017-07-30																														
802	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000802	L	N/A				G	5	1 Medium WPH on top of pole	L170000802(5)	L	D	SO	S	5									F	WD	G
802	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5			R	D	SO	S	5											
802	Jake O'Brien	Chad Harvey	2017-07-30																														
803	Jake O'Brien	Chad Harvey	2017-07-30	H DE	G	G	5		L170000803	L	N/A				G	5			L	D	SO	S	5			1	1	G	5			F	WD	G
803	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5			R	D	SO	S	5			1	1	P	3	Guy ran over, broke prefor	L170000803(5)			
803	Jake O'Brien	Chad Harvey	2017-07-30																														
804	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000804	L	3	65	WC	2015	G	5			L	D	SO	S	5									F	ST	G
804	Jake O'Brien	Chad Harvey	2017-07-30							R	3	65	WC	2015	G	5			R	D	SO	S	5											
804	Jake O'Brien	Chad Harvey	2017-07-30																														
805	Jake O'Brien	Chad Harvey	2017-07-30	E	G	G	5		L170000805	L	N/A				G	5			L	D	SO	S	5			1	1	G	5	Missing guy guards	L170000805(5)	F	WD	G
805	Jake O'Brien	Chad Harvey	2017-07-30							C	N/A				G	5			C	D	SO	S	5			2	2	G	5	Missing guy guards	L170000805(5)	B	WD	G
805	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5			R	D	SO	S	5			1	1	G	5	Missing guy guards	L170000805(5)			
806	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000806	L	3	60	DF	1968	G	5			L	D	SO	S	5									F	WD	G
806	Jake O'Brien	Chad Harvey	2017-07-30							R	3	60	DF	1968	G	5			R	D	SO	S	5											
806	Jake O'Brien	Chad Harvey	2017-07-30																														
807	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000807	L	3	55	WC	2017	G	5			L	D	SO	S	5									F	ST	G
807	Jake O'Brien	Chad Harvey	2017-07-30							R	3	55	WC	2017	G	5			R	D	SO	S	5											
807	Jake O'Brien	Chad Harvey	2017-07-30																														
808	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5	9 small 2 med WPH holes	L170000808	L	N/A				G	5			L	D	SO	S	5									F	WD	G
808	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5			R	D	SO	S	5											
808	Jake O'Brien	Chad Harvey	2017-07-30																														
809	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000809	L	4	55	WC	1968	F	5	7 small 2 medium WPH mid pole	L170000809	L	D	SO	S	5									F	WD	G
809	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5			R	D	SO	S	5											
809	Jake O'Brien	Chad Harvey	2017-07-30																														
810	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000810	L	N/A		DF	1968	G	5			L	D	SO	S	5									F	WD	G
810	Jake O'Brien	Chad Harvey	2017-07-30							R	4	55	WC	1968	G	5			R	D	SO	S	5											
810	Jake O'Brien	Chad Harvey	2017-07-30																														
811	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000811	L	3	60	WC	2017	G	5			L	D	SO	S	5									F	ST	G
811	Jake O'Brien	Chad Harvey	2017-07-30							R	3	60	WC	2017	G	5			R	D	SO	S	5											
811	Jake O'Brien	Chad Harvey	2017-07-30																														
812	Jake O'Brien	Chad Harvey	2017-07-30	E	G	G	5		L170000812	L	4	55	DF	1968	G	5			L	D	SO	S	5			3	3	G	5			F	WD	F
812	Jake O'Brien	Chad Harvey	2017-07-30							C	N/A				G	5			C	D	SO	S	5			2	2	G	5			B	WD	F
812	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5			R	D	SO	S	5			2	2	G	5	1 Guy missing guy guard	L170000812(5)			
813	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000813	L	3	55	WC	2017	G	5			L	D	SO	S	5									F	ST	G
813	Jake O'Brien	Chad Harvey	2017-07-30							R	3	55	WC	2017	G	5			R	D	SO	S	5											
813	Jake O'Brien	Chad Harvey	2017-07-30																														
814	Jake O'Brien	Chad Harvey	2017-07-30	E	G	G	5		L170000814	L	N/A				G	5			L	D	SO	S	5			2	2	G	5			F	WD	G

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Structure Number	Inpsctn Lead	Inspctn Second	Inspctn Date	STR Framing Type	STR No.	STR Straight-ness	STR Maint. Priority	STR Maintenance Comment	STR Deficiency Photo	POL Loc.	POL Class	POL Size	POL Species	POL Date Stamp	POL Cond.	POL Maint. Priority	POL Maintenance Comment	POL Deficiency Photo	FDN Loc	FDN Type	FDN Ground Type	FDN Ground Cond.	FDN Maintenance	FDN Maintenance Comment	FDN Deficiency Photo	G&A # of Guys	G&A # of Anchor	G&A Cond.	G&A Maint. Priority	G&A Maintenance Comment	G&A Deficiency Photo	XRM Loc.	XRM Type	XRM Cond.
814	Jake O'Brien	Chad Harvey	2017-07-30							C	N/A				G	5			C	D	SO	S	5			2	2	G	5			B	WD	G
814	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5			R	D	SO	S	5			2	2	G	5					
815	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000815	L	4	N/A		1968	G	5			L	D	SO	S	5									F	WD	G
815	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				F	5	2 med, 1 large WPH mid pole	.170000815(5)	R	D	SO	S	5											
815	Jake O'Brien	Chad Harvey	2017-07-30																														
816	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000816	L	N/A				G	5			L	D	SO	S	5									F	WD	G
816	Jake O'Brien	Chad Harvey	2017-07-30							R	4	55	DF	1968	G	5	2 Small WPH	.170000816(6)	R	D	SO	S	5											
816	Jake O'Brien	Chad Harvey	2017-07-30																														
817	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000817	L	N/A				G	5			L	D	SO	S	5									F	WD	G
817	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5	2 Med WPH, 3 Small WPH at top	.170000817(7)	R	D	SO	S	5											
817	Jake O'Brien	Chad Harvey	2017-07-30																														
818	Jake O'Brien	Chad Harvey	2017-07-30	E	G	G	5		L170000818	L	N/A				G	5			L	D	SO	S	5			2	2	G	5	Both missing guy guards	L170000818(5)	F	WD	G
818	Jake O'Brien	Chad Harvey	2017-07-30							C	N/A			1968	G	5			C	D	SO	S	5			2	2	G	5	Both missing guy guards	L170000818(5)			
818	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5			R	D	SO	S	5			2	2	G	5	Both missing guy guards	L170000818(5)			
819	Jake O'Brien	Chad Harvey	2017-07-30	H DE	G	G	5		L170000819										L	D	SO	S	5			2	2	G	5	Missing guy guards		F	WD	G
819	Jake O'Brien	Chad Harvey	2017-07-30																R	D	SO	S	5			2	2	G	5	Missing guy guards		B	WD	G
819	Jake O'Brien	Chad Harvey	2017-07-30																														
820	Jake O'Brien	Chad Harvey	2017-07-30	E	G	G	5	Upper sign faded on right side	L170000820	L	4	55	WC	1968	G	5			L	D	SO	S	5			2	2	G	5	Missing guards	L170000820(5)	F	WD	G
820	Jake O'Brien	Chad Harvey	2017-07-30							C	4	55	WC	1968	G	5			C	D	SO	S	5			2	2	G	5	Missing guy guards	L170000820(5)			
820	Jake O'Brien	Chad Harvey	2017-07-30							R	4	55	WC	1968	G	5			R	D	SO	S	5			2	2	G	5	Missing guy guards	L170000820(5)			
821	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000821	L	4	55	WC	1968	G	5	4 small WPH pole top	.170000821(7)	L	D	SO	S	5									F	WD	G
821	Jake O'Brien	Chad Harvey	2017-07-30							R	4	55	WC	1968	G	5	1 Small WPH pole top	.170000821(6)	R	D	SO	S	5									B	WD	G
821	Jake O'Brien	Chad Harvey	2017-07-30																														
822	Jake O'Brien	Chad Harvey	2017-07-30	A	G	LL	5	Leaning 8" right	L170000822	L	N/A				G	5			L	D	SO	S	5									F	WD	F
822	Jake O'Brien	Chad Harvey	2017-07-30							R	3	60	WC	1968	G	5			R	D	SO	S	5											
822	Jake O'Brien	Chad Harvey	2017-07-30																														
823	Jake O'Brien	Chad Harvey	2017-07-30	E	G	G	5		L170000823	L	N/A				G	5			L	D	SO	S	5			2	2	G	5			F	WD	F
823	Jake O'Brien	Chad Harvey	2017-07-30							C	N/A				G	5			C	D	SO	S	5			2	2	G	5			B	WD	F
823	Jake O'Brien	Chad Harvey	2017-07-30							R	N/A				G	5			R	D	SO	S	5			2	2	G	5					
824	Jake O'Brien	Chad Harvey	2017-07-30	A	G	G	5		L170000824	L	3	55	WC	1968	G	5			L	D	SO	S	5									F	WD	G
824	Jake O'Brien	Chad Harvey	2017-07-30							R	3	55	WC	1968	G	5			R	D	SO	S	5											
824	Jake O'Brien	Chad Harvey	2017-07-30																														
825	Jake O'Brien	Chad Harvey	2017-07-31	A	G	G	5		L170000825	L	N/A				G	5			L	D	SO	S	5									F	WD	F
825	Jake O'Brien	Chad Harvey	2017-07-31							R	N/A				F	5	Sm WPH lower section	.170000825(8)	R	D	SO	S	5											
825	Jake O'Brien	Chad Harvey	2017-07-31																														
826	Jake O'Brien	Chad Harvey	2017-07-31	A	G	G	5		L170000826	L	N/A				F	4	4 med WPH lower section 1 med W	170000826(12)	L	D	SO	S	5									F	WD	P
826	Jake O'Brien	Chad Harvey	2017-07-31							R	N/A				G	5			R	D	SO	S	5											
826	Jake O'Brien	Chad Harvey	2017-07-31																														
827	Jake O'Brien	Chad Harvey	2017-07-31	A	G	G	5		L170000827	L	N/A				G	5			L	D	SO	S	5									F	WD	G
827	Jake O'Brien	Chad Harvey	2017-07-31							R	N/A				F	5	1 med WPH lower section	.170000827(5)	R	D	SO	S	5											
827	Jake O'Brien	Chad Harvey	2017-07-31																														
828	Jake O'Brien	Chad Harvey	2017-07-31	D	G	G	5		L170000828	L	2	65	WC	2003	G	5			L	D	SO	S	5			1	1	G	5			F	WD	F
828	Jake O'Brien	Chad Harvey	2017-07-31							C	2	65	WC	2003	G	5			C	D	SO	S	5			2	2	G	5			B	WD	G
828	Jake O'Brien	Chad Harvey	2017-07-31							R	N/A	65	DF	1968	G	5			R	D	SO	S	5			1	1	G	5					
829	Jake O'Brien	Chad Harvey	2017-07-31	A	G	G	5		L170000829	L	N/A				G	5			L	D	SO	S	5									F	WD	P
829	Jake O'Brien	Chad Harvey	2017-07-31							R	N/A				G	5			R	D	SO	S	5											
829	Jake O'Brien	Chad Harvey	2017-07-31																														
830	Jake O'Brien	Chad Harvey	2017-07-31	A	G	G	5	Ahead top sign faded	L170000830	L	4	60	DF	1968	G	5			L	D	SO	S	5									F	WD	G
830	Jake O'Brien	Chad Harvey	2017-07-31							R	4	60	DF	1968	G	5			R	D	SO	S	5											
830	Jake O'Brien	Chad Harvey	2017-07-31																														
831	Jake O'Brien	Chad Harvey	2017-07-31	A	G	G	5		L170000831	L	4	55	WC	1968	G	5			L	D	SO	S	5									F	WD	G
831	Jake O'Brien	Chad Harvey	2017-07-31							R	4	50	WC	1968	G	5			R	D	SO	S	5											
831	Jake O'Brien	Chad Harvey	2017-07-31																														
832	Jake O'Brien	Chad Harvey	2017-07-31	A	G	G	5		L170000832	L	4	55	WC	1968	G	5			L	D	SO	S	5									F	WD	P
832	Jake O'Brien	Chad Harvey	2017-07-31							R	4	55	WC	1968	G	5			R	D	SO	S	5											
832	Jake O'Brien	Chad Harvey	2017-07-31																														

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833	Jake O'Brien	Chad Harvey	2017-07-31	A	G	G	5		L170000833	L	4	50	DF	1968	G	5			L	D	SO	S	5									F	WD	P
833	Jake O'Brien	Chad Harvey	2017-07-31							R	4	50	DF	1968	F	5	1 Med WPH top section	170000833(6)	R	D	SO	S	5											
833	Jake O'Brien	Chad Harvey	2017-07-31																														
834	Jake O'Brien	Chad Harvey	2017-07-31	A	G	G	5		L170000834	L	4	50	WC	1968	G	5			L	D	SO	S	5									F	WD	G
834	Jake O'Brien	Chad Harvey	2017-07-31							R	4	50	WC	2003	G	5			R	D	SO	S	5											
834	Jake O'Brien	Chad Harvey	2017-07-31																														
835	Jake O'Brien	Chad Harvey	2017-07-31	3DF	G	G	5		L170000835	L	1	80	DF	2005	G	5			L	D	SO	S	5			3	3	G	5			F	WD	G
835	Jake O'Brien	Chad Harvey	2017-07-31							C	1	80	DF	2005	G	5			C	D	SO	S	5			2	2	G	5			B	WD	G
835	Jake O'Brien	Chad Harvey	2017-07-31							R	1	80	DF	2005	G	5			R	D	SO	S	5			3	3	G	5					
836	Jake O'Brien	Chad Harvey	2017-07-31	3DE	G	G	5		L170000836	L	1	80	WC	2005	G	5			L	D	SO	S	5			3	3	G	5			F	WD	G
836	Jake O'Brien	Chad Harvey	2017-07-31							C	1	80	WC	2005	G	5			C	D	SO	S	5			2	2	G	5			B	WD	G
836	Jake O'Brien	Chad Harvey	2017-07-31							R	1	80	WC	2005	G	5			R	D	SO	S	5			3	3	G	5					

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113	2	Splitting throughough, twisted	L170000113(7), L170000113(8), L170000113(9)	L	WD	G	5			L	TG	CT	8	F	4	Needs 9 bells only has 8		1	SB	5	G						
113	5	Light twisting		R	WD	G	5			C	TG	CT	8	F	4	Needs 9 bells only has 8											
113										R	TG	CT	8	F	4	Needs 9 bells only has 8											
114	5			L	WD	E	5			L	TG	CT	8	G	5												
114										C	TG	CT	8	G	5												
114										R	TG	CT	8	G	5												
115	5			L	WD	G	5			L	BP	BS	8	P	4	Rust on top hub	L1720000115(7)										
115										C	BP	BS	8	P	4	Rust on top hub	L1720000115(8)										
115										R	BP	BS	8	P	4												
116	2	Splitting on right end	L170000116(5)	L	WD	G	5			L	BP	CT	8	P	3	String kicked ahead 6", one broken bell, top hub is rusty	L170000116(2), L170000116(6)										
116										C	BP	CT	8	P	4												
116										R	BP	CT	8	P	4												
117	3	Twisted	L170000117(5), L170000117(6)	L	WD	G	5			L	BP	CT	8	P	4												
117										C	BP	CT	8	P	4												
117										R	BP	CT	8	P	3	One chipped bell	L170000117(7)										
118	5			L	WD	G	5			L	BP	CT	8	P	4												
118	4	Twisted	L170000118(2), L170000118(4)							C	BP	CT	8	P	4												
118										R	BP	CT	8	P	4												
119	5			L	WD	G	5			L	BP	CT	8	P	4												
119	4	Twisted	L170000119(2), L170000119(4)							C	BP	CT	8	P	4												
119										R	BP	CT	8	P	4												
120	5			L	WD	E	5			L	TG	BS	8	G	5												
120										C	TG	BS	8	G	5												
120										R	TG	BS	8	G	5												
121	5			L	WD	E	5			L	TG	BS	8	G	5												
121										C	TG	BS	8	G	5												
121										R	TG	BS	8	G	5												
122	5			L	WD	E	5			L	BP	BS	8	P	4												
122										C	BP	BS	8	P	4												
122										R	BP	BS	8	P	4												
123	4	Weathered / twisted	, L170000123(7)	L	WD	F	5			L	BP	BS	8	P	4	Kicked back 6", top hub has rust	3), L170000123(5)										
123										C	BP	BS	8	P	4		L170000123(6)										
123										R	BP	BS	8	P	4												
124	4	Weathered	, L170000124(8)	L	WD	G	5			L	BP	BS	8	P	4												
124										C	BP	BS	8	P	4												
124										R	BP	BS	8	P	4												
125	5			L	WD	G	5			L	BP	BS	8	P	3	Top hub is rusty	L170000125(1)										
125										C	BP	BS	8	P	3	Top hub is rusty	L170000125(1)										
125										R	BP	BS	8	P	3	Top hub is discoloured	L170000125(1)										
126	4	Bowed 2-3"	, L170000126(3)	L	WD	G	5			L	BP	BS	8	P	4	Top hub has light rust	L170000126(4)										
126										C	BP	BS	8	P	4	Top hub has light rust	L170000126(5)										
126										R	BP	BS	8	P	4	Top hub has light rust	L170000126(6)										
127	4	Bowed 2-3"	, L170000127(3)	L	WD	G	5			L	BP	BS	8	P	4	Top hub is discoloured	L170000127(5)										

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127										C	BP	BS	8	P	4	Top hub is discoloured	L170000127(6)										
127										R	BP	BS	8	P	4	Top hub is discoloured	L170000127(7)										
128	5			L	WD	E	5			L	TG	BS	9	G	5													
128										C	TG	BS	9	G	5													
128										R	TG	BS	9	G	5													
129	5			L	WD	E	5			L	TG	BS	8	G	5													
129										R	TG	BS	8	G	5													
129																												
130	5			L	WD	E	5			L	TG	BS	8	G	5													
130										C	TG	BS	8	G	5													
130										R	TG	BS	8	G	5													
131	5			L	WD	G	5			L	BP	BS	8	P	4													
131										C	BP	BS	8	P	4													
131										R	BP	BS	8	P	4													
132	5			L	WD	E	5			L	TG	BS	8	G	5													
132										C	TG	BS	8	G	5													
132										R	TG	BS	8	G	5													
133	4	Weathered	L170000133(4)	L	WD	F	4	Weathered	L170000133(6)	L	BP	BS	8	P	4													
133	4	Weathered	L170000133(5)							C	BP	BS	8	P	4													
133										R	BP	BS	8	P	4													
134	5			L	WD	G	5			L	BP	BS	8	P	4	Discoloured top hub	L170000134(4)											
134										C	BP	BS	8	P	4	Discoloured top hub	L170000134(5)											
134										R	BP	BS	8	P	4	Discoloured top hub	L170000134(6)											
135	5			L	WD	E	5			L	TG	BS	9	E	5													
135										C	TG	BS	9	E	5													
135										R	TG	BS	9	E	5													
136	2	Light splitting on left end	L1720000136(6)	L	WD	G	5			L	BP	CT	8	P	4													
136										C	BP	CT	8	P	4													
136										R	BP	CT	8	P	3	Cotter pin coming out on second hub	L170000136(7)											
137	5			L	WD	E	5			L	TG	BS	8	E	5													
137										C	TG	BS	8	E	5													
137										R	TG	BS	8	E	5													
138	5			L	WD	E	5			L	TG	BS	9	E	5													
138										C	TG	BS	9	E	5													
138										R	TG	BS	9	E	5													
139	2	Light splitting on left end	L1720000139(6)	L	WD	G	5			L	BP	CT	8	P	4													
139										C	BP	CT	8	P	4													
139										R	BP	CT	8	P	4													
140	5			L	WD	E	5			L	TG	BS	9	E	5													
140										C	TG	BS	9	E	5													
140										R	TG	BS	9	E	5													
141	5			L	WD	E	5			L	TG	BS	8	E	5													
141										C	TG	BS	8	E	5													
141										R	TG	BS	8	E	5													
142	5			L	WD	E	5			L	TG	BS	9	E	5													
142										C	TG	BS	9	E	5													
142										R	TG	BS	9	E	5													
143	5			L	WD	E	5			L	TG	CT	8	E	5													
143										C	TG	CT	8	E	5													
143										R	TG	CT	8	E	5													
144	5			L	WD	E	5			L	TG	CT	8	E	5													
144										C	TG	CT	8	E	5													
144										R	TG	CT	8	E	5													
145	5			L	WD	E	5			L	TG	CT	8	E	5													
145										C	TG	CT	8	E	5													
145										R	TG	CT	8	E	5													

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146	5			L	WD	E	5			L	TG	CT	8	E	5												
146										C	TG	CT	8	E	5												
146										R	TG	CT	8	E	5												
147	5			L	WD	E	5			L	TG	CT	8	E	5												
147										C	TG	CT	8	E	5												
147										R	TG	CT	8	E	5												
148	5			L	WD	E	5			L	TG	CT	8	E	5												
148	5									C	TG	CT	8	E	5												
148										R	TG	CT	8	E	5												
149	5			L	WD	E	5			L	TG	CT	8	E	5												
149	5									C	TG	CT	8	E	5												
149										R	TG	CT	8	E	5												
150	5									L	BP	CT	8	P	4			2	HX	5	G						
150	5									C	BP	CT	8	P	4	Bird droppings on hubs	L170000150(5)										
150										R	BP	CT	8	P	4												
151	5			L	WD	F	5	Ahead brace bowed	L170000151(8)	L	BP	CT	8	P	4		L170000151(5)										
151										C	BP	CT	8	P	4		L170000151(6)										
151										R	BP	CT	8	P	4		L170000151(7)										
152	5			L	WD	E	5			L	TG	CT	8	E	5												
152										C	TG	CT	8	E	5												
152										R	TG	CT	8	E	5												
153	5			L	WD	E	5			L	TG	CT	8	E	5												
153										C	TG	CT	8	E	5												
153										R	TG	CT	8	E	5												
154	5	Light twisting on right end	, L170000154(9)	L	WD	G	5			L	BP	CT	8	P	4												
154										C	BP	CT	8	P	4	Rust on top hub	L170000154(7)										
154										R	BP	CT	8	P	3	1 broken bell and flash	), L170000154(6)										
155	5			L	WD	G	5	Both bowed	155(6), L170000155(7)	L	BP	CT	8	P	4	Pulled ahead 4-6"	L170000155(2)										
155										C	BP	CT	8	P	3	Top hub has heavy rust and possible	L170000155(5)										
155										R	BP	CT	8	P	4												
156	5			L	WD	G	5			L	BP	CT	8	P	4												
156										C	BP	CT	8	P	4												
156										R	BP	CT	8	P	4	Light rust on top hub	L170000156(5)										
157	5			L	WD	E	5			L	TG	CT	8	E	5												
157										C	TG	CT	8	E	5												
157										R	TG	CT	8	E	5												
158	5			L	WD	G	5			L	BP	CT	8	P	4	Very light rust on top hub	L170000158(6)										
158										C	BP	CT	8	P	4	Light rust on top hub	L170000158(5)										
158										R	BP	CT	8	P	4												
159	3	Arm twisting and slope grain on right end	, L170000159(8)	L	WD	G	5			L	BP	CT	8	P	3	1 Broken bell	L170000159(5)										
159										C	BP	CT	8	P	4												
159										R	BP	CT	8	P	4												
160	5			L	WD	F	5	Back brace bowed	L170000160(5)	L	TG	CT	8	E	5												
160										C	TG	CT	8	E	5												
160										R	TG	CT	8	E	5												
161	2	Bowed, weathered, and decayed	, L170000161(6)	L	WD	G	5			L	BP	CT	8	P	3	Heavy rust on hubs and flashover	L170000161(5)										
161										C	BP	CT	8	P	4												
161										R	BP	CT	8	P	3	Heavy rust on hubs	L170000161(6)										
162	5	Ahead bottom edge has light damage at mid se	L170000162(6)	L	WD	G	5			L	BP	CT	8	P	4	Pulled back 4-6"	L170000162(2)										
162										C	BP	CT	8	P	4												
162										R	BP	CT	8	P	4												
163	4	Bowed 2-3"	, L170000163(3)	L	WD	G	5			L	BP	BS	8	P	4												
163										C	BP	BS	8	P	4												
163										R	BP	BS	8	P	4												
164	4	Weathered	L170000164(10)	L	WD	F	4	Weathered	4(11), L170000164(12)	L	TG	BS	9	G	5			2	HX	G	5						
164	4	Weathered	L170000164(10)	R	WD	F	4	Weathered	4(11), L170000164(12)	C	TG	BS	9	G	5												

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164										R	TG	BS	9	G	5												
165	4	Bowed 4", weathered	, L170000165(6)	L	WD	G	5			L	BP	BS	8	P	4												
165	4	Bowed 4", weathered	, L170000165(6)							C	BP	BS	8	P	4												
165										R	BP	BS	8	P	4												
166	5			L	WD	E	5			L	TG	BS	8	G	5												
166										C	TG	BS	8	G	5												
166										R	TG	BS	8	G	5												
167	5									L	BP	BS	8	P	4			2	HX	G	5						
167	5									C	BP	BS	8	P	4												
167										R	BP	BS	8	P	4												
168	5									L	BP	BS	8	P	4			2	HX	G	5						
168	5									C	BP	BS	8	P	4												
168										R	BP	BS	8	P	4												
169	5	Weathered	, l170000169(3)	L	WD	F	4	Bowed	L170000169(5)	L	BP	BS	8	P	4												
169										C	BP	BS	8	P	4												
169										R	BP	BS	8	P	4												
170	4	Discoloured from rusting / needs galvanizing sp	L170000170(6)	L	WD	E	5			L	TG	BS	9	G	5												
170	4	Light damage on right end, needs galvanizing p	L170000170(5)							C	TG	BS	9	G	5												
170										R	TG	BS	9	G	5												
171	4	Weathered	, L170000171(4)	L	WD	G	5			L	BP	BS	8	P	4												
171	4	Weathered, twisted	, L170000171(4)							C	BP	BS	8	P	4												
171										R	BP	BS	8	P	4												
172	4	Weathered	, L170000172(3)	L	WD	G	5			L	BP	BS	8	P	4			2	HX	G	5						
172	4	Weathered	, L170000172(3)							C	BP	BS	8	P	4												
172										R	BP	BS	8	P	4												
173	4	Weathered	, L170000173(7)	L	WD	F	4	L170000173(1), L17000173(3)		L	BP	BS	8	P	4												
173	4	Weathered	, L170000173(7)							C	BP	BS	8	P	4												
173										R	BP	BS	8	P	4												
174	3	3 large knots in back arm	L170000174(5)							L	BP	BS	8	P	4												
174	4	Weathered	L170000174(6)							C	BP	BS	8	P	4												
174										R	BP	BS	8	P	4												
175	5			L	WD	E	5			L	TG	BS	8	G	5												
175										C	TG	BS	8	G	5												
175										R	TG	BS	8	G	5												
176	4	Bowed 4"	, L170000176(3)	L	WD	G	5			L	BP	BS	8	P	4												
176										C	BP	BS	8	P	4												
176										R	BP	BS	8	P	4												
177	3	Multiple knots throughout / weathered, bowed	L170000177(3)	L	WD	G	5			L	BP	BS	8	P	4	Rust on top hub	L170000177(1)										
177										C	BP	BS	8	P	4	Rust on top hub	L170000177(1)										
177										R	BP	BS	8	P	4	Rust on top hub	L170000177(1)										
178	4	Bowed 4", weathered	, L170000178(7)	L	WD	G	5			L	BP	BS	8	P	4	Rusty top hub	L170000178(1)										
178										C	BP	BS	8	P	4	Rusty top hub	L170000178(1)										
178										R	BP	BS	8	P	4	Rusty top hub	L170000178(1)										
179	3	Bowed, weathered	L170000179(8)	L	WD	G	5			L	BP	BS	8	P	2	Rusty top hub / crushed pin on secon	), L170000179(7)										
179	3	Splitting, weathered	, L170000179(7)							C	BP	BS	8	P	4	Rusty top hub	L170000179(8)										
179										R	BP	BS	8	P	4	Rusty top hub	L170000179(6)										
180	4	Weathered	, L170000180(7)	L	WD	G	5			L	BP	BS	8	P	4	Top bell is rusty	), L170000180(7)										
180	4	Weathered								C	BP	BS	8	P	4	Top bell is rusty	), L170000180(7)										
180										R	BP	BS	8	P	3	#4 bell has crushed pin	L170000180(5)										
181	5			L	WD	G	5			L	BP	BS	8	P	4												
181										C	BP	BS	8	P	4												
181										R	BP	BS	8	P	4												
182	5			L	WD	E	5			L	TG	BS	8	G	5												
182										C	TG	BS	8	G	5												
182										R	TG	BS	8	G	5												
183	5			L	WD	G	5			L	BP	BS	8	P	4												

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183										C	BP	BS	8	P	4												
183										R	BP	BS	8	P	4												
183	5			L	WD	G	5			L	BP	BS	8	P	4												
183										C	BP	BS	8	P	4												
183										R	BP	BS	8	P	4												
184	5	Weathered		L	WD	G	4	Missing centre sway bolt	L170000184(6)	L	BP	BS	8	P	4												
184										C	BP	BS	8	P	2	#3 Bell damaged pin, glass not sitting	L170000184(5)									
184										R	BP	BS	8	P	4												
185	5			L	WD	E	5			L	TG	BS	8	G	5												
185										C	TG	BS	8	G	5												
185										R	TG	BS	8	G	5												
186	5			L	WD	G	5			L	BP	BS	9	P	4			2	HX	G	5						
186	5									C	BP	BS	9	P	4												
186										R	BP	BS	9	P	4												
187	4	Twisted	L170000187(5)	L	WD	G	5			L	BP	BS	8	P	3	Top bell not seated properly, possible	L170000187(6)										
187										C	BP	BS	8	P	4												
187										R	BP	BS	8	P	4												
188	5			L	WD	G	5			L	BP	BS	8	P	4												
188										C	BP	BS	8	P	4												
188										R	BP	BS	8	P	4												
189	5			L	WD	G	5			L	BP	BS	8	P	4												
189										C	BP	BS	8	P	4												
189										R	BP	BS	8	P	4												
190	5									L	BP	BS	8	P	4												
190	5									C	BP	BS	8	P	4												
190										R	BP	BS	8	P	4												
191	5			L	WD	E	5			L	TG	CT	8	E	5												
191										C	TG	CT	8	E	5												
191										R	TG	CT	8	E	5												
192	5			L	WD	E	5			L	TG	CT	8	E	5												
192										C	TG	CT	8	E	5												
192										R	TG	CT	8	E	5												
193	5			L	WD	G	5			L	TG	CT	8,9	E	5			2	HX	G	5						
193	5			R	WD	G	5			C	TG	CT	8,9	E	5												
193										R	TG	CT	8,9	E	5												
194	5			L	WD	E	5			L	TG	CT	8	E	5												
194										C	TG	CT	8	E	5												
194										R	TG	CT	8	E	5												
195	3	Arm is weathered and has a new hole drilled through at left pole		L	WD	G	5	L170000195(5), L170000195(6), L170000195(8)		L	BP	CT	8	P	4												
195										C	BP	CT	8	P	4												
195										R	BP	CT	8	P	4	Light rust on top hub	L170000195(7)									
196	4	Twisting on ends	, L170000196(6)	L	WD	G	5			L	BP	CT	8	P	4												
196	4	Twisting on ends	, L170000196(6)							C	BP	CT	8	P	4	Rust on top hub	L170000196(7)									
196										R	BP	CT	8	P	4												
197	5			L	WD	G	5			L	BP	CT	8	P	4												
197	5									C	BP	CT	8	P	4	Dirty	L170000197(5)									
197										R	BP	CT	8	P	4												
198	4	Weathered & decaying	, L170000198(7)	L	WD	G	5			L	BP	CT	9	P	4			2	HX	G	5						
198	3	Arm has chunk missing on top edge and has ligh	L170000198(7)							C	BP	CT	9	P	4												
198										R	BP	CT	9	P	4												
199	5			L	WD	G	5			L	BP	CT	8	P	4												
199										C	BP	CT	8	P	4												
199										R	BP	CT	8	P	4												
200	5			L	WD	G	5			L	BP	CT	8	P	4	Pulled ahead 6-8"	L170000200(2)									
200										C	BP	CT	8	P	4	Pulled ahead 4-6"	L170000200(2)									
200										R	BP	CT	8	P	4												

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201	5			L	WD	E	5			L	TG	CT	8	E	5												
201										C	TG	CT	8	E	5												
201										R	TG	CT	8	E	5												
202	5	Top edge on left end has very light splitting (no	L170000202(7)							L	BP	CT	8	P	4			2	HX	G	5						
202	5									C	BP	CT	8	P	4												
202										R	BP	CT	8	P	4												
203	5			L	WD	F	5	Back brace bowed	L170000203(5)	L	BP	CT	8	P	4	Pulled back 4-6"	L170000203(2)									
203										C	BP	CT	8	P	4												
203										R	BP	CT	8	P	4	Light bird droppings	L170000203(6)									
204	5			L	WD	F	5	Back brace bowed	L170000204(5)	L	BP	CT	8	P	4												
204										C	BP	CT	8	P	4												
204										R	BP	CT	8	P	4												
205	5			L	WD	E	5			L	TG	CT	8	E	5												
205										C	TG	CT	8	E	5												
205										R	TG	CT	8	E	5												
206	5			L	WD	E	5			L	TG	CT	8	E	5												
206										C	TG	CT	8	E	5												
206										R	TG	CT	8	E	5												
207	2	Weathered and very light splitting on right end	L170000207(8)	L	WD	G	5			L	BP	CT	8	P	4	Light bird droppings	L170000207(9)									
207										C	BP	CT	8	P	4												
207										R	BP	CT	8	P	4												
208	5			L	WD	E	5			L	TG	CT	8	E	5												
208										C	TG	CT	8	E	5												
208										R	TG	CT	8	E	5												
209	3	5 knots close together and weathered	L170000209(8)	L	WD	G	5			L	BP	CT	8	P	4	Bird droppings	L170000209(6)									
209	5									C	BP	CT	8	P	4												
209										R	BP	CT	8	P	4												
210	5			L	WD	G	5			L	BP	CT	8	P	4												
210	4	Light twisting on right end	L170000210(8)							C	BP	CT	8	P	3	Heavy rust on top hub	L170000210(7)									
210										R	BP	CT	8	P	4												
211	5	Bowed due to not being adjusted properly, wea	L170000211(5)	L	WD	G	5			L	TG	CT	9	E	5												
211										C	TG	CT	9	E	5												
211										R	TG	CT	9	E	5												
212	5			L	WD	G	5			L	BP	BS	8	P	4												
212										C	BP	BS	8	P	4												
212										R	BP	BS	8	P	4												
213	5			L	WD	G	5			L	BP	BS	8	P	4												
213										C	BP	BS	8	P	4												
213										R	BP	BS	8	P	4												
214	5			L	WD	G	5			L	BP	BS	8	P	4												
214										C	BP	BS	8	P	4												
214										R	BP	BS	8	P	4												
215	5			L	WD	E	5			L	TG	BS	8	G	5												
215										C	TG	BS	8	G	5												
215										R	TG	BS	8	G	5												
216	5									L	BP	BS	8	P	4			2	HX	G	5						
216	5									C	BP	BS	8	P	4												
216										R	BP	BS	8	P	4												
217	5			L	WD	G	5			L	BP	BS	9	P	4			2	HX	G	5						
217										C	BP	BS	9	P	4												
217										R	BP	BS	9	P	4												
218	5	Weathered	L170000218(3)							L	BP	BS	8	P	4												
218	5	Weathered	L170000218(3)							C	BP	BS	8	P	4												
218										R	BP	BS	8	P	4												
219	5	Weathered	L170000219(3)	L	WD	G	5			L	BP	BS	8	P	4												
219										C	BP	BS	8	P	4												

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219										R	BP	BS	8	P	4												
220	5	Weathered		L	WD	G	5			L	BP	BS	8	P	4												
220										C	BP	BS	8	P	4												
220										R	BP	BS	8	P	4												
221	5	Weathered	, L170000221(3)	L	WD	G	5			L	BP	BS	8	P	4												
221										C	BP	BS	8	P	4												
221										R	BP	BS	8	P	4												
222	5	Bowed 4"	, L170000222(3)	L	WD	G	5			L	BP	BS	8	P	4												
222										C	BP	BS	8	P	4												
222										R	BP	BS	8	P	4												
223	5	Weathered	, L170000223(3)	L	WD	G	5			L	BP	BS	8	P	4												
223										C	BP	BS	8	P	4												
223										R	BP	BS	8	P	4												
224	5	Bowed 2-3"	, L170000224(3)	L	WD	G	5			L	BP	BS	8	P	4	Glass pulled ahead 4"	), L170000224(4)										
224										C	BP	BS	8	P	4	Glass pulled ahead 4"	), L170000224(4)										
224										R	BP	BS	8	P	4	Glass pulled ahead 4"	), L170000224(4)										
225	5			L	WD	G	5			L	TG	BS	8	G	5												
225										C	TG	BS	8	G	5												
225										R	TG	BS	8	G	5												
226	5			L	WD	G	5			L	TG	BS	8	G	5												
226										C	TG	BS	8	G	5												
226										R	TG	BS	8	G	5												
227	5			L	WD	G	5			L	TG	BS	8	G	5												
227										C	TG	BS	8	G	5												
227										R	TG	BS	8	G	5												
228	5			L	WD	G	5			L	TG	BS	8	G	5												
228										C	TG	BS	8	G	5												
228										R	TG	BS	8	G	5												
229	5	Weathered	, L170000229(3)	L	WD	G	5			L	BP	BS	8	P	4												
229										C	BP	BS	8	P	4												
229										R	BP	BS	8	P	4												
230	5			L	WD	E	5			L	TG	BS	8	G	5												
230										C	TG	BS	8	G	5												
230										R	TG	BS	8	G	5												
231	5	Weathered	, L170000231(3)	L	WD	G	5			L	TG	BS	9	G	5			2	HX	G	5						
231	5	Weathered	, L170000231(3)							C	TG	BS	9	G	5												
231										R	TG	BS	9	G	5												
232	3	Arm is splitting	L170000232(5)	L	WD	G	5			L	BP	BS	8	P	4												
232										C	BP	BS	8	P	4												
232										R	BP	BS	8	P	4												
233	5			L	WD	G	5			L	BP	BS	8	P	4												
233										C	BP	BS	8	P	4												
233										R	BP	BS	8	P	4												
234	5			L	WD	G	5			L	BP	BS	8	P	4												
234										C	BP	BS	8	P	4												
234										R	BP	BS	8	P	4												
235	5	Bowed 4"	, L170000235(3)	L	WD	G	5			L	BP	BS	8	P	4												
235										C	BP	BS	8	P	4												
235										R	BP	BS	8	P	4												
236	5			L	WD	E	5			L	TG	BS	9	G	5												
236	5									C	TG	BS	9	G	5												
236										R	TG	BS	9	G	5												
237	5	Bowed 3", weathered	, L170000237(7)	L	WD	G	5			L	BP	BS	8	P	3	2 Broken bells	L170000237(5)										
237										C	BP	BS	8	P	4												
237										R	BP	BS	8	P	4												
238	5	Weathered		L	WD	G	5			L	BP	BS	8	P	4												

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Structure Number	XRM Maint. Priority	XRM Maintenance Comment	XRM Deficiency Photo	XBR Loc.	XBR Type	XBR Cond.	XBR Maint. Priority	XBR Maintenance Comment	XBR Deficiency Photo	INS Loc.	INS TYPE	INS Fitting Type	INS Count	INS Cond.	INS Maint. Priority	INS Maintenance Comment	INS Deficiency Photo	VIB #/ phase	VIB Type	VI B Ma	VIB Maintenance Comment	VIB Def. Photo	AMK Cond.	AMK Maintenance Comment	AMK Deficiency Photo	AMK Maint. Priority	AMK Def. Photo
238	5	Weathered								C	BP	BS	8	P	4												
238										R	BP	BS	8	P	4												
239	5			L	WD	E	5			L	TG	BS	8	G	5												
239										C	TG	BS	8	G	5												
239										R	TG	BS	8	G	5												
240	5			L	WD	E	5			L	TG	BS	8	G	5												
240										C	TG	BS	8	G	5												
240										R	TG	BS	8	G	5												
241	5			L	WD	E	5			L	TG	BS	8	G	5												
241										C	TG	BS	8	G	5												
241										R	TG	BS	8	G	5												
242	5	Weathered / bowed 3"	, L170000242(3)	L	WD	G	5			L	BP	BS	8	P	4	Kicked ahead 3"											
242										C	BP	BS	8	P	4	Kicked ahead 3"											
242										R	BP	BS	8	P	4	Kicked ahead 3"											
243	5			L	WD	G	5			L	BP	BS	8	P	4												
243										C	BP	BS	8	P	4												
243										R	BP	BS	8	P	4												
244	5			L	WD	E	5			L	TG	BS	8	G	5												
244										C	TG	BS	8	G	5												
244										R	TG	BS	8	G	5												
245	5			L	WD	G	5			L	BP	BS	8	P	4												
245										C	BP	BS	8	P	4	Heavy rust on top hub rust on all hub), L170000245(6)											
245										R	BP	BS	8	P	4												
246	5			L	WD	G	5			L	BP	BS	8	P	4												
246										C	BP	BS	8	P	4												
246										R	BP	BS	8	P	4	Rust on top hub	L170000246(1)										
247	5			L	WD	E	5			L	TG	BS	8	G	5												
247										C	TG	BS	8	G	5												
247										R	TG	BS	8	G	5												
248	4	Left side is spliting	L710000248(4)	L	WD	G	5			L	BP	BS	8	P	4												
248										C	BP	BS	8	P	4												
248										R	BP	BS	8	P	4	Rust on top hub	L170000248(5)										
249	5			L	WD	E	5			L	TG	BS	8	G	5												
249										C	TG	BS	8	G	5												
249										R	TG	BS	8	G	5												
250	5	Bowed 4"	, L170000250(3)	L	WD	G	5			L	BP	BS	8	P	4	Rust on top hub, kicked back 6"	), L170000250(4)										
250										C	BP	BS	8	P	4	Rust on top hub, kicked back 6"	), L170000250(4)										
250										R	BP	BS	8	P	4	Rust on top hub, kicked back 6"	), L170000250(4)										
251	5			L	WD	E	5			L	TG	BS	8	G	5												
251										C	TG	BS	8	G	5												
251										R	TG	BS	8	G	5												
252	5	Weathered	, L170000252(6)	L	WD	G	5			L	BP	BS	8	P	4	Kicked back 4"	), L170000252(4)										
252										C	BP	BS	8	P	4	Kicked back 4"	), L170000252(4)										
252										R	BP	BS	8	P	4	Kicked back 4"	), L170000252(4)										
253	4	Bowed 3", weathered, twisted	, L170000253(4)	L	WD	G	5			L	BP	BS	8	P	4												
253										C	BP	BS	8	P	4												
253										R	BP	BS	8	P	4	Rust on top hub											
254	5			L	WD	G	5			L	BP	BS	8	P	4	Discoloured top hub											
254										C	BP	BS	8	P	4	Discoloured top hub											
254										R	BP	BS	8	P	4	Rusty top hub											
255	5			L	WD	E	5			L	TG	BS	8	G	5												
255										C	TG	BS	8	G	5												
255										R	TG	BS	8	G	5												
256	5			L	WD	E	5			L	TG	BS	8	G	5												
256										C	TG	BS	8	G	5												
256										R	TG	BS	8	G	5												

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257	5			L	WD	E	5			L	TG	BS	9	G	5			2	HX	G	5						
257	5			R	WD	E	5			C	TG	BS	9	G	5												
257										R	TG	BS	9	G	5												
258	5			L	WD	E	5			L	TG	CT	8	G	5	Pulled ahead 4-6"	), L170000258(4)										
258										C	TG	CT	8	G	5	Pulled ahead 4-6"	), L170000258(4)										
258										R	TG	CT	8	G	5	Pulled ahead 4-6"	), L170000258(4)										
259	5			L	WD	G	5			L	BP	CT	8	P	4												
259										C	BP	CT	8	P	4												
259										R	BP	CT	8	P	4	Pulled ahead 4-6"	L170000259(4)										
260	5			L	WD	E	5			L	TG	CT	8	G	5												
260										C	TG	CT	8	G	5												
260										R	TG	CT	8	G	5												
261	5			L	WD	G	5			L	BP	CT	8	P	4												
261										C	BP	CT	8	P	4												
261										R	BP	CT	8	P	4	Rust on top hub	L170000261(5)										
262	5			L	WD	E	5			L	TG	CT	8	G	5												
262										C	TG	CT	8	G	5												
262										R	TG	CT	8	G	5												
263	5			L	WD	G	5			L	BP	CT	8	P	4												
263										C	BP	CT	8	P	4	Bird droppings	L170000263(5)										
263										R	BP	CT	8	P	4												
264	5			L	WD	E	5			L	TG	CT	8	G	5												
264										C	TG	CT	8	G	5												
264										R	TG	CT	8	G	5												
265	5			L	WD	E	5			L	TG	CT	8	G	5												
265										C	TG	CT	8	G	5												
265										R	TG	CT	8	G	5												
266	5			L	WD	E	5			L	TG	CT	8	G	5												
266										C	TG	CT	8	G	5												
266										R	TG	CT	8	G	5												
267	5			L	WD	E	5			L	TG	CT	8	G	5												
267										C	TG	CT	8	G	5												
267										R	TG	CT	8	G	5												
268	5			L	WD	E	5			L	TG	CT	8	G	5												
268										C	TG	CT	8	G	5												
268										R	TG	CT	8	G	5												
269	2	Light splitting, slope grain, and twisting	, L170000269(8)	L	WD	G	5	Ahead brace bowed and weathered	L170000269(5)	L	BP	CT	8	P	4												
269										C	BP	CT	8	P	4												
269										R	BP	CT	8	P	4	Light rust top hub	L170000269(11)										
270	2	Heavy slope grain on left end	, L170000270(7)	L	WD	G	5			L	BP	CT	8	P	4	Rust on top hub	L170000270(5)										
270										C	BP	CT	8	P	4												
270										R	BP	CT	8	P	4												
271	2	Heaving bowing and splitting on bottom edge a	L170000271(7)	L	WD	G	5			L	BP	CT	8	P	2	Cotter pin has come out on top hub	L170000271(8)										
271										C	BP	CT	8	P	3	Rust on top hub	L170000271(7)										
271										R	BP	CT	8	P	3	Rust on top hub	L170000271(6)										
272	2	Bowed splitting, twisted, and slope grain *heav	L170000272(11)	L	WD	G	5			L	BP	CT	8	P	4												
272										C	BP	CT	8	P	4												
272										R	BP	CT	8	P	4												
273	5			L	WD	G	5			L	BP	CT	8	P	4	Rust on top hub, pulled back 4-6"	), L170000273(9)										
273										C	BP	CT	8	P	4	Pulled back 4-6"	), L170000273(4)										
273										R	BP	CT	8	P	4	Pulled back 4-6"	), L170000273(4)										
274	2	Light splitting on left end and decay	, L170000274(5)	L	WD	G	5			L	BP	CT	8	P	3	1 broken bell, 1 chipped bell and hea	), L170000274(9)										
274										C	BP	CT	8	P	3	Heavy rust on top hub	L170000274(10)										
274										R	BP	CT	8	P	4												
275	5			L	WD	E	5			L	TG	CT	8	G	5												
275										C	TG	CT	8	G	5												

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275										R	TG	CT	8	G	5												
276	5			L	WD	E	5			L	TG	CT	8	E	5												
276										C	TG	CT	8	E	5												
276										R	TG	CT	8	E	5												
277	5			L	WD	G	5			L	BP	CT	8	P	3	Heavy rust on hubs	L170000277(7)										
277										C	BP	CT	8	P	3	Rust and flashover	L170000277(8)										
277										R	BP	CT	8	P	4												
278	5			L	WD	G	5			L	BP	CT	8	P	4												
278										C	BP	CT	8	P	4												
278										R	BP	CT	8	P	3	Heavy rust on top hub	L170000278(5)										
279	5			L	WD	G	5			L	BP	CT	8	P	4												
279										C	BP	CT	8	P	4												
279										R	BP	CT	8	P	4												
280	5			L	WD	F	5	Back brace bowed	L170000280(5)	L	BP	CT	8	P	4												
280										C	BP	CT	8	P	4	Bird droppings	L170000280(7)										
280										R	BP	CT	8	P	4												
281	5			L	WD	G	5			L	BP	CT	9	P	4			2	HX	G	5						
281										C	BP	CT	9	P	4												
281										R	BP	CT	9	P	4												
282	2	Arms have light splitting on right end	L170000282(6)	L	WD	G	5			L	BP	CT	8	P	4												
282										C	BP	CT	8	P	4												
282										R	BP	CT	8	P	4												
283	5			L	WD	E	5			L	TG	CT	8	E	5												
283										C	TG	CT	8	E	5												
283										R	TG	CT	8	E	5												
284	5			L	WD	E	5			L	TG	CT	8	E	5												
284										C	TG	CT	8	E	5												
284										R	TG	CT	8	E	5												
285	5			L	WD	G	5			L	BP	CT	8	P	4												
285										C	BP	CT	8	P	3	Heavy rust on top bell	L170000285(5)										
285										R	BP	CT	8	P	3	Heavy rust on top bell	L170000285(6)										
286	4	Twisting on left end	L170000286(7)	L	WD	G	5			L	BP	CT	8	P	4												
286										C	BP	CT	8	P	4	Light rust on top hub	L170000286(5)										
286										R	BP	CT	8	P	3	Light rust on top hub	L170000286(6)										
287	2	Bowed and weathered	L170000287(7)	L	WD	G	5			L	BP	CT	8	P	4												
287										C	BP	CT	8	P	4												
287										R	BP	CT	8	P	4	Light rust on top hub	L170000287(8)										
288	3	Twisting on right and bowed	L170000288(7)	L	WD	G	5			L	BP	CT	8	P	4												
288										C	BP	CT	8	P	4												
288										R	BP	CT	8	P	3	Heavy rust on top hub	L170000288(8)										
289	5			L	WD	G	5			L	BP	CT	8	P	3	Rust on bells (possible flashover)	L170000289(7)										
289										C	BP	CT	8	P	4												
289										R	BP	CT	8	P	4												
290	5	Left end has light twisting	L170000290(8)							L	BP	CT	8	P	4												
290	5									C	BP	CT	8	P	4												
290										R	BP	CT	8	P	4												
291	5			L	WD	E	5			L	TG	CT	8	E	5												
291										C	TG	CT	8	E	5												
291										R	TG	CT	8	E	5												
292	2	Slope grain and bowed	L170000292(9)	L	WD	G	5			L	BP	CT	8	P	4												
292										C	BP	CT	8	P	4	Rust on top hub	L170000292(5)										
292										R	BP	CT	8	P	3	Flashover	), L170000292(7)										
293	5			L	WD	G	5			L	BP	BS	8	P	3	Rusty hubs	L170000293(5)										
293										C	BP	BS	8	P	3	Rusty hubs	L170000293(6)										
293										R	BP	BS	8	P	3	Rusty hubs	L170000293(7)										
294	5			L	WD	G	5			L	BP	BS	8	P	3	Rusty hubs	L170000294(5)										

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294										C	BP	BS	8	P	3	Rusty hubs	L170000294(5)										
294										R	BP	BS	8	P	3	Rusty hubs	L170000294(5)										
295	5			L	WD	G	5			L	BP	BS	8	P	4													
295	5									C	BP	BS	8	P	4													
295										R	BP	BS	8	P	4													
296	5			L	WD	G	5			L	BP	BS	8	P	4													
296	5									C	BP	BS	8	P	4													
296										R	BP	BS	8	P	3	Rusty top hub	L170000296(5)										
297	4	Slope grain / bowed 4"	, L170000297(1)	L	WD	G	5			L	BP	BS	8	P	4													
297										C	BP	BS	8	P	4													
297										R	BP	BS	8	P	4													
298	4	Bowed 4", twisted	, L170000298(4)	L	WD	G	5			L	BP	BS	8	P	4													
298										C	BP	BS	8	P	4													
298										R	BP	BS	8	P	4													
299	5	Weathered	, L170000299(3)	L	WD	G	5			L	BP	BS	8	P	4													
299										C	BP	BS	8	P	4													
299										R	BP	BS	8	P	4													
300	5			L	WD	G	5			L	BP	BS	8	P	3	Rusty hubs	L170000300(5)										
300										C	BP	BS	8	P	4													
300										R	BP	BS	8	P	4													
301	5	Weathered	, L170000301(3)	L	WD	F	5	Twisted	L170000301(5)	L	BP	BS	8	P	4													
301										C	BP	BS	8	P	4													
301										R	BP	BS	8	P	4													
302	5			L	WD	G	5			L	BP	BS	8	P	4													
302										C	BP	BS	8	P	4													
302										R	BP	BS	8	P	4													
303	3	Slope grain	, L170000303(7)	L	WD	G	5			L	BP	BS	8	P	4													
303										C	BP	BS	8	P	4													
303										R	BP	BS	8	P	3	Rusty top hub	L170000303(5)										
304	5			L	WD	G	5			L	BP	BS	8	P	4													
304										C	BP	BS	8	P	4													
304										R	BP	BS	8	P	4													
305	4	Bowed 4-6"	, L170000305(3)	L	WD	G	5			L	BP	BS	8	P	4													
305										C	BP	BS	8	P	4													
305										R	BP	BS	8	P	4													
306	4	Bowed 4"	, L170000306(3)	L	WD	G	5			L	BP	BS	8	P	4													
306										C	BP	BS	8	P	4													
306										R	BP	BS	8	P	4													
307	5	Bowed 3"	, L170000307(3)	L	WD	G	5			L	BP	BS	8	P	4													
307										C	BP	BS	8	P	4													
307										R	BP	BS	8	P	4													
308	5	Bowed 3", weathered	, L170000308(3)	L	WD	G	5			L	BP	BS	8	P	4													
308										C	BP	BS	8	P	4													
308										R	BP	BS	8	P	4													
309	5	Bowed 3"	, L170000309(3)	L	WD	G	5			L	BP	BS	8	P	4													
309										C	BP	BS	8	P	4													
309										R	BP	BS	8	P	4													
310	3	Bowed 6"+	, L170000310(3)	L	WD	G	5			L	BP	BS	8	P	4													
310										C	BP	BS	8	P	4													
310										R	BP	BS	8	P	4													
311	5			L	WD	G	5			L	BP	BS	8	P	4	String kicked back 6" rust on top hub	), L170000311(3)										
311										C	BP	BS	8	P	4	String kicked back 2"	), L170000311(4)										
311										R	BP	BS	8	P	4													
312	5	Bowed 3"	, L170000312(3)	L	WD	G	5			L	BP	BS	8	P	4													
312										C	BP	BS	8	P	4													
312										R	BP	BS	8	P	4													

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313	3	Slope grain, splitting	, L170000313(7)	L	WD	G	5			L	BP	BS	8	P	4												
313										C	BP	BS	8	P	4												
313										R	BP	BS	8	P	4												
314	5			L	WD	F	5	Top left ahead sway end is splitting	L170000314(7)	L	BP	BS	8	P	4												
314										C	BP	BS	8	P	4												
314										R	BP	BS	8	P	4												
315	3	Twisted, splitting	, L170000315(8)	L	WD	G	5			L	BP	BS	8	P	4												
315										C	BP	BS	8	P	4												
315										R	BP	BS	8	P	4												
316	5	Weathered	, L170000316(3)							L	BP	BS	8	P	2	1 Broken bell	L170000316(8)										
316	5	Weathered	, L170000316(3)							C	BP	BS	8	P	4												
316										R	BP	BS	8	P	2	1 Broken bell	L170000316(7)										
317	5			L	WD	G	5			L	BP	BS	8	P	4												
317										C	BP	BS	8	P	4												
317										R	BP	BS	8	P	4												
318	5			L	WD	E	5			L	TG	BS	9	G	5			2	HX	G	5						
318										C	TG	BS	9	G	5												
318										R	TG	BS	9	G	5												
319	4	Weathered, twisted	, L170000319(4)	L	WD	G	5			L	BP	BS	9	P	4			2	HX	G	5						
319	4	Weathered, twisted	, L170000319(4)							C	BP	BS	9	P	4												
319										R	BP	BS	9	P	4												
320	5			L	WD	G	5	Ahead brace bowed and weathered	L170000269(5)	L	EP	BS	N/A	G	5	Kicked ahead 3"											
320										C	EP	BS	N/A	G	5	Kicked ahead 3"											
320										R	EP	BS	N/A	G	5	Kicked ahead 3"											
321	5	Weathered		L	WD	G	5			L	BP	BS	8	P	4												
321										C	BP	BS	8	P	4												
321										R	BP	BS	8	P	4												
322	4	Bowed 4-6", weathered	, L170000322(6)	L	WD	G	5			L	BP	BS	8	P	4												
322										C	BP	BS	8	P	4												
322										R	BP	BS	8	P	4												
323	2	Bowed and twisted	, L170000323(8)	L	WD	G	5			L	BP	CT	8	P	4	Pulled ahead 4-6"	), L170000323(4)										
323										C	BP	CT	8	P	4	Pulled ahead 4-6"	), L170000323(4)										
323										R	BP	CT	8	P	4	Pulled ahead 4-6", rust on top hub	, L170000323(10)										
324	2	Bowed and slope grain	, L170000324(7)	L	WD	F	5	Bowed	L170000324(11)	L	BP	CT	8	P	4												
324										C	BP	CT	8	P	2	Cotter key has come out on second b	L170000324(8)										
324										R	BP	CT	8	P	4												
325	4	Twisting on left end	L170000325(7)	L	WD	F	5	Back brace bowed	L170000325(6)	L	BP	CT	8	P	4												
325										C	BP	CT	8	P	4												
325										R	BP	CT	8	P	4	Rust on top hub	L170000325(5)										
326	3	Left end twisted and two knot eyes on top of ar	L170000326(7)	L	WD	G	5			L	BP	CT	8	P	4	Pulled ahead 4-6"	), L170000326(4)										
326										C	BP	CT	8	P	4	Pulled ahead 4-6"	), L170000326(4)										
326										R	BP	CT	8	P	4												
327	5			L	WD	G	5			L	BP	CT	8	P	4												
327										C	BP	CT	8	P	4												
327										R	BP	CT	8	P	4												
328	2	Slope grain on right end	, L710000328(6)	L	WD	G	5			L	BP	CT	8	P	4												
328										C	BP	CT	8	P	4												
328										R	BP	CT	8	P	4	Rust on top hub	), L170000328(6)										
329	5			L	WD	G	5			L	BP	CT	8	P	4												
329										C	BP	CT	8	P	4												
329										R	BP	CT	8	P	4												
330	5									L	BP	CT	8	P	4												
330	5									C	BP	CT	8	P	4												
330										R	BP	CT	8	P	4												
331	5	L170000331(5), L170000331(6)		L	WD	F	3	Both braces bowed	331(7), L170000331(9)	L	BP	CT	8	P	4												
331										C	BP	CT	8	P	4												

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331										R	BP	CT	8	P	4												
332	2	Right end twisted and decay (*long back span)		L	WD	G	5	L170000332(5), L170000332(6)		L	BP	CT	8	P	4	Rust on top hub	L1700000332(8)										
332										C	BP	CT	8	P	4												
332										R	BP	CT	8	P	4												
333	2	Splitting throughout, bowed and weathered	, L170000333(7)	L	WD	G	5			L	BP	CT	8	P	4												
333										C	BP	CT	8	P	4												
333										R	BP	CT	8	P	3	Rust and flashover	), L170000333(9)										
334	2	Right end bowed, weathered *heavy span back	L170000334(10)	L	WD	G	5			L	BP	CT	8	P	4												
334										C	BP	CT	8	P	4												
334										R	BP	CT	8	P	3	Rust on top hub	L170000334(5)										
335	2	Slope grain and decay	, L170000335(7)	L	WD	G	5			L	BP	CT	8	P	4												
335										C	BP	CT	8	P	4												
335										R	BP	CT	8	P	4												
336	2	Light splitting on left end	L170000336(7)	L	WD	G	5			L	BP	CT	9	P	4												
336	5									C	BP	CT	9	P	4												
336										R	BP	CT	9	P	4												
337	2	Bowed and large knot with slope grain on the ri	L170000337(7)	L	WD	G	5			L	BP	CT	8	P	4												
337										C	BP	CT	8	P	4												
337										R	BP	CT	8	P	4	Light rust on top hub	L170000337(5)										
338	2	Light slope grain on left end, weathered and lig	L170000338(8)	L	WD	G	5			L	BP	CT	8	P	4												
338										C	BP	CT	8	P	4												
338										R	BP	CT	8	P	4												
339	2	Slope grain & weathered	, L170000339(8)	L	WD	G	5			L	BP	CT	8	P	4	Light rust on top hub	L170000339(9)										
339										C	BP	CT	8	P	4												
339										R	BP	CT	8	P	4												
340	5			L	WD	G	5			L	BP	CT	8	P	4												
340	5									C	BP	CT	8	P	4												
340										R	BP	CT	8	P	4												
341	2	Slope grain throughout	, L170000341(7)	L	WD	G	5			L	BP	CT	8	P	4												
341	5									C	BP	CT	8	P	4	Light rust	L170000341(6)										
341										R	BP	CT	8	P	3	Flashover	L170000341(5)										
342				L	WD	P	2	Slope grain and decay	2(10), L170000342(11)	L	BP	CT	8	P	4												
342										C	BP	CT	8	P	4												
342										R	BP	CT	8	P	4												
343	2	Slope grain throughout	L170000343(10)	L	WD	G	5			L	BP	CT	8	P	4												
343										C	BP	CT	8	P	4												
343										R	BP	CT	8	P	4	Rust on top hub	L170000343(5)										
344	5			L	WD	G	5			L	BP	CT	8	P	4												
344										C	BP	CT	8	P	4												
344										R	BP	CT	8	P	4												
345	5									L	BP	BS	8	P	4												
345	5									C	BP	BS	8	P	4												
345										R	BP	BS	8	P	4												
346	5			L	WD	G	5			L	BP	BS	8	P	4												
346										C	BP	BS	8	P	4												
346										R	BP	BS	8	P	4												
347	2	Splitting on right end	L170000347(5)	L	WD	G	5			L	BP	BS	8	P	4												
347										C	BP	BS	8	P	4												
347										R	BP	BS	8	P	4	Top bell cotter pin is pulled out											
348	5	Bowed 3"	, L170000348(3)	L	WD	G	5			L	BP	BS	8	P	4												
348										C	BP	BS	8	P	4												
348										R	BP	BS	8	P	4												
349	5			L	WD	G	5			L	BP	BS	8	P	4												
349										C	BP	BS	8	P	4												
349										R	BP	BS	8	P	4												
350	5	Weathered	, L170000350(3)	L	WD	G	5			L	BP	BS	8	P	4												

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350										C	BP	BS	8	P	4												
350										R	BP	BS	8	P	4												
351	5			L	WD	G	5			L	BP	BS	8	P	4												
351										C	BP	BS	8	P	4												
351										R	BP	BS	8	P	4												
352	5			L	WD	G	5			L	BP	BS	8	P	4												
352										C	BP	BS	8	P	4												
352										R	BP	BS	8	P	4												
353	3	Slope grain	L170000353(3)	L	WD	G	5			L	BP	BS	8	P	4												
353										C	BP	BS	8	P	4												
353										R	BP	BS	8	P	4												
354	3	Slope grain	L170000354(8)	L	WD	G	5			L	BP	BS	8	P	4												
354										C	BP	BS	8	P	4												
354										R	BP	BS	8	P	4												
355	5	Bowed 3"	L170000355(3)	L	WD	G	5			L	BP	BS	8	P	4												
355										C	BP	BS	8	P	4												
355										R	BP	BS	8	P	4												
356	5	Bowed 4"	L170000356(1)	L	WD	G	5			L	BP	BS	8	P	4												
356										C	BP	BS	8	P	4												
356										R	BP	BS	8	P	4												
357	4	Bowed 4"	L170000357(1)	L	WD	G	5			L	BP	BS	8	P	4												
357										C	BP	BS	8	P	4												
357										R	BP	BS	8	P	4												
358	5	Bowed 3"	L170000358(1)	L	WD	G	5			L	BP	BS	8	P	4												
358										C	BP	BS	8	P	4												
358										R	BP	BS	8	P	4												
359	5			L	WD	G	5			L	BP	BS	8	P	4												
359										C	BP	BS	8	P	4												
359										R	BP	BS	8	P	4												
360	5									L	BP	BS	8	P	4			2	HX	G	5						
360	5									C	BP	BS	8	P	4												
360										R	BP	BS	8	P	4												
361	5	Weathered	L170000361(7)	L	WD	G	5			L	BP	BS	8	P	4												
361										C	BP	BS	8	P	4												
361										R	BP	BS	8	P	4												
362	3	Slope grain	L170000362(6)	L	WD	G	5			L	BP	BS	8	P	4												
362										C	BP	BS	8	P	4												
362										R	BP	BS	8	P	4												
363	4	Weathered	L170000363(3)	L	WD	G	5			L	BP	BS	8	P	4												
363										C	BP	BS	8	P	4												
363										R	BP	BS	8	P	4												
364	5			L	WD	G	5			L	BP	BS	8	P	4												
364										C	BP	BS	8	P	4												
364										R	BP	BS	8	P	4												
365	5			L	WD	G	5			L	BP	BS	8	P	4												
365	5	Bowed 3"	L170000365(3)							C	BP	BS	8	P	4												
365										R	BP	BS	8	P	4												
366	5	Bowed 3"	L170000366(3)	L	WD	G	5			L	BP	BS	8	P	4												
366	5	Bowed 2"	L170000366(3)							C	BP	BS	8	P	4												
366										R	BP	BS	8	P	3	All hubs rusty	L170000366(5)										
367	4	Bowed 4"	L170000367(4)	L	WD	G	5	Sway is splitting on top right	L710000367(4)	L	BP	BS	8	P	4												
367										C	BP	BS	8	P	4												
367										R	BP	BS	8	P	4												
368	5	Weathered								L	BP	BS	8	P	4												
368	5	Weathered								C	BP	BS	8	P	4												
368										R	BP	BS	8	P	4												

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369	3	Ahead arm has slope grain and is splitting	L170000369(5)							L	BP	BS	8	P	4												
369	4	Weathered								C	BP	BS	8	P	4												
369										R	BP	BS	8	P	4												
370	5			L	WD	G	5			L	BP	BS	8	P	4												
370										C	BP	BS	8	P	3	Bells not seated properly	), L170000370(3)										
370										R	BP	BS	8	P	4												
371	3	Slope grain	, L170000371(7)	L	WD	G	5			L	BP	BS	8	P	4												
371										C	BP	BS	8	P	4												
371										R	BP	BS	8	P	4												
372	5	Arm bowed due to unevenly adjusted hardware	L170000372(4)	L	WD	G	5			L	BP	BS	9	P	4			2	HX	G	5						
372	5	Arm bowed due to unevenly adjusted hardware	L170000372(4)							C	BP	BS	9	P	4												
372										R	BP	BS	9	P	4												
373	5			L	WD	G	5			L	BP	BS	9	P	4			2	HX	G	5						
373										C	BP	BS	9	P	4												
373										R	BP	BS	9	P	4												
374	5			L	WD	F	5	Bowed, twisted	374(5), L170000374(6)	L	BP	BS	8	P	4												
374										C	BP	BS	8	P	4												
374										R	BP	BS	8	P	4												
375	5			L	WD	G	5			L	BP	BS	8	P	4												
375										C	BP	BS	8	P	4												
375										R	BP	BS	8	P	4	Kicked ahead 2"	L170000375(4)										
376	5	Bowed 3"	, L170000376(3)	L	WD	F	5	Bowed	L170000376(5)	L	BP	BS	8	P	4												
376										C	BP	BS	8	P	4												
376										R	BP	BS	8	P	4												
377	5	Bowed 3"	, L170000377(3)	L	WD	G	5	Ahead sway has chunk missing	L170000377(3)	L	BP	BS	8	P	4												
377										C	BP	BS	8	P	4												
377										R	BP	BS	8	P	4												
378	5			L	WD	G	5			L	BP	CT	9	P	4												
378	5									C	BP	CT	9	P	4												
378										R	BP	CT	9	P	4												
379	5			L	WD	F	5	Back brace bowed	L170000379(5)	L	BP	CT	8	P	4												
379										C	BP	CT	8	P	4												
379										R	BP	CT	8	P	4												
380	5			L	WD	F	5	Back brace bowed	L170000380(6)	L	BP	CT	8	P	4												
380										C	BP	CT	8	P	4												
380										R	BP	CT	8	P	4												
381	2	Splitting on right end		L	WD	G	5			L	BP	CT	9	P	4												
381	5									C	BP	CT	9	P	4												
381										R	BP	CT	9	P	4												
382	2	Left end bowed and twisting ahead and weathe	L170000382(8)	L	WD	G	5			L	BP	CT	8	P	4												
382										C	BP	CT	8	P	4	Light bird droppings	L171000382(9)										
382										R	BP	CT	8	P	4												
383	5			L	WD	G	5			L	BP	CT	8	P	4	Rust on top hub	L170000383(9)										
383										C	BP	CT	8	P	4												
383										R	BP	CT	8	P	4												
384	2	Splitting in midsection	, L170000384(9)	L	WD	G	5			L	BP	CT	8	P	4												
384	5									C	BP	CT	8	P	4												
384										R	BP	CT	8	P	4												
385	5			L	WD	G	5			L	BP	CT	8	P	4												
385										C	BP	CT	8	P	4												
385										R	BP	CT	8	P	4												
386	5			L	WD	G	5			L	BP	CT	8	P	4												
386										C	BP	CT	8	P	4												
386										R	BP	CT	8	P	4	Rust on top hub	L170000386(5)										
387	2	Splitting and slope grain throughout	, L170000387(7)	L	WD	G	5			L	BP	CT	8	P	4												
387										C	BP	CT	8	P	4												
387										R	BP	CT	8	P	4												

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388	2	Slope grain, splitting and bowed	, L170000388(7)	L	WD	G	5			L	BP	CT	8	P	4												
388										C	BP	CT	8	P	4												
388										R	BP	CT	8	P	4	Pulled ahead 4-6"	L170000388(4)									
389	5			L	WD	G	5			L	BP	CT	8	P	4												
389	5									C	BP	CT	8	P	4												
389										R	BP	CT	8	P	4												
390	5			L	WD	G	5			L	BP	CT	8	P	4												
390	2									C	BP	CT	8	P	4	Pulled ahead 4-6"	L170000390(4)									
390										R	BP	CT	8	P	4												
391	5			L	WD	F	5	Back brace twisted	L170000391(5)	L	BP	CT	8	P	4	Rust on top hub	L170000391(6)									
391										C	BP	CT	8	P	4												
391										R	BP	CT	8	P	4												
392	2	Bowed and twisted (*long span ahead and back	L170000392(7)	L	WD	G	5			L	BP	CT	8	P	4												
392										C	BP	CT	8	P	4												
392										R	BP	CT	8	P	4												
393	2	Heavy bowing, twisting, and slope grain	, L170000393(8)	L	WD	G	5			L	BP	CT	8	P	4												
393										C	BP	CT	8	P	4												
393										R	BP	CT	8	P	4												
394	4	Weathered	, L170000394(9)	L	WD	G	5			L	BP	CT	8	P	4												
394										C	BP	CT	8	P	4												
394										R	BP	CT	8	P	4												
395	5	* New arm								L	TG	CT	8	E	5												
395	5									C	TG	CT	8	E	5												
395										R	TG	CT	8	E	5												
396	2	Twisted and slope grain	, L170000396(7)							L	BP	CT	8	P	4												
396										C	BP	CT	8	P	4												
396										R	BP	CT	8	P	3	Top bell has heavy rust and pulled ba	), L170000396(8)									
397	2	Heavy splitting throughout	, L170000397(8)	L	WD	G	5			L	BP	CT	8	P	4												
397										C	BP	CT	8	P	4												
397										R	BP	CT	8	P	4												
398A	5									L	TG	CT	8	G	5												
398A										C	TG	CT	8	G	5												
398A										R	TG	CT	8	G	5												
398	5			L	WD	E	5			L	TG	CT	8	G	5												
398										C	TG	CT	8	G	5												
398										R	TG	CT	8	G	5												
399	2	Splitting throughout and weathered	, L170000399(7)	L	WD	G	5			L	BP	CT	8	P	4												
399										C	BP	CT	8	P	4												
399										R	BP	CT	8	P	4												
400	5			L	WD	G	5			L	BP	CT	8	P	4												
400										C	BP	CT	8	P	4												
400										R	BP	CT	8	P	4												
401	5	Right end has damage and decay	L170000401(5)	L	WD	G	5			L	BP	CT	8	P	4												
401	5									C	BP	CT	8	P	4												
401										R	BP	CT	8	P	4												
402	4	Weathered light decay	, L170000402(6)	L	WD	G	5			L	BP	CT	8	P	4	Very light rust on top hub	L170000402(5)									
402										C	BP	CT	8	P	4												
402										R	BP	CT	8	P	4												
403	5			L	WD	G	5			L	BP	CT	8	P	4												
403										C	BP	CT	8	P	4												
403										R	BP	CT	8	P	4												
404	2	Light splitting on top edges bowed, and weathe	L170000404(7)	L	WD	F	5	Back brace bowed	L170000404(5)	L	BP	CT	8	P	4	Top bell discoloured	L170000404(8)									
404										C	BP	CT	8	P	4												
404										R	BP	CT	8	P	4												
405	5	Bowed 4"	, L170000405(3)	L	WD	G	5			L	BP	BS	8	P	4												
405										C	BP	BS	8	P	4												

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405										R	BP	BS	8	P	4	Rusty top hub	L170000405(5)										
406	3	Ahead arm is splitting on left end	, L170000406(8)	L	WD	G	5			L	BP	BS	8	P	4												
406	5									C	BP	BS	8	P	4												
406										R	BP	BS	8	P	4												
407	5			L	WD	G	5			L	BP	BS	9	P	4			2	HX	G	5						
407	5									C	BP	BS	9	P	4												
407										R	BP	BS	9	P	4												
408	5			L	WD	G	5			L	BP	BS	8	P	4												
408										C	BP	BS	8	P	4												
408										R	BP	BS	8	P	4	Rust on top hub	L170000408(6)										
409	5			L	WD	E	5			L	TG	BS	8	G	5												
409										C	TG	BS	8	G	5												
409										R	TG	BS	8	G	5												
410	5			L	WD	G	5			L	BP	BS	8	P	4												
410										C	BP	BS	8	P	4												
410										R	BP	BS	8	P	4												
411	5									L	BP	BS	8	P	4												
411	5									C	BP	BS	8	P	4												
411										R	BP	BS	8	P	4												
412	5	Weathered	, L170000412(3)	L	WD	G	5			L	BP	BS	8	P	4												
412										C	BP	BS	8	P	4												
412										R	BP	BS	8	P	4												
413	5	Weathered		L	WD	G	5			L	BP	BS	8	P	4												
413	5	Weathered								C	BP	BS	8	P	4												
413										R	BP	BS	8	P	4												
414	5	Weathered	, L170000414(3)	L	WD	G	5			L	BP	BS	8	P	4												
414	5	Weathered	, L170000414(3)							C	BP	BS	8	P	4												
414										R	BP	BS	8	P	4												
415	2	Extensive spitting, twisted	, L170000415(6)	L	WD	F	4	Weathered	415(1), L170000415(3)	L	BP	BS	8	P	4												
415										C	BP	BS	8	P	4												
415										R	BP	BS	8	P	4												
416	5			L	WD	G	5			L	BP	BS	8	P	4												
416										C	BP	BS	8	P	4												
416										R	BP	BS	8	P	4												
417	5			L	WD	G	5			L	BP	BS	8	P	4												
417										C	BP	BS	8	P	4												
417										R	BP	BS	8	P	4												
418	5			L	WD	G	5			L	BP	BS	8	P	4												
418										C	BP	BS	8	P	4												
418										R	BP	BS	8	P	4												
419	5			L	WD	P	3	Top left sway is splitting	L170000419(7)	L	BP	BS	8	P	4												
419										C	BP	BS	8	P	4												
419										R	BP	BS	8	P	4												
420	3	Slope grain	, L170000420(6)	L	WD	G	5			L	BP	BS	8	P	4												
420										C	BP	BS	8	P	4												
420										R	BP	BS	8	P	4												
421	3	Bowed 3", slope grain	, L170000421(6)	L	WD	G	5			L	BP	BS	8	P	4												
421										C	BP	BS	8	P	4												
421										R	BP	BS	8	P	4												
422	5									L	BP	BS	8	P	4												
422	5									C	BP	BS	8	P	4												
422										R	BP	BS	8	P	4												
423	3	Weathered, twisted, bowed 4"	, L170000423(6)	L	WD	G	5			L	BP	BS	8	P	4												
423										C	BP	BS	8	P	4												
423										R	BP	BS	8	P	4												
424	4	Bowed 3"	, L170000424(3)	L	WD	G	5			L	BP	BS	8	P	4	Rusty hubs	L170000424(7)										

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424										C	BP	BS	8	P	4												
424										R	BP	BS	8	P	4	Top hub rusty	L170000424(5)										
425	3	Arm is splitting entire length	, L170000425(6)	L	WD	G	5			L	BP	BS	8	P	4												
425										C	BP	BS	8	P	4												
425										R	BP	BS	8	P	4												
426	5			L	WD	G	5			L	BP	BS	8	P	3	Top hub has heavy rust	L170000426(5)										
426										C	BP	BS	8	P	4												
426										R	BP	BS	8	P	4												
427	5			L	WD	E	5			L	TG	BS	8	G	5												
427										C	TG	BS	8	G	5												
427										R	TG	BS	8	G	5												
428	5			L	WD	G	5			L	BP	BS	8	P	3	Top hub rusty	L170000428(5)										
428										C	BP	BS	8	P	4												
428										R	BP	BS	8	P	4												
429	3	Splitting entire length	, L170000429(6)	L	WD	G	5			L	BP	BS	8	P	4												
429										C	BP	BS	8	P	4												
429										R	BP	BS	8	P	4												
430	3	Splitting entire length	, L170000430(6)	L	WD	G	5			L	BP	BS	8	P	4												
430										C	BP	BS	8	P	4												
430										R	BP	BS	8	P	4												
431	3	Splitting throughout, bowed due to unevenly ad	L170000431(8)	L	WD	F	5	Bowed	L170000431(5)	L	BP	BS	9	P	4			2	HX	G	5						
431	4	Weathered, bowed due to unevenly adjusted h	L170000431(8)							C	BP	BS	9	P	4												
431										R	BP	BS	9	P	4												
432	5	Bowed 3"	, L170000432(3)	L	WD	G	5			L	BP	BS	8	P	4												
432										C	BP	BS	8	P	4												
432										R	BP	BS	8	P	4												
433	3	Splitting entire length	, L170000433(6)	L	WD	G	5			L	BP	BS	8	P	4												
433										C	BP	BS	8	P	4												
433										R	BP	BS	8	P	4	Kicked ahead 4"	L170000433(4)										
434	5	Bowed 2"	, L170000434(3)	L	WD	G	5			L	BP	BS	8	P	4												
434										C	BP	BS	8	P	4	Kicked ahead 2"	), L170000434(4)										
434										R	BP	BS	8	P	4	Kicked ahead 3"	), L170000434(4)										
435	3	Splitting throughout, bowed 4", twisted	, L170000435(7)	L	WD	G	5			L	BP	BS	8	P	4												
435										C	BP	BS	8	P	4												
435										R	BP	BS	8	P	4												
436	3	Splitting throughout, bowed 3"	, L170000436(6)	L	WD	P	3	Top left end is spit 2'	L170000436(5)	L	BP	BS	8	P	4												
436										C	BP	BS	8	P	4												
436										R	BP	BS	8	P	4												
437	5			L	WD	E	5			L	TG	BS	9	G	5			2	HX	G	5						
437										C	TG	BS	9	G	5												
437										R	TG	BS	9	G	5												
438	4	Bowed 3", twisted, weathered	, L170000438(5)	L	WD	G	5			L	BP	BS	8	P	4												
438										C	BP	BS	8	P	4												
438										R	BP	BS	8	P	4												
439	5	Bowed 2"	L170000439(1)	L	WD	G	5			L	BP	BS	8	P	4												
439										C	BP	BS	8	P	4												
439										R	BP	BS	8	P	4												
440	3	Splitting, twisted	, L170000440(7)	L	WD	G	5			L	BP	BS	8	P	4												
440										C	BP	BS	8	P	4												
440										R	BP	BS	8	P	4												
441	5	Bowed 3"	, L170000441(3)	L	WD	G	5			L	BP	BS	8	P	4												
441										C	BP	BS	8	P	4												
441										R	BP	BS	8	P	4												
442	5			L	WD	G	5			L	BP	BS	8	P	4												
442										C	BP	BS	8	P	4												
442										R	BP	BS	8	P	4												

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443	5									L	TG	BS	8	G	5												
443	5									C	TG	BS	8	G	5												
443										R	TG	BS	8	G	5												
444	5			L	WD	G	5			L	TG	BS	9	G	5			2	HX	G	5						
444	5			R	WD	G	5			C	TG	BS	9	G	5												
444										R	TG	BS	9	G	5												
445	5			L	WD	E	5			L	TG	BS	8	G	5												
445										C	TG	BS	8	G	5												
445										R	TG	BS	8	G	5												
446	5			L	WD	E	5			L	TG	BS	8	G	5												
446										C	TG	BS	8	G	5												
446										R	TG	BS	8	G	5												
447	5			L	WD	E	5			L	TG	BS	8	G	5												
447										C	TG	BS	8	G	5												
447										R	TG	BS	8	G	5												
448	3	Left end chunk splintered off	L170000448(5)	L	WD	G	5			L	BP	BS	8	P	4												
448										C	BP	BS	8	P	4												
448										R	BP	BS	8	P	4												
449	4	Twisted, bowed 5"	L170000449(5)	L	WD	G	5			L	BP	BS	8	P	4												
449										C	BP	BS	8	P	4												
449										R	BP	BS	8	P	3	#3 Bell chipped	L170000449(6)										
450	5			L	WD	E	5			L	TG	BS	8	G	5												
450										C	TG	BS	8	G	5												
450										R	TG	BS	8	G	5												
451	5			L	WD	G	5			L	BP	BS	8	P	4												
451										C	BP	BS	8	P	4												
451										R	BP	BS	8	P	4												
452	4	Bowed 4"	L170000452(3)	L	WD	G	5			L	BP	BS	8	P	4												
452										C	BP	BS	8	P	4												
452										R	BP	BS	8	P	4												
453	5	Weathered, bowed 3"	L170000453(3)	L	WD	G	5			L	BP	BS	8	P	4												
453										C	BP	BS	8	P	4												
453										R	BP	BS	8	P	4												
454	5									L	TG	BS	8	G	5			2	HX	F	Right back is missing 1 preform to L0000454(5)						
454	5									C	TG	BS	8	G	5					4							
454										R	TG	BS	8	G	5												
455	3	Slope grain	L170000455(6)	L	WD	G	5			L	BP	BS	8	P	4												
455										C	BP	BS	8	P	4												
455										R	BP	BS	8	P	4												
456	5			L	WD	G	5			L	BP	BS	8	P	4												
456										C	BP	BS	8	P	4												
456										R	BP	BS	8	P	4	Kicked ahead 2"	L170000456(4)										
457	5	Bowed 3"	L170000457(3)	L	WD	G	5			L	BP	BS	8	P	4												
457										C	BP	BS	8	P	4												
457										R	BP	BS	8	P	4	Kicked ahead 2"	L170000457(4)										
458	5			L	WD	E	5			L	TG	BS	8	G	5												
458										C	TG	BS	8	G	5												
458										R	TG	BS	8	G	5												
459	5			L	WD	E	5			L	TG	BS	8	G	5												
459										C	TG	BS	8	G	5												
459										R	TG	BS	8	G	5												
460	5			L	WD	E	5			L	TG	BS	8	G	5												
460										C	TG	BS	8	G	5												
460										R	TG	BS	8	G	5												
461	5			L	WD	G	5			L	BP	CT	8	P	4												
461	5									C	BP	CT	8	P	4												

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461										R	BP	CT	8	P	4												
462	5			L	WD	E	5			L	TG	BS	8	G	5												
462	5									C	TG	BS	8	G	5												
462										R	TG	BS	8	G	5												
463	4	Weathered, twisted, bowed 3"	L170000463(7)	L	WD	G	5			L	BP	CT	8	P	4												
463										C	BP	CT	8	P	4												
463										R	BP	CT	8	P	4												
464	3	Bowed 4"	L170000464(3)	L	WD	G	5			L	EP	CT		G	5												
464										C	EP	CT		G	5												
464										R	EP	CT		G	5												
465	2	Extensive splitting on left side, weathered	L170000465(8)	L	WD	G	5			L	BP	CT	8	P	4												
465										C	BP	CT	8	P	4												
465										R	BP	CT	8	P	4												
466	5			L	WD	E	5			L	TG	BS	8	G	5												
466										C	TG	BS	8	G	5												
466										R	TG	BS	8	G	5												
467	5			L	WD	E	5			L	TG	BS	8	G	5												
467										C	TG	BS	8	G	5												
467										R	TG	BS	8	G	5												
468	5			L	WD	E	5			L	TG	BS	8	G	5												
468										C	TG	BS	8	G	5												
468										R	TG	BS	8	G	5												
469	5			L	WD	E	5			L	TG	BS	8	G	5												
469										C	TG	BS	8	G	5												
469										R	TG	BS	8	G	5												
470	5			L	WD	E	5			L	TG	BS	8	G	5												
470										C	TG	BS	8	G	5												
470										R	TG	BS	8	G	5												
471	5									L	TG	BS	8	G	5												
471										C	TG	BS	8	G	5												
471										R	TG	BS	8	G	5												
472	5			L	WD	E	5			L	TG	BS	8	G	5												
472										C	TG	BS	8	G	5												
472										R	TG	BS	8	G	5												
473	5	Weathered, bowed 3"	L170000473(3)	L	WD	G	5			L	BP	CT	8	P	4												
473										C	BP	CT	8	P	3	Top hub rusty	L170000473(6)										
473										R	BP	CT	8	P	3	Top hub heavy rust	L170000473(5)										
474	5			L	WD	E	5			L	TG	BS	8	G	5												
474										C	TG	BS	8	G	5												
474										R	TG	BS	8	G	5												
475	5			L	WD	G	5			L	TG	BS	8	G	5												
475										C	TG	BS	8	G	5												
475										R	TG	BS	8	G	5												
476	5			L	WD	E	5			L	TG	BS	8	G	5												
476										C	TG	BS	8	G	5												
476										R	TG	BS	8	G	5												
477	5	Weathered	L170000477(4)							L	TG	BS	8	G	5												
477	5	Weathered	L170000477(4)							C	TG	BS	8	G	5												
477										R	TG	BS	8	G	5												
478	5			L	WD	G	5			L	BP	CT	8	P	4												
478										C	BP	CT	8	P	4												
478										R	BP	CT	8	P	4												
479	5			L	WD	E	5			L	TG	BS	8	G	5												
479	5									C	TG	BS	8	G	5												
479										R	TG	BS	8	G	5												
480	5			L	WD	G	5			L	BP	CT	8	P	4												

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480	5									C	BP	CT	8	P	4												
480										R	BP	CT	8	P	4												
481	5									L	EP	BS		G	5												
481	5									C	EP	BS		G	5												
481										R	EP	BS		G	5												
482	5			L	WD	G	5			L	BP	CT	8	P	4												
482										C	BP	CT	8	P	3	Top hub rusty	L170000482(5)										
482										R	BP	CT	8	P	3	Top hub rusty	L170000482(5)										
483	5			L	WD	F	5	Weathered	L170000483(1)	L	BP	CT	8	P	4												
483										C	BP	CT	8	P	4												
483										R	BP	CT	8	P	4												
484	5			L	WD	E	5			L	TG	BS	8	G	5												
484										C	TG	BS	8	G	5												
484										R	TG	BS	8	G	5												
485	5			L	WD	E	5			L	TG	BS	8	G	5												
485										C	TG	BS	8	G	5												
485										R	TG	BS	8	G	5												
486	5			L	WD	E	5			L	TG	BS	8	G	5												
486										C	TG	BS	8	G	5												
486										R	TG	BS	8	G	5												
487	3	Slope grain, bowed 3", twisted	, L170000487(7)	L	WD	G	5			L	BP	CT	8	P	3	Top hub heavy rust	L170000487(7)										
487										C	BP	CT	8	P	4												
487										R	BP	CT	8	P	4												
488	5			L	WD	G	5			L	BP	CT	8	P	4												
488										C	BP	CT	8	P	4												
488										R	BP	CT	8	P	4												
489	3	Slope grain, bowed 4"	, L170000489(7)	L	WD	G	5			L	BP	CT	8	P	4												
489										C	BP	CT	8	P	4												
489										R	BP	CT	8	P	4												
490	5			L	WD	E	5			L	TG	BS	8	G	5												
490										C	TG	BS	8	G	5												
490										R	TG	BS	8	G	5												
491	5			L	WD	E	5			L	TG	BS	8	G	5												
491										C	TG	BS	8	G	5												
491										R	TG	BS	8	G	5												
492	5			L	WD	E	5			L	TG	BS	8	G	5												
492				R	WD	E	5			C	TG	BS	8	G	5												
492										R	TG	BS	8	G	5												
493	5			L	WD	G	5			L	BP	CT	8	P	3	Top hub has heavy rust	L170000493(5)										
493										C	BP	CT	8	P	4												
493										R	BP	CT	8	P	4												
494	5			L	WD	G	5			L	BP	CT	8	P	3	Top hub heavy rust	L170000494(5)										
494										C	BP	CT	8	P	4												
494										R	BP	CT	8	P	4												
495	5									L	BP	CT	8	P	4												
495										C	BP	CT	8	P	4												
495										R	BP	CT	8	P	4												
496	5			L	WD	G	5			L	BP	CT	8	P	4												
496										C	BP	CT	8	P	4												
496										R	BP	CT	8	P	4												
497	5			L	WD	E	5			L	TG	BS	8	G	5												
497										C	TG	BS	8	G	5												
497										R	TG	BS	8	G	5												
498	5			L	WD	G	5			L	BP	CT	8	P	3	Top hub heavy rust	L170000498(5)										
498										C	BP	CT	8	P	4												
498										R	BP	CT	8	P	4												

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499	5			L	WD	G	5			L	BP	CT	8	P	4												
499										C	BP	CT	8	P	4												
499										R	BP	CT	8	P	4												
500	5	Bowed 3"		L	WD	G	5			L	BP	CT	8	P	4												
500										C	BP	CT	8	P	4												
500										R	BP	CT	8	P	4												
501	5	Bowed 3"	, L170000501(3)	L	WD	G	5			L	BP	CT	8	P	4												
501										C	BP	CT	8	P	4												
501										R	BP	CT	8	P	4												
502	5			L	WD	G	5			L	BP	CT	8	P	4												
502										C	BP	CT	8	P	4												
502										R	BP	CT	8	P	4												
503	5									L	TG	BS	8	G	5			2	HX	G	5						
503	5									C	TG	BS	8	G	5												
503										R	TG	BS	8	G	5												
504	5			L	WD	G	5			L	BP	CT	8	P	4												
504										C	BP	CT	8	P	4												
504										R	BP	CT	8	P	4												
505	5	Bowed 2"	, L170000505(3)	L	WD	G	5			L	BP	CT	8	P	4												
505										C	BP	CT	8	P	4												
505										R	BP	CT	8	P	4												
506	5			L	WD	G	5			L	BP	CT	9	P	4			2	HX	G	5						
506	5									C	BP	CT	9	P	4												
506										R	BP	CT	9	P	4												
507	5	Bowed 4"		L	WD	G	5			L	BP	CT	8	P	4												
507	5	Bowed 4"								C	BP	CT	8	P	4												
507										R	BP	CT	8	P	4												
508	5			L	WD	G	5			L	TG	BS	9	G	5			2	SB	G	5						
508	5									C	TG	BS	9	G	5												
508										R	TG	BS	9	G	5												
509	5			L	WD	E	5			L	TG	BS	8	G	5												
509										C	TG	BS	8	G	5												
509										R	TG	BS	8	G	5												
510	5			L	WD	E	5			L	TG	BS	8	G	5												
510										C	TG	BS	8	G	5												
510										R	TG	BS	8	G	5												
511	5			L	WD	E	5			L	TG	BS	8	G	5												
511										C	TG	BS	8	G	5												
511										R	TG	BS	8	G	5												
512	5			L	WD	G	5			L	BP	CT	8	P	4												
512										C	BP	CT	8	P	4												
512										R	BP	CT	8	P	4												
513	5			L	WD	G	5			L	BP	CT	8	P	4												
513										C	BP	CT	8	P	4												
513										R	BP	CT	8	P	4												
514	5	Weathered	, L170000514(3)	L	WD	G	5			L	BP	CT	8	P	4	Kicked back 3"	L170000514(6)										
514	5	Weathered	, L170000514(3)							C	BP	CT	8	P	4	Top hub rusty	L170000514(5)										
514										R	BP	CT	8	P	4												
515	5			L	WD	G	5			L	BP	CT	8	P	4												
515	5									C	BP	CT	8	P	4												
515										R	BP	CT	8	P	4												
516	5									L	BP	CT	8	P	4												
516	5									C	BP	CT	8	P	4												
516										R	BP	CT	8	P	4												
517	5	Twisted, weathered	, L170000517(7)	L	WD	G	5			L	BP	CT	8	P	4												
517										C	BP	CT	8	P	4												

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517										R	BP	CT	8	P	4												
518	4	Weathered, splitting	, L170000518(7)	L	WD	G	5			L	BP	CT	8	P	4	Top hub rusty											
518										C	BP	CT	8	P	4												
518										R	BP	CT	8	P	4												
519	5			L	WD	G	5			L	BP	CT	8	P	4												
519										C	BP	CT	8	P	4												
519										R	BP	CT	8	P	4												
520	5	Bowed 4"		L	WD	G	5			L	BP	CT	8	P	4												
520	5	Bowed 4"								C	BP	CT	8	P	4												
520										R	BP	CT	8	P	4												
521	5			L	WD	E	5			L	TG	BS	9	G	5												
521	5									C	TG	BS	9	G	5												
521										R	TG	BS	9	G	5												
522	5			L	WD	G	5			L	BP	CT	8	P	4												
522	5	Bowed								C	BP	CT	8	P	4												
522										R	BP	CT	8	P	4												
523	5			L	WD	G	5			L	BP	CT		G	5												
523	5	Splintering on right end	L170000523(5)							C	BP	CT		G	5												
523										R	BP	CT		G	5												
524	5			L	WD	E	5			L	TG	BS	9	G	5												
524										C	TG	BS	9	G	5												
524										R	TG	BS	9	G	5												
525	5			L	WD	G	5			L	BP	CT	8	P	4	Kicked ahead 4"	), L170000525(4)										
525	5									C	BP	CT	8	P	4	Kicked ahead 4"	), L170000525(4)										
525										R	BP	CT	8	P	4	Kicked ahead 4"	), L170000525(4)										
526	5			L	WD	G	5			L	BP	CT	8	P	4												
526	5									C	BP	CT	8	P	4												
526										R	BP	CT	8	P	4												
527	5			L	WD	G	5			L	BP	CT	8	P	4												
527										C	BP	CT	8	P	4												
527										R	BP	CT	8	P	4												
528	5			L	WD	G	5			L	BP	BS	9	P	4												
528	5									C	BP	BS	9	P	4												
528										R	BP	BS	9	P	4												
529	5									L	BP	CT	8	P	4												
529	5									C	BP	CT	8	P	4												
529										R	BP	CT	8	P	4												
530	5			L	WD	G	5			L	EP	CT	8	G	5												
530										C	EP	CT	8	P	4												
530										R	EP	CT	8	G	5												
531	4	Bowed, twisted	, L170000531(7)	L	WD	G	5			L	BP	CT	8	P	4												
531	3	Slope grain, bowed, twisted	, L170000531(7)							C	BP	CT	8	P	4												
531										R	BP	CT	8	P	4												
532	5			L	WD	G	5			L	BP	CT	8	P	4	Discoloured hubs	L170000532(6)										
532	3	Slope grain	, L170000532(8)							C	BP	CT	8	P	4												
532										R	BP	CT	8	P	4												
533	5			L	WD	G	5			L	BP	CT	8	P	4												
533	5									C	BP	CT	8	P	4												
533										R	BP	CT	8	P	4												
534	3			L	WD	G	5			L	BP	BS	8	P	4												
534										C	BP	BS	8	P	4												
534										R	BP	BS	8	P	4												
534	5			L	WD	G	5			L	BP	CT	8	P	4	Discoloured hubs	L170000534(1)										
534										C	BP	CT	8	P	4	Discoloured hubs	L170000534(1)										
534										R	BP	CT	8	P	4	Discoloured hubs	L170000534(1)										
535	4	Bowed 4", Twisted	, L170000535(5)	L	WD	G	5			L	BP	CT	8	P	4	Discoloured hubs	L170000535(5)										

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535										C	BP	CT	8	P	4												
535										R	BP	CT	8	P	4												
536	3	Slope grain, bowed 4"		L	WD	G	5			L	BP	CT	8	P	4												
536										C	BP	CT	8	P	4												
536										R	BP	CT	8	P	4												
537	5	Bowed 3"	, L170000537(3)	L	WD	G	5			L	BP	CT	8	P	4												
537										C	BP	CT	8	P	4												
537										R	BP	CT	8	P	4												
538	5	Bowed	, L170000538(3)	L	WD	G	5			L	BP	CT	8	P	4	Kicked back 20"	L170000538(2)										
538										C	BP	CT	8	P	4												
538										R	BP	CT	8	P	4												
539	5			L	WD	G	5			L	BP	CT	8	P	4												
539										C	BP	CT	8	P	4	Top hub rusty	L170000539(6)										
539										R	BP	CT	8	P	4												
540	5									L	BP	CT	8	P	4												
540										C	BP	CT	8	P	4												
540										R	BP	CT	8	P	4												
541	5			L	WD	G	5			L	BP	CT	8	P	4												
541										C	BP	CT	8	P	4												
541										R	BP	CT	8	P	4												
542	5			L	WD	G	5			L	BP	CT	8	P	4												
542										C	BP	CT	8	P	4												
542										R	BP	CT	8	P	4												
543	5			L	WD	G	5			L	BP	CT	8	P	4												
543	5									C	BP	CT	8	P	4												
543										R	BP	CT	8	P	4												
544	5			L	WD	G	5			L	BP	CT	8	P	4												
544	5									C	BP	CT	8	P	4												
544										R	BP	CT	8	P	4												
545	5			L	WD	G	5			L	BP	CT	8	P	4												
545										C	BP	CT	8	P	4	Heavy rust on top hub	L170000545(3)										
545										R	BP	CT	8	P	4												
546	5			L	WD	G	5			L	BP	CT	8	P	4												
546										C	BP	CT	8	P	4												
546										R	BP	CT	8	P	4												
547	5			L	WD	G	5			L	BP	CT	8	P	4												
547										C	BP	CT	8	P	4	Kicked ahead 3"	), L170000547(4)										
547										R	BP	CT	8	P	4												
548	5			L	WD	G	5			L	BP	CT	8	P	4												
548										C	BP	CT	8	P	4												
548										R	BP	CT	8	P	4												
549	4	Bowed 4+	, L170000549(3)	L	WD	G	5			L	BP	CT	8	P	4												
549										C	BP	CT	8	P	4												
549										R	BP	CT	8	P	3	#3 Bell not seated properly	L170000549(8)										
550	5			L	WD	G	5			L	BP	CT	8	P	4												
550										C	BP	CT	8	P	4												
550										R	BP	CT	8	P	4												
551	5			L	WD	G	5			L	BP	CT	8	P	4												
551										C	BP	CT	8	P	4												
551										R	BP	CT	8	P	4												
552	4	Bowed 4" +	, L170000552(3)	L	WD	G	5			L	BP	CT	8	P	4												
552										C	BP	CT	8	P	4												
552										R	BP	CT	8	P	4												
553	5									L	BP	CT	8	P	4												
553	5									C	BP	CT	8	P	4												
553										R	BP	CT	8	P	4												

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554	5			L	WD	G	5			L	BP	CT	8	P	4												
554										C	BP	CT	8	P	4												
554										R	BP	CT	8	P	4												
555	5			L	WD	G	5			L	BP	CT	8	P	4												
555										C	BP	CT	8	P	4												
555										R	BP	CT	8	P	4												
556	5			L	WD	G	5			L	BP	CT	8	P	3	#7 Bell not seated properly	L170000556(5)										
556										C	BP	CT	8	P	4												
556										R	BP	CT	8	P	4												
557	5			L	WD	G	5			L	BP	CT	8	P	4												
557										C	BP	CT	8	P	4												
557										R	BP	CT	8	P	4	Top hub rusty	L17100557(5)										
558	5	Weathered	, L170000558(3)	L	WD	F	5	Weathered	558(1), L170000558(3)	L	BP	CT	8	P	4												
558										C	BP	CT	8	P	4												
558										R	BP	CT	8	P	4												
559	5	Weathered	, L170000559(3)	L	WD	G	5			L	BP	CT	8	P	4												
559	5	Weathered	, L170000559(3)							C	BP	CT	8	P	4												
559										R	BP	CT	8	P	4												
560	5			L	WD	G	5			L	BP	CT	8	P	4												
560	5									C	BP	CT	8	P	4												
560										R	BP	CT	8	P	4												
561	5			L	WD	G	5			L	BP	CT	8	P	4												
561	5									C	BP	CT	8	P	4												
561										R	BP	CT	8	P	4												
562	5									L	BP	CT	8	P	4	Dirty		2	HX	G	5						
562										C	BP	CT	8	P	4	Dirty											
562										R	BP	CT	8	P	4	Dirty											
563	5	Bowed 3"	, L170000563(3)	L	WD	G	5			L	BP	CT	8	P	4	Kicked back 4-6"	2), L170000563(4)										
563										C	BP	CT	8	P	4	Back 2-4"	2), L170000563(4)										
563										R	BP	CT	8	P	4	Dirty											
564	5			L	WD	F	5	Twisted	L170000564(7)	L	BP	CT	8	P	4	Dirty		2	HX	G	5						
564				R	WD	G	5			C	BP	CT	8	P	4	Dirty											
564										R	BP	CT	8	P	4	Dirty											
565	5	Weathered	, L170000565(6)	L	WD	G	5			L	BP	CT	8	P	4	Dirty back 3"											
565										C	BP	CT	8	P	4	Dirty											
565										R	BP	CT	8	P	4	Dirty											
566	5	Weathered	L170000566(7)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
566	3	Splitting	L170000566(7)							C	BP	CT	8	P	4	Dirty											
566										R	BP	CT	8	P	4	Dirty, back 3"	L170000566(4)										
567	5	Weathered	, L170000567(3)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
567										C	BP	CT	8	P	4	Dirty											
567										R	BP	CT	8	P	3	Dirty											
568	5			L	WD	G	5			L	BP	CT	9	P	4	Dirty											
568										C	BP	CT	9	P	4	Dirty											
568										R	BP	CT	9	P	4	Dirty											
569	5	Weathered	L170000569(6)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
569	3	Splitting on left side	L170000569(5)							C	BP	CT	8	P	4	Dirty											
569										R	BP	CT	8	P	4	Dirty											
570	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
570										C	BP	CT	8	P	4	Dirty, ahead 2"	2), L170000570(4)										
570										R	BP	CT	8	P	4	Dirty, ahead 2"	2), L170000570(4)										
571	3	Bowed 3"	, L170000571(3)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
571										C	BP	CT	8	P	4	Dirty											
571										R	BP	CT	8	P	4	Dirty											
572	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
572										C	BP	CT	8	P	4	Dirty											

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572										R	BP	CT	8	P	4	Dirty											
573	3	Splitting	, L170000573(6)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
573										C	BP	CT	8	P	4	Dirty											
573										R	BP	CT	8	P	4	Dirty											
574	4	Bowed 3"	), 170000574(3)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
574										C	BP	CT	8	P	4	Dirty											
574										R	BP	CT	8	P	4	Dirty											
575	5			L	WD	G	5			L	BP	CT	9	P	4	Dirty		2	HX	G	5						
575	5									C	BP	CT	9	P	4	Dirty											
575										R	BP	CT	9	P	4	Dirty											
576	4	Bowed 4"		L	WD	G	5			L	BP	CT	8	P	4	Dirty											
576										C	BP	CT	8	P	4	Dirty											
576										R	BP	CT	8	P	4	Dirty											
577	5									L	TG	BS	8	G	5			2	SB	G	5						
577										C	TG	BS	8	G	4												
577										R	TG	BS	8	F	4	Broken bell (not there)	L170000578(5)										
578	2	Splitting, Arm Damage	, L170000578(7)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
578										C	BP	CT	8	P	4	Dirty											
578										R	BP	CT	8	P	4	Dirty											
579	5	Bowed	, L170000579(3)	L	WD	G	5			L	TG	BS	8	G	5												
579										C	TG	BS	8	G	5												
579										R	TG	BS	8	G	5												
580	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty	L170000580(6)										
580										C	BP	CT	8	P	4	Dirty	L170000580(7)										
580										R	BP	CT	8	P	4	Dirty	L170000580(8)										
581	4	Bowed	, L170000581(7)	L	WD	G	5			L	BP	CT	8	P	4												
581										C	BP	CT	8	P	4												
581										R	BP	CT	8	P	4	Rust on 4th hub	L170000581(5)										
582	5			L	WD	F	5	Back brace bowed	L170000582(6)	L	BP	CT	8	P	4	Pulled ahead 6-8", Dirty	L170000582(2)										
582										C	BP	CT	8	P	3	Rust on top hubs, 1 chipped bell, Dirty	L170000582(7)										
582										R	BP	CT	8	P	4	Dirty											
583	2	Slope grain on right end	, L170000583(7)	L	WD	G	5			L	BP	CT	8	P	4												
583										C	BP	CT	8	P	4												
583										R	BP	CT	8	P	4												
584	2	Bowing, twisting, light slope grain	, L170000584(8)	L	WD	G	5			L	BP	CT	8	P	4	Rust on top hub, Dirty	L170000584(9)										
584										C	BP	CT	8	P	4	Dirty											
584										R	BP	CT	8	P	4	Dirty											
585	2	Left end of arm light splitting	, L170000585(9)	L	WD	G	5			L	BP	CT	8	P	4												
585										C	BP	CT	8	P	3	Heavy rust on top end	L170000585(6)										
585										R	BP	CT	8	P	3	Heavy rust on top end	L170000585(7)										
586	2	Bowed, light splitting, damage on top of right si	L170000586(10)	L	WD	G	5			L	BP	CT	8	P	4												
586										C	BP	CT	8	P	4	Light rust top hub	L170000586(7)										
586										R	BP	CT	8	P	3	Flashover	L170000586(8)										
587	5			L	WD	E	5			L	TG	BS	8	G	5												
587										C	TG	BS	8	G	5												
587										R	TG	BS	8	G	5												
588	2	Bowed, left end splitting	, L170000588(6)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
588										C	BP	CT	8	P	4	Dirty											
588										R	BP	CT	8	P	4	Dirty, bird droppings	L170000588(5)										
589	5			L	WD	E	5			L	TG	BS	8	G	5												
589										C	TG	BS	8	G	5												
589										R	TG	BS	8	G	5												
590	5			L	WD	E	5			L	TG	BS	8	G	5												
590										C	TG	BS	8	G	5												
590										R	TG	BS	8	G	5												
591	5			L	WD	E	5			L	TG	BS	8	G	5												

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591										C	TG	BS	8	G	5												
591										R	TG	BS	8	G	5												
592	5			L	WD	E	5			L	TG	BS	8	G	5												
592										C	TG	BS	8	G	5	Light bird droppings	L170000592(5)										
592										R	TG	BS	8	G	5												
593	5			L	WD	E	5			L	TG	BS	8	G	5												
593										C	TG	BS	8	G	5												
593										R	TG	BS	8	G	5												
594	5			L	WD	E	5			L	TG	BS	8	G	5												
594										C	TG	BS	8	G	5												
594										R	TG	BS	8	G	5												
595	3	Light splitting at left pipe	L170000595(5)							L	BP	CT	8	G	5												
595	3	Bottom edge damaged at left end	L170000595(6)							C	BP	CT	8	G	5												
595										R	BP	CT	8	G	5												
596	5			L	WD	E	5			L	TG	BS	8	G	5												
596										C	TG	BS	8	G	5												
596										R	TG	BS	8	G	5												
597	2	Light splitting right end		L	WD	G	5			L	BP	CT	8	P	4	Rust on top hub	L170000597(6)										
597										C	BP	CT	8	P	4	Rust on top hub	L170000597(7)										
597										R	BP	CT	8	P	4	Rust on top hub	L170000597(8)										
598	2	Light splitting, slope grain	, L170000598(9)	L	WD	G	5			L	BP	CT	8	P	4	Left top hub rusty	L170000598(5)										
598										C	BP	CT	8	P	4												
598										R	BP	CT	8	P	4	Possible flashover	L170000599(6)										
599	5			L	WD	G	5			L	BP	CT	8	P	4												
599										C	BP	CT	8	P	4												
599										R	BP	CT	8	P	4												
600	5	Weathered	, L170000600(6)	L	WD	G	5			L	BP	CT	8	P	4												
600										C	BP	CT	8	P	4												
600										R	BP	CT	8	P	4												
601	5			L	WD	E	5			L	TG	BS	8	G	5												
601										C	TG	BS	8	G	5												
601										R	TG	BS	8	G	5												
602	5			L	WD	E	5			L	TG	BS	8	G	5												
602										C	TG	BS	8	G	5												
602										R	TG	BS	8	G	5												
603	2	Light slope, largest knot right end	, L170000603(6)	L	WD	G	5			L	BP	CT	8	P	3	Possible flashover	L170000603(7)										
603										C	BP	CT	8	P	4												
603										R	BP	CT	8	P	4												
604	2	Light splitting throughout, damage on bottom e	L170000604(8)	L	WD	G	5			L	BP	CT	8	P	4												
604										C	BP	CT	8	P	4												
604										R	BP	CT	8	P	4												
605	5			L	WD	E	5			L	TG	BS	8	G	5												
605										C	TG	BS	8	G	5												
605										R	TG	BS	8	G	5												
606	5			L	WD	G	5			L	BP	CT	8	P	4												
606										C	BP	CT	8	P	4												
606										R	BP	CT	8	P	3	Possible Flashover	), L170000606(6)										
607	4	Twisted, weathered	L170000607(10)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
607										C	BP	CT	8	P	4	Dirty											
607										R	BP	CT	8	P	4	Dirty											
608	5			L	WD	E	5			L	TG	BS	8	G	5												
608										C	TG	BS	8	G	5												
608										R	TG	BS	8	G	5												
609	5			L	WD	E	5			L	TG	BS	8	G	5												
609										C	TG	BS	8	G	5												
609										R	TG	BS	8	G	5												

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610	5			L	WD	G	5			L	BP	CT	8	P	3	Pulled ahead 2-6", Dirty, #6 bell cotte	), L170000610(4)										
610										C	BP	CT	8	P	4	Dirty	), L170000610(4)										
610										R	BP	CT	8	P	4	Dirty	), L170000610(4)										
611	5			L	WD	F	5	Ahead brace bowed and twisted	L171000611(6)	L	BP	CT	8	P	4													
611										C	BP	CT	8	P	4												
611										R	BP	CT	8	P	4	Pulled ahead 4-6"	L170000611(4)										
612	5			L	WD	E	5			L	TG	BS	8	G	5													
612										C	TG	BS	8	G	5												
612										R	TG	BS	8	G	5												
613	2	Weathered, light slope grain, right end	, L170000613(7)	L	WD	G	5			L	BP	CT	8	P	4													
613										C	BP	CT	8	P	4												
613										R	BP	CT	8	P	4	Flashover	L170000613(5)										
614	2	Bowed and twisted	L170000614(10)	L	WD	G	5			L	BP	CT	8	P	4	Rust, top hub	L170000614(5)										
614										C	BP	CT	8	P	4												
614										R	BP	CT	8	P	4	Light rust top hub	L170000614(6)										
615	5			L	WD	F	5	Bowed (back brace)	615(4), L170000615(5)	L	BP	CT	8	P	4													
615										C	BP	CT	8	P	4												
615										R	BP	CT	8	P	4	Light rught top hub	L170000615(6)										
616	5	Light damage, bottom edge at centre (newer laminated arm)		L	WD	G	5			L	BP	CT	8	P	4													
616										C	BP	CT	8	P	4												
616										R	BP	CT	8	P	4												
617	5			L	WD	G	5			L	BP	CT	8	P	4	Light rust top hub	L170000617(5)										
617										C	BP	CT	8	P	4	Light rust top hub	L170000617(6)										
617										R	BP	CT	8	P	4	Light rust top hub	L170000617(7)										
618	5			L	WD	G	5			L	BP	CT	8	P	3	Flashover	L170000618(5)										
618										C	BP	CT	8	P	4												
618										R	BP	CT	8	P	4												
619	2	Light splitting, slope grain throughout	, L170000619(9)	L	WD	P	2	Ahead brace broken	9(10), L170000619(11)	L	BP	CT	8	P	4													
619										C	BP	CT	8	P	4	Rust on top hub	L170000619(7)										
619										R	BP	CT	8	P	4												
620	5			L	WD	G	5			L	TG	BS	8	P	4													
620										C	TG	BS	8	P	4												
620										R	TG	BS	8	P	4												
621	5	Branches on arm from possible nest	L170000621(7)	L	WD	G	5			L	BP	CT	8	P	4	Dirty												
621										C	BP	CT	8	P	3	Light rust and possible fashover, dirty	L170000621(5)										
621										R	BP	CT	8	P	3	Rust on hubs, flashover, dirty	), L170000621(7)										
622	2	Light splitting, twisted, light slope grain, and bo	L170000622(10)	L	WD	G	5			L	BP	CT	8	P	4	Discoloured top hub	L170000622(10)										
622										C	BP	CT	8	P	4	Dirty											
622										R	BP	CT	8	P	4	Rusting top hub, Dirty	L170000622(11)										
623	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty bottom bells, light rust	L170000623(5)										
623										C	BP	CT	8	P	3	Dirty bottom bells, rust and possible	L170000623(6)										
623										R	BP	CT	8	P	4	Dirty bottom bells, rust on top hub	L170000623(7)										
624	5			L	WD	F	5	Ahead brace bowed		L	TG	BS	8	G	5													
624										C	TG	BS	8	G	5												
624										R	TG	BS	8	G	5												
625	2	Twisted, light splitting throughout	, L170000625(9)	L	WD	G	5			L	BP	CT	8	P	4	Dirty, pulled back 6-8", rust on top hu	L170000625(10)										
625										C	BP	CT	8	P	4	Dirty											
625										R	BP	CT	8	P	4	Dirty											
626	2	Splitting on left half	, L170000625(6)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
626										C	BP	CT	8	P	4	Dirty											
626										R	BP	CT	8	P	4	Dirty, light rust top bells	L170000626(8)										
627	2	Splitting and slope grain throughout twisted	, L170000626(7)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
627										C	BP	CT	8	P	4	Dirty											
627										R	BP	CT	8	P	4	Dirty, discoloured hubs possible flash	L170000627(8)										
628	2	Large knothole, right side	, L170000628(7)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
628										C	BP	CT	8	P	4	Dirty											

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628										R	BP	CT	8	P	4	Rust on top hub, dirty	L170000628(5)										
629	4	Arm twisted on right end	L170000629(5)	L	WD	F	5	Sway twisted	L170000629(6)	L	BP	CT	8	P	4	Dirty											
629										C	BP	CT	8	P	4	Dirty											
629										R	BP	CT	8	P	4	Dirty											
630	5	Weathered	, L170000630(6)							L	BP	CT	8	P	4	Dirty											
630	5	Back left arm bottom edge damaged, weathere	L170000630(7)							C	BP	CT	8	P	4	Dirty											
630										R	BP	CT	8	P	4	Dirty											
631	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
631										C	BP	CT	8	P	2	Dirty, possible flashover	L170000631(5)										
631										R	BP	CT	8	P	2	Dirty, possible flashover	L170000631(6)										
632	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
632										C	BP	CT	8	P	4	Dirty											
632										R	BP	CT	8	P	4	Dirty											
633	5			L	WD	G	5			L	GP	CT	8	P	4	Top hub discoloured, Dirty	L170000633(5)										
633										C	GP	CT	8	P	4	Dirty											
633										R	GP	CT	8	P	4	Light rust top hub dirty	L170000633(6)										
634	5			L	WD	F	5	Back brace bowed	L170000634(5)	L	BP	CT	8	P	2	Dirty, light rust top hub	L170000634(6)										
634										C	BP	CT	8	P	2	Dirty, light rust and possible flashove	L170000634(7)										
634										R	BP	CT	8	P	2	Dirty, light rust and possible flashove	L170000634(8)										
635	2	Slap grain on left, bowed	, L170000635(8)	L	WD	G	5			L	BP	CT	8	P	2	Dirty, heavy rust	L170000635(7)										
635										C	BP	CT	8	P	4	Dirty											
635										R	BP	CT	8	P	4	Dirty											
636	2	Bowed and twisted	L170000636(10)	L	WD	F	5	Back brace bowed and twisted	L170000636(5)	L	BP	CT	8	P	4	Dirty											
636										C	BP	CT	8	P	4	Rust on top hub	L170000636(11)										
636										R	BP	CT	8	P	4	Rust and possible flashover	, L170000636(13)										
637	5	Left end has light damage and decay	, L170000637(8)	L	WD	G	5			L	BP	CT	8	P	4	Dirty, top hub light rust	), L170000637(6)										
637										C	BP	CT	8	P	4	Dirty											
637										R	BP	CT	8	P	4	Dirty											
638	2	Arm splitting on right end	, L170000638(6)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
638										C	BP	CT	8	P	4	Dirty											
638										R	BP	CT	8	P	3	Dirty, heavy rust possible flashover	), L170000638(8)										
639	5	Light bowing	L170000639(1)	L	WD	G	5			L	BP	CT	8	P	3	Dirty, rust and flashover	L170000639(6)										
639										C	BP	CT	8	P	4	Dirty											
639										R	BP	CT	8	P	4	Pulled back 4-6", Dirty, rust on top hu	), L170000639(5)										
640	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
640										C	BP	CT	8	P	2	Dirty, 2nd bell from bottom cotter ke	), L170000640(6)										
640										R	BP	CT	8	P	3	Dirty, heavy rust on top hub	L170000640(7)										
641	2	Arm splitting on right end	L170000641(5)	L	WD	G	5			L	BP	CT	8	P	4	Dirty, light rust top hub	L170000641(6)										
641										C	BP	CT	8	P	4	Dirty											
641										R	BP	CT	8	P	4	Dirty											
642	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
642										C	BP	CT	8	P	3	Heavy rust top hub	L170000642(8)										
642										R	BP	CT	8	P	4	Pulled ahead 4-6"	L170000642(9)										
643	3	Top arm bowed	, L170000643(7)	L	WD	G	5			L	BP	CT	8	P	4	Pulled back 6-8", dirty, rusted top hu	), L170000643(8)										
643										C	BP	CT	8	P	4	Pulled back 6-8", dirty, rusted hub	), L170000643(9)										
643										R	BP	CT	8	P	4	Pulled back 6-8", dirty, rusted top hu	L170000643(10)										
644	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
644										C	BP	CT	8	P	4	Dirty											
644										R	BP	CT	8	P	4	Dirty											
645	5	Twisted light damage bottom end on the right,	L170000645(10)	L	WD	F	5	Back brace top left end decayed	L170000645(12)	L	BP	CT	8	P	4	Light rust on top hub	L170000645(7)										
645										C	BP	CT	8	P	4	Light rust on top hub	L170000645(8)										
645										R	BP	CT	8	P	4	Light rust on top hub	L170000645(9)										
646	5			L	WD	F	5	Back arm weathered, light splitting to	646(5), L170000646(6)	L	BP	BS	8	P	3	Dirty (very)	L170000646(7)										
646										C	BP	CT	8	P	3	Dirty (very)	L170000646(8)										
646										R	BP	BS	8	P	3	Dirty (very)	L170000646(9)										
647	5			L	WD	G	5			L	BS	CT	8	P	3	Very dirty	L170000647(7)										

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647										C	BS	CT	8	P	3	Very dirty	L170000647(8)										
647										R	BS	CT	8	P	3	Very dirty	L170000647(9)										
648	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty	L170000648(5)										
648										C	BP	CT	8	P	3	Rust top hub, dirty	), L170000648(6)										
648										R	BP	CT	8	P	3	Rabbits foot lodged in suspension bra	L170000645(7)										
649	5			L	WD	G	5			L	BP	CT	8	P	3	Very dirty	L170000649(8)										
649										C	BP	CT	8	P	3	very dirty	L170000649(9)										
649										R	BP	CT	8	P	3	Very dirty	L170000649(10)										
650	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
650										C	BP	CT	8	P	4	Dirty											
650										R	BP	CT	8	P	4	Dirty											
651	2	Splitting and decay on left end weathered	L170000651(11)	L	WD	G	5			L	BP	CT	8	P	4	Pulled ahead 4-6"											
651										C	BP	CT	8	P	4	Pulled ahead 4-6"											
651										R	BP	CT	8	P	4	Dirty											
652	5			L	WD	F	5	ahead bowed (ahead brace)	L170000652(7)	L	BP	CT	8	P	4	Dirty											
652										C	BP	CT	8	P	4	Dirty											
652										R	BP	CT	8	P	4	Dirty											
653	5			L	WD	G	5			L	BP	CT	8	P	3	Dirty (very)	L170000653(7)										
653										C	BP	CT	8	P	3	Dirty (very)	L170000653(8)										
653										R	BP	CT	8	P	3	Dirty (very)	L170000653(9)										
654	5			L	WD	F	5	Ahead brace bowed and twisted	L170000654(5)	L	BP	CT	8	P	4													
654										C	BP	CT	8	P	4												
654										R	BP	CT	8	P	4												
655	5			L	WD	G	5			L	BP	BS	9	P	4	Dirty											
655										C	BP	BS	9	P	4	Dirty											
655										R	BP	BS	9	P	4	Back right bell cotter key has come ou	L170000655(5)										
656	3	Heavy twisting	, L170000656(8)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
656										C	BP	CT	8	P	4	Dirty, light rust											
656										R	BP	CT	8	P	4	Dirty											
657	5			L	WD	F	5	Bowed and damaged on bottom end	L170000657(6)	L	BP	CT	8	P	4	Dirty											
657										C	BP	CT	8	P	4	Dirty, possible flashover											
657										R	BP	CT	8	P	4	Dirty											
658	3	Twisted, very light splintering right end	, L170000658(7)	L	WD	G	5			L	EP	CT	N/A	G	5												
658										C	EP	CT	N/A	G	5												
658										R	P	CT	N/A	G	5												
659	5									L	BP	CT	8	P	2	Top insulator ball and socket not seat	L170000659(9)	2	HX	G	5						
659	5	Light twisting right arm	L170000659(6)							C	BP	CT	8	P	4	Dirty											
659										R	BP	CT	8	P	4	Dirty											
660	2	Splitting on left end, and twisted	), 170000660(7)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
660	5									C	BP	CT	8	P	4	Dirty											
660										R	BP	CT	8	P	4	Dirty											
661	2	Splitting on left end, left end twisted	, L170000661(6)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
661	5									C	BP	CT	8	P	4	Dirty											
661										R	BP	CT	8	P	4	Dirty											
662	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
662	5									C	BP	CT	8	P	4	Dirty											
662										R	BP	CT	8	P	4	Dirty											
663	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
663	5									C	BP	CT	8	P	4	Dirty											
663										R	BP	CT	8	P	4	Dirty											
664	5			L	WD	G	5			L	BP	CT	8	P	2	Heavy rust on top end	L170000664(8)										
664	2	Light splitting and slope grain throughout	L170000664(12)							C	BP	CT	8	P	4	Rust on hubs	L170000664(9)										
664										R	BP	CT	8	P	2	Rust on hubs possible flashover	, L170000664(13)										
665	2	Bowed, light slope grain and light splitting throu	L170000665(7)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
665	2	Bowed and twisted	, L170000665(6)							C	BP	CT	8	P	4	Dirty											
665										R	BP	CT	8	P	4	Dirty											

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666	5			L	WD	F	5	Back brace bowed	L170000666(12)	L	BP	CT	9	P	4	Dirty												
666	4	Weathered and decayed	, L170000666(8)							C	BP	CT	9	P	4	Dirty												
666										R	BP	CT	9	P	4	Dirty												
667	5			L	WD	F	5	Bowed and twisted	L170000667(9)	L	BP	CT	8	P	4	Pulled back	L170000667(2)											
667										C	BP	CT	8	P	4	Dirty												
667										R	BP	CT	8	P	2	Flashover	), L170000667(6)											
668	2	Twisted and Bowed	, L170000668(6)	L	WD	G	5			L	BP	CT	8	P	4	Dirty												
668										C	BP	CT	8	P	4	Dirty												
668										R	BP	CT	8	P	4	Dirty												
669	5	Light twisting on left end	, L170000669(6)	L	WD	G	5			L	BP	CT	8	P	4	Dirty												
669										C	BP	CT	8	P	4	Dirty												
669										R	BP	CT	8	P	4	Dirty												
670	2	Splitting and slope grain, heavy splitting	, L170000670(6)	L	WD	G	5			L	BP	CT	8	P	4	Dirty												
670										C	BP	CT	8	P	4	Dirty												
670										R	BP	CT	8	P	4	Dirty												
671	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty												
671										C	BP	CT	8	P	3	Rust and flashover	L170000671(5)											
671										R	BP	CT	8	P	4	Dirty												
672	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty, rust on top hub	L170000672(5)											
672										C	BP	CT	8	P	4	Dirty, rust on top hub	L170000672(6)											
672										R	BP	CT	8	P	4	Dirty, rust												
673	5									L	BP	CT	8	P	4	Dirty												
673	5									C	BP	CT	8	P	4	Dirty												
673										R	BP	CT	8	P	4	Dirty												
674	2	Slope grain on left and decay	, L170000674(8)	L	WD	G	5			L	BP	CT	8	P	4	Dirty												
674										C	BP	CT	8	P	4	Dirty												
674										R	BP	CT	8	P	3	Rust on top hub	L170000674(9)											
675	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty												
675										C	BP	CT	8	P	4	Dirty												
675										R	BP	CT	8	P	4	Dirty												
676	5			L	WD	G	5			L	BP	CT	8	P	3	Rust on hubs (heavy)	L170000676(5)											
676										C	BP	CT	8	P	4	Dirty												
676										R	BP	CT	8	P	3	Rust on hubs/flashover	L170000676(6)											
677	5			L	WD	G	5			L	BP	CT	8	P	4	Rust on hubs	L170000677(5)											
677										C	BP	CT	8	P	4	Dirty												
677										R	BP	CT	8	P	4	Dirty												
678	2	Slope grain and weathered	, L170000678(6)	L	WD	F	5	Ahead brace twisted	L170000678(8)	L	BP	CT	8	P	4	Dirty												
678										C	BP	CT	8	P	4	Dirty												
678										R	BP	CT	8	P	4	Dirty												
679	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty												
679										C	BP	CT	8	P	4	Dirty												
679										R	BP	CT	8	P	4	Dirty, top bell light rust	L170000679(5)											
680	5			L	WD	F	5	Twisted	L170000680(8)	L	BP	CT	8	P	4	Dirty, heavy rust top hub	L170000680(7)											
680				R	WD	G	5			C	BP	CT	8	P	4	Dirty												
680										R	BP	CT	8	P	4	Dirty												
681	5			L	WD	G	5			L	BP	CT	8	P	3	Pulled ahead 4-6"	), L170000681(7)											
681	5									C	BP	CT	8	P	3	pulled ahead 4-6", rust on top hubs	), L170000681(4)											
681										R	BP	CT	8	P	3	Dirty, rust on top hubs	L170000681(8)											
682	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty												
682										C	BP	CT	8	P	4	Dirty												
682										R	BP	CT	8	P	4	Dirty, light rust on hubs	L170000682(5)											
683	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty												
683										C	BP	CT	8	P	3	Dirty, rust on hubs, flashover	L170000683(7)											
683										R	BP	CT	8	P	4	Dirty, rust on hubs, flashover	L170000683(8)											
684	5			L	WD	G	5			L	BP	CT	8	P	4	Back 4-6"	L170000684(2)											
684										C	BP	CT	8	P	4	Dirty												

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684										R	BP	CT	8	P	4	Dirty											
685	4	Light twisting on right end	L170000685(5)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
685										C	BP	CT	8	P	4	Dirty											
685										R	BP	CT	8	P	4	Dirty											
686	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
686										C	BP	CT	8	P	4	Dirty											
686										R	BP	CT	8	P	4	Dirty											
687	2	Slope grain, twisting on left end	, L170000687(8)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
687										C	BP	CT	8	P	4	Dirty											
687										R	BP	CT	8	P	4	Dirty											
688	2	Splitting bottom edge at right pole and left pole	L170000688(9)	L	WD	G	5			L	BP	CT	8	P	4												
688										C	BP	CT	8	P	4												
688										R	BP	CT	8	P	4	Rust on top hub	L170000688(5)										
689	5			L	WD	F	5	Ahead brace light splitting at centre	689(8), L170000689(9)	L	BP	CT	8	P	4	Light rust on top hub	L170000689(5)										
689										C	BP	CT	8	P	4	Dirty											
689										R	BP	CT	8	P	4	Heavy rust	L170000689(6)										
690	2	Weathered, light splitting on left end	, L170000690(9)	L	WD	G	5			L	BP	CT	8	P	4	Pulled ahead 4-6"	L170000690(2)										
690										C	BP	CT	8	P	4	Pulled ahead 4-6"	L170000690(2)										
690										R	BP	CT	8	P	4	Dirty											
691	2	Slope grain on left ends of both arms	, L170000691(6)							L	BP	CT	8	P	4	Dirty											
691	5									C	BP	CT	8	P	4	Dirty											
691										R	BP	CT	8	P	4	Dirty											
692	5			L	WD	G	5			L	BP	CT	9	P	2	Dirty	L170000692(13)	2	HX	G	5						
692										C	BP	CT	9	P	2	Dirty	L170000692(14)										
692										R	BP	CT	9	P	2	Dirty	L170000692(15)										
693	5			L	WD	G	5			L	BP	CT	8	P	4												
693										C	BP	CT	8	P	4												
693										R	BP	CT	8	P	4												
694	2	Splitting throughout	, L170000694(7)	L	WD	G	5			L	BP	CT	8	P	4	Pulled back 8-10"	L170000694(2)										
694	2	Splitting throughout	, L170000694(7)							C	BP	CT	8	P	4												
694										R	BP	CT	8	P	4												
695	2	Heavy twisting and light slope grain throughout	L170000695(8)	L	WD	G	5			L	BP	CT	8	P	4	Light rust on top hub	L170000695(9)										
695										C	BP	CT	8	P	4	Heavy rust on top hub	L170000695(10)										
695										R	BP	CT	8	P	4												
696	2	Heavy twisting and light splitting on right end		L	WD	G	5			L	BP	CT	9	P	3	Dirty	L170000696(9)	2	HX	G	5						
696	2	Heavy twisting								C	BP	CT	9	P	3	Dirty	L170000696(10)										
696										R	BP	CT	9	P	3	Dirty	L170000696(11)										
697	5			L	WD	G	5			L	BP	CT	8	P	3	Light rust and possible flashover	), L170000697(6)										
697										C	BP	CT	8	P	4	Rust on top hub	L170000697(7)										
697										R	BP	CT	8	P	4												
698	2	Light splitting throughout	, L170000698(6)	L	WD	G	5			L	BP	CT	8	P	4	Pulled back 4-6"	L170000698(2)										
698										C	BP	CT	8	P	4												
698										R	BP	CT	8	P	4												
699	5			L	WD	G	5			L	GP	CT	8	G	5												
699	5									C	GP	CT	8	F	5	Light rust on hubs	L170000699(5)										
699										R	GP	CT	8	G	5												
700	5			L	WD	G	5			L	BP	CT	8	P	4	Rust on top hub	L170000700(5)										
700	5									C	BP	CT	8	P	4	Rust on top hub	L170000700(6)										
700										R	BP	CT	8	P	4												
701	5	Light splitting throughout	L170000701(6)	L	WD	G	5			L	BP	CT	8	P	4	Rust on top hub bulled back 4-6"	), L170000701(7)										
701	2	Splitting on right end	L170000701(5)							C	BP	CT	8	P	4	Pulled back 4-6"	L170000701(4)										
701										R	BP	CT	8	P	4	Rust on top hub	L170000701(8)										
702	5			L	WD	G	5			L	BP	BS	9	P	4			2	HX	G	5						
702	3	Twisted throughout	, L170000702(6)							C	BP	BS	9	P	4												
702										R	BP	BS	9	P	4												
703	5			L	WD	G	5			L	BP	CT	8	P	4												

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703	2	Slope grain throughout	L170000703(9)							C	BP	CT	8	P	4												
703										R	BP	CT	8	P	4												
704	5			L	WD	G	5			L	BP	CT	8	P	4												
704										C	BP	CT	8	P	4												
704										R	BP	CT	8	P	4												
705	5			L	WD	G	5			L	BP	BS	9	P	3	Dirty	L170000705(5)	2	HX	G	5						
705	5									C	BP	BS	9	P	3	Dirty possible flashover	L170000705(6)										
705										R	BP	BS	9	P	3	Dirty	L170000705(7)										
706	4	Left end has light twisting	L170000706(5)	L	WD	G	5			L	BP	CT	8	P	4												
706										C	BP	CT	8	P	4	Light rust top hub	L170000706(6)										
706										R	BP	CT	8	P	4												
707	3	Large knot left of left pole	L170000707(5)	L	WD	G	5			L	BP	CT	8	P	4												
707										C	BP	CT	8	P	4												
707										R	BP	CT	8	P	4												
708	5			L	WD	G	5			L	BP	CT	8	P	4												
708	5									C	BP	CT	8	P	3	1st and 2nd socket not sitting proper	L170000708(5)										
708										R	BP	CT	8	P	4												
709	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
709										C	BP	CT	8	P	4	Dirty											
709										R	BP	CT	8	P	4	Dirty											
710	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
710										C	BP	CT	8	P	4	Dirty											
710										R	BP	CT	8	P	4	Dirty											
711	5			L	WD	G	5			L	BP	BS	8	P	4	Dirty											
711										C	BP	BS	8	P	4	Dirty											
711										R	BP	BS	8	P	4	Dirty											
712	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
712										C	BP	CT	8	P	4	Dirty											
712										R	BP	CT	8	P	4	Dirty											
713	5									L	TG	BS	8	G	5												
713	5									C	TG	BS	8	G	5												
713										R	TG	BS	8	G	5												
714	5			L	WD	G	5			L	BP	BS	9	P	4	Dirty		2	HX	G	5						
714										C	BP	BS	9	P	4	Dirty											
714										R	BP	BS	9	P	4	Dirty											
715	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
715										C	BP	CT	8	P	4	Dirty											
715										R	BP	CT	8	P	4	Dirty											
716	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
716										C	BP	CT	8	P	4	Dirty, rust on top hub	L170000716(5)										
716										R	BP	CT	8	P	4	Dirty											
717	5			L	WD	P	3	Ahead brace has large split at centre	L170000717(7)	L	BP	CT	8	P	4	Dirty, pulled back 6-8"	L170000717(2)										
717	2	Arm has slope grain throughout	L170000717(6)							C	BP	CT	8	P	4	Dirty											
717										R	BP	CT	8	P	4	Dirty											
718	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
718										C	BP	CT	8	P	4	Dirty											
718										R	BP	CT	8	P	4	Dirty											
719	5			L	WD	G	5			L	BP	CT	8	P	4												
719	4	Bowed 4"	L170000719(3)							C	BP	CT	8	P	4												
719										R	BP	CT	8	P	4												
720	5			L	WD	G	5			L	BP	CT	8	P	4												
720	5									C	BP	CT	8	P	4												
720										R	BP	CT	8	P	4												
721	5	Weathered, twisted	L170000721(3)	L	WD	G	5			L	BP	CT	9	P	4			2	HX	G	5						
721	5	Weathered, twisted	L170000721(3)							C	BP	CT	9	P	4												
721										R	BP	CT	9	P	4												

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722	5			L	WD	G	5			L	TG	BS	9	G	5												
722										C	TG	BS	9	G	5												
722										R	TG	BS	9	G	5												
723	5			L	WD	G	5			L	TG	BS	8	G	5												
723										C	TG	BS	8	G	5												
723										R	TG	BS	8	G	5												
724	5									L	TG	BS	8	G	5												
724										C	TG	BS	8	G	5												
724										R	TG	BS	8	G	5												
725	5			L	WD	G	5			L	TG	BS	8	G	5												
725										C	TG	BS	8	G	5												
725										R	TG	BS	8	G	5												
726	5			L	WD	G	5			L	BP	CT	9	P	4			2	HX	G	5						
726	5			R	WD	G	5			C	BP	CT	9	P	4												
726										R	BP	CT	9	P	4												
727	5			L	WD	G	5			L	TG	BS	8	G	5												
727										C	TG	BS	8	G	5												
727										R	TG	BS	8	G	5												
728	5			L	WD	G	5			L	BP	CT	9	P	4			2	HX	G	5						
728	5									C	BP	CT	9	P	4												
728										R	BP	CT	9	P	4												
729	5			L	WD	G	5			L	TG	BS	8	G	5												
729										C	TG	BS	8	G	5												
729										R	TG	BS	8	G	5												
730	5			L	WD	G	5			L	TG	BS	8	G	5												
730										C	TG	BS	8	G	5												
730										R	TG	BS	8	G	5												
731	5			L	WD	G	5			L	BP	CT	9	P	4												
731	5									C	BP	CT	9	P	4												
731										R	BP	CT	9	P	4												
732	5			L	WD	G	5			L	TG	BS	8	G	5												
732										C	TG	BS	8	G	5												
732										R	TG	BS	8	G	5												
733	5			L	WD	G	5			L	TG	BS	8	G	5												
733										C	TG	BS	8	G	5												
733										R	TG	BS	8	G	5												
734	5			L	WD	G	5			L	BP	CT	8	P	4												
734										C	BP	CT	8	P	4												
734										R	BP	CT	8	P	4												
735	5			L	WD	G	5			L	BP	CT	8	P	4												
735										C	BP	CT	8	P	4												
735										R	BP	CT	8	P	4												
736	5			L	WD	G	5			L	BP	CT	9/12	P	4	9 Back / 12 ahead	), L170000736(4)	2	HX	G	5						
736	5									C	BP	CT	9/12	P	4	9 Back / 12 ahead	), L170000736(4)										
736										R	BP	CT	9/12	P	4	9 Back / 12 ahead	), L170000736(4)										
737	5			L	WD	G	5			L	GP	CT	8	G	5												
737										C	GP	CT	8	G	5												
737										R	GP	CT	8	G	5												
738	5			L	WD	G	5			L	GP	CT	8	G	5	Kicked back 8"	), L170000738(4)										
738										C	GP	CT	8	G	4	Kicked back 8", one chipped bell	), L170000738(6)										
738										R	GP	CT	8	G	5	Kicked back 8"	), L170000738(4)										
739	5			L	WD	G	5			L	TG	BS	8	G	5												
739										C	TG	BS	8	G	5												
739										R	TG	BS	8	G	5												
740	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
740										C	BP	CT	8	P	4	Dirty											

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740										R	BP	CT	8	P	4	Dirty											
741	5			L	WD	G	5			L	BP	CT	8	P	4	Kicked ahead 4", Dirty	), L170000741(4)										
741										C	BP	CT	8	P	4	Kicked ahead 4", Dirty	), L170000741(4)										
741										R	BP	CT	8	P	4	Kicked ahead 4", Dirty	), L170000741(4)										
742	5									L	BP	CT	8	P	4	Dirty	3), L10000742(4)										
742	5									C	BP	CT	8	P	4	Dirty	3), L10000742(4)										
742										R	BP	CT	8	P	4	Dirty	3), L10000742(4)										
743	5			L	WD	G	5			L	BP	CT	8	P	4	Leaning back 2-4"	), L170000743(4)										
743										C	BP	CT	8	P	4	Leaning back 2-4"	), L170000743(4)										
743										R	BP	CT	8	P	4												
744	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
744										C	BP	CT	8	P	4	Dirty											
744										R	BP	CT	8	P	4	Dirty											
745	5			L	WD	G	5			L	TG	BS	9	G	5			2	HX	G	5						
745	5									C	TG	BS	9	G	5												
745										R	TG	BS	9	G	5												
746	3	Splitting on right side	L170000746(5)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
746	5									C	BP	CT	8	P	4	Dirty											
746										R	BP	CT	8	P	4	Dirty											
747	5			L	WD	G	5			L	TG	BS	8	G	5												
747	5									C	TG	BS	8	G	5												
747										R	TG	BS	8	G	5												
748	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
748										C	BP	CT	8	P	4	Dirty											
748										R	BP	CT	8	P	4	Kicked ahead 4"	L170000748(4)										
749	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
749										C	BP	CT	8	P	4	Dirty											
749										R	BP	CT	8	P	4	Dirty											
750	5			L	WD	G	5			L	TG	BS	8	G	5												
750										C	TG	BS	8	G	5												
750										R	TG	BS	8	G	5												
751	5			L	WD	G	5			L	TG	BS	8	G	5												
751										C	TG	BS	8	G	5												
751										R	TG	BS	8	G	5												
752	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
752										C	BP	CT	8	P	4	Dirty											
752										R	BP	CT	8	P	4	Dirty											
753	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
753										C	BP	CT	8	P	4	Dirty											
753										R	BP	CT	8	P	4	Dirty											
754	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
754										C	BP	CT	8	P	4	Dirty											
754										R	BP	CT	8	P	4	Dirty											
754A	5									L	EP	BS		G	5												
754A	5									C	EP	BS		G	5												
754A										R	EP	BS		G	5												
755	5			L	WD	G	5			L	TG	BS	8	G	5												
755										C	TG	BS	8	G	5												
755										R	TG	BS	8	G	5												
756	4	Bowed 3"	L170000756(3)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
756										C	BP	CT	8	P	4	Dirty											
756										R	BP	CT	8	P	4	Dirty											
757	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
757										C	BP	CT	8	P	4	Dirty											
757										R	BP	CT	8	P	4	Dirty											
758	4	Bowed 3"	L170000758(3)	L	WD	G	5			L	BP	CT	8	P	4	Kicked ahead 3"	L170000758(2)										

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758										C	BP	CT	8	P	4	Kicked ahead 3"	L170000758(2)										
758										R	BP	CT	8	P	4	Kicked ahead 3"	L170000758(2)										
759	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
759										C	BP	CT	8	P	4	Dirty											
759										R	BP	CT	8	P	4	Dirty											
760	4	Weathered	L170000760(5)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
760										C	BP	CT	8	P	4	Dirty											
760										R	BP	CT	8	P	4	Dirty											
761	4	Bowed 2"	, L170000761(3)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
761										C	BP	CT	8	P	4	Dirty											
761										R	BP	CT	8	P	4	Dirty											
762	5									L	TG	BS	8	G	5												
762										C	TG	BS	8	G	5												
762										R	TG	BS	8	G	5												
763	3	Splitting	L170000763(6)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
763										C	BP	CT	8	P	4	Dirty											
763										R	BP	CT	8	P	4	Dirty											
764	4	Bowed 3"	, L170000764(3)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
764										C	BP	CT	8	P	4	Dirty, Top hub rusty	), L170000764(6)										
764										R	BP	CT	8	P	4	Dirty, Top hub rusty	), L170000764(6)										
765	3	Splitting	L170000765(5)	L	WD	G	5			L	BP	CT	9	P	4	Dirty		2	HX	G	5							
765	5									C	BP	CT	9	P	4	Dirty											
765										R	BP	CT	9	P	4	Dirty											
766	4	Bowed 3"	L170000766(4)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
766										C	BP	CT	8	P	4	Dirty											
766										R	BP	CT	8	P	4	Dirty											
767	5			L	WD	G	5			L	EP	CT	8	G	5												
767										C	EP	CT	8	G	5												
767										R	EP	CT	8	G	5												
768	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
768										C	BP	CT	8	P	4	Dirty											
768										R	BP	CT	8	P	4	Dirty											
769	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
769										C	BP	CT	8	P	4	Dirty											
769										R	BP	CT	8	P	4	Dirty											
770	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
770										C	BP	CT	8	P	4	Dirty											
770										R	BP	CT	8	P	4	Dirty											
771	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
771										C	BP	CT	8	P	4	Dirty											
771										R	BP	CT	8	P	4	Dirty											
772	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
772										C	BP	CT	8	P	4	Dirty											
772										R	BP	CT	8	P	4	Dirty											
773	4	Weathered		L	WD	G	5			L	BP	CT	8	P	4	Dirty											
773	4	Weathered								C	BP	CT	8	P	4	Dirty											
773										R	BP	CT	8	P	4	Dirty											
774	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
774	3	Bottom arm left side splitting	L170000774(6)							C	BP	CT	8	P	4	Dirty											
774										R	BP	CT	8	P	4	Dirty											
775	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
775	5									C	BP	CT	8	P	4	Dirty											
775										R	BP	CT	8	P	4	Dirty											
776	5	Weathered		L	WD	G	5			L	BP	CT	8	P	4	Dirty											
776										C	BP	CT	8	P	4	Dirty											
776										R	BP	CT	8	P	4	Dirty											

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777	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
777										C	BP	CT	8	P	4	Dirty											
777										R	BP	CT	8	P	4	Dirty, kicked ahead 3"	L170000777(4)										
778	5	Bowed	, L170000778(3)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
778										C	BP	CT	8	P	4	Dirty											
778										R	BP	CT	8	P	4	Dirty											
779	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
779										C	BP	CT	8	P	4	Dirty											
779										R	BP	CT	8	P	4	Dirty											
780	5	Weathered, Bowed 3"	, L170000780(3)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
780										C	BP	CT	8	P	4	Dirty											
780										R	BP	CT	8	P	4	Top hub rust	L170000780(5)										
781	5	Bowed 3"	, L170000781(3)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
781										C	BP	CT	8	P	4	Dirty											
781										R	BP	CT	8	P	4	Dirty											
782	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
782										C	BP	CT	8	P	4	Dirty											
782										R	BP	CT	8	P	4	Dirty											
783	5			L	WD	G	5			L	EP	CT		G	5												
783										C	EP	CT		G	5												
783										R	EP	CT		G	5												
784	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
784										C	BP	CT	8	P	4	Dirty											
784										R	BP	CT	8	P	4	Dirty											
785	4	Bowed 4"	, L170000785(3)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
785										C	BP	CT	8	P	4	Dirty											
785										R	BP	CT	8	P	4	Dirty											
786	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
786										C	BP	CT	8	P	4	Dirty											
786										R	BP	CT	8	P	4	Dirty											
787	5									L	BP	CT	9	P	4	Dirty		2	HX	G	5						
787										C	BP	CT	9	P	4	Dirty											
787										R	BP	CT	9	P	4	Dirty											
788	5	Weathered	, L170000788(3)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
788	5	Weathered	, L170000788(3)							C	BP	CT	8	P	4	Dirty											
788										R	BP	CT	8	P	4	Dirty											
789	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
789										C	BP	CT	8	P	4	Dirty											
789										R	BP	CT	8	P	4	Dirty											
790	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
790										C	BP	CT	8	P	4	Dirty											
790										R	BP	CT	8	P	4	Dirty											
791	3			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
791										C	BP	CT	8	P	4	Dirty											
791										R	BP	CT	8	P	4	Dirty											
792	5	Bowed 4"	, L170000792(3)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
792										C	BP	CT	8	P	4	Dirty											
792										R	BP	CT	8	P	4	Dirty											
793	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
793										C	BP	CT	8	P	4	Dirty											
793										R	BP	CT	8	P	4	Dirty											
794	5			L	WD	G	5			L	BP	CT	8	P	3	Kicked back 2", and rust on top hub, [illegible], L170000794(5)											
794										C	BP	CT	8	P	4	Dirty											
794										R	BP	CT	8	P	4	Dirty											
795	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
795										C	BP	CT	8	P	4	Dirty											

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795										R	BP	CT	8	P	4	Dirty											
796	5	Bowed 3"	, L170000796(3)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
796										C	BP	CT	8	P	4	Dirty, kicked back 4"	, L1700000796(4)										
796										R	BP	CT	8	P	4	Dirty, kicked back 3"	, L1700000796(4)										
797	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
797										C	BP	CT	8	P	4	Dirty											
797										R	BP	CT	8	P	4	Dirty											
798	5	Bowed 3"	, L170000798(3)	L	WD	G	5			L	BP	CT	8	P	4	Dirty, top hub rusty	L170000798(5)										
798										C	BP	CT	8	P	4	Dirty											
798										R	BP	CT	8	P	4	Dirty, top hub rusty	L170000798(6)										
799	5									L	BP	CT	8	P	4	Dirty		2	HX	G	5						
799	5									C	BP	CT	8	P	4	Dirty											
799										R	BP	CT	8	P	4	Dirty											
800	5			L	WD	G	5			L	BP	CT	8	P	4	Rust top hub	L170000800(5)										
800										C	BP	CT	8	P	4	Dirty											
800										R	BP	CT	8	P	4	Rust top hub	L170000800(6)										
801	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty, rust on hubs, flashover	L170000801(5)										
801										C	BP	CT	8	P	4	Dirty, rust on top hubs	L170000801(5)										
801										R	BP	CT	8	P	4	Dirty, rust on top hubs	L170000801(5)										
802	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
802										C	BP	CT	8	P	4	Dirty											
802										R	BP	CT	8	P	4	Dirty											
803	5			L	WD	G	5			L	BP	CT	9	P	4	Dirty		2	HX	G	5						
803										C	BP	CT	9	P	4	Dirty											
803										R	BP	CT	9	P	4	Dirty											
804	5			L	WD	G	5			L	TG	BS	8	G	5												
804										C	TG	BS	8	G	5												
804										R	TG	BS	8	G	5												
805	5									L	BP	CT	8	P	4	Dirty		2	HX	G	5						
805	5									C	BP	CT	8	P	4	Dirty											
805										R	BP	CT	8	P	4	Dirty											
806	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
806										C	BP	CT	8	P	4	Dirty											
806										R	BP	CT	8	P	4	Dirty											
807	5			L	WD	G	5			L	TG	BS	8	G	5												
807										C	TG	BS	8	G	5												
807										R	TG	BS	8	G	5												
808	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
808										C	BP	CT	8	P	4	Dirty											
808										R	BP	CT	8	P	4	Dirty											
809	5									L	EP	BS	8	G	5												
809										C	EP	BS	8	G	5												
809										R	EP	BS	8	G	5												
810	5			L	WD	G	5			L	EP	BS	8	G	5												
810										C	EP	BS	8	G	5												
810										R	EP	BS	8	G	5												
811	5			L	WD	G	5			L	TG	BS	8	G	5												
811										C	TG	BS	8	G	5												
811										R	TG	BS	8	G	5												
812	5	Weathered		L	WD	G	5			L	TG	BS	8	G	5			2	HX	G	5						
812	5	Weathered		R	WD	G	5			C	TG	BS	8	G	5												
812										R	TG	BS	8	G	5												
813	5			L	WD	G	5			L	TG	BS	8	G	5												
813										C	TG	BS	8	G	5												
813										R	TG	BS	8	G	5												
814	5			L	WD	G	5			L	TG	BS	8	G	5			2	HX	G	5						

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814	5			R	WD	G	5			C	TG	BS	8	G	5												
814										R	TG	BS	8	G	5												
815	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
815										C	BP	CT	8	P	4	Dirty											
815										R	BP	CT	8	P	4	Dirty											
816	5	Bowed 2"	, L170000816(3)	L	WD	G	5			L	BP	CT	8	P	4	Top hub rusty	L170000816(5)										
816										C	BP	CT	8	P	4	Dirty											
816										R	BP	CT	8	P	4	Dirty											
817	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
817										C	BP	CT	8	P	4	Dirty											
817										R	BP	CT	8	P	4	Dirty											
818	5			L	WD	G	5			L	BP	CT	9	P	4	Dirty											
818				R	WD	G	5			C	BP	CT	9	P	4	Dirty											
818										R	BP	CT	9	P	4	Dirty											
819	5			L	WD	G	5			L	BP	CT	9	P	4	Dirty		2	HX	G	5						
819	5									C	BP	CT	9	P	4	Dirty											
819										R	BP	CT	9	P	4	Dirty											
820	5									L	BP	CT	8	P	4	Dirty		2	HX	G	5						
820										C	BP	CT	8	P	4	Dirty											
820										R	BP	CT	8	P	4	Dirty											
821	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty											
821	5									C	BP	CT	8	P	4	Dirty											
821										R	BP	CT	8	P	4	Dirty											
822	5	Weathered	, L170000822(3)	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
822										C	BP	CT	8	P	4	Dirty											
822										R	BP	CT	8	P	4	Dirty											
823	5	Weathered		L	WD	G	5			L	BP	CT	9	P	4	Dirty		2	HX	G	5						
823	5	Weathered		R	WD	G	5			C	BP	CT	9	P	4	Dirty											
823										R	BP	CT	9	P	4	Dirty											
824	5			L	WD	G	5			L	BP	CT	8	P	4	Dirty, kicked ahead 2-3"	), L170000824(4)										
824										C	BP	CT	8	P	4	Kicked ahead 2-3"	), L170000824(4)										
824										R	BP	CT	8	P	4	Kicked ahead 2-3"	), L170000824(4)										
825	3	Bowed and weathered	L170000825	L	WD	G	5			L	BP	CT	8	P	4	Dirty											
825										C	BP	CT	8	P	4												
825										R	BP	CT	8	P	4												
826	2	Splitting throughout	, L170000826(9)	L	WD	G	5			L	BP	CT	8	P	3	Rust on top hub, pulled ahead 6-8"	), L170000826(7)										
826										C	BP	CT	8	P	3	Rust on top hub, pulled ahead 6-8"	), L170000826(8)										
826										R	BP	CT	8	P	4	Rust on top hub, pulled ahead 6-8"	), L170000826(9)										
827	5			L	WD	G	5			L	BP	CT	8	P	3	Rust on hubs	L170000827(7)										
827										C	BP	CT	8	P	3	Rust on hubs	L170000827(6)										
827										R	BP	CT	8	P	4	Dirty											
828	5									L	GP	CT	8	G	5			2	HX	G	5						
828	5									C	GP	CT	8	G	5												
828										R	GP	CT	8	G	5												
829	2	Splitting on right end	L170000829(5)	L	WD	G	5			L	BP	CT	8	P	3	Rust on top hub	L170000829(6)										
829										C	BP	CT	8	P	3	Rust on top hub	L170000829(7)										
829										R	BP	CT	8	P	4												
830	5			L	WD	G	5			L	BP	CT	8	P	4	Rust on top hub	L170000830(6)										
830										C	BP	CT	8	P	4												
830										R	BP	CT	8	P	4												
831	5			L	WD	G	5			L	BP	CT	8	P	4												
831										C	BP	CT	8	P	4												
831										R	BP	CT	8	P	3	Flashover	L170000832(5)										
832	2	Splitting on left end	L170000832(5)	L	WD	G	5			L	BP	CT	8	P	3	Heavy rust on top hub	L170000832(5)										
832										C	BP	CT	8	P	4												
832										R	BP	CT	8	P	4	Dirty	L170000832(6)										

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833	2	Light slope grain and minor damage to bottom	L170000833(7)	L	WD	F	5	Back brace bowed	L170000833(5)	L	BP	CT	8	P	4												
833										C	BP	CT	8	P	4												
833										R	BP	CT	8	P	4												
834	5			L	WD	G	5			L	GP	BS	8	G	5												
834										C	GP	BS	8	G	5												
834										R	GP	BS	8	G	5												
835	5			L	WD	G	5			L	GP	BS	9/8	G	5	Left jumper top hub folded	L170000835(5)	3	SB	G	5		G	RIVER CROSSING		5	
835	5			R	WD	G	5			C	GP	BS	9/8	G	5												
835										R	GP	BS	9/8	G	5												
836	5			L	WD	G	5			L	GP	BS	9/8	G	5			3	SB	G	5		F	White wrap coming off on left and centre pole		5	
836	5			R	WD	G	5			C	GP	BS	9/8	G	5									L170000836(5), L170000836(6)			
836										R	GP	BS	9/8	G	5												

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	XRM Maint. Priority	XRM Maintenance Comment	XRM Deficiency Photo	XBR Loc.	XBR Type	XBR Cond.	XBR Maint. Priority	XBR Maintenance Comment	XBR Deficiency Photo	INS Loc.	INS TYPE	INS Fitting Type	INS Count	INS Cond.	INS Maint. Priority	INS Maintenance Comment	INS Deficiency Photo	VIB #/ phase	VIB Type	VI B Ma	VIB Maintenance Comment	VIB Def. Photo	AMK Cond.	AMK Maintenance Comment	AMK Deficiency Photo	AMK Maint. Priority	AMK Def. Photo

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
113	Cnd	G	5			Grd	G	5			G	5			P/A	HD	15	N			5				
113	Shd	G	5			b	O	3	MISSING																
113																									
114	Cnd	G	5			Grd	G	5			G	5			P/A	HD	15	N	N		5				
114						b	O	3	MISSING																
114																									
115						Grd	F	4	Ground molding needs staples	L172000115(5), L172000115(6)	G	5			P/A	HD	18	N	N		5				
115						b	O	3	MISSING																
115																									
116	Cnd	G	5			Grd	F	4	Needs staples	L170000116(7)	G	5			P/A	MD	12	N	N		5				
116	Shd	G	5			b	O	3	Missing																
116																									
117	Cnd	G	5			Grd	F	4	Needs staples on molding	L172000117(8), L1720000117(9)	G	5			P/A	MD	12	N	N		5				
117						b	O	3	Missing																
117																									
118	Cnd	G	5			b	O	4	Missing		F	5			P/A	HD	12	N	N		5				
118																									
118																									
119	Cnd	G	5	Compression sleeves ahead left and centre		b	O	4	Missing		G	5			P/A	LD	12	N	N		5				Driveway crossing ahead
119																									
119																									
120	Cnd	G	5			b	G	5			G	5			P/A	LD	10	N	N		5				Road and 3 phase crossing ahead old str butts are 8' ahead
120																									L171000120(5), L17100120(6)
120																									
121	Cnd	G	5			b	G	5			G	5			P/A	LD	12	N	N		5				
121																									
121																									
122	Cnd	G	5	1 phase crossing ahead		b	O	4	Missing		G	5			P/A	LD	10	N	N		5				
122																									
122																									
123	Cnd	G	5			b	O	4	Missing		G	5			P/A	MD	10	N	N		5				
123																									
123																									
124	Cnd	G	5			b	O	4	Missing		G	5			P/A	MD	12	N	N		5				
124																									
124																									
125	Cnd	G	5			b	O	4	Missing		G	5			P/A	LD	10	N	N		5				
125																									
125																									
126	Cnd	G	5			b	O	4	Missing		G	5			P/A	MD	10	N	N		5				
126																									
126																									
127	Cnd	G	5			b	O	4	Missing		G	5			P/A	HD	20	Y	Y	25	2	Danger poplar trees are in horse	0000127(8)		

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
127																									
127																									
128	Cnd	G	5			b	G	5			G	5			P/A	MD	14	N	N		5				
128																									
128																									
129	Cnd	G	5	Driveway crossing ahead/one splice in left phase ahead		b	G	5			G	5												4	Old str butts 8' ahead
129																									
129																									
130	Cnd	G	5			b	G	5																4	Old str butts 8' ahead
130																									
130																									
131	Cnd	G	5			b	O	4	Missing		G	5			P/A	MD	15	N	N		4			4	1 phase crossing ahead
131																									
131																									
132	Cnd	G	5			b	G	5			G	5			P/A	MD	12	N	N		5			4	Old str butts are 8' back
132																									Old str glass on ground at str (5)
132																									driveway crossing ahead (6)
133	Cnd	G	5			b	O	4	Missing		G	5			P/A	MD	12	N	N		5				
133																									
133																									
134	Cnd	G	5			b	O	4	Missing		G	5													Driveway crossing ahead
134																									
134																									
135	Cnd	G	5			b	G	5			G	5			P/A	HD	15	N	N		5				Driveway crossing ahead
135																									
135																									
136	Cnd	G	5								G	5			P/A	HD	12	N	N		5				
136																									
136																									
137	Cnd	G	5			b	G	5			G	5			P/A	HD	12	N	N		5				
137																									
137																									
138	Cnd	G	5			b	G	5			G	5			P/A	HD	12	N	N		5				
138																									
138																									
139	Cnd	G	5								G	5			P/A	HD	10	N	N		5				
139																									
139																									
140	Cnd	G	5			b	G	5			G	5			P/A	HD	16	N	N		5				
140																									
140																									
141	Cnd	G	5			b	G	5			G	5			P/A	HD	16	N	N		5				Driveway crossing ahead
141																									
141																									
142	Cnd	G	5	Patch rod ahead centre phase		b	G	5			G	5			P/A	HD	16	N	N		5				25KV Line crossing ahead
142																									
142																									
143	Cnd	G	5	Centre has 2 compression sleeves and left and right have		b	G	5			G	5			P/A	LD	12	N	N		5				Driveway crossing ahead, 14 kv line crossing ahead
143																									
143																									
144	Cnd	G	5			b	G	5			G	5			P/A	HD	16	N	N		5				Driveway crossing ahead, 14.4 kv line crossing ahead
144																									
144																									
145	Cnd	G	5			b	G	5			G	5			P/A	MD	10	N	N		5				
145																									
145																									

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
146	Cnd	G	5			b	G	5			G	5			P/A	LD	5	N	N		5				
146																									
146																									
147	Cnd	G	5			b	G	5			G	5			P/A	MD	5	N	N		5				Driveway ahead, telephone crossing ahead
147																									
147																									
148	Cnd	G	5			b	G	5			G	5			P/A	LD	10	N	N		5				
148																									
148																									
149	Cnd	G	5			b	G	5			G	5			P/A	MD	10	N	N		5				
149																									
149																									
150	Cnd	G	5			b	O	3	Missing		G	5			P/A	MD	15	N	N		5				
150																									
150																									
151	Cnd	G	5								F	4	Loose right bottom xbrace bolt	L170000151(9)	P/A	HD	15	Y	Y	25	4	Tree 10' from phase	)000151(10)		
151																									
151																									
152	Cnd	G	5			b	G	5			G	5			P/A	HD	12	N	N		5				Driveway crossing ahead, 14.4 kv line crossing ahead
152																									
152																									
153	Cnd	G	5			b	G	5			G	5			P/A	HD	20	N	N		5				
153																									
153																									
154	Cnd	G	5								G	5			P/A	HD	15	N	N		5				
154																									
154																									
155	Cnd	G	5	Compression splice ahead centre & right							G	5			P/A	LD	8	N	N		5				
155																									
155																									
156	Cnd	G	5	Compression splice ahead left							G	5			P/A	LD	8	N	N		5				
156																									
156																									
157	Cnd	G	5			b	G	5			G	5			P/A	LD	8	N	N		5				
157																									
157																									
158	Cnd	G	5								G	5			P/A	MD	15	N	N		5				
158																									
158																									
159	Cnd	G	5								G	5			P/A	HD	15	N	N		5				
159																									
159																									
160	Cnd	G	5								F	4	Right bottom brace bolt is loose	L170000160(5)	P/A	LD	10	N	N		5				
160																									
160																									
161	Cnd	G	5								G	5			P/A	HD	15	N	N		5				
161																									
161																									
162	Cnd	G	5								G	5			P/A	HD	15	N	N		5				
162																									
162																									
163	Cnd	G	5			b	O	4	Missing		G	5			P/A	HD	15	N	N		5				
163																									
163																									
164	Cnd	G	5			b	G	5			G	5			P/A	MD	12	N	N		5				
164																									

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Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
164																									
165	Cnd	G	5			b	O	4	Missing		G	5			P/A	LD	8	N	N		5				
165																									
165																									
166	Cnd	G	5	One comp splice each phase ahead		b	G	5			G	5			P/A	MD	10	N	N		5				Old str butts 6' ahead, driveway crossing ahead
166																									
166																									
167	Cnd	G	5			b	O	4	Missing		G	5			P/A	LD	12	N	N		5				Highway crossing ahead
167																									
167																									
168	Cnd	G	5			b	O	4	Missing		G	5			P/A	LD	5	N	N		5				
168																									
168																									
169	Cnd	G	5			b	O	4	Missing		G	5	Apparent centre sway bolt has been repai	L170000169(7)	P/A	LD	4	N	N		5				
169																									
169																									
170	Cnd	G	5			b	G	5			G	5			P/A	LD	5	N	N		5				Old str butts are 8' back, L170000170(7), L170000170(8)
170																									
170																									
171	Cnd	G	5								G	5	Rusty		P/A	LD	6	N	N		5				
171																									
171																									
172	Cnd	G	5								G	5	Rusty	L170000172(6)	P/A	LD	6	N	N		5				
172																									
172																									
173	Cnd	G	5								G	5	Rusty		P/A	LD	4	N	N		5				
173																									
173																									
174	Cnd	G	5								G	5	Rusty		P/A	LD	8	N	N		5				
174																									
174																									
175	Cnd	G	5			b	G	5			G	5			P/A	LD	6	N	N		5				Old str butts are 8' ahead, L170000175(5), L170000175(6)
175																									
175																									
176	Cnd	G	5								G	5	Rusty		P/A	MD	8	N	N		5				
176																									
176																									
177	Cnd	G	5	One splice in left and centre phase ahead							G	5	Rusty		P/A	MD	6	N	N		5				
177																									
177																									
178	Cnd	G	5								G	5	Rusty		P/A	LD	4	N	N		5				
178																									
178																									
179	Cnd	G	5								G	5	Rusty		P/A	MD	8	N	N		5				
179																									
179																									
180	Cnd	G	5								G	5	Rusty		P/A	LD	6	N	N		5				
180																									
180																									
181	Cnd	G	5								G	5	Rusty		P/A	LD	4	N	N		5				
181																									
181																									
182	Cnd	G	5			b	G	5			G	5	Rusty		P/A	LD	6	N	N		5				
182																									
182																									
183	Cnd	G	5								G	5			P/A	LD	6	N	N		5				

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Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
183																									
183																									
183	Cnd	G	5								G	5			P/A	LD	6	N	N		5				
183																									
183																									
184	Cnd	G	5								G	5			P/A	LD	6	N	N		5		Customer says str is constantly creaking and making noise		
184																									
184																									
185	Cnd	G	5			b	G	5			G	5			P/A	LD	4	N	N		5		Highway crossing ahead, old str butts are 8' back		
185																									L170000185(5), L170000185(6)
185																									
186	Cnd	G	5								G	5													3 phase crossing ahead
186																									
186																									
187	Cnd	G	5	One comp splice in each phase ahead							G	5			P/A	LD	6	N	N		5				
187																									
187																									
188	Cnd	G	5								G	5			P/A	LD	6	N	N		5				
188																									
188																									
189	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
189																									
189																									
190	Cnd	G	5	1 Phase crossing ahead							G	5			P/A	LD	4	N	N		5				
190																									
190																									
191	Cnd	G	5			b	G	5			G	5			P/A	LD	5	N	N		5				Driveway crossing ahead
191																									
191																									
192	Cnd	G	5			b	G	5			G	5			P/A	LD	6	N	N		5				
192																									
192																									
193	Cnd	G	5			b	G	5			F	5	Left xbrace centre bolt loose	L17100193(7)	W	LD	6	N	N		5				
193																									
193																									
194	Cnd	G	5			b	G	5			G	5			P/A, S/P	MD	25	N	N		5				
194																									
194																									
195	Cnd	G	5								G	5			P/A	HD	25	Y	Y	25	2	Trees 2' from phase	'0000195(9)		
195																									
195																									
196	Cnd	G	5								G	5			P/A	HD	25	Y	Y	25	2	Trees 2' from phases (needs brus	000196(10)		
196																									
196																									
197	Cnd	G	5								G	5			P/A	HD	25	Y	Y	25	3	Trees 10' from phase	'0000197(6)		
197																									
197																									
198	Cnd	G	5			b	O	3	Missing		G	5			P/A	HD	20	N	N		5				
198																									
198																									
199	Cnd	G	5	Compression splices ahead right and left phases							G	5			P/A	MD	10	N	N		5				
199																									
199																									
200	Cnd	G	5								G	5			P/A	LD	10	N	N		5				
200																									
200																									

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
201	Cnd	G	5			b	G	5			G	5			W	MD	12	N	N		5				Road crossing ahead, 14.4kv line crossing ahead
201																									
201																									
202	Cnd	G	5			b	O	3	Missing		G	5			W	MD	8	N	N		5				
202																									
202																									
203	Cnd	G	5								G	5			P/A, W	MD	8	N	N		5				
203																									
203																									
204	Cnd	G	5								F	4	Xbrace centre bolt is loose	L170000204(6)	W	HD	10	N	N		5				
204																									
204																									
205	Cnd	G	5	Patch rod ahead right phase		b	G	5							W	LD	8	N	N		5				Road crossing ahead, secondary line crossing ahead
205																									
205																									
206	Cnd	G	5	Patch rod ahead right phase		b	G	5			G	5			P/A	LD	5	N	N		5				
206																									
206																									
207	Cnd	G	5	Patch rod ahead right phase							G	5			P/A	MD	20	N	N		5				
207																									
207																									
208	Cnd	G	5	Patch rod ahead right phase							G	5			P/A	MD	20	N	N		5				
208																									
208																									
209	Cnd	G	5								G	5			P/A	HD	20	Y	Y	20	3	Trees 10' from phase	'0000209(9)		
209																									
209																									
210	Cnd	G	5								F	5	Bottom left brace bolt loose due to shrink	L170000210(6)	P/A	HD	20	Y	Y	20	3	Trees 12' from conductor	'0000210(9)		
210																									
210																									
211	Cnd	G	5	Compression sleeves back all phases							G	5			P/A	HD	20	N	N		5				
211																									
211																									
212	Cnd	G	5								G	5			P/A	MD	20	N	N		5				
212																									
212																									
213	Cnd	G	5								G	5			P/A	MD	20	Y	N		5	L170000213(7)			
213																									
213																									
214	Cnd	G	5								G	5			P/A	MD	12	N	N		5				Old str butts 20' ahead
214																									L170000214(5), L170000214(6), L170000214(7), L710000214(8), L170000214(9)
214																									
215	Cnd	G	5			b	G	5			G	5			P/A	LD	6	N	N		5				Old str butts 6' back
215																									L170000215(5), L170000215(6)
215																									
216	Cnd	G	5			b	O	4	Missing		G	5			P/A	LD	7	N	N		5				
216																									
216																									
217	Cnd	G	5			b	O	4	Missing		G	5			P/A, W	LD	8	N	N		5				
217																									
217																									
218	Cnd	G	5			b	O	4	Missing		G	5			P/A	LD	4	N	N		5				
218																									
218																									
219	Cnd	G	5								G	5			P/A, W	LD	6	N	N		5				
219																									

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Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
219																									
220	Cnd	G	5								G	5			P/A, W	MD	6	N	N		5				
220																									
220																									
221	Cnd	G	5								G	5			P/A, W	MD	6	N	N		5				
221																									
221																									
222	Cnd	G	5								G	5			P/A	MD	20	Y	N		5	L170000222(5)			
222																									
222																									
223	Cnd	G	5								P	3	Missing centre sway bolt hardware	L170000223(5)	P/A, W	LD	20	Y	N		5	L170000223(6), L170000223(7)			
223																									
223																									
224	Cnd	G	5								G	5			P/A, W	MD	20	Y	N		5	L170000224(5)			
224																									
224																									
225	Cnd	G	5			b	G	5			G	5			P/A, W	MD	20	Y	Y	25	2	Trees within 3' of phase	?0000225(8)		
225																									
225																									
226	Cnd	G	5			b	G	5			G	5			P/A	LD	10	N	N		5				
226																									
226																									
227	Cnd	G	5			b	G	5			G	5			P/A, W	LD	6	N	N		5				
227																									
227																									
228	Cnd	G	5			b	G	5			G	5			W	LD	5	N	N		5				
228																									
228																									
229	Cnd	G	5			b	O	4	Missing		G	5			P/A, W	MD	6	N	N		5				
229																									
229																									
230	Cnd	G	5			b	G	5			G	5			P/A	MD	20	Y	Y	20	3	Young poplars growing close to r	?0000230(7)	tr butts are 10' ahead highway crossing ahead	
230																									L170000230(5), L170000230(6)
230																									
231	Cnd	G	5			b	O	4	Missing		G	5			P/A	MD	2	N	N		5				
231																									
231																									
232	Cnd	G	5								G	5			W	LD	6	N	N		5				
232																									
232																									
233	Cnd	G	5								G	5			W	MD	4	N	N		5				
233																									
233																									
234	Cnd	G	5								G	5			P/A, W	MD	15	N	N		5				
234																									
234																									
235	Cnd	G	5								G	5			P/A	HD	20	N	N		5				
235																									
235																									
236	Cnd	G	5								G	5			P/A	LD	6	N	N		5				
236																									
236																									
237	Cnd	G	5								G	5			P/A	LD	8	N	N		5				
237																									
237																									
238	Cnd	G	5								G	5			P/A, W	MD	8	N	N		5				

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
238																									
238																									
239	Cnd	G	5			b	G	5			G	5			P/A, W	LD	8	N	N		5				Str is buzzing
239																									
239																									
240	Cnd	G	5			b	G	5			G	5			P/A, W	LD	6	N	N		5				Old str butts 8' back
240																									L170000240(5), L170000240(6)
240																									
241	Cnd	G	5			b	G	5			G	5			P/A	LD	6	N	N		5				Old str butts 8' ahead
241																									L170000241(5), L170000241(6)
241																									
242	Cnd	G	5	One comp splice ahead in centre phase							G	5			P/A	LD	6	N	N		5				
242																									
242																									
243	Cnd	G	5								G	5			P/A, W	LD	6	N	N		5				
243																									
243																									
244	Cnd	G	5			b	G	5			G	5			P/A	LD	4	N	N		5				
244																									
244																									
245	Cnd	G	5								G	5			P/A, W	LD	6	N	N		5				
245																									
245																									
246	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
246																									
246																									
247	Cnd	G	5			b	G	5			G	5			P/A	LD	6	N	N		5				Old str butts 8' back
247																									L170000247(5), L170000247(6)
247																									
248	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
248																									
248																									
249	Cnd	G	5			b	G	5			G	5			P/A	LD	6	N	N		5				Old str butts 8' ahead
249																									L170000249(5), L170000249(6)
249																									
250	Cnd	G	5								G	5			P/A, W	LD	6	N	N		5				
250																									
250																									
251	Cnd	G	5			b	G	5			G	5			P/A	LD	7	N	N		5				Old str butts are 8' back
251																									L170000251(5), L170000251(6)
251																									
252	Cnd	G	5	One compression splice in each phase ahead							G	5			P/A	LD	5	N	N		5				
252																									
252																									
253	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
253																									
253																									
254	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
254																									
254																									
255	Cnd	G	5			b	G	5			G	5			P/A	LD	4	N	N		5				Old str butts 8' back
255																									L170000255(5), L170000255(6)
255																									
256	Cnd	G	5			b	G	5			G	5			P/A	LD	4	N	N		5				Old str butts 8' ahead
256																									L170000256(5), L170000256(6)
256																									

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Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
257	Cnd	G	5			b	G	5			G	5			P/A	LD	4	N	N		5				
257																									
257																									
258	Cnd	G	5			b	G	5			G	5			W	LD	6	N	N		5				
258																									
258																									
259	Cnd	G	5								G	5			W	LD	8	N	N		5				
259																									
259																									
260	Cnd	G	5			b	G	5			G	5			W	LD	8	N	N		5				
260																									
260																									
261	Cnd	G	5								F	4	Xbrace centre butt is loose	L170000261(7)	W	LD	8	N	N		5				
261																									
261																									
262	Cnd	G	5			b	G	5			G	5			W	LD	6	N	N		5				
262																									
262																									
263	Cnd	G	5	Compression sleeves ahead all phases							F	4	Left bottom brace bolt loose due to shrink	L170000263(6)	W	LD	6	N	N		5				
263																									
263																									
264	Cnd	G	5			b	G	5			G	5			W	LD	6	N	N		5				Road crossing ahead
264																									
264																									
265	Cnd	G	5			b	G	5			G	5			W	LD	4	N	N		5				
265																									
265																									
266	Cnd	G	5			b	G	5			G	5			W	LD	4	N	N		5				Road crossing ahead, 14.4 kv line crossing ahead
266																									
266																									
267	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
267																									
267																									
268	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
268																									
268																									
269	Cnd	G	5								G	5			W	LD	4	N	N		5				
269																									
269																									
270	Cnd	G	5								G	5			W	LD	4	N	N		5				14.4 KV line crossing
270																									
270																									
271	Cnd	G	5								F	3	Xbrace centre bolt loose	L170000271(9)	W	LD	4	N	N		5				
271																									
271																									
272	Cnd	G	5								G	5			W	LD	2	N	N		5				
272																									
272																									
273	Cnd	G	5								F	4	Xbrace centre bolt loose	L170000273(10)	W	LD	6	N	N		5				
273																									
273																									
274	Cnd	G	5								G	5			W	LD	6	N	N		5				
274																									
274																									
275	Cnd	G	5	Compression splice ahead all phases		b	G	5			G	5			W	LD	6	N	N		5				
275																									

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Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
275																									
276	Cnd	G	5			b	G	5			G	5			W	LD	8	N	N		5				
276																									
276																									
277	Cnd	G	5								F	4	Xbrace centre bolt loose	L170000277(11)	W	LD	6	N	N		5				
277																									
277																									
278	Cnd	G	5								F	5		L170000278(9)	W	LD	8	N	N		5				
278																									
278																									
279	Cnd	G	5								G	5			W	LD	4	N	N		5				
279																									
279																									
280	Cnd	G	5								G	5			W	LD	4	N	N		5				
280																									
280																									
281	Cnd	G	5								F	4	Xbrace centre bolt loose	L170000281(7)	W	LD	4	N	N		5				
281																									
281																									
282	Cnd	G	5								F	3	Nut missing on right suspension bracket a	L170000282(9)	W	LD	6	N	N		5				
282																									
282																									
283	Cnd	G	5			b	G	5			G	5			W	LD	3	N	N		5				Driveway crossing ahead
283																									
283																									
284	Cnd	G	5	Compression sleeve ahead left phase		b	G	5			G	5			W	LD	6	N	N		5				
284																									
284																									
285	Cnd	G	5	Compression sleeves ahead centre and left							G	5			W	LD	4	N	N		5				
285																									
285																									
286	Cnd	G	5								F	4	Bottom right brace bolt loose due to shrin	L170000286(8)	W	LD	5	N	N		5				
286																									
286																									
287	Cnd	G	5								F	3	xbrace centre bolt missing a nut	L170000287(10)	W	LD	4	N	N		5				
287																									
287																									
288	Cnd	G	5								F	3	Xbrace centre bolt is loose	L170000288(10)	W	LD	6	N	N		5				
288																									
288																									
289	Cnd	G	5								P	2	Left suspension bracket missing both nuts	L170000289(6)	W	LD	6	N	N		5				
289																									
289																									
290	Cnd	G	5								G	5			W	LD	6	N	N		5				
290																									
290																									
291	Cnd	G	5			b	G	5			G	5			W	LD	6	N	N		5				
291																									
291																									
292	Cnd	G	5								G	5			W	LD	6	N	N		5				
292																									
292																									
293	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
293																									
293																									
294	Cnd	G	5	1 Compression sleeve left phase ahead							F	4	Loose sway bolts	L170000294(6)	P/A	LD	4	N	N		5				

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Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
294																									
294																									
295	Cnd	G	5	1 Comp sleeve in all phases ahead							G	5			P/A	LD	5	N	N		5				
295																									
295																									
296	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
296																									
296																									
297	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
297																									
297																									
298	Cnd	G	5								G	5			P/A, W	LD	6	N	N		5				
298																									
298																									
299	Cnd	G	5								G	5			P/A, W	LD	3	N	N		5				
299																									
299																									
300	Cnd	G	5								G	5			W	LD	4	N	N		5				
300																									
300																									
301	Cnd	G	5								G	5			P/A, W	LD	3	N	N		5				
301																									
301																									
302	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
302																									
302																									
303	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
303																									
303																									
304	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
304																									
304																									
305	Cnd	G	5								G	5			P/A, W	LD	5	N	N		5				
305																									
305																									
306	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
306																									
306																									
307	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
307																									
307																									
308	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
308																									
308																									
309	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
309																									
309																									
310	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
310																									
310																									
311	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
311																									
311																									
312	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
312																									
312																									

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Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
313	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
313																									
313																									
314	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
314																									
314																									
315	Cnd	G	5								G	5			P/A, W	LD	3	N	N		5				
315																									
315																									
316	Cnd	G	5			b	O	4	Missing		G	5			P/A, W	LD	6	N	N		5				
316																									
316																									
317	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
317																									
317																									
318	Cnd	G	5			b	G	5			G	5			P/A, W	LD	4	N	N		5				
318																									
318																									
319	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
319																									
319																									
320	Cnd	G	5	Patch rod ahead on centre phase							G	5			P/A, W	LD	3	N	N		5				
320																									
320																									
321	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
321																									
321																									
322	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
322																									
322																									
323	Cnd	G	5								G	5			W	LD	4	N	N		5				
323																									
323																									
324	Cnd	G	5								P	3	Xbrace centre bolt is coming off	L170000324(10)	W	LD	4	N	N		5				
324																									
324																									
325	Cnd	G	5								G	5			W	LD	4	N	N		5				
325																									
325																									
326	Cnd	G	5								F	4	Xbrace centre bolt is loose	L170000326(8)	S/P, P/A	MD	15	N	N		5				
326																									
326																									
327	Cnd	G	5								G	5			W	MD	10	N	N		5				
327																									
327																									
328	Cnd	G	5								F	5	Right guy hook is loose due to shrinkage	L170000328(7)	W	MD	6	N	N		5				
328																									
328																									
329	Cnd	G	5								G	5			W	LD	5	N	N		5				
329																									
329																									
330	Cnd	G	5								G	5			W	LD	4	N	N		5				
330																									
330																									
331	Cnd	G	5								F	4	Xbrace centre bolt loose	L170000331(8)	W	LD	4	N	N		5				
331																									

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Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
331																									
332	Cnd	G	5								F	3	Xbrace centre bolt loose	L170000332(7)	W	LD	4	N	N		5				
332																									
332																									
333	Cnd	G	5								F	4	Xbrace centre bolt loose	L170000333(11)	W	LD	2	N	N		5				
333																									
333																									
334	Cnd	G	5								F	4	Xbrace centre bolt loose and right guy hoo	L170000334(12)	W	LD	4	N	N		5				
334																									
334																									
335	Cnd	G	5								G	5			W	LD	4	N	N		5				
335																									
335																									
336	Cnd	G	5			b	O	3	Missing		G	5			P/A	LD	4	N	N		5				
336																									
336																									
337	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
337																									
337																									
338	Cnd	G	5	Compression splices ahead all phases							G	5			W	LD	4	N	N		5				
338																									
338																									
339	Cnd	G	5								G	5			W	LD	4	N	N		5				
339																									
339																									
340	Cnd	G	5								G	5			W	LD	4	N	N		5				
340																									
340																									
341	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
341																									
341																									
342	Cnd	G	5								G	5			W	LD	4	N	N		5				
342																									
342																									
343	Cnd	G	5								G	5			W	LD	4	N	N		5				
343																									
343																									
344	Cnd	G	5								G	5			W	LD	4	N	N		5				
344																									
344																									
345	Cnd	G	5			b	O	4	Missing		G	5			P/A	MD	12	N	N		5				
345																									
345																									
346	Cnd	G	5								G	5			P/A	LD	6	N	N		5				
346																									
346																									
347	Cnd	G	5								G	5			P/A	LD	6	N	N		5				
347																									
347																									
348	Cnd	G	5								G	5			P/A	LD	6	N	N		5				Trees cut down are laying on ROW road
348																									L170000348(5), L170000348(6)
348																									
349	Cnd	G	5								G	5			P/A	LD	6	N	N		5				
349																									
349																									
350	Cnd	G	5								G	5													No access, by foot only

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Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
350																									
350																									
351	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
351																									
351																									
352	Cnd	G	5								G	4	Loose bottom sway bolt right side	L1700000352(5)	P/A	MD	4	N	N		5				
352																									
352																									
353	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
353																									
353																									
354	Cnd	G	5								P	3	Double arm brackets are missing the bott	L170000354(7)	P/A	LD	4	N	N		5				
354																									
354																									
355	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
355																									
355																									
356	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
356																									
356																									
357	Cnd	G	5								F	3	Loose centre sway nut can hear hardware	L170000357(5)	P/A	LD	4	N	N		5				
357																									
357																									
358	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
358																									
358																									
359	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
359																									
359																									
360	Cnd	G	5			b	O	4	Missing		G	5			P/A	LD	4	N	N		5				Faded pole top numbers
360																									L170000360(3)
360																									
361	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
361																									
361																									
362	Cnd	G	5								F	2	Missing top right sway flat, lock, nut	L170000362(5)	P/A	LD	4	N	N		5				
362																									
362																									
363	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
363																									
363																									
364	Cnd	G	5								P	3	loose eye bolts all phases	, L170000364(5)	P/A	LD	4	N	N		5				
364																									
364																									
365	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
365																									
365																									
366	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
366																									
366																									
367	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
367																									
367																									
368	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
368																									
368																									

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Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
369	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
369																									
369																									
370	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
370																									
370																									
371	Cnd	G	5								G	5			P/A	LD	3	N	N		5				
371																									
371																									
372	Cnd	G	5								G	5			W	HD	14	N	N		5	Water body crossing ahead 3 glass found 30' on rought side of str			
372																									L170000372(7)
372																									
373	Cnd	G	5								G	4	Loose bridle guy bolt right side	L170000373(9)	P/A	LD	3	N	N		5				
373																									
373																									
374	Cnd	G	5								G	4	Loose centre sway bolt	L170000374(7)	P/A	LD	2	N	N		5				
374																									
374																									
375	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
375																									
375																									
376	Cnd	G	5								P	3	Broken centre sway bolt	L170000376(5)	P/A	LD	4	N	N		5				
376																									
376																									
377	Cnd	G	5								G	5			P/A	LD		N	N		5				Gully crossing ahead, no road
377																									
377																									
378	Cnd	G	5			b	O	3	Missing		G	5			W	LD	4	N	N		5				
378																									
378																									
379	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
379																									
379																									
380	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
380																									
380																									
381	Cnd	G	5			b	O	3	Missing		G	5			P/A	LD	4	N	N		5				
381																									
381																									
382	Cnd	G	5								G	5			W	LD	4	N	N		5				
382																									
382																									
383											F	4	Left bottom brace bolt loose due to shrink	L170000383(6)											
383																									
383																									
384	Cnd	G	5	Patch rod ahead centre and compression sleeves ahead all phases							F	3	Xbrace centre bolt is loose, centre and rig	L170000384(7)	W	LD	4	N	N		5				
384																									
384																									
385	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
385																									
385																									
386	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
386																									
386																									
387	Cnd	G	5								G	5			W	LD	4	N	N		5				
387																									
387																									

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Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
388	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
388																									
388																									
389	Cnd	G	5								P	2	Bottom right brace bolt has come out	L170000389(5)	P/A	LD	4	N	N		5				
389																									
389																									
390	Cnd	G	5								P	2	Xbrace centre bolt is loose and the botton	L170000390(9)	P/A	LD	4	N	N		5				
390																									
390																									
391	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
391																									
391																									
392	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
392																									
392																									
393	Cnd	G	5								P	3	Xbrace centre bolt is loose	L170000393(9)	P/A	LD	4	N	N		5				
393																									
393																									
394	Cnd	G	5	Compression splice ahead right							P	2	Xbrace centre bolt is broken	L170000394(7)	P/A	LD	4	N	N		5				
394																									
394																									
395	Cnd	G	5	Compression splices ahead left and centre		b	O	3	Missing		G	5			P/A	LD	4	N	N		5				
395																									
395																									
396	Cnd	G	5			b	G	5			G	5			P/A	LD	4	N	N		5				Structure is part of the old little fox PT site
396																									
396																									
397	Cnd	G	5								F	3	Xbrace centre bolt is loose	L170000397(9)	P/A	LD	4	N	N		5				
397																									
397																									
398A	Cnd	G	5			b	G	5			G	5			P/A	LD	4	N	N		5				Structure is part of the new little fox PT site
398A																									
398A																									
398	Cnd	G	5			b	G	5			G	5			P/A	LD	4	N	N		5				
398																									
398																									
399	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
399																									
399																									
400	Cnd	G	5								F	4	Xbrace centre bolt loose	L170000400(5)	P/A	LD	4	N	N		5				
400																									
400																									
401	Cnd	G	5								P	2	Left suspension bracket is missing a nut xL	L170000401(8)	P/A, W	LD	4	N	N		5				
401																									
401																									
402	Cnd	G	5								G	5			W	LD	4	N	N		5				
402																									
402																									
403	Cnd	G	5								G	5			W	LD	6	N	N		5				
403																									
403																									
404	Cnd	G	5								G	5			W	LD	4	N	N		5				
404																									
404																									
405	Cnd	G	5	One comp sleeve in centre phase ahead							G	5			P/A	LD	3	N	N		5				
405																									

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405																									
406	Cnd	G	5								P	2	Missing both bottom side nuts on centre a	L170000406(7)	P/A	LD	3	N	N		5				
406																									
406																									
407	Cnd	G	5								G	5			P/A, W	MD	4	N	N		5				
407																									
407																									
408	Cnd	G	5								G	5			W	LD	6	N	N		5				
408																									
408																									
409	Cnd	G	5			b	G	5			G	5			P/A, W	LD	4	N	N		5				Old str butts 15' ahead
409																									L170000409(5), L170000409(4)
409																									
410	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
410																									
410																									
411	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
411																									
411																									
412	Cnd	G	5								G	5			P/A, W	MD	12	N	N		5				No access, foot only
412																									
412																									
413	Cnd	G	5								G	5			P/A, W	MD	12	N	N		5				
413																									
413																									
414	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
414																									
414																									
415	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
415																									
415																									
416	Cnd	G	5								G	5													
416																									
416																									
417	Cnd	G	5								F	4	Centre sway bolt has loose nut	L170000417(7)	P/A, W	LD	4	N	N		5				
417																									
417																									
418	Cnd	G	5								F	4	Top right sway bolt is loose	L170000418(6)	P/A, W	LD	4	N	N		5				
418																									
418																									
419	Cnd	G	5								P	3	Both top sway bolts are loose	), L17000419(9)	P/A, W	LD	4	N	N		5				
419																									
419																									
420	Cnd	G	5								G	5													Missing pole top number on right pole 1
420																									
420																									
421	Cnd	G	5	One comp splice in centre phase ahead							G	5			P/A	LD	4	N	N		5				
421																									
421																									
422	Cnd	G	5								G	5			W	LD	4	N	N		5				
422																									
422																									
423	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
423																									
423																									
424	Cnd	G	5								G	3	Missing centre sway nut, lock, pal	L170000424(6)	P/A, W	LD	4	N	N		5				

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424																									
424																									
425	Cnd	G	5			b	O	4	Missing		G	5			P/A	LD	2	N	N		5				
425																									
425																									
426	Cnd	G	5								G	3	Missing centre sway nut, lock, pal	L170000426(6)	P/A	LD	2	N	N		5				
426																									
426																									
427	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
427																									
427																									
428	Cnd	G	5			b	O	4			G	5			P/A	LD	2	N	N		5				
428																									
428																									
429	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
429																									
429																									
430	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
430																									
430																									
431	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
431																									
431																									
432	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
432																									
432																									
433	Cnd	G	5			b	O	4	Missing		G	5			P/A	LD	2	N	N		5				
433																									
433																									
434	Cnd	G	5								G	2	Missing flat, lock, nut, pal on centre sway	L170000434(5)	P/A	LD	2	N	N		5				
434																									
434																									
435	Cnd	G	5			b	O	4	Missing		G	5			P/A	LD	2	N	N		5				
435																									
435																									
436	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
436																									
436																									
437	Cnd	G	5												P/A	LD	2	N	N		5				
437																									
437																									
438	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
438																									
438																									
439	Cnd	G	5								G	3	Loose sway arm bolts	, L170000439(6)	P/A	LD	2	N	N		5				
439																									
439																									
440	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
440																									
440																									
441	Cnd	G	5								G	4	Bottom right sway bolt is loose	L170000441(5)	P/A	LD	2	N	N		5				
441																									
441																									
442	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
442																									
442																									

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Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
443	Cnd	G	5								G	5			P/A	LD	2	N	N		5				Hiway crossing ahead
443																									
443																									
444	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				
444																									
444																									
445	Cnd	G	5	One comp splice in each phase ahead		b	G	5			G	5			P/A	LD	2	N	N		5				Old str butts 6' ahead
445																									L170000445(5), L170000445(6)
445																									
446	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				Old str butts 6' back
446																									L170000445(9), L170000445(10)
446																									
447	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				Old str butts 8' ahead
447																									L170000447(5), L170000447(6)
447																									
448	Cnd	G	5								G	4	Centre sway bolt loose	L170000448(6)	P/A	LD	2	N	N		5				
448																									
448																									
449	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
449																									
449																									
450	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5	Old str butts 7' ahead			L170000450(5), L170000450(6)
450																									
450																									
451	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
451																									
451																									
452	Cnd	G	5								G	4			P/A	MD	4	N	N		5				
452																									
452																									
453	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
453																									
453																									
454	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				
454																									
454																									
455	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
455																									
455																									
456	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
456																									
456																									
457	Cnd	G	5	One comp spliec in right phase ahead							G	5			P/A	LD	2	N	N		5				
457																									
457																									
458	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				Old str butts 10' ahead
458																									L170000458(5), L170000458(6)
458																									
459	Cnd	G	5								G	5			P/A	LD	2	N	N		5				Old str butts 10' ahead
459																									L170000459(5), L170000459(6)
459																									
460	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				Old str butts 6' ahead
460																									L170000460(6)
460																									
461	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
461																									

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461																									
462	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				Old str butts 8' ahead
462																									L170000462(7), L170000462(8)
462																									
463	Cnd	G	5								G	5			P/A, W	LD	4	N	N		5				
463																									
463																									
464	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
464																									
464																									
465	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
465																									
465																									
466	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				Old str butts 8' ahead road and 1 phase crossing ahead
466																									L170000466(5), L170000466(6)
466																									
467	Cnd	G	5	One splice in each phase ahead		b	G	5			G	5			P/A, W	LD	2	N	N		5				
467																									
467																									
468	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				Old str butts 8' back
468																									L170000468(5), L170000468(6)
468																									
469	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				Secondary line crossing ahead
469																									
469																									
470	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				Bail clamp ahead 10' on right phase
470																									L170000470(4)
470																									
471	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				
471						Grd	G	5																	
471																									
472	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				
472																									
472																									
473	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
473																									
473																									
474	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				Old str butts 8' ahead
474																									L170000474(5), L170000474(6)
474																									
475	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				Old str butts 8' ahead
475																									L170000475(5), L170000475(6)
475																									
476	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				Old str butts 8' ahead
476																									L170000476(5), L170000476(6)
476																									
477	Cnd	G	5			b	O	4	Missing		G	5			P/A	LD	2	N	N		5	Span guy pole picture (good condition), span guy crosses highway			
477																									L170000477(6)
477																									
478	Cnd	G	5	1 Comp splice ahead in right phase 2 comp splices ahead in centre phase							G	5			P/A, W	LD	2	N	N		5				
478																									
478																									
479	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				
479																									
479																									
480	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				Missing pole top number

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
480																									L170000480(5)
480																									
481	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				Old str butts 15' back
481						Grd	G	5																	L170000481(7), L170000481(8)
481																									
482	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
482																									
482																									
483	Cnd	G	5	One comp splice ahead in left and centre phase							G	5			P/A, W	LD	2	N	N		5				
483																									
483																									
484	Cnd	G	5	One comp splice ahead centre phase		b	G	5			G	5			P/A, W	LD	2	N	N		5				Old str butts ahead 10'
484																									L170000484(7), L170000484(8)
484																									
485	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				Old str butts 6' back
485																									L170000485(5), L170000485(6)
485																									
486	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				Old str butts 6' back
486																									L170000486(5), L170000486(6)
486																									
487	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
487																									
487																									
488	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
488																									
488																									
489	Cnd	G	5								G	3	Missing front and back hardware on centr	L170000489(6)	P/A	LD	2	N	N		5				
489																									
489																									
490	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				Old str butts 6' ahead
490																									L170000490(5), L170000490(6)
490																									
491	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				Highway crossing ahead
491																									Old str butts 8' back
491																									L170000491(5), L170000491(6)
492	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				
492																									
492																									
493	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
493																									
493																									
494	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
494																									
494																									
495	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
495																									
495																									
496	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
496																									
496																									
497	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				Old str butts 8' ahead
497																									L170000497(5)
497																									
498	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
498																									
498																									

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
499	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
499																									
499																									
500	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
500																									
500																									
501	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
501																									
501																									
502	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
502																									
502																									
503	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				
503																									
503																									
504	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
504																									
504																									
505	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
505																									
505																									
506	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
506																									
506																									
507	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				This str is a peak str
507																									
507																									
508	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
508																									
508																									
509	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				Old str butts 10' ahead
509																									L170000509(5), L170000509(6)
509																									
510	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				Old str butts 8' back
510																									L170000510(5), L170000510(6)
510																									
511	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				Old str butts 6' back
511																									L170000511(5), L170000511(6)
511																									
512	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
512																									
512																									
513	Cnd	G	5	2 Automatic splices ahead in left phase							G	5			P/A, W	LD	2	N	N		5				
513																									
513																									
514	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
514																									
514																									
515	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
515																									
515																									
516	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
516																									
516																									
517	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
517																									

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
517																									
518	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
518																									
518																									
519	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
519																									
519																									
520	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
520																									
520																									
521	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				
521																									
521																									
522	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
522																									
522																									
523	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
523																									
523																									
524	Cnd	G	5			b	G	5			G	5			P/A, W	LD	2	N	N		5				
524																									
524																									
525	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
525																									
525																									
526	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
526																									
526																									
527	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
527																									
527																									
528	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
528																									
528																									
529	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
529																									
529																									
530	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				Missing ahead pole top number
530																									L170000530(5)
530																									
531	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
531																									
531																									
532	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
532																									
532																									
533	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
533																									
533																									
534	Cnd	G	5			b	O	4			G	5			P/A	LD	2	N	N		5				
534																									
534																									
534	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
534																									
534																									
535	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				

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Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
535																									
535																									
536	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
536																									
536																									
537	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
537																									
537																									
538	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
538																									
538																									
539	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
539																									
539																									
540	Cnd	G	5								F	4	Missing one nut on centre suspension bra	L170000540(6)	P/A, W	LD	2	N	N		5				
540																									
540																									
541	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
541																									
541																									
542	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
542																									
542																									
543	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
543																									
543																									
544	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
544																									
544																									
545	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
545																									
545																									
546	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
546																									
546																									
547	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				Str being replaced 2017
547																									
547																									
548	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
548																									
548																									
549	Cnd	G	5	One comp splice in each phase ahead							G	5			P/A, W	LD	2	N	N		5				Planned str replacement in 2017
549																									
549																									
550	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
550																									
550																									
551	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
551																									
551																									
552	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
552																									
552																									
553	Cnd	G	5								F	4	2 Loose nuts on suspension bracket left si	L170000553(10)	P/A, W	LD	2	N	N		5				
553																									
553																									

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Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
554	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
554																									
554																									
555	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
555																									
555																									
556	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
556																									
556																									
557	Cnd	G	5			b	O	4	Missing		G	5			P/A, W	LD	2	N	N		5				
557																									
557																									
558	Cnd	G	5								F	3	Missing flat, lock, nut, pal on centre sway	L170000558(5)	P/A, W	LD	2	N	N		5				
558																									
558																									
559	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
559																									
559																									
560	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				
560																									
560																									
561	Cnd	G	5	One comp splice in each phase ahead							G	5			P/A, W	LD	2	N	N		5				
561																									
561																									
562	Cnd	G	5			b	O	3	Missing		G	5			W	LD	2	N	N		5				
562																									
562																									
563	Cnd	G	5								G	5			W	LD	2	N	N		5				
563																									
563																									
564	Cnd	G	5								G	5			W	LD	2	N	N		5				
564																									
564																									
565	Cnd	G	5								G	5			W	LD	1	N	N		5				
565																									
565																									
566	Cnd	G	5								G	5			W	LD	2	N	N		5				
566																									
566																									
567	Cnd	G	5								G	4	Missing a flat on centre sway bolt missing.	L170000567(8)	W	LD	2	N	N		5				
567																									
567																									
568	Cnd	G	5			b	O	3	Missing		F	5	Bridal guy hardware loose	L170000568(7)	W	LD	2	N	N		5				
568																									
568																									
569	Cnd	G	5								F	4	Loose bride guide	L170000569(3)	W	LD	2	N	N		5				
569																									
569																									
570	Cnd	G	5								G	5			W	LD	2	N	N		5				
570																									
570																									
571	Cnd	G	5								G	5			W	LD	2	N	N		5				
571																									
571																									
572	Cnd	G	5								G	5			W	LD	2	N	N		5				
572																									

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Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
572																									
573	Cnd	G	5	Splices (compression sleeve) each phase ahead							G	5			W	LD	2	N	N		5				
573																									
573																									
574	Cnd	G	5								G	5			W	LD	2	N	N		5				
574																									
574																									
575	Cnd	G	5			b	O	3	Missing		G	5			W	LD	1	N	N		5				
575																									
575																									
576	Cnd	G	5								F	4	Loose centre sway hardware	L170000576(5)	W	LD	2	N	N		5				
576																									
576																									
577	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
577																									
577																									
578	Cnd	G	5								G	5			W	LD	2	N	N		5				
578																									
578																									
579	Cnd	G	5								G	5			W	LD	2	N	N		5				
579																									
579																									
580	Cnd	G	5								G	5			W	LD	4	N	N		5				
580	Shd	G	5																						
580																									
581	Cnd	G	5								G	5			W	LD	3	N	N		5				
581	Shd	G	5																						
581																									
582	Cnd	G	5								G	5			W	LD	4	N	N		5				
582																									
582																									
583	Cnd	G	5								G	5			W	LD	2	N	N		5				
583																									
583																									
584	Cnd	G	5								G	5			W	LD	4	N	N		5				
584																									
584																									
585	Cnd	G	5								G	5			W	LD	4	N	N		5				
585																									
585																									
586	Cnd	G	5	Sleeve ahead centre							G	5			W	LD	2	N	N		5				
586																									
586																									
587	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
587																									
587																									
588	Cnd	G	5								F	5	Xbrace centre bolt loose	L170000588(7)	W	LD	2	N	N		5				
588																									
588																									
589	Cnd	G	5			b	G	5			G	5			S/P	MD	30	Y	Y	30	4	Tree 10' from conductor	'0000589(8)		
589																									
589																									
590	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
590																									
590																									
591	Cnd	G	5			b	G	5			G	5			W	LD	4	N	N		5				

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Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
591																									
591																									
592	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
592																									
592																									
593	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
593																									
593																									
594	Cnd	G	5			b	G	5			G	5			W	LD	4	N	N		5				
594																									
594																									
595	Cnd	G	5			b	O	3	Missing		G	5			P/A, W	LD	15	N	N		5				
595																									
595																									
596	Cnd	G	5			b	G	5			G	5			W	LD	3	N	N		5				
596																									
596																									
597	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
597																									
597																									
598	Cnd	G	5			b	O	3	Missing		G	5			W	LD	2	N	N		5				
598																									
598																									
599	Cnd	G	5								G	5			W	LD	2	N	N		5				
599																									
599																									
600	Cnd	G	5								G	5			W	LD	2	N	N		5				
600																									
600																									
601	Cnd	G	5								F	5	Top left arm gain installed backwards	L170000601(7)	W	LD	2	N	N		5				Driving Crossing ahead
601																									
601																									
602	Cnd	G	5	Splice ahead all phases		b	G	5			G	5			W	LD	2	N	N		5				
602																									
602																									
603	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
603																									
603																									
604	Cnd	G	5								G	5			W	LD	2	N	N		5				
604																									
604																									
605	Cnd	G	5								G	5			W	LD	2	N	N		5				
605																									
605																									
606	Cnd	G	5								G	5			W	LD	2	N	N		5				
606																									
606																									
607	Cnd	G	5								G	5			W	LD	2	N	N		5				
607																									
607																									
608	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
608																									
608																									
609	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
609																									
609																									

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
610	Cnd	G	5								G	5			W	LD	2	N	N		5				
610																									
610																									
611	Cnd	G	5								G	5			W	LD	2	N	N		5				
611																									
611																									
612	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
612																									
612																									
613	Cnd	G	5	Compression splices all phases							G	5			W	LD	2	N	N		5				
613																									
613																									
614	Cnd	G	5								G	5			W	LD	2	N	N		5				
614																									
614																									
615	Cnd	G	5								G	5			W	LD	2	N	N		5				
615																									
615																									
616	Cnd	G	5			b	O	3	Missing on split bolt		G	5			W	LD	2	N	N		5				
616																									
616																									
617	Cnd	G	5								G	5			W	LD	2	N	N		5				
617																									
617																									
618	Cnd	G	5								P	2	Brace bolt (left bottom)	L170000618(10)	W	LD	2	N	N		5				
618																									
618																									
619	Cnd	G	5								P	3	Bottom left brace bolt, nut and washer ha	L170000619(9)	W	LD	2	N	N		5				
619																									
619																									
620	Cnd	G	5								G	5			W	LD	2	N	N		5				
620																									
620																									
621	Cnd	G	5								G	5			W	LD	2	N	N		5				
621																									
621																									
622	Cnd	G	5								G	5			W	LD	2	N	N		5				
622																									
622																									
623	Cnd	G	5								G	5			W	LD	2	N	N		5				
623																									
623																									
624	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
624																									
624																									
625	Cnd	G	5								G	5			W	LD	2	N	N		5				
625																									
625																									
626	Cnd	G	5								G	5			W	LD	2	N	N		5				
626																									
626																									
627	Cnd	G	5								G	5			W	LD	2	N	N		5				
627																									
627																									
628	Cnd	G	5								G	5			W	LD	2	N	N		5				Both poles standing in 2' of water
628																									

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
628																									
629	Cnd	G	5								G	5			W	LD	2	N	N		5				
629																									
629																									
630	Cnd	G	5	Splices ahead all phases		b	O	3	Missing		G	5			W	LD	2	N	N		5				
630																									
630																									
631	Cnd	G	5	Splices ahead all phases							G	5	Bottom left brace bolt loose due to shrink	L17000631(7)	W	LD	2	N	N		5				
631																									
631																									
632	Cnd	G	5								F	5	Centre brace bolt loose due to shrinkage	L170000631(5)	W	LD	2	N	N		5				
632																									
632																									
633	Cnd	G	5								G	5			W	LD	1	N	N		5				
633																									
633																									
634	Cnd	G	5								G	5			W	LD	2	N	N		5				
634																									
634																									
635	Cnd	G	5	All phases have compression sleeves							G	5			W	LD	2	N	N		5				
635																									
635																									
636	Cnd	G	5								G	5			W	LD	2	N	N		5				
636																									
636																									
637	Cnd	G	5								G	5			SP	LD	0	N	N		5				
637																									
637																									
638	Cnd	G	5								G	5			SP	LD	0	N	N		5				
638																									
638																									
639	Cnd	G	5								G	5			SP	LD	0	N	N		5				
639																									
639																									
640	Cnd	G	5								G	5			SP	LD	0	N	N		5				Top ahead sign faded
640																									L170000640(5)
640																									
641	Cnd	G	5								G	5			SP	LD	0	N	N		5				
641																									
641																									
642	Cnd	G	5								G	5			W	LD	2	N	N		5				
642																									
642																									
643	Cnd	G	5								G	5			W	LD	2	N	N		5				
643																									
643																									
644	Cnd	G	5								F	5	Bottom right brace bolt due to shrinkage	L170000644(5)	SP	LD	0	N	N		5				
644																									
644																									
645	Cnd	G	5								F	5	Left bottom brace bolt loose due to shrink	170000645(11)	W	LD	2	N	N		5				
645																									
645																									
646	Cnd	G	5	Compression sleeve ahead left phase							G	5			W	LD	1	N	N		5				
646																									
646																									
647	Cnd	G	5	Compression sleeves ahead right and centre							G	5			W	LD	2	N	N		5				

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
647																									
647																									
648	Cnd	G	5								G	5			W	LD	2	N	N		5				
648																									
648																									
649	Cnd	G	5								G	5			W	LD	2	N	N		5				
649																									
649																									
650	Cnd	G	5								F	5	Xbrace centre bolt loose due to shrinkage	L170000650(5)	W	LD	2	N	N		5				
650																									
650																									
651	Cnd	G	5								G	5			W	LD	2	N	N		5				
651																									
651																									
652	Cnd	G	5								G	5			W	LD	2	N	N		5				
652																									
652																									
653	Cnd	G	5								G	5			W	LD	2	N	N		5				
653																									
653																									
654	Cnd	G	5								F	4	Centre brace bolt loose due to shrinkage	L170000654(6)	W	LD	2	N	N		5				
654																									
654																									
655	Cnd	G	5			b	O	3	Missing		G	5			W	LD	3	N	N		5				
655																									
655																									
656	Cnd	G	5								F	5	Bottom left brace bolt loose due to shrink	L170000656(7)	W	LD	2	N	N		5				
656																									
656																									
657	Cnd	G	5								G	5			P/A, W	MD	20	Y	Y	20	4	Trees 12' from conductor	'0000657(7)		
657																									
657																									
658	Cnd	G	5								F	4	Xbrace centre bolt loose	L170000657(8)	W	LD	2	N	N		5				
658																									
658																									
659	Cnd	G	5			b	O	3	Missing		G	5			W	LD	2	N	N		5				
659																									
659																									
660	Cnd	G	5	Splices ahead left and centre phases							G	5			W	LD	2	N	N		5				
660																									
660																									
661	Cnd	G	5								G	5			W	LD	3	N	N		5				
661																									
661																									
662	Cnd	G	5								G	5			W	LD	2	N	N		5				
662																									
662																									
663	Cnd	G	5								G	5			W	LD	2	N	N		5				
663																									
663																									
664	Cnd	G	5								G	5			W	LD	2	N	N		5				
664																									
664																									
665	Cnd	G	5								P	3	Xbrace centre bolt loose	L170000665(8)	W	LD	2	N	N		5				
665																									
665																									

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
666	Cnd	G	5								G	5			W	LD	1	N	N		5				
666																									
666																									
667	Cnd	G	5	Stacked washers bottom right brace	L170000667(8)						G	5			W	LD	2	N	N		5				Left bottom brace bolt loose due to shrinkage
667																									
667																									
668	Cnd	G	5								P	4	Stacked washer left bottom, loose xbrace	L170000668(8)	W	LD	1	N	N		5				
668																									
668																									
669	Cnd	G	5								G	5			W	LD	2	N	N		5				
669																									
669																									
670	Cnd	G	5								G	5			W	LD	1	N	N		5				
670																									
670																									
671	Cnd	G	5								G	5			W	LD	1	N	N		5				
671																									
671																									
672	Cnd	G	5	Patch rod ahead left phase							G	5			W	LD	1	N	N		5				
672																									
672																									
673	Cnd	G	5	Compression sleeves ahead all phases		b	O	3	Missing		G	5			W	LD	1	N	N		5				
673																									
673																									
674	Cnd	G	5								G	5			W	LD	1	N	N		5				
674																									
674																									
675	Cnd	G	5								G	5			W	LD	1	N	N		5				
675																									
675																									
676	Cnd	G	5								G	5			W	LD	1	N	N		5				
676																									
676																									
677	Cnd	G	5								G	5			W	LD	1	N	N		5				
677																									
677																									
678	Cnd	G	5								G	5	Left bottom brace bolt base due to shrink	L170000678(8)	W	LD	2	N	N		5				
678																									
678																									
679	Cnd	G	5								G	5			W	LD	2	N	N		5				
679																									
679																									
680	Cnd	G	5								G	5			W	LD	2	N	N		5				
680																									
680																									
681	Cnd	G	5								G	5			W	LD	1	N	N		5				
681																									
681																									
682	Cnd	G	5								G	5			W	LD	2	N	N		5				
682																									
682																									
683	Cnd	G	5								G	5			W	LD	4	N	N		5				
683																									
683																									
684	Cnd	G	5								G	5			W	LD	2	N	N		5				
684																									

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
684																									
685	Cnd	G	5								P	3	Xbrace centre bolt loose	L170000685(6)	W	LD	1	N	N		5				
685																									
685																									
686	Cnd	G	5								G	5			W	LD	2	N	N		5				
686																									
686																									
687	Cnd	G	5								G	5			W	LD	2	N	N		5				
687																									
687																									
688	Cnd	G	5								G	5			W	LD	2	N	N		5				
688																									
688																									
689	Cnd	G	5								G	5			W	LD	1	N	N		5				
689																									
689																									
690	Cnd	G	5								G	5			W	LD	2	N	N		5				
690																									
690																									
691	Cnd	G	5								G	5			W	LD	0	N	N		5				Structure is being replaced
691																									
691																									
692	Cnd	G	5			b	O	3	Missing		G	5			P/A	LD	0	N	N		5				Structure is being replaced
692																									
692																									
693	Cnd	G	5								F	5	Rightr bottom xbrace bolt is loose due to	L170000692(5)	P/A	LD	0	N	N		5				
693																									
693																									
694	Cnd	G	5								P	2	xbrace centre bolt is coming out	L170000693(9)	P/A	LD	0	N	N		5				
694																									
694																									
695	Cnd	G	5								P	3	Xbrace centre bolt coming out	L170000695(13)	P/A	LD	0	N	N		5				
695																									
695																									
696	Cnd	G	5	Compression sleeves ahead all phases		b	O	3	Missing		G	5			W	LD	0	N	N		5				
696																									
696																									
697	Cnd	G	5								G	5			P/A	LD	0	N	N		5				
697																									
697																									
698	Cnd	G	5								G	5			P/A	LD	0	N	N		5				
698																									
698																									
699	Cnd	G	5			b	G	5			G	5			P/A	LD	0	N	N		5				
699																									
699																									
700	Cnd	G	5								G	5			P/A	LD	0	N	N		5				
700																									
700																									
701	Cnd	G	5								G	5			P/A	LD	0	N	N		5				
701																									
701																									
702	Cnd	G	5			b	O	3	Missing		G	5			P/A	LD	0	N	N		5				
702																									
702																									
703	Cnd	G	5								P	3	Bottom right brace bolt loose and xbrace	L170000703(14)	P/A	LD	0	N	N		5				

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Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
703																									
703																									
704	Cnd	G	5								G	5			P/A	LD	0	N	N		5				
704																									
704																									
705	Cnd	G	5			b	O	3	Missing		F	4	Xbrace centre bolt loose	1700000705(10)	P/A	LD	0	N	N		5				
705																									
705																									
706	Cnd	G	5	Compression sleeve ahead on right phase							G	5			P/A	LD	0	N	N		5				
706																									
706																									
707	Cnd	G	5								G	5			P/A	LD	0	N	N		5				
707																									
707																									
708	Cnd	G	5								P	3	Xbrace centre bolt coming off	L170000708(6)	P/A	LD	0	N	N		5				
708																									
708																									
709	Cnd	G	5								F	4	Xbrace centre bolt loose	L170000709(7)	P/A	LD	0	N	N		5				
709																									
709																									
710	Cnd	G	5								F	3	Xbrace centre bolt coming out	L170000710(8)	P/A	LD	0	N	N		5				
710																									
710																									
711	Cnd	G	5								G	5			W	LD	20	N	N		5				
711																									
711																									
712	Cnd	G	5								G	5			P/A	LD	0	N	N		5				
712																									
712																									
713	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
713																									
713																									
714	Cnd	G	5			b	P	3	Missing		G	5			W	LD	2	N	N		5				
714																									
714																									
715	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
715																									
715																									
716	Cnd	G	5								G	5			P/A	LD	0	N	N		5				
716																									
716																									
717	Cnd	G	5								G	5			W	LD	2	N	N		5				
717																									
717																									
718	Cnd	G	5								F	5	Centre bolt on xbrace is loose	L170000718(5)	W	LD	2	N	N		5				
718																									
718																									
719	Cnd	G	5								G	5			P/A, W	LD	2	N	N		5				Str is being replaced summer 2017
719																									
719																									
720	Cnd	G	5								G	5			P/A, W	LD	10	N	N		5				
720																									
720																									
721	Cnd	G	5								G	5			P/A, W	LD	6	N	N		5				
721																									
721																									

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Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
722	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				
722																									
722																									
723	Cnd	G	5			b	G	5			G	5			P/A	LD	1	N	N		5				
723																									
723																									
724	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				
724																									
724																									
725	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				
725																									
725																									
726	Cnd	G	5			b	O	4	Missing		O	4	Missingfront and back hardware on left ce	L170000726(6)	P/A	LD	2	N	N		5				
726																									
726																									
727	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				
727																									
727																									
728	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
728																									
728																									
729	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				
729																									
729																									
730	Cnd	G	5			b	G	5			G	5			P/A	LD	2	N	N		5				
730																									
730																									
731	Cnd	G	5								G	5			P/A	LD	4	N	N		5				
731																									
731																									
732	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
732																									
732																									
733	Cnd	G	5			b	G	5							P/A	LD	2	N	N		5				
733																									
733																									
734	Cnd	G	5			b	O	4	Missing		G	5			P/A	LD	2	N	N		5				
734																									
734																									
735	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
735																									
735																									
736	Cnd	G	5								G	5			P/A	LD	2	N	N		5				
736																									
736																									
737	Cnd	G	5								G	5			W	LD	2	N	N		5				
737																									
737																									
738	Cnd	G	5								G	5	Loose guy hardware	L170000738(5)	W, SP	LD	15	N	N		5				Swamp in between structures
738																									
738																									
739	Cnd	G	5								G	5			W	LD	2	N	N		5				
739																									
739																									
740	Cnd	G	5								G	5			W	LD	2	N	N		5				
740																									

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
740																									
741	Cnd	G	5								G	5			W	LD	3	N	N		5				
741																									
741																									
742	Cnd	G	5			b	O	3	Missing		G	5			W	LD	1	N	N		5				
742																									
742																									
743	Cnd	G	5								G	5			W	LD	2	N	N		5				
743																									
743																									
744	Cnd	G	5								G	5			W	LD	2	N	N		5				
744																									
744																									
745	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
745																									
745																									
746	Cnd	G	5								G	5			W	LD	2	N	N		5				
746																									
746																									
747	Cnd	G	5			b	O	3	Missing left pole		G	5			W	LD	2	N	N		5				
747																									
747																									
748	Cnd	G	5								G	5			W	LD	2	N	N		5				
748																									
748																									
749	Cnd	G	5								G	5			W	LD	2	N	N		5				
749																									
749																									
750	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
750																									
750																									
751	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
751																									
751																									
752	Cnd	G	5								G	5			W	LD	2	N	N		5				
752																									
752																									
753	Cnd	G	5								G	5			W	LD	2	N	N		5				
753																									
753																									
754	Cnd	G	5								G	5			W	LD	2	N	N		5				
754																									
754																									
754A	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
754A																									
754A																									
755	Cnd	G	4	Armour rod not snapped down, centre and left		b	G	5			G	5			W	LD	2	N	N		5				
755																									
755																									
756	Cnd	G	5								G	5			W	LD	2	N	N		5				
756																									
756																									
757	Cnd	G	5								G	4	Loose centre sway bolt	L170000757(5)	W	LD	2	N	N		5				
757																									
757																									
758	Cnd	G	5								G	4	Loose centre sway bolt	L170000758(5)	W	LD	2	N	N		5				

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
758																									
758																									
759	Cnd	G	5								G	4	Loose centre sway bolt	L170000759(7)	W	LD	2	N	N		5				
759																									
759																									
760	Cnd	G	5								G	4	Missing centre sway bolt hardware	L170000760(6)	W	LD	2	N	N		5				Missig pole top number on Right pole
760																									L170000760(5)
760																									
761	Cnd	G	5								G	5			W	LD	2	N	N		5				
761																									
761																									
762	Cnd	G	5			b	G	5			G	5			W	LD	1	N	N		5				
762																									
762																									
763	Cnd	G	5								G	4	Missing centre sway hardware	L170000763(7)	W	LD	2	N	N		5				
763																									
763																									
764	Cnd	G	5								G	5			W	LD	2	N	N		5				
764																									
764																									
765	Cnd	G	5			b	G	5			G	4	Centre sway bolt loose		W	LD	2	N	N		5				
765																									
765																									
766	Cnd	G	5			b	O	3	Missing		G	5			W	LD	2	N	N		5				
766																									
766																									
767	Cnd	G	5								G	5			W	LD	2	N	N		5				
767																									
767																									
768	Cnd	G	5								G	5			W	LD	2	N	N		5				
768																									
768																									
769	Cnd	G	5								G	4	Centre sway hardware missing	L170000769(5)	W	LD	2	N	N		5				
769																									
769																									
770	Cnd	G	5								G	5			W	LD	2	N	N		5				
770																									
770																									
771	Cnd	G	5								G	5			W	LD	2	N	N		5				
771																									
771																									
772	Cnd	G	5								G	5			W	LD	2	N	N		5				
772																									
772																									
773	Cnd	G	5								G	5			W	LD	2	N	N		5				
773																									
773																									
774	Cnd	G	5								G	5			W	LD	2	N	N		5				
774																									
774																									
775	Cnd	G	5								G	4	Centre sway bolt missing hardware		W	LD	3	N	N		5				
775																									
775																									
776	Cnd	G	5	Splices ahead all 3 phases							G	5			W	LD	2	N	N		5				
776																									
776																									

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
777	Cnd	G	5								G	4	Centre sway bolt loose / missing	L170000777(6)	W	LD	2	N	N		5				
777																									
777																									
778	Cnd	G	5								G	5			W	LD	2	N	N		5				
778																									
778																									
779	Cnd	G	5								G	5	Loose left bottom sway bolt, centre sway	L170000779(6)	W	LD	4	N	N		5				
779																									
779																									
780	Cnd	G	5								G	5			W	LD	2	N	N		5				
780																									
780																									
781	Cnd	G	5								G	5			W	LD	2	N	N		5				
781																									
781																									
782	Cnd	G	5								G	5			W	LD	2	N	N		5				
782																									
782																									
783	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
783																									
783																									
784	Cnd	G	5								G	5			W	LD	2	N	N		5				
784																									
784																									
785	Cnd	G	5								G	5			W	LD	2	N	N		5				
785																									
785																									
786	Cnd	G	5								G	5			W	LD	2	N	N		5				
786																									
786																									
787	Cnd	G	5			b	O	3	Missing		G	5	Loose primary hardware	L170000787(6)	W	LD	2	N	N		5				
787																									
787																									
788	Cnd	G	5								G	5			W	LD	2	N	N		5				
788																									
788																									
789	Cnd	G	5								G	5			W	LD	2	N	N		5				
789																									
789																									
790	Cnd	G	5								G	4	Loose hardware on centre sway bolt		W	LD	2	N	N		5				
790																									
790																									
791	Cnd	G	5								G	5			W	LD	2	N	N		5				
791																									
791																									
792	Cnd	G	5								G	5			W	LD	2	N	N		5				
792																									
792																									
793	Cnd	G	5								G	5			W	LD	2	N	N		5				
793																									
793																									
794	Cnd	G	5	Compression sleeve around left phase							G	5			W	LD	2	N	N		5				
794																									
794																									
795	Cnd	G	5								G	5			W	LD	2	N	N		5				Single phase line
795																									

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
795																									
796	Cnd	G	5								G	5			W	LD	2	N	N		5				
796																									
796																									
797	Cnd	G	5								G	5			W	LD	2	N	N		5				
797																									
797																									
798	Cnd	G	5								G	5			W	LD	2	N	N		5				
798																									
798																									
799	Cnd	G	5								G	5			W	LD	2	N	N		5				
799																									
799																									
800	Cnd	G	5								G	5			W	LD	2	N	N		5				
800																									
800																									
801	Cnd	G	5								G	5			W	LD	2	N	N		5				
801																									
801																									
802	Cnd	G	5								G	5			W	LD	2	N	N		5				
802																									
802																									
803	Cnd	G	5								G	5			W	LD	2	N	N		5				
803																									
803																									
804	Cnd	G	5								G	5			W	LD	2	N	N		5				
804																									
804																									
805	Cnd	G	5								G	5			W	LD	2	N	N		5				
805																									
805																									
806	Cnd	G	5								G	5			W	LD	2	N	N		5				
806																									
806																									
807	Cnd	G	5								G	5			W	LD	2	N	N		5				
807																									
807																									
808	Cnd	G	5								G	5			W	LD	2	N	N		5				
808																									
808																									
809	Cnd	G	5			b	G	5			G	5			W	LD	3	N	N		5				
809																									
809																									
810	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
810																									
810																									
811	Cnd	G	5			b	G	5			G	5			W	LD	4	N	N		5				
811																									
811																									
812	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
812																									
812																									
813	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
813																									
813																									
814	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
814																									
814																									
815	Cnd	G	5								G	5			W	LD	2	N	N		5				
815																									
815																									
816	Cnd	G	5								G	5			W	LD	2	N	N		5				
816																									
816																									
817	Cnd	G	5								G	5			W	LD	2	N	N		5				
817																									
817																									
818	Cnd	G	5			b	O	3	Missing		G	5			W	LD	2	N	N		5				River Span
818																									
818																									
819	Cnd	G	5			b	O	3	Missing		G	5			W	LD	2	N	N		5				
819																									
819																									
820	Cnd	G	5								G	5			W	LD	2	N	N		5				
820																									
820																									
821	Cnd	G	5			b	O	3	Missing		G	5			W	LD	2	N	N		5				
821																									
821																									
822	Cnd	G	5								G	5			W	LD	3	N	N		5				
822																									
822																									
823	Cnd	G	5			b	O	3	Missing		G	5			W	LD	2	N	N		5				
823																									
823																									
824	Cnd	G	5								G	5			W	LD	2	N	N		5				
824																									
824																									
825	Cnd	G	5								G	5			W	LD	2	N	N		5				
825																									
825																									
826	Cnd	G	5	Compression sleeves ahead all phases							F	5	Xbrace centre bolt loose	L170000826(13)	W	LD	2	N	N		5				
826																									
826																									
827	Cnd	G	5								G	5			W	LD	2	N	N		5				
827																									
827																									
828	Cnd	G	5			b	P	3	Missing		G	5			W	LD	2	N	N		5				
828																									
828																									
829	Cnd	G	5								G	5			W	LD	2	N	N		5				
829																									
829																									
830	Cnd	G	5								G	5			W	LD	2	N	N		5				
830																									
830																									
831	Cnd	G	5								G	5			W	LD	2	N	N		5				
831																									
831																									
832	Cnd	G	5								G	5			W	LD	2	N	N		5				
832																									
832																									

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments
833	Cnd	G	5								G	5			W	LD	2	N	N		5				
833																									
833																									
834	Cnd	G	5			b	G	5			G	5			W	LD	2	N	N		5				
834																									
834																									
835	Cnd	G	5			b	G	5			G	5			S/P	LD	8	N	N	8	5				Yukon river crossing
835																									
835																									
836	Cnd	G	5			b	G	5			G	5			P/A	MD	20	N	N		5				
836																									
836																									

Line Inspection Summary
Year: 2017

Line: L171
Aishihik to Whitehorse (Takhini)

129 km, Built in 1976
611 Structures

Structure Number	C&S ID	C&S Cond.	C&S Maint. Priority	C&S Maintenance Comment	C&S Deficiency Photo	G&B ID	G&B Cond.	G&B Maint. Priority	G&B Maintenance Comment	G&B Deficiency Photo	HDW Cond.	HDW Maint. Priority	HDW Maintenance Comment	HDW Deficiency Photo	VEG Species	VEG Density	VEG Height	VEG Clearance Concern?	VEG Danger Tree?	VEG Dngr Tree (ft)	VEG Maint. Priority	VEG Maintenance Comments	VEG Defiency Photo	GRL Maint. Priority	GRL Additional Comments

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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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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.

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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

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.

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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

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.

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

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 .

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,

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.

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.

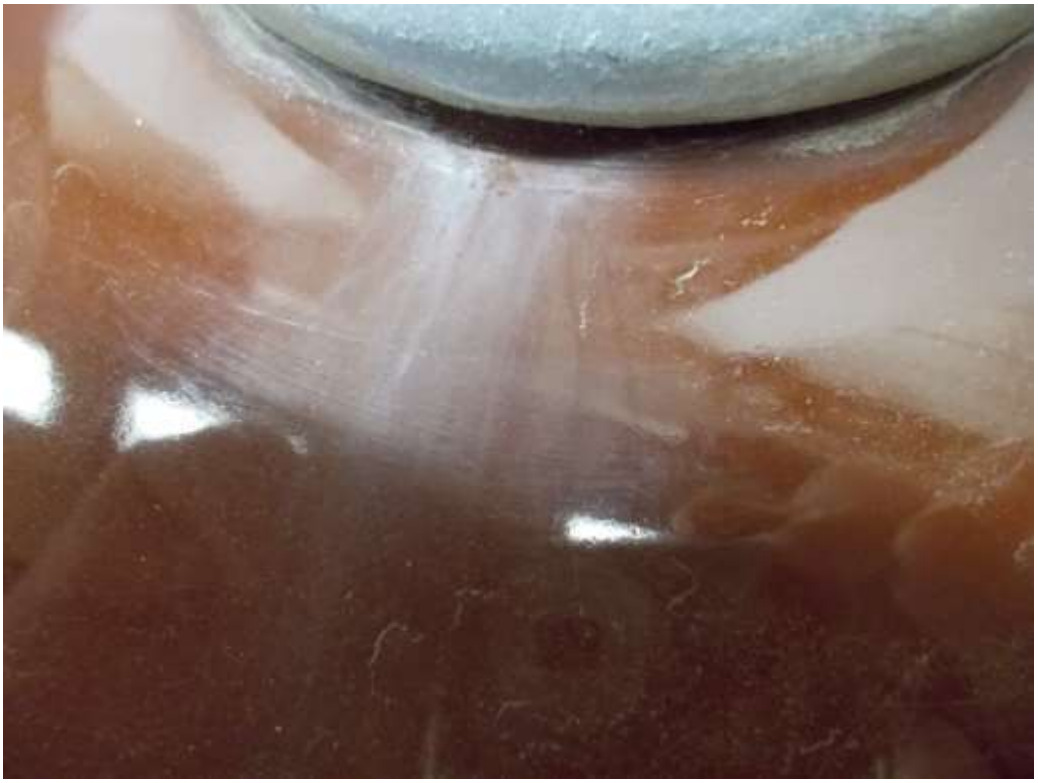

Figure 2 - Electrical activity etched in the stain,

Figure 3 – Arcing damage

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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	

The results relate only to the items tested
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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

- 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

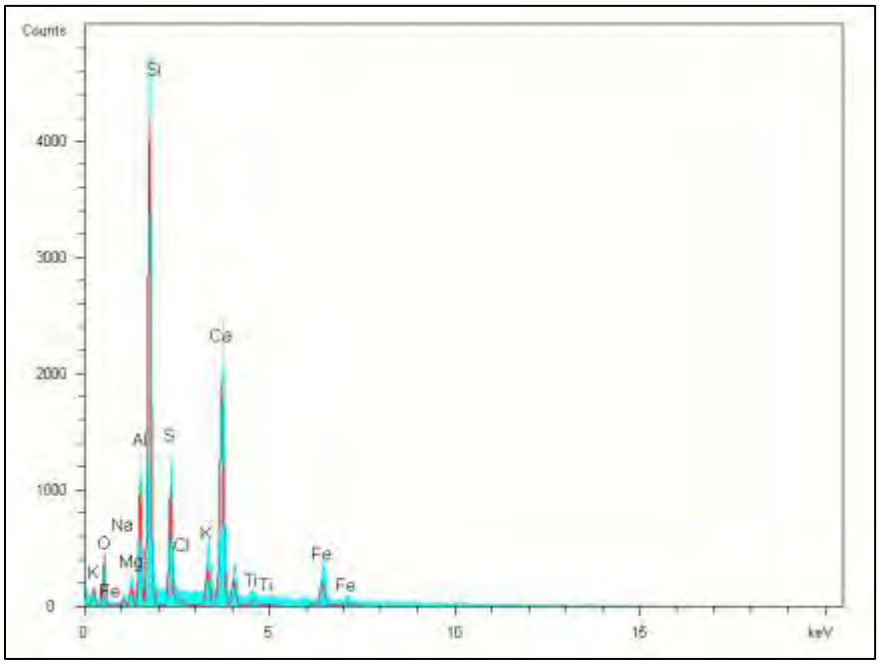
Figure 7: Typical condition of underside of insulator, with no dust like debris on underside

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

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

(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			

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			
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	Electrical 18.0	Electrical 3.1	Electrical 15 + 3x3.1 = 24.3
1273-8B (10 kip)	11	16	Cap pullout	E			18.0<24.3
1273-9B (10 kip)	20	20	Cap pullout	Both			
1273-10B (10 kip)	23	23	Cap pullout, pin loose	Both	Mechanical 19.3	Mechanical 2.5	Mechanical 15 + 3x2.5 = 22.5
1273-11B (10 kip)	14	15	Cap pullout	E			19.3<22.5
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			

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			
1273-2C	15	20	Pin stretch and pullout	E	Electrical 18.6	Electrical 2.7	Electrical 15 + 3x2.7 = 23.1
1273-3C	19	19	Pin stretch and pullout	M			
1273-4C	12	22	Pin stretch and pullout	E			18.6<23.1
1273-5C (10 kip)	21	21	Cap pullout Porcelain cracked	Both	Mechanical 19.3	Mechanical 2.0	Mechanical 15 + 3x2.0 = 21.0
1273-6C (10 kip)	22	22	Porcelain fell off	M			18.6<21.0
1273-7C	20	20	Pin stretch and pullout	M			

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 $X \geq R + 3S$.

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

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Figure A3

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CONDITION ASSESSMENT AND EVALUATION OF TYPE "ASX" CROSS ARMS

Test Report Number: TR01171.01-R1

Client Request Number: PO# CS15019
Powertech Proposal: 16-4573

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EXECUTIVE SUMMARY

A condition assessment and evaluation of in-service crossarms from a 138 kV transmission line operated by Yukon Energy was performed by Powertech Labs, to determine the remaining load carrying capacity of the crossarms, and whether they still meet both historical and upgraded modern design load requirements. The crossarms were from angled tangent structures, in which the angle of the crossarms is approximating that of the sloping terrain. Six pairs of crossarms were received, and subjected to a visual examination and condition assessment, with full scale structure testing and flexural testing performed.

Significant cracking was evident on two pairs of the as received crossarms, indicating that in-service failures have happened on the 138 kV line. However, the overall condition of the other crossarms can be considered fair. No rot or insect damage is present, and although the crossarms do contain sporadic large knots and sloping grain, these features are within the allowable provisions of structural lumber grades common for crossarm use.

In general the crossarm assembly performed well during the full-scale vertical and longitudinal load tests. The vertical loads achieved agree with the prediction based on the flexural test results. No anomalies were found at the connections and hardware. One of the three vertical loads obtained from full-scale testing was lower in comparison to others, as it failed prematurely in splitting alone an existing crack through the pole and crossarm connection. This failure mode is similar to the observed cracking on the two as-received pairs mentioned above.

The longitudinal load test demonstrated that the crossarm assembly has adequate remaining strength against the design load applied on a typical tangent structure.

Based on flexural test results the remaining vertical load carrying capacity at the high side phase was predicted followed by a statistical analysis. The statistical analysis shows that in the conservative approach, the existing crossarm system has a high probability of not meeting the vertical design loads of the modern standard. In particular, the remaining vertical load carrying capacity of the crossarm assembly is not adequate to withstand the 50 mm hoar frost scenario, even on a standard span.

Given the high probability of not meeting design vertical loads and the age of the crossarms (close to 50 years old), as well as evidence of failure in service, it is recommended that the replacement of these crossarms should be initiated to mitigate the risk of failure in service, with the following priorities suggested:

- Long spans should be given priority for replacement over short spans
- Crossing structures should be given priority over non-crossing structures
- For all spans, those structures in which knots and checks are noted around connection points should be given priority over structures in which these features are not seen

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INTRODUCTION

Yukon Energy operates and maintains a 138 kV transmission line from Whitehorse to Vangorda. The transmission line contains angled tangent structures, identified as type "ASX", for sloping locations. These structures consist of double wood crossarms on wood poles in a typical H-frame structure, with the crossarms mounted at an angle approximating that of the sloping terrain. A crossarm from such a structure failed in the spring of 2015, with no snow or ice load on the line, and no apparent anomalous events. Powertech Labs was contracted to test and evaluate the mechanical performance and material properties of the existing aged in-service wood crossarms; to determine the remaining load carrying capacity of the crossarms and whether they can still meet both the historical and the upgraded load requirements.

SCOPE

The scope of the work included the following examinations and tests:

- Visual examination and condition assessment of the existing in-service crossarm samples
- Full-scale structure testing of the crossarms for evaluating remaining load carrying capacity in the vertical and longitudinal directions as well as the corresponding stiffness and connection points
- Flexural testing as per ASTM D198-09 on specimens removed from the crossarm samples to determine bending strength (modulus of rupture (MOR) and modulus of elasticity (MOE))

From the results of the testing, a statistical and serviceability analysis was performed to determine whether a typical crossarm set is serviceable for given load requirement scenarios.

DESIGN DOCUMENTATION

Limited design documentation for the 138 kV type ASX H-frame structures was available due to the age of the original construction (late 1960s). The structure detail, with nominal dimensions and typical hardware, are contained in drawing NCP-29029, and is available as an appendix to the report. Regardless of the slope, the following conditions are common to the ASX type structure:

- Center to center pole spacing is 16'
- Crossarms were to be drilled in the field to provide 14' phase spacing

The original design conditions pertaining to conductor properties, load conditions and tension limitations were also provided. These included the stringing table and charts (tension and sag) for various ruling spans. The longest ruling span was identified as 1605' (490m).

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No information related to vertical or longitudinal design loads or reliability based design were available. Based on information received from Yukon Energy for a previous crossarm test project, the following vertical design loads were used for the serviceability analysis:

- Standard span, 50 mm hoar frost = 2920 Lbs
- Standard span, CSA ML = 1260 Lbs
- Long span, 50 mm hoar frost = 3860 Lbs
- Long span, CSA ML = 2000 Lbs

VISUAL INSPECTION

Upon receipt, the cross arms were visually inspected to assess the current condition, and the spacing of the connection points measured to determine structure angle. The structure number was labeled on each set of crossarms, with the exception of one set of crossarms. For identification purposes, this set of crossarms is herein referred to as UK (unknown).

Figure 1 is a portion of the design drawing of the tangent structure. For each set of crossarms, the following measurements were taken:

- Low side to high side pole connection points
- Low side connection to load line
- High side connection point to load line

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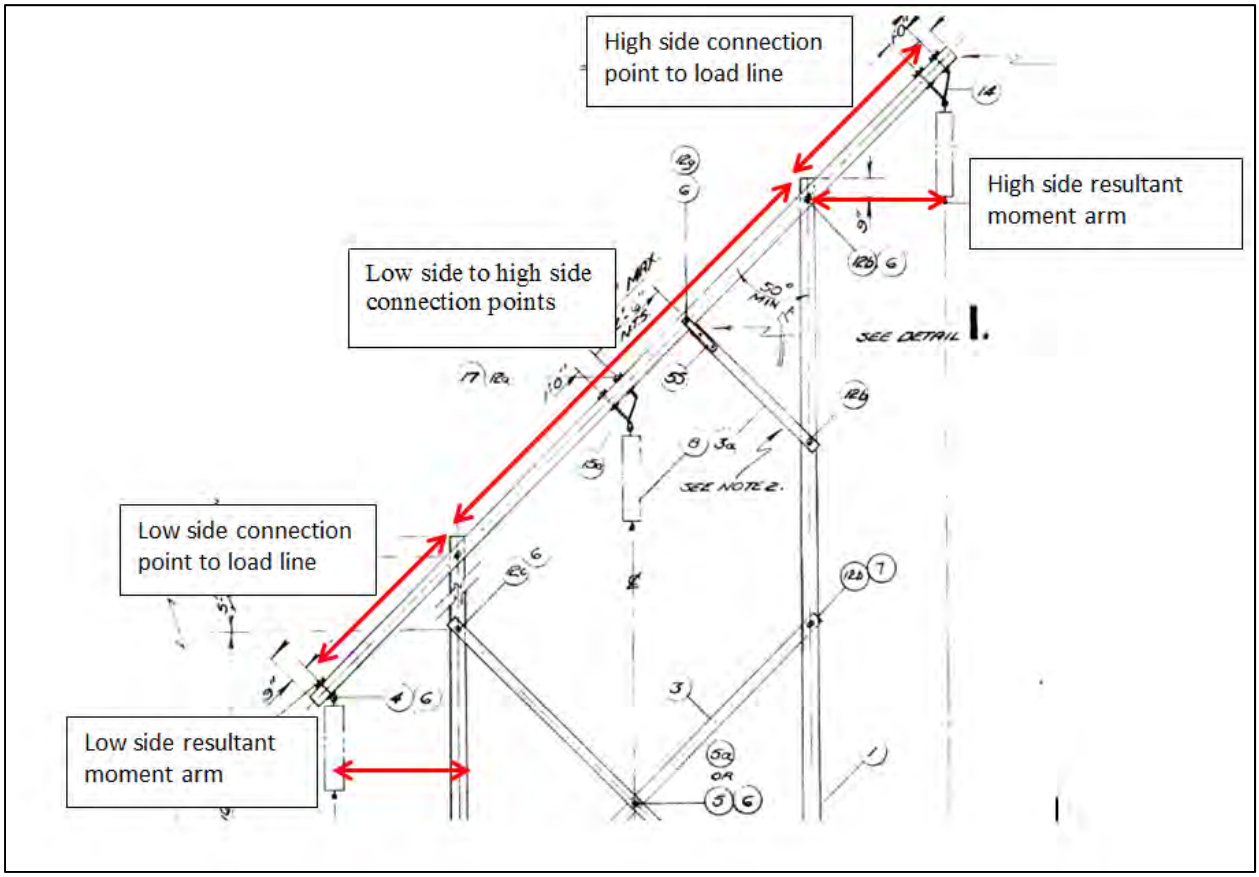

Figure 1: Portion of Design Drawing

Given the set center to center pole spacing of 16', the resultant crossarm angle and horizontal moment arms of the structures were calculated and are seen tabulated in Table 1.

Table 1: Crossarm Hole Spacing and Resultant Angles and Moment Arms

Str. #	Low to High Side Connection Points	Resultant Angle	Low Side Connection Point to Load Line	Resultant Horizontal Moment Arm		High Side Connection Point to Load Line	Resultant Horizontal Moment Arm	
	(inches)	(degrees)	(Inches)	(Inches)	(Feet)	(Inches)	(Inches)	(Feet)
UK	209	23.3	78	71.7	6.0	84	77.2	6.4
723	221	29.7	82.5	71.7	6.0	90	78.2	6.5
724	239.5	36.7	89.5	71.7	6.0	97.5	78.2	6.5
725	220	29.2	82.5	72.0	6.0	90	78.5	6.5
730	236.5	35.7	84	68.2	5.7	80	64.9	5.4
735	221	29.7	83	72.1	6.0	88.5	76.9	6.4

From the measurements, it can be seen that 3 of the sampled structures were nominally 30 degrees, 2 were 36 degrees, with one set of crossarms at the comparatively low angle of 23.3

Also of note is that the high side of the structures consistently has a higher resultant horizontal moment arm, typically 6" longer than that of the low side.

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The condition of the crossarms was evaluated with respect to ANSI standard O5.3-2002 "Sold Sawn-Wood Crossarms and Braces – Specifications and Dimensions" and WCLB Standard #17, "Grading Rules for West Coast Lumber", with the following observations noted:

- The crossarms are predominantly straight, with little bow or warpage
- Incising marks are seen along the length of the wood, indicative of a pressure treatment, likely PENTA
- No significant rot or insect damage is seen in the crossarms
- Several of the crossarms contained large knots with the grain pattern at an angle respect to the longitudinal axis, however the size and spacing of the knots and the angle of the grain were within the allowable provisions of grading
    - Several knots exceeded the allowable 1-7/8" diameter, however these were sporadic and not indicative of the general condition
    - The slope of the grain in the middle 1/3 of the length is not to exceed 1 in 15, no crossarms exceeded this limit
- One crossarm from Structure 735 appeared to be completely failed through its high side connection point. The crossarm had 2 drill holes on the high side, with a knot present between the drill holes, and a significant check running through the connection point. Transverse cracking is also seen in this crossarm indicating the section was over-stressed in bending. The presence of the double holes did weaken the strength
- One crossarm from Structure 730 appeared to be completely failed, with several fractures present around the brace connection point location and the high side connection point
- Several of the crossarms had either elongated drilled connection holes points on the high side or two thru-holes for connection points very close to each other. As indicated on the drawing, the crossarms were drilled in the field to accommodate the angle, which likely presented challenges to the installation crew, leading to elongated or hogged-out connection point holes or re-drilling of a hole after the initial installation did not fit
- Checks (cracks along the woods grain pattern, but not passing through the entire thickness) are seen sporadically in the crossarms
- Significant checks are seen through the high side connection points of structures 725 and 727 These checks had not yet developed to splits; however it is likely the checks opened to their current level during service and shows the high side of the structure is susceptible to premature failure

Examples of the features noted in the inspection are seen in Figures 2 through 8.

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Figure 2: As Received Condition, Structure 723, High Side Connection Point Elongated

Figure 3: As Received Condition, Structure 724, High Side Connection Point

Figure 4: As Received Condition, Structure 725, High Side Connection Point with Checks

Figure 5: As Received Condition, Structure 725. Note Large Knots and Wide Grain Spacing

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Figure 6: As Received Condition, Structure 727, High Side Connection Point with Check

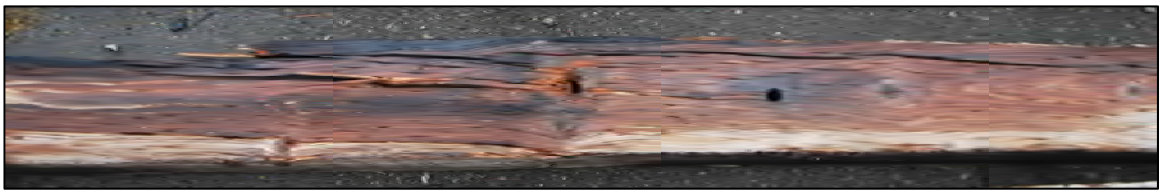

Figure 7: As Received Condition, Structure 730. Cracking and Splitting Around Brace Connection Point

Figure 8: As Received Condition, Failed Structure 735

EVALUATION METHODOLOGY

To determine the remaining vertical and longitudinal load carrying capacity of the crossarms, and to perform reliability based statistical analysis, both full scale load tests and flexural tests are required. In the design of the structure, the expected failure mode of the crossarms is in flexure (bending), typically in the section encompassing the connection to the pole in which the maximum bending stress is present. In this scenario, the wood fibers on the tension side of the bend fracture. This is the predominant mode of failure in H-frame crossarm structures; however crossarms can fail by cracking through existing checks and various other defects present in the wood. The full scale testing therefore provides important information on whether the crossarms will fail as theoretically expected, or if there is a likelihood of atypical failures, and at what loads these failures occur at.

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The standardized flexural tests allows for a statistically significant population of specimens to be tested, as multiple samples can be taken from one crossarm. Assuming the data obtained from the specimens are representative, the test results are used to quantify statistically the remaining vertical load carrying capacity of the crossarm population through a Weibull analysis, with upper and lower bounds. When predicting the vertical load capacity based on flexural test results, the typical failure mode of bending is assumed. By performing both tests, the data obtained can be cross validated.

Selection of the crossarms for full-scale tests were based predominantly on the condition of the crossarms, with the crossarms deemed most structurally sound tested. The selection included 2 sets that were of the same structure angle (nominal 30 degrees) as that of the failed sample, with the final set at a lower angle of 23 degrees. For the vertical testing, the high side phase location was loaded as this was the side in which the failure and the majority of cracking and checking were seen

For the flexural test, 10 specimens were cut from the untested or unaffected crossarms such that the connection point to the wood poles was centered between the loading noses, the area of highest bending stress.

FULL SCALE TEST SETUP

A test frame was built in the mechanical lab at Powertech Labs in accordance with Yukon Energy's type ASX H-frame design specifications. Two 12" x 12" x 0.5" steel I-beams were used to support the crossarm samples with spacing of 16 ft between the two columns. One of the two steel columns (south side) was anchored using an existing anchor pad and another column (north side) was anchored using an anchor system specially built for anchoring the column. The anchoring system was comprised of two 12" x 12" x 0.5" I-beams connected to other anchor pads for longitudinal and transverse constraints. Three concrete blocks each weighing 4300 lbs (20 kN) were placed on the anchoring system to provide vertical restraint to the north column.

To represent the actual connection between crossarms and wood poles, a wood pole was selected from BC Hydro's pole yard and sectioned to a semi-elliptical cross section. The sectioned wood column was placed and fastened between the two flanges of the I-beam so that a wood to wood connection existed as per actual installation practices.

Yukon Energy provided the standard hardware (tie plates, clevis bolts and square washers) used for the pole and phase connections, which were used in assembling the structure in the mechanical lab as per the design drawing.

The crossarms from the structures 723, 724 and UK were selected for vertical testing, with the crossarm pair from structure 7 used for the longitudinal test.

For the vertical load test, the vertical load was applied to the south end using a 10-ton overhead crane through a pulley attached to an anchor pad. A load cell was placed in line with the overhead crane on the north end, and a displacement transducer attached to the cross arm. The load and displacement were subsequently data logged with a Soltec high speed data acquisition system.

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Images of the test setup can be seen in Figures 9 through 11.

For the longitudinal test, the longitudinal load was applied to the south end using the same overhead crane through a pulley attached to a short I beam anchored to the ground. A load cell was placed in line with the overhead crane on the south end, and a displacement transducer attached to the cross arm. The load and displacement were subsequently data logged with a Soltec high speed data acquisition system. Images of the test setup can be seen in Figures 12.

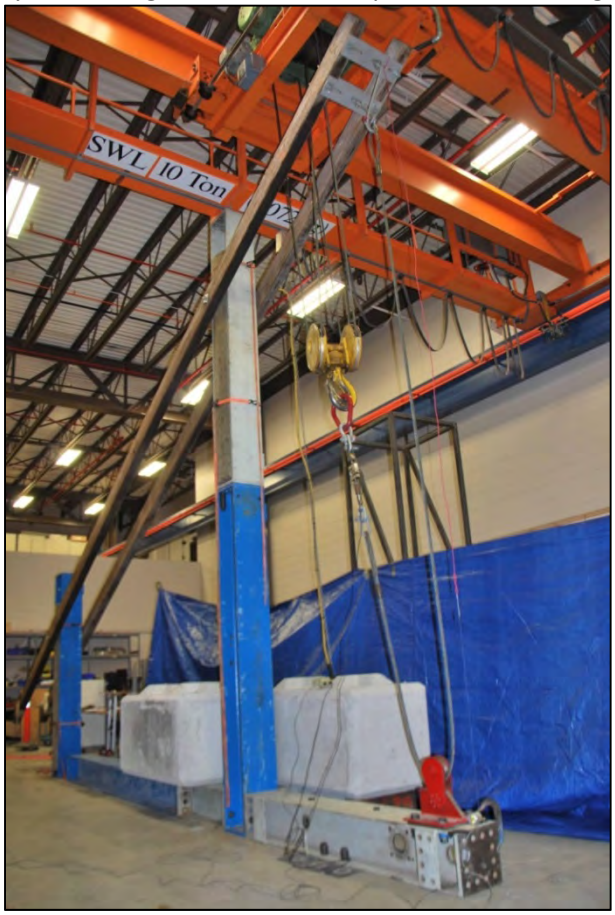

Figure 9: View of Test Setup for Full Scale Mechanical Test of Wood Crossarms, 30-Degree Angle

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Figure 10: View of High Side of Test Setup, 30-Degree Angle

Figure 11: View of High Side of Test Setup, 23-Degree Angle

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Figure 12: View of Longitudinal Test Setup with Load Applied to Low Side Insert picture

FULL SCALE MECHANICAL TEST RESULTS

Three full-scale vertical load tests were performed with the ultimate loads achieved summarized in Table 2.

It was observed that:

- The near side crossarm of structure 723 failed at an ultimate load of 3,743 lbs when a crack developed at the connection point, likely from an existing shallow check, and propagated along the angle grain pattern

- Both crossarms of structure 725 failed simultaneously, at an ultimate load of 4,046 lbs. The near side crossarm failed when the wood fibers on the tension side of the bend fractured under load. The far side crossarm failed through its connection point, propagating between several large knots

- The crossarms of the unknown (UK) structure achieved the highest vertical load carrying capacity, with the near side crossarm fracturing on the tension side just above the connection point at a load of 6,735 lbs. No knots or checks were present in the immediate area of failure

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- Before the ultimate loads were reached the entire system performed well and no anomalies were found at the crossarm, pole connections as well as the tie plates and hardware, and no excessive displacement was noticed

- The failure mode of structure 725 and UK was as theoretically expected, fracture of the wood fibers on the tension side of the section subject to maximum bending stress. The differing failure mode of structure 723 however illustrates that the theoretical bending failure mode cannot be assumed for all structures, as existing defects and anomalies in the structure can lead to low failure loads

- The average of the three ultimate vertical loads achieved is 4,841 Lbs and the COV 34%

- The vertical loads achieved in general agree with the remaining vertical load carrying capacity calculated based on flexural test results shown in Table 5

Load versus displacement data for the final load to failure tests for each crossarm are seen in Figures 13 through 15. Images of the bending deflection, failure modes and features noted during the vertical testing are seen in Figures 17 through 23.

Table 2: Summary of Ultimate Vertical Load Carrying Capacity of Crossarms

Structure ID	Ultimate Vertical Load Achieved (lbs)	Deflection at Load (inches)
723	3743	3.78
725	4046	4.07
Unknown	6735	9.89
Average	4841	-
COV	0.34	-

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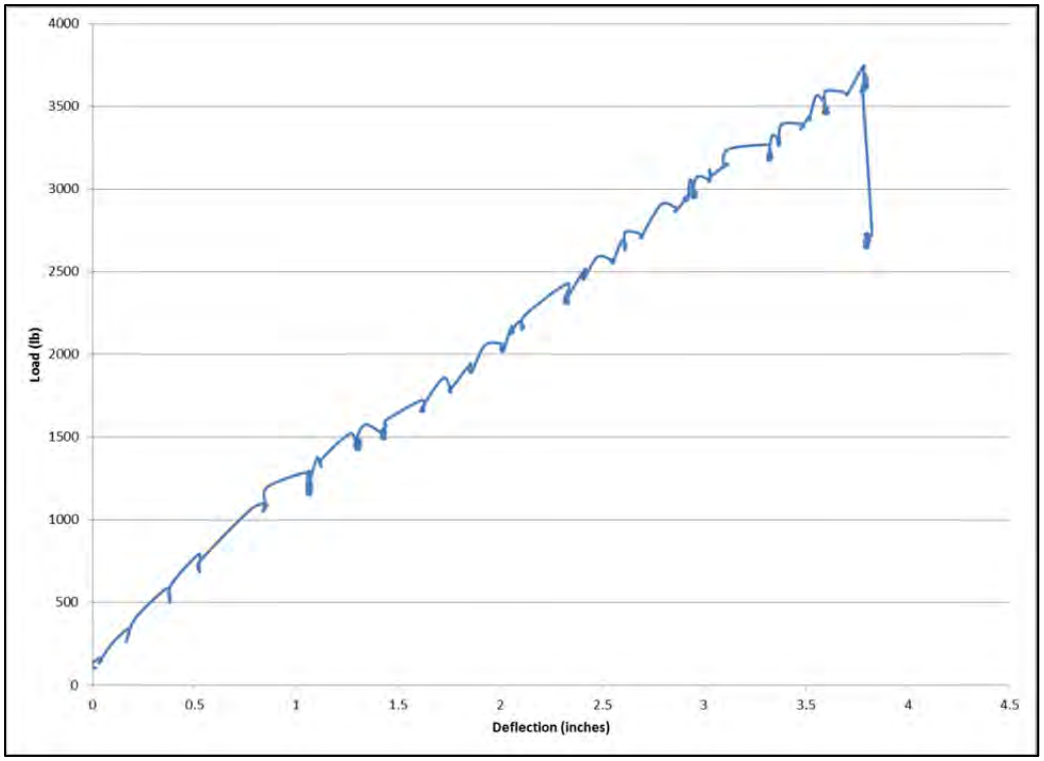

Figure 13: Vertical #1 – Structure 723 - Load vs Deflection

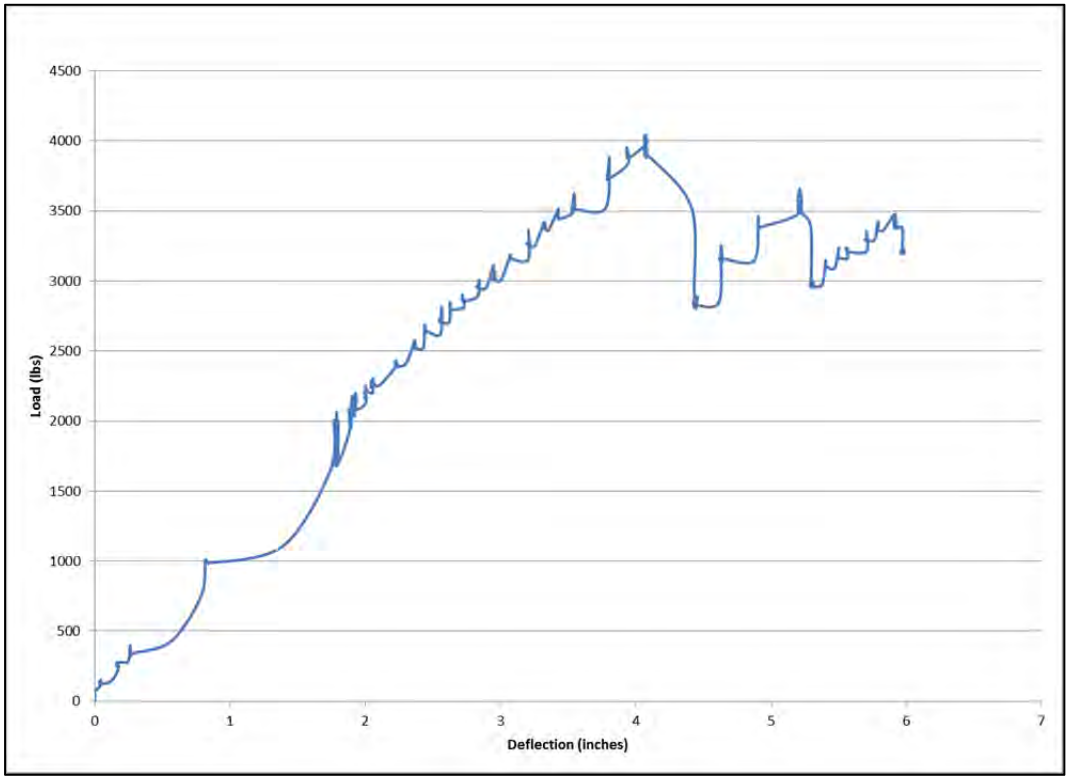

Figure 14: Vertical #2 – Structure 725 - Load vs Deflection

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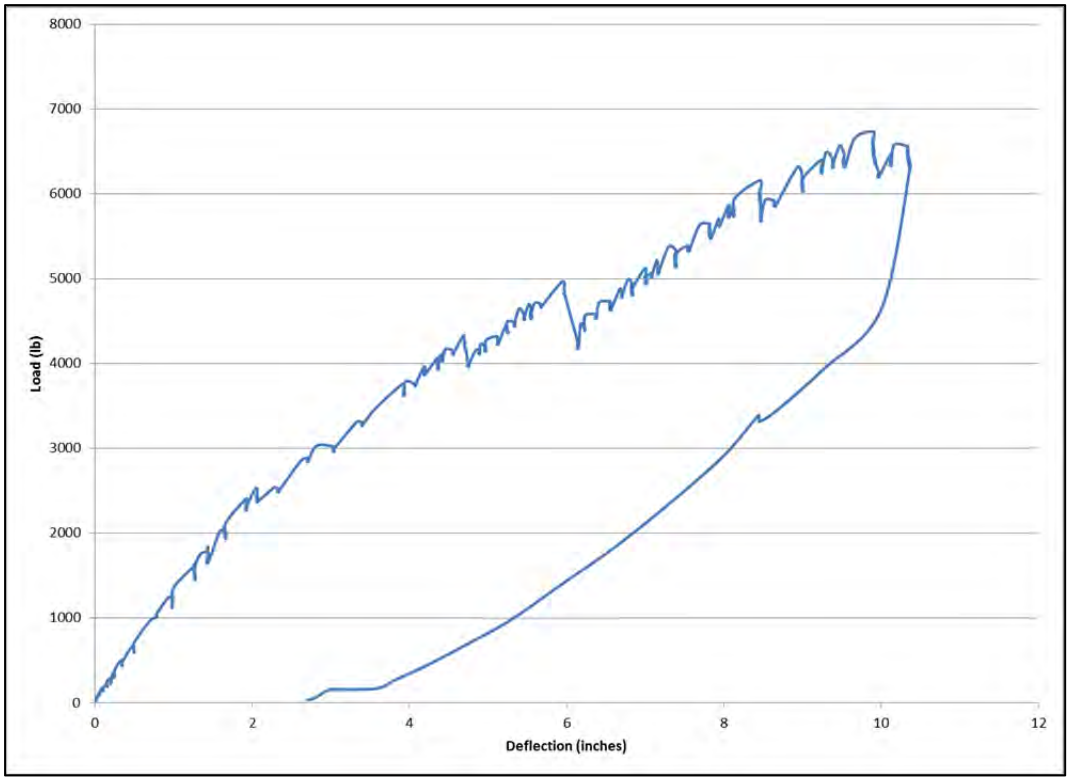

Figure 15: Vertical #3 – Structure Unknown - Load vs Deflection

Figure 16: Structure 723 Failure on Near Side Crossarm Through Connection Point

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Figure 17: Structure 723 Failure on Near Side Crossarm Through Connection Point

Figure 18: Structure 725 Failure on Front Side Crossarm on Tension Side of Beam at Knot Near Connection Point

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Figure 19: Structure 725 Failure on Near Side Crossarm on Tension Side of Beam at Knot Near Connection Point

Figure 20: Structure 725 Failure on Back Crossarm on Tension Side of Beam Between Knot and Connection Point

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Figure 21: Structure UK, Failure Above Connection Point on Tension Side

One longitudinal load test was performed on structure 140. The load versus displacement data for the longitudinal test is seen graphically in Figure 22, with the bending deflection achieved seen in Figures 23.

The longitudinal load test was stopped at 3,560 Lbs without breaking the crossarm completely. It was observed that

- Cracking began to occur on the tension side of the bend at approximately 3,000 lbs.
- Linear-elastic response of the crossarm assemblies were observed throughout the entire loading and unloading process as shown in Figure 22.

It should be noted that the proof load achieved is much higher than the longitudinal load that a tangent structure would subjected to, thus the remaining longitudinal load carrying capacity is adequate.

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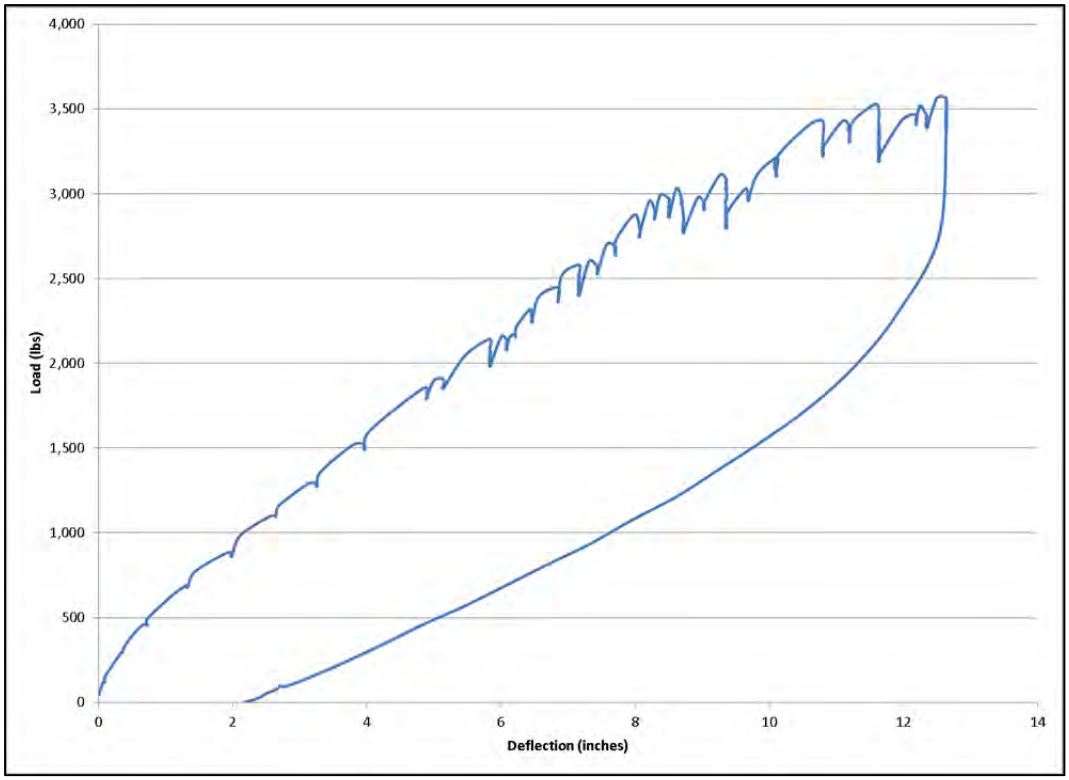

Figure 22: Longitudinal Test Load vs Deflection

Figure 23: Structure Longitudinal Test, Deflection Under Load of 3,500 lbs

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FLEXURAL TEST

The objective of the flexural test was to determine the material properties of the wood crossarms: modulus of rupture (bending strength), modulus of elasticity, and maximum shear stress. The results can be used to estimate the bending and shear strength of the crossarm assembly at any section and to predict the remaining vertical load carrying capacity.

Two-point loading tests were conducted as per ASTM D198-09 using Powertech's Tinius-Olsen test machine as shown in Figure 24. A displacement transducer was attached to the intersection of the beam center and natural axis.

Figure 24: Flexural Test Setup

It was observed that for all tests, that the failure initiated at either existing checks or knots located on the tension side, or the connection hole, and in between loading points, where the beam is subject to maximum bending stress. Based on deflection measured and maximum break load, the MOE, MOR and shear stress were calculated and summarized in Table 3. Load versus displacement data for each specimen is seen in Figures 25 through 34. Images of the typical failure mode of the beams are seen in Figures 35 through 39.

Of particular interest was the low failure of samples cut from the sister crossarm of 735, with the same transverse fracture pattern noted. In the case of sample 735C, the breaking load was substantially lower than the average.

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Table 3: Flexural Test Results

Specimen ID	Defl. at 5,000 lbs	Modulus of Elasticity (MOE)		Breaking Load		Modulus of Rupture (MOR)		Max Shear Stress	
	(mm)	psi (10^6)	MPa	lbs	kN	psi	Mpa	psi	MPa
724A	4.96	1.48	10,210	10,447	46	3,619	25	270	1.9
724B	4.82	1.523	10,507	13,223	59	4,580	32	342	2.4
727A	7.17	1.024	7,063	10,188	45	3,529	24	263	1.8
727B	4.99	1.472	10,149	17,773	79	6,157	42	459	3.2
730A	6.30	1.166	8,038	9,498	42	3,290	23	246	1.7
730B	5.99	1.226	8,454	10,932	49	3,787	26	283	1.9
735A	6.03	1.218	8,398	9,665	43	3,348	23	250	1.7
735B	6.90	1.064	7,339	11,645	52	4,034	28	301	2.1
735C	-			4,328	19	1,499	10	112	0.8
735D	4.96	1.480	10,210	10,382	46	3,596	25	268	1.9
Mean	**5.79**	**1.31**	**8,930**	**10,808**	**48**	**3,744**	**26**	**279**	**1.9**
Std. Dev	**0.85**	**0.18**	**1,272**	**3,175**	**14**	**1,100**	**8**	**82**	**0.6**

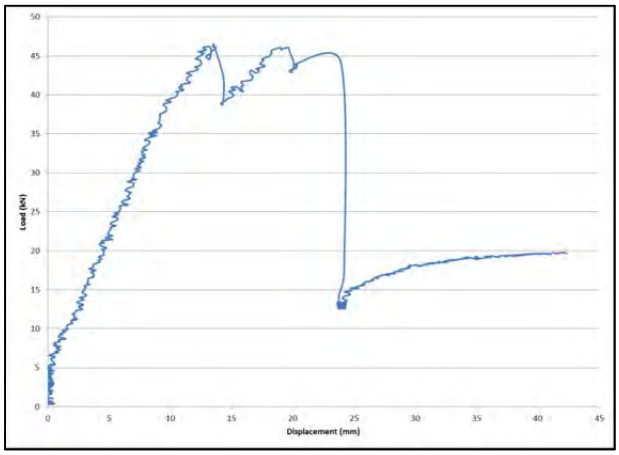

Figure 25: 724A Load vs Displacement

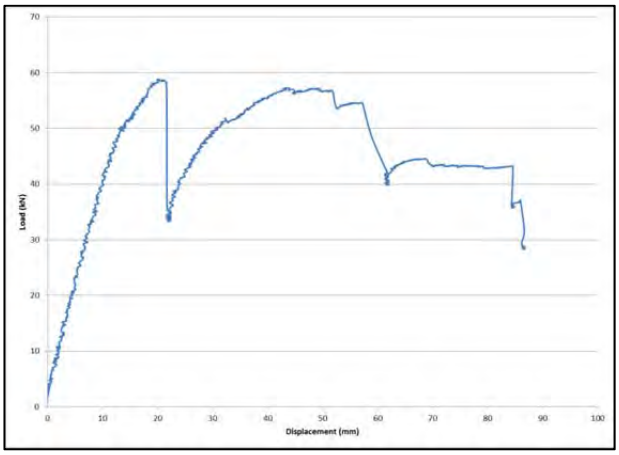

Figure 26: 724B Load vs Displacement

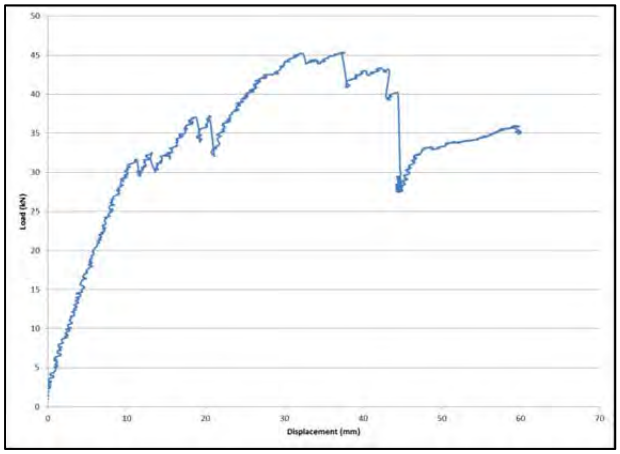

Figure 27: 727A Load vs Displacement

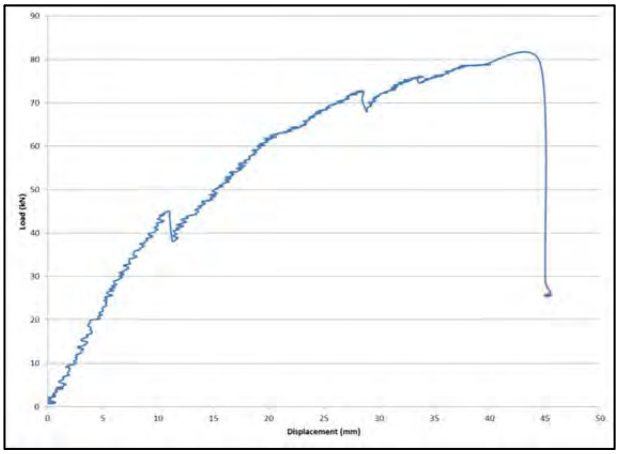

Figure 28: 727B Load vs Displacement

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Table 3: Flexural Test Results

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724B	4.82	1.523	10,507	13,223	59	4,580	32	342	2.4
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735B	6.90	1.064	7,339	11,645	52	4,034	28	301	2.1
735C	-			4,328	19	1,499	10	112	0.8
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Mean	**5.79**	**1.31**	**8,930**	**10,808**	**48**	**3,744**	**26**	**279**	**1.9**
Std. Dev	**0.85**	**0.18**	**1,272**	**3,175**	**14**	**1,100**	**8**	**82**	**0.6**

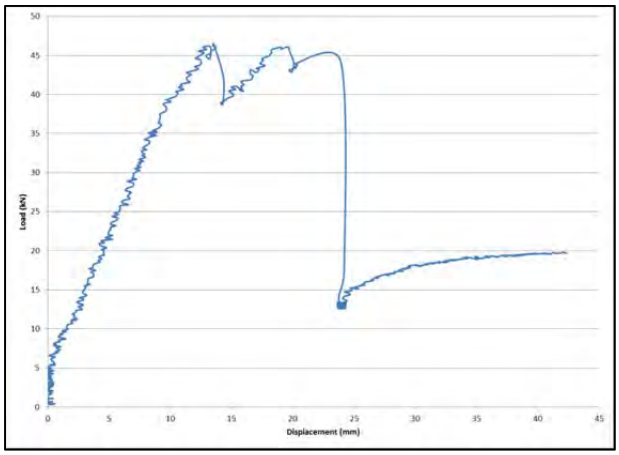

Figure 25: 724A Load vs Displacement

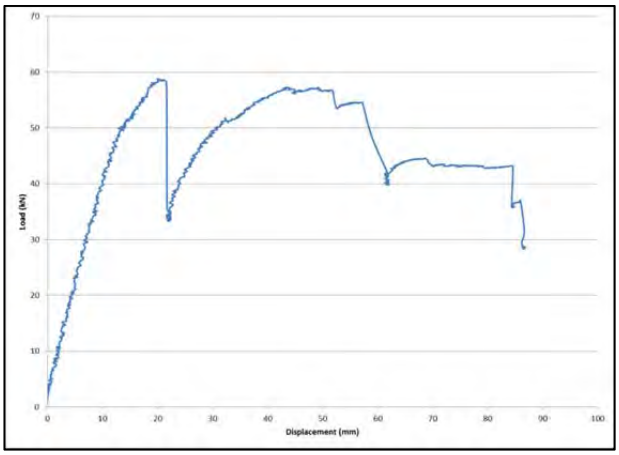

Figure 26: 724B Load vs Displacement

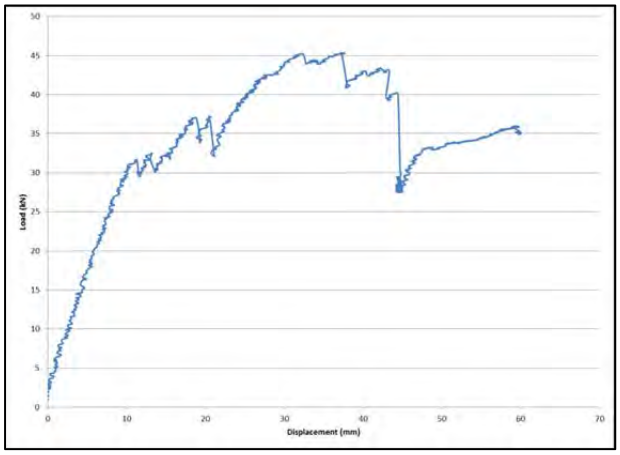

Figure 27: 727A Load vs Displacement

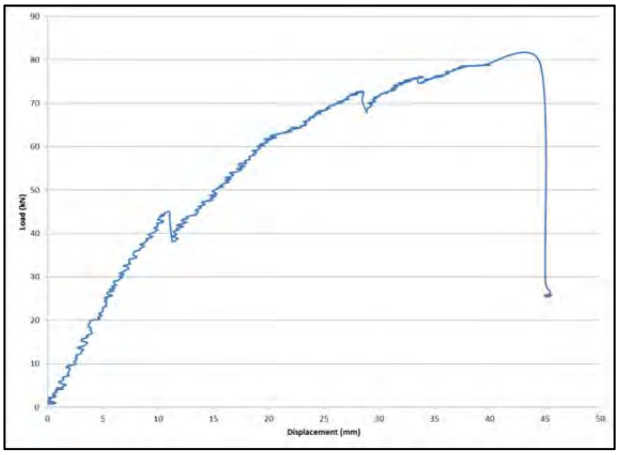

Figure 28: 727B Load vs Displacement

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Figure 35: Failure at Knot on Tension Side, Sample 727A

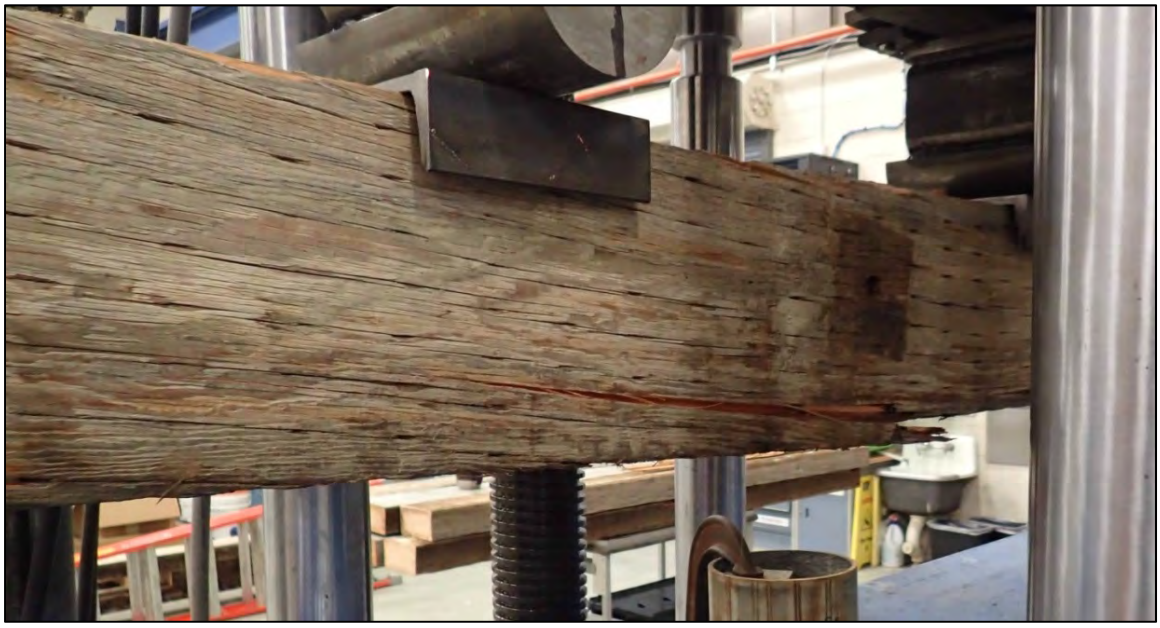

Figure 36: Failure Through Check on Tension Side, Sample 735B

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Figure 37: Failure Through Connection Point, Sample 733C

Figure 38: Transverse Failure Next to Connection Point, Sample 735C

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STATISTICAL ANALYSIS

In order to determine whether the existing crossarm assemblies in the system can withstand the design vertical loads, a reliability analysis was carried out based on the flexural and full-scale vertical load test. It was assumed that

- The section subject to maximum bending stress is the connection of the high side pole to the crossarm
- The maximum bending arm (connection to the high side phase) is 6.5 feet
- The specimen samples are representative to the crossarm population of the line

Based on the flexural test results, the vertical load carrying capacity at the crossarm high side phase was calculated as below, and is summarized in Table 4:

- Vertical load (single arm) = bending strength (MOR) x Section Modulus / bending arm

Where:

- Section modulus = depth of beam ^{2} x width of beam /6 = 7.75^2 x 3.75 /6 = 37.54 in^3
- Length of bending arm = 6.5 ft = 78 inches

Table 4: Estimate of vertical load carrying capacity at high side connection

MOR (psi)	Single arm (Lbs)	Double arms (Lbs)
3,619	1742	3483
4,580	2204	4409
3,529	1699	3397
6,157	2963	5926
3,290	1583	3167
3,787	1823	3645
3,348	1611	3222
4,034	1941	3883
1,499	721	1443
3,596	1731	3461

It can be seen from Table 4 that the remaining capacity ranges from 1,443 lbs to 5,926 lbs, with a mean of 3,604 lbs and a standard deviation of 1,116 Lbs. To get the statistical significance of the loads estimated above, a Weibull analysis was performed using Weibull ++8, developed by ReliaSoft. The data shown in Table 4 combined with the full-scale load test results were fitted using two parameter Weibull distributions, and plotted as shown in Figure 39. The lack of data points was taken care of by the lower bound and upper bound also plotted with a 90% confidence level. The curves provide a probabilistic description of the remaining load carrying capacity of the crossarm assemblies. It can be used to estimate the probability of remaining capacity being exceeded by a given vertical load with lower and upper bounds and a confidence level.

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Table 5 gives an example of the probabilities calculated for the given design vertical loads. It should be noted that the probabilities cannot be used to compare the actual probability of failure the line has experienced. To predict probability of crossarm failure, a structural reliability analysis need to be performed in which both uncertainties involved in material properties and weather loads are taken into account, as well as differing failure modes. The procedure and methodology are detailed in the two CEATI reports [1, 2] Powertech has prepared.

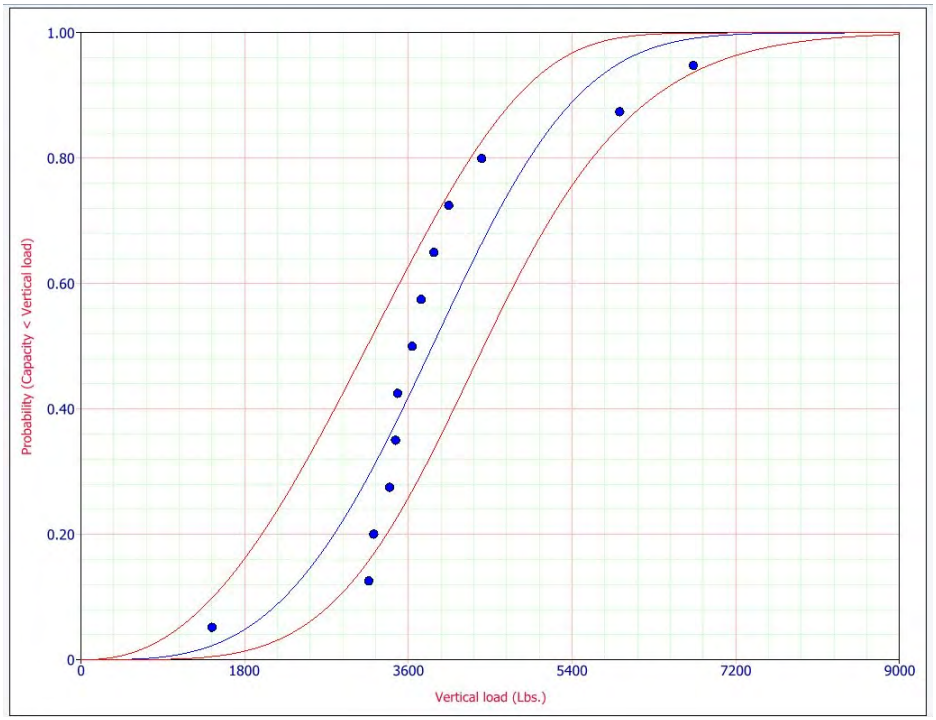

Figure 39: Probability description of load carrying capacity at high side connection including lower and upper bound with 90% confidence level

Table 5: Probability of not meeting design vertical loads (90% confidence level)

Design vertical load (Lbs)	Probability of not meeting a given design vertical load		
	Upper bound	Lower bound	Average
1,260 (Standard span, CSA ML)	7.2%	0.28%	1.43%
2,000 (Long span, CSA ML)	20.3%	2.2%	6.9%
2,920 (Standard span, 50 mm hoar frost)	43.7%	11.4%	23.2%
3,860 (Long span, 50 mm hoar frost)	69.7%	33.0%	49.9%

It can be seen from Table 5 that due to the lack of sample size, the gap between lower bound and upper bound is quite large. For example, the probability of vertical load carrying capacity not meeting 2,000 Lbs could range from 2.2% to 20.3% with average of 6.9%. For conservative purpose one could use the upper bound for the worst case scenario if needed. In this approach, it can be seen that the existing double wood crossarm system has a high probability of not meeting the design vertical loads formulated for the transmission line (7.2%, 20.3%, 43.7% and 69.7% for four load cases respectively, with 90% confidence level).

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CONCLUSIONS AND RECOMMENDATIONS

From the evaluation and test results, the following conclusions and recommendations are made:

- The overall condition of the crossarms can be considered fair. No rot or insect damage is present, and although the crossarms do contain sporadic large knots and sloping grain, these features are within the allowable provisions of structural lumber grades common from crossarm use

- Significant cracking evident on two pairs of as received crossarms indicates that in-service failures did happen on the 138 kV line

- In general the crossarm assembly performs well during the full-scale vertical and longitudinal load tests. The vertical loads achieved agree with the prediction based on the flexural test results. No anomalies were found on the connections and hardware. One of the three vertical loads obtained from full-scale tests was 3,743 lbs, which does not meet the design load of 3,860 lbs.

- The low full scale test result was a result of the failure initiating through a shallow check at the connection point, rather than the theoretical assumed failure of fibers on the tension side of the maximum bending stress.

- Based on test results and analysis, the remaining vertical load carrying capacity of the crossarm assembly is not adequate to withstand the 50 mm hoar frost, even on a standard span

- Allowing for the worst case scenario (upper bound), the existing double wood crossarm system has a high probability of not meeting the vertical design loads of the modern standard

- The longitudinal load carrying capacity is adequate

- Given the high probability of not meeting design vertical loads and the age of the crossarms (close to 50 year old) as well as evidence of failure in service, it is recommended that the replacement of these crossarms should be initiated to mitigate the risk of failure in service, with replacement prioritized as follows:

  - Long spans should be given priority for replacement over short spans
  - Crossing structures should be given priority over non-crossing structures
  - For all spans, those structures in which knots and checks are noted around connection points should be given priority over structures in which these features are not seen

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REFERENCE:

[1] CEATI report No. T003700-3301 – *"Assessing Design Approaches for Overhead Transmission Lines under Climatic Loads for New Projects as well as for Verification of Lines to be Upgraded"*
[2] CEATI Report No. T044700-5047 – " *Assessment of the structural reliability of distribution overhead wood pole lines"*

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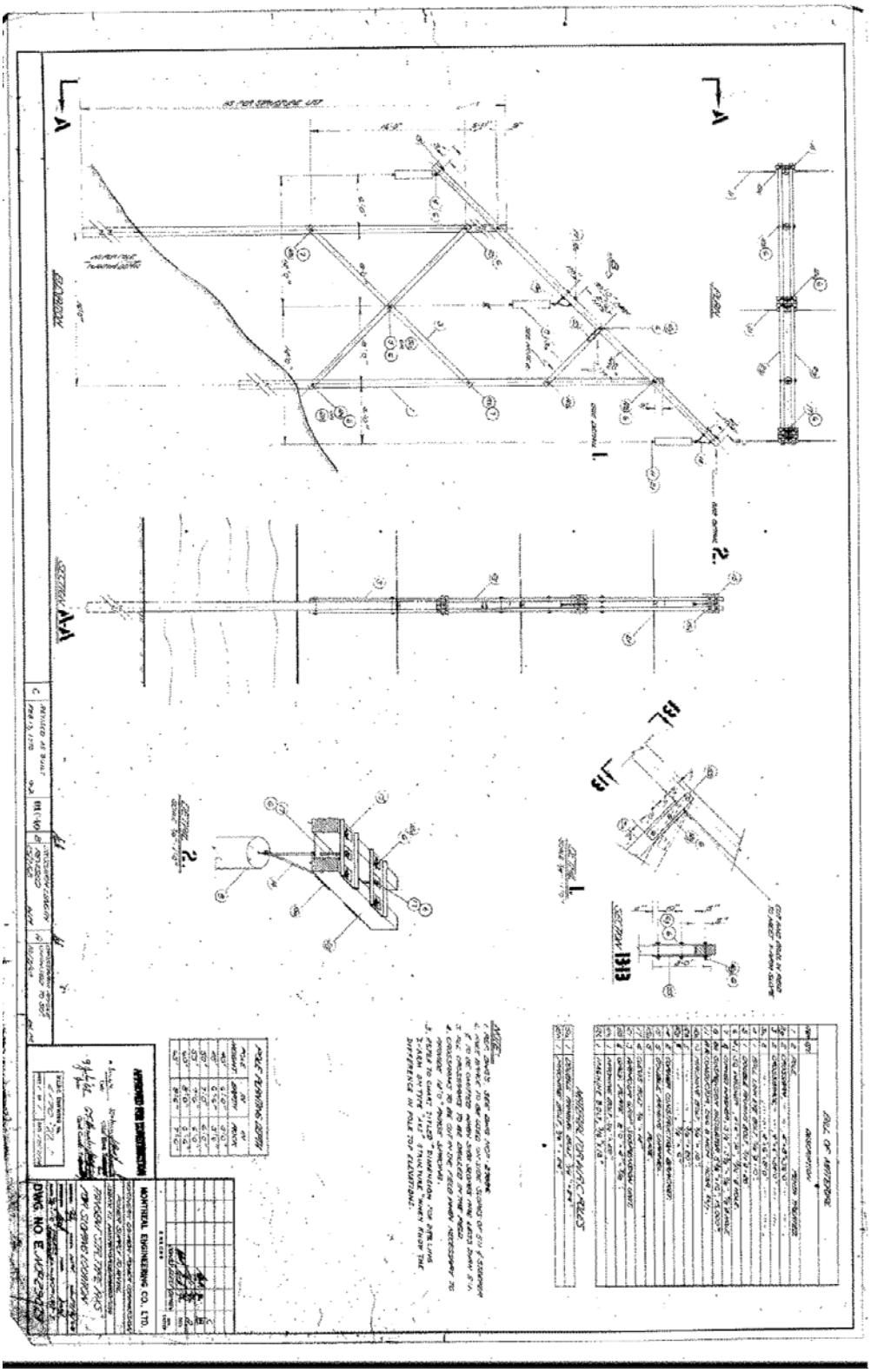
APPENDIX: Structure drawing NCP-29029



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Powertech
MECHANICAL TECHNOLOGY AND TESTING

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February 5, 2015
Report No.: TR00750.01R0

Yukon Energy Corporation
#2 Miles Canyon Road
Whitehorse, YK
Y1A 6S7

Attention: Mr. Ed Peake, Manager, Electrical Operations

Dear Mr. Peake

Re: Condition Assessment and Evaluation of 138 kV Wood Cross Arms

SUMMARY

Wood crossarms utilized in single crossarm H-frame structures from an existing 138 kV transmission line were supplied by Yukon Energy Corporation for full scale mechanical testing and flexural testing. The crossarms of the transmission line are scheduled to be replaced by steel crossarms, the testing was undertaken to assess the existing structural integrity of the crossarms and their serviceability with respect to updated design criteria for the line, and gauge the immediacy of the replacement program. Four (4) vertical load scenarios were identified in the design, based on span and hoar frost loading, increasing in load severity.

The full scale test portion entailed testing the existing crossarms to each level, and then to failure to determine the ultimate load carrying capacity of the crossarms. In the test, a dead load at each design criteria level was applied to one end phase, with the opposite end phase then loaded to that level. The middle phase connection point was left unloaded, as this represented the worst case scenario in service; all three phases loaded, with the center phase dropping out, leading to maximum bending stress in the beam. None of the 4 crossarms tested reached the final design load criteria, 1 failed below the second criteria, two below the third level and one just before the final design load criteria.

The flexural testing of the crossarms provided the material properties of the wood, from which the load carrying capacity at the crossarm end phase was calculated and a reliability analysis carried out to develop a probabilistic description (Weibull curve) of both the factored and unfactored loads.

Based on the test results, it can be stated that the existing single wood crossarms do not meet the updated design criteria for the line. The design criteria itself takes into account load factors in combination with worst case climate load scenarios. From the reliabilities obtained against the unfactored design load, it is seen that the probability of any immediate failures of existing crossarms is low. However, it is recommended that the replacement program of steel crossarms should begin as soon as operational practicability dictates. The replacement program can be guided as follows:

- Long spans should be given priority for replacement over short spans
- Crossing structures should be given priority over non-crossing structures
- For all spans, those structures in which knots and checks are noted around connection points should be given priority over structures in which these features are not seen

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INTRODUCTION

The 138 kV L170 transmission line operated by Yukon Energy Corporation currently consists of single wood crossarms on wood poles in a typical H-frame construction. A replacement program is being considered for the transmission line, in which the existing wood crossarms will be replaced by steel crossarms. As part of the replacement program, the criteria and design load requirements for the transmission line have been updated to current CSA standards. Powertech Labs Inc was contracted to conduct mechanical and material property testing on representative samples of the existing crossarms, to determine their serviceability with regards to the new design criteria, and gauge the immediacy of need for replacement. The testing consisted of full scale testing of the crossarms on a mockup of the H-frame structure, as well as flexural testing to determine the modulus of rupture (bending strength), modulus of elasticity and maximum fiber shear strength of the wood members.

DESIGN DOCUMENTATION

The design documentation for the 138 kV H-frame structures was provided by Yukon Energy, and is available as an appendix to the report. The full scale test program was based on the 4 vertical design loadings indicated in the document, consisting of the following load scenarios ranked in load severity:

1. Standard span, CSA medium loading 250m = 1,260 lbs
2. Long span, CSA medium loading 395m = 2,000 lbs
3. Standard span, 50 mm hoar frost 340m = 2,920 lbs
4. Long span, 50 mm hoar frost 450m = 3,860 lbs

The longitudinal load carrying capacity of the crossarms was also included in the test program, consisting of the conductor tie down load and was considered to be 400 lbs in which a 2.0 load factor is included

VISUAL INSPECTION

Upon receipt, the cross arms were visually inspected to assess the current condition, with the following observations noted:

- The crossarms were structurally sound, with no major mechanical damage or rot noted, including around the connection point through holes
- The crossarms are predominantly straight, with little bow or warpage
- Incising marks are seen along the length of the wood, indicative of a pressure treatment, likely PENTA
- The crossarms contain very few knots, knots that do exist are relatively small and tight; as such the lumber is considered to be of a good grade, likely 1 common if applying current softwood dimensional lumber grades
- Checks (cracks along the woods grain pattern, but not passing through the entire thickness) are seen sporadically in the crossarms

Based on the observations noted, the current overall condition of the wood crossarms is considered to be good; the crossarms are structurally sound and of good grade. Examples of the features noted in the inspection are seen in Figures 1 and 2.

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Figure 1: Overall view of crossarm from structure 128. Crossarm is sound, with very few knots along length. Knots that are present are relatively small and tight

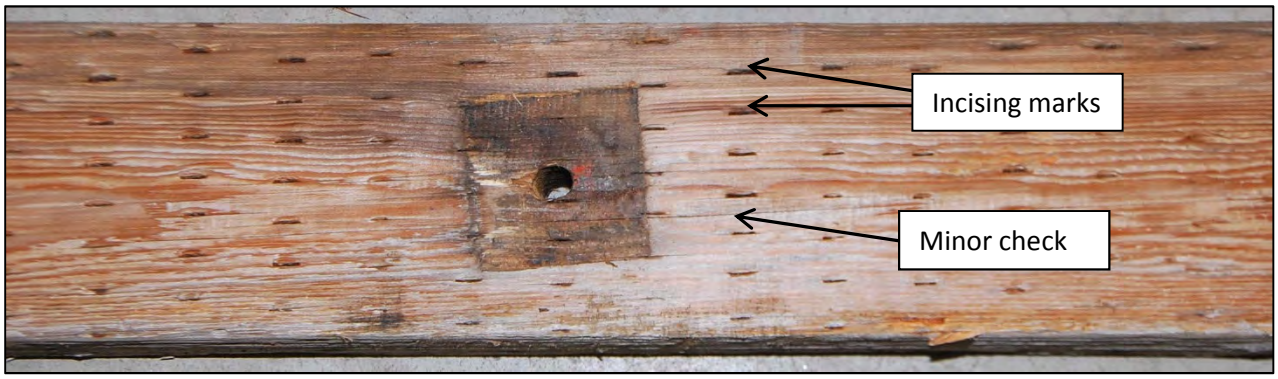

Figure 2: Macro view of crossarm from structure 141 around wood pole connection point. Note regular incising marks indicative of pressure treatment. No rot noted around through holes, some minor checks

FULL SCALE MECHANICAL TEST SETUP

A test frame was built in the mechanical lab at Powertech Labs in accordance with Yukon Energy's 138 kV H-frame design specifications. Two 12" x 12" x 0.5" steel I-beams were used to support the crossarm samples with spacing of 16 ft between the two columns. One of the two steel columns (south side) was anchored using an existing anchor pad and another column (north side) was anchored using an anchor system specially built for anchoring the column (Figure 3). The anchoring system was comprised of two 12" x 12" x 0.5" I-beams connected to other anchor pads for longitudinal and transverse constraints. Three concrete blocks each weighing 4300 lbs (20 kN) were placed on the anchoring system to provide vertical restraint to the north column.

To represent the actual connection between crossarms and wood poles, a wood pole was selected from BC Hydro's pole yard and sectioned to a semi-elliptical cross section. The sectioned wood column was placed and fastened between the two flanges of the I-beam so that a wood to wood connection existed as per actual installation practices. The connection interface for the testing is seen schematically in Figure 4.

Standard ¾" diameter Hubbell cold weather crossarm bolts and large flat plate washers were used to fasten the crossarms to the test columns. Standard ¾" eyebolts were used as the phase connection hardware, with a large flat washer plate placed on the topside of the crossarm. The connection hardware used is seen in Figures 5 and 6.

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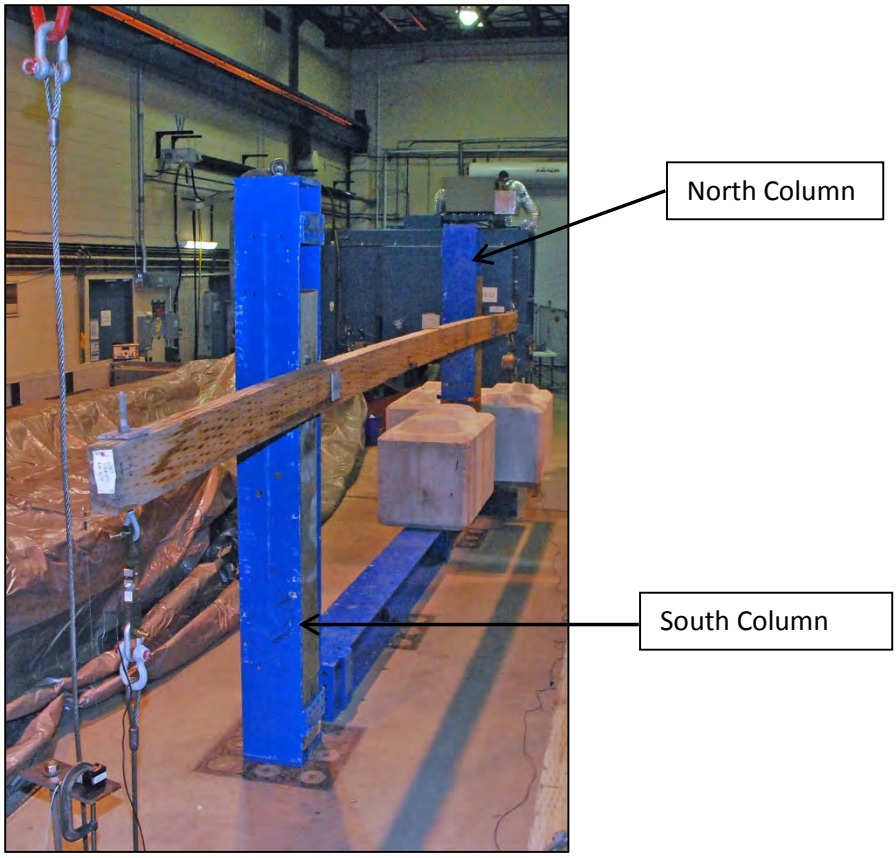

Figure 3: Test setup for full scale mechanical test of wood crossarms

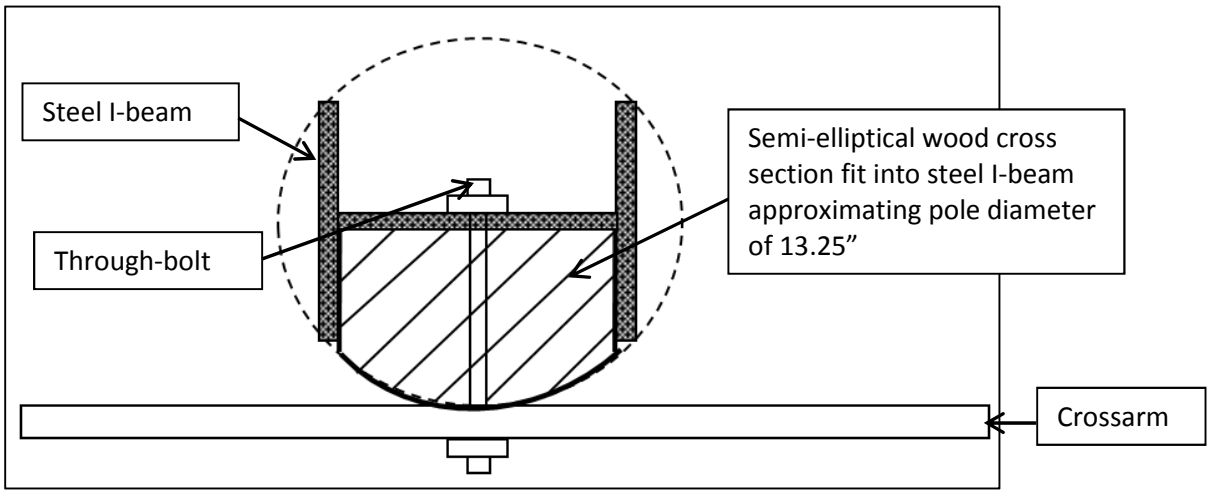

Figure 4: Schematic representation of connection interface for testing

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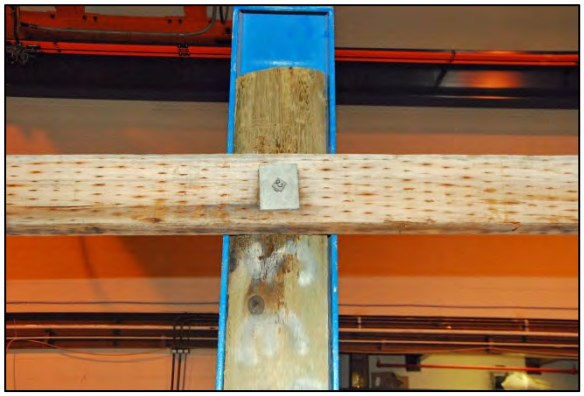

Figure 5: Single ¾" diameter crossarm bolt and flat washer used to connect crossarm

Figure 6: ¾" eyebolt and flat washer used as phase connection

The typical setup for the vertical load tests is shown schematically in Figure 7. The vertical load was applied to the south end using a 10-ton overhead crane through a pulley attached to an anchor pad. A dead load was applied to the north end to simulate the worst-case scenario for the line (i.e. all phases under equal load, center phase drops out leading to maximum bending stress at H-frame connection points). The dead load at the north end was applied via a chain hoist and load cell, seen in Figure 8. A load cell was placed in line with the overhead crane on the south end, and a displacement transducer attached to the cross arm. The load and displacement were subsequently data logged with a Soltec high speed data acquisition system. The setup at the south end is seen in Figure 9.

Each load scenario was treated independently, with the loads applied in the following manner:

- Apply dead load of 1,260 lbs to north end, apply load up to 1,260 lbs at south end, record observations, unload
- Apply load of 2,000 lbs to north end, apply load up to 2,000 lbs at south end, record observations, unload
- Apply load of 2,920 lbs to north end, apply load up to 2,920 lbs at south end, record observations, unload
- Apply load of 3,840 lbs to north end, apply load up to 3,840 lbs at south end, record observations
- Continue applying load to south end until failure

For the longitudinal test, the load was applied to the south end using the overhead crane and pulley attached to a short beam anchored to the ground opposite of the application point. No dead load was applied to the north end for the longitudinal test.

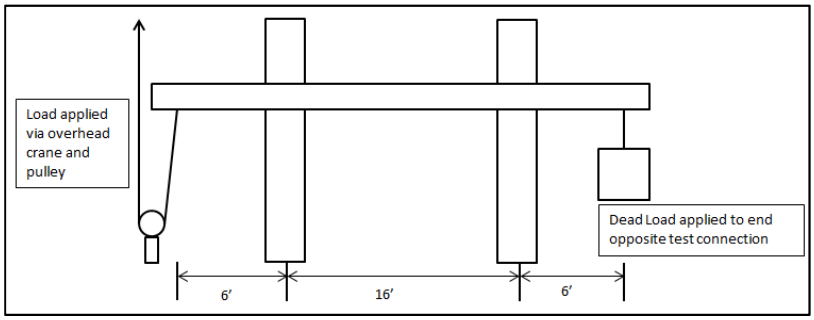

Figure 7: Schematic representation of full scale load test

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Figure 8: Chain hoist and load cell for application of dead load at north end

Figure 9: Load cell, displacement transducer and pulley for application of live load at south end

FULL SCALE MECHANICAL TEST RESULTS

The vertical load carrying capacity of the crossarms is seen summarized in Table 1. Detailed deflection data and observations for each test iteration for all crossarms samples are compiled in Table 2. None of the tested samples achieved the final load severity (3,840 Lbs) of the design criteria.

All samples reached the first design load criteria of 1,260 lbs. At this load no apparent damage or cracking of wood fiber was noted. At the second design load criteria of 2,000 lbs 3 of the 4 samples showed cracking of fiber and opening of existing checks along their length.

Crossarm 128 failed to meet the second load criteria of 2,000 lbs, fracturing at 1,429 lbs. Failure occurred as existing checks opened up and propagated between knots present within the crossarm. The failure of this crossarm at a relatively low load illustrates the effects of the knots to the structural integrity of the beam. Several knots were present on the tension side of the bend in the high stress area around the connection point; the orientation and presence of these knots is the reason for low failure.

Crossarms 142and 624 failed during the attempted application of the third design load criteria.

Crossarm 142 failed during the application of the dead load at the north end, with the south end completely unloaded. The failure occurred spanning several knots on the tension side, again illustrating the effect of knots within the wood grain structure.

Crossarm 624 achieved the highest vertical load carrying capacity, failing just short of the final design load criteria. No knots were present in the immediate area of failure; failure initiated from the through hole connection point.

Load versus displacement data for the final load to failure tests for each crossarm are seen in Figures 10 through 13. Images of the bending deflection, failure modes and features noted during the vertical testing are seen in Figures 15 through 23.

The longitudinal test of structure 140 was stopped at 1,200lbs, 3 times the design load criteria of the longitudinal load carrying capacity. The test was not carried through to ultimate failure as the load was already 3 times the design load, which itself has a safety factor of 2.0. The load versus displacement data for the longitudinal test is seen graphically in Figure 14, with the bending deflection achieved seen in Figure 24.

Table 1: Summary of Ultimate Load Carrying Capacity of Crossarms

Structure ID	Ultimate Vertical Load Achieved (lbs)	Constant Load at North End (lbs)	Deflection at Load (mm)
620	3,442	3,860	264
128	1,429	2,000	91
624	2,450	2,920	163
142	2400	2,400	118

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Table 2: Deflection Data and Observations for All Vertical Load Scenarios

Test ID	Structure #	Load Scenario	Dead Load (North End)	Applied Load (South End)	Deflection at Applied load	Observations
1	620	1	1,260	1,260	104	Minor creaking of wood, no apparent damage
2		2	2,000	2,000	153	Existing checks opening up along crossarm length
3		3	2,920	2,920	210	Additional opening and lengthening of checks along crossarm length
4		4	3,860	3,442	264	Fracture of wood grain at connection point
5	128	1	1,260	1,260	60	Existing checks opening along length
6		2	2,000	1,429	91	Checks present under knot in high stress area adjacent to connection point fractures
7	624	1	1,260	1,260	68	Minor creaking of wood
8		2	2,000	2,000	110	Continuation of creaking, no checks in immediate area of connection point
9		3	2,920	2,450	163	Sudden failure initiating from connection point
10	142	1	1,260	1,260	53	Minor creaking of wood
11		2	2,000	2,000	118	Existing checks opening along crossarm length
12		3	2,400	---	N/A	Sudden failure initiating from knot in high stress area adjacent to connection point

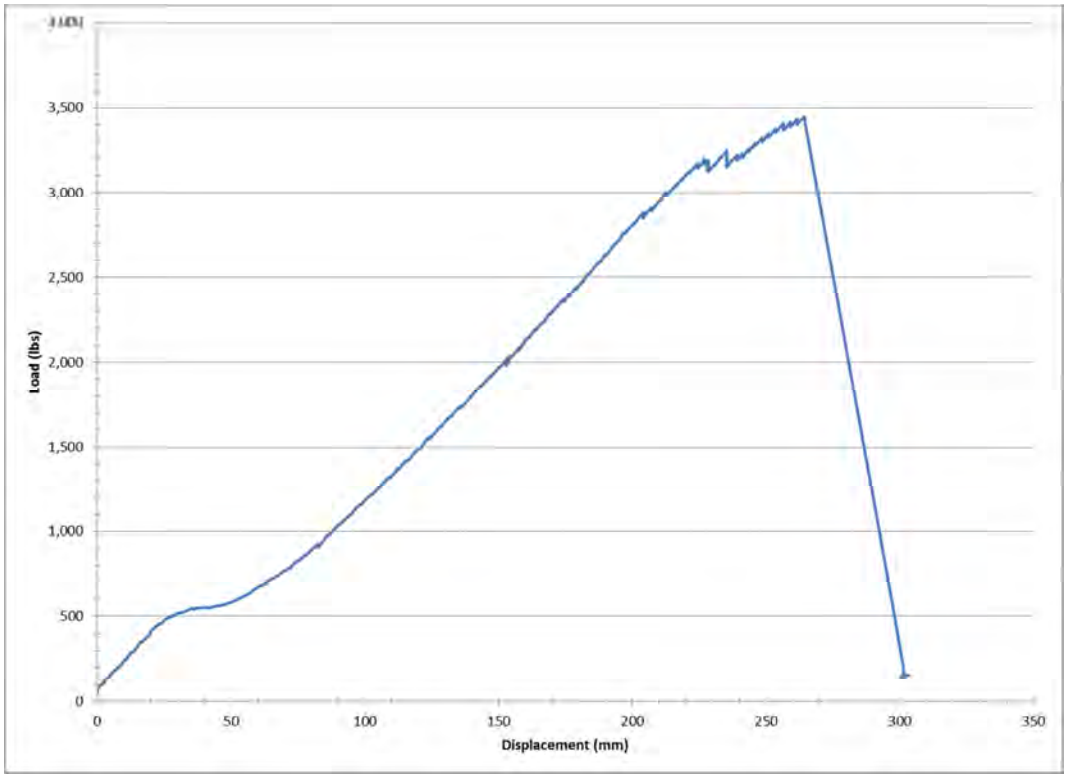

Figure 10: Structure 620, load vs displacement graph for final load scenario to failure b n

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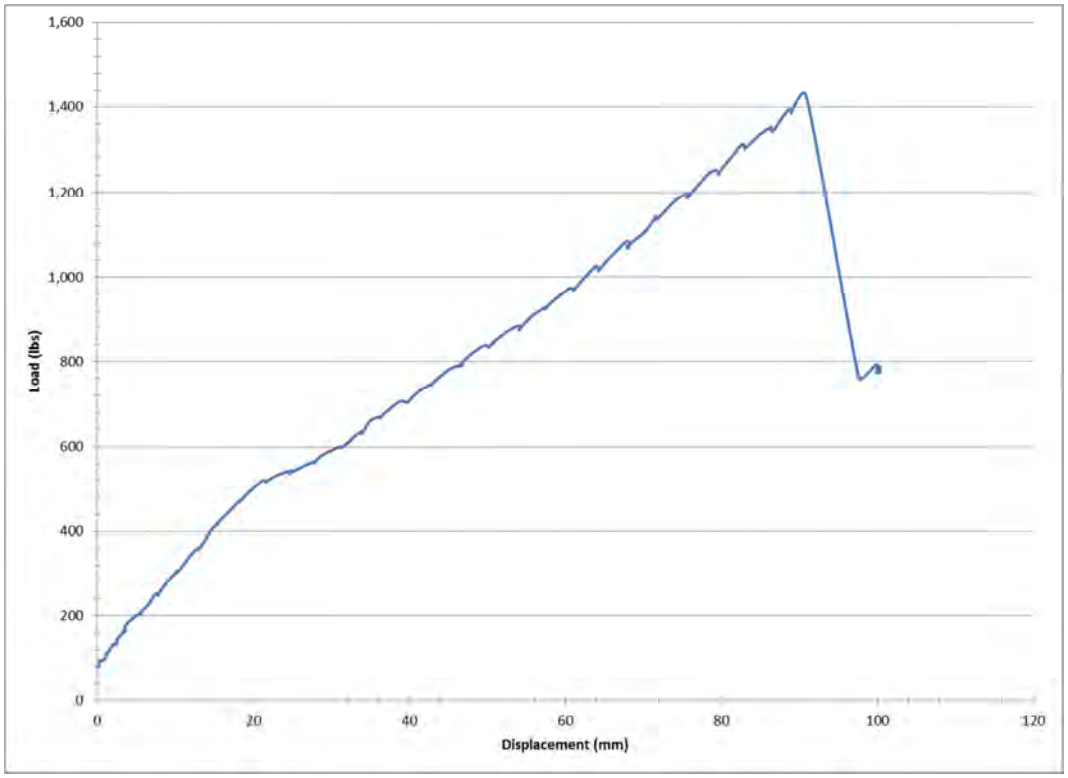

Figure 11: Structure 128, load vs displacement graph for final load scenario to failure

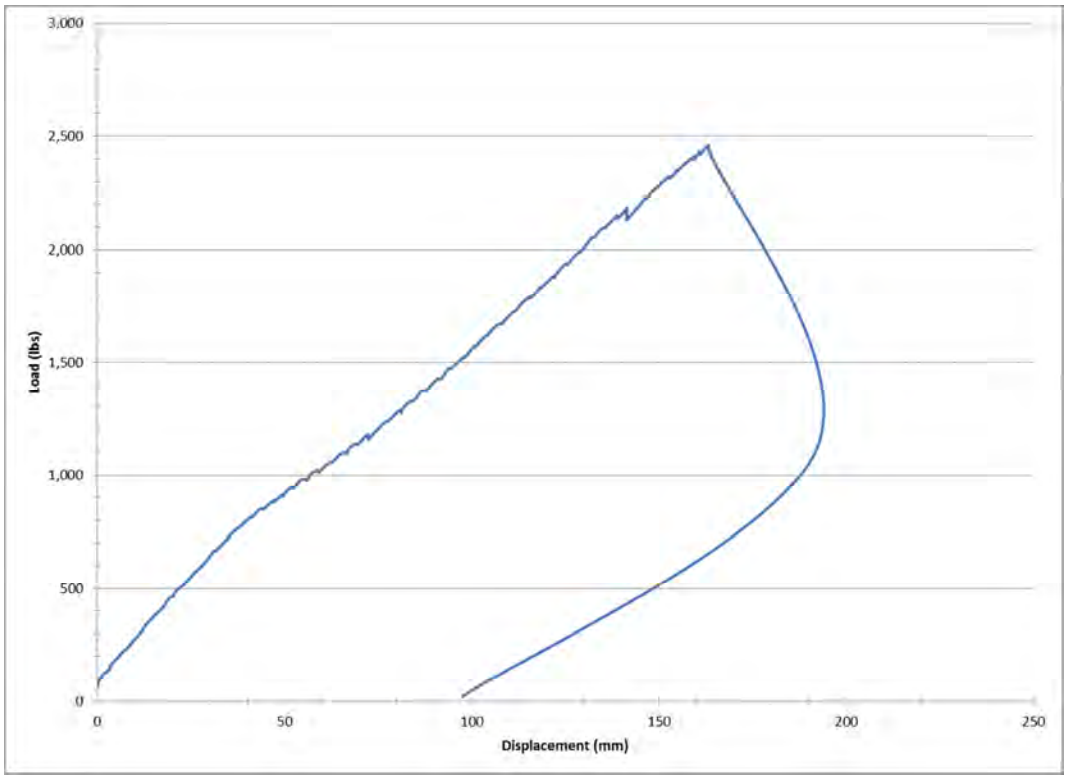

Figure 12: Structure 624, load vs displacement graph for final load scenario to failure

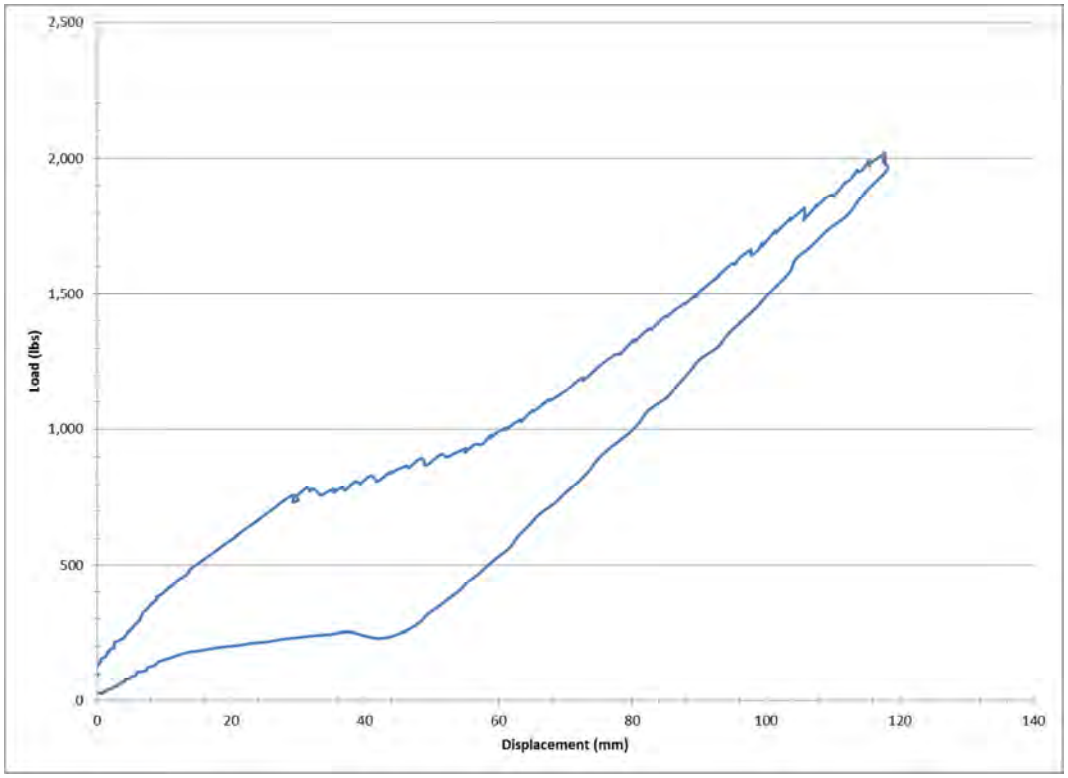

Figure 13: Structure 142, load vs displacement graph for final load scenario

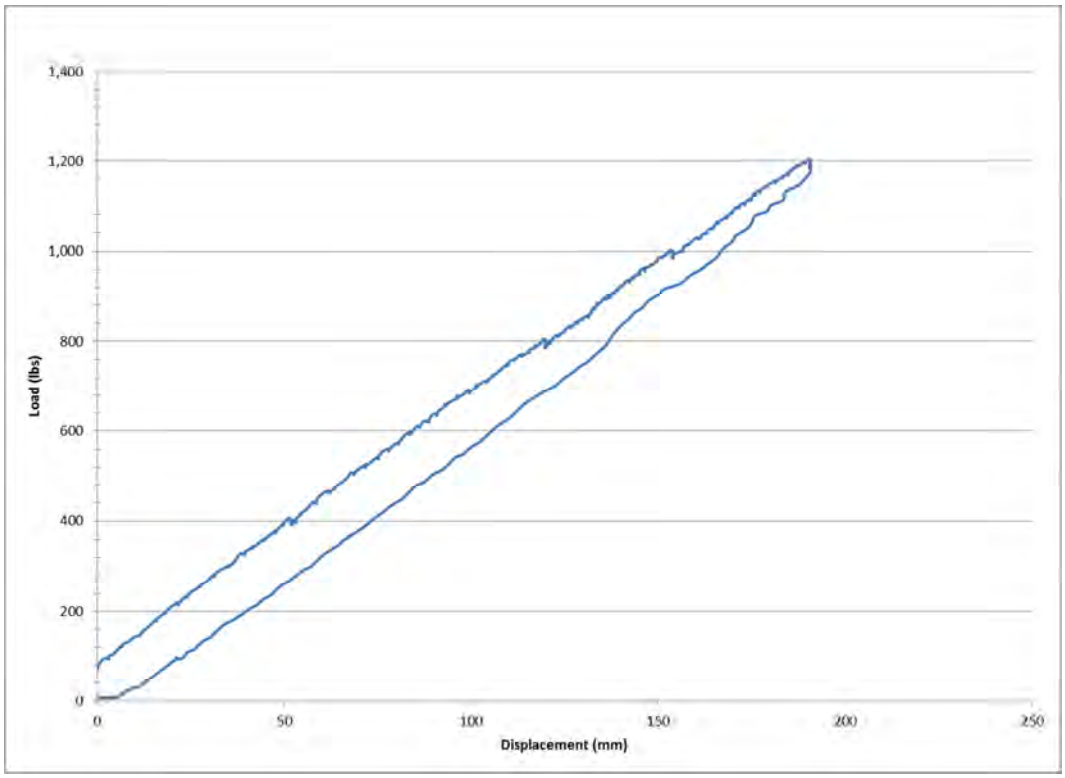

Figure 14: Structure 140, load vs displacement graph for longitudinal test

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Figure 15: Structure 620, checks and cracks opening up on crossarm at 2,000 lb vertical load

Figure 16: Structure 620, check opening up on tension side of bend at 2,920 lbs

Figure 17: Structure 620, check opening up on tension side of bend at 2,920 lbs

Figure 18: Structure 620, side view of deflection at 2920

Figure 19: Structure 620, failure at 3,900 lbs, vertical load

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Figure 20: Structure 128, failure at 1,420 lbs, vertical load, side view showing bending through beam

Figure 21: Structure 128, failure at 1,420 lbs, vertical load, front view

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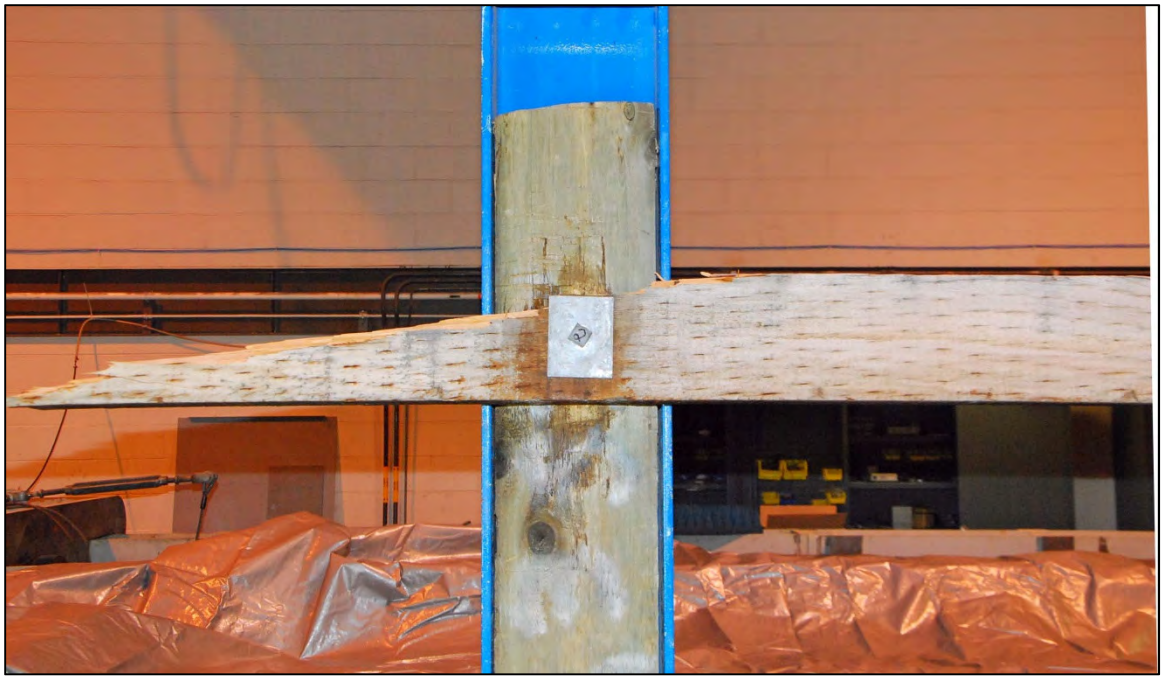

Figure 22: Structure 624, failure at 1,420 lbs, vertical load, front view

Figure 23: Structure 142, failure at 2,400 lbs, vertical load

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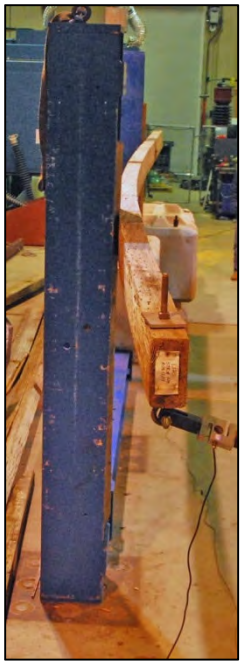

Figure 24: Structure 140, longitudinal load of 1,000 lbs

FLEXURAL TEST

The objective of the flexural test was to determine the material properties of the wood crossarms: modulus of rupture (bending strength), modulus of elasticity, and maximum shear stress. Two-point loading tests were conducted using Powertech's Tinius-Olsen test machine as shown in 25. A displacement transducer was attached to the intersection of the beam center and natural axis. Eight specimens with full size cross sections and a span of 2.7m were cut from the crossarms. The specimens were cut such that the connection point to the wood poles was centered between the loading noses, the area of highest bending stress.

Figure 25: Two-point flexural loading test setup for flexural testing

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It was observed that for all tests, that the failure initiated at either existing checks or knots located on the tension side, or the connection hole, and in between loading points, where the beam is subject to maximum bending stress. Based on deflection measured and maximum break load, the MOE, MOR and shear stress were calculated and summarized in Table 3. Images of the typical failure mode of the beams are seen in Figures 26 and 27, with the load versus displacement data for each specimen seen in Figures 28 through 35.

Table 3: Flexural Test Results

Specimen ID	Defl. at 10,000 lbs	Modulus of Elasticity (MOE)		Breaking Load		Modulus of Rupture (MOR)		Max Shear Stress	
	(mm)	psi (10^6)	MPa	lbs	kN	psi	Mpa	psi	MPa
128	14.90	2.94	20,272	17,964	80	9,629	66.4	508	3.5
135	17.20	2.55	17,561	16,946	75	9,083	62.6	479	3.3
138-A	14.77	2.97	20,451	17,160	76	9,198	63.4	485	3.3
138-B	19.13	2.29	15,789	11,461	51	6,143	42.4	324	2.2
141-A	11.75	3.73	25,706	18,001	80	9,649	66.5	509	3.5
141-B	14.60	3.00	20,688	16,306	73	8,740	60.3	461	3.2
142	14.68	2.98	20,576	13,213	59	7,082	48.8	374	2.6
624	14.85	2.95	20,340	15,081	67	8,083	55.7	427	2.9
Mean	**15.24**	**2.93**	**20,173**	**15,766**	**70**	**8,451**	**58.3**	**446**	**3.1**
Std. Dev	**2.01**	**0.38**	**2,674**	**2,207**	**10**	**1,183**	**8.1**	**62**	**0.4**

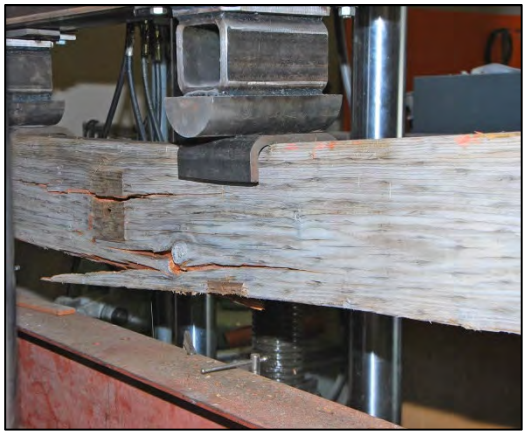

Figure 26: Failure of flexural sample at knot on tension side. Fracturing at connection point also noted

Figure 27: Failure of flexural sample through connection point and checks on tension side

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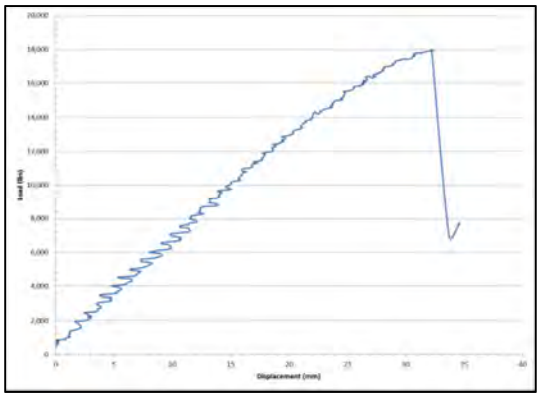

Figure 28: 128, load vs displacement

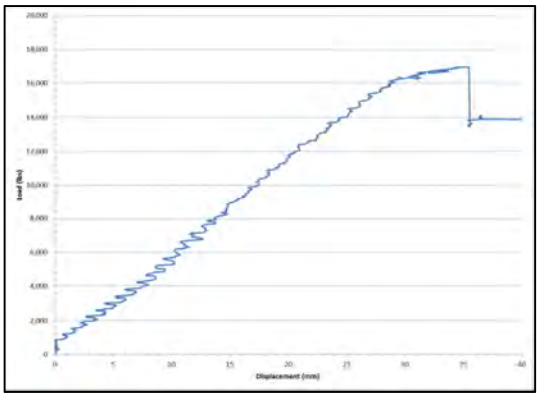

Figure 29: 135, load vs displacement

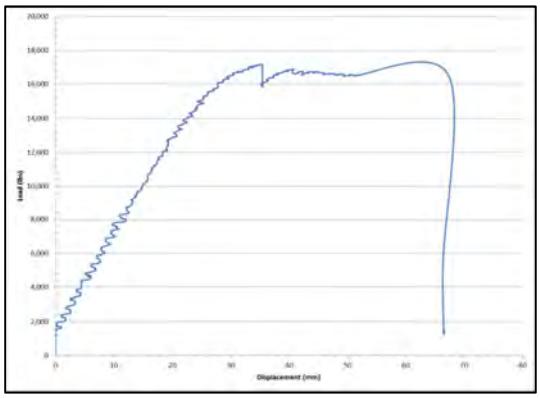

Figure 30: 138-A, load vs displacement

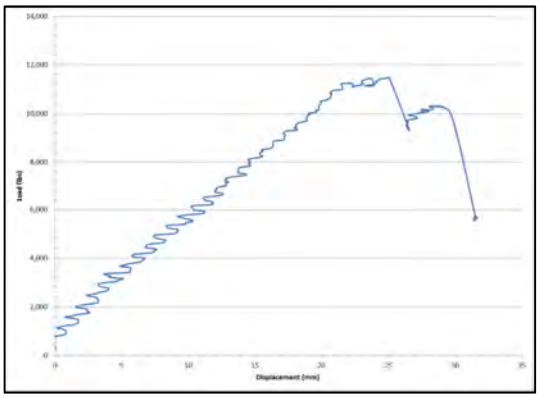

Figure 31: 138-B, load vs displacement

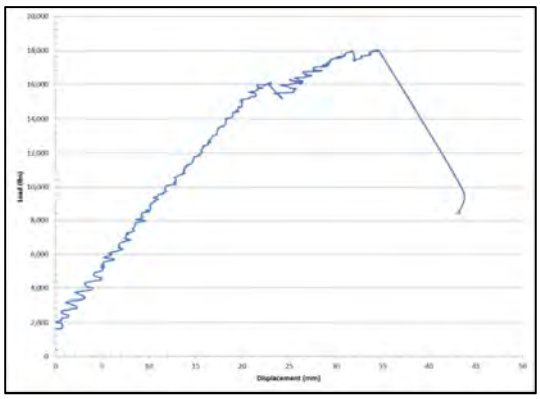

Figure 32: 141-A, load vs displacement

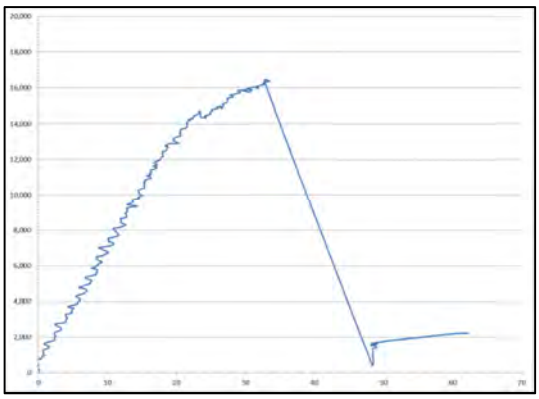

Figure 33: 141-B, load vs displacement

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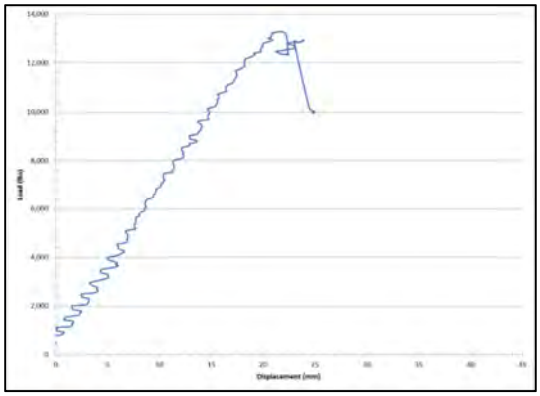

Figure 34: 142, load vs displacement

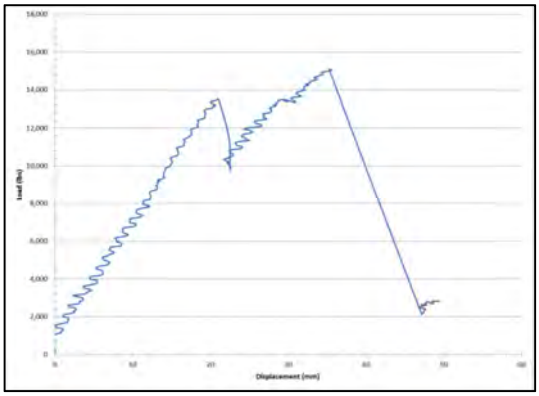

Figure 35: 624, load vs displacement

STATISTICAL ANALYSIS

Based on the flexural test results, the load carrying capacity at the crossarm end phase was calculated. A reliability analysis was then carried out to develop a probabilistic description (Weibull curve, Figure 36) of the load carrying capacity. Based on the curve, the probability of the load carrying capacity exceeding the specified design loads were quantified and provided in Table 4.

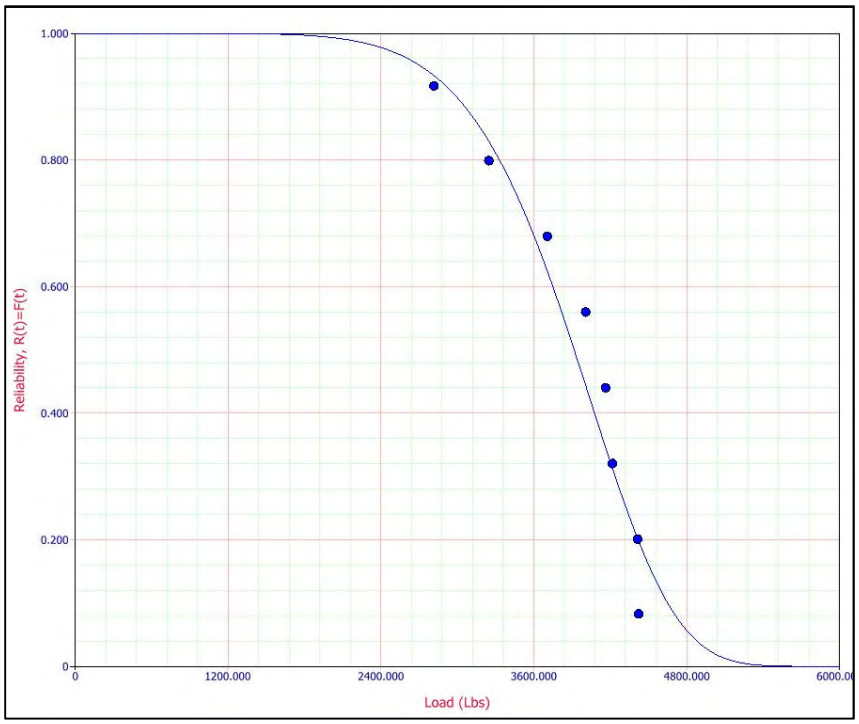

Figure 36: Reliability curve of the load carrying capacity at end phase

Table 4: Reliability for each of the design load cases (95% confidence level)

Factored Design load (Lbs)	Reliability of the load carrying capacity exceeding factored design loads	Unfactored Design load (Lbs).*	Reliability of the load carrying capacity exceeding unfactored design load
1,260	96%	630	99%
2,000	86%	1000	98%
2,920	63%	1460	94%
3,860	25%	1930	87%

*vertical load factor of 2.0 is used

CONCLUSIONS AND RECOMMENDATIONS

The wood crossarms are considered to be in good condition; however checks and knots within the beams, and their random proximity to the high stress areas could significantly reduce the load carrying capacity, as demonstrated by the test results.

Based on the test results and the reliability analysis, it can be seen that the existing single wood crossarms of the H-frame structures have a high probability of not meeting the updated design load criteria formulated for the transmission line (4%, 14%, 37% and 75% for four load cases respectively, with 95% confidence level).

The design loads themselves incorporate load factors, and are worst case scenarios; from the reliabilities obtained against the unfactored design load, it is seen that the probability of any immediate failures of existing crossarms is low. However, it is recommended that the replacement of these crossarms should be initiated, in order for the line to meet the new design criteria. The replacement program can proceed along operational convenience, with the following considerations:

- Long spans should be given priority for replacement over short spans
- Crossing structures should be given priority over non-crossing structures
- For all spans, those structures in which knots and checks are noted around connection points should be given priority over structures in which these features are not seen

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REFERENCE: **Application, Tab 5.2.1.6, pages 5-15 to 5-16**

ISSUE: **Transmission Line Refurbishment – L178 Project**

QUOTE: "Outages on the L178 currently trip at S164 (Takhini Substation) and can result in an outage on the Takhini-Carmacks L170 transmission line. Failure to complete this element of the refurbishment project would increase the risk of component failure on L178 resulting in a split in the North-South grid and significant thermal generation costs in the northern gird to maintain supply to all customers."

"The $1.3 million budget will cover the work done in 2021, which is only a portion of the full L178 transmission line refurbishment forecast to cost $8.3 million (costs to be brought into rate base each year as each year's work is completed)."

QUESTION:

a) Please provide the number and duration of outages on transmission line L178 experienced in the last 10 years, on a per annum basis, and the costs incurred due to these outages.

b) Please explain when YEC expects this project to be completed.

c) What is the expected annual frequency and duration of outages due to component failure on L178 if this project is not completed? What costs would YEC continue to incur if the project is not completed? Given the expected frequency and duration, please estimate the additional annual costs resulting from the need for additional thermal generation due to those outages.

ANSWER:

(a)

The number and duration of outages on transmission line L178 experienced in the last 10 years are summarized in Table 1 below.

Table 1: Number and Duration of Outages – 2011 to 2020

Year	Unplanned Outages	Planned Outages	Total Outages	Outage Hours
2011	2	0	2	18.31
2012	2	0	2	1.49
2013	1	0	1	0.19
2014	3	8	11	17.25
2015	4	3	7	5.66
2016	5	5	10	8.5
2017	6	14	20	32.05
2018	6	2	8	69.42
2019	6	0	6	70.15
2020	10	4	14	78.14

The total costs incurred from 2014-2020 due to outages on L178 is $1,213,581 ($782,723 O&M and $430,858 capital). The average annual cost over the period is $173,368. Cost estimate amounts are available for the period from Jan 2014-Dec 2020.[1]

(b)

Not known at this time; remaining works will be allocated to future fiscal periods as resources and priorities warrant.

(c)

There is an expected annual outage frequency due to component failure of 2 – 5 failures per year increasing with the age of the line. Outage duration can be anywhere from 1 day to a week or more depending heavily on access. Access is much more of an issue in an unplanned event.

Unplanned repairs cost substantially more. A helicopter charge of $3500 – $7000 is typical on L178 just to locate the failure that caused the outage. In a planned scenario crews are on site with materials and civil work complete.

Diesel costs during summer conditions to run the town of Faro are approximately $300/hour. It usually takes at least 24 hours to respond and complete a repair on a simple

[1] New financial software implemented in late 2013.

failure with reasonably good access. A difficult repair with challenging access could take up to a week or more. Consequently, diesel cost per event would likely be in the range of $7,200-$36,000.

On planned maintenance projects Civil & Mob costs would normally be divided over many structures. In an unplanned failure, Civil & Mob costs for a challenging repair can easily be $25,000 - $40,000 or more for a single structure. The type of failure could be a broken cross arm or structure. A failure in easily accessed locations would have a civil cost usually of $10,000 or less.

Labour and Equipment and Travel cost for the onsite structure repair are about $16,500 for a 12 hour work day during the regular work week. 1 – 2 days of full crew for onsite and preparation/monitoring

In summary, an unplanned repair estimated cost per event can be from $35,000 to $110,000. With historical 2-5 failures on this line, the costs may range between $70,000 to $550,000 annually. It is noted that the line is aging and the repair costs continue to increase, and YEC expects higher failure rates if the identified issues are not addressed. L178 is geographically located in difficult terrain that provides challenging access to the structures. Depending on the location of the problem, costs and repair durations can escalate quickly.

It is also noted that L178 line protection is not as secure or advanced as the other lines mostly due to the lack of a breaker at Carmacks where the line splits. This protection scheme under certain conditions results in faults on L178 impacting the whole system by splitting the grid at Takhini and Minto substations. This results in significantly more customer outages and longer restoration durations.

A challenging repair in winter would leave a substantial amount of generation unavailable to support grid requirements.

REFERENCE: **Application, Tab 5.2.1.7, page 5-16**

ISSUE: **Breaker Replacement Program Project**

QUOTE: "The project involves replacement of twelve aging circuit breakers in various substations throughout the Yukon, including the replacement of five 34.5 kV Medium Voltage (MV) and five 138 kW High Voltage (HV) breakers. Many of the breakers are 40 years old, replacement parts are not available and any damage to aging components could result in lengthy outages to implement repairs or eventual replacement of a breaker, impacting system reliability. Restricted operation of some breakers and non-routine maintenance are becoming increasingly frequent."

"Replacement of 7 high voltage (138kV) breakers in YEC substations at Aishihik Faro, Riverside and Takhini: this was initiated in 2018 and was to be completed in 2019. The high voltage breaker replacement program was completed in 2019 with a total cost of $2.26 million." (footnote removed)

QUESTION:

a) Please explain how often YEC tested the breakers involved in this project to assess their reliability in the past 40 years and how often maintenance work was required. If possible, please provide the number of times maintenance was conducted on these breakers in the last 10 years, on a per annum basis, and the cost of this maintenance work.

b) YEC stated that five HV breakers were being replaced in one instance of its application and that seven HV breakers were being replaced in another instance. Please confirm the correct number of HV breakers being replaced in this project.

ANSWER:

(a)

Testing frequency of breakers is every 5 years. Costs for the testing are largely labour with a small material component. YEC tests on average 5 breaker per year at a cost of $5000 per breaker, total cost $25,000.

It should be noted that these breakers were 40 years old, spare parts were not available, and any failure of aging components may have led to lengthy outages to repair.

(b)

Seven breakers were replaced in this project.

REFERENCE: **Application, Tab 5.2.1.8, pages 5-17 to 5-18**

ISSUE: **Replacement of the P125 Head Gate Project**

QUOTE: "The P125 Hydro Plant originally commissioned in 1958 … The headgates at the P125 plant are located above the plant at the water intake structure … To date, the headgates have never been overhauled."

"An external engineering firm (SNC Lavalin) performed tests and structural assessments of the P125 headgates in 2019 that indicate that the headgates can no longer be relied upon for emergency closure or for single device isolation. The gates were tested, in a controlled situation, to determine if they would close during emergency conditions and two out of the three gates did not close. This failure could result in a unit runaway / over-speed that could potentially cause severe damage to the unit as well as the plant."

"The scope of the project includes the removal of existing headgates, design and installation of new headgates and control systems, and refurbishment of the headgate hoist mechanism. YEC tendered and proceeded with work on the WH2 headgate in 2020 … It is expected that the WH2 headgate will be completed in 2020 at a forecast cost of $2.3 million."

"… is assessing team capacity to complete replacement and refurbishment of the gates and related infrastructure for units WH1 and WH3 in 2021 … and that the WH1 and WH3 headgates will be completed in 2021 at a forecast cost of $3.5 million."

QUESTION:

a) Please explain how often YEC tested out the headgates at the P125 Hydro Plant in the past to assess their reliability and how often maintenance work was required. If possible, please provide the number of times maintenance was conducted on the headgates in the last 10 years, on a per annum basis, and the cost of this maintenance work.

b) Please provide the tests, structural assessments and any other studies conducted to show that the headgates could no longer be relied upon.

c) Please provide and explain the studies conducted to mitigate the concerns brought on by the existing headgates. For example, how was the design of new headgates and control systems carried out, and how was the preferred solution reached? Please describe the results of the assessment in which it was determined that work on the WH2 headgate needed to be carried out before work on the WH1 and WH3 headgates.

d) Please indicate whether work for the WH2 headgate was completed in 2020. Did YEC staff complete this portion of the project, or was an external consultant required? If an external consultant was required, please provide details on the selection process of the contractor and how costs were awarded.

e) Please provide an update on the work currently completed for the WH1 and WH3 headgates. For example, what objectives have been met so far, and is YEC expecting this portion of the project to be completed by 2021? Additionally, will YEC complete this portion of the project, or will an external consultant be required?

ANSWER:

(a)

The head gates are used annually during the hydro planned maintenance. There is annual maintenance on the hoist motors (grease/oil) and regular pulley inspections. Cost for this maintenance is less than $5,000.

(b)

Please see Attachment 1 and Attachment 2 to this response which provides reports from SNC regarding the inspection and assessment of the P125 Headgates.

(c)

Studies determined that the P125 Headgates are not certifiable for Single Device Isolation. Tests determined the headgates could not close fully in an emergency. Additional

concerns were the reliability of the hoist and controls. The new gates, hoist controls and refurbished hoist addressed each of these concerns. WH2 was selected to be done first because of the upcoming WH2 Uprate and the need for reliable means of isolation.

The P125 Headgate Assessment report is provided Attachment 1 to YUB-YEC-1-56(b). The inspection report from SNC regarding the inspection and assessment of the P125 Headgates is provided as Attachment 2 of YUB-YEC-1-56(b).

(d)

The WH2 Headgate Project was completed in 2020. The work was carried out by a prime contractor selected through an RFP process.

The RFP was issued and posted publicly through MERX. Two bids were received and were evaluated. A best value approach was taken with points awarded based on the following criteria: technical, cost and FN content. The Proponent with the highest total score was recommended.

(e)

YEC will complete the preliminary design and tendering of the WH1 and WH3 headgate in 2021 for project completion in 2022. YEC will engage an engineering firm for assistance with this process.

SNC·LAVALIN	Technical Report P125 Headgate Assessment	Page 1 of 14 Date: Sept. 4, 2019
CLEAN POWER	654773-3000-45E4-0001	Revision No.: 0

OWNER: ***Yukon Energy Corporation***

PROJECT: ***WH2 Uprate Project***

PROFESSIONAL ENGINEER
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SEPT. 4, 2019

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REVISION INDEX

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1.0 INTRODUCTION

1.1 General

Yukon Energy Corporation's (YEC) P125 hydroelectric generating station was constructed in 1958 on the Yukon River in Whitehorse, Yukon Territory. The original plant included two double-regulated Kaplan turbine-generators (WH1 and WH2) each with a capacity of 5.8 MW. The powerhouse was extended in 1969 to add a third 8.4 MW propeller type unit (WH3). The power intakes for the three units are located at the end of a 600 m long approach channel located on the left side of the dam and spillway. Three penstocks connect the power intakes to the powerhouse.

The intake structure includes stoplogs and emergency closing headgates for each unit. One set of stoplogs is available to isolate any one of the three units. Each unit has an emergency closing headgate and dedicated wire-rope hoist. Headgates for units WH1 and WH2 were installed in 1958 with the original construction, while the third intake was left otherwise blocked. The third headgate (for unit WH3) was added in 1969 along with the addition of the third turbine-generator unit. Since their original installation it is understood that the headgates have not undergone any major maintenance or repair works. The headgates are intended to provide isolation for safe work downstream, and to close against flow in case of emergency.

Photograph 1 - WH1 Headgate Inspection Position

The WH2 turbine-generator unit is to be refurbished and "uprated" in year 2021. As part of its mandate as Owner's Engineer for the WH2 Uprate Project, SNC-Lavalin Inc. (SLI) was asked to review the condition of balance-of-plant equipment related to the WH2 unit and define the scope for required upgrades. This work identified that a detailed assessment of the headgates was required. The three intakes are identical apart from age and minor design differences of the WH3 headgate. As such, the scope for headgate assessment was extended to include the WH1 and WH3 intake headgates.

Inspections of the three headgates were completed by SLI and YEC in May and June 2019. Following the inspections, SLI analysed stresses in the headgates with consideration of the as-found conditions of each gate. This technical report documents the results of the inspections and analysis and makes recommendations based on the findings.

1.2 Purpose

The objective of the assessment is to verify if the P125 headgates and hoists are fit for purpose in their current condition, and to define the scope of work required to either refurbish and/or replace equipment as necessary. Where appropriate, the assessment considers the estimated costs for both refurbishment and replacement options.

1.3 Key Parameters

WH1 / WH2 Headgates:	
Design/Manufacture	Dominion Bridge
Gate type	Fixed-Wheel Vertical Lift
Year of manufacture	1958
Fabrication method	Riveted
Height – Clear opening	4.11 m
Height – To lintel seal	4.15 m
Width – Clear opening	3.81 m
Width – Seal to seal	3.94 m
Width – Wheel to wheel	4.18 m
Elevation of sill	641.91 m
Original design maximum head	10.67 m
Normal operating maximum head*	11.19 m
Material	ASTM A36
Gate mass (including concrete ballast)	8050 kg

WH1 / WH2 Headgate Hoists:	
Design/Manufacture	Dominion Bridge
Hoist type	Wire-rope
Capacity	12700 kg
Hoisting speed	2.1 m/min
Lowering speed	3.4 m/min
Power supply	550 V / 3 ph. / 60 Hz
Rated motor capacity	5.6 kW
Control panel voltage	125 VDC

* Units are routinely operated at heads that exceed the original design values.

WH3 Headgate:	
Design/Manufacture	Dominion Bridge
Gate type	Fixed-Wheel Vertical Lift
Year of manufacture	1969
Fabrication method	Welded
Height – Clear opening	4.11 m
Height – To lintel seal	4.15 m
Width – Clear opening	3.81 m
Width – Seal to seal	3.96 m
Width – Wheel to wheel	4.18 m
Elevation of sill	641.91 m
Original design maximum head	10.67 m
Normal operating maximum head*	11.19 m
Material	ASTM A36
Gate mass (including concrete ballast)	8050 kg
WH3 Headgate Hoist:	
Design/Manufacture	Dominion Bridge
Hoist type	Wire-rope
Capacity	13600 kg
Hoisting speed	1.2 m/min
Lowering speed	3.0 m/min

Power supply	550 V / 3 ph. / 60 Hz
Rated motor capacity	3.7 kW
Control panel voltage	115 VAC

* Unit is routinely operated at heads that exceed the original design values.

1.4 Reference Documents

Document Number	Title
TK1081.B2.W9.27	Specification for Headgate and Stoplog Equipment
NCP 9879	Intake – General Layout
E51563	WH1 / WH2 Headgate Assembly Drawing
E52304	WH1 / WH2 Headgate Hoist Assembly Drawing
M0186-1	WH3 Headgate Assembly Drawing
M0187-L1	WH3 Headgate - Details
M0188	WH3 Headgate Hoist Assembly Drawing
Memo – J Vines to G Dunbrack, June 24 2019	P125 / WH2 Headgate Inspection
Memo – C Kasongo to G Dunbrack, Aug 09 2019	P125 / WH1, WH3 Headgate Inspection

2.0 METHODOLOGY

The following sections describe the methods used in the various aspects of the headgate assessment.

2.1 Condition Assessment

Inspections of all three headgates were completed in May and June of 2019. The headgates were raised to their highest position possible using their wire rope hoists. Gate inspections included:

- Cleaning of headgates
- Visual inspection of gate structural steel and connections
- Dimensional measurements
- Corrosion pitting measurements
- Visual inspection and measurement of rivet condition

- Visual inspection of one-wheel bushing condition (WH2 gate only)
- Ultrasonic thickness measurements
- Magnetic particle inspections

Gate guides were inspected by YEC using a remote operated vehicle, with video recording.

The headgate hoists were visually inspected and observed during operation.

Notes, photographs, and measurement results from the inspections were recorded and documented in memoranda.

2.2 Gate Stress Analysis

Calculations were prepared to estimate the normal stress in the structural elements of the headgates in their current condition. The calculations consider the measured thickness of structural elements and ultrasonic checks were completed during the inspections. A reservoir level of 653.1 m is assumed in the analysis based on the maximum normal operating range observed at P125. At this stage, the analysis does not consider seismic or flood conditions, as it is only preliminary. A more detailed analysis should be done at the next stage.

The analysis was performed using the allowable stress method, with the allowable tensile stress defined as 60% of yield strength and the allowable shear stress defined as 2/3 of the allowable tensile stress. These limits are within the normal range of allowable stresses used in the industry, as summarized in the following table.

Standard	Allowable Tensile Stress
P.F. Erbisti, Design of Hydraulic Gates (2014)	68% S_y
ASME Boiler and Pressure Vessel Code	67% S_y
CAN/CSA S16	60% S_y
DIN 19704-1976	60% S_y
BC Hydro Design Standard H2124/H2676	54% S_y
US Army Corps of Engineers EM 1110-2-2105	50% S_y

S_y = Yield strength

Where possible, the allowable stress was defined based on material test results. For WH1 and WH2 this was done based on a coupon sample tested in 2010. Material test data was not available for the WH3 headgate so a minimum yield strength based on the ASTM standard (A36) was assumed.

Calculations included:

- Bending stress, shear stress and deflection in horizontal girders according to methods of Erbisti (2014)
- Skinplate stress according to DIN 19704 – 1976

- Vertical end-girder bending and shear stress approximated as a simply supported beam
- Wheel contact stresses according to Erbisti (2014)
- Wheel axle shear stress assuming simple support
- Wheel bushing stress according to Erbisti (2014)

Stress in the skinplate was calculated with plate thickness determined by the UT measurements and also with consideration of reduced thickness due to area-averaged pitting corrosion depth.

2.3 Hoist Analysis

Calculations were prepared to check the adequacy of the hoist capacity and to verify the wire rope loads are acceptable. The estimate of hoist loads included the calculation of buoyancy, wheel friction, seal friction, and hydraulic downpull. Wheel friction and seal friction calculations were based on the methods presented in Erbisti (2014).

The hydraulic downpull was approximated based on a simplified method presented in Erbisti (2014) wherein a downpull factor (k) is multiplied by the product of the gate cross-sectional area and the hydrostatic pressure on the gate. The k-factor was assumed at 0.2 based on a review of gate lip designs and model test data presented by Erbisti.

The capacity of the wire rope was checked against the required hoisting loads. The wire rope strength was taken from the Machinery's Handbook according to the rope type specified on the hoist assembly drawings.

3.0 RESULTS

3.1 Condition Assessment Results

The results of the headgate inspections were presented in memoranda (see Section 1.4 herein). In summary, the WH1 and WH2 headgates were found to have significant corrosion on the skinplate (primarily the upstream side), the webs of horizontal girders, and somewhat less corrosion on vertical end-girders. Although the thickness of the skinplate was found to be greater than as shown in the drawings, corrosion pitting on the skinplate was measured to depths exceeding 4 mm. The heads of rivets were found to have varying levels of corrosion, with some rivet heads in good condition and others heavily corroded. The shaft of rivets inspected were found to have no corrosion. Wheels and wheel bushings were found to be in good condition. The dimensions of the gate were found to match the design drawings, with the exception of the skinplate thickness. Magnetic particle inspections did not identify any cracks in the areas inspected, including rivet hole locations, drainage holes in horizontal girder webs, wheel axle holes in vertical end-girders, and in the inspected wheel bushing pin.

In comparison, the WH3 headgate was found to be in much better condition. The extent of inspection was limited to the top section of the gate, as a result of the limit switches on the hoist limiting travel. However, from inspection of the top section it was found that there was much less corrosion than the WH1 and WH2 headgates. Again, the skinplate thickness was found to exceed what is shown on the design drawings. Welds, to the

extent that they could be visually inspected, appeared to be in good condition. Wheels appeared in good condition although were found to not turn as easily as those on the other headgates. Measured dimensions were found to match the design drawings, with the exception of the skinplate thickness. Magnetic particle inspections did not find any cracks in the areas inspected.

The gate guides of WH2 appeared from the ROV videos to be in good condition. Some roughness due to corrosion appears to be present, although it is difficult to quantify from the video. The condition of guides on WH1 and WH3 could not be clearly ascertained from the videos, but they are expected to be in similar condition.

The wire ropes of all three gate hoists were observed to have some corrosion and wear. It is not clear from the available maintenance history whether the ropes have been replaced since the original installation. The gearbox of the WH2 hoist was inspected and the gears found to be in good condition. Greasing points on all three hoists showed signs of recent greasing and maintenance staff report that regular greasing is part of normal maintenance schedules. Operation of the wire rope hoists was observed to be smooth and trouble-free. The local control panels for all three gate hoists are using outdated technology and are expected to be at or beyond their design life.

3.2 Gate Stress Analysis Results

The main results of the stress analysis for the headgates are summarized in the following table. Where multiple elements (girders, skinplate sections, etc.) were evaluated the maximum calculated stresses are shown. Although the WH3 headgate was found to have little corrosion, a nominal reduction in thickness of 0.5 mm was assumed to be conservative.

Description	**Percent of Allowable Stress**			
	WH1 / WH2 Headgates		**WH3 Headgate**	
	Original Plate Thickness	Thickness After Corrosion	Original Plate Thickness	Thickness After Corrosion
Horizontal girder – Bending	74%	n/a	92%	n/a
Horizontal girder – Shear	38%	65%	48%	54%
Skinplate stress	139%	172%	148%	162%
Vertical end-girder – Bending	55%	n/a	58%	n/a
Vertical end-girder – Shear	25%	n/a	29%	n/a
Wheel contact stress	56%	n/a	56%	n/a

Description	Percent of Allowable Stress			
	WH1 / WH2 Headgates		WH3 Headgate	
	Original Plate Thickness	Thickness After Corrosion	Original Plate Thickness	Thickness After Corrosion
Wheel axle shear	16%	n/a	16%	n/a
Wheel bushing	35%	n/a	35%	n/a
Rivet tension	66%	n/a	n/a	n/a
Rivet shear	89%	n/a	n/a	n/a

The summary table shows that most elements of the gates are within allowable stress limits, except the skinplates which have stresses far exceeding the allowable stress. After consideration of thickness reduction due to corrosion, the stress in the WH1/WH2 skinplates slightly exceeds the tested yield strength of the material.

3.3 Hoist Analysis Results

The hoist load calculations found a maximum hoist load of approximately 15,600 kg, which exceeds the rated capacity of the hoists. This hoist load is estimated for the condition of lifting the gates to their filling position when the downstream water passage is dewatered. As noted in Section 2.3, the hydraulic downpull on the gates is approximated according to a simplified method, therefore there is some uncertainty in the estimated maximum hoist load.

The capacity of the wire ropes was found to have a factor of safety of 4.6 over the calculated maximum hoist load. Industry standard requires a minimum factor of safety of 5.0.

4.0 DISCUSSION

4.1 Refurbishment / Replacement Options

Due to the extensive corrosion pitting damage observed on the WH1 and WH2 headgates refurbishment is not seen as a practical option. Extensive welding work would be required to repair the corrosion pitting damage. Additional stiffeners would need to be added to reduce the skinplate stress. Due to the condition of rivets all the rivets would need to be removed and replaced by welded fabrication. With such extensive work a careful program of dimensional control would need to be put in place. As such, there is no advantage seen in refurbishing these gates as compared to replacing them.

The WH3 headgate was found to be in good condition and therefore refurbishment is possible. The high stresses found in the skinplate can be addressed by the addition of vertical stiffeners midway between the existing vertical stiffeners. This would lower the skinplate stresses into the allowable range. Refurbishment would include sandblasting and recoating the gate.

Based on the video inspections it is expected that the embedded guides for all three gates can be refurbished. Work should include detailed inspection and measurement, followed by machining if/as necessary to achieve typical flatness and verticality.

Refurbishment of all three headgate hoists is possible. Wire ropes should be replaced with new wire ropes, which would provide an increased safety factor due to improvements in wire rope strength since the original equipment was supplied. Other hoist components can be dismantled, cleaned and greased. Gearbox oil should be drained, gears cleaned, and refilled with oil.

The local controls for all three wire rope hoists should be replaced with modern control systems. Instrumentation (limit switches) on the hoists should be replaced due to age.

4.2 Cost Estimates

The costs for the refurbishment (where appropriate) and replacement of the equipment were estimated by scaling from recent projects and similar market quotations recently obtained. In some cases the costs were estimated by SNC and YEC based on calculated quantities and estimated unit rates and labour. Budgetary quotations were requested from vendors but none were able to provide the estimates at time of reporting due to seasonal resource limitations. The cost estimates are summarized in the following table.

Equipment	Refurbish Cost	Replace Cost
WH1 and WH2 Headgates	n/a	$465,900
WH3 Headgate	$150,000	$233,000
Embedded Parts Repair x3	$656,300	n/a
Wire rope hoists c/w controls x3	$645,600	$855,000

The accuracy of the estimates is at the level of an AACE Class 4 estimate.

4.3 Outage Costs

It will be necessary to shut down the units while work is being done on the headgates and hoists. As such, consideration was given to the evaluation of outage costs (lost generation) for the refurbishment and replacement options. Gate refurbishment options would require removal of the gate(s) to a shop for a period of time during which the respective unit must be out of service. In comparison, gate replacement options would require shorter duration outages since the new gate would be ready to install earlier.

Refurbishment of the WH1 and WH2 headgates is not practical as mentioned in Section 4.1, therefore associated outage costs will not be evaluated.

It is understood that there are times of the year when the WH3 generating unit is not typically used and therefore outage costs are insignificant (no lost generation). If the work is planned for a period of time when the unit is not scheduled for operation, then the outage costs do not need to be considered in the evaluation of options.

It is anticipated that refurbishment of the headgate hoists would be completed during the same outage as the gate refurbishment/replacement work. As such, the costs of outage do not factor into the decision to refurbish or replace the hoists.

4.4 Engineering Costs

An estimate of engineering hours was used to establish a budget for engineering related to the headgate works. This would include detailed tender design and analysis, drafting, preparation of procurement specifications, tender support, review of vendor shop drawings and submittals. For replacement of all three headgates plus refurbishment of the hoists and upgrades of the controls, the engineering costs are estimated as follows:

Mechanical Engineering Hours	400
Electrical Engineering Hours	210
PM / Administrative Hours	120
Total Cost	$85,000

If the WH3 headgate is refurbished rather than replaced then an additional 250 mechanical engineering hours would be required. The total cost in that case would be $114,000.

4.5 Shop Inspection and Field Inspection Costs

In case YEC wishes to engage an engineering consultant or a third party to carry out shop inspections and field inspections, for installation and commissioning, the associated costs are estimated as under:

Hours for Mechanical Inspections	160
Hours for Electrical Inspections (including commissioning supervision)	60
PM / Administrative Hours	40
Expenses (travel and stay)	$14,000
Total Cost	$45,000

The hours and expenses for inspections are tentative and based on initial planning for replacement/refurbishment works. These costs can be confirmed after YEC's planning for inspections is determined and schedule for replacement/refurbishment works is firmed up.

5.0 CONCLUSION AND RECOMMENDATIONS

The assessment has shown that the stresses in all three headgate skinplates are far beyond the acceptable limits. As such, the headgates should not be relied upon to isolate the water passages for the purpose of worker access. If personnel access in the water passage is required then the stoplogs must be used, or the headgates could be safely used at a reduced water level (approximate elevation 649 m).

Refurbishment of the WH1 and WH2 headgates is not practical due to the extent of corrosion. These gates should be replaced.

The wire rope hoists can be effectively refurbished (and local controls replaced) for a lower cost than replacement with new hoists. As such, this option is preferred over providing completely new wire rope hoists.

The WH3 gate could either be refurbished or replaced. This then yields two options for the project scope: ***Option A*** would include refurbishment of the WH3 headgate and ***Option B*** would consider replacement of the WH3 headgate. Both options would include replacement of the WH1 and WH2 headgates, refurbishment of all three wire rope hoists, and replacement of the local control panels. The costs are summarized as follows:

Scope Item	Option A	Option B
WH1 and WH2 Headgates – Replacement	$465,900	$465,900
WH3 Headgate	$150,000	$233,000
Embedded Parts Repair x3	$656,300	$656,300
Wire rope hoists c/w new controls x3 - Refurbishment	$645,600	$645,600
Engineering	$114,000	$85,000
Shop Inspection and Field Inspection Costs	$45,000	$45,000
Total Cost	**$2,076,800**	**$2,130,800**

The cost estimates above are Class 4 estimates and exclude all owner's costs, taxes, bonds, risk, contingency and other indirect costs.

The costs for the two options are within 5% of each other. It is worth noting that although Option A is less expensive, there is more risk involved. Risks would include the potential of finding the gate to be in worse condition than expected when it is fully removed from the slot, and the risk that extended duration of in-shop gate refurbishment would result in delays to the outage period.

Additionally, replacement of the WH3 headgate will result in a longer service life for the equipment when compared with refurbishment. Option B appears favourable, considering that the cost estimates for both options are close in value, and it involves less risk of cost and schedule variation and may result in a longer service life.

Further evaluation should be done to obtain more certainty on costs for the two options by obtaining budget quotations from several vendors. That work can be done in parallel with the engineering required to support the final procurement activities.

SNC Lavalin Inc.
Suite 500 –745 Thurlow Street
Vancouver, BC, Canada, V6E 0C5
604.662.3555 604.331.4644

Memorandum

To: **Geoff Dunbrack, P.Eng., Yukon Energy Corporation**

Cc.: **Manzoor Qadir, P.Eng., Yukon Energy Corporation**

Date: **August 9, 2019**

From: **Cyril Kasongo, P.Eng.**

Subject: **P125 / WH1 & WH3 Headgates Inspection**

1 INTRODUCTION

On June 26-28, 2019 YEC and SNC-Lavalin carried out inspections of WH1 and WH3 headgates at YEC's P125 hydroelectric facility. An inspector from TEAM Industrial Services (TISI Inc.) was on site to provide non-destructive testing (NDT) services for the inspection. In addition, YEC self-performed an underwater inspection of the WH3 headgate guides using a remote-operated vehicle (ROV).

This memo documents the observations gathered during the inspections. It also serves as an addendum to previously released WH2 headgate condition assessment memorandum (ref. "P125 / WH2 Headgate Inspection").

2 WH1 HEADGATE INSPECTION

2.1 Inspection Setup

The WH1 headgate was lifted above the concrete intake deck using its dedicated hoist system. The hoist drum was dogged and locked-out in position to secure the headgate's position during the inspection. Due to intake configuration, the bottom section of the gate body remained enclosed within the intake "dog-house"; thus, not entirely accessible for inspection.

Rolling scaffold was set up on the upstream side of the gate to provide safe access. Fall-arrest anchors were set up on the concrete hoist tower structures above the work area and harnesses were worn by participants whenever working at height.

The inspection position of WH1 headgate is shown on Photo 1.

Measurements on the gate skin-plate were referenced according to the diagram shown on Figure 1.

Photo 1 *– WH1 Headgate Inspection Position (looking downstream)*

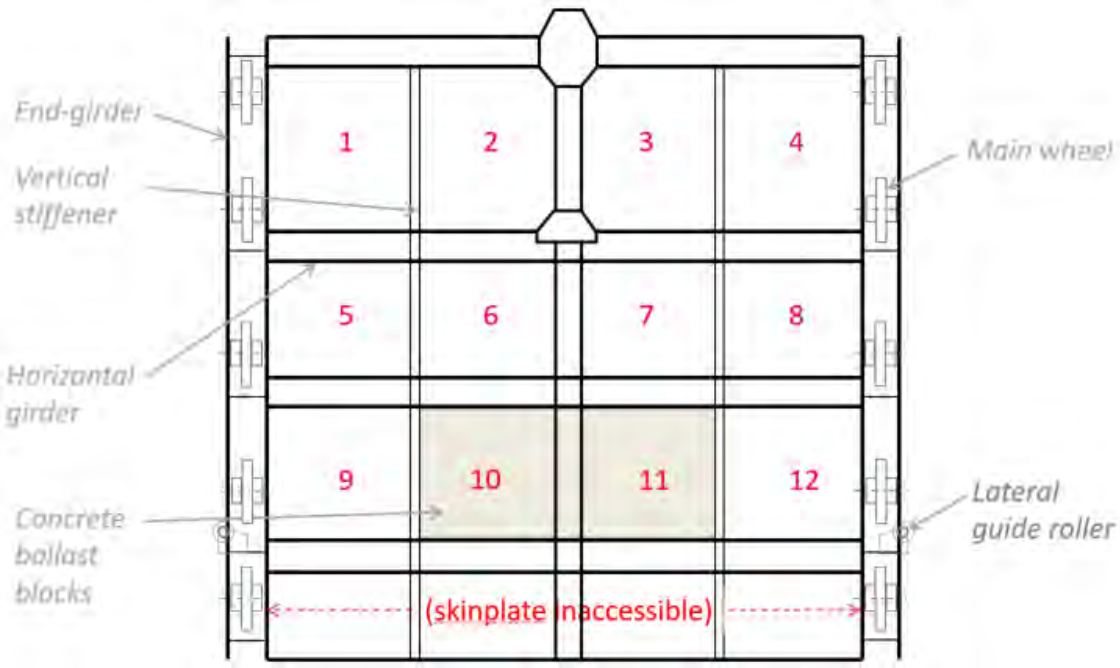


Figure 1 *– WH1 Headgate – Skin-plate Reference Diagram (looking downstream)*

2.2 Dimensional Checks

WH1 headgate dimensions were verified by YEC against historical design drawing E51563 shown in APPENDIX A. Measurements were taken with a typical construction-grade measuring tape. No significant deviations from the design drawing were identified. However, NDT inspection later revealed some discrepancies on the skin-plate wall thickness (see Section 2.4 NDT Inspection).

2.3 Corrosion Pitting Measurement

Corrosion products and tubercles were densely observed on all areas of the WH1 headgate body. More particularly on: the upstream side of the skin-plate, the webs of the horizontal girders, the end girders, and the rivet heads. Overall, the WH1 headgate condition was very similar to WH2 headgate (if not slightly more damaged by corrosion).

Given strong similarities between WH1 and WH2 headgates condition, YEC/SNC-Lavalin decided to perform pitting measurement only on the two most corroded skin-plate panels; i.e. areas #4 and #6 per Figure 1 reference diagram.

In order expose pit cavities and proceed with measurements, YEC personnel performed:

i. Pressure washing of the headgate to remove sediment and mud deposits; followed by

ii. Localized grinding of the headgate surface to remove rust built-ups and tubercles.

Trough-type corrosion pits of various shapes were revealed including: narrow pits, deep pits; shallow pits, wide pits, and elliptical pits. A calibrated bridge-cam gauge was used to measure pitting corrosion depth. Measurements and photographs (skin-plate panels #4 and 6#) are shown in APPENDIX B.

The following table summarizes the corrosion pitting measurements for the WH1 headgate:

Skin-Plate Area Ref.	Approximate Percent Pitted area	Largest Single Pitted Area	Maximum Pitting depth	Typical Average Pitting Depth within Pitted Areas (estimate)
#4	20%	≈ 8” x 6”	6 mm	2.875 mm
#6	20%	≈ 6” x 9”	3 mm	2.416 mm

Table 1 – *Summary of skin-plate corrosion pitting measurements for WH1 headgate*

Average pitting depths in areas #4 and #6 of WH1 headgate (respectively 2.8mm and 2.4mm) are superior to measurements on WH2 headgate’s worst corroded panel (approximately 2.0mm).

2.4 NDT Inspection

Ultrasonic testing (UT) measurements were performed on the following structural members of the WH1 headgate: skin-plate, horizontal girder web, and end-girder web. Skin-plate wall thickness records ranged from 0.375 inches to 0.449 inches. The average measured thickness is 0.420 inches; i.e. 0.045” thicker than what is shown on historical design drawing E51563 showing 0.375”.

Magnetic particle (MP) inspection was also carried out to check for cracks in randomly selected structural joints, rivet heads and adjacent base material. No cracking was observed.

Detailed examination reports for UT and MP inspections have been prepared by TISI Inc. technician and included in Appendix C.

2.5 Wheel Inspection

The accessible main wheels of WH1 headgate (8 out of 10) were checked for rotation. They were found to be stiff and hard to turn by hand. The rolling surface of the wheels showed signs of roughening as well as corrosion (small tubercles) extending to the wheel axles.

The lateral guide rollers of WH1 headgate (2 out of 2) were also checked for rotation. They were found to be seized/stuck on their axle and unable to operate. The surface of the rollers showed heavy signs of deterioration including densely distributed rust and corrosion tubercles.

See pictures below compiled for reference.

Main wheel @ (Row 2, Right Bank)

Main wheel @ (Row 4, Left Bank)

Main wheel @ (Row 3, Left Bank)

***Photo 2** – WH1 Main Wheels Condition*

WH1 left bank guide roller

WH1 right bank guide roller

***Photo 3** – WH1 Lateral Guide Rollers Condition*

3 WH3 HEADGATE INSPECTION

3.1 Inspection Setup

Due to inability to bypass the gate hoist limit switch, the WH3 headgate could not be fully lifted above the concrete intake deck. The body of the gate remained partially submerged in water and enclosed within the intake “dog-house”. Hence, inspection was limited to the upper section of WH3 headgate (approximately 1/4 of vertical height).

The hoist drum was dogged and locked-out in position to secure the headgate’s position during the inspection.

The inspection position of WH3 headgate is shown on Photo 4.

Measurements on the gate skin-plate were referenced according to the diagram shown on Figure 2.

Photo 4 *– WH3 Headgate Inspection Position (looking downstream)*

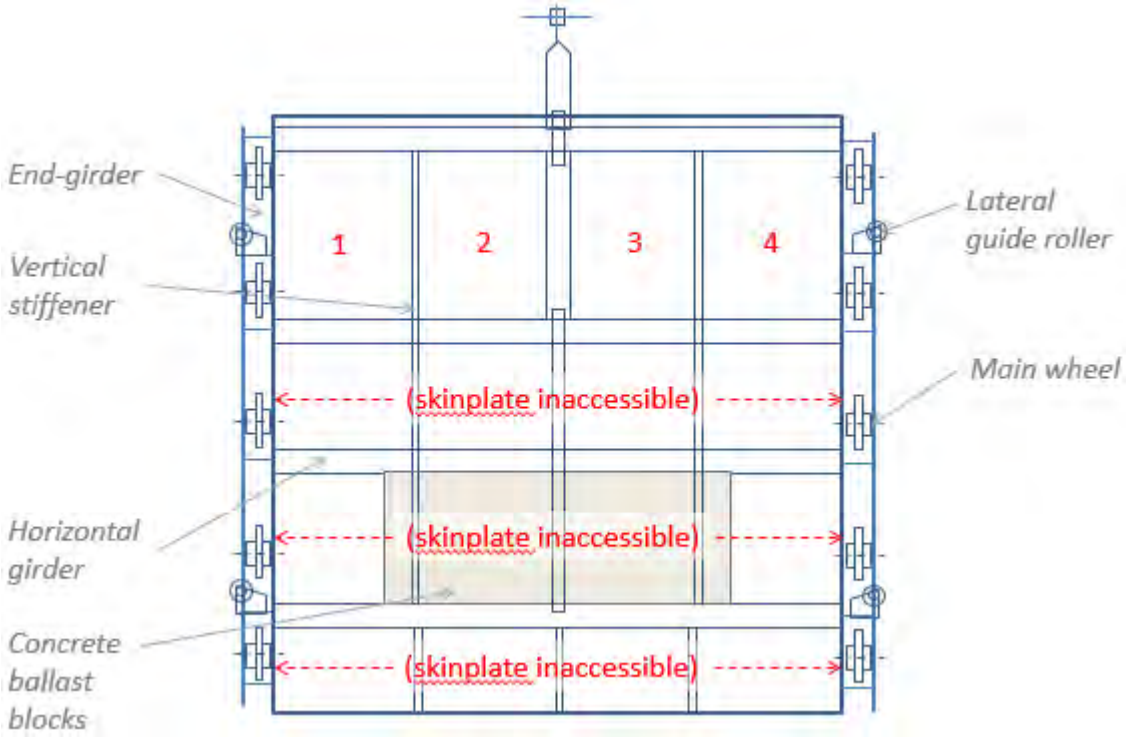


Figure 2 *– WH3 Headgate – Skin-plate Reference Diagram (looking downstream)*

3.2 Dimensional Checks

WH3 headgate dimensions were verified by YEC against historical design drawing M0186-1 shown in APPENDIX D. Measurements were taken with a typical construction-grade measuring tape. No significant deviations from the design drawing were identified. However, NDT inspection later revealed some discrepancies on the skin-plate wall thickness (see Section 3.4 NDT Inspection).

3.3 Corrosion Pitting Measurement

WH3 headgate was found to be in relatively good condition in comparison with WH1 and WH2 headgates, both severely corroded. Rust and wear spots were observed in low to moderate quantity; no signs of pitting corrosion (i.e. tubercles) were revealed on structural members of WH3 headgate.

Top View (Left Bank)

Front View (Right Bank)

Photo 5 *– WH3 Headgate Overall Surface Condition*

3.4 NDT Inspection

Ultrasonic testing (UT) measurements were performed on the following structural members of the WH3 headgate: skin-plate, horizontal girder web, and end-girder web. Skin-plate wall thickness records ranged from 0.431" to 0.461". The average measured thickness is 0.447" (against 0.375" on historical design drawings).

Magnetic particle (MP) inspection was also carried out to check for fatigue/stress cracks. As there are no rivets on WH3 headgate (welded construction), testing was made on a dozen of weld samples. No cracking was observed.

Detailed examination reports for UT and MP inspections have been prepared by TISI Inc. technician and included in APPENDIX E.

3.5 Wheel Inspection

The accessible main wheels of WH3 headgate (2 out of 10) were checked for rotation. They were found to be easily rotating when being turned by hand. The rolling surface of the wheels showed normal signs of roughening. The wheel axles showed more advanced signs of wear including coating flaking and surface rust.

The lateral guide rollers of WH3 headgate (2 out of 4) were also checked for rotation. They were found to be seized/stuck on their axle and unable to operate. The surface of the rollers showed heavy signs of deterioration including densely distributed rust and corrosion tubercles.

See pictures below compiled for reference.

WH3 Main Wheel @ (Row 1, Right Bank)

Photo 6 *– WH3 Main Wheels Condition*

WH3 left bank guide roller

WH3 right bank guide roller

Photo 7 *– WH3 Lateral Guide Rollers Condition*

3.6 ROV Inspection

Underwater inspection was carried out by YEC using their own Remotely Operated Vehicle (ROV). Video record of the inspection provided to SNC-Lavalin and reviewed.

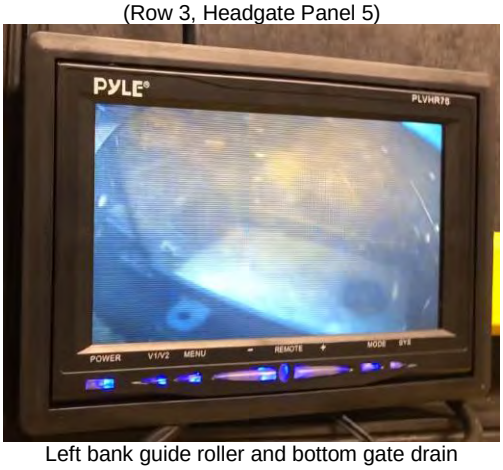
The video generally shows that the WH3 headgate body is in decent condition relative to WH1/WH2 headgates. Localised corrosion spots were observed on structural members but no apparent pits/tubercles.

Unfortunately, the gate guides (wheel and seal paths) could not observed properly due to lack of light and poor visibility. The second stage concrete surrounding the guides appeared to be in good condition with no cracking, spalling or break-out observed in the video.

Snap-shots taken from parts of the ROV video are included shown below for reference. The video files remain on the YEC Sharepoint website.

Localised rust spot on left bank end girder
(Row 3, Headgate Panel 5)

Vertical stiffener showing no signs of rust
(Row 3, Headgate Panel 6)



Left bank guide roller and bottom gate drain
(Row 4, Headgate Panel 13)

Right bank end girder
(Row 4, Headgate Panel 16)

***Photo 8** – WH3 Headgate ROV Inspection Video Snapshots*

4 CONCLUSION

Dimensionally the WH1 and WH3 headgates were found to largely match their respective historical design drawings. Presence of concrete ballasts was also confirmed.

WH1 headgate displayed significant level of deterioration and corrosion comparable to WH2 headgate. Severe pitting corrosion was observed on critical structural members gate (skin-plate, girders, stiffeners, rivet heads) as well as gate wheels and rollers (seized or hardly rotating for the majority). Altougth the WH1 headgate skin-plate is thicker than shown on historical drawings, the wall thickness reduction induced by the observed pitting corrosion will result in higher stresses. Preliminary calculations (and past checks by KCB) have already shown the skin-plate to have higher than typically

allowable stresses. Corrosion observed on the rivet heads puts into question the capacity of the rivets to resist the tensile forces placed on them.

WH3 headgate showed a better overall condition than WH1/WH2 headgates with more reasonable levels of rust build-ups. No signs of pitting corrosion were observed. This may be attributable to the fact that WH3 was built 12 years after WH1/WH2 (1956 vs. 1968); hence with improved materials, coatings and fabrication methods. Another noticeable advantage of WH3 headgate is its welded construction, versus riveted for WH1/WH2. The welds appeared to be in good condition with no cracks revealed during magnetic particle examination.

The measurements taken and recorded in this memo will be used by SNC-Lavalin in their gate stress analysis and considerations for refurbishment/replacement options.

Sincerely,

Cyril Kasongo, P. Eng., PMP
Mechanical Engineer
Clean Power

APPENDIX A WH1 Headgate Historical Drawing (Ref. E51563)

13'-8½" ROLLER CRS.

12'-11 C. TO C. OF SEALS (FREE)

12'-6" CLEAR WIDTH OF OPENING.

¾ DIA. HOLES

FLOW

2 THORNS OF No. 14 SOLID COPPER WIRE IN RUBBER HOSE

HOSE RETAINING CLIPS (13) TO BE PLACED CLOSE TO 8 CSK SCREWS AND BENEATH THE CANVAS STOPWATER.

STOP ROBBIE HOSE HERE

BOTTOM OF GATE

VIEW SHOWING GATE SEAL AND RUBBER HOSE

3x2½x3/8L (CUT)

¾ CLEAR SEAL COMPRESSED

THESE HOLES TO BE DRILLED IN INSTALLATION AT FACE OF PLATE IN HOIST WAY

GENERAL MODIFICATION TO SECTION

SECTION D.D (ENLARGED)

12'-6 HEIGHT OF OPENING

PART No.	QUAN.	MARK No.	DESCRIPTION	MATERIAL	WEIGHT
1	XBIT	K 999.18	18 DIAMOND TO ROLLER	A.C.S.	A1434/P1
2	XBIT	"	5⅝" BD. LUBRIC. BUSHING (243 LUBRICATION)	STORES	A 1434/P2
* 3	XBIT	"	MACHINED FACES, 5⅞ TYPE 304	BRASS	W.I.G.
* 4	4		3⅝ DIA ROLLER PIN, MACHINED ONLY	STEEL	4F.
* 5	3		TOP SEAL 5¾ - 12 3D.	BRASS	A1434/P3
* 6	3		8 OZ. CANVAS SEAL 4" WIDE SCARFED IN REVERSED AT FINAL FIELD ASSEMBLY 3E.	STORES	
* 7	3		BOT SEAL RETAINING BAR 2¾ x ⅜ 3D.	ST'L.	
* 8	3		TOP SEAL BACKING HOSE 1¼ O.D. 3F.	RUBBER	STORES
* 9	3		SIDE SEAL 7" x ½ 3C & 3A	BRASS	A1434/P3
10	3		SIDE SEAL RETAINING BAR 3½ x ⅜ 3A	ST'L.	
11	3		SIDE SEAL BACKING HOSE 1¼ O.D. 3G.	RUBBER	STORES
* 12	3		8 OZ. CANVAS SEAL 4" WIDE SCARFED IN REVERSED AT FINAL FIELD ASSEMBLY 3H.		STORES
* 13	3		HOSE RETAINING CLIP 1" x ⅜ GA. 3E.	BRONZE	STORES
14	4		SIDE GUIDE ROLLER ASSEMBLY		4A, 4B
	4		5¾ DIA. ROLLER	M.S.	4D.
	4		¾ DIA. ROLLER PIN	MACH. ST.	4C.
*	4	BILL ONLY	A-2001 OILITE BUSHING 1 7/16 x 2⅝ x 2¼ LG.	BZ.	STORES

NOTE

ITEMS MARKED THUS * TO COME FROM OUR LACHINE PLANT STORES AND TO BE SHIPPED DIRECT TO OUR VANCOUVER PLANT.

MARK SHIPMENT: D. B. CO. LACHINE, CONT.# A1434
D. B. CO. VANCOUVER, CONT.# M0006

C

¾ BOT PLATE

1-4

B

D

D1

18@55 BR.I. ◇

8@13⅞"C

1A

18@55 BR.I. ◇

20 DIA DRAIN HOLE

◇ 18@55 BR.I CUT

2-5½x3½x3/8L

¾ SKIN PL

6x3½x3/8L

Burn 4½ HOLE IN ⅜ BEAM WEB

⅜ FILL

18@55 BR.I ◇

4½ HOLE

20 DIA DRAIN HOLE

3½x3½x3/8L ALTERNATE

◇ 24 @ 79.9" (CUT)

8@13⅞"C

1B

6'-6" CONCRETE BY PURCHASER. TOTAL = 35 CU. FT REQUIRED
WEIGHT = 4880 LBS

4 MAX PITCH PTCH'ED TO WHEELS

6" MAX PITCH

7

18@55 BR.I ◇

¾ DIA HIGH STRENGTH BOLTS WITH HARDENED WASHERS @ MAX. PITCH. NUTS TO BE ON THE INSIDE

6" CENTRE HOLE

8 DIA VENT HOLE

DOUBLING BEAM CAN BE PLACED WHERE IF NECESSARY

PAINT

PAINT

PAINT

PAINT

3 MAX FILLET WELD

PLANE BOTH PLATES TRUE & SQUARE

14'-10½" IN CANS

V. LEADING DOWNSTREAM

NOTE:-

END GIRDERS & HORIZONTAL GIRDERS ARE TO BE ASSEMBLED TOGETHER IN SHOP WITH ¾ DIA BOLTS IN 18 DIA HOLES.

WHEN END GIRDERS HAVE BEEN TRULY ALIGNED WITH EACH OTHER AND WITH THE GATE, THE HOLES IN THE CONNECTING ANGLES IN THE END GIRDERS & IN THE HORIZONTAL GIRDERS ARE TO BE REAMED IN SHOP TO 18.0 FOR ¾ RIVETS

FACE OF ROLLER PATH

4 TOP SEAL (FREE)

TOP BEAM

10 x ¾ PL

MACHINE THIS EDGE FOR WORKING FACE

16 x ⅜ PL

4"x3"x⅜L (CUT 5'-3½")

2-5½x3½x3/8L

BOTTOM OF GATE MUST BE IN THIS PLANE (STRAIGHT LINE) AFTER ASSEMBLY

BOTTOM OF GATE TO ℄ OF TOP SEAL (FREE) 13'-7"

BOTTOM TO CLEAR BUSED HOLE

FLOW

PLUG CAPS DENTED PAIN "DATED" TO CONTINUED SEALING STRIP

½ DIA BOLT WITH HEX NUT & LOCK WASHER

3.0 P. EXISTS TO CLEAR ROLLER HEB

8-4½-21

½ SHIMS

1'-10½" GAUGE

BUTT WELD

SECTION B.B

C.G. OF GATE

8¾

FACE OF ROLLER PATH

6

BORE & SEAT FOR 2½ DIA PIN

18@55 BR.I

2-5½x3½x3/8L

BUTT WELD GUSSET PL TO SKIN PL

TOP BEAM MUST BE STRAIGHT AND TRUE AFTER ASSEMBLY

4" MAX. PITCH OF ¾ RIVETS

18@55 BR.I ◇

2-5½x3½x3/8L

6x3½x3/8L

FLOW

RADIUS

6x3½x3/8L

N.S. ONLY

BARE EDGES FOR CAULKING

1'-7" CONCRETE

8@13.75"C

4'-0"

4'-0"

½ FILL

BRACE PL

2-8½x2½x½

2-8½x2½x½

½ DIA HIGH STRENGTH BOLTS WITH HARDENED STEEL WASHERS

SILL EL 2100.0

SECTION C.C

13'-8½" ROLLER CRS.

12'-6 CLEAR WIDTH OF OPENING

1½ FACE

1" RAD

42

12½ 10 13

11 12 13

FACE OF ROLLER PATH

MACHINING MUST BE TO THIS FACE

2

3

4

14

3 CSK SLOTTED ¾ BOLTS

¾ DIA. RIVETS

SECTION A.A. (ENLARGED)

FLOW

35'-0 MAX HEAD OVER SILL

NOTES:

1. USE 80° CSK SLOTTED FLAT HEAD ⅝ DIA. STEEL CAPSCREWS WITH SMALLS HEX NUTS FOR SEAL RETAINING BARS.
2. USE ¾ DIA RIVETS THROUGHOUT EXCEPT AS NOTED
3. DO NOT USE LOCKWASHERS ON GATE - USE PLATE OR BEVEL WASHERS AS REQUIRED.
4. CAULKING PITCH = 3" MAX. PITCH AT SEALS = 4½ MAX ELSEWHERE. PITCH: 6 PER CHORD OF RIVETS.
5. GATES TO BE COMPLETELY SHOP ASSEMBLED, MATCH MARKED & KNOCKED DOWN FOR SHIPMENT.
6. APPROX. WT. OF GATE + CONCRETE (NET) = 17700 LBS

4164

DESIGNED FROM
REVISED FROM CONT A/1430 DWG E.D. 960
TO CONT A-1435 DWG E 52304

GENERAL ORDER No. C/P FILE No. 14 | 14 DATED OCT. 2nd 1956
WELDING STEEL CSA W59 1946

VANCOUVER FABRICATION

REVISION No.	DATE	REVISION	MADE BY
A	OCT 4/57	VIEW SHOWING GATE SEAL AND RUBBER HOSE ADDED.	M.H.
B	SEPT 3RD/57	DESIGN ALTERED TO SUIT MATERIAL SUBSTITUTION. DETAILS DUE TO SAME.	A.D.
C	AUG 1ST 1957	MODIFIED TO SUIT NAVAL SPECIFICATION BY VANCOUVER.	R.M.M.
D	AUG 5TH 1957	WELDING NOTE ADDED.	K.M.H.
	JULY 20TH	WAS 18@55" NF	

MATERIAL BILL

DOMINION BRIDGE CO., LIMITED
LACHINE, QUE.

DESCRIPTION "NO" HEAD GATE S" FOR OPENING 12'-6 WIDE X 12'-6 HIGH. MAX. H.D. OVER SILL = 25'-0 WHITEHORSE PONDS

DETAIL DESIGN ASSEMBLY OF HEAD GATE "1"

PROPRIETOR NORTHERN CANADA POWER COMMISSION.

ENGINEERS MONTREAL ENGINEERING CO. LTD.

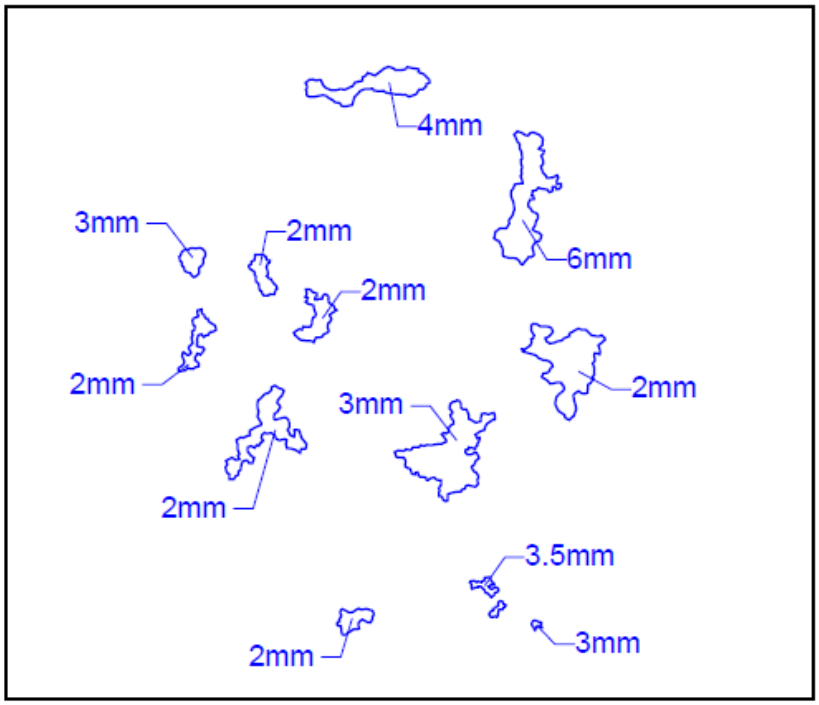
DESIGN
DRAWN P.D.L. JAN. 21/57 FILE
CHECKED
APPROVED
SCALE 1"=1 FOOT
DEPT. DESIGN

DESIGN - AS DASHBOARD, BY DRWG NO. E.1
VAULT NO. E-51565
CONT. A 1434

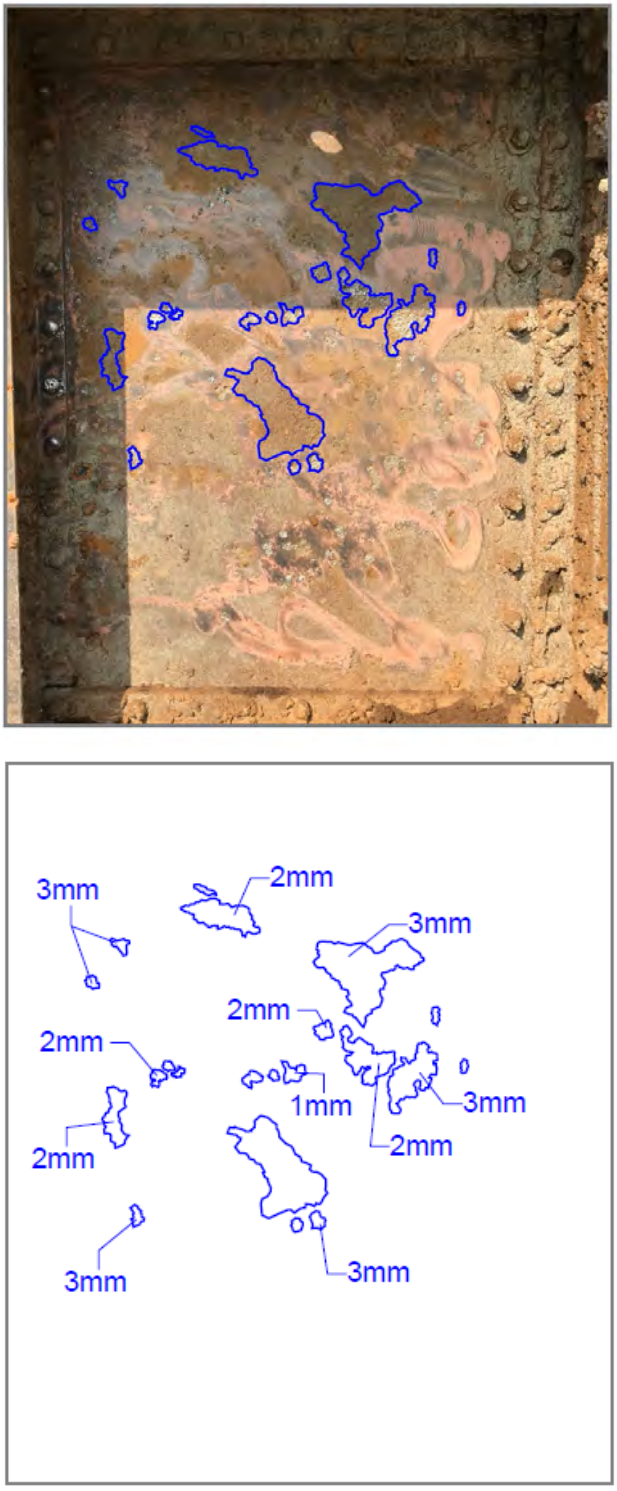
SHIPPING BILL — MADE IN CANADA

APPENDIX B WH1 Headgate Pitting Corrosion Mapping and Photographs

Pitting corrosion mapping and depth measurment on upstream side of WH1 Headgate
SKIN-PLATE PANEL #4



Pitting corrosion mapping and depth measurment on upstream side of WH1 Headgate
SKIN-PLATE PANEL #6



APPENDIX C WH1 Headgate NDT Inspection Reports

TEAM Industrial Services
TISI Canada Inc.
ISO 9001: 2008

2507 - 84 Avenue, Edmonton, Alberta T6P 1K1
Phone (780) 417-7777 Fax: (780) 417-1185

ULTRASONIC EXAMINATION REPORT

UT – 1084 – 01-BB

CLIENT: **Yukon Energy Corporation** DATE: **June 27, 2019** PAGE: 1 OF 4

INVOICE ADDRESS: Box 5920, #2 Mikes Canyon Rd Whitehorse, Yukon Y1A 6S7 WORK LOCATION: YEC Whitehorse hydro plant

EXAMINATION STANDARD: ASME V Article 5 2017 ACCEPTANCE STANDARD: Customer information

TEAM PROCEDURE: UT.ASME.EDM.3 R2 EXAMINATION OF: WH3 Headgate

TEAM JOB NO.:	50191084
BRANCH NO.:	5301
PO No.:	
WO No.:	

SURFACE CONDITION: ☑ AS GROUND ☐ MACHINED ☑ PAINTED ☐ SAND BLAST ☑ BASE METAL ☐ AS WELDED

SCANNING SURFACE: MATERIAL: Carbon steel ☑ MANUAL UT ☐ AUTO UT

TEST EQUIPMENT AND MATERIALS:

INSTRUMENT: Olympus MODEL: Epoch 600 SERIAL No.: 140607001 CAL. DATE: Jan. 14, 2019 CABLE TYPE/LENGTH: Dual 6'

COUPLANT: UT-X CAL. BLOCKS: Metric Step Wedge SN 281713 SCANNING LIMITATION: Intake gate access

TRANSDUCER + SERIAL No.	ANGLE	FREQUENCY	CRYSTAL SIZE / TYPE	PRIMARY REFERENCE REFLECTOR/AMPLITUDE/DISTANCE/dB / TRANSFER	SCAN SENSITIVITY	RANGE CALIBRATION
GE FDU Gamma S/N 13D01GA5	0°	5 MHz	6.25 mm Dual	BWE @ 80% FSH	As required	50 mm

PURPOSE: Ultrasonic thickness readings were performed on the skin plates, horizontal webs, vertical channels and end channels on WH3 intake gate to measure remaining wall thickness.

RESULTS: Thickness readings are recorded on Pages 2-3.

General Notes:
1) All thickness measurents are in inches

TECHNICIANS:

INTERPRETATION IS IN ACCORDANCE WITH THE ABOVE MENTIONED STANDARDS, TO THE BEST OF MY PROFESSIONAL ABILITY

(PRINT): Brad Buechler CGSB/SNT LEVEL: II/II REG. NO.: 11076 (SIGN): Brad J. Buechler

(PRINT): CGSB/SNT LEVEL: REG. NO.: (SIGN):

THE ABOVE REPRESENTATION IS A PROFESSIONAL OPINION. FINAL INTERPRETATION IS THE RESPONSIBILITY OF THE CLIENT. I HAVE READ AND AM IN FULL AGREEMENT WITH THE CONTENTS OF THIS REPORT.

CLIENT REPRESENTATIVE: (PRINT): (SIGN):

A023 UTE R4

TEAM Industrial Services
TISI Canada Inc.
ISO 9001: 2008
2507 - 84 Avenue, Edmonton, Alberta T6P 1K1
Phone (780) 417-7777 Fax: (780) 417-1185

ULTRASONIC EXAMINATION CON'T REPORT

CLIENT: **Yukon Energy Corporation** DATE: **June 27, 2019** PAGE: 2 OF 4

EXAMINATION OF: WH3 Headgate WORK LOCATION: YEC Whitehorse hydro plant

UT – 1084 – 01-BB

SKIN PLATE

	Top left corner	Top right corner	Centre	Btm left corner	Btm right corner
Panel #1	0.448	0.446	0.431	0.461	0.445
Panel #2	0.451	0.449	0.432	0.444	0.449
Panel #3	0.451	0.451	0.452	0.446	0.449
Panel #4	0.451	.451	0.431	0.447	0.452

VERTICAL CHANNELS

	Top of channel	Btm of channel
Panel #1/2	0.336	0.332
Panel #2/3	0.411	0.401
Panel #3/4	0.329	0.331

END CHANNELS

	Top of channel	Btm of channel
Panel #1	0.669	0.665
Panel #4	0.688	0.692

TECHNICIANS

INTERPRETATION IS IN ACCORDANCE WITH THE ABOVE MENTIONED STANDARDS, TO THE BEST OF MY PROFESSIONAL ABILITY

(PRINT): Brad Buechler CGSB/SNT LEVEL: II/II REG. NO.: 11076 (SIGN): Brad J. Buechler

(PRINT): CGSB/SNT LEVEL: REG. NO.: (SIGN):

THE ABOVE REPRESENTATION IS A PROFESSIONAL OPINION. FINAL INTERPRETATION IS THE RESPONSIBILITY OF THE CLIENT. I HAVE READ AND AM IN FULL AGREEMENT WITH THE CONTENTS OF THIS REPORT.

CLIENT REPRESENTATIVE: (PRINT): (SIGN):

A023 UTE R4

TEAM Industrial Services
TISI Canada Inc.
ISO 9001: 2008
2507 - 84 Avenue, Edmonton, Alberta T6P 1K1
Phone (780) 417-7777 Fax: (780) 417-1185

ULTRASONIC EXAMINATION CON'T REPORT

CLIENT: **Yukon Energy Corporation** DATE: **June 27, 2019** PAGE: 3 OF 4

EXAMINATION OF: WH3 Headgate WORK LOCATION: YEC Whitehorse hydro plant

UT – 1084 – 01-BB

HORIZONTAL BEAM WEBS

	Left side	Right Side
Panel #1	0.415	0.416
Panel #2	0.414	0.411
Panel #3	0.421	0.424
Panel #4	0.425	0.424
Panel #5	0.416	0.429
Panel #6	0.426	0.403
Panel #7	0.419	0.428
Panel #8	0.401	0.402

HORIZONTAL BEAM FLANGES

	Left side	Right Side
Panel #1		
Upstream flange	0.657	0.651
Downstream flange	0.655	0.655
Panel #2		
Upstream flange	0.643	0.641
Downstream flange	0.641	0.652
Panel #3		
Upstream flange	0.653	0.651
Downstream flange	0.649	0.651
Panel #4		
Upstream flange	0.652	0.651
Downstream flange	0.651	0.652

TECHNICIANS

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ULTRASONIC EXAMINATION CON'T REPORT

CLIENT: **Yukon Energy Corporation** DATE: **June 27, 2019** PAGE: 4 OF 4

EXAMINATION OF: WH3 Headgate WORK LOCATION: YEC Whitehorse hydro plant

UT – 1084 – 01-BB

TECHNICIANS

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A023 UTE R4

TEAM Industrial Services
TISI Canada Inc.

TISI CANADA INC. NDE TIME REPORT

EMPLOYEE No. _____

CLIENT	Yukon Energy Corporation	*JOB No.*	*50191084*	*VEHICLE No.*	Driving Force rental
CONTACT	Geoff Dunbrack	*TIMESHEET No.*	*BB-1084-01*	*CAMERA No.*	
LOCATION	YEC Whitehorse hydro plant	*CLIENT PO No.:*		*CLIENT WO No.:*	
DESCRIPTION	WH3 Headgate	*OTHER No.*			

Employee Name (Full Name)	DATE: (mm/dd/yy)	TIME IN 24 hr clock	TIME OUT 24 hr clock	WORK HOURS (CHARGEABLE)			TRAVEL HOURS			KMS	LOA	SHIFT DIFF	WELD QUANTITY			OT MEALS	EMPLOYEE HOURS (NON-CHARGEABLE)			SHOP HRS		DRD READINGS
				REG	OT1	OT2	REG	OT1	OT2	(RETURN)	(QTY)	(HRS)	QTY	SIZE	SCH	(QTY)	REG	OT1	OT2	REG	OT1	(mR)
Brad Buechler	June 26, 2019	4:30	18:00	2		5.5	6				1											
	June 27, 2019	6:30	18:00	8		3.5					1											
	June 28, 2019	7:00	19:30	8		0.5		4			1											

CONSUMABLES (QTY)			RADIOGRAPHIC FILM		EQUIPMENT		REPORT NUMBERS
MT / PT (CAN)	UT (COUPLANT)	PAUT (WEDGES)	QTY	DESCRIPTION	QTY	DESCRIPTION	UT–1084–01-BB
1					1	UT flaw detector	MT-1084-02-BB
					1	MPI yoke	UT–1084–03-BB
							MT-1084-04-BB

NOTES _____

CLIENT REPRESENTATIVE: *PRINT* _____ *SIGN* _____

By signing this report, I agree that I have received all documentation, film or any other material realted to the work listed on this report.

097 TR R1

TEAM Industrial Services
TISI Canada Inc.
2507 - 84 Avenue, Edmonton, Alberta T6P 1K1
Phone (780) 417-7777 Fax: (780) 417-1185

MAGNETIC PARTICLE EXAMINATION REPORT

MT – 1084 – 02-BB

CLIENT: **Yukon Energy Corporation** DATE: **June 27, 2019** PAGE: 1 OF 1

INVOICE ADDRESS: Box 5920, #2 Mikes Canyon Rd Whitehorse, Yukon Y1A 6S7 WORK LOCATION: YEC Whitehorse hydro plant

EXAMINATION STANDARD: ASTM E 709 - 2017 ACCEPTANCE STANDARD: Customer Information

TEAM PROCEDURE: MT.CSA.1 R0 EXAMINATION OF: WH3 Headgate

TEAM JOB NO.:	50191084
BRANCH NO.:	5301
JOB NO.:	
AFE NO.:	

SURFACE CONDITION: ☐ AS GROUND ☐ MACHINED ☐ PAINTED ☐ SAND BLAST ☑ BASE METAL ☐ AS WELDED

MATERIAL: Carbon steel THICKNESS: 0.75" TEMPERATURE: 20 °C

TEST EQUIPMENT AND MATERIALS:

EQUIPMENT	MODEL AND SERIAL NO.	MAGNETIZING CURRENT	TEST MEDIUM/CONSUMABLES	MANUFACTURER /BATCH NO./CONCENTRATION
☑ AC YOKE	Contour Probe B300 S/N:9874	☑ AC	☑ WET VISIBLE	Magnaflux 7HF batch # 16F03K
☑ DAILY LIFT TEST	10 lbs. SN: 1126 Status: Pass	☐ DC	☐ DRY POWDER	
☑ WHITE LIGHT	Incandescent Flashlight 3 C cell	☐ N/A (Permanent Magnet)	☑ CONTRAST PAINT	Magnaflux WCP-2 batch # 17L12K
☑ LIGHT INTENSITY	176fc	☑ CONTINUOUS	☐ WET FLUORESCENT	
☑ LIGHT METER	Accumax XRP-3000 S/N: 1942038 cal due 11/30/2019	☐ RESIDUAL	☐ SETTELMENT TEST	

BLACK LIGHT INTENSITY BEFORE EXAMINATION: N/A µw/CM² BLACK LIGHT INTENSITY AFTER EXAMINATION: N/A µw/CM² WHITE LIGHT/BACKGROUND: N/A

PURPOSE: A Colour Contrast Magnetic Particle Examination was performed on the following:

WH3 Headgate

-Approximately 10 samples of weld was examined for fatigue/stress cracking after cleaning and removal of paint.

RESULTS: No cracking or other relevant indications were found at time of examination.

TECHNICIANS:

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CLIENT REPRESENTATIVE: (PRINT): (SIGN):

A026 MPE R4

APPENDIX D WH3 Headgate Historical Drawing (Ref. M0186-1)

4 3 2 1

13'-8½ CTR. TO CTR ROLLERS

1"=1'

LUBRITE BUSHING - 101a - ORD. on SK.# 101
ECCENTRIC PIN - 2a - ORD. on DRG.# 2
6 GD. BRASS WASHERS - 102a ORD. on SK.# 100
105a - BRASS FACED RUBBER 'J' SEAL - ORD. on SK.# 105 - STEP SPLICE AS NOTED on SK.# 105 - CEMENTED BUTT JOINT TO MANUFACTURERS SPECIFICATION.
102a - 16" DIA. STEEL ROLLER - ORD. on SK.# 102 - PO.# A4387
SECT. M-M
NOTE 'A' - MAX. DEVIATION IN PLANE OF SEAL PAD ± 1/16 - CHECK DEVIATION IN SKIN & PROVIDE THICKER BAR & FACE IF REQ'D.
SECT. K-K
SEE NOTE 'A'
FACE OF SEAL PADS
FACE OF LINTEL
3/16 SEAL DEFLECTION
105a
pp
ms
pm
pn
pq
pr
pa
ABT 6
1/4 FACE - IF REQ'D
(SEAL - TYP pm & pn)
MB.R.B 7/16 x 3/8 x 1'-4 3/4 - pf
ma - WF 18 B 76 x 7/8 x 3/8 @ 65# x 13'-0
2" DRAIN HOLES
md
mf
pd
pc
mc
7/8 x 3/4 notch 'pp'
3'-3
7'-4½
6'-6 3/8
℄ SYM. ABT. EXCEPT SHOWN AT ℄
FACE OF ROLLER PATH
12'-6 4
16 spaces @ d = 5'-0
3½ 3 3½
3¼ Alt. more
1-pn
CUT BOTH FLG'S @ 45°
1-md
20-6 3/4 HEX HD. S.S. BOLT x 3
1-pp - BAR 2 1/4 x 3/8 x 13'-2
1-pm - BAR 2 1/4 x 5/16 x 12'-6 3/4 - SEE NOTE 'A'
1-ms - L 3 x 3/8 x 4 x 12'-8 3/4 (cut L3 x 2 x 4)
1-pq - MBR 76 x 3/8 x 13'-9 (F.I.E.)
BUTTWELD TO R pb
1-pb - MB.R.B 33 x 3/8 x 13'-4 (F.I.E.)
1-mf
1-mg
1-mh
1-mk
1-mc
1-mp
1-pt (FS)
1-ps (FS)
1-mg
1-mq
1-mn
1-mf
1-mh
1-mk
1-mc
1-mp
1-pt (FS)
1-ps (FS)
1-mg
FACE
mf - WF 18 B 65 x 41'-3
mh - WF 18 B 55 x 41'-3
mc - WF 18 B 55 x 13'-0
1-pc - R 7 3/4 x 3/8 x 13'-9 (CHECK ABT.) (F.I.E. & F.I.S.)
1-pd - MBR 1/2 x 3 1/2 x 3'-2
1-pa - R 3 x 1/2 x 3'-2
1-pb - R 3 x 1/2 x 3'-2
1-pe - R 3 x 1/2 x 3'-2
1-pf - R 3 x 1/2 x 3'-2
1-pg - R 3 x 1/2 x 3'-2
1-ph - R 3 x 1/2 x 3'-2
1-pk - R 3 x 1/2 x 3'-2
1-pl - R 3 x 1/2 x 3'-2
1-pm - R 3 x 1/2 x 3'-2
1-pn - R 3 x 1/2 x 3'-2
1-pp - R 3 x 1/2 x 3'-2
1-pq - R 3 x 1/2 x 3'-2
1-pr - R 3 x 1/2 x 3'-2
1-ps - R 3 x 1/2 x 3'-2
1-pt - R 3 x 1/2 x 3'-2
1-pu - R 3 x 1/2 x 3'-2
1-pv - R 3 x 1/2 x 3'-2
1-pw - R 6 x 1/2 x 6
3 1/16" BORE.
ph - MB.R.B 74 x 5/8 x 1'-4 3/4
2" DRAIN HOLE
2" DRAIN HOLE in 'mq' 4½" HOLE in 'mb'
mq (SECT. D-D)
mb - WF 18 B 65 # x 13'-0 (SECT. F-F)
SECTION D-D
SECTION F-F
SYMM ABT. ℄
ROLLER SIDE FRAMES TO BE SUB-ASSEMBLED & BE DC FACED BEFORE BURNING PIN HOLES
NOTE 'B' - MAX. DEVIATION IN PLANE OF FACE OF ALL GATE ROLLERS ± 1/32 - ADJUST ECCENTRIC PINS & CHECK BEFORE WELDING RECESS BARS 'pa' to 'pe'
1-ha
2-b³
1-mv L 6 x 4 x 3/4 x 10'-2
1-pad
1-pae
1-paf
1-pag
2-100a
1-101a
1-102a
1-2a
1-3a
2-b⁴
1-pg
1-pf
1-pe
1-pd
1-ph
1-pk
1-pl
1-pm
1-pn
1-pp
1-pq
1-pr
1-ps
1-pt
1-pu
1-pv
1-pw
1-px
1-py
1-pz
1-qa
1-qb
1-qc
1-qd
1-qe
1-qf
1-qg
1-qh
1-qk
1-ql
1-qm
1-qn
1-qp
1-qq
1-qr
1-qs
1-qt
1-qu
1-qv
1-qw
1-qx
1-qy
1-qz
1-ra
1-rb
1-rc
1-rd
1-re
1-rf
1-rg
1-rh
1-rk
1-rl
1-rm
1-rn
1-rp
1-rq
1-rr
1-rs
1-rt
1-ru
1-rv
1-rw
1-rx
1-ry
1-rz
1-sa
1-sb
1-sc
1-sd
1-se
1-sf
1-sg
1-sh
1-sk
1-sl
1-sm
1-sn
1-sp
1-sq
1-sr
1-ss
1-st
1-su
1-sv
1-sw
1-sx
1-sy
1-sz
1-ta
1-tb
1-tc
1-td
1-te
1-tf
1-tg
1-th
1-tk
1-tl
1-tm
1-tn
1-tp
1-tq
1-tr
1-ts
1-tt
1-tu
1-tv
1-tw
1-tx
1-ty
1-tz
1-ua
1-ub
1-uc
1-ud
1-ue
1-uf
1-ug
1-uh
1-uk
1-ul
1-um
1-un
1-up
1-uq
1-ur
1-us
1-ut
1-uu
1-uv
1-uw
1-ux
1-uy
1-uz
1-va
1-vb
1-vc
1-vd
1-ve
1-vf
1-vg
1-vh
1-vk
1-vl
1-vm
1-vn
1-vp
1-vq
1-vr
1-vs
1-vt
1-vu
1-vv
1-vw
1-vx
1-vy
1-vz
1-wa
1-wb
1-wc
1-wd
1-we
1-wf
1-wg
1-wh
1-wk
1-wl
1-wm
1-wn
1-wp
1-wq
1-wr
1-ws
1-wt
1-wu
1-wv
1-ww
1-wx
1-wy
1-wz
1-xa
1-xb
1-xc
1-xd
1-xe
1-xf
1-xg
1-xh
1-xk
1-xl
1-xm
1-xn
1-xp
1-xq
1-xr
1-xs
1-xt
1-xu
1-xv
1-xw
1-xx
1-xy
1-xz
1-ya
1-yb
1-yc
1-yd
1-ye
1-yf
1-yg
1-yh
1-yk
1-yl
1-ym
1-yn
1-yp
1-yq
1-yr
1-ys
1-yt
1-yu
1-yv
1-yw
1-yx
1-yy
1-yz
1-za
1-zb
1-zc
1-zd
1-ze
1-zf
1-zg
1-zh
1-zk
1-zl
1-zm
1-zn
1-zp
1-zq
1-zr
1-zs
1-zt
1-zu
1-zv
1-zw
1-zx
1-zy
1-zz
SECTION B-B
NOTE - GATE SEAL 105a TO PROTECT 16 BEHIND FACED EDGE OF GATE
SECTION P-P
DETAIL OF R 'ha'
SECTION G-G
SECT. A-A
VIEW H-H
SECT. J-J
SECT. C-C
SECT. N-N
TYP - CUT O.S. & CHIP FLUSH
SEAL WELD TYP
MACH. AFTER WELD NO PAINT
1 REQ'D - MK. 1A
NOTE - GATE WILL BE SHIPPED SEAL FACE DOWN - IMPORTANT THAT SEALS & MACHINED EDGE OF GATE BE PROTECTED FOR SHIPMENT

APPROVED
10 Jan 68
This approval of interpretation of the work to be done does not relieve the seller of responsibility for accuracy of details.

FINAL DRAWING
30001 6

REVISIONS	MADE BY	CHK'D BY	DATE	ZONE	REVISION LETTER

WHEELABRATE - YES

SPECIFICATION Montreal Eng. Co. Ltd.	PREPARATION OF HOLES
MATERIAL A36 & NTD	
PAINT Epoxy - SEE SK.# 104	
SHOP WELDED	
FIELD RIVETS	EDGE PREPARATION
OPEN HOLES 9/16 EXCEPT NTD.	
	MATERIAL ON LOOSE BILL No. 12, 16, & 1c

DOMINION BRIDGE COMPANY LIMITED — Vancouver, B.C.

DRAWN W.M. Feb/68	PROPRIETOR Northern Canada Power Commission
CHECKED R.M.S. 11/Jan	PURCHASER Montreal Engineering Co. Ltd.
APPROVED	DESCRIPTION Whitehorse Rapids Power Plant
	UNIT # 3 Powerhouse Extension
SCALE	DETAIL — HEADGATE —

CONTRACT No. M0186
DRAWING No. 1

APPENDIX E WH3 Headgate NDT Inspection Report

TEAM Industrial Services
TISI Canada Inc.
ISO 9001: 2008

2507 - 84 Avenue, Edmonton, Alberta T6P 1K1
Phone (780) 417-7777 Fax: (780) 417-1185

ULTRASONIC EXAMINATION REPORT

UT – 1084 – 03-BB

CLIENT: **Yukon Energy Corporation** DATE: **June 28, 2019** PAGE: 1 OF 4

INVOICE ADDRESS: Box 5920, #2 Mikes Canyon Rd Whitehorse, Yukon Y1A 6S7 WORK LOCATION: YEC Whitehorse hydro plant

EXAMINATION STANDARD: ASME V Article 5 2017 ACCEPTANCE STANDARD: Customer information

TEAM PROCEDURE: UT.ASME.EDM.3 R2 EXAMINATION OF: WH1 Headgate

TEAM JOB NO.:	50190850
BRANCH NO.:	5301
PO No.:	
WO No.:	

SURFACE CONDITION: ☑ AS GROUND ☐ MACHINED ☑ PAINTED ☐ SAND BLAST ☑ BASE METAL ☐ AS WELDED

SCANNING SURFACE: MATERIAL: Carbon steel ☑ MANUAL UT ☐ AUTO UT

TEST EQUIPMENT AND MATERIALS:

INSTRUMENT: Olympus MODEL: Epoch 600 SERIAL No.: 140607001 CAL. DATE: Jan. 14, 2019 CABLE TYPE/LENGTH: Dual 6'

COUPLANT: UT-X CAL. BLOCKS: Metric Step Wedge SN 281713 SCANNING LIMITATION: Intake gate access

TRANSDUCER + SERIAL No.	ANGLE	FREQUENCY	CRYSTAL SIZE / TYPE	PRIMARY REFERENCE REFLECTOR/AMPLITUDE/DISTANCE/dB / TRANSFER	SCAN SENSITIVITY	RANGE CALIBRATION
GE FDU Gamma S/N 13D01GA5	0°	5 MHz	6.25 mm Dual	BWE @ 80% FSH	As required	50 mm

PURPOSE: Ultrasonic thickness readings were performed on the skin plates, horizontal webs, vertical channels and end channels on WH1 intake gate to measure remaining wall thickness.

RESULTS: Thickness readings are recorded on Pages 2-3.

General Notes:
1) All thickness measurents are in inches.
2) Thickness measurements were taken on non-corroded/pitted base material to measure nominal wall thickness. Areas of corrosion were measured by hand with bridge cam gauge by YEC.
3) Thickness measurements recorded as "no access" were due to cement squares blocking access to surrounding steel.

TECHNICIANS:

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ULTRASONIC EXAMINATION CON'T REPORT

CLIENT: **Yukon Energy Corporation** DATE: **June 28, 2019** PAGE: 2 OF 4

EXAMINATION OF: WH1 Headgate WORK LOCATION: YEC Whitehorse hydro plant

UT – 1084 – 03-BB

SKIN PLATE

	Top left corner	Top right corner	Centre	Btm left corner	Btm right corner
Panel #1	0.416	0.419	0.432	0.436	0.439
Panel #2	0.416	0.421	0.449	0.447	0.453
Panel #3	0.418	0.415	0.433	0.441	0.435
Panel #4	0.433	0.437	0.432	0.436	0.444
Panel #5	0.434	0.436	0.446	0.427	0.429
Panel #6	0.435	0.445	0.434	0.419	0.436
Panel #7	0.433	0.429	0.441	0.422	0.425
Panel #8	0.431	0.432	0.433	0.428	0.431
Panel #9	0.392	0.387	0.396	0.402	0.398
Panel #10	0.383	0.381	0.378	no access	no access
Panel #11	0.386	0.384	0.389	no access	no access
Panel #12	0.375	0.379	0.382	0.395	0.397

TECHNICIANS

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ULTRASONIC EXAMINATION CON'T REPORT

CLIENT: **Yukon Energy Corporation** DATE: **June 28, 2019** PAGE: 3 OF 4

EXAMINATION OF: WH1 Headgate WORK LOCATION: YEC Whitehorse hydro plant

UT – 1084 – 03-BB

HORIZONTAL WEBS

	Left side	Right Side
Panel #1	0.443	0.448
Panel #2	0.441	0.445
Panel #3	0.438	0.435
Panel #4	0.442	0.446
Panel #5	0.451	0.473
Panel #6	0.461	0.464
Panel #7	0.459	0.462
Panel #8	0.465	0.462
Panel #9 top	0.431	0.428
Panel #9 btm	0.511	0.516
Panel #10 top	0.421	0.423
Panel #10 btm	no access	no access
Panel #11 top	0.426	0.422
Panel #11 btm	no access	no access
Panel #12 top	0.443	0.439
Panel #12 btm	0.492	0.498

Note: Panels #1 - #8; measurements taken on top side of panels

END CHANNELS

	Top of channel	Btm of channel
Panel #1	0.615	0.615
Panel #5	0.618	0.615
Panel #9	0.621	0.606
Panel #4	0.632	0.631
Panel #8	0.628	0.625
Panel #12	0.617	0.611

VERTICAL CHANNELS

	Top of channel	Btm of channel
Panel #1/2	0.301	0.301
Panel #2/3	0.413	0.417
Panel #3/4	0.332	0.338
Panel #5/6	0.306	0.297
Panel #6/7	0.308	0.305
Panel #7/8	0.339	0.341
Panel #9/10	0.321	0.319
Panel #10/11	no access	no access
Panel #11/12	0.318	0.315
Centre strap vertical channel		0.411

Note: Panel #2/3 is a vertical beam

TECHNICIANS

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TEAM Industrial Services
TISI Canada Inc.
ISO 9001: 2008
2507 - 84 Avenue, Edmonton, Alberta T6P 1K1
Phone (780) 417-7777 Fax: (780) 417-1185

ULTRASONIC EXAMINATION CON'T REPORT

CLIENT: **Yukon Energy Corporation** DATE: **June 28, 2019** PAGE: 4 OF 4

EXAMINATION OF: WH1 Headgate WORK LOCATION: YEC Whitehorse hydro plant

UT – 1084 – 03-BB

TECHNICIANS

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TISI Canada Inc.

MAGNETIC PARTICLE EXAMINATION REPORT

2507 - 84 Avenue, Edmonton, Alberta T6P 1K1
Phone (780) 417-7777 Fax: (780) 417-1185

MT – 1084 – 04-BB

CLIENT: **Yukon Energy Corporation** DATE: **June 28, 2019** PAGE: 1 OF 2

INVOICE ADDRESS: Box 5920, #2 Mikes Canyon Rd Whitehorse, Yukon Y1A 6S7 WORK LOCATION: YEC Whitehorse hydro plant

EXAMINATION STANDARD: ASTM E 709 - 2017 ACCEPTANCE STANDARD: Customer Information

TEAM PROCEDURE: MT.CSA.1 R0 EXAMINATION OF: WH1 Headgate

TEAM JOB NO.:	50191084
BRANCH NO.:	5301
JOB NO.:	
AFE NO.:	

SURFACE CONDITION: ☐ AS GROUND ☐ MACHINED ☐ PAINTED ☐ SAND BLAST ☑ BASE METAL ☐ AS WELDED

MATERIAL: Carbon steel THICKNESS: 0.75" TEMPERATURE: 20 °C

TEST EQUIPMENT AND MATERIALS:

EQUIPMENT	MODEL AND SERIAL NO.	MAGNETIZING CURRENT	TEST MEDIUM/CONSUMABLES	MANUFACTURER /BATCH NO./CONCENTRATION
☑ AC YOKE	Contour Probe B300 S/N:9874	☑ AC	☑ WET VISIBLE	Magnaflux 7HF batch # 16F03K
☑ DAILY LIFT TEST	10 lbs. SN: 1126 Status: Pass	☐ DC	☐ DRY POWDER	
☑ WHITE LIGHT	Incandescent Flashlight 3 C cell	☐ N/A (Permanent Magnet)	☑ CONTRAST PAINT	Magnaflux WCP-2 batch # 17L12K
☑ LIGHT INTENSITY	176fc	☑ CONTINUOUS	☐ WET FLUORESCENT	
☑ LIGHT METER	Accumax XRP-3000 S/N: 1942038 cal due 11/30/2019	☐ RESIDUAL	☐ SETTELMENT TEST	

BLACK LIGHT INTENSITY BEFORE EXAMINATION: N/A µw/CM² BLACK LIGHT INTENSITY AFTER EXAMINATION: N/A µw/CM² WHITE LIGHT/BACKGROUND: N/A

PURPOSE: A Colour Contrast Magnetic Particle Examination was performed on the following:

WH1 Headgate

-Adjacent base material was examined around a quantity of 10 rivet heads after cleaning and removal of paint on rivet head and adjacent base material.

RESULTS: No cracking or other relevant indications were found at time of examination.

TECHNICIANS:

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CLIENT REPRESENTATIVE: (PRINT): (SIGN):

A026 MPE R4

TEAM Industrial Services
TISI Canada Inc.

MAGNETIC PARTICLE CONTINUATION REPORT

2507 - 84 Avenue, Edmonton, Alberta T6P 1K1
Phone (780) 417-7777 Fax: (780) 417-1185

CLIENT: **Yukon Energy Corporation** DATE: **June 28, 2019** PAGE: 2 OF 2

EXAMINATION OF: WH1 Headgate WORK LOCATION: YEC Whitehorse hydro plant

MT – 1084 – 04-BB

TECHNICIANS

INTERPRETATION IS IN ACCORDANCE WITH THE ABOVE MENTIONED STANDARDS, TO THE BEST OF MY PROFESSIONAL ABILITY

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CLIENT REPRESENTATIVE: (PRINT): (SIGN):

A026 MPE R4

REFERENCE: **Application, Tab 5.2.1.9, pages 5-18 to 5-19**

ISSUE: **WH2 Uprate Project**

QUOTE: "Whitehorse Hydro #2 (WH2) was commissioned in 1958 and is one of the three units installed at P125. It is a Kaplan Turbine unit with nominal rating of a 5.8 MW and is currently operating with the original runner, rotor, stator and windings from 1958. WH2 asset health has been declining due to its age, and there is an increased risk of failure and related unplanned outages and costs. Specifically, the generator has exceeded a typical winding life of 40 years; and issues have been identified with oil leaks at the runner blade to hub seals and with possible voids in the concrete behind the draft tube liner. In the circumstances, it was considered prudent to rewind the generator in order to mitigate these risks and their potential reliability and cost implications. External studies also determined that unit efficiency would be improved with a new runner of modern design." (emphasis added)

"In 2017, Hatch completed an economic assessment of various uprate options at the Whitehorse Rapids Generating Station (WRGS). The report concluded that the uprating of the WH1 or WH2 units would be the most cost-effective option and provide the best payback of the WRGS hydro units. Management selected the uprating of WH2 over WH1 since there are existing known issues with the WH2 governor, and the uprating project would resolve these issues."

"The project is planned to be implemented over a three year period (2019 21), and is expected to add 6.4 GWh/yr additional hydraulic generation to the grid [starting in the third quarter of 2021]. The project is also expected to increase dependable capacity of WH2 by 0.94 MW… YEC contracted Litostroj Power to undertake the runner fabrication with the following concurrent activities planned for 2020: governor fabrication, balance of plant civil construction; balance of plant P&C design completion, relace of balance of plant request for proposal, and delivery of materials to Whitehorse."

QUESTION:

a) Please explain how often YEC carried out tests on WH2 in the past to assess its reliability and how often maintenance work was required. If possible, please provide the number of times maintenance was conducted on WH2 in the last 10 years, on a per annum basis, and the cost of this maintenance work. For example, how many times did YEC rewind the generator?

b) Please indicate if any unplanned outages have occurred with WH2. If confirmed, please provide the number and duration of these outages in the last 10 years, on a per annum basis, and the costs incurred due to these outages.

c) Please provide the external studies showing that unit efficiency would be improved with a new runner of modern design, and explain the improvements found with this design. Additionally, please indicate which consultant carried out these studies, and provide details on the selection process of the contractor and how costs were awarded.

d) Please provide Hatch's economic assessment of the various uprate options at the Whitehorse Rapids Generating Station, and provide the costs of all the uprate options explored in this assessment.

e) Please provide further detail on YEC's choice of uprating WH2 over WH1. For example, what process was carried out to determine that WH2 required uprating over WH1? Did YEC conduct technical meetings with its staff or carry out an assessment comparing issues between both assets?

f) Please provide an update on the work currently completed for this project. Is YEC currently on schedule with this project?

ANSWER:

(a)

YEC carries out annual scheduled maintenance and testing on WH2.

A major overhaul was completed in 2016 at a cost of $686,764. The generator has never been rewound since it was put into service in 1958. All major components of WH2 are original.

There is also annual maintenance work scheduled for 2-3 weeks per year. Average costs for this work is $80,000-$100,000 depending on discoveries (cavitation). YEC historically performs 10 year major overhauls on the major hydro assets.

(b)

Please see Attachment 1 to this response which provides WH2 KPIs from YTD back to 2015. The forced outage rate is very low. Costs would be difficult to provide due to the very low failure rate. Costs are captured in the general O&M accounts.

(c)

Please see also YUB-YEC-1-57(d) Attachment 1 which provides the Hatch study. Section 3 of this report outlines the benefits of replacing the runner as well as some of the other improvements that are being made to the WH2 Unit. Assessments for WH1 are applicable to WH2 as noted in the report.

Issues with existing unit performance are noted in Section 3.1. More specifically, the section notes issues with oil leakage at the runner blade to hub seals and with possible voids in the concrete behind the draft tube liner. Section 3.1 notes efficiency tests were conducted on WH1 in 2009 by Hydro Power Performance Engineering, Inc. (HPPE) for the KGS Group. Turbine flow was measured using flow meters installed at the intake. The tests indicated performance as follows:

- Peak turbine efficiency = 88.1%;
- Peak efficiency flow = 23 m3/s;
- Efficiency at full load = 82.3%;
- Full load flow = 39.5 m3/s; and
- Full load turbine output = 5.74 MW at 18 m net head.

Figure 3-2 of the report shows the efficiency of the existing turbine based on the testing done by HPPE, the efficiency of a modern state of the art turbine derived from model test information, and the estimated efficiency of the WH1 turbine with a new runner and possible stay vane modifications. The efficiency curve for the existing turbine is for the optimum wicket gate – runner blade relationship. The estimated increase in efficiency with a new runner is approximately 4%. Figure 3-2 also shows the estimated turbine performance for a new runner with a 10% increase in flow. The increase in energy and capacity for the various uprate options are discussed in Section 7.

Hatch was awarded the work to undertake the study noted through a competitive RFP process. Proposals were evaluated based on technical and organization competence and price; and demonstrate the best value for price submitted.

(d)

Please see the Hatch study provided as Attachment 1 to this response. The costs for each option assessed in the Hatch study are provided in Table 10-1 of the attached (excerpted below). Assessments for WH1 are applicable to WH2.

Option	Uprated Unit	Increased Turbine Flow (Y/N)	Load Scenario	Avoided Thermal Generation (MWh/yr)	Avoided Thermal Capacity (MW)	Capital Cost ($M)	Cost Incl. Disassemby & Install (Y/N)	Cost Incl. Generator Rewind (Y/N)	NPV 30 years ($M)	B/C ratio 30 years	Simple Payback Period (Years)	Discounted Payback Period (Years)
1-1	WH1	N	1	559	0.09	1.99	Y	N	0.21	1.11	19 yrs	28 yrs
1-1A	WH1	N	1	559	0.09	1.78	N	N	0.41	1.23	17 yrs	24 yrs
1-3	WH1	N	3	932	0.16	1.99	Y	N	0.98	1.52	12 yrs	15 yrs
1-3A	WH1	N	3	932	0.16	1.78	N	N	1.18	1.69	11 yrs	13 yrs
1-4	WH1	N	4	1491	0.23	1.99	Y	N	1.18	1.61	12 yrs	14 yrs
1-4A	WH1	N	4	1491	0.23	1.78	N	N	2.26	2.29	9 yrs	9 yrs
2-1	WH3	N	1	47	0.01	2.58	Y	N	-2.43	0.04	No Payback	No Payback
2-1A	WH3	N	1	47	0.01	1.18	N	N	-1.06	0.09	No Payback	No Payback
2-4	WH3	N	4	430	0.07	2.6	Y	N	-1.61	0.36	>45 yrs	>45 yrs
2-4A	WH3	N	4	430	0.07	1.2	N	N	-0.23	0.80	20 yrs	>45 yrs
3-1	WH4	N	1	395	0.05	4.26	Y	Y	-2.84	0.30	No Payback	No Payback
3-1A	WH4	N	1	395	0.05	2.30	N	N	-1.16	0.47	37 yrs	No Payback
4-1	WH1	Y	1	488	0.15	4.78	Y	Y	-2.68	0.43	No Payback	No Payback
4-1A	WH1	Y	1	488	0.15	2.74	N	N	-0.68	0.75	27 yrs	No Payback
4-4	WH1	Y	4	1879	0.40	4.78	Y	Y	0.28	1.06	14 yrs	23 yrs
4-4A	WH1	Y	4	1879	0.4	2.74	N	N	2.23	1.85	9 yrs	10 yrs
5-1	WH4 - K	N	1	1583	0.70	10.38	Y	Y	-6.18	0.39	42 yrs	No Payback
5-4	WH4 - K	N	4	47	1.00	10.4	Y	Y	1.20	1.12	14 yrs	23 yrs
6-1	WH1 & 2	N	1	795	0.09	3.97	Y	N	-0.95	0.75	27 yrs	No Payback

(e)

WH2 was selected over WH1 because the energy output of WH2 is higher based on the plant configuration. That is, WH2 produces more energy because it exhausts mid-stream; WH1 exhausts against the bank of the river which creates a loss of efficiency. Otherwise, the units are essentially identical units. Additionally, WH2 was having a problem with its governor, i.e., the WH2 governor was having issues with MW control and resolution was required.

(f)

Design and manufacturing are complete and the site work is currently underway. YEC is currently on schedule with the WH2 Uprate.

KPI Report: Unit Status

02/22/2021 10:48

			2021-Q1 1259 hrs		2020-Q1,Q2,Q3,Q4 8784 hrs			2019-Q1,Q2,Q3,Q4 8760 hrs			2018-Q1,Q2,Q3,Q4 8760 hrs	
			AVAILABLE	PLANNED	AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED	AVAILABLE	PLANNED
			99.1%	0.9%	41.2%	Reliablity 42.8%	1.6%	92.8%	Reliablity 100%	7.1%	61.2%	38.8%
WHITEHORSE	THERMAL	WG2	99%	1%	41%	57%	2%	93%	0%	7%	61%	39%

KPI Report: Unit Status

02/22/2021 10:48

			2017-Q1,Q2,Q3,Q4 8760 hrs			2016-Q1,Q2,Q3,Q4 8784 hrs			2015-Q1,Q2,Q3,Q4 8760 hrs		
			AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED	AVAILABLE	FORCED	PLANNED
			84.2%	Reliablity 99.9%	15.7%	93.2%	Reliablity 99.9%	6.7%	93.8%	Reliablity 98.9%	5.1%
WHITEHORSE	THERMAL	WG2	84%	0%	16%	93%	0%	7%	94%	1%	5%

Report

WH1, WH3 and WH4 Turbine Uprate Study

H352985-00000-200-230-0001

JULY 4, 2017
ELECTRICAL

2017-07-04	2	Approved for Use	P. Rodrigue / E. Cheung / Joel Guilbaud	S. Smith	N/A	S. Smith
DATE	REV.	STATUS	PREPARED BY	CHECKED BY	APPROVED BY	APPROVED BY
				Discipline Lead	Functional Manager	Project Manager

Ver: 04.03

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Executive Summary

A study considering uprating the turbines at Yukon Energy Corporation's (YEC's) Whitehorse Generating Station (WGS) has been undertaken by Hatch Ltd. (Hatch). The study includes a technical and economic review and analysis of the potential options for the uprating of units WH1, WH3, and WH4 at the Whitehorse Generating Station.

The generating units at WGS have three different types of turbines – WH1 and WH2, installed in 1958, have Kaplan turbines with a nominal rating of 5.8 MW; WH3, installed in 1969, has an 8.4 MW fixed-blade propeller turbine; and the newest unit (WH4) has a 20 MW fixed-blade propeller turbine installed in 1984.

Based on information and data provided by YEC, the generating units are maintained and overhauled on a regular basis. A detailed condition assessment by Knight Piesold, in 2016, did not identify major issues with the equipment. WH3 has experienced major blade cracking problems with the turbine runner in 2003, and there are some runner blade to hub seal issues on WH1 and WH2. Nevertheless, the turbines and generators do not appear to be near their end of useful life. However, although no specific issues have been identified with the generator windings, given their age rewind of the WH1 and WH2 generators may be prudent to mitigate risks associated with a winding failure and resulting unplanned outage.

The principal benefit of uprating the turbines at WGS is the ability for YEC to offset more costly thermal (diesel and LNG) generation. Replacement of the existing turbine runners with a new runner of modern design will increase generating unit efficiency and power output. A further increase in power will be possible by increasing the flow capacity of the new runner. Other than possible modifications to the existing stay vanes to improve approach flow into the runners, other major modifications are not envisioned.

Generator work associated with the uprate will be limited; however, depending on the capacity increase, it may include stator and rotor rewind. If stator and rotor rewind is not required to accommodate capacity increases, YEC may still consider taking advantage of the outage associated with the uprate to complete a rewind of the stator and rotor given the age of the existing generator windings.

To ascertain the benefits of potential turbine uprate options, operation and unit disptach of YEC's complete system including Whitehorse, Aishihik and Mayo hydro facilites as well as the thermal units were simulated using 14 years of flow records in conjunction with projected load forecasts provided by YEC.

There were 6 main uprate options studied for the Units WH1 to WH4. They are numbered as 1-1 through 6-1 in Table ES-1 below. There were also a number of sub-options considered as follows:

- Options suffixed by 1-'A' etc., considered the impacts to the financial case of a base option if costs associated with life extension activities such as turbine/generator disassembly and reassembly were either included or excluded from the costs assigned to the turbine uprate estimate.
- Options suffixed by 1-'4' etc., considered applying a different load scenario (ie. load scenario 3 or 4) to one of the base case options to compare the results of the different load scenario on the financial case for each base uprate option.

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The cost of the various turbine uprate options were estimated using budgetary runner costs provided by turbine manufacturers along with reference cost information from other comparable projects.

The economic benefit of the various turbine uprate options will depend on the load scenario applied as well as how the various uprate costs are accounted for. The uprate program can be undertaken on its own or it can be completed as part of a 10-year equipment overhaul or part of generator rewind for life extension. A summary of costs, benefits, and benefit/cost ratios for the various turbine uprate options considered is presented in Table ES-1. The details of each of the options are identified in the table columns. The unit that is being uprated is shown in column 2; column 3 indicates whether the uprated unit is designed to have the same turbine flow or an increased turbine flow. Column 4 gives the assumed load scenario. Columns 8 and 9 indicate whether or not generator dismantling, re-installation and rewind are factored into the economic evaluation for that particular option or considered as part of a separate 10-year overhaul or unit life extension project that would be carried out at the same time as the work associated with the uprate.

Table ES-1: Uprate Cost/Benefit Summary

Option	Uprated Unit	Increased Turbine Flow (Y/N)	Load Scenario	Avoided Thermal Generation (MWh/yr)	Avoided Thermal Capacity (MW)	Capital Cost ($M)	Cost Incl. Disassemby & Install (Y/N)	Cost Incl. Generator Rewind (Y/N)	NPV 30 years ($M)	B/C ratio 30 years	Simple Payback Period (Years)	Discounted Payback Period (Years)
1-1	WH1	N	1	559	0.09	1.99	Y	N	0.21	1.11	19 yrs	28 yrs
1-1A	WH1	N	1	559	0.09	1.78	N	N	0.41	1.23	17 yrs	24 yrs
1-3	WH1	N	3	932	0.16	1.99	Y	N	0.98	1.52	12 yrs	15 yrs
1-3A	WH1	N	3	932	0.16	1.78	N	N	1.18	1.69	11 yrs	13 yrs
1-4	WH1	N	4	1491	0.23	1.99	Y	N	1.18	1.61	12 yrs	14 yrs
1-4A	WH1	N	4	1491	0.23	1.78	N	N	2.26	2.29	9 yrs	9 yrs
2-1	WH3	N	1	47	0.01	2.58	Y	N	-2.43	0.04	No Payback	No Payback
2-1A	WH3	N	1	47	0.01	1.18	N	N	-1.06	0.09	No Payback	No Payback
2-4	WH3	N	4	430	0.07	2.6	Y	N	-1.61	0.36	>45 yrs	>45 yrs
2-4A	WH3	N	4	430	0.07	1.2	N	N	-0.23	0.80	20 yrs	>45 yrs
3-1	WH4	N	1	395	0.05	4.26	Y	Y	-2.84	0.30	No Payback	No Payback
3-1A	WH4	N	1	395	0.05	2.30	N	N	-1.16	0.47	37 yrs	No Payback
4-1	WH1	Y	1	488	0.15	4.78	Y	Y	-2.68	0.43	No Payback	No Payback
4-1A	WH1	Y	1	488	0.15	2.74	N	N	-0.68	0.75	27 yrs	No Payback
4-4	WH1	Y	4	1879	0.40	4.78	Y	Y	0.28	1.06	14 yrs	23 yrs
4-4A	WH1	Y	4	1879	0.4	2.74	N	N	2.23	1.85	9 yrs	10 yrs
5-1	WH4 - K	N	1	1583	0.70	10.38	Y	Y	-6.18	0.39	42 yrs	No Payback
5-4	WH4 - K	N	4	47	1.00	10.4	Y	Y	1.20	1.12	14 yrs	23 yrs
6-1	WH1 & 2	N	1	795	0.09	3.97	Y	N	-0.95	0.75	27 yrs	No Payback

The evaluation summarized in the table above demonstrates that uprating WH1 is economically attractive. The work associated with the uprate project can also be combined with a generator life extension program that includes stator rewind and rotor refurbishment to take advantage of the outage associated with the uprate project. A small increase in turbine flow can also provide added benefit.

Uprating of WH3 and WH4 can also be attractive, but only if there is a significant increase in forecast load from what has been provided by YEC. With power and energy demands similar to present conditions, uprating these units do not appear to be economically attractive at this time.

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The study has also included an assessment of the cost of converting WH3 for operation as a synchronous condenser for providing reactive power. The estimated cost for this conversion is $288,000. However, at present, there is no requirement for reactive power and thus no benefit in carrying out this work.

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1. Introduction

This report presents the results of a study investigating the potential options for the uprate of the WH1, WH3 and WH4 turbines at the Whitehorse Generating Station (WGS). The report has been prepared by Hatch Ltd. (Hatch) for Yukon Energy Corporation (YEC).

The study addresses the technical issues, costs and benefits of improving the performance of the generating units at YEC's Whitehorse plant. The assessment includes:

- A review of the potential, efficiency, capacity and energy increases for the generating units.
- An assessment of the potential hydraulic, mechanical and electrical impacts of the upgrade.
- An estimate of associated costs for the upgrades.
- A cost/benefit analysis.
- A review of the issues associated with converting WH3 to have the capability of operating in synchronous condenser mode.
- Other related issues, such as rehabilitation, refurbishment and modernization.

The work associated with the report included a site visit by Hatch electrical and mechanical engineers in early November 2016 to briefly inspect the facilities, collect drawings and other information, and to discuss the operation of WGS with YEC personnel.

The study primarily addresses three of the four generating units at the facility (WH1, WH3 and WH4). However, as WH1 and WH2 are essentially identical, the issues, costs and benefits relating to WH1 will also generally apply to WH2.

A description of the Whitehorse plant is provided in Section 2 of this report. Sections 3, 4 and 5 present the issues and costs associated with uprating Units WH1, WH3 and WH4 respectively. The conversion of WH3 for use as a synchronous condenser is discussed in Section 6. Potential energy increases for the uprated turbines are reviewed in Section 7 and a cost benefit analysis is presented in Section 8. A discussion of results is given in Section 9 and the conclusions of the study are summarized in Section 10. Drawings and other supporting information and data are included as appendices to this report.

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2. Plant Description

2.1 General

The 40 MW Whitehorse Generating Station (WGS) is an important component of YEC's 132.5 MW generation portfolio. Other facilities include an additional 52 MW of hydro generation (Aishihik and Mayo), 31 MW of diesel, 8.8 MW of LNG units and 0.7 MW of wind generation. The generating facilities are connected to YEC's power grid which covers central and southern Yukon and operates isolated from the main North American electricity grid. One other station, the 1.3 MW Fish Lake hydro plant owned by ATCO Electric, also supplies power to the YEC grid.

WGS is located on the Yukon River on the outskirts of Whitehorse. The plant was constructed in 1956 when the first two units (WH1 and WH2) each with a capacity of 5.8 MW went into operation. A third unit (WH3), 8.4 MW in capacity, was added to the Whitehorse powerhouse in 1969. The power intakes are located at the end of a channel approximately 500 m long located on the left side of the dam and spillway. Three penstocks connect the power intakes to the powerhouse (WH0 or P125).

A second powerhouse was completed in 1984 with a single 20 MW generating unit (WH4). The intake for powerhouse WH4 (or P127) is located at the dam on the left side of the spillway, with a short penstock leading down to the powerhouse. A tailrace channel approximately 500 m long, directs flow from the powerhouse back into the river on the right side of the WH0 powerhouse. The downstream end of the tailrace has a fish screen structure whereby screens are installed in the summer to prevent fish from entering the WH4 tailrace.

Units WH1 and WH2 are equipped with adjustable blade Kaplan turbines and WH3 and WH4 have fixed blade propeller turbines. WGS has a gross head of approximately 19 m and a maximum discharge of 275 m^3/s.

The plant operates generally as a run-of-river facility although there is some water control available at the Marsh Lake Control Structure upstream of the plant. Figure 2-1 shows the WGS facility.

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Figure 2-1: Whitehorse Generating Station

2.2 Generating Units

The principle technical data for the WGS generating units are provided in Table 2-1.

Table 2-1: Generating Unit Data

	WH1 & WH2	WH3	WH4
Turbine			
• Manufacturer	KMW	Allis Chalmers	GE
• Type	vertical Kaplan	vertical propeller	vertical propeller
• Rated power	5.6 MW	8.4 MW	21.3 MW
• Rated head	18.6 m	18.0 m	18.2 m
• Rated discharge	34.5 m^3/s	50 m^3/s	131 m^3/s
• Speed	300 rpm	200 rpm	150 rpm
• Runner diameter	2.226 m	2.790 m	4.159 m
• Number of runner blades	4	4	5
• Distributor centerline	El 630.75 m	El 630.75 m	El 633.00 m
• Runner centerline	El 629.86 m	El 729.69 m	El 731.63 m
• Inlet type	spiral case	spiral case	spiral case

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	WH1 & WH2	WH3	WH4
• Draft tube type	elbow	elbow	elbow
• Minimum tailwater level	El 633.3 m	El 633.3 m	El 633.8 m
Generator			
• Manufacturer	Westinghouse	CGE	CGE
• Type	umbrella	umbrella	umbrella
• Rated output	6700 kVA	9400 kVA	23,600 kVA
• Power factor	0.85	0.85	0.85
• Rated power	5695 kW	7990 kW	20,060 kW
• Speed	300 rpm	200 rpm	150 rpm
• Voltage	6900 V	6900 V	6900 V
• Insulation class	B	B	F
• Cooling	air	air	air-to-water heat exchangers
• Exciter type	rotating	rotating	static
In service date	1958	1969	1984

All four generating units have vertical shaft turbines directly connected to vertical synchronous generators. The turbines have embedded steel spiral cases and elbow draft tubes that are integral with the powerhouse concrete substructure.

WH1 and WH2 have mechanical gate shaft type governors. WH3 also has a gate shaft governor; however the original mechanical governor head has been converted to a digital head. WH4 is equipped with a cabinet actuator governor, which was originally a mechanical governor and has been converted to a digital governor.

WH1, WH2, and WH3 have rotating exciters with static automatic voltage regulators. WH4 has a full static excitation system.

Original Equipment Manufacturer (OEM) drawings of the turbines and generators as well as general arrangement drawings of the powerhouse structure and the plant single line diagrams are included in Appendix A.

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3. WH1 Uprate

3.1 General / Existing Performance

WH1 (and WH2) are the oldest units at the plant, and have been in operation for nearly 60 years.

The turbines for both units generally operate in a reliable manner. They are dewatered for inspection and maintenance every year and are fully dismantled every 10 years. The last 10-year overhaul of WH1 was in 2015.

There are apparently some issues with oil leakage at the runner blade to hub seals and with possible voids in the concrete behind the draft tube liner.

The turbine has stainless steel runner blades and discharge ring. Cavitation damage is minimal and occurs on the suction side of the blades as well as on the draft tube liner just below the discharge ring. The damage is repaired each year during the annual outage.

Efficiency tests were conducted on WH1 in 2009 by Hydro Power Performance Engineering, Inc. (HPPE) for the KGS Group. Turbine flow was measured using flow meters installed at the intake. The tests indicated performance as follows:

- Peak turbine efficiency = 88.1%
- Peak efficiency flow = 23 m^3/s
- Efficiency at full load = 82.3%
- Full load flow = 39.5 m^3/s
- Full load turbine output = 5.74 MW at 18 m net head

Being an adjustable blade turbine, the unit has a wide operating range, from full load down to approximately 2 MW.

There are no major issues currently identified with the WH1 generator. Operating data indicates that the generator stator temperatures are fairly low. This is further discussed in Section 3.5.

3.2 Uprate Options

It will be possible to improve the performance of WH1 by installing a new turbine runner of modern design. The uprate options include:

- New more efficient Kaplan runner with the same flow capacity as the existing turbine. The increase in maximum power output will be directly proportional to the increase in turbine efficiency.

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- New more efficient Kaplan runner with increased flow capacity. This will further increase the maximum power output, with the power limit generally governed by the cavitation characteristics of the runner.

The performance characteristics of the uprated turbines are discussed in Section 3.3 below.

It would also be possible to install a new fixed blade propeller runner in place of the Kaplan design. This would provide increased efficiency and power, with a much lower runner cost. However output variation would be quite restrictive, with the units operating more or less at a single output. Therefore this option has not been studied in detail.

3.3 Performance Characteristics

The peak efficiency of the existing WH1 turbine is 88.1% as mentioned above. A modern Kaplan turbine operating under similar head and flow conditions would have a peak efficiency of approximately 94%. However, it is unlikely that this full efficiency increase can be achieved with only a new runner. The reason is that turbine efficiency must also encompass the spiral case, stay vanes, wicket gates and draft tube. A typical breakdown of losses for an axial flow (Kaplan or propeller) turbine is as follows:

- Runner hydraulic losses = 35% of total losses
- Runner periphery leakage losses = 5% of total losses
- Spiral case losses = 10% of total losses
- Stay vane losses = 10% of total losses
- Wicket gate losses = 10% of total losses
- Draft tube losses = 25 % of total losses
- Mechanical losses = 5% of total losses

While some modification of stay vanes is possible if necessary, the other components would be difficult to modify and as such would not be changed. Therefore a full efficiency increase to present day levels would be difficult to achieve. In particular, the turbine draft tube can have a significant effect on turbine performance.

The dimensions of the WH1 turbine components and water passages have been compared with a modern design. Also the diffusion characteristics of the draft tube have been reviewed, particularly in the critical elbow area where flow separation can negatively affect efficiency. The existing design appears to be fairly consistent with a modern turbine, as indicated in Table 3-1. The spiral case inlet diameter, as a ratio or runner diameter, appears fairly large, and this should help reduce losses. The draft tube is relatively shallow, which can be a concern. Nevertheless the diffusion characteristics of the draft tube appear to be good, with appropriate acceleration in the elbow area as illustrated on Figure 3-1.Some reduction in efficiency when compared to a modern design should also be assumed.

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Table 3-1: Turbine Dimensions

Turbine Dimensions	WH1	WH3	WH4	Typical Modern Design
Runner diameter (D) – m	2.236	2.781	4.159	
Spiral case inlet diam.(A) – m	3.526	4.157	6.500	
Wicket gate circle diam. (W) – m	2.819	3.353	4.905	
Wicket gate height (H) – m	0.989	1.105	1.690	
Number of wicket gates	22	20	20	
Draft tube depth (Dr)* – m	4.493	8.039	11.300	
A/D	1.58	1.49	1.56	1.3
W/D	1.27	1.20	1.18	1.2
H/D	0.44	0.40	0.41	0.4
Dr/D	2.02	2.98	2.72	2..5 – 2.8

* Distance from runner centerline to bottom of elbow

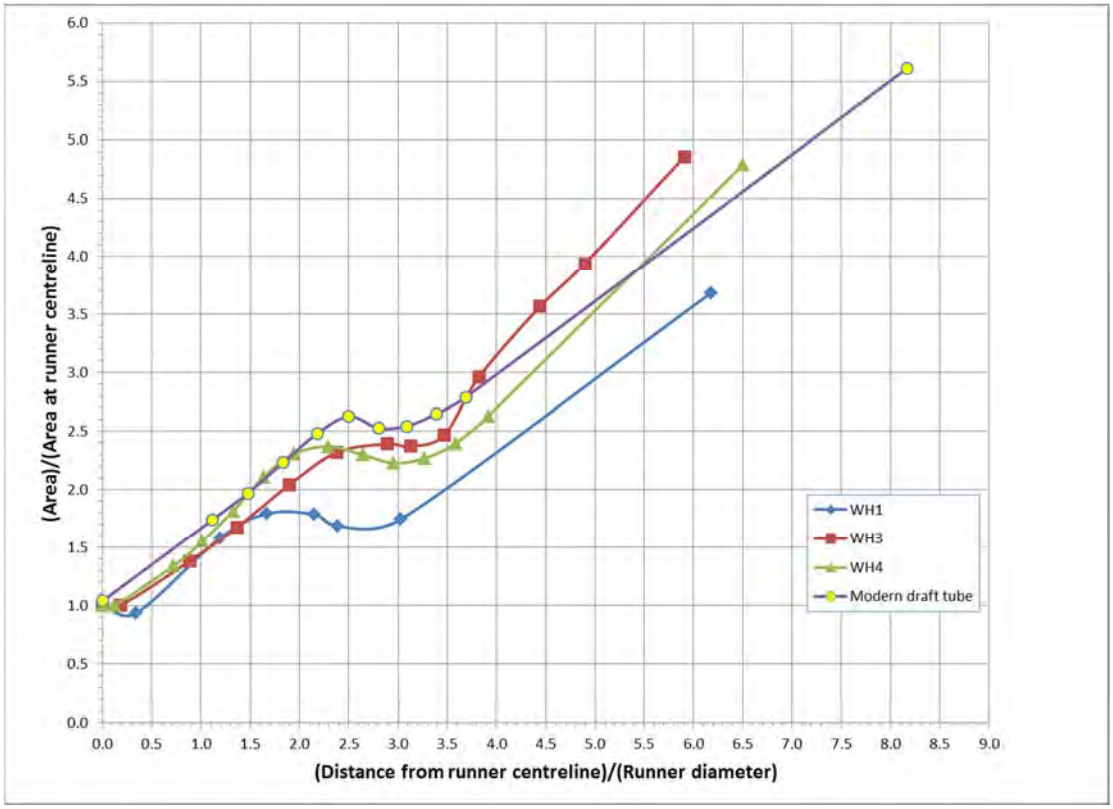

Figure 3-1: Draft Tube Characteristics

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Figure 3-2 shows the efficiency of the existing turbine based on the testing done by HPPE, the efficiency of a modern state of the art turbine derived from model test information, and the estimated efficiency of the WH1 turbine with a new runner and possible stay vane modifications. WH3 and WH4 turbine curves are also shown for reference. The efficiency curve for the existing turbine is for the optimum wicket gate – runner blade relationship. The estimated increase in efficiency with a new runner is approximately 4%.

It is possible to replace only the runner blades, keeping the same runner hub including the internal blade operating mechanism. Equipment cost would be reduced for this option. However, it is expected that the level of efficiency increase would not match that of a complete new runner, and would perhaps be 50% of the increase as compared to a completely new runner, there would also be increased uncertainty in the performance of the new runner. Furthermore, fitting the new runner blades to the existing runner hub would require an increased outage for the uprate project as this could not be done until the existing generating unit was dismantled.

The new runner could also potentially be designed for some nominal increase in flow capacity. The limit for a potential flow increase is dictated by the cavitation characteristics of the runner as runner diameter, speed, and setting relative to tailwater level are fixed. From a review of model test information for similar turbine designs it appears that a 5 to 10% increase in flow will be possible. The higher flow runner will result in some reduction in efficiency, as losses in the spiral case, stay ring and draft tube increase with the square of the flow. Figure 3-2 also shows the estimated turbine performance for a new runner with a 10% increase in flow. The increase in energy and capacity for the various uprate options are discussed in Section 7.

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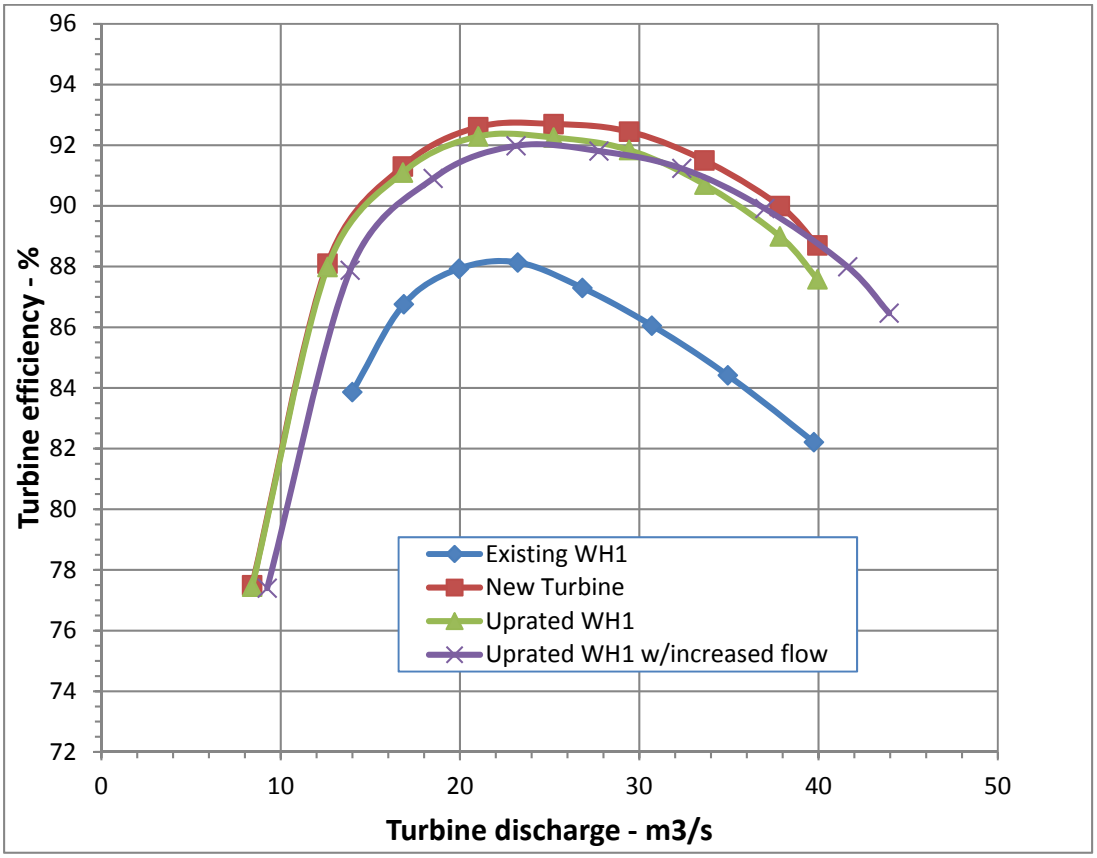

Figure 3-2: WH1 Turbine Performance

3.4 Mechanical Impacts

3.4.1 Turbine Shaft

The turbine is forged steel with an estimated outside diameter of 375 mm and inside diameter of 140 mm (both scaled from the drawing). The shaft material characteristics are not known, but a common shaft material is equivalent to ASTM A668 Class D, which has a yield strength of 260 MPa. At the present maximum turbine power of 5800 kW the torsional shear stress is 18.8 MPa, which is only 7.2% of tensile yield.

A common criterion for allowable shaft stress is for torsional shear to be 1/6 (16.7%) of yield as this provides a safety factor of 3, assuming shear yield strength is 50% of tensile yield strength. The calculated stress is significantly below this allowable stress level. Therefore the shaft should be adequate even with a substantial increase in power.

3.4.2 Turbine Guide Bearing

The load on the turbine guide bearing should not materially change with a new turbine runner. Load may actually be reduced as the new runner should have improved mechanical and hydraulic balance over the existing unit.

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3.4.3 Turbine Wicket Gate Operating Mechanism

There are two conditions that govern the wicket gate torque:

- Maximum torque to move the gates to full closed position.
- Maximum torque when opening the gates, which typically occurs in the 60 to 80% gate range.

The torque to fully close the wicket gates will remain unchanged, but the hydraulic torque to open the gates increases with the square of the flow.

It is not certain as to which torque governs the wicket gate servomotor size. Governor systems have traditionally been conservatively sized; therefore a problem is not expected. However, this would require site test verification if a new runner with increased flow capacity is selected.

On many uprated turbines, it is also necessary to increase the servomotor stroke to allow increase wicket gate opening. This is often accommodated by machining the servomotor piston or providing a new piston with adjusted length.

3.4.4 Generator Shaft

The generator shaft is forged steel with an outside diameter of 381 mm and an estimated inside diameter of 140 mm (scaled from the drawing). The shaft material is not known, but a common Westinghouse shaft material has a shear yield of 248 MPa. Allowable torsional shear will be 41 MPa. The calculated shear stress is 17.5 MPa, well below the allowable value. Therefore the shaft should be adequate even with a substantial increase in power.

3.4.5 Generator Bearings

The generator guide bearing load is dependent on the mechanical unbalance of the rotor as well as the air gap, which impacts the magnetic unbalance. Assuming that the mechanical balance and air gap meet recognized standards after the upgrade, there will be no issue with guide bearing load.

The load on the thrust bearing is equal to the weight of turbine and generator rotating parts plus the maximum hydraulic thrust. The weight of the rotating parts will be essentially unchanged. A new turbine runner could possibly be slightly heavier or lighter; however the runner weight is only a small fraction of the total weight of rotating parts. Hydraulic thrust is generally a function of the turbine runner area in plan, and this will also be unchanged. As total thrust loads will be nearly the same there should be no issues with the thrust bearing.

3.4.6 Generator Brackets

The generator brackets will not be affected by the by a turbine or generator uprate. The upper brackets support the generator floor plates. The lower bracket supports the thrust bearing and has a much higher load. However, as thrust bearing load is essentially unchanged, the lower bracket will not be affected.

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3.4.7 Generator Rotor

The normal stress levels in the rotor spider are due to the weight of the rim, the compressive stress from the interference fit of the rim, and the stress due to torque transfer between the shaft and the rotor rim. The stress due to torque transfer will be higher if turbine power increases. However, evaluation of the rotor on other Westinghouse generators of similar or earlier vintage has indicated no significant issues with increased stresses due to torque transfer.

Turbine runaway speed should not significantly change with a new runner design; therefore stresses in the rotor spider at runaway speed will be nearly the same. These stress levels are generally quite low.

With regard to the rotor rim and poles, the highest stresses occur at runaway speed, which should not materially change.

3.4.8 Generator Stator and Stator Foundation

The highest stress in the generator stator and stator foundation occur as a result of short circuit conditions or a faulty synchronization. These loads are a function of the stator dimensions and the winding configuration, and therefore should not change materially even if the generator is rewound to accommodate a higher power output.

3.5 Electrical Impacts

An overall assessment of the electrical impacts of uprating the WH1 turbine is summarized below, assuming a nominal 10% increase in power. Recommendations are described where applicable, and their associated implementation costs are included in Section 3.7. This information applies to both WH1 and WH2 generators.

3.5.1 Generator

WH1 is a 6.7 MVA umbrella type synchronous generator rated at 6.9 kV and 0.85 power factor, with a full load current of 561 A. It was manufactured in Hamilton, Ontario in 1958 by Westinghouse. The generator incorporates a type of Class B (130 °C) insulation derived using mica in combination with a synthetic resin for all windings, connections, parallel rings, and bus work. By comparison, the designed temperature rises are 60 °C, 50 °C, and 65 °C for the windings, core, and collector rings respectively given an ambient temperature of 40 °C.

For cooling, fan blades attached to the rotor rim are used to force air through the brushgear, spider, and windings of the generator. The lubrication system for the generator bearings is cooled by circulating water through copper cooling coils.

During the site inspection, WH1 and WH2 were noted to be generating at approximately 5 MVA, 6.8 kV, and unity power factor. Although this operating point is only 75% of full load, the existing thermocouples indicated an average stator temperature of only 34 °C. Given that these observations were made during the winter season when outdoor air temperatures are lower, supplied trend data from October 2015 was also reviewed. However, it was noted that

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the generators also run relatively cool. For example, at an operating point of 6.7 MVA, 6.8 kV, and unity power factor, the stator temperature was recorded as 42.7 °C.

Per the guaranteed data in the original specifications not including excitation losses, the overall efficiency of the generator is 95.85% at full load and 0.85 power factor, and it is 96.6% at full load and unity power factor.

YEC regularly performs cleaning and testing of the generator on an annual basis. According to the latest preventative maintenance report, the stator, rotor, and neutral grounding resistor were all megger-tested with no significant issues identified. Additional instrumentation, as well as protection and control tests were also conducted and the equipment was generally found to be functioning as designed. Partial discharge test information was not available for WH1 (and WH2).

Based on the information above, WH1 should be able to generate at an uprated output that is 10% higher than its nameplate capacity without exceeding the maximum rated operating temperature of its insulation system. However, given that the generator is approximately 60 years old without yet having undergone a major overhaul YEC could take advantage of the outage required to complete the mechanical upgrade work to replace the existing stator winding and also refurbish the rotor field poles and windings. Although the longevity of the existing generator is supported by the low operating temperature and lack of heavy thermal cycling, the generator has exceeded a typical winding life of 40 years, implying increased risk of failure, which may lead to an extended unplanned outage while repairs are undertaken.

Hatch notes that the existing generator CTs (current transformers) have 600:5 A ratios and the split phase CTs have 300:5 A ratios. These instrumentation transformers will not be able to accommodate the uprated generator current and will need to be replaced.

The generator excitation system is discussed in Section 3.5.3. No work is expected for the existing neutral leads, neutral grounding resistor, and potential transformers (PTs) which will be compatible with the uprated generator.

In summary, the following work is recommended:

- Replacement of the stator windings with modern Class F insulation, improved wedging, and marginally higher efficiency.
- Refurbishment the rotor poles using modern Class F insulation, upgrade of the pole windings, and replacement of the rotor brushgear and collectors.
- Replacement of thermocouples with higher accuracy RTD (resistance temperature detectors).
- Replacement of CTs with higher current ratings.
- Replacement of aging surge arresters and capacitors (presently located within the excitation cabinet) to prevent equipment damage from fast transients and lightning surges.

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3.5.2 *Generator Main Leads*

The generator main leads connect the generator terminals to the powerhouse 6.9 kV switchgear and consist of one armoured 500 kcmil cable per phase. These cables are routed through cable trays on the Generator Floor and then enter the WH0 Control Room on the Main Floor via individual ducts for each cable in the ceiling.

Throughout their route, the cables were found to be arranged with at least one cable diameter spacing between them. If they are assumed to be rated at a conservative 75 °C operating temperature, the cables have an ampacity of at least 620 A. Thus they will be able to pass the generator's uprated current of 561 A x 1.1 = 617 A.

In summary, no work is required.

3.5.3 *Excitation System*

The excitation system consists of an original main rotary exciter as well as an upgraded pilot static exciter. The main rotary exciter is a DC generator rated 50 kW, 125 V, and, according to its nameplate, it can produce up to 400 A. The pilot exciter including the automatic voltage regulator is Basler model SR125H.

WH1 currently requires a field current of 365 A when operating at rated capacity, voltage, and power factor. If the generator capacity is uprated by 10%, the existing excitation system will not have adequate capacity to drive the required field current and voltage on a continuous basis (including a margin of at least 5% for voltage variations from the generator's rated voltage). The actual field current ratings and excitation requirements will be confirmed once the new generator winding is designed and capacity confirmed.

A replacement of the rotary excitation system with a fully static excitation system will improve the stability of the generator by enabling it to more quickly and aggressively respond to transients and abnormal system conditions. As well, a more modern system will improve reliability and operational efficiencies by providing additional diagnostics, telemetry, and redundant components. Since a complete static excitation system primarily utilizes solid state devices, there is substantially reduced maintenance. Legacy electronic components which are subject to wear and sudden failures such as rheostats and potentiometers are also eliminated.

The size of the generator field leads is currently not known. They should be verified for adequate capacity to conduct the higher generator rated field current.

In summary, the following work is recommended:

- Replacement of the excitation system with a static exciter (transformer and rectifier).

3.5.4 *Medium Voltage (6.9 kV) Switchgear*

The generator output from WH1 is connected to a vacuum generator circuit breaker in the 6.9 kV switchgear, manufactured by Rosen's Electrical Equipment, located in the Control Room. The uprated generator current of 617 A is well below the 2000 A continuous rating of the generator circuit breaker. The 6.9 kV switchgear also houses circuit breakers for a feed from the WH2 generator as well as connections to the Spillway and Substation.

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If all of the generators (WH1, WH2, WH3, and WH4) are each uprated, the fault level at this 6.9 kV switchgear is expected to marginally increase. This increased short circuit level should remain under the maximum 500 MVA (42 kA) rating of the circuit breakers.

Since annual contact resistance and megger testing of the switchgear have also indicated that there are no problems with the equipment, the 6.9 kV switchgear does not have to be upgraded at this time.

The cables between the switchgear and the Substation were not accessible for inspection. The size of these cables should be verified for adequate capacity to accommodate the higher generator current once confirmed.

Note that an arc-flash study will have to be completed to re-evaluate the resulting incident energy values and PPE (personal protective equipment) requirements.

In summary, the following work is recommended:

- Arc-flash study and re-evaluation for the switchgear.

3.5.5 Station Service

Auxiliary loads in the WH0 Powerhouse are supplied from a motor control center (MCC) which in turn is fed by a 500 kVA, 6.9 kV – 600 V station service transformer located in the Substation. The auxiliary loads include generator lift pumps, governor oil HPUs (hydraulic pressure units), glycol cooling water pumps, and HVAC (heating, ventilation, and air conditioning).

It is expected that the demands of these loads will not change significantly as a result of uprating the turbine and generator. Thus no material upgrades to the station service system are expected. In the unlikely event that new or larger starters are needed, there are spare compartments available in the existing MCC.

In summary, no work is required.

3.5.6 Step-up Transformer

There are no step-up transformers dedicated to WH1. Presently, the generator output is directed to the Whitehorse Rapids Substation, which combines generation from the hydroelectric facilities and the adjacent diesel and gas plants. At the Substation, power is transformed from 6.9 kV to 138 kV and 34.5 kV for transmission and distribution. There is no equipment at the Substation which is specific to WH1 and would require replacement with the uprating of WH1.

In summary, no work is required.

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3.6 Balance of Plant Impacts

The impact of turbine uprate on the balance of plant equipment and services would be minimal. The heat load in the powerhouse would increase approximately in direct proportion to the increase in generator power. The ventilation system summer performance in Powerhouse WH0 will require study as to its effectiveness and ventilation capacity increased as required.

Other systems should not change.

3.7 Estimated Cost and Schedule

The estimated cost in present day (2017) dollars for the two turbine uprate options are summarized in Table 3-2 below. The basis of the estimates are:

- Budget prices for new runners provided by turbine suppliers.
- Actual pricing as well as reference pricing from other comparable projects with similar equipment.
- Nominal cost allowances for small items such as servomotor pistons.

Requests for budgetary runner pricing were sent to several turbine manufacturers, and responses were received from Norcan, Andritz Hydro, Voith and GE (formerly Alstom). There was a wide range of runner prices from suppliers, and an intermediate value was selected for the cost estimate. A summary of pricing is included in Appendix C.

For the alternative where there is no turbine flow increase, the generator power level has been limited to the existing capacity. This essentially eliminates costs associated with the generator and associated electrical equipment, except for generator dismantling and re-installation costs. Given the age of the generator windings, it may be prudent to rewind the generator stator when uprating the turbine. However, as this would be a life extension activity, the generator rewind cost was not included as part of the turbine uprate cost benefit analysis.

If it is concluded that generator rewind is warranted for equipment life extension, it can be argued that the associated generator dismantling and reinstallation costs for both of the options in Table 3-2 should not be part of the turbine uprate cost. For the option with increased turbine flow capacity, the cost of generator rewind and rotor pole refurbishment would also be excluded from the turbine uprate cost. The estimated total cost attributed to turbine uprate for the two options would then be as follows:

- Same turbine flow $1,784,000
- Increased turbine flow $2,739,000

Some reduction in cost would be expected if it is decided to uprate both WH1 and WH2. The savings would likely be in the new runner supply costs, as well as stator winding supply costs.

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These costs may be about 20% less for the second unit. For schedule reasons the site work would likely occur one year apart. Therefore no significant saving on site costs are foreseen.

The total time required for an uprate program for WH1, including upfront engineering, equipment tendering, equipment procurement, is estimated to be approximately 23 months. A preliminary schedule is included in Appendix B. The unit outage time is estimated to be 4.5 months. This allows some time for turbine and generator rehabilitation work that would typically be done when the equipment is dismantled. The rehabilitation work is not attributed to the uprate; therefore it is not included in the capital cost discussed above. The schedule includes generator rewind; however it would not be significantly shortened if a rewind is not required. The outage would be scheduled appropriately to minimize cost implications to YEC from the outage. This is discussed in Section 7 and included in the cost benefit analysis in Section 8.

Table 3-2: Capital Cost Estimate for WH1 Turbine Uprate

		Same Turbine Flow	***Increased Turbine flow***
1	**Dismantling and Re-installation**		
1.1	Turbine & generator dismantling	$380,000	$380,000
1.2	Turbine & generator reinstallation and testing	$580,000	$580,000
2	**Turbine**		
2.1	New turbine runner	$530,000	$530,000
2.2	Stay vane modications	$80,000	$80,000
2.3	New servomotor pistons		$10,000
3	**Generator**		
3.1	Replace stator windings		$1,000,000
3.2	Refurbish rotor poles		$450,000
3.3	Replace thermocouples with RTD's		$25,000
3.4	Replace CT's		$75,000
3.5	Replace surge arrestors & capacitors		$100,000
4	**Exciter**		
4.1	Replace exciter		$500,000
5	**6.9 kV Switchgear**		
5.1	Arc flash evaluation		$10,000
6	**Balance of plant**		
6.1	Ventilation system upgrade		$40,000
	Subtotal	$1,570,000	$3,780,000
	Contingency (15%)	$235,500	$567,000
	Construction cost	$1,805,500	$4,347,000
	Engineering and administration (10%)	$180,550	$434,700
	Estimated total cost	$1,986,050	$4,781,700

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3.8 Equipment Life Considerations

The expected life of the turbine and generator equipment and the possibility of major failure can influence an uprate program. The existing equipment is approaching 60 years of age.

The WH1 turbine does not appear to be approaching the end of its useful life. As mentioned in Section 3.1, the turbines are dismantled every 10 years for overhaul. YEC personnel have not noted major problems with the turbine, and the 2016 Knight Piesold condition report does not identify significant turbine issues. Kaplan runner hub seal leakage has been noted as well as some spiral case leakage (on WH2). However, these issues should not materially affect equipment life. Cavitation damage to the turbine is reported to be manageable.

There are operating plants with Kaplan turbines dating from the 1930's, which are the earliest designs, still in use. A further 30-year operating life for the existing WH1 turbine can be foreseen.

Likewise, extended operation of the WH1 generator should be possible. There are numerous hydro generators dating from the 1920's and earlier that are still in use. The primary issue with the generator is the stator windings and, to some extent, the stator core. The existing windings are approaching 60 years in life as compared to an average generator winding life of about 40 years. This does not mean that the windings are in immediate danger of failing. Various factors influence winding life. For example, a "rule of thumb" is that a 10°C reduction in winding temperature can double winding life. WH1 temperatures are low. There are hydro generators in operation with 80-year old windings. As mentioned in Section 3.5.1, generator inspection reports indicate satisfactory generator condition. Unfortunately, there is no historical partial discharge (PDA) data to allow trending of stator winding condition.

Nevertheless, it is difficult to project the life of the generator stator, and it would be appropriate to plan for a rewind in the next 10 years. Further, as mentioned in Section 3.5.1, if a 10% increase in power output is planned, the generator stator and rotor should be rewound regardless.

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4. WH3 Uprate

4.1 General / Existing Performance

WH3 went into operation in 1969. The turbine is a fixed blade propeller type; therefore unlike WH1 and WH2, it has a limited power range for efficient operation. It is the least efficient unit at the facility and therefore is the last unit operated.

The turbine is dewatered for inspection every year and there is a planned overhaul on a 10-year cycle.

In February 2003, the unit was shut down when severe turbine vibration was noted. Upon inspection, a long crack completely through one of the blades was identified extending from the trailing edge to near the leading edge of the blade. NDT inspection indicated some cracking in a similar location on the three of the other blades. A root cause assessment of the problem was made by BC Hydro, and it was concluded that the cracking was related to the age of the turbine and the number of starts and stops, possibly aggravated by material embrittlement due to welding. The cracks were repaired using a procedure prepared by BC Hydro.

The turbine has not had a major overhaul since the 2003/2004 outage for the blade cracking issue and associated repair. The runner material is carbon steel, and cavitation damage is relatively light and predominately on the pressure side of the blades. There is also some damage on the draft tube liner just below the discharge ring. Repairs are made by welding each year, generally over a 3-day period.

Efficiency tests were conducted on WH3 in 2009 by HPPE for the KGS Group. Turbine flow was measured by current meters at the intake. The tests indicated performance as follows:

- Peak turbine efficiency = 86.2%
- Peak efficiency flow = 53.8 m^3/s
- Efficiency at full load = 77.3%
- Full load flow = 62.0 m^3/s
- Full load turbine power = 8.22 MW at 17.5 m net head

The turbine has a rough operating zone between approximately 5.5 MW to 6 MW, and has increased vibration below 6 MW.

There are no major issues identified with the WH3 generator. Operating data indicates that the generator stator temperatures are fairly low.

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4.2 Uprate Options

It will be possible to improve the performance of WH3 by installing a new turbine runner of modern design. The uprate options include:

- New more efficient propeller runner with the same flow capacity as the existing turbine. The increase in maximum power output will be directly proportional to the increase in turbine efficiency.
- New more efficient propeller runner with increased flow capacity. This will further increase the maximum power output, with the power limit generally dictated by the cavitation characteristics of the runner.
- Retrofit the turbine with a Kaplan runner to allow operation over a wide range of flow. This has significant implications for the generator because of higher runaway speed as well as impacts to the turbine and generator shaft and the turbine discharge ring. These issues are further discussed in Section 4.4.9.

The performance characteristics of the uprated WH3 turbine are discussed in Section 4.3.

The limited operating range of the propeller runner is a disadvantage of WH3.The possibility of installing a mixed flow runner rather than a conventional fixed blade propeller runner has also been considered. The mixed flow runner has a different blade shape, generally a higher number of blades, and provides a somewhat less “peaky” efficiency curve when compared to a propeller runner. However the turbine speed, runner diameter, and head combination are not well suited to a mixed flow runner. A comparison of the WH3 and WH4 turbines with mixed flow turbines is shown in Table 4-1. A lower operating speed (N11) and lower specific speed (Nq) would be required for a mixed flow turbine design with a flatter efficiency curve. Therefore, a mixed flow runner does not appear to be a suitable option. In addition it is expected that the supply cost for a mixed flow runner would be about 10% higher than a conventional fixed blade propeller runner because of the increased length and number of blades

Table 4-1: Runner Comparison

	WH3	WH4	Cabinet Gorge U3	EB Campbell U7 and 8
Runner type	Propeller	Propeller	Mixed flow	Mixed flow
Head (m)	18.0	18.2	29.0	31.9
Runner diameter (m)	2.79	4.159	5.380	4.311
Speed (rpm)	200	150	120	120
Discharge (m^3/s)	62.0	135.2	292	293.3
Unit speed (N11)	***131.5***	***146.2***	***119.9***	***91.6***
Unit Discharge (Q11)	1.877	1.832	1.870	1.461
Specific Speed (Nq)	***180.2***	***197.9***	***164.0***	***110.7***

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4.3 Performance Characteristics

The peak efficiency of the existing WH3 turbine is 86.2% as mentioned in Section 4.1. A modern propeller turbine operating under similar head and flow conditions would have a peak efficiency of about 94%. However, the same issues as discussed in Section 3.3 will limit the efficiency that can be achieved with a new runner.

The dimensions of the WH3 turbine components and water passages have been reviewed and compared with a modern design. Also the diffusion characteristics of the draft tube have been reviewed, particularly in the critical elbow area where flow separation can negatively affect efficiency. The turbine appears to be fairly consistent with a modern turbine as shown on Table 3-1 and Figure 3-1 Nevertheless, efficiency levels somewhat lower than a modern design should be assumed.

Figure 4-1 shows the efficiency of the existing turbine based on the testing done by HPPE, the efficiency of a modern state of the art turbine derived from model test information and the estimated efficiency of the WH3 turbine with a new runner and possible stay vane modifications. The estimated increase in peak efficiency with a new runner is still quite sizeable and is approximately 6%. The increase in energy and capacity for the uprate options are discussed in Section 7.

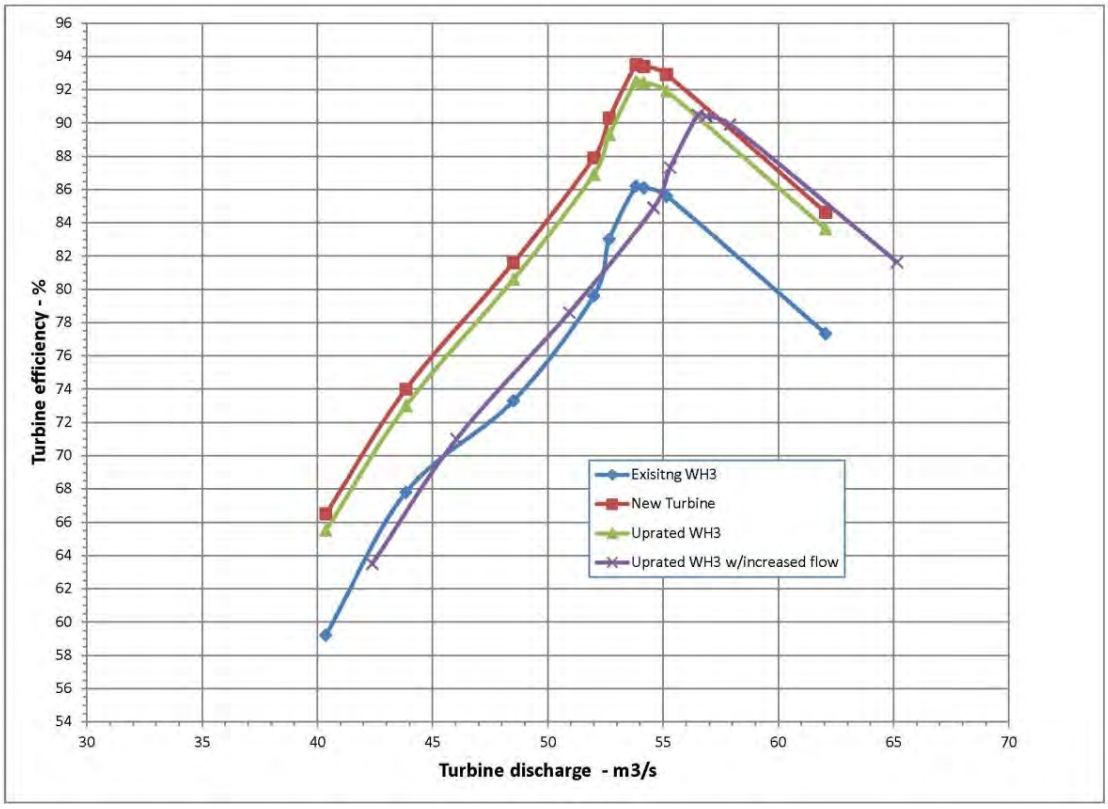

Figure 4-1: WH3 Performance

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The new runner could also be designed for some increase in flow capacity. The limit is dictated by cavitation characteristics, as the runner diameter, speed, and setting relative to tailwater level are fixed. From a review of model test information for similar turbine designs, it appears that a 5% increase in flow will be possible. The higher flow runner will result in some reduction in efficiency, as losses in the spiral case, stay ring and draft tube increase with the square of the flow. Figure 4-1 also shows the estimated turbine performance for a new runner with a 5% increase in flow.

Installation of a Kaplan runner in place of the fixed blade propeller runner is possible, but there are significant mechanical impacts as discussed in Section 4.4. A performance curve for a Kaplan runner is shown on Figure 4-2. The increase in energy and capacity for the uprate options are discussed in Section 7.

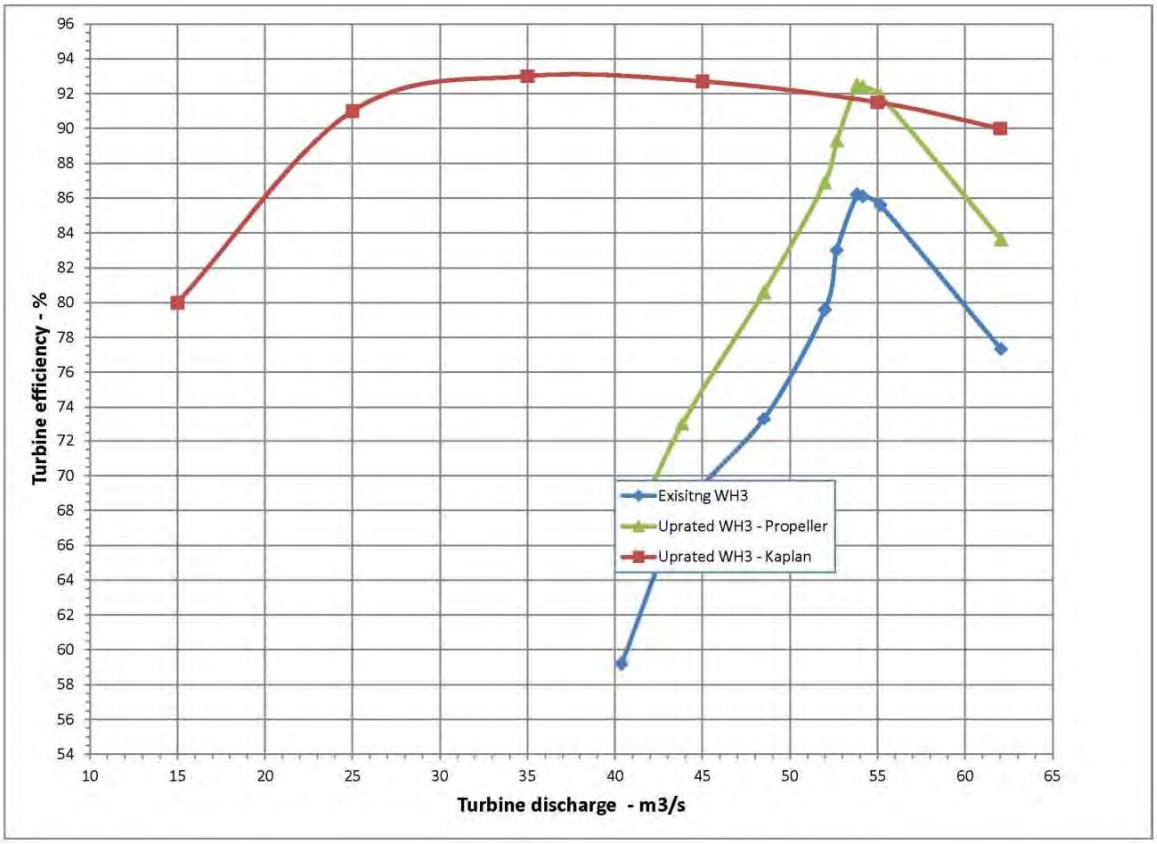

Figure 4-2: WH3 Kaplan and Propeller Runners

4.4 Mechanical Impacts

The mechanical issues relating to uprating the WH3 turbine are reviewed in the sections below. The issues associated with a new propeller runner are addressed in Section 4.4.1 to Section 4.4.8. The additional implications for installation of a Kaplan runner are discussed in Section 4.4.9.

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4.4.1 *Turbine Shaft*

The turbine is forged steel with an outside diameter of 356 mm. From the drawings, the shaft appears to have no inner bore. The shaft material characteristics are not known, but a common shaft material is equivalent to ASTM A668 Class D, which has a yield strength of 260 MPa. At the present maximum turbine power of 8220 kW, the torsional stress is 44.5 MPa which is which is 17.1 % of tensile yield.

A common criterion for allowable shaft stress is for torsional stress to be 1/6 (16.7%) of yield as this provides a safety factor of 3, assuming shear yield strength is 50% of tensile yield strength. The calculated stress is above this value. If turbine power is increased by 10%, the stress levels would be 18.8% of yield or 13% over the criteria. This may still be suitable but is becoming marginal. A review of the files to determine actual shaft strength is recommended depending on the level of uprate. A new shaft with higher strength steel could also be procured; however this is unusual on turbine uprate projects. A new shaft would have the same diameter as the existing shaft to avoid impacting the guide bearing and shaft seal design.

4.4.2 *Turbine Guide Bearing*

The load on the turbine guide bearing should not materially change with a new turbine runner. Load may actually be reduced if the new runner should have more accurate mechanical and hydraulic balance.

4.4.3 *Turbine Wicket Gate Operating Mechanism*

There are two conditions that govern the wicket gate torque:

- Maximum torque to move the gates to full closed position.
- Maximum torque when opening the gates, which typically occurs in the 60 to 80% gate range.

The torque to fully close the wicket gates will remain unchanged, but the hydraulic torque to open the gates increases with the square of the flow.

It is not certain as to which torque governs the wicket gate servomotor size. Governor systems have traditionally been conservatively sized; therefore a problem is not expected. However this would require site test verification if a new runner with increased flow capacity is selected.

On some uprated turbines it is necessary to increase the servomotor stroke to allow increase wicket gate opening. This is often accommodated by machining the servomotor piston or providing a new piston with adjusted length.

4.4.4 *Generator Shaft*

The generator shaft is forged steel with a diameter of 356 mm, the same as the turbine shaft. Therefore the issues discussed above for the turbine shaft will apply.

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4.4.5 *Generator Bearings*

The generator guide bearing load is dependent on the mechanical unbalance of the rotor as well as the air gap, which impacts the magnetic unbalance. Assuming that the mechanical balance and air gap meet recognized standards after the upgrade, there will be no issue on guide bearing load.

The load on the thrust bearing is equal to the weight of turbine and generator rotating parts plus the maximum hydraulic thrust. The weight of the rotating parts will be essentially unchanged. A new turbine runner could possibly be slightly heavier or lighter; however the runner is only a small fraction of the total weight of rotating parts. Hydraulic thrust is generally a function of the turbine runner area in plan, and this will also be unchanged. As total thrust loads will be neatly the same, there should be no issues with the thrust bearing.

4.4.6 *Generator Brackets*

The generator brackets will not be affected by the by a turbine or generator uprate. The upper brackets support the generator floor plates. The lower bracket supports the thrust bearing and has a much higher load. However, as thrust bearing load is unchanged, the lower bracket will not be affected.

4.4.7 *Generator Rotor*

The normal stress levels in the rotor spider are due to the weight of the rim, the compressive stress from the interference fit of the rim, and the stress due to torque transfer between the shaft and the rotor rim. The stress due to torque transfer will be higher if turbine power increases. However, evaluation of the rotor on other GE generators of similar or earlier vintage has indicated no significant issues with increased stresses due to torque transfer.

Turbine runaway speed should not significantly change with a new runner design; therefore stresses in the rotor spider at runaway speed will be nearly the same. These stress levels are generally quite low.

With regard to the rotor rim and poles, the highest stresses occur at runaway speed, which should not materially change.

4.4.8 *Generator Stator and Stator Foundation*

The highest stress in the generator stator and stator foundation occur during short circuit conditions or on faulty synchronization. These loads are a function of the stator dimensions and the winding configuration, and therefore should not change materially even if the generator is rewound for higher power output.

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4.4.9 Impacts of a Kaplan Runner

Replacement of the propeller runner with a Kaplan design will significantly increase the operating range of WH3. However, the Kaplan runner will have a number of additional impacts on the equipment, as summarized below:

- Modification to the bottom half of the discharge ring should be made to create a spherical surface that matches the runner blades as they rotate.
- New turbine shaft with internal bore for the oil piping to the runner blade servomotor.
- Possible head cover modifications to suit the Kaplan runner hub.
- New generator shaft with internal bore for the oil piping to the runner blade servomotor.
- Oil head to be mounted on top of the generator.
- Modifications to the generator collector.
- Possible thrust bearing upgrade as hydraulic thrust may increase by approximately 20%.
- Address higher runaway speed, as discussed below.
- Provide a blade positioner to operate the runner blades or provide a completely new governor that has both wicket gate and runner blade control features.

The effect of higher runaway speed on the generator would require careful study. The runaway speed of the propeller design is about 200% of synchronous speed, while a Kaplan turbine is typically 250% to 275% of synchronous speed. Stresses in the pole to rim connection vary with the square of the speed; therefore stress levels will be increased 55% to 90% when a Kaplan runner is installed. As stresses at runaway speed usually govern the design, it is reasonable to assume that the existing generator was not designed for the increased runaway speed.

It is likely that the existing rotor spider would be adequate to withstand the increased runaway speed; however it is expected that a new rotor rim and poles would need to be procured and as a result this option carries substantial cost implications. On some units, centrifugal mechanical over-speed protection has been provided. The device directs oil to the runner blade servomotors to move the blades to a steep position where runaway speed is lower. This is not the ideal approach as there are implications of reduced reliability/safety; however, maximum “off cam” runaway speed where the blades and gates are unsynchronized should not occur. The overspeed protection device is designed to be as failsafe as possible.

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4.5 Electrical Impacts

An overall assessment of the electrical impacts of uprating the WH3 turbine is summarized below, assuming a nominal 10% increase in power. Recommendations are described where applicable, and their associated implementation costs are included in Section 4.7.

4.5.1 Generator

WH3 is a 9.4 MVA umbrella type synchronous generator rated at 6.9 kV and 0.85 power factor, with a full load current of 787 A. It was manufactured in Peterborough, Ontario in 1968 by General Electric. The generator incorporates a type of Class B (130 °C) insulation made of asphalt mica for all windings, connections, parallel rings, and bus work. By comparison, the designed temperature rise is 60 °C for the windings given an ambient temperature of 40 °C.

For cooling, fan blades attached to the rotor are used to force air through the brushgear, spider, and windings of the generator. The lubrication system for the generator bearings is cooled by circulating water through copper cooling coils.

During the site inspection, WH3 was noted to be generating at approximately 8 MVA, 6.8 kV, and unity power factor. Although this operating point is only 85% of full load, thermocouples indicated an average stator temperature of only 40 °C. Given that these observations were made during the winter season when outdoor air temperatures are lower, supplied trend data from October 2015 was also inspected. However, it was noted that the generators also run fairly cool. For example, at an operating point of 8.8 MVA, 6.9 kV, and 0.99 power factor, the stator temperature is 47.0 °C.

Per the guaranteed data in the original specifications not including excitation losses, the overall efficiency of the generator is 96.5% at full load and 0.85 power factor.

YEC regularly performs cleaning and testing of the generator annually. According to the latest preventative maintenance report, the stator, rotor, and neutral grounding resistor were all megger-tested to be without problems. Additional instrumentation, as well as protection and control tests were also conducted and the equipment was found to be functioning as designed. Partial discharge test information was not available for WH3.

Based on the information above, WH3 should be able to generate at an uprated value of 10% higher than its nameplate capacity without exceeding the maximum operating temperature of its insulation. However, given that the generator is approximately 50 years old without yet having undergone a major overhaul, it would make sense to take advantage of the outage required to complete the mechanical upgrade work to also replace the existing stator winding and also refurbish the rotor field poles and windings. Although the longevity of the existing generator is supported by the low operating temperature and reduced run time compared to the other units, the generator has exceeded a typical winding life of 40 years, implying increased risk of failure, which may lead to an extended unplanned outage while repairs are undertaken.

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The generator excitation system is discussed in Section 4.5.3. No work is expected for the existing neutral leads, neutral grounding resistor, CTs, and PTs which will be compatible with the uprated generator.

In summary, the following work is recommended:

- Replacement of the stator windings with modern Class F insulation, improved wedging, and marginally higher efficiency.
- Refurbishment the rotor poles using modern Class F insulation, upgrade of the pole windings, and replacement of the rotor brushgear and collectors.
- Replacement of thermocouples with higher accuracy RTD (resistance temperature detectors).
- Replacement of aging surge arresters and capacitors (presently located within the excitation cabinet) to prevent equipment damage from fast transients and lightning surges.

4.5.2 Generator Leads

The generator leads connect the generator terminals to the powerhouse 6.9 kV switchgear and consist of two armoured 500 kcmil cables per phase. These cables are routed through cable trays on the Generator Floor and then enter the WH0 Control Room on the Main Floor via individual ducts for each cable in the ceiling.

Throughout their route, the cables were found to be arranged with at least one cable diameter spacing between them. If they are assumed to be rated at a conservative 75 °C operating temperature, the cables have an ampacity of at least 1240 A. Thus they will be able to pass the generator's uprated current of 787 A x 1.1 = 866 A.

In summary, no work is required.

4.5.3 Excitation System

The excitation system consists of an original main rotary exciter as well as an upgraded pilot static exciter. The main rotary exciter is a DC generator rated 70 kW, 125 V, and, according to its nameplate, it can produce up to 580 A. The pilot exciter including the automatic voltage regulator is Basler model SR125E.

WH3 currently requires a field current of 550 A when operating at rated capacity, voltage, and power factor. If the generator capacity is uprated by 10%, the existing excitation system will not have adequate capacity to drive the required field current and voltage on a continuous basis (including a margin of at least 5% for voltage variations from the generator's rated voltage). The exact field current ratings and excitation requirements will be confirmed once the new generator is designed.

Hatch notes that a replacement of the rotary excitation system with a fully static excitation system will improve the stability of the generator by enabling it to more quickly and aggressively respond to transients and abnormal system conditions. As well, a more modern

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system will improve reliability and operational efficiencies by providing additional diagnostics, telemetry, and redundant components. Since a complete static excitation system primarily utilizes solid state devices, there is substantially reduced maintenance. Legacy electronic components which are subject to wear and sudden failures such as rheostats and potentiometers are also eliminated.

The size of the field leads is currently not known. They should be verified for adequate capacity to conduct the higher generator rated field current.

In summary, the following work is recommended:

- Replacement of the excitation system with a static exciter (transformer and rectifier).

4.5.4 Medium Voltage (6.9 kV) Switchgear

The generator output from WH3 is connected to a vacuum generator circuit breaker in a dedicated 6.9 kV switchgear cubicle, manufactured by Rosen's Electrical Equipment, located in the Control Room. The uprated generator current of 866 A is well below the 2000 A continuous rating of the generator circuit breaker. The load side of this circuit breaker is connected to the Substation.

If all of the generators (WH1, WH2, WH3, and WH4) are each uprated, the fault level at this 6.9 kV switchgear is expected to marginally increase. This increased short circuit level should remain under the maximum 500 MVA (42 kA) rating of the circuit breaker.

Since annual contact resistance and megger testing of the switchgear have also indicated that there are no problems with the equipment, the 6.9 kV switchgear does not have to be upgraded.

The cables between the switchgear and the Substation were not accessible for inspection. The size of the cables should be verified for adequate capacity to conduct the higher generator current.

Note that an arc-flash study will have to be completed to re-evaluate the resulting incident energy values and PPE (personal protective equipment) requirements.

In summary, the following work is recommended:

- Arc-flash study and re-evaluation for the switchgear.

4.5.5 Station Service

The WH3 station service loads are connected to the same MCC and source as the WH1 configuration. Refer to Section 3.5.5 for more information.

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4.5.6 Step-up Transformer

There are no step-up transformers dedicated to WH3. Presently, power outputted by the generator is directed to the Whitehorse Rapids Substation, which combines generation from the hydroelectric facilities and the adjacent diesel and gas plant. At the substation, power is transformed from 6.9 kV to 138 kV and 34.5 kV for transmission and distribution. There is no equipment at the substation which is specific to WH3 and needs to be replaced in coordination with uprating WH3.

In summary, no work is required.

4.6 Balance of Plant Impacts

The impact of turbine uprate on the balance of plant equipment and services would be minimal. The heat load in the powerhouse would increase approximately in direct proportion to the increase in generator power. The ventilation system summer performance in Powerhouse WH0 will require study as to its effectiveness and ventilation capacity increased as required.

Other systems should not change.

4.7 Estimated Cost

The estimated cost in present day (2017) dollars for the three turbine uprate options are summarized in Table 4-2. The basis of the estimates are as given in Section 3.7 for WH1. As discussed for WH1 for the uprate option with no increase in turbine power, no allowance is made for generator rewind. For energy estimates, power has been limited to the existing generator capacity.

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Table 4-2: Capital Cost Estimate for WH3 Turbine Uprate

		Same Turbine Flow	*Increased Turbine flow*	*Kaplan Runner*
1	**Dismantling and Re-installation**			
1.1	Turbine & generator dismantling	$425,000	$425,000	$425,000
1.2	Turbine & generator reinstallation and testing	$725,000	$725,000	$725,000
2	**Turbine**			
2.1	New turbine runner	$760,000	$760,000	$1,250,000
2.2	Stay vane modications	$130,000	$130,000	$130,000
2.3	New servomotor pistons		$20,000	
2.4	Discharge ring modifications			$450,000
2.5	New turbine shaft			$120,000
2.6	Head cover modifications			$40,000
2.7	Blade postioner and oil head			$250,000
2.8	Overspeed protection device			$80,000
3	**Generator**			
3.1	Replace stator windings		$1,500,000	$1,500,000
3.2	Refurbish rotor poles		$400,000	$400,000
3.3	Replace thermocouples with RTD's		$25,000	$25,000
3.4	Replace surge arrestors & capacitors		$100,000	$100,000
3.5	New generator shaft			$120,000
3.6	Thrust beating upgrade			$100,000
3.7	Collector ring modifications			$20,000
4	**Exciter**			
4.1	Replace exciter		$500,000	$500,000
5	**6.9 kV Switchgear**			
5.1	Arc flash evaluation		$10,000	$10,000
6	**Balance of plant**			
6.1	Ventilation system upgrade		$40,000	$40,000
	Subtotal	$2,040,000	$4,635,000	$6,285,000
	Contingency (15%)	$306,000	$695,250	$942,750
	Construction cost	$2,346,000	$5,330,250	$7,227,750
	Engineering and administration (10%)	$234,600	$533,025	$722,775
	Estimated total cost	**$2,580,600**	**$5,863,275**	**$7,950,525**

WH3 was last overhauled in 2003/2004. If it is assumed that the turbine uprate work would be done during the next overhaul and the costs for turbine and generator dismantling and reinstallation are included as part of the overhaul, the turbine uprate costs will be reduced. Similarly, if generator rewind costs are assigned to life extension, the cost for stator and rotor work can also be excluded from the turbine uprate cost. The estimated total cost attributed to turbine uprate for the three options would then be as follows:

- No change in turbine flow $1,177,000
- Increased turbine flow $2,024,000
- Kaplan runner $4,112,000

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The total time required for the turbine uprate is estimated to be 24 months, only marginally longer than for WH1. A preliminary schedule is included in Appendix B. A schedule for a Kaplan runner installation has not been developed; however, it is anticipated that the schedule would be increased by two months for the Kaplan option.

4.8 Equipment Life Considerations

The expected life of the turbine and generator equipment and the possibility of major failure can influence an uprate program. The same considerations discussed in Section 3.8 for WH1 apply to WH3. The WH3 turbine is newer than WH1 and WH2, and no near term end of useful life is foreseen. It appears that the severe blade cracking issues on the turbine runner have been addressed 13 years ago with no recurring problems.

The WH3 generator is also newer than WH1 and WH2. Therefore extended operation should be possible. The primary issue with the generator is the stator windings and, to some extent, the stator core. The existing windings are approaching 50 years in life as compared to an average generator winding life of about 40 years. This does not mean that the windings are in immediate danger of failing. Nevertheless, it is difficult to project the life of the generator stator. As mentioned in Section 4.5.1, if a 10% increase in power output is planned, the generator stator and rotor should be rewound.

5. WH4 Uprate

5.1 General / Existing Performance

Unit WH4 went into operation in 1984 and is the newest unit at the Whitehorse station. The turbine is a fixed blade propeller type; therefore unlike WH1 and WH2, it has a limited power range for efficient operation. The turbine is dewatered for inspection every year and there is a planned overhaul on a 10-year cycle.

The last major overhaul of the turbine was in 2007, and another overhaul is planned for 2017.

Performance of the WH4 turbine is based on index tests conducted in 1984, shortly after the unit went into operation. The estimated performance was as follows:

- Peak turbine efficiency = 93.0%
- Peak efficiency flow = 128.4 m^3/s
- Efficiency at full load = 91.2%
- Full load flow = 135.2 m^3/s
- Full load turbine power = 22 MW at 18.2 m net head

Unlike WH1 and WH3, the WH4 site testing did not include actual turbine flow measurements. Therefore the efficiency numbers are based on the assumption that actual efficiency equals that predicted by the turbine model.

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Because of rough operation and vibration, the unit is restricted to power levels above approximately 16 MW in summer when tailrace levels are high, and 18 MW in winter when tailwater levels are lower.

There are no major issues that have been identified with the WH4 generator. Operating data indicates that the generator stator temperatures are fairly low.

Refer to Hatch report H354082-00000-260-066-0001 - Yukon Energy - Whitehorse Generating Station Unit WH4 Capacity Increase Desktop Study - June 2017 for additonal information pertaining to the potential uprate of WH4.

5.2 Uprate Options

It will be possible to improve the performance of WH4 by installing a new turbine runner of modern design. The uprate options include:

- New more efficient propeller runner with the same flow capacity as the existing turbine. The increase in maximum power output will be directly proportional to the increase in turbine efficiency.
- New more efficient propeller runner with increased flow capacity. This will further increase the maximum power output, with the power limit generally dictated by the cavitation characteristics of the runner.
- Retrofit the turbine with a Kaplan runner to allow operation over a wide range of flow. This has significant implications with the generator because of higher runaway speed as well as impacts to the turbine and generator shaft and the turbine discharge ring, similar to a possible Kaplan installation in WH3.

The performance characteristics of the uprated WH4 turbine are discussed in Section 5.3.

A mixed flow runner has also been considered for WH4. However, for the reasons discussed in Section 4.2 the mixed flow design is unsuitable for this installation.

5.3 Performance Characteristics

The peak efficiency of the existing WH4 turbine is 93 % as mentioned in Section 5.1. A modern propeller turbine operating under similar head and flow conditions would have a peak efficiency of about 94%. However, because of limitations with the turbine fixed parts, as discussed in Section 3.3, the efficiency that can be achieved with a new runner may not reach this level.

The dimensions of the WH4 turbine components and water passages are close to a modern design. The draft tube is also similar to a modern design. This is illustrated in Table 3-1 and on Figure 3-1.

Figure 5-1 shows the efficiency of the existing turbine based on the index testing done in 1984, the efficiency of a modern state of the art turbine derived from model test information,

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and the estimated efficiency of the WH4 turbine with a new runner and possible stay vane modifications. The increment is quite small. However, it is possible that the actual efficiency of the present WH4 turbine is slightly lower than estimated.

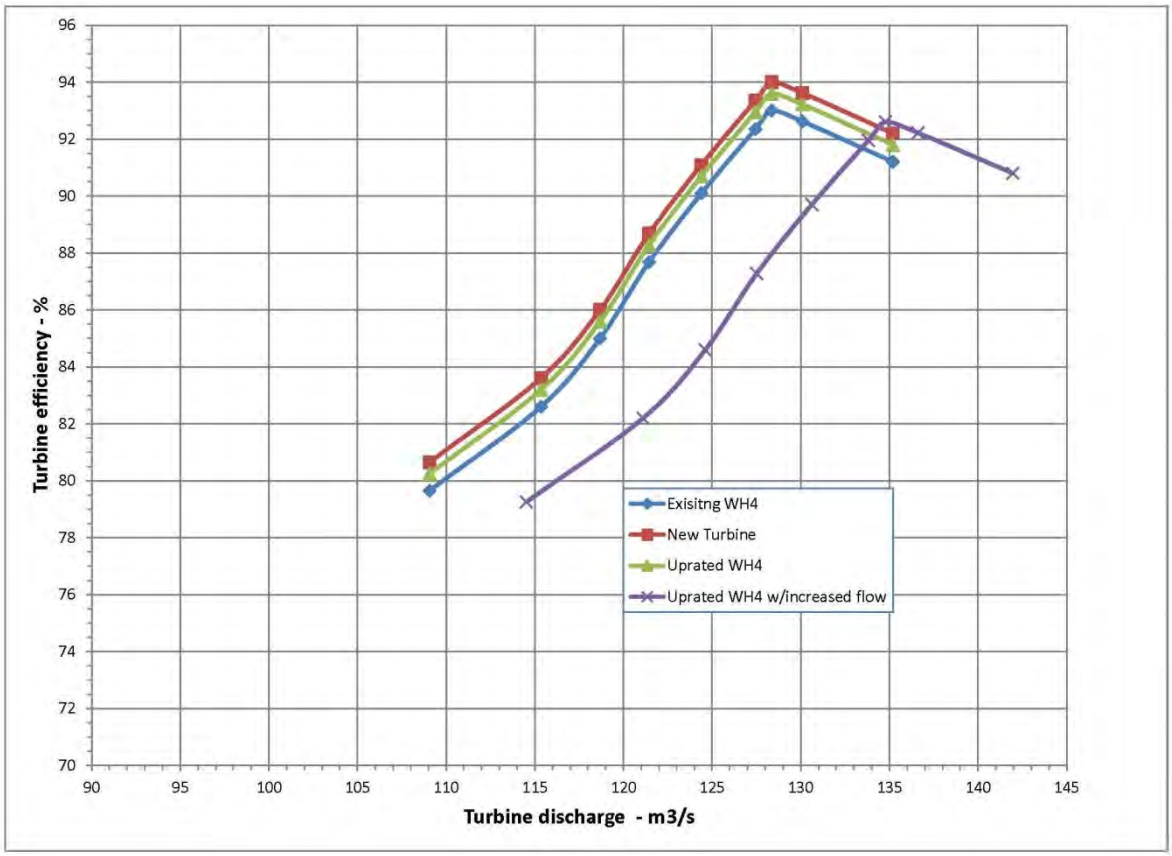

Figure 5-1: WH4 Performance

The new runner could also be designed for some increase in flow capacity. The limit for the turbine is dictated by cavitation characteristics, as the runner diameter, speed, and setting relative to tailwater level are fixed. From a review of model test information for similar turbine designs, it appears that a 5% increase in flow will be possible. The higher flow runner will result in some reduction in efficiency, as losses in the spiral case, stay ring and draft tube increase with the square of the flow. Figure 5-1 also shows the estimated turbine performance for a new runner with a 5% increase in flow.

A higher flow runner needs to be considered with caution, given that intake flow conditions are less than ideal and surface vortices are already evident. The vortices are related to the cross flow caused by spillway discharges as well as the intake submergence. An assessment of submergence using a common empirical formula indicates the submergence should be deeper. For increased turbine flow the requirement for an intake vortex suppressor should be evaluated.

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Installation of a Kaplan runner in place of the fixed blade propeller runner is possible, but there are significant mechanical impacts as discussed in Section 4.4. A performance curve for a Kaplan runner is shown on Figure 5-2.

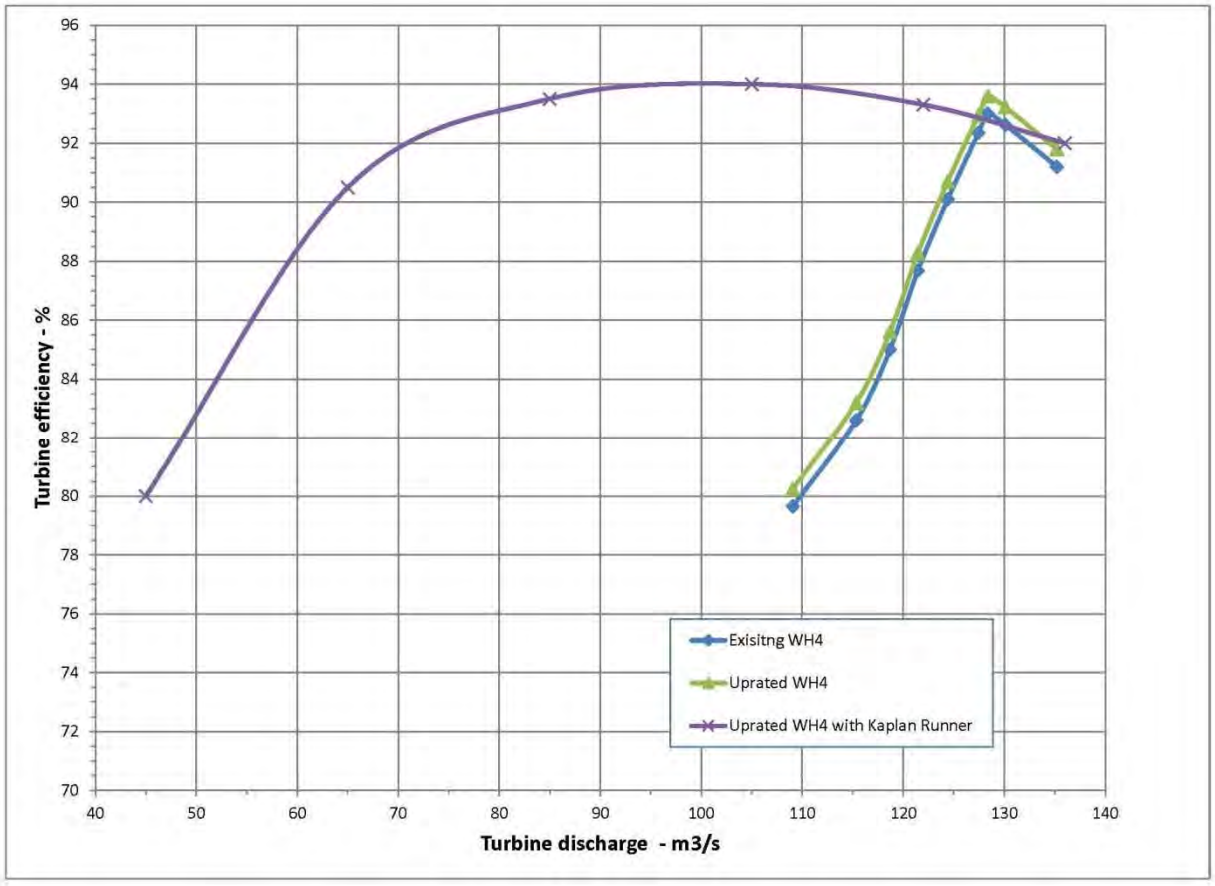

Figure 5-2: WH4 Kaplan and Propeller Runners

5.4 Mechanical Impacts

A review of the mechanical issues uprating to turbine uprate is summarized in the subsections below. Sections 5.4.1 to 5.4.8 address the issues with a new propeller runner. The additional implications for installation of a Kaplan runner are discussed in Section 5.4.9.

5.4.1 Turbine Shaft

The turbine is forged steel with an outside diameter of 546 mm and an inside diameter of 152 mm. The drawings indicate that shaft material is ASTM A668 Class D, which has a yield strength of 260 MPa. At the present maximum turbine power of 22,000 kW the torsional stress is 44.1 MPa which is which is 17 % of tensile yield.

A common criterion for allowable shaft stress is for torsional stress to be 1/6 (16.7%) of yield as this provides a safety factor of 3, assuming shear yield strength is 50% of tensile yield

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strength. The calculated stress is marginally above this value. If turbine power is increased by 5%, the stress levels would be 17.9% of yield or 7% over the criteria. This would be considered satisfactory.

5.4.2 Turbine Guide Bearing

The load on the turbine guide bearing should not materially change with a new turbine runner. Load may actually be reduced because the new runner has more accurate mechanical and hydraulic balance.

5.4.3 Turbine Wicket Gate Operating Mechanism

There are generally two conditions that govern the wicket gate torque:

- Maximum torque to move the gates to full closed position.
- Maximum torque when opening the gates, which typically occurs in the 60 to 80% gate range.

The original commissioning data indicated a problem with wicket gate stall when moving in the closing direction at very high gate openings. For this reason the 100% gate opening was adjusted to a lower position. The turbine power guarantee was still achieved at the reduced gate opening. For an option with increased turbine flow, a means of increasing the servomotor closing force is required. This could be new servomotors of slightly larger capacity or perhaps springs that provide added closing force from maximum gate opening.

5.4.4 Generator Shaft

The generator shaft is forged steel with a diameter of 356 mm, the same as the turbine shaft. Stress levels will be the same as in the turbine shaft.

5.4.5 Generator Bearings

The generator guide bearing load is dependent on the mechanical unbalance of the rotor as well as the air gap, which impacts the magnetic unbalance. Assuming that the mechanical balance and air gap meet recognized standards after the upgrade, there will be no issue on guide bearing load.

The load on the thrust bearing is equal to the weight of turbine and generator rotating parts plus the maximum hydraulic thrust. The weight of the rotating parts will be essentially unchanged. A new turbine runner could be possibly slightly heavier or lighter; however, the runner weight is only a small fraction of the total weight of rotating parts. Hydraulic thrust is generally a function of the turbine runner area in plan, and this will also be unchanged. As total thrust loads will be nearly the same there should be no issues with the thrust bearing.

5.4.6 Generator Brackets

The generator brackets will not be affected by the by a turbine or generator uprate. The upper brackets support the generator floor plates. The lower bracket supports the thrust bearing and has a much higher load. However, as thrust bearing load is unchanged, the lower bracket will not be affected.

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5.4.7 *Generator Rotor*

The normal stress levels in the rotor spider are due to the weight of the rim, the compressive stress from the interference fit of the rim, and the stress due to torque transfer between the shaft and the rotor rim. The stress due to torque transfer will increase if turbine power increases. However, evaluation of the rotor on other GE generators of similar vintage has indicated no significant issues with increased stresses due to torque transfer.

Turbine runaway speed should not significantly change with a new runner design; therefore stresses in the rotor spider at runaway speed will remain unchanged. These stress levels are generally quite low.

With regard to the rotor rim and poles, the highest stresses occur at runaway speed, which should not materially change.

5.4.8 *Generator Stator and Stator Foundation*

The highest stress in the generator stator and stator foundation occur on short circuit conditions or of faulty synchronization. These loads are a function of the stator dimensions and the winding configuration, and therefore should not change even if the generator is rewound for higher power output.

5.4.9 *Impacts of a Kaplan Runner*

Replacement of the propeller runner with a Kaplan design will significantly increase the operating range of WH4. However, the Kaplan runner will have a number of additional impacts on the equipment, as summarized below:

- Modification to the bottom half of the discharge ring should be made to create a spherical surface that matches the runner blades as they rotate.
- New turbine shaft with internal bore for the oil piping to the runner blade servomotor.
- Possible head cover modifications to suit the Kaplan runner hub.
- New generator shaft with internal bore for the oil piping to the runner blade servomotor.
- Oil head to be mounted on top of the generator.
- Modifications to the generator collector.
- Possible thrust bearing upgrade as hydraulic thrust may increase by about 20%.
- Address higher runaway speed, as discussed below.
- Provide a blade positioner to operate the runner blades or provide a completely new governor that has both wicket gate and runner blade control features.

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The effect of higher runaway speed on the generator would require careful study. The runaway speed of the propeller design is about 200% of synchronous speed, while a Kaplan turbine is typically 250% to 275% of synchronous speed. Stresses in the pole to rim connection vary with the square of the speed; therefore stress levels will be increased 55% to 90% when a Kaplan runner is installed. As stresses at runaway speed usually govern the design, it is reasonable to assume that the existing generator was not designed for the increased runaway speed.

It is likely that the existing rotor spider would be adequate to withstand the increased runaway speed; however it is expected that a new rotor rim and poles would need to be procured and as a result this option carries substantial cost implications. On some units, centrifugal mechanical over-speed protection has been provided. The device directs oil to the runner blade servomotors to move the blades to a steep position where runaway speed is lower. This is not the ideal approach as there are implications of reduced reliability/safety; however maximum “off cam” runaway speed where the blades and gates are unsynchronized should not occur. The overspeed protection device is designed to be as failsafe as possible.

5.5 Electrical Impacts

An overall assessment of the electrical impacts of uprating the WH4 turbine is summarized below. Recommendations are described where applicable, and their associated implementation costs are included in Section 5.7.

5.5.1 Generator

WH4 is a 23.6 MVA umbrella type synchronous generator rated at 6.9 kV and 0.85 power factor, with a full load current of 1975 A. It was manufactured in Peterborough, Ontario in 1983 by General Electric. The generator incorporates Class F (155 °C) insulation for all windings, connections, parallel rings, and bus work. By comparison, the designed temperature rise is 60 °C for the windings, given an ambient temperature of 40 °C.

For cooling, fans attached to the rotor are used to force air through the brushgear, spider, and windings of the generator. The lubrication system for the generator bearings is cooled by circulating water through copper cooling coils. The generator is also equipped with air-to-water heat exchangers.

During the site inspection, WH4 was noted to be generating at approximately 19 MVA, 6.9 kV, and 0.96 power factor. Although this operating point is only 80% of full load, thermocouples indicated an average stator temperature of only 65 °C. Given that these observations were made during the winter season when outdoor and cooling water temperatures are lower, supplied trend data from October 2015 was also inspected. However, it was noted that the generators also run cool. For example, at an operating point of 19.5 MVA, 6.8 kV, and 0.99 power factor, the stator temperature was 68.4 °C.

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Per guaranteed data in the specifications not including excitation losses, the overall efficiency of the generator is 97.26% at full load and 0.85 power factor, and 97.89% at full load and unity power factor.

YEC regularly performs cleaning and testing of the generator annually. According to the latest preventative maintenance report, the stator, rotor, and neutral grounding resistor were all megger-tested and no issues were identified. Additional instrumentation, as well as protection and control tests were also conducted and the equipment was found to be functioning as designed. Partial discharge (PD) tests were last conducted in April 2016 and found that WH4 was exhibiting minor levels of PD which are typically not a concern but should be monitored.

Based on the information above, WH4 is able to generate at an uprated value of 5% higher than its nameplate capacity without exceeding the maximum operating temperature of its insulation. Given that the generator is only thirty years old and it is also equipped with a higher rated temperature class of insulation, no major upgrades to the stator windings and rotor windings or poles are necessary.

The generator excitation system is discussed in Section 5.5.3. No work is expected for the existing neutral leads, neutral grounding resistor, CTs, and PTs which will be compatible with the uprated generator.

In summary, no work is required.

5.5.2 Generator Leads

The generator leads connect the generator terminals to the powerhouse 6.9 kV switchgear and consist of three armoured 500 kcmil cables per phase. These cables are routed through cable trays on the Generator Floor and then enter the switchgear on the Main Floor via individual ducts for each cable in the ceiling.

Throughout their route, the cables were found to be arranged with one cable diameter spacing between them. Since the WH4 installation is more modern, the cables are assumed to be rated with a 90°C operating temperature which yields an ampacity of 2100 A. Thus they will be able to pass the generator's uprated current of 1975 A x 1.05 = 2074 A.

In summary, no work is required.

5.5.3 Excitation System

The excitation system consists of an excitation transformer and static exciter rectifier. While the transformer is built by Polygon and rated at 720 kVA, 6.9 kV – 465 V, the rectifier is manufactured by General Electric (type Silcomatic IV) with a 153 VDC, 1090 A continuous, and 1576 A 30-second output. The exciter is also capable of outputting a ceiling voltage of 600 VDC at 985 A.

Given that the WH4 generator presently has a rated field current of 1050 A at rated capacity, voltage, and power factor, an uprating of the generator by 5% will overload the continuous capabilities of the existing excitation system. An additional margin of at least 5% for voltage variations from the generator's rated voltage should also be designed in. Thus, the exciter

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rectifier will need to be replaced, but it is possible to retain the exciter transformer because its capacity appears to be sufficient.

The size of the field leads is currently not known. They should be verified for adequate capacity to conduct the higher rated generator field current.

In summary, the following work is recommended:

- Replacement of the exciter rectifier with a model capable of higher current output.

5.5.4 Medium Voltage (6.9 kV) Switchgear

The generator output from WH4 is connected to a vacuum generator circuit breaker in a dedicated 6.9 kV switchgear cubicle, manufactured by Schneider Electric, located on the Main Floor. The uprated generator current of 2074 A is well below the 3000 A continuous rating of the generator circuit breaker. The load side of this circuit breaker is connected to a step-up transformer directly outside of the Powerhouse.

If all of the generators (WH1, WH2, WH3, and WH4) are each uprated, the fault level at this 6.9 kV switchgear is expected to marginally increase. This increased short circuit level remains under the maximum 500 MVA (42 kA) rating of the circuit breaker.

Since annual contact resistance and megger testing of the switchgear have also indicated that there are no problems with the equipment, the 6.9 kV switchgear does not need to be upgraded.

The cables between the switchgear and the Substation were not accessible for inspection. The size of these cables should be verified for adequate capacity to conduct the higher generator current.

Note that an arc-flash study will have to be completed to re-evaluate the resulting incident energy values and PPE (personal protective equipment) requirements.

In summary, the following work is recommended:

- Arc-flash study and re-evaluation for the switchgear.

5.5.5 Station Service

Auxiliary loads in the Powerhouse are supplied from an MCC which in turn is fed by a 500 kVA, 6.9 kV – 600 V station service transformer located on the Main Floor. The auxiliary loads include generator lift pumps, governor oil HPUs (hydraulic pressure units), glycol cooling water pumps, and HVAC (heating, ventilation, and air conditioning).

It is expected that the demands of these loads will not change significantly as a result of uprating the turbine and generator. Thus no material upgrades to the station service system are expected. In the unlikely event that new or larger starters are required, there are spare compartments available in the existing MCC.

In summary, no work is required.

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5.5.6 Step-up Transformer

A dedicated oil-filled step-up transformer (T9) adjacent to the Powerhouse steps up the voltage of the WH4 generator from 6.9 kV to 138 kV. It has a capacity rating of 18 MVA (ONAN) and 24 MVA (ONAF).

The transformer was manufactured in 1983 and has undergone insulation and oil analysis by Orbis in May 2016. The test report states that “T9 has already served 34 years in continuous service [and] this transformer is a critical asset as it allows WH4 to connect on to the entire system with WH4 being considered a ‘backbone’ generator for the entire YEC system.” It further recommends that the transformer be replaced in the next five years in order to avoid the risk of a forced outage. Given that this transformer will also be slightly overloaded to 25 MVA if WH4 is uprated by 5%, the replacement of this transformer would also be justified.

There is a short transmission line span between the step-up transformer and the Substation. By visual inspection from the ground, the size of this line is estimated to be at least 300 kcmil, which has an ampacity of 400 A. Due to the relatively small amount of current which is conducted by this line (i.e., 100 A), Hatch believes that this existing line will not need to be upgraded even if WH4 is uprated. However, the actual capacity and condition of this line should be confirmed.

In summary, the following work is recommended:

- Replace step-up transformer.

5.6 Balance of Plant Impacts

The impact of turbine uprate on the balance of plant equipment and services would be relatively small. The cooling water flow may need to be upgraded to accommodate added heat load on the generator heat exchangers. As the generator is totally enclosed, the increase in powerhouse ventilation load should be very small.

Other systems should not change.

5.7 Estimated Cost

The estimated cost in present day (2017) dollars for the two turbine uprate options are summarized in Table 5-1. The basis of the estimate is the same as described in Section 3.7 for WH1.

The next WH4 overhaul is scheduled for this year. This work will include the installation of a new generator rotor spider. It is unlikely that this work would be delayed to allow procurement a new runner for turbine uprate. Therefore turbine and generator dismantling and re-installation costs cannot be omitted from the turbine uprate costs.

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Because the WH4 unit is larger than WH1 and WH3, the overall schedule is slightly longer than the schedule for the other units. Two schedules are included in Appendix B, one for a new propeller runner and one for a conversion to a Kaplan unit. The preliminary schedule for the propeller runner is approximately 27 months and it is 29 months for the Kaplan. The Kaplan schedule is understandably longer because of added time for runner manufacture and increased site work for items such as the discharge ring modifications.

Table 5-1: Capital Cost Estimate for WH4 Turbine Uprate

		Same Turbine Flow	*Increased Turbine flow*	*Kaplan Runner*
1	**Dismantling and Re-installation**			
1.1	Turbine & generator dismantling	$710,000	$710,000	$710,000
1.2	Turbine & generator reinstallation and testing	$1,080,000	$1,080,000	$1,080,000
2	**Turbine**			
2.1	New turbine runner	$1,400,000	$1,400,000	$2,250,000
2.2	Stay vane modications	$180,000	$180,000	$180,000
2.3	New servomotor pistons		$40,000	
2.4	Discharge ring modifications			$900,000
2.5	New turbine shaft			$180,000
2.6	Head cover modifications			$50,000
2.7	Blade positioner and oil head			$360,000
2.8	Overspeed protection device			$100,000
3	**Generator**			
3.1	Replace stator windings			
3.2	Refurbish rotor poles			
3.3	Replace thermocouples with RTD's			
3.4	Replace surge arrestors & capacitors			
3.5	New generator shaft			$180,000
3.6	Thrust bearing upgrade			$120,000
3.7	Collector ring modifications			$25,000
3	**Generator Leads**			
4.1	Replace generator leads			
5	**Exciter**			
5.1	Replace exciter		$500,000	$500,000
6	**6.9 kV Switchgear**			
6.1	Arc flash evaluation		$10,000	$10,000
7	**Step-up Transformer**			
7.1	Replace step-up transformer		$1,500,000	$1,500,000
8	**Balance of plant**			
8.1	Upgrade cooling water system		$60,000	$60,000
	Subtotal	$3,370,000	$5,480,000	$8,205,000
	Contingency (15%)	$505,500	$822,000	$1,230,750
	Construction cost	$3,875,500	$6,302,000	$9,435,750
	Engineering and administration (10%)	$387,550	$630,200	$943,575
	Estimated total cost	**$4,263,050**	**$6,932,200**	**$10,379,325**

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5.8 Equipment Life Considerations

WH4 is the newest of the units at the WGS, and as such has a longer projected life. There have been issues with the generator rotor spider in recent years and these are being addressed with the installation of a new spider design later this year.

There are no turbine issues that threaten to shorten the equipment life and, as discussed in Section 5.5.1 rewind of the generators in the near term does not appear necessary, even with a nominal increase in turbine power.

6. Conversion of WH3 to Operate as a Synchronous Condenser

6.1 Conceptual Design

An evaluation has been made of the requirements and associated costs for converting WH3 to allow operation as a synchronous condenser for reactive power support. Hydro units are often ideally suited for synchronous condenser operation, and this is achieved by motoring the unit synchronized to the grid with the turbine runner spinning in air to reduce the motoring power.

Conversion of WH3 would include addition of a compressed air system with air receiver and associated piping valves and controls to allow depressing the tailwater level to approximately 1.5 m below the bottom of the runner. A conceptual design has been developed for the system, which includes:

- An 11 m^3/min 700 kPa rotary screw compressor.
- A 12 m^3 air receiver.
- Piping from the air receiver to the turbine pit with multiple connections in the turbine head cover for air admission. If possible, the piping will partly use the existing turbine vent piping. However, if not possible, additional air openings will be added to the head cover.
- Control valves and air release valves for initiating the tailwater depression and for refilling the runner area with water.
- Water level sensing piping and controls at the draft tube access door for sensing the water level in the draft tube and controlling admission of “make-up” air.
- Modification of the generating unit controls to initiate and control tailwater depression and to disable reverse power protection when the unit is operating as a synchronous condenser.

The piping from the air receiver to the turbine would be sized to allow the water level to be depressed below the bottom of the runner in approximately 10 seconds. This would minimize power transients or spikes when initiating tailwater depression and synchronous condenser operation.

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When operating as a synchronous condenser, the power requirement motoring the unit is estimated to be approximately 800 kW.

Possible locations for the new equipment have been reviewed, as space within the powerhouse is limited. The air receiver in particular is quite large in size. The best location may be on the main generator floor, although two half size tanks could possibly be located on the turbine floor between WH3 and WH2. A higher pressure system (2000 kPa) to reduce air receiver size has also been evaluated; however the equipment cost is higher.

It would also be possible to combine the tailwater depression system with the existing service air system for the powerhouse. However, considering that a reliable service and brake air system will still be required, the savings with this approach appear to be minimal. Such an option could be revisited if the concept proceeds beyond the preliminary study phase.

6.2 Mechanical Impacts

Mechanical impacts, in addition to the new compressed air system described above, include:

- Connecting the air supply to the existing turbine head cover vent piping.
- Addition of water level instrumentation at the draft tube door.

It is important to manage water leakage at the wicket gates during synchronous condenser operation in order to minimize the make-up compressed air supply and to keep the power requirements for motoring the generator at a minimum. At the time of the site visit, it was mentioned by YEC that wicket gate nose-to-tail clearances are good and end (top and bottom) clearances are minimum. Therefore it is assumed that gate leakage would not be an issue.

6.3 Electrical Impacts

Electrical impacts are primarily control related, and include:

- Modifications to the existing generator control PLC program to process synchronous condenser air and water level instrumentation and valve control, air admission valve control, air exhaust valve control, generator operational interlocks, governor control logic changes, and new alarms.
- Disabling reverse power protection.
- Addition of control switches at the local generator control panels and interfaces at the remote control center to switch the generator into and out of sync condense mode.

The control system modifications would not be a minor item as considerable reverse-engineering of the existing software may be necessary, in addition to implementation and testing of the new code and overall design.

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6.4 Balance of Plant Impacts

Except for the items mentioned in Section 6.3 above no balance of plant impacts are foreseen.

6.5 Estimated Cost

The estimated cost for conversion of WH3 for synchronous condenser operation is presented in Table 6-1. Equipment supply prices were obtained from suppliers. Installation, control system modification and miscellaneous costs are internal estimates.

Table 6-1: Capital Cost Estimate for WH3 as Synchronous Condenser

		Estimated Cost
1	**Equipment Supply**	
1.1	Air compressor	$35,000
1.2	Air receiver	$16,000
1.3	Piping and valves	$8,000
1.4	Instrumentation	$4,000
2	**Installation**	
2.1	Install compressor and receiver	$25,000
2.2	Piping, valve & instrument installation	$24,000
2.3	Connection to existing piping and draft tube	$3,000
2.4	Instrumentation wiring	$3,000
3	**Turbine-Generator Control Modifications**	
3.1	Control modifications	$100,000
	Subtotal	$218,000
	Contingency (15%)	$32,700
	Construction cost	$250,700
	Engineering and administration (15%)	$37,300
	Estimated total cost	**$288,000**

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7. Potential Energy Increase

7.1 Hydrology and Water Levels

7.1.1 Background Information

Flow data for the Yukon River at Whitehorse is available from the Water Survey of Canada flow gauge 09AB001 in Whitehorse, with daily flow records since 1944. There is a significant seasonal variation in river flow, as illustrated in Figure 7-1.

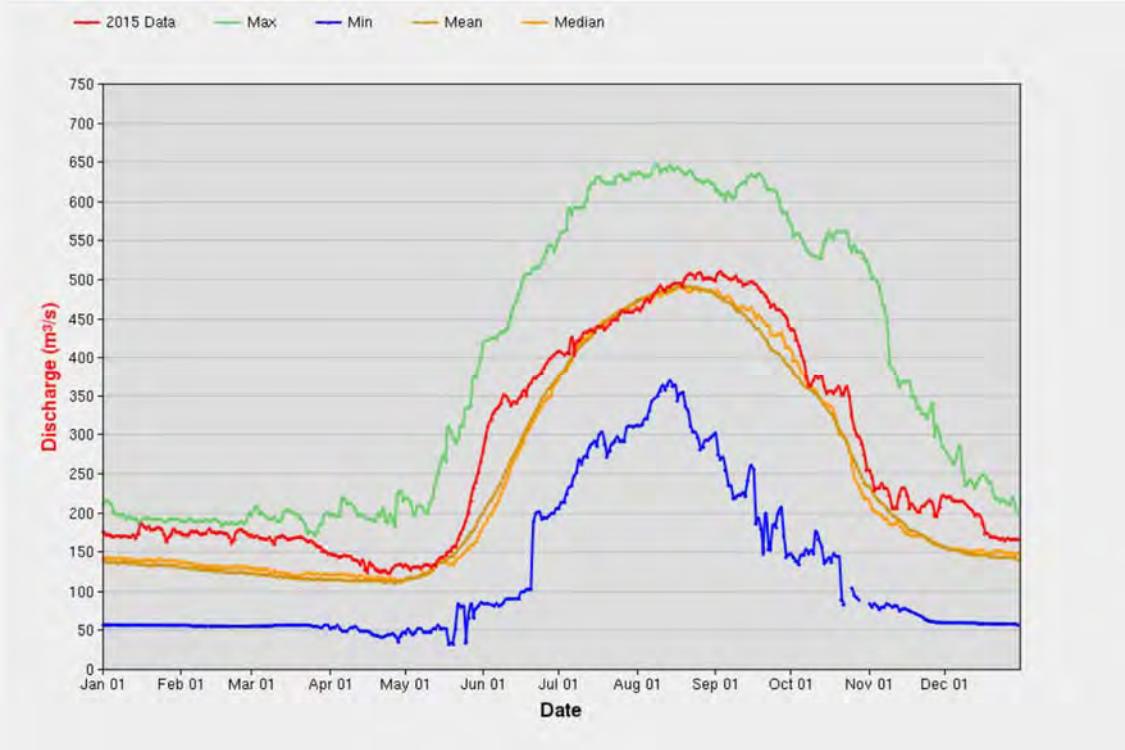

Figure 7-1: Yukon River Flows at Whitehorse

Monthly flow duration curves based on daily data are shown on Figure 7-2 and Figure 7-3.

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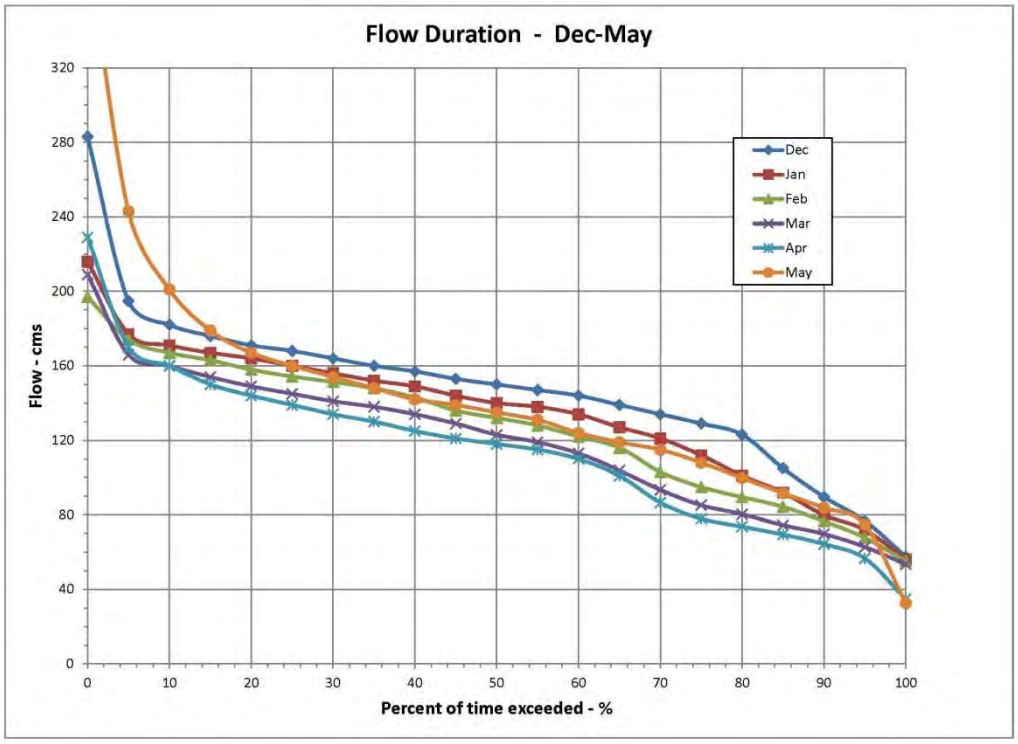

Figure 7-2: Monthly Flow Duration – Dec-May

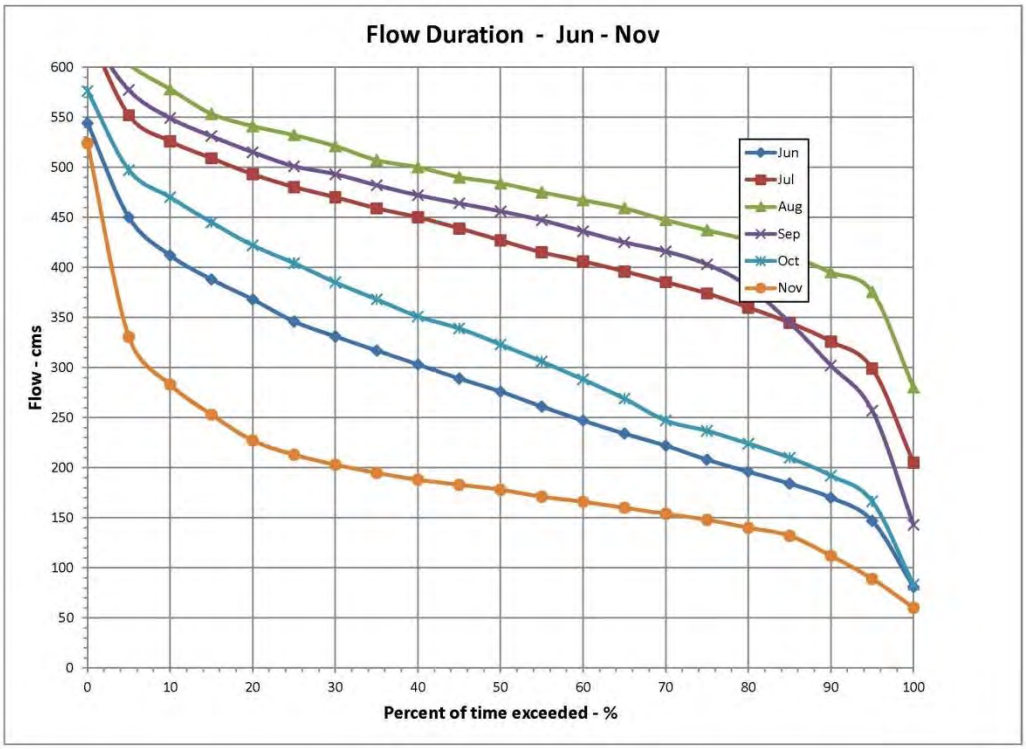

Figure 7-3: Monthly Flow Duration – Jun-Nov

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The headwater level at the WGS is held constant at El 653.1 m.

Tailwater level at Powerhouse W0 varies with plant discharge as well as the downstream lake level. A plot of tailwater level versus plant discharge is shown on Figure 7-4. The tailwater level at WH4 is higher because of the head loss in the tailrace channel as well as the river bed profile at the channel exit. In addition, the fish screens that are installed at the end of the channel in the summer months increase the tailwater levels by about 0.4 m. The difference between the WH4 tailwater and the WH0 tailwater levels versus WH4 discharge is shown on Figure 7-5.

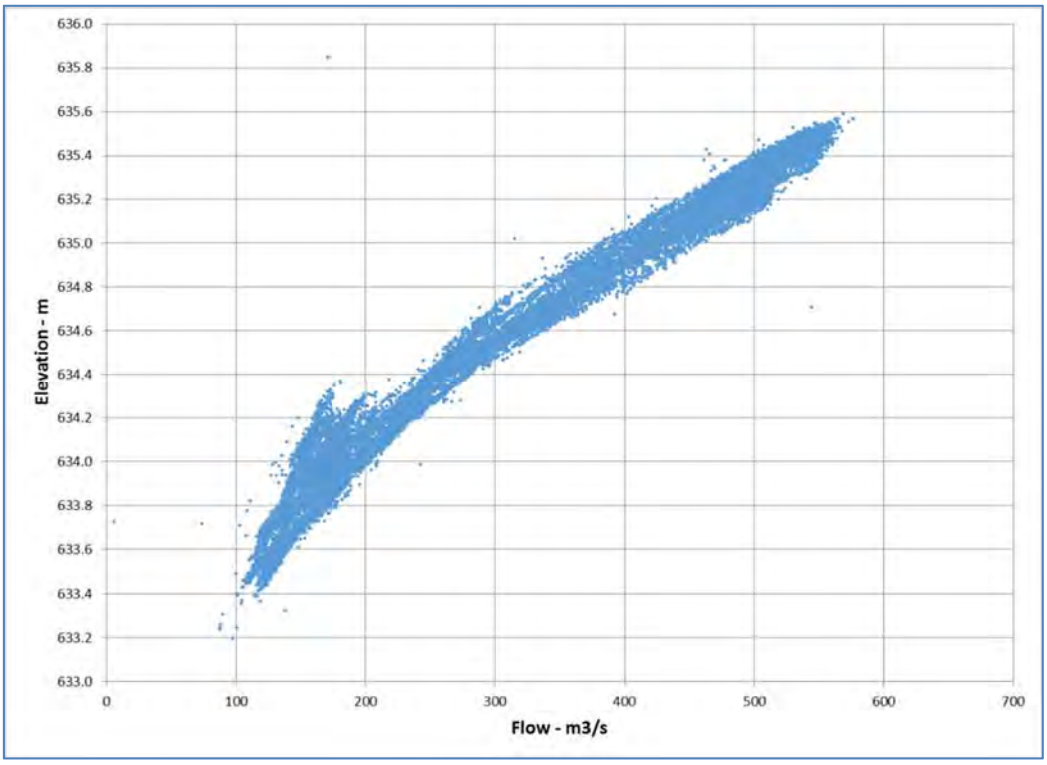

Figure 7-4: Tailwater level at WH0 powerhouse

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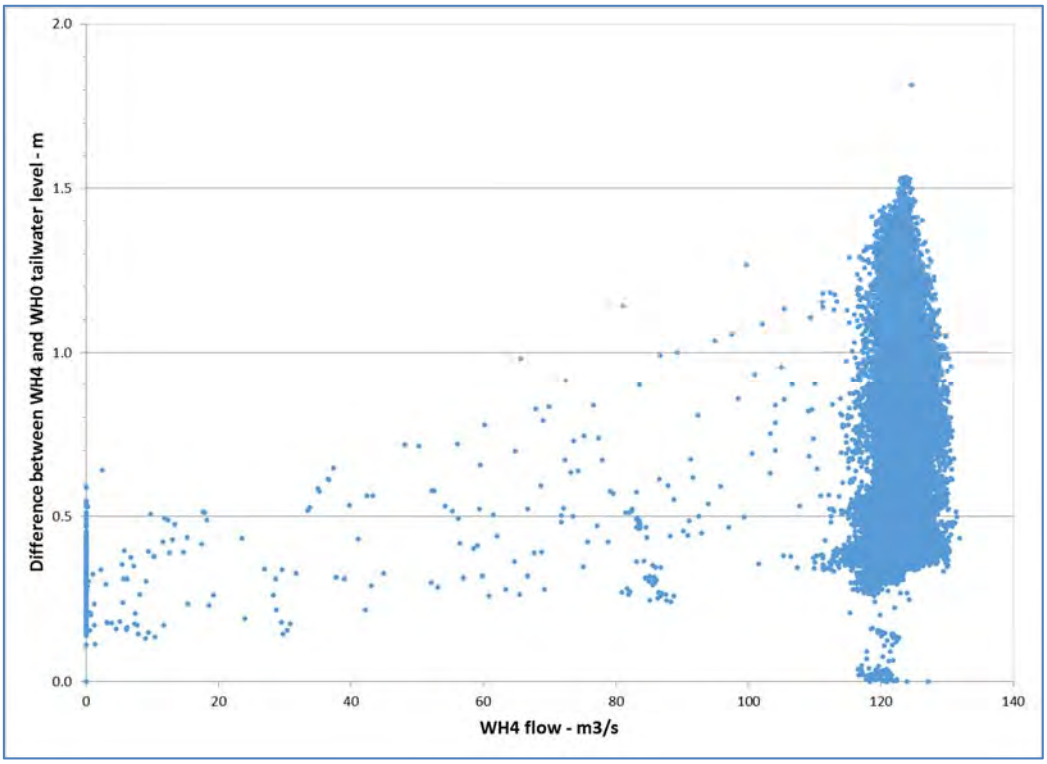

Figure 7-5: Difference between WH4 and WH0 tailwater levels

7.1.2 Representative Hydrologic Sequences

The uprate study for WGS requires YEC's complete generation system to be analyzed. Therefore the Marsh Lake flows in the Aishihik and Mayo rivers must be considered, in addition to the Yukon River flow. The available hydrology for the three rivers covers different periods, with the fourteen years between 1981 to 1994 being the overlapping period for all three rivers. To determine if the 14 overlapping years is adequate for the system study, each year in the 1951 to 1994 available hydrology was ranked from the wettest to driest, and the distribution of the 1981 to 1994 years was examined.

As seen in the table below, the 1981 to 1994 flows (shown in bold) cover the range of the entire record well. However, there are more occurrences of wet years. Therefore, the duration curve of the daily flows for the 1981 to 1994 series was compared with that of the entire 1951 to 1994 record. As indicated on Figure 7-6, the two curves match well at both the upper and lower end, with the 1981 to 1994 series being only slightly higher in the mid-range. Therefore, the 14 years are a good representation of the hydrology of the three rivers.

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Table 7-1: Ranking of Marsh Lake Average Flow

Rank	Year	Average Daily Flow (m^3/s)	Rank	Year	Average Daily Flow (m^3/s)
1	***1981***	314.3	23	1971	247.3
2	1963	301.2	24	1976	245.5
3	***1993***	295.4	25	***1987***	239.6
4	***1989***	289.1	26	1968	238.2
5	1957	286.2	27	1952	236.8
6	***1990***	282.1	28	1972	235.5
7	1953	281.6	29	1960	234.6
8	1961	278.1	30	1954	233.4
9	***1994***	277.3	31	1966	228.7
10	1979	269.9	32	1965	224.3
11	***1992***	268.5	33	1974	221.6
12	1977	264.2	34	1959	219.7
13	1962	264.1	35	***1983***	218.0
14	***1991***	263.5	36	1951	213.3
15	1975	262.9	37	1958	213.1
16	***1988***	260.7	38	1978	210.9
17	1980	259.4	39	***1985***	204.2
18	1969	255.8	40	1956	197.4
19	1964	252.3	41	1970	194.1
20	***1986***	249.7	42	***1984***	191.2
21	1967	248.8	43	1955	186.4
22	***1982***	247.6	44	1973	181.5

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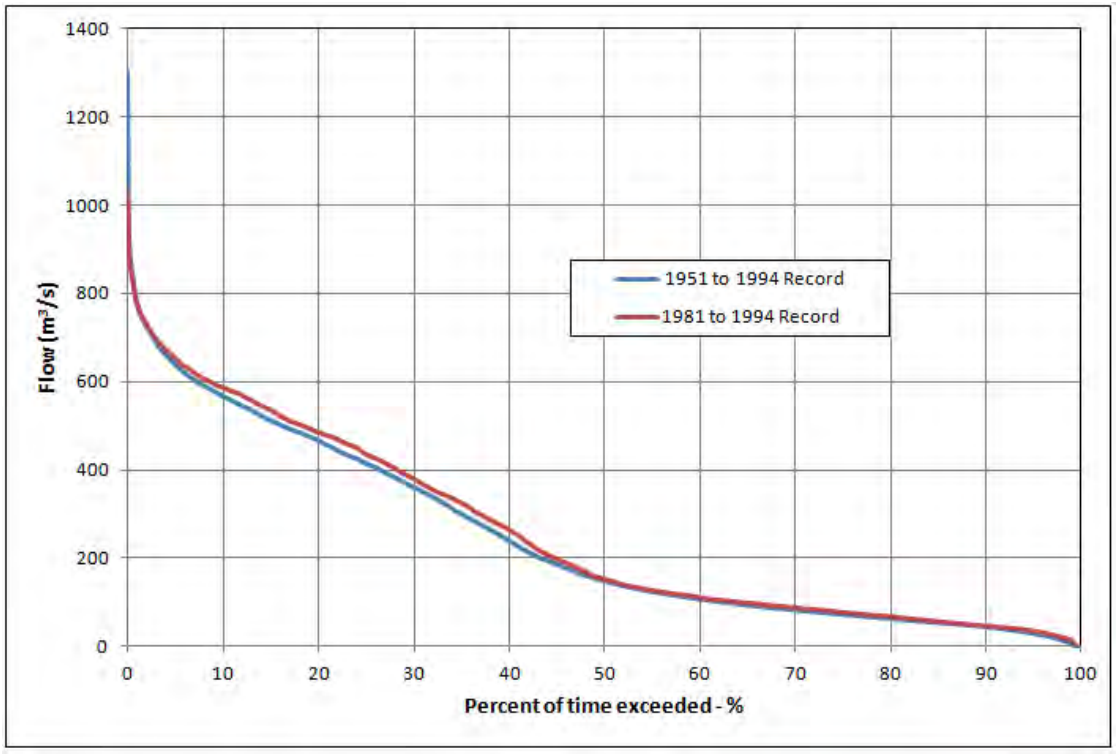

Figure 7-6: Marsh Lake Daily Flow Duration Curve

7.2 System Load

YEC's power system operates as an isolated grid where generation equals power demand and the generating units must regulate system frequency and provide voltage support to the system. YEC has provided three load scenarios for monthly power demands that included projected load forecasts until 2035. The three Load Scenarios, designated 1, 3 and 4 are illustrated on Figure 7-7 to Figure 7-9.

Load Scenario 1 represents today's power demand with relatively small projected load increases over the next 20 years. Load Scenarios 3 and 4 reflect increased mining development in the region, whereby power requirements increase much more rapidly but peak in the 2025 to 2030 timeframe, with loads in 2035 similar to Scenario 1.

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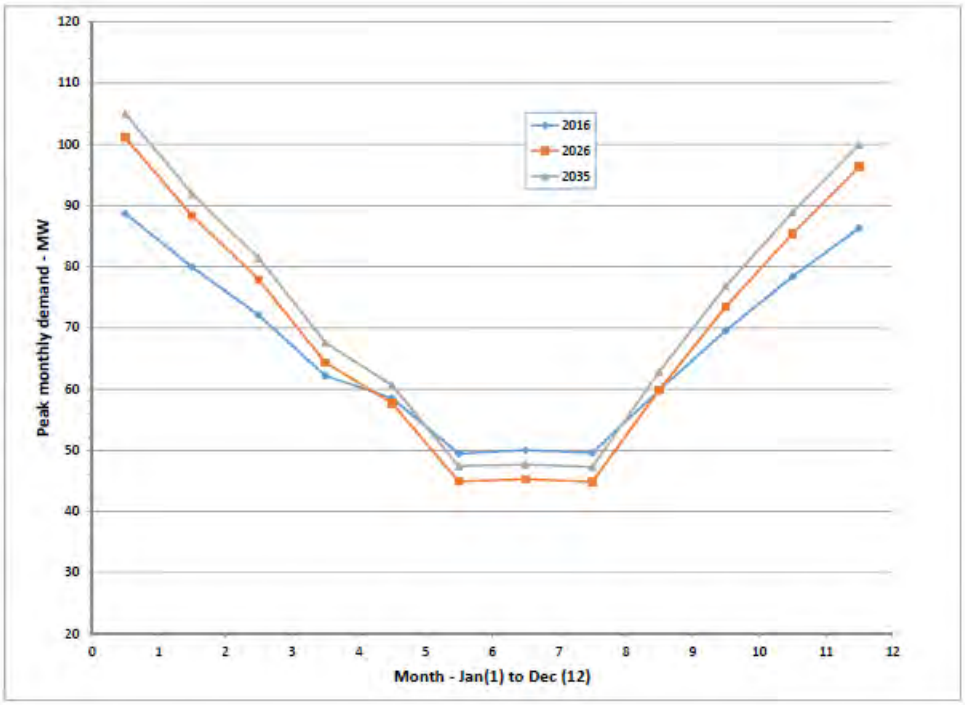

Figure 7-7: Load Scenario 1 Power Demand

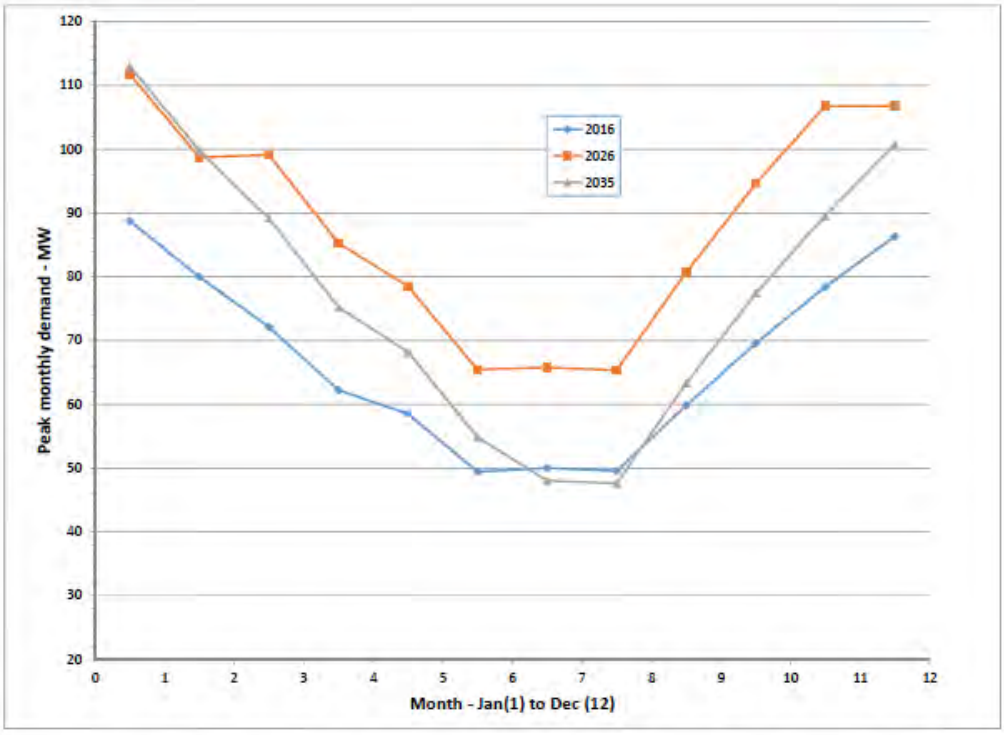

Figure 7-8: Load Scenario 3 Power Demand

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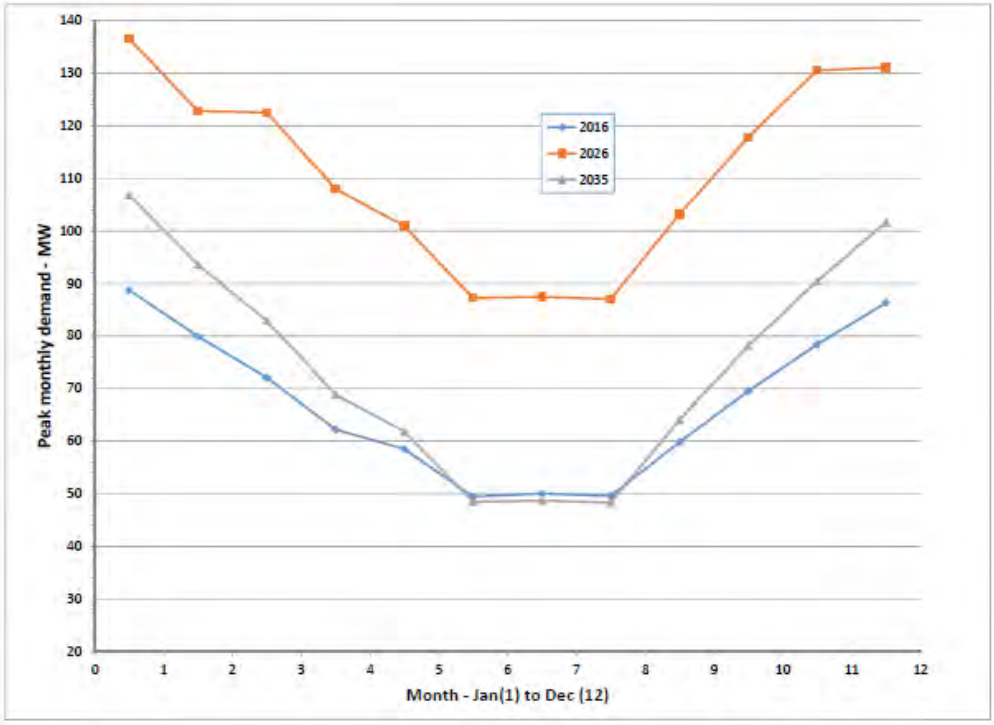

Figure 7-9: Load Scenario 4 Power Demand

The forecasts for these three Load Scenarios, which included both average monthly energy requirements and peak power demands are included in Appendix D.

At present virtually all power and energy demand is met with YEC's hydro units, with thermal (diesel and LNG) units utilized during peak periods, particularly in winter when energy demands are high due to heating load, and available flow for hydro generation is low. There is also increased thermal generation when hydro units are out of service. The benefit of uprating the hydro units is a reduction in thermal generation and the cost savings associated with this.

7.3 Method of Analysis

To assess the energy gains that would occur with unit upgrade options, a YEC system simulation was undertaken. To define detailed system operation for the status quo facilities, and for unit upgrade options, a simulation was undertaken for the load year 2020.

The simulation included the complete generation system, namely:

- Whitehorse (WH1, WH2, WH3 and WH4)
- Aishihik

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- Mayo
- Diesel/LNG plants.

While the small wind generator and ATCO Electric's Fish Lake hydro also provide energy to the YEC grid, these generating facilities are small; therefore they were not included in the energy model.

The Vista Decision Support System (Vista DSS™) was employed, specifically the LT Vista module, which evaluates operation for numerous hydrologic sequences (14 representative sequences as discussed in Section 7.1.2). A daily time-step was utilized, with each day further subdivided into three sub-periods (peak, off-peak, premium peak). The sub-periods were developed from hourly load forecasts for 2017 provided by YEC. Figure 7-10 shows examples of hourly load forecast (from YEC) and the sub-period simulation used in the VISTA model.

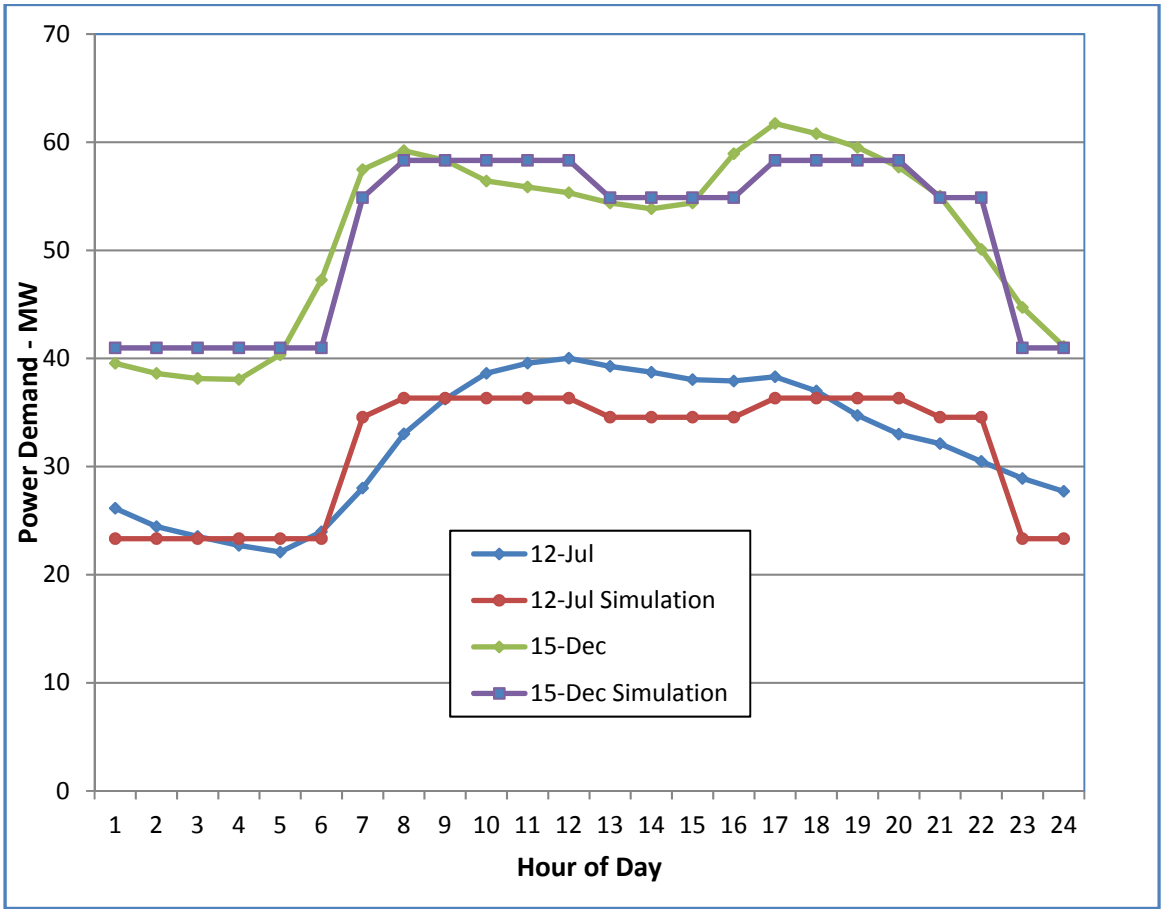

Figure 7-10: Hourly Load Variation

For all energy analysis an allowance was made for 5 MW of hydro spinning reserve.

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A Base case run was undertaken for the status quo conditions. Operation for upgrade options was evaluated in two different ways, as follows.

1) Flows for each Whitehorse unit, for each day and sub-period of the simulation, and for each of the 14 hydrologic sequences, were listed in a spreadsheet. The revised unit characteristics were used to derive the modified power output for each line. Energy gains were also calculated for each line item. These values were aggregated and average annual energy gains were computed.

2) The detailed system simulation was repeated in Vista DSS™ for each option.

Given the various turbine uprate options discussed in Sections 3, 4 and 5 as well as the different load scenarios and variation in load over time discussed above, a very large number of permutations are possible for the system energy analysis. Nine different options were selected for the detailed energy simulation, as summarized in Table 7-2. These options were selected in stages, with the later options determined based on the results of the earlier analysis.

The results of these analyses were used to assess the cost benefit of the nine options and also for assessing the attractiveness of other uprate options.

Table 7-2: Summary of Options for Energy Simulations

Option #	Description	Load Scenario	Load Year
1-1	Uprate WH1 with no increase in flow	1	2020
2-1	Uprate WH3 with no increase in flow	1	2020
3-1	Uprate WH4 with no increase in flow	1	2020
4-1	Uprate WH1 with 10% increase in flow	1	2020
5-1	Uprate WH4 with a Kaplan runner	1	2020
6-1	Uprate WH1 & WH2 with no increase in flow	1	2020
1-4	Uprate WH1 with no increase in flow	4	2025
2-4	Uprate WH3 with no increase in flow	4	2025
5-4	Uprate WH4 with a Kaplan runner	4	2025

While this study does not specifically address uprating of WH2; this was considered in Option 6-1 to assess the extent that uprating of more than one unit would influence the economics of turbine uprating.

Load Scenario 1 is a power and energy demand that is similar to existing conditions and will give a conservatively low estimate of incremental benefits for turbine uprate. Load Scenario 4 is a high or aggressive power and energy demand and represents the upper limit to incremental benefits of turbine uprate. The two scenarios are illustrated in Figure 7-11.

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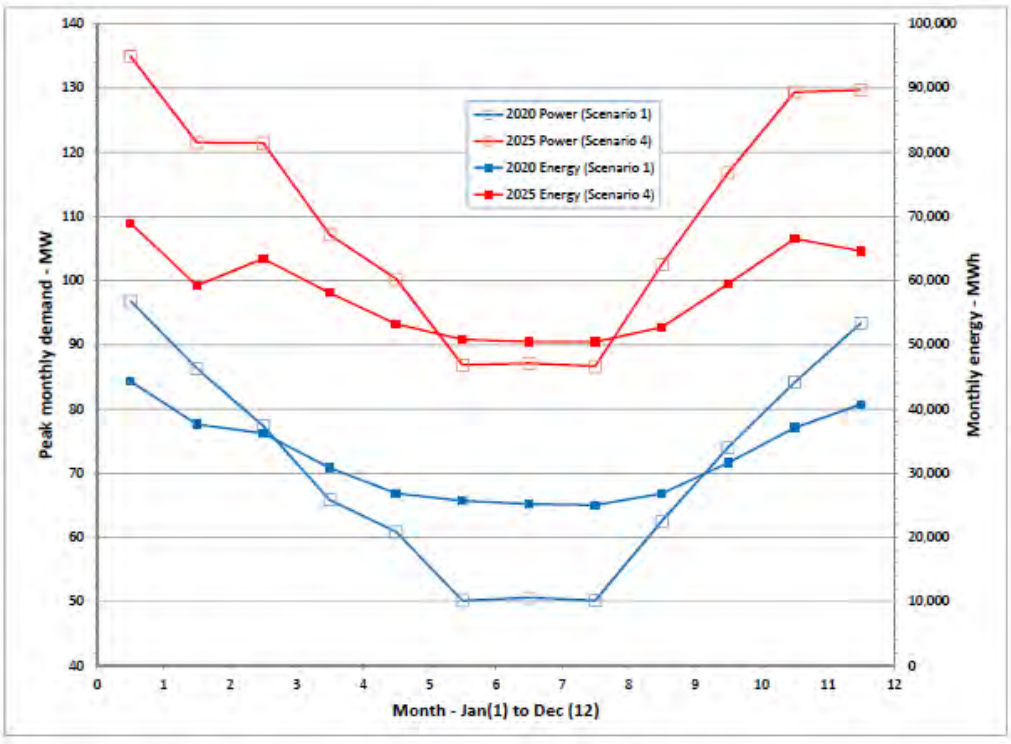

Figure 7-11: Scenarios 1 and 4

7.4 Energy Estimates

The table below summarizes the incremental energy (reduction in thermal energy) for the options summarized in Section 7.3. The average monthly generation for each of the Whitehorse units in the nine options is included in Appendix E.

Table 7-3: Incremental Thermal Generation Estimate

Option	Annual Thermal Generation (MWh)	Base Case Thermal Generation (MWh)	Incremental Thermal Generation (MWh)
1-1	14,888	15,448	-559
2-1	15,400	15,448	-47
3-1	15,053	15,448	-395
4-1	14,960	15,448	-488
5-1	13,864	15,448	-1583
6-1	14,653	15,448	-795
1-4	226,067	227,558	-1491
2-4	227,127	227,558	-430
5-4	223,573	227,558	-4020

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7.5 Avoided Capacity Additions

Uprating of the turbines will reduce the capacity of future thermal generating additions. The avoided capacity additions for each of the options was estimated by determining for each option the maximum thermal power over the 14 years of simulation and comparing this with the maximum thermal power for the base case. The results are presented below.

Table 7-4: Avoided Thermal Capacity Addition

Option	Peak Thermal Power (MW)	Base Case Peak Thermal Power (MW)	Avoided Thermal Capacity (MW)
1-1	24.37	24.46	0.09
2-1	24.45	24.46	0.01
3-1	24.41	24.46	0.05
4-1	24.31	24.46	0.15
5-1	23.76	24.46	0.70
6-1	24.37	24.46	0.09
1-4	94.24	94.47	0.23
2-4	94.41	94.47	0.07
5-4	94.42	94.47	1.00

7.6 Energy Loss During Associated Outage for Turbine Uprate

In addition to the estimates of incremental generation for each of the options, a base case simulation was made with WH4 out of operation. From this simulation it was determined that, on the average, there would be added thermal generation of 12.2 MWh per day in the summer months when WH4 is not operational. This estimated daily energy was used to estimate the cost of lost energy when the unit is removed from service for the uprate work. For uprate of WH1 and WH3, the daily average added thermal generation was reduced in proportion to the capacity of the unit.

7.7 Other Options

There are a number of different turbine uprate options as discussed in Sections 3, 4 and 5 as well as different power and energy demand scenarios. Incremental thermal generation and avoided thermal capacity additions have been estimated for other options using the detailed results of the energy simulations summarized in Sections 7.4 and 7.5 above. The overall summary of options is presented in Table 7-5. The results shown in bold are the nine options from the Vista energy analysis presented in Tables 7-3 and 7-4, the other power and energy values are interpolated results based on the Vista analysis.

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Table 7-5: Summary of Options

			Load Scenario 1		Load Scenario 3		Load Scenario 4	
Option	Uprated Unit	Increased Turbine Flow (Y/N)	Avoided Thermal Generation (MWh/yr)	Avoided Thermal Capacity (MW)	Avoided Thermal Generation (MWh/yr)	Avoided Thermal Capacity (MW)	Avoided Thermal Generation (MWh/yr)	Avoided Thermal Capacity (MW)
1	WH1	N	***559***	***0.09***	932	0.16	***1491***	***0.23***
2	WH3	N	***47***	***0.01***	200	0.04	***430***	***0.07***
3	WH4	N	***395***	***0.05***	664	0.11	1067	0.16
4	WH1	Y	***488***	***0.15***	1040	0.28	1879	0.40
5	WH4	N (K)	***1583***	***0.70***	2558	0.85	***4020***	***1.00***
6	WH1 & 2	N	***795***	***0.09***	1336	0.16	2147	0.23

8. Cost Benefit Analysis

An economic analysis has been undertaken to assess the overall net benefit and benefit-cost ratio of the various turbine uprate options. The two key benefits are:

- Avoided thermal generation.
- Future capacity offset.

Specifically, the avoided thermal generation relates to the additional production of energy by the turbines that will replace a fraction of the thermal energy generation. The future capacity offset relates to the thermal capacity that will not be built in future years due to the additional turbine capacity (i.e. efficiency improvements and/or flow increase).

The magnitude of the key benefits was derived from the energy analysis as discussed in Section 7.

Principal assumptions used in the economic analysis are as follows:

- Real discount rate: 3.38%.
- Value of diesel/LNG energy offset: $200 per MWh.
- Value of added LNG capacity offset: $2,500,000 per MW.
- Distribution of capital costs: based on the construction schedule and generally over two years with 45% the first year and 55% the second.
- The results of the analysis are presented in Table 8-1. Detailed sheets for each option are included in Appendix F.

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There were 6 main uprate options studied for the Units WH1 to WH4. They are numbered as 1-1 through 6-1 in Table 8-1 below. There are also a number of sub-options that were considered as follows:

- Options suffixed by 1-'A' etc., considered the impacts to the financial case of a base option if costs associated with life extension activities such as turbine/generator disassembly and reassembly were either included or excluded from the costs assigned to the turbine uprate estimate.
- Options suffixed with 1-'4' etc., considered applying a different load scenario (ie. load scenario 3 or 4) to one of the base case options to compare the results of the different load scenario on the financial case for each base uprate case.

The details of each of the options are identified in the table columns. The unit that is being uprated is shown in column 2; column 3 indicates whether the uprated unit is designed to have the same turbine flow or increased turbine flow. Column 4 gives the assumed load scenario. Columns 8 and 9 indicate whether or not generator dismantling, re-installation and rewind are factored into the economic evaluation for that particular option or considered as part of a separate 10-year unit overhaul or unit life extension project that would be carried out at the same time as the work associated with the uprate.

Table 8-1: Economic Analysis of Turbine Uprate Options

Option	Uprated Unit	Increased Turbine Flow (Y/N)	Load Scenario	Avoided Thermal Generation (MWh/yr)	Avoided Thermal Capacity (MW)	Capital Cost ($M)	Cost Incl. Disassemby & Install (Y/N)	Cost Incl. Generator Rewind (Y/N)	NPV 30 years ($M)	B/C ratio 30 years	Simple Payback Period (Years)	Discounted Payback Period (Years)
1-1	WH1	N	1	559	0.09	1.99	Y	N	0.21	1.11	19 yrs	28 yrs
1-1A	WH1	N	1	559	0.09	1.78	N	N	0.41	1.23	17 yrs	24 yrs
1-3	WH1	N	3	932	0.16	1.99	Y	N	0.98	1.52	12 yrs	15 yrs
1-3A	WH1	N	3	932	0.16	1.78	N	N	1.18	1.69	11 yrs	13 yrs
1-4	WH1	N	4	1491	0.23	1.99	Y	N	1.18	1.61	12 yrs	14 yrs
1-4A	WH1	N	4	1491	0.23	1.78	N	N	2.26	2.29	9 yrs	9 yrs
2-1	WH3	N	1	47	0.01	2.58	Y	N	-2.43	0.04	No Payback	No Payback
2-1A	WH3	N	1	47	0.01	1.18	N	N	-1.06	0.09	No Payback	No Payback
2-4	WH3	N	4	430	0.07	2.6	Y	N	-1.61	0.36	>45 yrs	>45 yrs
2-4A	WH3	N	4	430	0.07	1.2	N	N	-0.23	0.80	20 yrs	>45 yrs
3-1	WH4	N	1	395	0.05	4.26	Y	Y	-2.84	0.30	No Payback	No Payback
3-1A	WH4	N	1	395	0.05	2.30	N	N	-1.16	0.47	37 yrs	No Payback
4-1	WH1	Y	1	488	0.15	4.78	Y	Y	-2.68	0.43	No Payback	No Payback
4-1A	WH1	Y	1	488	0.15	2.74	N	N	-0.68	0.75	27 yrs	No Payback
4-4	WH1	Y	4	1879	0.40	4.78	Y	Y	0.28	1.06	14 yrs	23 yrs
4-4A	WH1	Y	4	1879	0.4	2.74	N	N	2.23	1.85	9 yrs	10 yrs
5-1	WH4 - K	N	1	1583	0.70	10.38	Y	Y	-6.18	0.39	42 yrs	No Payback
5-4	WH4 - K	N	4	47	1.00	10.4	Y	Y	1.20	1.12	14 yrs	23 yrs
6-1	WH1 & 2	N	1	795	0.09	3.97	Y	N	-0.95	0.75	27 yrs	No Payback

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The analysis shows that uprating of the WH1 turbine is economically positive for Load Scenario 1 load (Option 1-1), although the payback period is 19 years. The benefits are improved slightly if the uprate is considered to be an “add-on” to a life extension program for generator work (Option 1-1A). For the increased load demand of Load Scenarios 3 and 4 (Option 1-3 and 1-4) the benefits are further improved, but the payback period still remains at 9 to 12 years. A new runner with increased flow (Option 4-4) does not improve the economics for the uprate of WH1 due to the corresponding reduction in turbine efficiency as a result of the increased flow. Uprating of both WH1 and WH2 reduces the benefit cost ratio to less than 1.0.

Uprate of WH3 is not economically attractive even if the turbine work associated with the uprate is carried out as part of a separate 10-year equipment overhaul or a generator rewind (life extension) project.

Uprate of WH4 provides more benefit than uprate of WH3; however, the results indicate that this option also does not appear to be economically attractive.

The retrofit of a Kaplan runner into WH4 results in the greatest energy benefit of all the options considered. However, there is significant added capital cost for a Kaplan conversion which makes the economic evaluation even less attractive than a simple propeller runner retrofit on WH4.

With the exception of WH1, all other unit uprate options even assuming Load Scenario 4 all had a benefit/cost ration of less than or slightly over 1.0.

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9. Discussion

The efficiency improvements associated with a replacement runner for WH1 results in a positive economic benefit, with a NPV situated between $0.2M and $2.26M over a 30-year lifetime and a payback period of 9 to 19 years depending on the Option chosen and the assumed Load Scenario selected. It is therefore suggesting that WH1 efficiency improvements should be implemented. However the payback period is fairly long even under the assumption of the higher demand Load Scenarios 3 and 4.

Uprating of both WH1 and WH2 does not appear economically attractive. When only WH1 is uprated, it has preferential loading, which will increase the operating hours of this unit when compared to WH2. If the goal is to have equal operating hours on WH1 and WH2, then benefit of WH1 upgrade will be reduced.

An uprated turbine with increased flow capacity provides slightly higher economic benefit if it is assumed that the cost of uprating the generator is part of a separate life extension project rather than included with the turbine uprate. This is a reasonable assumption as the generators are now almost 60 years old and the stator windings have never been replaced. While there is no indication of a near term problem with the windings, they are now well beyond the typical winding life.

The economic benefit of uprating WH1 is based on an efficiency increase of approximately 4%. There is obviously some uncertainty in both the measured performance of the existing unit and the predicted performance of an uprated turbine. This represents an added risk to WH1 uprate.

Uprate of WH3 is not economic even with an increase in energy demand. This perhaps seems counterintuitive, as WH3 has a lowest measured efficiency and a significant performance improvement is predicted with a new runner. The reason for this is that WH3 has a limited useful operating range in the context of total powerhouse flow. Presently WH4 is base loaded while WH1 and WH2 cover variable load. This will not change even if the WH3 turbine efficiency is significantly increased. Installation of a Kaplan runner in WH3 would increase its operational range. However, the Kaplan option has much higher cost; therefore this option would not be economic.

WH4 is also shown to be uneconomic. Once reason for this in the high efficiency of the existing turbine, resulting is a low efficiency gain (approximately 0.6%) with an uprated runner. It is possible that the existing efficiency is slightly overstated, which would make WH4 slightly more attractive. However, it is difficult to foresee an increase sufficiently high to make uprate of this unit attractive.

The high load growth scenario associated with Options 1-4 and 1-4A (WH1) presents by large the highest NPV and benefit/cost ratio of all options. Even though this option is based on a hypothetical load growth, it provides further evidence that the efficiency improvement for WH1 should be performed – as further economic benefits might materialize for this option if the

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power demand increases in future years. It also indicates that WH2 should be upgraded in high load growth cases.

Other turbine uprate options presented in this analysis are shown to be not economically attractive at present (i.e. efficiency improvements for WH3 and WH4) and should be reassessed in future years if significant changes in the energy demand and supply patterns are to occur.

The above general conclusions are considered realistic; nevertheless, there are other items to consider:

- Even if YEC elects to not uprate any of the turbines at WGS, the replacement of the cams that define the WH1 and WH2 wicket gate runner blade relationship is recommended. This is consistent with the recommendation made by HPPE in its report on the 2009 performance tests. Per the HPPE report the increment efficiency with an updated cam is expected to be in the range of 2%. The energy analysis completed as part of this study shows that a 4% increase in turbine efficiency results in an average annual reduction of 559 MWh in thermal generation. From this it can be assumed that a new cam will provide half this energy or 280 MWh (in addition to the upgrade energy gain). This is a sizeable amount of energy considering the relatively low cost of a new governor cam. If YEC is uncertain about the true incremental efficiency with a new gate-blade relationship an additional index test can be performed to confirm the 2009 test results. A full efficiency test whereby flow is measured is not required, only a relatively index test.
- The analysis for Option 5-1 (Kaplan runner in WH4) does not consider the benefit of added operating flexibility for YEC system operations. This may be difficult to quantify. It also should be cautioned that the retrofit of a propeller turbine to a Kaplan design is a significant undertaking, and more detailed evaluation would be warranted prior to a final decision on such an option.

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10. Conclusions

The performance of the turbines WH1, WH3 and WH4 at the Whitehorse Generating Station can be improved with new runners of modern design. Options with uprated turbines that have the same flow capacity, but higher efficiency, as well as turbines with increased flow capacity have been investigated. The benefit of uprating the turbines is primarily a reduction in more costly thermal (diesel or LNG) generation.

Uprating of WH1 with a more efficient runner has a projected positive net benefit. A higher flow runner should be possible but as efficiency would be reduced slightly the higher flow runner does not provide improved economics.

Uprating of either WH3 or WH4 does not appear attractive. The turbines for these units are fixed blade propeller type, which have very limited load variation capabilities and as such limited operational flexibility. As an alternative to new fixed blade propeller runners, these units could be converted to a Kaplan design. Energy benefits would increase and the units would have much better operating flexibility. However, estimated costs for a Kaplan conversion are significantly higher and as a result, this option does not appear to be financially attractive.

A summary of costs, benefits, and benefit/cost ratios for the various turbine uprate options considered is presented in Table 10-1.

Table 10-1: Uprate Cost/Benefit Summary

Option	Uprated Unit	Increased Turbine Flow (Y/N)	Load Scenario	Avoided Thermal Generation (MWh/yr)	Avoided Thermal Capacity (MW)	Capital Cost ($M)	Cost Incl. Disassemby & Install (Y/N)	Cost Incl. Generator Rewind (Y/N)	NPV 30 years ($M)	B/C ratio 30 years	Simple Payback Period (Years)	Discounted Payback Period (Years)
1-1	WH1	N	1	559	0.09	1.99	Y	N	0.21	1.11	19 yrs	28 yrs
1-1A	WH1	N	1	559	0.09	1.78	N	N	0.41	1.23	17 yrs	24 yrs
1-3	WH1	N	3	932	0.16	1.99	Y	N	0.98	1.52	12 yrs	15 yrs
1-3A	WH1	N	3	932	0.16	1.78	N	N	1.18	1.69	11 yrs	13 yrs
1-4	WH1	N	4	1491	0.23	1.99	Y	N	1.18	1.61	12 yrs	14 yrs
1-4A	WH1	N	4	1491	0.23	1.78	N	N	2.26	2.29	9 yrs	9 yrs
2-1	WH3	N	1	47	0.01	2.58	Y	N	-2.43	0.04	No Payback	No Payback
2-1A	WH3	N	1	47	0.01	1.18	N	N	-1.06	0.09	No Payback	No Payback
2-4	WH3	N	4	430	0.07	2.6	Y	N	-1.61	0.36	>45 yrs	>45 yrs
2-4A	WH3	N	4	430	0.07	1.2	N	N	-0.23	0.80	20 yrs	>45 yrs
3-1	WH4	N	1	395	0.05	4.26	Y	Y	-2.84	0.30	No Payback	No Payback
3-1A	WH4	N	1	395	0.05	2.30	N	N	-1.16	0.47	37 yrs	No Payback
4-1	WH1	Y	1	488	0.15	4.78	Y	Y	-2.68	0.43	No Payback	No Payback
4-1A	WH1	Y	1	488	0.15	2.74	N	N	-0.68	0.75	27 yrs	No Payback
4-4	WH1	Y	4	1879	0.40	4.78	Y	Y	0.28	1.06	14 yrs	23 yrs
4-4A	WH1	Y	4	1879	0.4	2.74	N	N	2.23	1.85	9 yrs	10 yrs
5-1	WH4 - K	N	1	1583	0.70	10.38	Y	Y	-6.18	0.39	42 yrs	No Payback
5-4	WH4 - K	N	4	47	1.00	10.4	Y	Y	1.20	1.12	14 yrs	23 yrs
6-1	WH1 & 2	N	1	795	0.09	3.97	Y	N	-0.95	0.75	27 yrs	No Payback

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The schedule for an uprate, allowing for procurement is approximately two years. Advanced planning will be necessary for such a program. The outage for the uprate work would ideally be in the summer, when load demand is low. The unit outage itself would be in the range of four to five months.

Modification of WH3 for synchronous condenser operation is also possible. The major changes would be the installation of a large compressed air system to depress the tailwater below the runner and allow the unit to be motored in air, in addition to control system modifications. However, at present there is no demand for added reactive power. The reactive power requirements for the YEC system are currently met by operating the existing hydro units at slightly below unity power factor.

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Appendix A
Powerhouse and Equipment Drawings (Existing)

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DETAIL OF PENSTOCK STIFFENER.

PENSTOCK DIMENSIONS

TYPE	#1	#2	#3
STRAIGHT PIPE WITH 6"x3½"x½ L STIFFENERS @ 2'-7⅞" & 3'-6" O/C. LENGTH	64'-11⅜"	65'-4⅛"	64'-5⅜"
BEND #1 RADIUS	37'-6"	37'-6"	37'-6"
HORZ. Δ	111°-8½'-7"	-	139°-10'-21"
PROFILE VERT. Δ	24°-5'-3"	24°-30'-39"	23°-26'-22"
TRUE Δ	26°-24'-36"	24°-30'-39"	23°-8'-10"
STRAIGHT PIPE WITH 6"x3½"x½ L STIFFENERS @ 5'-9" O.C. LENGTH	87'-4⅛"	87'-0⅝"	87'-6⅞"
BEND #2	SIMILAR TO BEND #1	SIMILAR TO BEND #2	SIMILAR TO BEND #1
STRAIGHT PIPE WITH 6"x3½"x½ L STIFFENERS @ 5'-9" O.C.	19'-9 3/32"	20'-5/16"	10'-8⅛"

PLAN SHOWING CUTAWAY VIEW OF PENSTOCKS #1 & #2
SCALE 1" = 20'

TYPICAL PENSTOCK SECTION DOWNSTREAM OF FIRST BEND

SECTION B-B
SCALE 1"=10'-0"
(FOR EXCAVATION DETAILS SEE DRWG. "NCP. 10280")

EL. 2109 (TOP OF ROCK TOE.)
(AFTER BACKFILLING.)

TYPICAL SECTION C-C
SCALE: 1"=10'
PENSTOCK ON EARTH & ROCK

152-4

SECTION THROUGH MANHOLE
(3'4"X3'4" SQUARE)
SCALE: 1"=1'-0"

TYPICAL EXPANSION JOINT.
SCALE 3"=1'-0"

FOR PENSTOCK	UPSTREAM EXP. JOINT	DOWNSTREAM EXP. JOINT
#1	B - M. B10/B1L, B - M.B1R/B2L	H - M.B1L/B2L, H - M.B2R/B3L
#2	A - M. B10/B1L, B - M.C1R/B2L	A - M.B1L/B2L, D - M.B2R/B3L
#3	H - M. B10/B1L, B - M.C1R/B2L	A - M.B1L/B2L, D - M.B2R/B3L

NOTE:
THE DOWNSTREAM END OF THE EXP. JOINT WILL BE WELDED ON THE INSIDE, IN 1958, ONLY PROVIDED WITH A WATER SEAL IF SETTLEMENT CONTINUES.

SECTION A-A SCALE 1"=20'-0"

SECTION E-E SCALE 1"=20'-0"

SECTION F-F
SCALE 1"=10'-0"

SECTION D-D
SCALE: 1"=10'
PENSTOCK IN ROCK CUT.

REFERENCE DRAWINGS

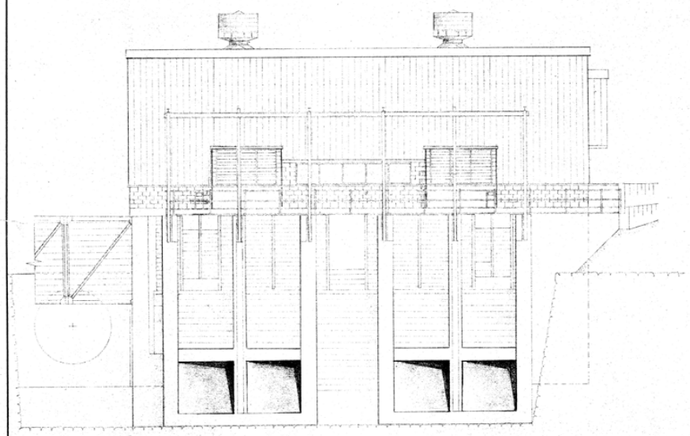
GENERAL LAYOUT OF DEVELOPMENT	NCP 10052
POWERHOUSE TOPOGRAPHY	NCP 10306
PENSTOCK EXCAVATION	NCP 10310
POWERHOUSE EXCAVATION	NCP 10219
PENSTOCK ERECTION & CONSTRUCTION DETAILS, VICTORIA MACHINERY & DEPOT CO. ONTARIO LTD	NCP 11469
PENSTOCK HANDLE	

APPROVED FOR CONSTRUCTION
Dec 11/52 — Chief Civil Engineer
Dec 30/52 — Chief Consulting Engineer

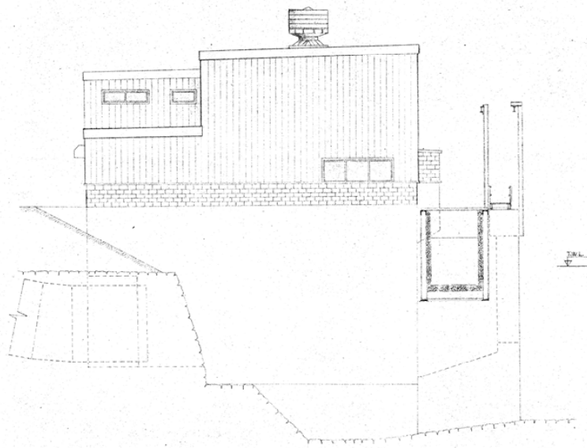
MONTREAL ENGINEERING CO. LTD.
CONSULTING AND OPERATING ENGINEERS
N.C. POWER COMMISSION
W.H. RAPIDS POWER DEVELOPMENT
PENSTOCKS
PLAN, PROFILE & SECTIONS
DWG. NO. NCP 9 [illegible]

REV.	DESCRIPTION	BY	CHK	DATE
H	DETAIL AROUND ANCH. BLOCK 30" JOINT CHANGED, SECTION THRU EXP. JOINT ADDED, BACKFILLING NOTES TO SECTION D-D, DETAIL LOWERED 6"	JHM	JHM	OCT 1 '58
G	MANHOLE, SPEED, DETAIL OF PENSTOCK SUPPORT WORK	JHM	JHM	10/28/57
F	REVISION OF TO SUITE WITH PENSTOCK AS INSTALLED	JHM	JHM	ANNOTATED
E	MINOR REVISIONS AND DETAILS ADJUSTMENT TO SUITE	JHM	KGB	
D	REVISED			
C	GENERAL PENSTOCK IN CRAWN AND INTERMEDIATE PROFILES	JHM	KGB	
B	DIAG. OF PENSTOCK SUPPORTS ADDED, PENSTOCK PROFILE	JHM	KGB	
A				

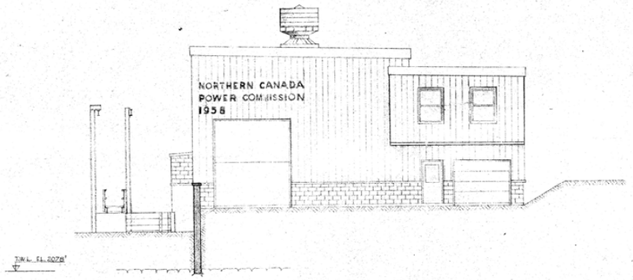
CHECKS: CONST. | ELEC. | DRAWN | LETTER



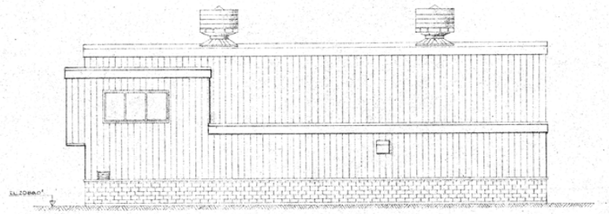
DOWNSTREAM SIDE



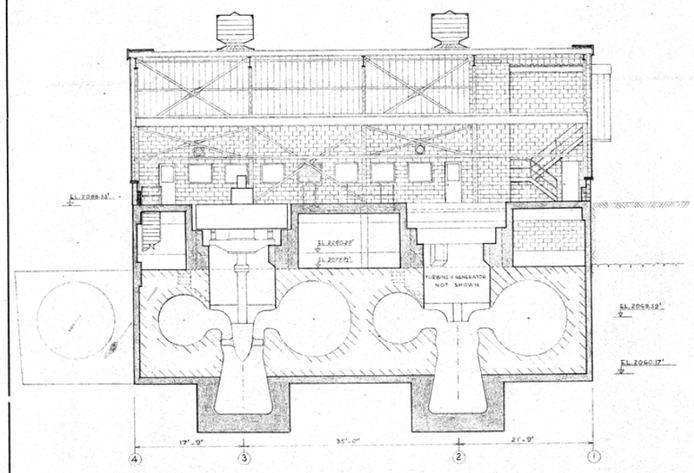
SOUTH ELEVATION



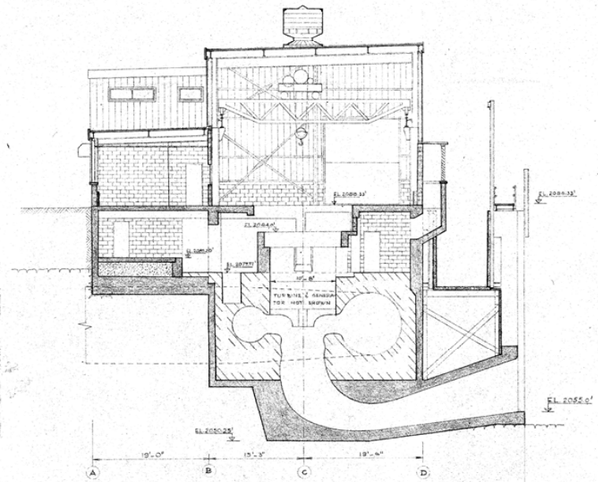
NORTH ELEVATION



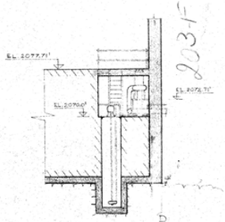
UPSTREAM SIDE



SECTION B-B



SECTION A-A



SECTION C-C

REFERENCE DWGS:
NCP. 10018 POWERHOUSE PLANS.
NCP-10015 PENSTOCK
NCP-10160 SUPERSTRUCTURE STEEL DETAILS.

WH-15 S.E.

REV.	DESCRIPTION	BY
F	TRACING REDRAWN, REVISED IN ORDER TO HAVE DWG "AS BUILT"	
E	3 MAY 33. ROOF VENTILATORS DRAWN TO SCALE, TURBINE FLOOR LOWERED 1½" STREAM ELEVATION ADDED.	R.B.
D	7 FEB. 33. DOWNSTREAM FACE OF POWERHOUSE CHANGED, DRAFT TUBE GATE DECK REVISED.	R.B. L.J.
C	16 JAN. 33. ACCESS TO TURBINE PIT AND NEUTRAL SUBSILL RELOCATED. PUMP #2 ALTERED.	R.B.
B	30. NOV. 1956 DRAFT TUBE RESHAPED, WALL THICKNESS ALTERED, PUMP PIER LAYOUT REVISED, SUMPS & ROOF LOWERED. PILOT EXCITER REMOVED, DRAFT TUBE GATE REVISED.	By E.H.
A	29. OCT. 56. CUT-OFF WALL AND ANCHOR BLOCK PENSTOCK #3 ADDED.	BY H.D.L.

CHECKS

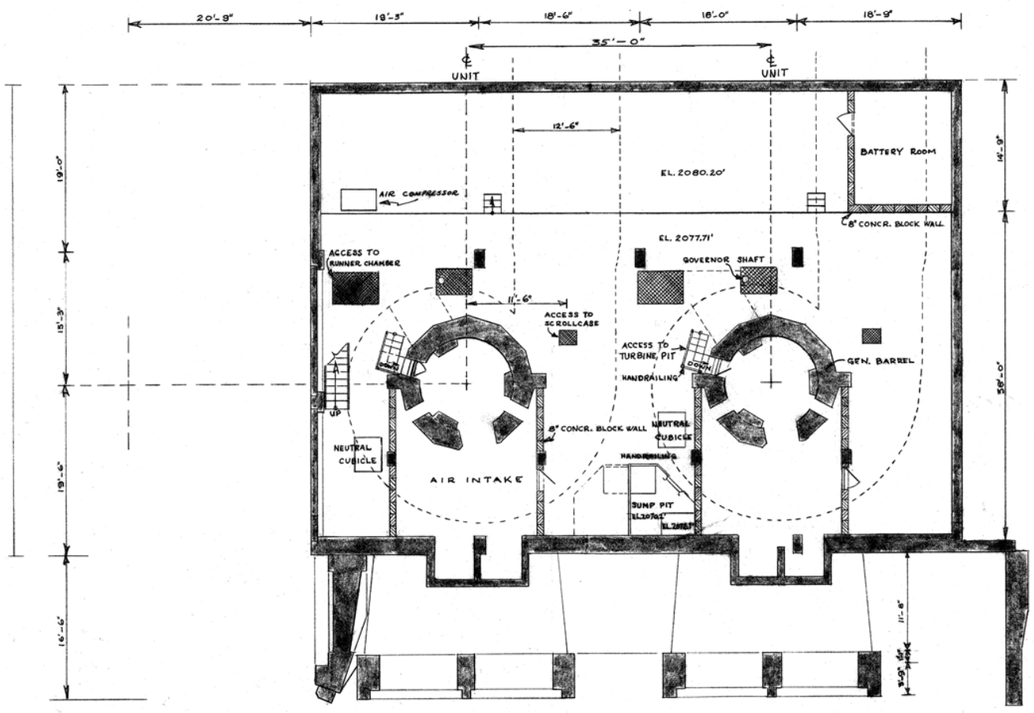
MONTREAL ENGINEERING CO., LTD.
CONSULTING AND OPERATING ENGINEERING SERVICES

NORTHERN CANADA POWER COMMISSION
WHITEHORSE RAPIDS POWER DEVELOPMENT

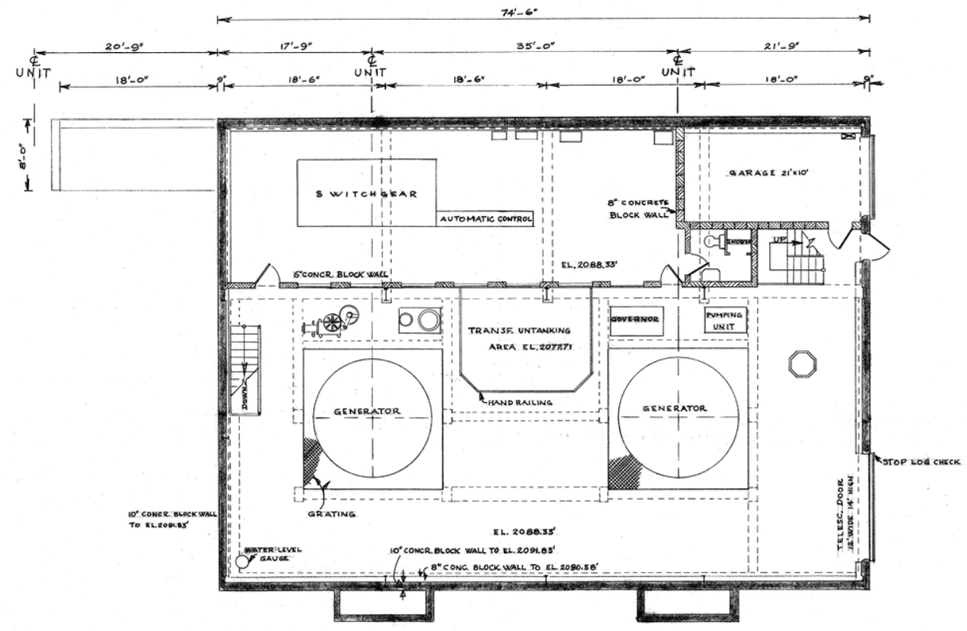
GENERAL LAYOUT
POWER HOUSE
SECTIONS & ELEVATIONS

Designed: Drawn: R. M. Date: 14 SEPT. 1954
Pers. Eng.: J.H.M. Scale: 1/8" = 1'-0"
Passed:
W.O. No. NCP-3-371-3

DWG. No. NCP-10019



TURBINE FLOOR EL. 2077.71'



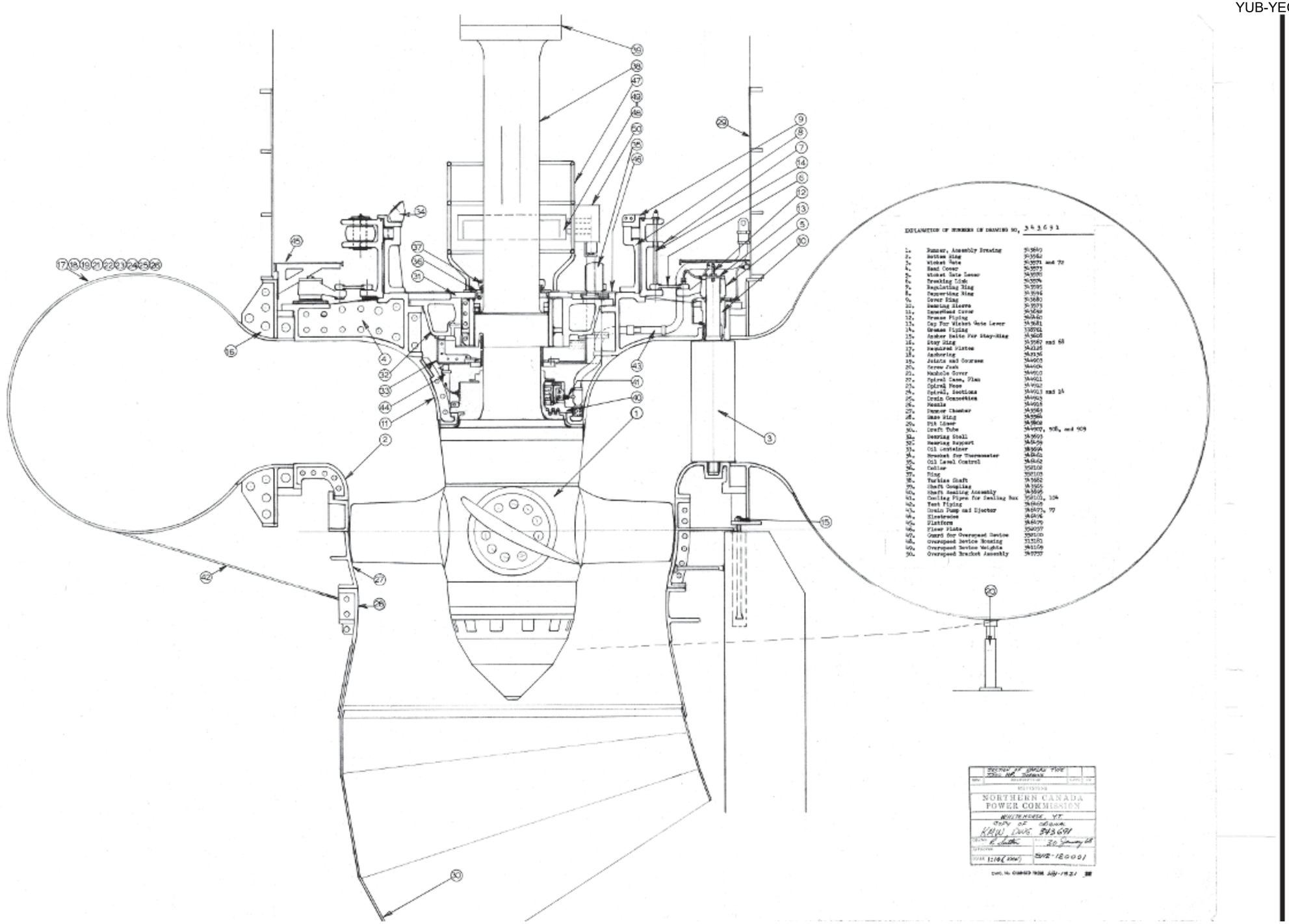
GENERATOR FLOOR EL. 2088.33'

P125-601	EQUIPMENT LAYOUT
DRAWING NO.	TITLE
REFERENCE DRAWINGS	

NAME	DATE		ORIGINAL							
ISSUED TO			DESCRIPTION	WORK ORDER	DRAWN BY	CHECKED BY	APPROVED FOR CONSTRUCTION BY	CHK'D AS BUILT DWG. & UPDATED		

NORTHERN CANADA POWER COMMISSION
WHITEHORSE RAPIDS HYDRO PLANT
General Layout
POWERHOUSE PLANS

DRAWN:	CHECKED:	DATE: 23 Feb. 68	DWG. No. P125-602 △
TRACED:	APPROVED:	SCALE: 1/8" = 1'-0"	

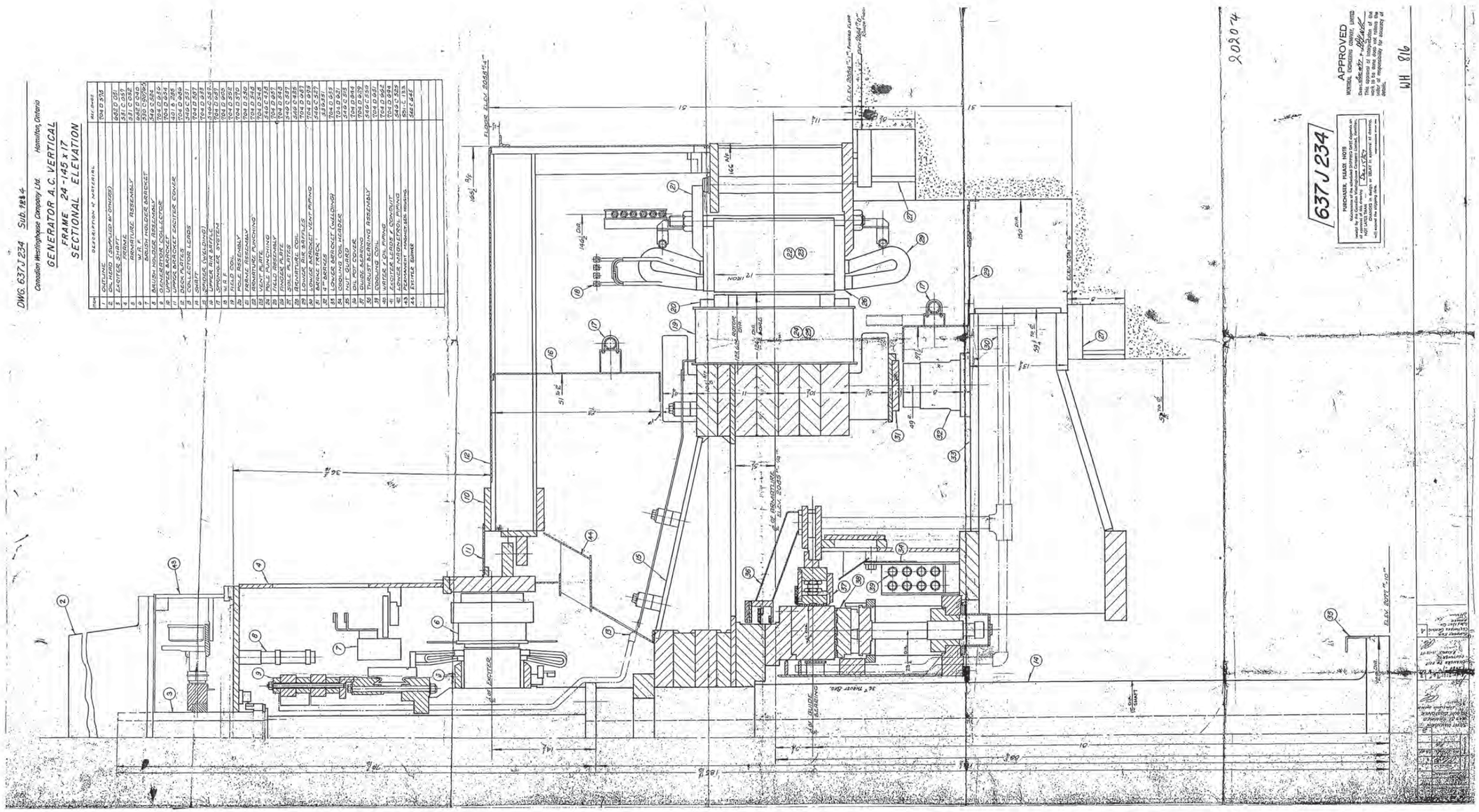

EXPLANATION OF NUMBERS ON DRAWING NO. 343691
1. Runner, Assembly Drawing 343690
2. Bottom Ring 343682
3. Wicket Gate 343671 and 72
4. Head Cover 343673
5. Wicket Gate Lever 343695
6. Breaking Link 343678
7. Regulating Ring 343680
8. Supporting Ring 343696
9. Cover Ring 343683
10. Bearing Sleeve 343679
11. Somershead Cover 343689
12. Grease Piping 343681
13. Cap For Wicket Gate Lever 343681
14. Grease Piping 338781
15. Anchor Bolts For Stay-Ring 343698
16. Stay Ring 343687 and 88
17. Required Piston 342185
18. Anchoring 342136
19. Joints and Courses 344695
20. Screw Jack 344694
21. Manhole Cover 344693
22. Spiral Case, Plan 344691
23. Spiral Nose 343692
24. Spiral, Sections 344691 and 94
25. Drain Connection 344695
26. Manis 344698
27. Runner Chamber 343686
28. Base Ring 343684
29. Pit Liner 343804
30. Draft Tube 344697, 698, and 699
31. Bearing Shell 343693
32. Bearing Support 343694
33. Oil Container 343694
34. Bracket for Thermometer 343682
35. Oil Level Control 344682
36. Collar 338108
37. Ring 338103
38. Turbine Shaft 343682
39. Shaft Coupling 343695
40. Shaft Sealing Assembly 343695
41. Cooling Pipes for Sealing Box 338103, 104
42. Test Piping 343695
43. Drain Pump and Ejector 343677, 77
44. Electrodes 343676
45. Platform 343679
46. Floor Plate 338097
47. Guard for Overspeed Device 338100
48. Overspeed Device Housing 313181
49. Overspeed Device Weights 343156
50. Overspeed Bracket Assembly 343737
SECTION OF DRAFT TUBE
DWG. NO. 343691
NORTHERN CANADA
POWER COMMISSION
WHITEHORSE, YT.
STAFF OF DRAWN
KAIU DWG. 343691
E. Smith
20 January 48
SCALE 1:10 (when)
SIZE - IE-0001

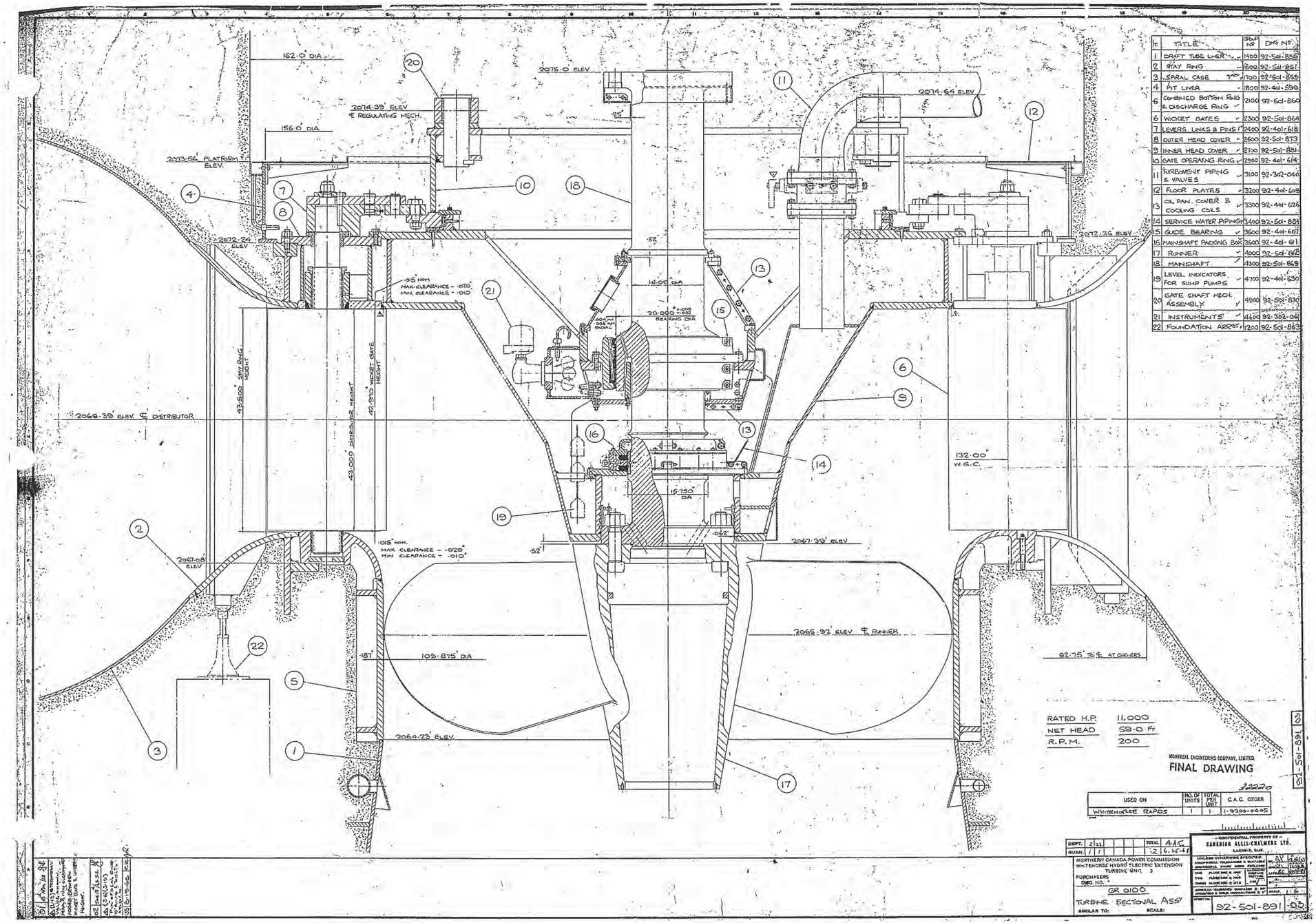
DWG. 637J234 Sub. #14

Canadian Westinghouse Company Ltd. Hamilton, Ontario

GENERATOR A.C. VERTICAL
FRAME 24'-1.45 x 17
SECTIONAL ELEVATION

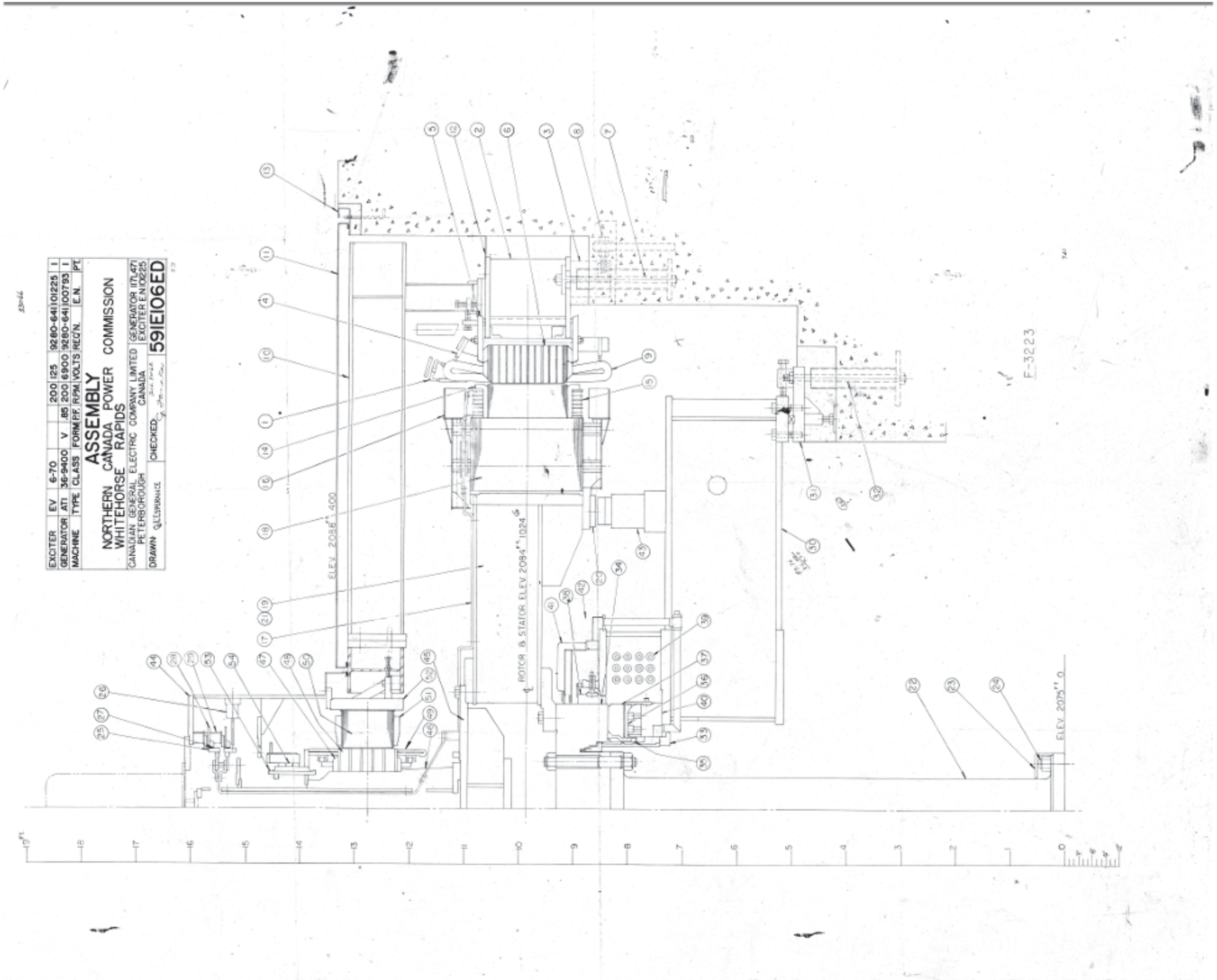
ITEM	DESIGNATION & NOTATION	REQ'D PART
1	COIL ASSY.	704 D 935
2	COIL HEAD (SUPPLIED AS CHOSES)	640 D 081
3	EXCITER SHAFT	640 C 187
4	FRAME, STRUCTURE ASSEMBLY	331 C 082
5	W.R.T.	640 D 040
6	BRUSH HOLDER BRACKET	330 C 08782
7	BRUSH HOLDER ASSEMBLY	640 C 084
8	CORE & COIL ASSEMBLY	704 D 949
9	UPPER BRACKET EXCITER COVER	704 D 934
10	UPPER BRACKET	704 D 934
11	UPPER BRACKET EXCITER COVER	401 B 788
12	COLLECTOR LEADS	704 D 934
13	COIL EXCITER LEADS	349 C 831
14	SHAFT	704 D 597
15	SPIDER (WELDING)	704 D 941
16	SPIDER ASSEMBLY	704 D 941
17	SPRINKLER SYSTEM	704 D 969
18	W.R.F.	704 D 965
19	FIELD COIL	704 D 936
20	FIELD ASSEMBLY	704 D 970
21	FRAME ASSEMBLY	704 D 930
22	ARMATURE PUNCHING	704 D 948
23	WEB PUNCHING	349 C 434
24	FIELD ASSEMBLY	704 D 967
25	RIDGE PLATE	704 D 951
26	RIDGE PLATE	349 C 891
27	ARMATURE COIL	349 D 435
28	LOWER AIR BAFFLES	704 D 943
29	LOWER BRACKET VENT PIPING	349 C 527
30	ARMATURE	704 D 944
31	4" BRACES	330 B 91
32	LOWER BRACKET (WELDING)	704 D 953
33	DOWEL COIL HEADER	349 C 951
34	THRUST PLATE	704 D 954
35	OIL POT COVER	704 D 944
36	GUIDE BEARING	704 D 959
37	THRUST BEARING ASSEMBLY	704 D 960
38	OIL PIPING	704 D 961
39	WATER & OIL PIPING	704 D 962
40	EXCITER LEADS & CONDUIT	704 D 964
41	LOWER BRACKET PIPING	704 D 954
42	EXCITER FRAME PIPING	501 C 113
43	EXCITER BUMPER	5662 645





F	TITLE	GRUP Nº	DWG Nº
1	DRAFT TUBE LINER	1400	92-501-856
2	STAY RING	1600	92-501-857
3	SPIRAL CASE	1700	92-501-858
4	PIT LINER	1800	92-401-590
5	COMBINED BOTTOM RING & DISCHARGE RING	2100	92-501-860
6	WICKET GATES	2300	92-501-864
7	LEVERS, LINKS & PINS	2400	92-401-618
8	OUTER HEAD COVER	2500	92-501-873
9	INNER HEAD COVER	2700	92-501-881
10	GATE OPERATING RING	2900	92-401-614
11	TURBOVENT PIPING & VALVES	3100	92-302-040
12	FLOOR PLATES	3200	92-401-609
13	OIL PAN, COVER & COOLING COILS	3300	92-401-626
14	SERVICE WATER PIPING	3400	92-501-881
15	GUIDE BEARING	3600	92-401-607
16	MAINSHAFT PACKING BOX	3600	92-401-611
17	RUNNER	4000	92-501-868
18	MAINSHAFT	4300	92-501-869
19	LEVEL INDICATORS FOR SUMP PUMPS	4700	92-401-630
20	GATE SHAFT MECH. ASSEMBLY	4900	92-501-870
21	INSTRUMENTS	4600	92-302-040
22	FOUNDATION ARRST.	1200	92-501-863

FIGURE 8


EXCITER EV 6-70 200 125 9280-641 I01225 I
GENERATOR ATI 36-9400 V .85 200 6900 9280-641 I00793 I
MACHINE TYPE CLASS FORM PF RPM VOLTS REQ'N. E.N. PT
ASSEMBLY
NORTHERN CANADA POWER COMMISSION
WHITEHORSE RAPIDS
CANADIAN GENERAL ELECTRIC COMPANY LIMITED PETERBOROUGH CANADA
GENERATOR 117,477
EXCITER E.N. 00225
DRAWN CHECKED
59IEI06ED
F-3223
ELEV. 2086' 4.00
ELEV. 2084' 10.24
ROTOR & STATOR ELEV. 2084'
ELEV. 2075' 0

REV. REG. No. D88281

UNIT
1 2 3 4 5
5000 3500 3000 6500 6500
FAN (F1) 1000
FAN (F2) 1000
FAN (F3) 2500
FAN (F5)
SIDING TYPE 1
SIDING TYPE 2
SIDING TYPE 1
BY STEEL 2001 DESIGNER
1800 1800 1800 1800 1000 150
ROOF DRAIN TYP.
TO VENT PIPE EL. 651.000
BRACING ON LINE 'B' TO BE ONLY BETWEEN BAY LINES 2 & 3 AND 4 & 5.
TO SUMP
CRANE RAIL BEAM
BRACING ON LINE 'A'
TOP OF CRANE RAIL EL. 647.500
APPROX. TOP OF ROCK
RIGID INSULATION
VENTILATION PIPE 250 I.D.
EL. 645.200
LADDER Nº 1
LADDER Nº 2
SIDING TYPE 1
GROUT CAP (100 BLOCK WALL 50 RIGID INSULATION 250 CONCRETE
900 DEEP x 7 315 LONG LOUVER EL. 642.000
EL. 641.000
TRANSFORMER PAD
EL. 640.300
EL. 641.000
I.J.
EL. 639.190
EL. 637.270
EL. 637.000
PENSTOCK CONCRETE
EL. 636.300 AVERAGE SUMMER TAILWATER LEVEL ALL UNITS RUNNING
EL. 634.700 AVERAGE WINTER TAILWATER LEVEL WITH UNIT #4 DISCHARGING 125 M 3/S
EL. 633.000 ℄ DISTRIBUTOR
EL. 631.000
SPIRAL CASE
EL. 629.250
EL. 626.000
EL. 625.000
DRAFT TUBE STEEL LINER
END OF STEEL LINER
C.J.
2700
EL. 620.900
EL. 620.200
EL. 619.500
EL. 619.300
EL. 618.450

LEGEND
FIRST STAGE CONCRETE
SECOND STAGE CONCRETE
EXCAVATED ROCK
I.J. - ISOLATION JOINT
C.J. - CONSTRUCTION JOINT

FIGURE 14

APPROVED FOR CONSTRUCTION
CONTRACT NO. 460-81
SCALE: 1:50 1 5 0 1 2 3 4 m
AS BUILT

NOTES
1. BLOCK WALL AND RIGID INSULATION TO CONFORM TO NATIONAL BUILDING CODE OF CANADA.

0200-1002 SITE LAYOUT w/s PORTION PLAN & SECTION
0200-1001 GENERAL PLAN OF PROJECT
REFERENCE DRAWINGS

PROFESSIONAL ENGINEER YUKON TERRITORY J.O.H. HUNT

REVISIONS
No 5 DETAIL OF WALL SIGNAL CONNECTION MOVED & TO VENT AS ABOVE. LOUVER REVISED
No 4 LOUVER ADDED
No 3 APPROVED FOR CONSTRUCTION
No 2 REVISED AS BUILT

APPROVED FOR CONSTRUCTION
Discipline Head - Mechanical
Discipline Head - Electrical
Discipline Head - Construction

SCALE AS SHOWN
DESIGNED
DRAWN TOYO K DEC 15/80
CHKD
PASSED
APPROVED

NORTHERN CANADA POWER COMMISSION
WHITEHORSE UNIT No. 4
POWERHOUSE
GENERAL ARRANGEMENT
SECTION THRU ℄ OF UNIT SHEET 1
MONENCO CONSULTANTS PACIFIC LTD.
ORIGINAL PREPARED IN VANCOUVER
DWG. No. NCP7824-4 0280 1003
REGISTRY No. D 88283
PLATE no. 41

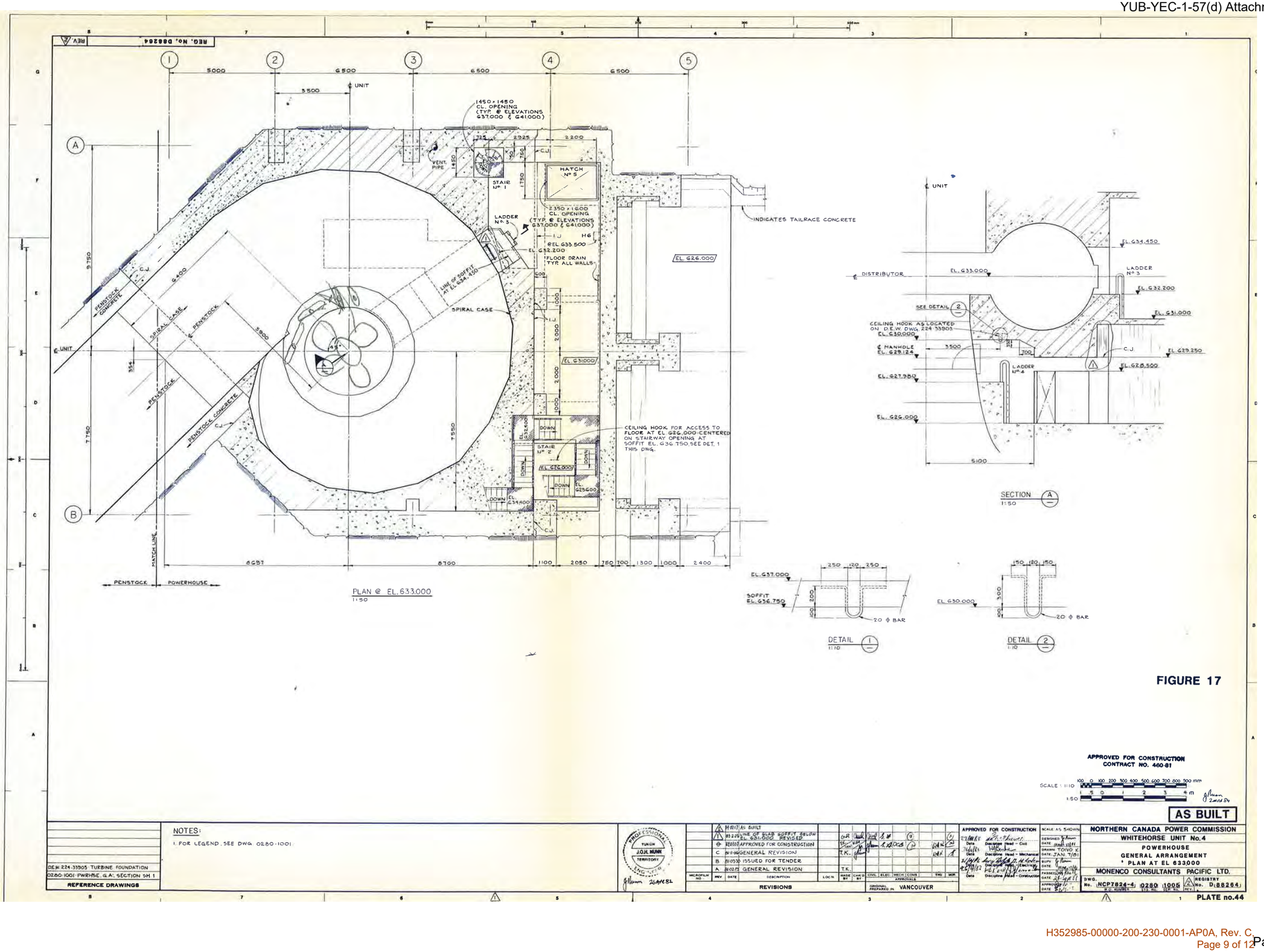


FIGURE 17

APPROVED FOR CONSTRUCTION
CONTRACT NO. 460-81

SCALE : 1:10 / 1:50

AS BUILT

NOTES:
1. FOR LEGEND, SEE DWG. 0280-1001.

REFERENCE DRAWINGS
DEW. 224-33903 TURBINE FOUNDATION
0280-1001 PWRHSE. G.A. SECTION SH. 1

REVISIONS												
MICROFILM NO.	REV.	DATE	DESCRIPTION	LOC'N.	MADE BY	CHK'D BY	CIVIL	ELEC.	MECH.	CONST.	ENG.	MGR.
	A	82 JUL 15	AS BUILT		GR							
	B	82 JUL 15	LINE OF SLAB SOFFIT BELOW EL. 633.000 REVISED		GR							
	C	81 DEC 10	APPROVED FOR CONSTRUCTION		GR							
	D	81 DEC 09	GENERAL REVISION		T.K.							
	E	81 OCT 30	ISSUED FOR TENDER		T.K.							
	F	81 OCT 15	GENERAL REVISION		T.K.							

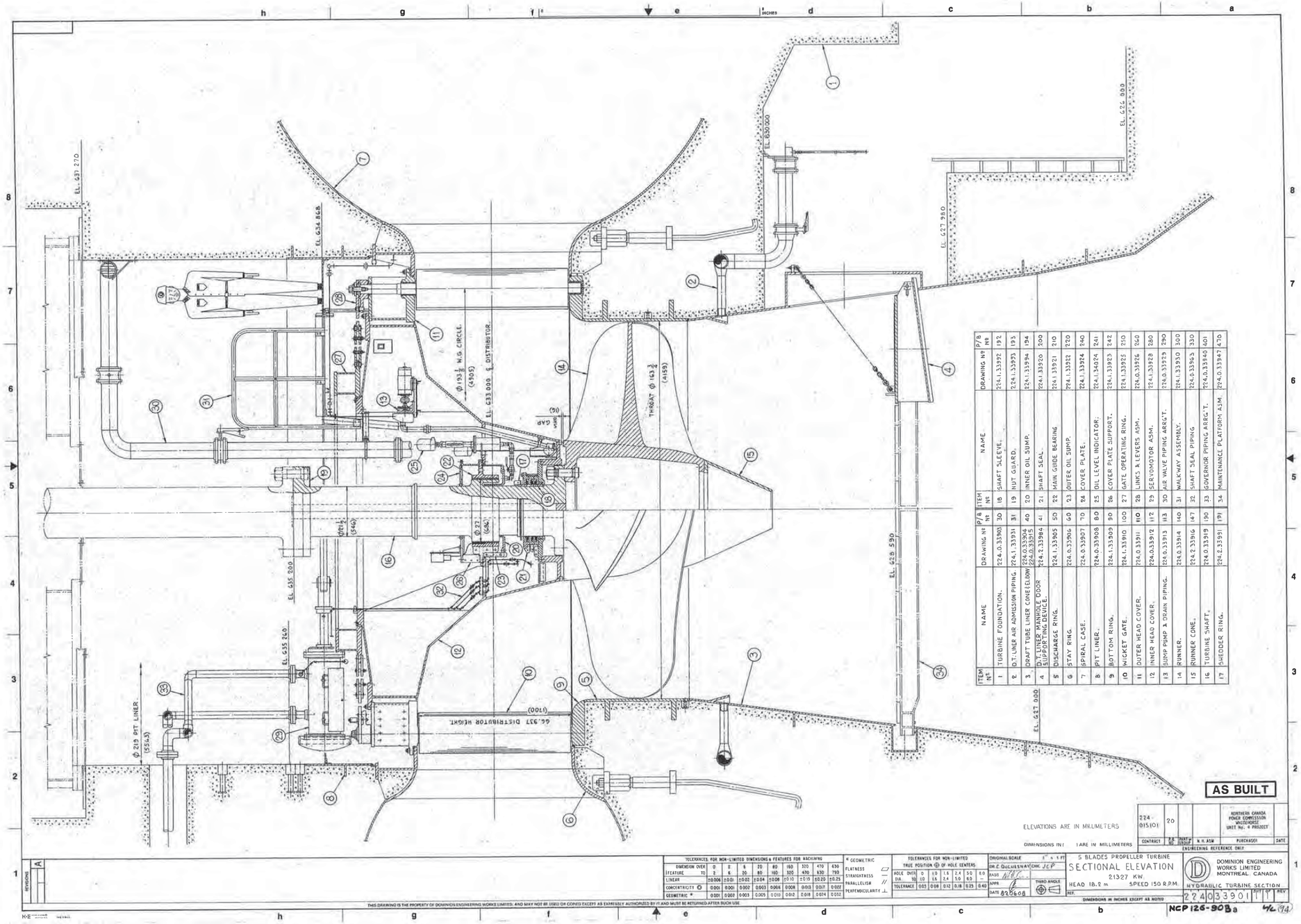
ORIGINAL PREPARED IN: VANCOUVER

APPROVED FOR CONSTRUCTION
Date 27/10/81 — Discipline Head – Civil
Date 26/10/81 — Discipline Head – Mechanical
Date 27/10/81 — Discipline Head – Electrical
Date 27/10/81 — Discipline Head – Construction

SCALE AS SHOWN
DESIGNED G. Hamm DATE JAN. 1981
DRAWN TOYO K. DATE JAN. 7/81
SUP'D G. Hamm DATE
PASSED DATE
APPROVED DATE

NORTHERN CANADA POWER COMMISSION
WHITEHORSE UNIT No. 4
POWERHOUSE
GENERAL ARRANGEMENT
PLAN AT EL 633000
MONENCO CONSULTANTS PACIFIC LTD.
DWG. No. HCP7824-4 | 0280 | 1005 | REGISTRY No. D88264 | REV. 1

PLATE no.44



ITEM Nº	NAME	DRAWING Nº	P/B Nº
1	TURBINE FOUNDATION.	224-0.33903	30
2	D.T. LINER AIR ADMISSION PIPING.	224-1.33931	31
3	DRAFT TUBE LINER CONE ELBOW.	224-0.33904	40
4	D.T. LINER MANHOLE DOOR SUPPORTING DEVICE.	224-2.33984	41
5	DISCHARGE RING.	224-1.33905	50
6	STAY RING.	224-0.33906	60
7	SPIRAL CASE.	224-0.33907	70
8	PIT LINER.	224-0.33908	80
9	BOTTOM RING.	224-1.33909	90
10	WICKET GATE.	224-1.33910	100
11	OUTER HEAD COVER.	224-0.33911	110
12	INNER HEAD COVER.	224-0.33912	112
13	SUMP PUMP & DRAIN PIPING.	224-0.33913	113
14	RUNNER.	224-0.33914	140
15	RUNNER CONE.	224-2.33916	147
16	TURBINE SHAFT.	224-0.33919	190
17	SHEDDER RING.	224-2.33991	191
18	SHAFT SLEEVE.	224-1.33992	192
19	NUT GUARD.	224-1.33993	193
20	INNER OIL SUMP.	224-1.33994	194
21	SHAFT SEAL.	224-1.33920	200
22	MAIN GUIDE BEARING	224-1.33921	210
23	OUTER OIL SUMP.	224-1.33922	220
24	COVER PLATE.	224-1.33924	240
25	OIL LEVEL INDICATOR.	224-1.34024	241
26	COVER PLATE SUPPORT.	224-1.33923	242
27	GATE OPERATING RING.	224-1.33925	250
28	LINKS & LEVERS ASM.	224-0.33926	260
29	SERVOMOTOR ASM.	224-1.33928	280
30	AIR VALVE PIPING ARR'GT.	224-0.33929	290
31	WALKWAY ASSEMBLY.	224-1.33930	300
32	SHAFT SEAL PIPING	224-0.33963	330
33	GOVERNOR PIPING ARR'G'T.	224-0.33960	401
34	MAINTENANCE PLATFORM ASM.	224-0.33947	470

CONTRACT	P.O. No.	PART OF GROUP	K. H. ASH	PURCHASER	DATE
224-01501	20			NORTHERN CANADA POWER COMMISSION WHITEHORSE UNIT No. 4 PROJECT	

ENGINEERING REFERENCE ONLY

REF.	224	0	33901	1	1	REV.

DIMENSIONS IN INCHES EXCEPT AS NOTED

TOLERANCES FOR NON-LIMITED DIMENSIONS & FEATURES FOR MACHINING									
DIMENSION OVER	0	2	6	30	80	160	320	470	630
IFEATURE TO	2	6	30	80	160	320	470	630	780
LINEAR	±0.006	±0.01	±0.02	±0.04	±0.08	±0.10	±0.15	±0.20	±0.25
CONCENTRICITY ⌖	0.001	0.001	0.002	0.003	0.006	0.008	0.013	0.017	0.022
GEOMETRIC *	0.001	0.002	0.003	0.005	0.010	0.012	0.018	0.024	0.032

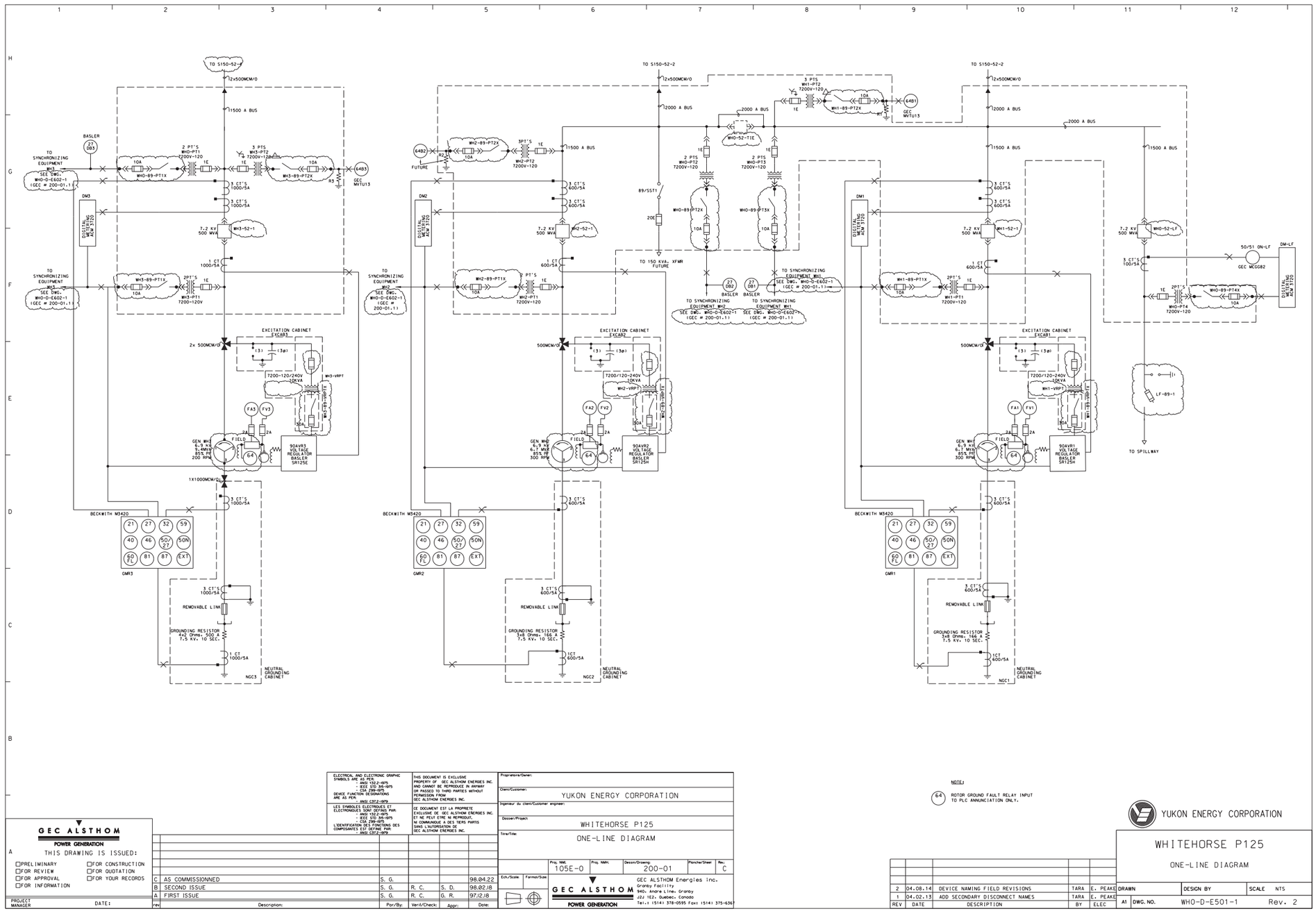
* GEOMETRIC	
FLATNESS	▱
STRAIGHTNESS	—
PARALLELISM	//
PERPENDICULARITY	⊥

TOLERANCES FOR NON-LIMITED TRUE POSITION Ⓜ OF HOLE CENTERS							
HOLE DIA. OVER	0	1.0	1.6	2.4	3.5	5.0	8.0
DIA. TO	1.0	1.6	2.4	3.5	5.0	8.0	
TOLERANCE	0.05	0.08	0.12	0.18	0.25	0.40	

ORIGINAL SCALE 1" = 1 FT	
DR. C. QUEVILLON	CHK. J.C.P
BASE	
APPR.	
DATE 82/06/08	THIRD ANGLE

REVISIONS		
A		

K-E



NOTE:
(64) ROTOR GROUND FAULT RELAY INPUT TO PLC ANNUNCIATION ONLY.

ELECTRICAL AND ELECTRONIC GRAPHIC SYMBOLS ARE AS PER:
- ANSI Y32.2-1975
- IEEE 532 315/1975
- CSA Z99-1975
DEVICE FUNCTION DESIGNATIONS ARE AS PER:
- ANSI C37.2-1979

LES SYMBOLES ELECTRIQUES ET ELECTRONIQUES SONT DEFINIS PAR:
- ANSI Y32.2-1975
- IEEE 532 315/1975
- CSA Z99-1975
L'IDENTIFICATION DES FONCTIONS DES COMPOSANTES EST DEFINIE PAR:
- ANSI C37.2-1979

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Client/Customer: YUKON ENERGY CORPORATION
Signataire du client/Customer engineer:
Dossier/Project: WHITEHORSE P125
Titre/Title: ONE-LINE DIAGRAM

Proj. NAM.	Proj. NMH.	Dessin/Drawing	Planche/Sheet	Rev.
105E-0		200-01		C

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GEC ALSTHOM Energies inc.
Granby Facility
940, Andre Line, Granby
J2J 1E2, Quebec, Canada
Tel.: (514) 378-0595 Fax: (514) 375-6367

GEC ALSTHOM
POWER GENERATION

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☐FOR REVIEW ☐FOR QUOTATION
☐FOR APPROVAL ☐FOR YOUR RECORDS
☐FOR INFORMATION

PROJECT MANAGER DATE:

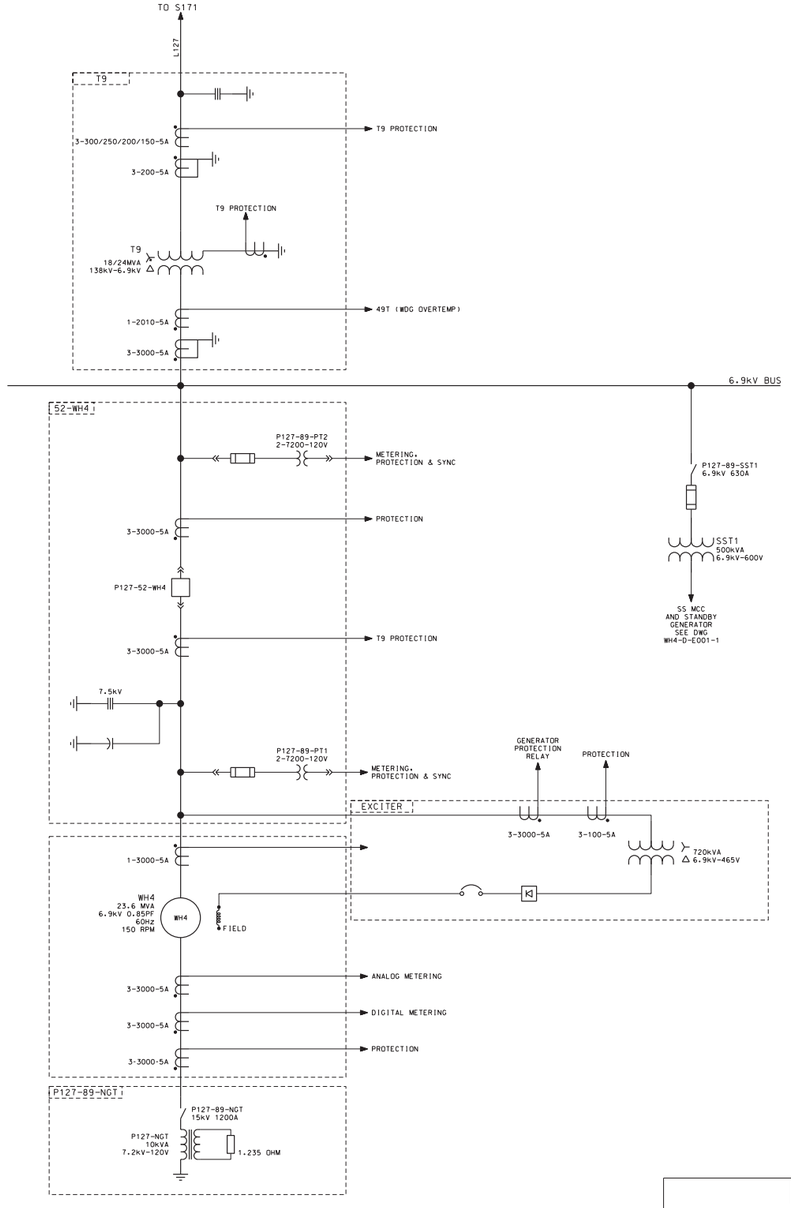
rev.	Description:	Par/By:	Verif/Check:	Appr:	Date:
C	AS COMMISSIONNED	S. G.			98.04.22
B	SECOND ISSUE	S. G.	R. C.	S. D.	98.02.18
A	FIRST ISSUE	S. G.	R. C.	G. R.	97.12.18

YUKON ENERGY CORPORATION

WHITEHORSE P125
ONE-LINE DIAGRAM

REV	DATE	DESCRIPTION	BY	ELEC
2	04.08.14	DEVICE NAMING FIELD REVISIONS	TARA	E. PEAKE
1	04.02.13	ADD SECONDARY DISCONNECT NAMES	TARA	E. PEAKE

DRAWN | DESIGN BY | SCALE NTS
A1 DWG. NO. WHO-D-E501-1 Rev. 2



AS BUILT
BBA
DATE: 2010-04-28

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CADD

BBA www.bba.ca No: 5954003-WH4E501a

YUKON ENERGY CORPORATION

WHITEHORSE HYDRO UNIT #4
GENERATION
SINGLE LINE DIAGRAM

NO.	DATE	REVISIONS	BY	CIVIL	DESIGN	ELEC	MECH	PROT	STND	P.ENG	E.MAN
1	2010-04-28	AS BUILT	F.B.			K.A.M.				W.B.L.	
0	2010-02-12	NEW DRAWING	M.H.			K.A.M.				W.B.L.	

NO.	DATE	REVISIONS	BY	CIVIL	DESIGN	ELEC	MECH	PROT	STND	P.ENG	E.MAN

REF. DWG. NO.	REF. DWG. TITLE
WH5-D-E100-1	SPILLGATES SINGLE LINE DIAGRAM
WH4-D-E500-1	RELAYING METERING SCHEMATIC DIAGRAM
WH4-D-E001-1	600V SINGLE LINE DIAGRAM
WAFSYSTEMSWMAP	SYSTEM SWITCHING MAP
NCP7824-40400-1001	RELAYING & METERING SINGLE LINE

APPROVALS		DATE	APPROVALS		DATE
PROTECTION			MECHANICAL		
STANDARD			CIVIL		
PROJECT ENG.			DESIGN		
ENG. MANAGER			ELECTRICAL	W.B. LEDGER	2010-04-28

DRAWN M. HALLE | DESIGN BY K. AU | SCALE NTS

A1 | DWG. NO. WH4-D-E501-1 | REV. 1

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Appendix B
Preliminary Uprate Schedules

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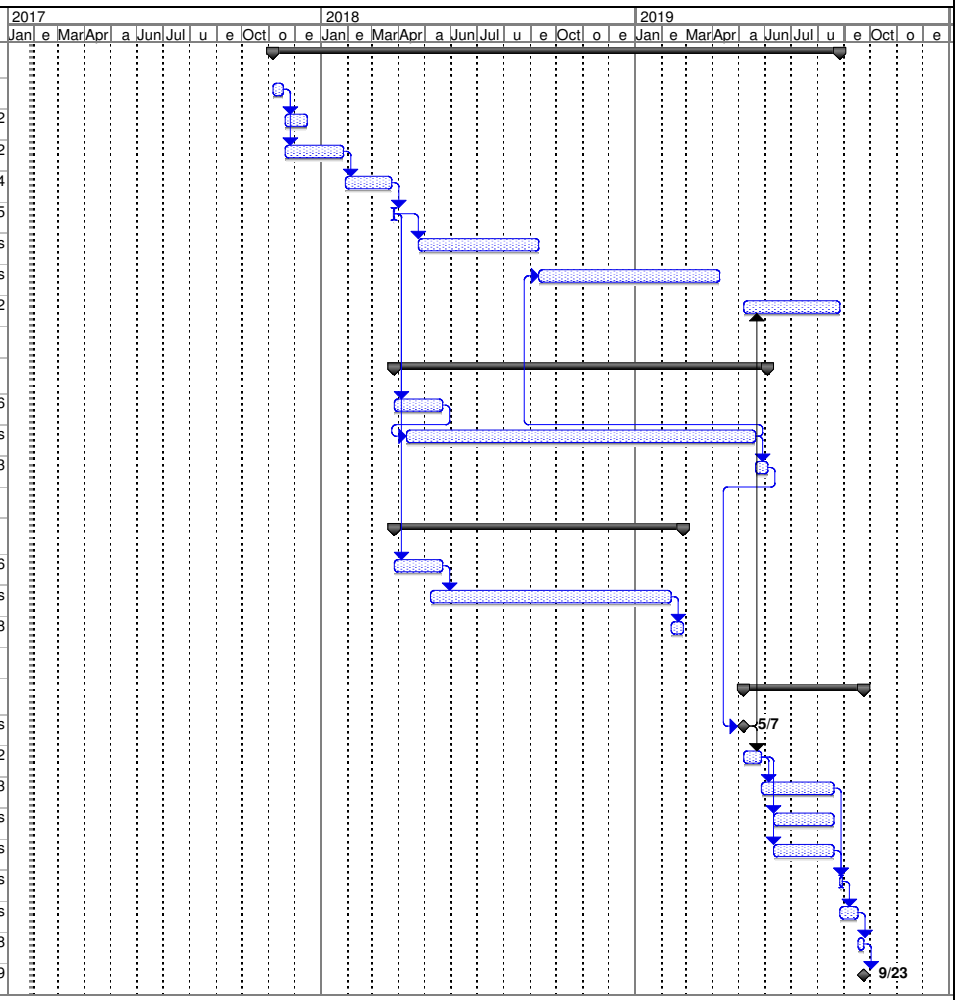
Figure B-1
WHITEHORSE GENERATING STATION
PRELIMINARY SCHEDULE - WH1 UPRATE ALT 1
Jan 20, 2017

ID	Task Name	Duration	Start	Finish	Predecessors
1	**Engineering**	**471 days**	**Mon 11/6/17**	**Mon 8/26/19**	
2	Project definiion	2 wks	Mon 11/6/17	Fri 11/17/17	
3	Prepare specifications and tender documents	4 wks	Mon 11/20/17	Fri 12/15/17	2
4	Tendering	10 wks	Mon 11/20/17	Fri 1/26/18	2
5	Evaluation and negotiate contract	8 wks	Mon 1/29/18	Fri 3/23/18	4
6	Contract award	1 day	Mon 3/26/18	Mon 3/26/18	5
7	Contractor submittal review	20 wks	Tue 4/24/18	Mon 9/10/18	6FS+20 days
8	QA shop inspection	30 wks	Tue 9/11/18	Mon 4/8/19	13FS-180 days
9	QA site support	16 wks	Tue 5/7/19	Mon 8/26/19	22
10					
11	**Turbine manufacture**	**310 days**	**Tue 3/27/18**	**Mon 6/3/19**	
12	Runner design	8 wks	Tue 3/27/18	Mon 5/21/18	6
13	Manufacture runner	58 wks	Tue 4/10/18	Mon 5/20/19	12FS-30 days
14	Delivery	2 wks	Tue 5/21/19	Mon 6/3/19	13
15					
16	**Generator manufacture**	**240 days**	**Tue 3/27/18**	**Mon 2/25/19**	
17	Design	8 wks	Tue 3/27/18	Mon 5/21/18	6
18	Manufacture windings	40 wks	Tue 5/8/18	Mon 2/11/19	17FS-10 days
19	Delivery	2 wks	Tue 2/12/19	Mon 2/25/19	18
20					
21	**Site work**	**100 days**	**Tue 5/7/19**	**Mon 9/23/19**	
22	Unit out of service	0 days	Tue 5/7/19	Tue 5/7/19	14FS-20 days
23	Generator and turbine dismantling	3 wks	Tue 5/7/19	Mon 5/27/19	22
24	Generator rewind	12 wks	Tue 5/28/19	Mon 8/19/19	23
25	Generator rehabilitation work	10 wks	Tue 6/11/19	Mon 8/19/19	23FS+10 days
26	Turbine rehabilitation work	10 wks	Tue 6/11/19	Mon 8/19/19	23FS+10 days
27	New runner install	3 days	Tue 8/27/19	Thu 8/29/19	26,24FS+5 days
28	Turbine and generator reinstallation	3 wks	Tue 8/27/19	Mon 9/16/19	27FS-3 days
29	Testing	1 wk	Tue 9/17/19	Mon 9/23/19	28
30	Unit returned to service	0 days	Mon 9/23/19	Mon 9/23/19	29



Task — Progress — Summary — External Tasks — Split
Split — Milestone — Project Summary — External MileTask

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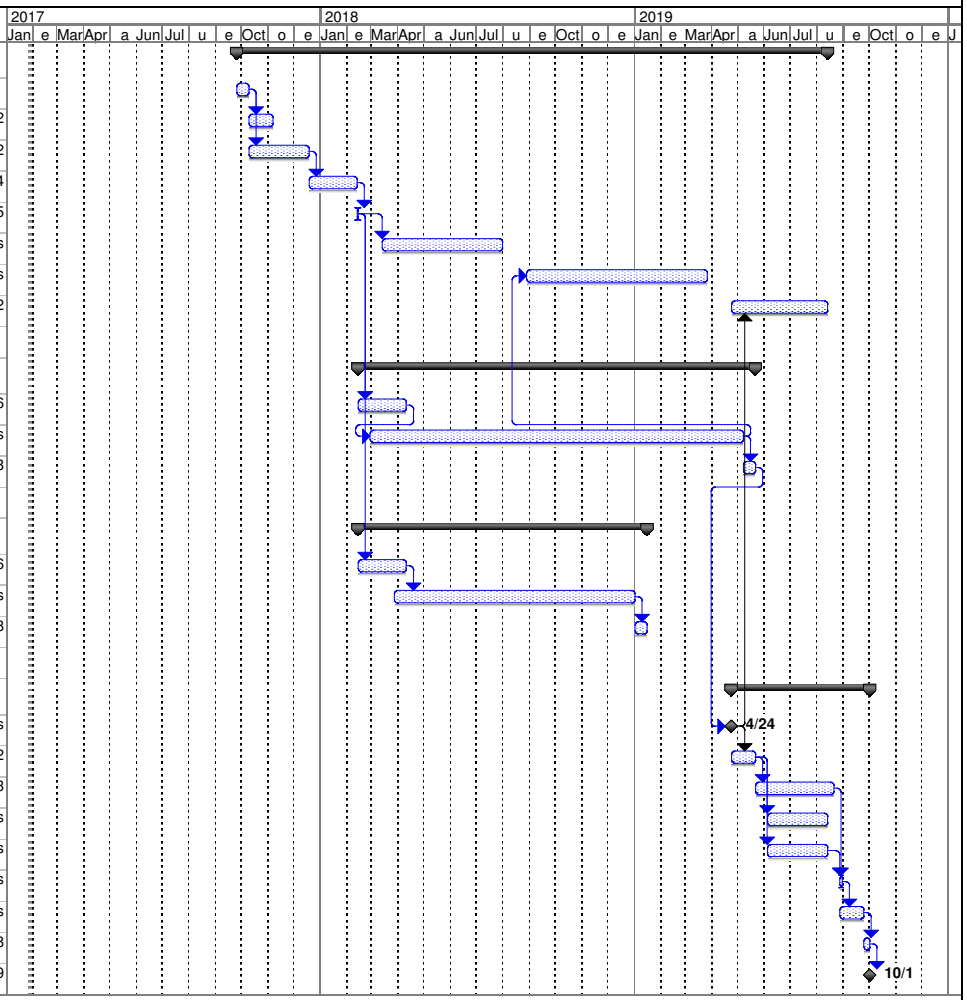
Figure B2
WHITEHORSE GENERATING STATION
PRELIMINARY SCHEDULE - WH3 UPRATE
Jan 20, 2017

ID	Task Name	Duration	Start	Finish	Predecessors
1	**Engineering**	**491 days**	**Tue 9/26/17**	**Tue 8/13/19**	
2	Project definition	2 wks	Tue 9/26/17	Mon 10/9/17	
3	Prepare specifications and tender documents	4 wks	Tue 10/10/17	Mon 11/6/17	2
4	Tendering	10 wks	Tue 10/10/17	Mon 12/18/17	2
5	Evaluation and negoitiate contract	8 wks	Tue 12/19/17	Mon 2/12/18	4
6	Contract award	1 day	Tue 2/13/18	Tue 2/13/18	5
7	Contractor submittal review	20 wks	Wed 3/14/18	Tue 7/31/18	6FS+20 days
8	QA shop inspection	30 wks	Wed 8/29/18	Tue 3/26/19	13FS-180 days
9	QA site support	16 wks	Wed 4/24/19	Tue 8/13/19	22
10					
11	**Turbine manufacture**	**330 days**	**Wed 2/14/18**	**Tue 5/21/19**	
12	Runner design	8 wks	Wed 2/14/18	Tue 4/10/18	6
13	Manufacture runner	62 wks	Wed 2/28/18	Tue 5/7/19	12FS-30 days
14	Delivery	2 wks	Wed 5/8/19	Tue 5/21/19	13
15					
16	**Generator manufacture**	**240 days**	**Wed 2/14/18**	**Tue 1/15/19**	
17	Design	8 wks	Wed 2/14/18	Tue 4/10/18	6
18	Manufacture windings	40 wks	Wed 3/28/18	Tue 1/1/19	17FS-10 days
19	Delivery	2 wks	Wed 1/2/19	Tue 1/15/19	18
20					
21	**Site work**	**115 days**	**Wed 4/24/19**	**Tue 10/1/19**	
22	Unit out of service	0 days	Wed 4/24/19	Wed 4/24/19	14FS-20 days
23	Generator and turbine dismantling	4 wks	Wed 4/24/19	Tue 5/21/19	22
24	Generator rewind	13 wks	Wed 5/22/19	Tue 8/20/19	23
25	Generator rehabilitation work	10 wks	Wed 6/5/19	Tue 8/13/19	23FS+10 days
26	Turbine rehabilitation work	10 wks	Wed 6/5/19	Tue 8/13/19	23FS+10 days
27	New runner install	3 days	Wed 8/28/19	Fri 8/30/19	26,24FS+5 days
28	Turbine and generator reinstallation	4 wks	Wed 8/28/19	Tue 9/24/19	27FS-3 days
29	Testing	1 wk	Wed 9/25/19	Tue 10/1/19	28
30	Unit returned to service	0 days	Tue 10/1/19	Tue 10/1/19	29



Task Progress Summary External Tasks Split
Split Milestone Project Summary External MileTask

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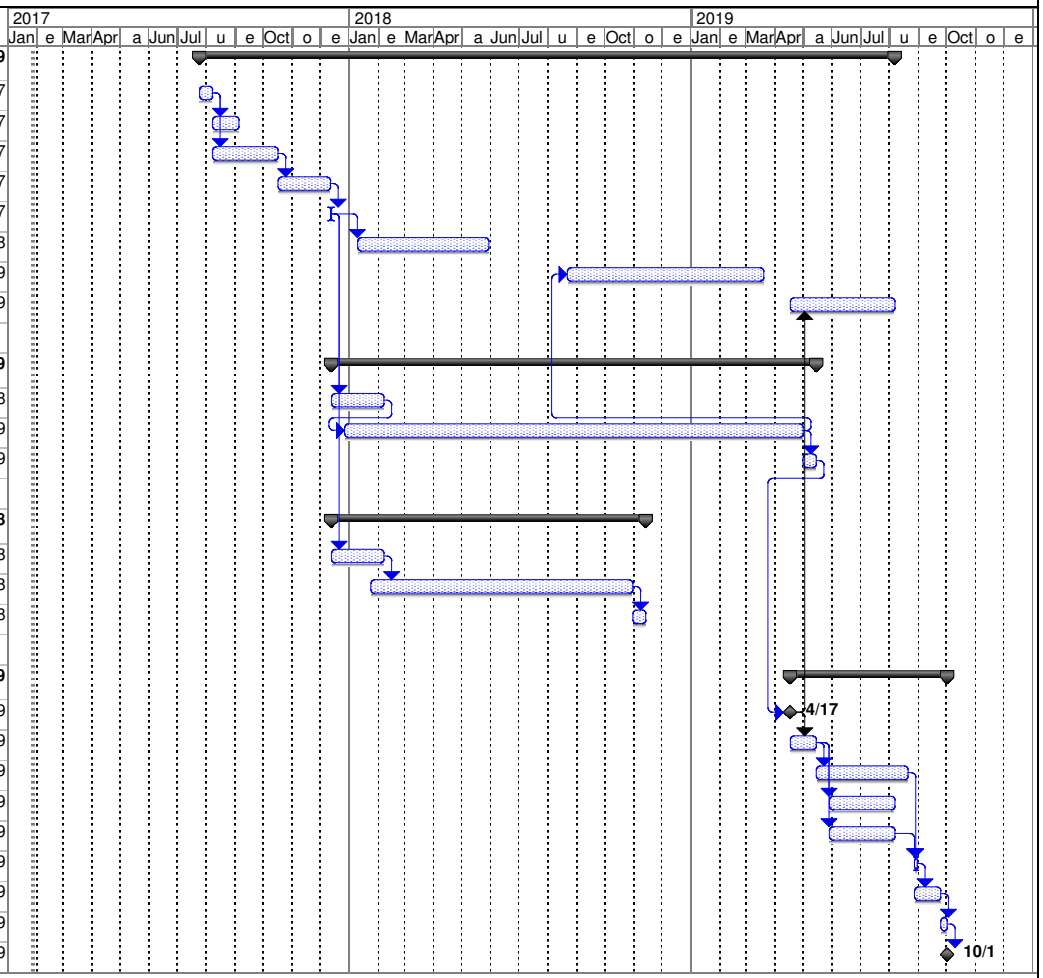
Figure B3
WHITEHORSE GENERATING STATION
PRELIMINARY SCHEDULE - WH4 UPRATE
Jan 20, 2017

ID	Task Name	Duration	Start	Finish
1	**Enginneering**	**531 days**	**Tue 7/25/17**	**Tue 8/6/19**
2	Project definition	2 wks	Tue 7/25/17	Mon 8/7/17
3	Prepare specifications and tender documents	4 wks	Tue 8/8/17	Mon 9/4/17
4	Tendering	10 wks	Tue 8/8/17	Mon 10/16/17
5	Evaluation and negoitiate contract	8 wks	Tue 10/17/17	Mon 12/11/17
6	Contract award	1 day	Tue 12/12/17	Tue 12/12/17
7	Contractor submittal review	20 wks	Wed 1/10/18	Tue 5/29/18
8	QA shop inspection	30 wks	Wed 8/22/18	Tue 3/19/19
9	QA site support	16 wks	Wed 4/17/19	Tue 8/6/19
10				
11	**Turbine manufacture**	**370 days**	**Wed 12/13/17**	**Tue 5/14/19**
12	Runner design	8 wks	Wed 12/13/17	Tue 2/6/18
13	Manufacture runner	70 wks	Wed 12/27/17	Tue 4/30/19
14	Delivery	2 wks	Wed 5/1/19	Tue 5/14/19
15				
16	**Generator manufacture**	**240 days**	**Wed 12/13/17**	**Tue 11/13/18**
17	Design	8 wks	Wed 12/13/17	Tue 2/6/18
18	Manufacture windings	40 wks	Wed 1/24/18	Tue 10/30/18
19	Delivery	2 wks	Wed 10/31/18	Tue 11/13/18
20				
21	**Site work**	**120 days**	**Wed 4/17/19**	**Tue 10/1/19**
22	Unit out of service	0 days	Wed 4/17/19	Wed 4/17/19
23	Generator and turbine dismantling	4 wks	Wed 4/17/19	Tue 5/14/19
24	Generator rewind	14 wks	Wed 5/15/19	Tue 8/20/19
25	Generator rehabilitation work	10 wks	Wed 5/29/19	Tue 8/6/19
26	Turbine rehabilitation work	10 wks	Wed 5/29/19	Tue 8/6/19
27	New runner install	3 days	Wed 8/28/19	Fri 8/30/19
28	Turbine and generator reinstallation	4 wks	Wed 8/28/19	Tue 9/24/19
29	Testing	1 wk	Wed 9/25/19	Tue 10/1/19
30	Unit returned to service	0 days	Tue 10/1/19	Tue 10/1/19



Task Progress Summary External Tasks Split
Split Milestone Project Summary External MileTask

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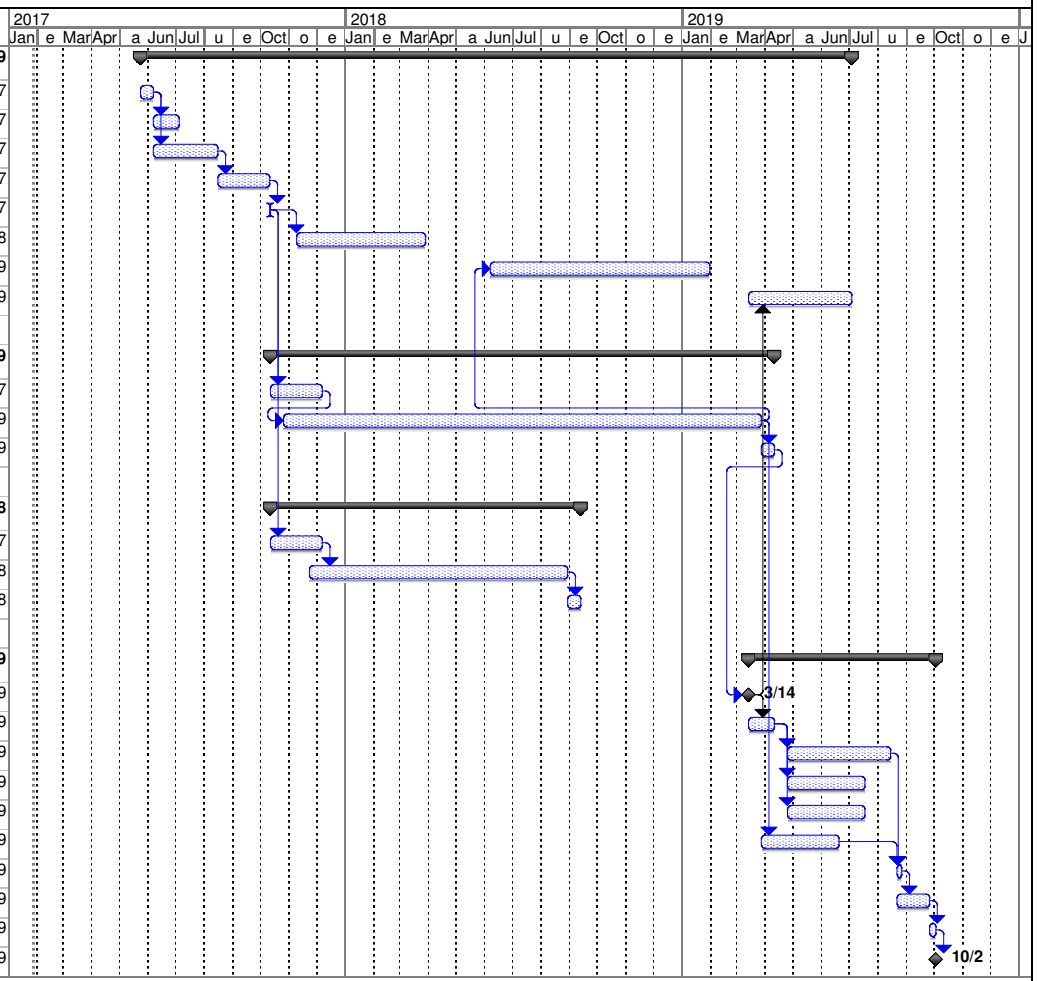
Figure B-4
WHITEHORSE GENERATING STATION
PRELIMINARY SCHEDULE - WH4 UPRATE - KAPLAN RUNNER
Jan 20, 2017

ID	Task Name	Duration	Start	Finish
1	**Engineering**	**551 days**	**Wed 5/24/17**	**Wed 7/3/19**
2	Project definition	2 wks	Wed 5/24/17	Tue 6/6/17
3	Prepare specifications and tender documents	4 wks	Wed 6/7/17	Tue 7/4/17
4	Tendering	10 wks	Wed 6/7/17	Tue 8/15/17
5	Evaluation and negotiate contract	8 wks	Wed 8/16/17	Tue 10/10/17
6	Contract award	1 day	Wed 10/11/17	Wed 10/11/17
7	Contractor submittal review	20 wks	Thu 11/9/17	Wed 3/28/18
8	QA shop inspection	34 wks	Thu 6/7/18	Wed 1/30/19
9	QA site support	16 wks	Thu 3/14/19	Wed 7/3/19
10				
11	**Turbine manufacture**	**390 days**	**Thu 10/12/17**	**Wed 4/10/19**
12	Runner design	8 wks	Thu 10/12/17	Wed 12/6/17
13	Manufacture runner	74 wks	Thu 10/26/17	Wed 3/27/19
14	Delivery	2 wks	Thu 3/28/19	Wed 4/10/19
15				
16	**Generator manufacture**	**240 days**	**Thu 10/12/17**	**Wed 9/12/18**
17	Design	8 wks	Thu 10/12/17	Wed 12/6/17
18	Manufacture windings	40 wks	Thu 11/23/17	Wed 8/29/18
19	Delivery	2 wks	Thu 8/30/18	Wed 9/12/18
20				
21	**Site work**	**145 days**	**Thu 3/14/19**	**Wed 10/2/19**
22	Unit out of service	0 days	Thu 3/14/19	Thu 3/14/19
23	Generator and turbine dismantling	4 wks	Thu 3/14/19	Wed 4/10/19
24	Generator rewind	16 wks	Thu 4/25/19	Wed 8/14/19
25	Generator rehabilitation work	12 wks	Thu 4/25/19	Wed 7/17/19
26	Turbine rehabilitation work	12 wks	Thu 4/25/19	Wed 7/17/19
27	Discharge ring work	12 wks	Thu 3/28/19	Wed 6/19/19
28	New runner install	3 days	Thu 8/22/19	Mon 8/26/19
29	Turbine and generator reinstallation	5 wks	Thu 8/22/19	Wed 9/25/19
30	Testing	1 wk	Thu 9/26/19	Wed 10/2/19
31	Unit returned to service	0 days	Wed 10/2/19	Wed 10/2/19



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Appendix C
Budget Prices for New Runners

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Appendix C

Whitehorse Generating Station
WH1, WH2 and WH3 Turbine Uprate Study
Budget Prices for New Runners

Supplier 1

- Design and supply new runners
  - WH1: $ 345,106
  - WH (new blades only): $ 285,571
  - WH3: $ 392,593
- Excludes delivery (from eastern Canada)

Supplier 2

- Design and supply new runners
  - WH1: $1,700,000
  - WH3: $1,760,000
  - WH4: $1,910,000
- Includes delivery
- Excludes import duties

Supplier 3

- Design and supply new runners
  - WH1: $ 491,220
  - WH3: $ 281,714
  - WH4: $ 577,066
- Excludes delivery (from India)

Supplier 4

- Design and supply new runners
  - WH1: $ 530,000
  - WH3: $ 760,000
  - WH4: $1,400,000
- Assumes WH1 and WH2 runners purchased as a single contract

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Appendix D
Load Forecasts

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Yukon Energy
WH1, 3 and 4 Turbine Uprate Study
H352985

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Year	Month	Monthly Peak Demand with Losses (MW)		
		Sc.1	Sc.3	Sc.4
2016	1	88.74	88.77	88.73
2016	2	79.94	79.97	79.94
2016	3	72.10	72.12	72.10
2016	4	62.20	62.22	62.21
2016	5	58.51	58.50	58.51
2016	6	49.45	49.43	49.45
2016	7	50.01	50.00	50.02
2016	8	49.58	49.57	49.58
2016	9	59.83	59.83	59.83
2016	10	69.54	69.55	69.54
2016	11	78.39	78.41	78.39
2016	12	86.32	86.34	86.32
2017	1	90.31	90.37	92.07
2017	2	81.16	81.21	82.92
2017	3	73.12	73.16	74.89
2017	4	62.89	62.93	64.66
2017	5	58.93	58.94	60.70
2017	6	49.53	49.52	51.31
2017	7	50.07	50.07	51.85
2017	8	49.64	49.64	51.42
2017	9	60.32	60.34	62.10
2017	10	70.39	70.42	72.16
2017	11	79.49	79.52	81.25
2017	12	87.67	87.72	89.44
2018	1	92.33	92.47	94.30
2018	2	82.74	82.86	84.69
2018	3	74.43	74.54	76.36
2018	4	63.79	63.88	65.70
2018	5	59.51	59.57	61.42
2018	6	49.69	49.72	51.58
2018	7	50.21	50.24	70.13
2018	8	49.78	49.81	69.70
2018	9	61.00	61.06	80.95
2018	10	71.50	71.59	91.47
2018	11	80.92	81.02	100.90
2018	12	89.43	89.55	98.28
2019	1	94.52	96.61	103.83
2019	2	84.48	86.53	93.70
2019	3	75.87	77.88	96.16
2019	4	64.80	66.77	85.01
2019	5	60.20	62.14	80.39
2019	6	49.95	51.84	70.06
2019	7	50.44	52.32	70.53
2019	8	50.01	51.89	70.10
2019	9	61.78	63.72	81.98
2019	10	72.73	74.72	93.01
2019	11	82.48	84.51	102.83
2019	12	91.34	93.40	100.59
2020	1	96.88	99.19	111.29
2020	2	86.33	88.57	100.56
2020	3	77.39	79.56	102.58
2020	4	65.85	67.94	90.85
2020	5	60.87	62.92	85.80
2020	6	50.14	52.12	74.91
2020	7	50.61	70.62	75.34
2020	8	50.18	70.19	74.91
2020	9	62.55	82.66	87.51
2020	10	74.00	94.19	99.15
2020	11	84.16	104.40	109.46
2020	12	93.40	102.54	107.69
2021	1	98.68	108.12	130.69

Year	Month	Monthly Energy with Losses (MWh)		
		Sc.1	Sc.3	Sc.4
2016	1	45,136	45,159	45,134
2016	2	38,964	38,973	38,962
2016	3	37,847	37,858	37,847
2016	4	33,174	33,182	33,174
2016	5	29,670	29,669	29,670
2016	6	28,818	28,820	28,819
2016	7	28,451	28,452	28,452
2016	8	28,227	28,232	28,226
2016	9	29,708	29,716	29,705
2016	10	33,905	33,919	33,899
2016	11	38,593	38,611	38,582
2016	12	41,838	41,860	41,823
2017	1	45,798	45,830	46,847
2017	2	38,779	38,796	39,834
2017	3	38,323	38,343	39,378
2017	4	33,487	33,503	34,549
2017	5	29,871	29,878	30,938
2017	6	28,944	28,955	30,015
2017	7	28,548	28,557	29,619
2017	8	28,334	28,351	29,412
2017	9	29,895	29,915	30,975
2017	10	34,232	34,261	35,313
2017	11	39,106	39,143	40,189
2017	12	42,445	42,490	43,536
2018	1	42,740	46,614	47,634
2018	2	35,575	39,429	40,481
2018	3	35,059	38,918	39,979
2018	4	30,047	33,899	34,983
2018	5	26,308	30,148	31,251
2018	6	25,301	29,143	30,258
2018	7	24,873	28,714	41,284
2018	8	24,675	28,529	41,099
2018	9	26,326	30,190	42,354
2018	10	30,822	34,707	47,272
2018	11	35,905	39,813	51,973
2018	12	39,358	43,284	48,803
2019	1	43,551	48,623	53,124
2019	2	36,239	41,275	45,247
2019	3	35,674	40,717	50,000
2019	4	30,489	35,513	46,660
2019	5	26,628	31,628	43,177
2019	6	25,546	30,549	41,691
2019	7	25,090	30,093	41,643
2019	8	24,900	29,917	41,480
2019	9	26,632	31,666	42,850
2019	10	31,280	36,352	47,979
2019	11	36,560	41,676	52,950
2019	12	40,112	45,259	49,931
2020	1	44,317	49,571	56,405
2020	2	37,630	42,822	49,079
2020	3	36,219	41,406	52,963
2020	4	30,856	35,992	49,352
2020	5	26,871	31,959	45,677
2020	6	25,705	30,784	44,073
2020	7	25,217	41,738	43,982
2020	8	25,032	41,569	43,837
2020	9	26,838	43,002	45,332
2020	10	31,623	48,255	50,697
2020	11	37,084	53,387	55,966
2020	12	40,723	50,428	53,104
2021	1	44,960	54,867	66,470

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Year	Month	Monthly Peak Demand with Losses (MW)		
		Sc.1	Sc.3	Sc.4
2021	2	87.73	97.06	119.42
2021	3	78.54	98.92	121.05
2021	4	66.63	86.90	108.81
2021	5	61.35	81.55	103.39
2021	6	50.24	70.34	91.99
2021	7	50.69	70.78	92.38
2021	8	50.26	70.35	91.95
2021	9	63.11	83.34	105.20
2021	10	74.97	95.30	117.38
2021	11	85.42	105.84	128.11
2021	12	94.95	104.32	126.76
2022	1	100.73	110.55	134.20
2022	2	89.35	99.00	122.27
2022	3	79.85	100.49	123.37
2022	4	67.54	88.02	110.52
2022	5	61.92	82.31	104.64
2022	6	50.40	70.64	92.63
2022	7	50.84	71.05	92.98
2022	8	50.41	70.62	92.55
2022	9	63.77	84.20	106.58
2022	10	76.06	96.64	119.40
2022	11	86.88	107.60	130.71
2022	12	96.75	106.45	129.87
2023	1	96.13	106.33	129.88
2023	2	84.34	94.32	117.36
2023	3	74.55	95.47	117.99
2023	4	61.87	82.57	104.59
2023	5	55.95	76.54	98.32
2023	6	44.06	64.44	85.77
2023	7	44.48	64.83	86.07
2023	8	44.06	64.41	85.64
2023	9	57.89	78.52	100.37
2023	10	70.57	91.41	113.77
2023	11	81.72	102.75	125.58
2023	12	91.90	101.95	125.19
2024	1	98.25	108.78	132.94
2024	2	86.04	96.30	119.87
2024	3	75.93	97.08	120.04
2024	4	62.86	83.74	106.11
2024	5	56.62	77.37	99.46
2024	6	44.34	64.83	86.40
2024	7	44.74	65.20	86.66
2024	8	44.32	64.77	86.23
2024	9	58.64	79.44	101.62
2024	10	71.74	92.80	115.58
2024	11	83.26	104.55	127.86
2024	12	93.77	104.12	127.91
2025	1	99.66	110.33	134.94
2025	2	87.18	97.55	121.51
2025	3	76.89	98.14	121.43
2025	4	63.57	84.53	107.16
2025	5	57.14	77.95	100.28
2025	6	44.59	65.13	86.87
2025	7	44.98	65.48	87.11
2025	8	44.55	65.05	86.68
2025	9	59.21	80.08	102.50
2025	10	72.58	93.73	116.82
2025	11	84.31	105.70	129.37
2025	12	95.02	105.48	129.69
2026	1	101.13	111.76	136.53
2026	2	88.38	98.72	122.81

Year	Month	Monthly Energy with Losses (MWh)		
		Sc.1	Sc.3	Sc.4
2021	2	37,362	46,618	58,055
2021	3	36,673	51,221	62,634
2021	4	31,157	47,471	58,705
2021	5	27,067	43,699	54,805
2021	6	25,828	42,020	53,051
2021	7	25,310	41,891	52,902
2021	8	25,131	41,741	52,799
2021	9	27,005	43,274	54,463
2021	10	31,911	48,703	60,125
2021	11	37,534	54,063	65,771
2021	12	41,254	51,229	63,134
2022	1	45,562	53,896	66,433
2022	2	37,847	45,475	57,686
2022	3	37,112	50,022	62,178
2022	4	31,457	46,074	57,867
2022	5	27,274	42,164	53,703
2022	6	25,972	40,396	51,767
2022	7	25,432	40,240	51,564
2022	8	25,261	40,105	51,495
2022	9	27,198	41,734	53,353
2022	10	32,219	47,339	59,364
2022	11	37,990	52,922	65,431
2022	12	41,786	50,204	63,020
2023	1	46,135	52,939	66,027
2023	2	38,308	44,333	56,891
2023	3	37,530	48,818	61,254
2023	4	31,748	44,673	56,541
2023	5	27,478	40,623	52,093
2023	6	26,117	38,768	49,973
2023	7	25,557	38,578	49,702
2023	8	25,394	38,458	49,662
2023	9	27,389	40,177	51,693
2023	10	32,515	45,944	58,015
2023	11	38,419	51,731	64,466
2023	12	42,287	49,122	62,256
2024	1	46,692	53,833	67,650
2024	2	39,589	45,919	59,132
2024	3	37,944	49,486	62,448
2024	4	32,044	45,159	57,406
2024	5	27,692	40,981	52,721
2024	6	26,279	39,043	50,452
2024	7	25,701	38,824	50,124
2024	8	25,549	38,716	50,110
2024	9	27,599	40,513	52,282
2024	10	32,825	46,426	58,863
2024	11	38,857	52,394	65,635
2024	12	42,794	49,878	63,593
2025	1	47,265	54,602	68,964
2025	2	39,229	45,676	59,251
2025	3	38,379	50,053	63,421
2025	4	32,364	45,570	58,115
2025	5	27,932	41,282	53,239
2025	6	26,467	39,275	50,850
2025	7	25,870	39,027	50,474
2025	8	25,726	38,927	50,469
2025	9	27,829	40,787	52,745
2025	10	33,156	46,817	59,518
2025	11	39,317	52,934	66,529
2025	12	43,322	50,494	64,600
2026	1	47,806	55,169	69,801
2026	2	39,675	46,137	59,914

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Year	Month	Monthly Peak Demand with Losses (MW)		
		Sc.1	Sc.3	Sc.4
2026	3	77.90	99.13	122.53
2026	4	64.33	85.27	108.00
2026	5	57.71	78.51	100.92
2026	6	44.90	65.44	87.24
2026	7	45.28	65.77	87.46
2026	8	44.85	65.34	87.02
2026	9	59.84	80.69	103.20
2026	10	73.47	94.60	117.79
2026	11	85.41	106.77	130.57
2026	12	96.32	106.76	131.10
2027	1	102.73	113.25	135.17
2027	2	89.70	99.95	121.19
2027	3	79.02	100.16	120.74
2027	4	65.18	86.06	105.96
2027	5	58.37	79.11	98.69
2027	6	45.30	65.79	84.77
2027	7	45.65	66.10	84.97
2027	8	45.22	65.68	84.53
2027	9	60.55	81.34	101.03
2027	10	74.46	95.52	115.88
2027	11	86.63	107.90	128.86
2027	12	97.75	108.09	129.59
2028	1	104.66	114.92	136.45
2028	2	91.31	101.32	122.24
2028	3	80.36	101.32	121.62
2028	4	66.21	86.94	106.64
2028	5	59.17	79.78	99.19
2028	6	45.79	66.19	85.04
2028	7	46.11	66.48	85.23
2028	8	45.69	66.05	84.80
2028	9	61.41	82.07	101.57
2028	10	75.65	96.54	116.65
2028	11	88.10	109.17	129.82
2028	12	99.49	109.58	129.16
2029	1	105.79	115.71	134.94
2029	2	92.27	102.00	120.73
2029	3	81.21	101.93	109.02
2029	4	66.90	87.44	94.04
2029	5	59.75	80.21	86.57
2029	6	46.21	66.50	72.41
2029	7	46.51	66.77	72.61
2029	8	46.09	66.35	72.18
2029	9	62.03	82.52	88.95
2029	10	76.43	97.10	104.04
2029	11	89.01	109.81	117.18
2029	12	100.51	110.30	129.22
2030	1	106.74	116.31	132.76
2030	2	93.08	102.52	118.60
2030	3	81.94	102.42	106.99
2030	4	67.51	87.86	92.06
2030	5	60.26	80.55	84.57
2030	6	46.58	66.74	70.44
2030	7	46.87	54.31	70.65
2030	8	46.44	53.88	70.22
2030	9	62.56	70.17	86.96
2030	10	77.10	84.84	102.00
2030	11	89.77	97.58	115.08
2030	12	101.37	109.28	127.07
2031	1	106.98	114.71	117.21
2031	2	93.33	100.97	103.23
2031	3	82.23	89.81	91.83

Year	Month	Monthly Energy with Losses (MWh)		
		Sc.1	Sc.3	Sc.4
2026	3	38,794	50,477	64,016
2026	4	32,676	45,884	58,538
2026	5	28,170	41,517	53,539
2026	6	26,656	39,457	51,067
2026	7	26,039	39,187	50,653
2026	8	25,907	39,096	50,659
2026	9	28,066	41,009	53,007
2026	10	33,488	47,132	59,901
2026	11	39,769	53,366	67,067
2026	12	43,842	50,990	65,221
2027	1	48,473	55,741	68,991
2027	2	40,228	46,611	59,011
2027	3	39,315	50,923	63,083
2027	4	33,073	46,225	57,506
2027	5	28,477	41,781	52,434
2027	6	26,905	39,673	49,914
2027	7	26,267	39,384	49,480
2027	8	26,148	39,299	49,480
2027	9	28,374	41,263	51,862
2027	10	33,912	47,474	58,819
2027	11	40,337	53,819	66,058
2027	12	44,490	51,498	64,234
2028	1	49,246	56,293	69,219
2028	2	41,744	47,971	60,177
2028	3	39,914	51,341	63,224
2028	4	33,528	46,543	57,605
2028	5	28,829	42,025	52,504
2028	6	27,190	39,869	49,962
2028	7	26,528	39,559	41,328
2028	8	26,420	39,480	41,316
2028	9	28,717	41,487	44,095
2028	10	34,378	47,774	50,633
2028	11	40,953	54,212	58,262
2028	12	45,186	51,938	63,060
2029	1	50,011	56,735	67,863
2029	2	41,491	47,427	58,399
2029	3	40,499	51,680	57,131
2029	4	33,974	46,805	49,693
2029	5	29,172	42,231	44,223
2029	6	27,468	40,039	42,106
2029	7	26,780	39,713	41,251
2029	8	26,682	39,635	41,223
2029	9	29,041	41,672	43,961
2029	10	34,813	48,012	50,425
2029	11	41,523	54,516	57,966
2029	12	45,826	52,271	62,705
2030	1	50,581	56,954	65,376
2030	2	41,960	47,611	55,982
2030	3	40,930	51,845	54,714
2030	4	34,295	46,929	47,329
2030	5	29,419	42,329	41,904
2030	6	27,660	40,114	39,799
2030	7	26,946	31,591	38,943
2030	8	26,845	31,504	38,898
2030	9	29,247	33,956	41,605
2030	10	35,095	39,908	47,999
2030	11	41,900	46,842	55,462
2030	12	46,247	51,251	60,146
2031	1	50,837	55,767	58,463
2031	2	42,175	46,977	49,178
2031	3	41,128	45,905	47,923

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Year	Month	Monthly Peak Demand with Losses (MW)		
		Sc.1	Sc.3	Sc.4
2031	4	67.82	75.31	77.09
2031	5	60.56	68.01	69.69
2031	6	46.87	54.24	55.70
2031	7	47.15	54.50	55.92
2031	8	46.73	54.08	55.50
2031	9	62.86	70.33	72.04
2031	10	77.40	84.95	86.90
2031	11	90.02	97.62	99.79
2031	12	101.61	109.27	111.63
2032	1	107.17	114.78	116.62
2032	2	93.54	101.08	102.79
2032	3	82.49	89.97	91.55
2032	4	68.10	75.51	76.95
2032	5	60.84	68.22	69.60
2032	6	47.15	54.46	55.73
2032	7	47.42	54.72	55.97
2032	8	46.99	54.30	55.54
2032	9	63.13	70.53	71.93
2032	10	77.65	85.12	86.65
2032	11	90.24	97.75	99.41
2032	12	101.81	109.36	111.13
2033	1	106.46	114.08	114.96
2033	2	93.02	100.56	101.39
2033	3	82.16	89.65	90.40
2033	4	67.95	75.37	76.06
2033	5	60.80	68.18	68.85
2033	6	47.26	54.58	55.20
2033	7	47.54	54.85	48.34
2033	8	47.12	54.43	47.92
2033	9	63.06	70.46	64.02
2033	10	77.40	84.87	78.50
2033	11	89.80	97.31	91.00
2033	12	101.21	108.77	102.52
2034	1	105.82	113.55	107.20
2034	2	92.55	100.19	93.80
2034	3	81.86	89.43	83.00
2034	4	67.81	75.30	68.83
2034	5	60.75	68.19	61.72
2034	6	47.35	54.71	48.21
2034	7	47.63	54.98	48.47
2034	8	47.22	54.57	48.05
2034	9	62.98	70.44	63.97
2034	10	77.16	84.71	78.27
2034	11	89.39	97.00	90.60
2034	12	100.67	108.34	101.97
2035	1	105.04	113.00	106.81
2035	2	91.96	99.79	93.56
2035	3	81.45	89.18	82.89
2035	4	67.59	75.21	68.86
2035	5	60.63	68.19	61.83
2035	6	47.39	54.83	48.44
2035	7	47.70	48.01	48.71
2035	8	47.28	47.59	48.29
2035	9	62.83	63.30	64.05
2035	10	76.82	77.41	78.21
2035	11	88.88	89.55	90.41
2035	12	100.01	100.77	101.67

Year	Month	Monthly Energy with Losses (MWh)		
		Sc.1	Sc.3	Sc.4
2031	4	34,455	39,143	40,633
2031	5	29,552	34,156	35,279
2031	6	27,765	32,347	33,196
2031	7	27,034	31,596	32,342
2031	8	26,925	31,498	32,289
2031	9	29,337	33,937	34,960
2031	10	35,193	39,854	41,263
2031	11	42,008	46,746	48,618
2031	12	46,349	51,124	53,237
2032	1	50,810	55,616	57,881
2032	2	43,070	47,782	49,678
2032	3	41,115	45,806	47,493
2032	4	34,463	39,087	40,309
2032	5	29,575	34,131	35,035
2032	6	27,788	32,331	32,981
2032	7	27,050	31,578	32,135
2032	8	26,925	31,466	32,074
2032	9	29,316	33,882	34,710
2032	10	35,126	39,747	40,925
2032	11	41,883	46,573	48,173
2032	12	46,182	50,907	52,727
2033	1	50,609	55,388	57,124
2033	2	42,007	46,694	48,085
2033	3	40,963	45,640	46,881
2033	4	34,359	38,975	39,800
2033	5	29,506	34,059	34,603
2033	6	27,728	32,270	32,575
2033	7	26,986	31,515	27,386
2033	8	26,847	31,392	27,320
2033	9	29,207	33,781	29,924
2033	10	34,949	39,583	36,055
2033	11	41,621	46,330	43,203
2033	12	45,862	50,614	47,699
2034	1	50,262	55,074	52,288
2034	2	41,732	46,451	43,361
2034	3	40,698	45,410	42,184
2034	4	34,163	38,813	35,200
2034	5	29,362	33,946	30,075
2034	6	27,598	32,172	28,074
2034	7	26,855	31,419	27,246
2034	8	26,704	31,286	27,178
2034	9	29,029	33,646	29,755
2034	10	34,689	39,378	35,816
2034	11	41,258	46,038	42,877
2034	12	45,433	50,266	47,326
2035	1	49,812	54,719	51,919
2035	2	41,373	46,176	43,088
2035	3	40,352	45,150	41,938
2035	4	33,902	38,626	35,038
2035	5	29,163	33,815	29,975
2035	6	27,418	32,057	27,998
2035	7	26,678	26,956	27,180
2035	8	26,524	26,821	27,114
2035	9	28,817	29,154	29,673
2035	10	34,393	34,818	35,680
2035	11	40,858	41,392	42,672
2035	12	44,972	45,571	47,089

Appendix E
Energy Model – Average Monthly

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Whitehorse Generating Station - Turbine Uprate Study
Average Monthly Generation - Load Scenario 1

	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
						(MWh)							
Base Case													
WH1	2460	2125	2261	1757	1789	2621	2555	2595	2609	2862	2858	2348	28842
WH2	1310	1098	1018	209	557	1912	1917	1950	2103	2316	2483	1348	18223
WH3	540	252	0	0	708	282	1045	1235	2790	3726	3217	1213	15007
WH4	15247	13782	15261	13806	10730	12501	12375	12196	12259	14252	14572	15198	162178
Thermal	4140	3692	3467	2111	153	1	0	0	2	101	892	887	15448
													239697
										Maximum Thermal Power (MW)			24.460
Option 1-1 (WH1 high efficiency)													
WH1	2780	2441	2588	1837	1735	2983	3066	3059	3059	3249	3318	2671	32786
WH2	1144	924	835	158	413	1482	1541	1549	1967	2134	2296	1224	15667
WH3	538	251	0	0	469	226	677	1091	2522	3670	3150	1171	13765
WH4	15227	13758	15242	13866	11167	12626	12608	12277	12212	14109	14416	15084	162592
Thermal	4008	3575	3342	2023	154	2	0	0	2	95	843	844	14888
													239697
										Maximum Thermal Power (MW)			24.370
Option 2-1 (WH3 high efficiency)													
WH1	2467	2123	2262	1746	1842	2484	2294	2344	2381	2836	2876	2363	28016
WH2	1322	1088	1018	209	709	1466	1349	1394	1592	2227	2512	1345	16232
WH3	543	283	0	0	866	784	1933	2222	3730	3977	3319	1267	18924
WH4	15231	13767	15260	13819	10371	12584	12314	12016	12059	14118	14440	15146	161125
Thermal	4134	3689	3467	2109	149	1	0	0	2	100	877	872	15400
													239697
										Maximum Thermal Power (MW)			24.450
Option 3-1 (WH4 high efficiency)													
WH1	2531	2187	2333	1805	1771	2618	2529	2575	2597	2875	2895	2409	29125
WH2	1335	1123	1044	219	530	1845	1748	1843	2105	2318	2516	1379	18007
WH3	540	257	0	0	648	308	951	1151	2728	3762	3250	1222	14817
WH4	15233	13763	15244	13821	10862	12548	12664	12407	12330	14205	14497	15122	162696
Thermal	4058	3619	3386	2038	125	1	0	0	2	97	866	861	15053
													239697
										Maximum Thermal Power (MW)			24.410
Option 4-1 (WH1 increased flow)													
WH1	2830	2480	2608	1908	2091	3120	3221	3213	3256	3380	3433	2722	34261
WH2	1088	875	797	176	639	1417	1520	1531	2032	2051	2235	1182	15542
WH3	536	252	0	55	1091	218	570	944	2284	3659	3106	1146	13861
WH4	15215	13751	15240	13695	9974	12562	12581	12289	12190	14073	14407	15097	161073
Thermal	4027	3593	3362	2049	143	2	0	0	1	94	843	846	14960
													239697
										Maximum Thermal Power (MW)			24.310
Option 5-1 (WH4 Kaplan)													
WH1	2872	2533	2746	2610	2861	3198	2856	2749	2755	3176	3199	2628	34183
WH2	2283	1933	2194	2151	2052	2926	2308	2143	2357	2720	2815	1640	27520
WH3	1823	1470	1120	1128	3144	3333	2643	2205	2986	3989	4005	1998	29844
WH4	12890	11598	12786	10349	5847	7862	10085	10880	11664	13285	13159	13880	134285
Thermal	3829	3416	3160	1645	33	0	0	0	1	88	845	847	13864
													239697
										Maximum Thermal Power (MW)			23.760
Option 6-1 (WH1 & WH2 high efficiency)													
WH1	2628	2295	2433	1809	1714	2881	3000	3012	3081	3117	3081	2531	31581
WH2	1354	1134	1050	205	601	1945	2273	2277	2639	2521	2683	1444	20127
WH3	541	250	0	4	780	149	417	675	2052	3528	3200	1175	12771
WH4	15221	13743	15227	13856	10695	12342	12202	12013	11989	14001	14247	15028	160565
Thermal	3953	3527	3297	2009	147	1	0	0	1	90	812	815	14653
													239697
										Maximum Thermal Power (MW)			24.370

Whitehorse Generating Station - Turbine Uprate Study
Average Monthly Generation - Load Scenario 4

	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
						(MWh)							
Base Case													
WH1	2289	2038	2293	1878	1355	3020	3624	3648	3628	3425	2803	2778	32778
WH2	978	883	1021	320	204	2563	3624	3620	3628	3280	2570	2464	25155
WH3	189	94	14	0	142	3889	5868	5877	5686	4881	3048	2653	32340
WH4	15192	13736	15198	14246	13013	14370	14215	13945	13773	14930	14821	15292	172730
Thermal	31541	27636	29918	26652	12813	6185	6239	7020	9226	19032	25666	25629	227558
													490560
										Maximum Thermal Power (MW)			94.471
Option 1-4 (WH1 - High efficiency)													
WH1	2565	2285	2586	2007	1410	3365	3887	3896	3833	3742	3231	3239	36045
WH2	823	743	854	248	179	2422	3524	3522	3540	3159	2325	2198	23538
WH3	193	94	14	0	116	3800	5801	5817	5646	4854	3044	2645	32023
WH4	15217	13754	15213	14315	13090	14339	14206	13939	13767	14925	14821	15300	172887
Thermal	31390	27509	29777	26527	12733	6101	6152	6934	9154	18867	25486	25435	226067
													490560
										Maximum Thermal Power (MW)			94.240
Option 2-4 (WH3 - High efficiecy)													
WH1	2287	2035	2290	1890	1338	2967	3621	3639	3623	3459	2852	2828	32830
WH2	984	886	1021	317	213	2494	3621	3632	3623	3305	2619	2518	25233
WH3	189	94	14	40	186	4069	5876	5895	5707	4916	3064	2662	32710
WH4	15196	13740	15201	14209	13014	14348	14211	13938	13767	14924	14821	15292	172660
Thermal	31533	27632	29918	26640	12775	6150	6242	7005	9221	18944	25552	25517	227127
													490560
										Maximum Thermal Power (MW)			94.410
Option 5-4 (WH4 Kaplan)													
WH1	2741	2458	2728	2616	2548	3311	3711	3645	3615	3577	3036	3031	37017
WH2	2187	1894	2030	2168	1294	3103	3711	3645	3615	3338	2305	2151	31440
WH3	1555	1442	1638	443	401	4580	5944	5928	5738	5512	4876	4775	42832
WH4	12540	11289	12497	11919	11917	13036	14087	13957	13819	14184	13121	13367	155734
Thermal	31166	27303	29550	25950	11367	5998	6117	6935	9154	18936	25570	25492	223537
													490560
										Maximum Thermal Power (MW)			93.417

Appendix F
Economic Analysis

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Table 1-1

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	1-1	
Syslem load =	Scenario 1	
Whitehorse Generating Unit Status		
- WH1 =	Efficiency Improvement	
- WH2 =	Existing	
- WH3 =	Existing	
- WH4 =	Existing	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	1,986,050	($)
Capital cost distribution:		
- Year 1 =	45	(%)
- Year 2 =	55	(%)
- Year 3 =	0	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$894	$894	0		0	$0	$0
2018	$1,092	$1,057	179		-36	$0	-$35
2019	$0	$0	-559		112	$0	$105
2020	$0	$0	-559		112	$0	$101
2021	$0	$0	-559		112	$0	$98
2022	$0	$0	-559		112	$0	$95
2023	$0	$0	-559		112	$0	$92
2024	$0	$0	-559		112	$0	$89
2025	$0	$0	-559	0.090	112	$225	$258
2026	$0	$0	-559		112	$0	$83
2027	$0	$0	-559		112	$0	$80
2028	$0	$0	-559		112	$0	$78
2029	$0	$0	-559		112	$0	$75
2030	$0	$0	-559		112	$0	$73
2031	$0	$0	-559		112	$0	$70
2032	$0	$0	-559		112	$0	$68
2033	$0	$0	-559		112	$0	$66
2034	$0	$0	-559		112	$0	$64
2035	$0	$0	-559		112	$0	$61
2036	$0	$0	-559		112	$0	$59
2037	$0	$0	-559		112	$0	$58
2038	$0	$0	-559		112	$0	$56
2039	$0	$0	-559		112	$0	$54
2040	$0	$0	-559		112	$0	$52
2041	$0	$0	-559		112	$0	$50
2042	$0	$0	-559		112	$0	$49
2043	$0	$0	-559		112	$0	$47
2044	$0	$0	-559		112	$0	$46
2045	$0	$0	-559		112	$0	$44
2046	$0	$0	-559		112	$0	$43
2047	$0	$0	-559		112	$0	$41
2048	$0	$0	-559		112	$0	$40
2049	$0	$0	-559		112	$0	$39
2050	$0	$0	-559		112	$0	$37
2051	$0	$0	-559		112	$0	$36
2052	$0	$0	-559		112	$0	$35
2053	$0	$0	-559		112	$0	$34
2054	$0	$0	-559		112	$0	$33
2055	$0	$0	-559		112	$0	$32
2056	$0	$0	-559		112	$0	$31
2057	$0	$0	-559		112	$0	$30
2058	$0	$0	-559		112	$0	$29
2059	$0	$0	-559		112	$0	$28
2060	$0	$0	-559		112	$0	$27

PV Cost ($1000)	$1,950	**PV Energy & Capacity ($1000)**	**20 years**	$1,692
			30 years	$2,157
			40 years	$2,491

	NPV ($1000)	B/C Ratio	Simple Payback Period	Discounted Payback Period
20 years	***-$259***	***0.87***	**19 yrs**	**28 yrs**
30 years	***$207***	***1.11***		
40 years	***$540***	***1.28***		

Table 1-1A

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	1-1A	
Syslem load =	Scenario 1	
Whitehorse Generating Unit Status		
- WH1 =	Efficiency Improvement	
- WH2 =	Existing	
- WH3 =	Existing	
- WH4 =	Existing	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	1,784,000	($)
Capital cost distribution:		
- Year 1 =	45	(%)
- Year 2 =	55	(%)
- Year 3 =	0	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$803	$803	0		0	$0	$0
2018	$981	$949	179		-36	$0	-$35
2019	$0	$0	-559		112	$0	$105
2020	$0	$0	-559		112	$0	$101
2021	$0	$0	-559		112	$0	$98
2022	$0	$0	-559		112	$0	$95
2023	$0	$0	-559		112	$0	$92
2024	$0	$0	-559		112	$0	$89
2025	$0	$0	-559	0.090	112	$225	$258
2026	$0	$0	-559		112	$0	$83
2027	$0	$0	-559		112	$0	$80
2028	$0	$0	-559		112	$0	$78
2029	$0	$0	-559		112	$0	$75
2030	$0	$0	-559		112	$0	$73
2031	$0	$0	-559		112	$0	$70
2032	$0	$0	-559		112	$0	$68
2033	$0	$0	-559		112	$0	$66
2034	$0	$0	-559		112	$0	$64
2035	$0	$0	-559		112	$0	$61
2036	$0	$0	-559		112	$0	$59
2037	$0	$0	-559		112	$0	$58
2038	$0	$0	-559		112	$0	$56
2039	$0	$0	-559		112	$0	$54
2040	$0	$0	-559		112	$0	$52
2041	$0	$0	-559		112	$0	$50
2042	$0	$0	-559		112	$0	$49
2043	$0	$0	-559		112	$0	$47
2044	$0	$0	-559		112	$0	$46
2045	$0	$0	-559		112	$0	$44
2046	$0	$0	-559		112	$0	$43
2047	$0	$0	-559		112	$0	$41
2048	$0	$0	-559		112	$0	$40
2049	$0	$0	-559		112	$0	$39
2050	$0	$0	-559		112	$0	$37
2051	$0	$0	-559		112	$0	$36
2052	$0	$0	-559		112	$0	$35
2053	$0	$0	-559		112	$0	$34
2054	$0	$0	-559		112	$0	$33
2055	$0	$0	-559		112	$0	$32
2056	$0	$0	-559		112	$0	$31
2057	$0	$0	-559		112	$0	$30
2058	$0	$0	-559		112	$0	$29
2059	$0	$0	-559		112	$0	$28
2060	$0	$0	-559		112	$0	$27

PV Cost ($1000)	$1,752	**PV Energy & Capacity ($1000)**	**20 years**	$1,692
			30 years	$2,157
			40 years	$2,491

	NPV ($1000)	B/C Ratio	Simple Payback Period	Discounted Payback Period
20 years	***-$60***	***0.97***	**17 yrs**	**24 yrs**
30 years	***$405***	***1.23***		
40 years	***$739***	***1.42***		

Table1-3

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	1-3	
Syslem load =	Scenario 3	
Whitehorse Generating Unit Status		
- WH1 =	Existing	
- WH2 =	Existing	
- WH3 =	Existing	
- WH4 =	Efficiency Improvement	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	1,986,050	($)
Capital cost distribution:		
- Year 1 =	10	(%)
- Year 2 =	40	(%)
- Year 3 =	50	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$199	$199	0		0	$0	$0
2018	$794	$768	254		-51	$0	-$49
2019	$993	$929	-559		112	$0	$105
2020	$0	$0	-746		149	$0	$135
2021	$0	$0	-932		186	$0	$163
2022	$0	$0	-932		186	$0	$158
2023	$0	$0	-932		186	$0	$153
2024	$0	$0	-932		186	$0	$148
2025	$0	$0	-932	0.160	186	$400	$449
2026	$0	$0	-932		186	$0	$138
2027	$0	$0	-932		186	$0	$134
2028	$0	$0	-932		186	$0	$129
2029	$0	$0	-879		176	$0	$118
2030	$0	$0	-825		165	$0	$107
2031	$0	$0	-772		154	$0	$97
2032	$0	$0	-719		144	$0	$87
2033	$0	$0	-666		133	$0	$78
2034	$0	$0	-612		122	$0	$70
2035	$0	$0	-559		112	$0	$61
2036	$0	$0	-559		112	$0	$59
2037	$0	$0	-559		112	$0	$58
2038	$0	$0	-559		112	$0	$56
2039	$0	$0	-559		112	$0	$54
2040	$0	$0	-559		112	$0	$52
2041	$0	$0	-559		112	$0	$50
2042	$0	$0	-559		112	$0	$49
2043	$0	$0	-559		112	$0	$47
2044	$0	$0	-559		112	$0	$46
2045	$0	$0	-559		112	$0	$44
2046	$0	$0	-559		112	$0	$43
2047	$0	$0	-559		112	$0	$41
2048	$0	$0	-559		112	$0	$40
2049	$0	$0	-559		112	$0	$39
2050	$0	$0	-559		112	$0	$37
2051	$0	$0	-559		112	$0	$36
2052	$0	$0	-559		112	$0	$35
2053	$0	$0	-559		112	$0	$34
2054	$0	$0	-559		112	$0	$33
2055	$0	$0	-559		112	$0	$32
2056	$0	$0	-559		112	$0	$31
2057	$0	$0	-559		112	$0	$30
2058	$0	$0	-559		112	$0	$29
2059	$0	$0	-559		112	$0	$28
2060	$0	$0	-559		112	$0	$27

PV Cost ($1000)	$1,896	**PV Energy & Capacity ($1000)**	**20 years**	$2,398
			30 years	$2,879
			40 years	$3,224

	NPV ($1000)	B/C Ratio	Payback Period	Discounted Payback Period
20 years	***$502***	***1.26***	**12 yrs**	**15 yrs**
30 years	***$983***	***1.52***		
40 years	***$1,328***	***1.70***		

Table 1-3A

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	1-3A	
Syslem load =	Scenario 3	
Whitehorse Generating Unit Status		
- WH1 =	Efficiency Improvement	
- WH2 =	Existing	
- WH3 =	Existing	
- WH4 =	Existing	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	1,784,000	($)
Capital cost distribution:		
- Year 1 =	10	(%)
- Year 2 =	40	(%)
- Year 3 =	50	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$178	$178	0		0	$0	$0
2018	$714	$690	254		-51	$0	-$49
2019	$892	$835	-559		112	$0	$105
2020	$0	$0	-746		149	$0	$135
2021	$0	$0	-932		186	$0	$163
2022	$0	$0	-932		186	$0	$158
2023	$0	$0	-932		186	$0	$153
2024	$0	$0	-932		186	$0	$148
2025	$0	$0	-932	0.160	186	$400	$449
2026	$0	$0	-932		186	$0	$138
2027	$0	$0	-932		186	$0	$134
2028	$0	$0	-932		186	$0	$129
2029	$0	$0	-879		176	$0	$118
2030	$0	$0	-825		165	$0	$107
2031	$0	$0	-772		154	$0	$97
2032	$0	$0	-719		144	$0	$87
2033	$0	$0	-666		133	$0	$78
2034	$0	$0	-612		122	$0	$70
2035	$0	$0	-559		112	$0	$61
2036	$0	$0	-559		112	$0	$59
2037	$0	$0	-559		112	$0	$58
2038	$0	$0	-559		112	$0	$56
2039	$0	$0	-559		112	$0	$54
2040	$0	$0	-559		112	$0	$52
2041	$0	$0	-559		112	$0	$50
2042	$0	$0	-559		112	$0	$49
2043	$0	$0	-559		112	$0	$47
2044	$0	$0	-559		112	$0	$46
2045	$0	$0	-559		112	$0	$44
2046	$0	$0	-559		112	$0	$43
2047	$0	$0	-559		112	$0	$41
2048	$0	$0	-559		112	$0	$40
2049	$0	$0	-559		112	$0	$39
2050	$0	$0	-559		112	$0	$37
2051	$0	$0	-559		112	$0	$36
2052	$0	$0	-559		112	$0	$35
2053	$0	$0	-559		112	$0	$34
2054	$0	$0	-559		112	$0	$33
2055	$0	$0	-559		112	$0	$32
2056	$0	$0	-559		112	$0	$31
2057	$0	$0	-559		112	$0	$30
2058	$0	$0	-559		112	$0	$29
2059	$0	$0	-559		112	$0	$28
2060	$0	$0	-559		112	$0	$27

PV Cost ($1000)	$1,703	**PV Energy & Capacity ($1000)**	**20 years**	$2,398
			30 years	$2,879
			40 years	$3,224

	NPV ($1000)	B/C Ratio	Payback Period	Discounted Payback Period
20 years	***$695***	***1.41***	**11 yrs**	**13 yrs**
30 years	***$1,176***	***1.69***		
40 years	***$1,521***	***1.89***		

Table 1-4

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	1-4	
Syslem load =	Scenario 4 - High Growth	
Whitehorse Generating Unit Status		
- WH1 =	Efficiency Improvement	
- WH2 =	Existing	
- WH3 =	Existing	
- WH4 =	Existing	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	1,986,050	($)
Capital cost distribution:		
- Year 1 =	45	(%)
- Year 2 =	55	(%)
- Year 3 =	0	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$894	$894	0		0	$0	$0
2018	$1,092	$1,057	254		-51	$0	-$49
2019	$0	$0	-559		112	$0	$105
2020	$0	$0	-1,025		205	$0	$186
2021	$0	$0	-1,491		298	$0	$261
2022	$0	$0	-1,491		298	$0	$253
2023	$0	$0	-1,491		298	$0	$244
2024	$0	$0	-1,491		298	$0	$236
2025	$0	$0	-1,491	0.230	298	-$575	-$212
2026	$0	$0	-1,491		298	$0	$221
2027	$0	$0	-1,491		298	$0	$214
2028	$0	$0	-1,491		298	$0	$207
2029	$0	$0	-1,358		272	$0	$182
2030	$0	$0	-1,225		245	$0	$159
2031	$0	$0	-1,092		218	$0	$137
2032	$0	$0	-958		192	$0	$116
2033	$0	$0	-825		165	$0	$97
2034	$0	$0	-692		138	$0	$79
2035	$0	$0	-559		112	$0	$61
2036	$0	$0	-559		112	$0	$59
2037	$0	$0	-559		112	$0	$58
2038	$0	$0	-559		112	$0	$56
2039	$0	$0	-559		112	$0	$54
2040	$0	$0	-559		112	$0	$52
2041	$0	$0	-559		112	$0	$50
2042	$0	$0	-559		112	$0	$49
2043	$0	$0	-559		112	$0	$47
2044	$0	$0	-559		112	$0	$46
2045	$0	$0	-559		112	$0	$44
2046	$0	$0	-559		112	$0	$43
2047	$0	$0	-559		112	$0	$41
2048	$0	$0	-559		112	$0	$40
2049	$0	$0	-559		112	$0	$39
2050	$0	$0	-559		112	$0	$37
2051	$0	$0	-559		112	$0	$36
2052	$0	$0	-559		112	$0	$35
2053	$0	$0	-559		112	$0	$34
2054	$0	$0	-559		112	$0	$33
2055	$0	$0	-559		112	$0	$32
2056	$0	$0	-559		112	$0	$31
2057	$0	$0	-559		112	$0	$30
2058	$0	$0	-559		112	$0	$29
2059	$0	$0	-559		112	$0	$28
2060	$0	$0	-559		112	$0	$27

PV Cost ($1000)	$1,950	**PV Energy & Capacity ($1000)**	**20 years**	$2,669
			30 years	$3,135
			40 years	$3,469

	NPV ($1000)	B/C Ratio	Simple Payback Period	Discounted Payback Period
20 years	***$719***	***1.37***	**12 yrs**	**14 yrs**
30 years	***$1,184***	***1.61***		
40 years	***$1,518***	***1.78***		

Table 1-4A

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	1-4A	
Syslem load =	Scenario 4 - High Growth	
Whitehorse Generating Unit Status		
- WH1 =	Efficiency Improvement	
- WH2 =	Existing	
- WH3 =	Existing	
- WH4 =	Existing	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	1,784,000	($)
Capital cost distribution:		
- Year 1 =	45	(%)
- Year 2 =	55	(%)
- Year 3 =	0	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$803	$803	0		0	$0	$0
2018	$981	$949	254		-51	$0	-$49
2019	$0	$0	-559		112	$0	$105
2020	$0	$0	-1,025		205	$0	$186
2021	$0	$0	-1,491		298	$0	$261
2022	$0	$0	-1,491		298	$0	$253
2023	$0	$0	-1,491		298	$0	$244
2024	$0	$0	-1,491		298	$0	$236
2025	$0	$0	-1,491	0.230	298	$575	$669
2026	$0	$0	-1,491		298	$0	$221
2027	$0	$0	-1,491		298	$0	$214
2028	$0	$0	-1,491		298	$0	$207
2029	$0	$0	-1,358		272	$0	$182
2030	$0	$0	-1,225		245	$0	$159
2031	$0	$0	-1,092		218	$0	$137
2032	$0	$0	-958		192	$0	$116
2033	$0	$0	-825		165	$0	$97
2034	$0	$0	-692		138	$0	$79
2035	$0	$0	-559		112	$0	$61
2036	$0	$0	-559		112	$0	$59
2037	$0	$0	-559		112	$0	$58
2038	$0	$0	-559		112	$0	$56
2039	$0	$0	-559		112	$0	$54
2040	$0	$0	-559		112	$0	$52
2041	$0	$0	-559		112	$0	$50
2042	$0	$0	-559		112	$0	$49
2043	$0	$0	-559		112	$0	$47
2044	$0	$0	-559		112	$0	$46
2045	$0	$0	-559		112	$0	$44
2046	$0	$0	-559		112	$0	$43
2047	$0	$0	-559		112	$0	$41
2048	$0	$0	-559		112	$0	$40
2049	$0	$0	-559		112	$0	$39
2050	$0	$0	-559		112	$0	$37
2051	$0	$0	-559		112	$0	$36
2052	$0	$0	-559		112	$0	$35
2053	$0	$0	-559		112	$0	$34
2054	$0	$0	-559		112	$0	$33
2055	$0	$0	-559		112	$0	$32
2056	$0	$0	-559		112	$0	$31
2057	$0	$0	-559		112	$0	$30
2058	$0	$0	-559		112	$0	$29
2059	$0	$0	-559		112	$0	$28
2060	$0	$0	-559		112	$0	$27

PV Cost ($1000)	$1,752	**PV Energy & Capacity ($1000)**	**20 years**	$3,551
			30 years	$4,016
			40 years	$4,350

	NPV ($1000)	B/C Ratio	Simple Payback Period	Discounted Payback Period
20 years	***$1,799***	***2.03***	**9 yrs**	**9 yrs**
30 years	***$2,264***	***2.29***		
40 years	***$2,598***	***2.48***		

Table 2-1

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	2-1	
Syslem load =	Scenario 1	
Whitehorse Generating Unit Status		
- WH1 =	Existing	
- WH2 =	Existing	
- WH3 =	Efficiency Improvement	
- WH4 =	Existing	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	2,580,600	($)
Capital cost distribution:		
- Year 1 =	45	(%)
- Year 2 =	55	(%)
- Year 3 =	0	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$1,161	$1,161	0		0.0	$0	$0.0
2018	$1,419	$1,373	438		-87.7	$0	-$84.8
2019	$0	$0	-47		9.4	$0	$8.8
2020	$0	$0	-47		9.4	$0	$8.5
2021	$0	$0	-47		9.4	$0	$8.2
2022	$0	$0	-47		9.4	$0	$8.0
2023	$0	$0	-47		9.4	$0	$7.7
2024	$0	$0	-47		9.4	$0	$7.4
2025	$0	$0	-47	0.010	9.4	$25	$26.4
2026	$0	$0	-47		9.4	$0	$7.0
2027	$0	$0	-47		9.4	$0	$6.7
2028	$0	$0	-47		9.4	$0	$6.5
2029	$0	$0	-47		9.4	$0	$6.3
2030	$0	$0	-47		9.4	$0	$6.1
2031	$0	$0	-47		9.4	$0	$5.9
2032	$0	$0	-47		9.4	$0	$5.7
2033	$0	$0	-47		9.4	$0	$5.5
2034	$0	$0	-47		9.4	$0	$5.3
2035	$0	$0	-47		9.4	$0	$5.2
2036	$0	$0	-47		9.4	$0	$5.0
2037	$0	$0	-47		9.4	$0	$4.8
2038	$0	$0	-47		9.4	$0	$4.7
2039	$0	$0	-47		9.4	$0	$4.5
2040	$0	$0	-47		9.4	$0	$4.4
2041	$0	$0	-47		9.4	$0	$4.2
2042	$0	$0	-47		9.4	$0	$4.1
2043	$0	$0	-47		9.4	$0	$4.0
2044	$0	$0	-47		9.4	$0	$3.8
2045	$0	$0	-47		9.4	$0	$3.7
2046	$0	$0	-47		9.4	$0	$3.6
2047	$0	$0	-47		9.4	$0	$3.5
2048	$0	$0	-47		9.4	$0	$3.4
2049	$0	$0	-47		9.4	$0	$3.2
2050	$0	$0	-47		9.4	$0	$3.1
2051	$0	$0	-47		9.4	$0	$3.0
2052	$0	$0	-47		9.4	$0	$2.9
2053	$0	$0	-47		9.4	$0	$2.8
2054	$0	$0	-47		9.4	$0	$2.7
2055	$0	$0	-47		9.4	$0	$2.7
2056	$0	$0	-47		9.4	$0	$2.6
2057	$0	$0	-47		9.4	$0	$2.5
2058	$0	$0	-47		9.4	$0	$2.4
2059	$0	$0	-47		9.4	$0	$2.3
2060	$0	$0	-47		9.4	$0	$2.3

PV Cost ($1000)	$2,534	**PV Energy & Capacity ($1000)**	**20 years**	$60
			30 years	$101
			40 years	$130

	NPV ($1000)	B/C Ratio	Simple Payback Period	Discounted Payback Period
20 years	***-$2,474***	***0.02***	**No Payback**	**No Payback**
30 years	***-$2,433***	***0.04***		
40 years	***-$2,404***	***0.05***		

Table 2-1A

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	2-1A	
Syslem load =	Scenario 1	
Whitehorse Generating Unit Status		
- WH1 =	Existing	
- WH2 =	Existing	
- WH3 =	Efficiency Improvement	
- WH4 =	Existing	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	1,177,000	($)
Capital cost distribution:		
- Year 1 =	45	(%)
- Year 2 =	55	(%)
- Year 3 =	0	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$530	$530	0		0.0	$0	$0.0
2018	$647	$626	438		-87.7	$0	-$84.8
2019	$0	$0	-47		9.4	$0	$8.8
2020	$0	$0	-47		9.4	$0	$8.5
2021	$0	$0	-47		9.4	$0	$8.2
2022	$0	$0	-47		9.4	$0	$8.0
2023	$0	$0	-47		9.4	$0	$7.7
2024	$0	$0	-47		9.4	$0	$7.4
2025	$0	$0	-47	0.010	9.4	$25	$26.4
2026	$0	$0	-47		9.4	$0	$7.0
2027	$0	$0	-47		9.4	$0	$6.7
2028	$0	$0	-47		9.4	$0	$6.5
2029	$0	$0	-47		9.4	$0	$6.3
2030	$0	$0	-47		9.4	$0	$6.1
2031	$0	$0	-47		9.4	$0	$5.9
2032	$0	$0	-47		9.4	$0	$5.7
2033	$0	$0	-47		9.4	$0	$5.5
2034	$0	$0	-47		9.4	$0	$5.3
2035	$0	$0	-47		9.4	$0	$5.2
2036	$0	$0	-47		9.4	$0	$5.0
2037	$0	$0	-47		9.4	$0	$4.8
2038	$0	$0	-47		9.4	$0	$4.7
2039	$0	$0	-47		9.4	$0	$4.5
2040	$0	$0	-47		9.4	$0	$4.4
2041	$0	$0	-47		9.4	$0	$4.2
2042	$0	$0	-47		9.4	$0	$4.1
2043	$0	$0	-47		9.4	$0	$4.0
2044	$0	$0	-47		9.4	$0	$3.8
2045	$0	$0	-47		9.4	$0	$3.7
2046	$0	$0	-47		9.4	$0	$3.6
2047	$0	$0	-47		9.4	$0	$3.5
2048	$0	$0	-47		9.4	$0	$3.4
2049	$0	$0	-47		9.4	$0	$3.2
2050	$0	$0	-47		9.4	$0	$3.1
2051	$0	$0	-47		9.4	$0	$3.0
2052	$0	$0	-47		9.4	$0	$2.9
2053	$0	$0	-47		9.4	$0	$2.8
2054	$0	$0	-47		9.4	$0	$2.7
2055	$0	$0	-47		9.4	$0	$2.7
2056	$0	$0	-47		9.4	$0	$2.6
2057	$0	$0	-47		9.4	$0	$2.5
2058	$0	$0	-47		9.4	$0	$2.4
2059	$0	$0	-47		9.4	$0	$2.3
2060	$0	$0	-47		9.4	$0	$2.3

PV Cost ($1000)	$1,156	**PV Energy & Capacity ($1000)**	**20 years**	$60
			30 years	$101
			40 years	$130

	NPV ($1000)	B/C Ratio	Simple Payback Period	Discounted Payback Period
20 years	***-$1,095***	***0.05***	**No Payback**	**No Payback**
30 years	***-$1,055***	***0.09***		
40 years	***-$1,026***	***0.11***		

Table 2-4

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	2-4	
Syslem load =	Scenario 4	
Whitehorse Generating Unit Status		
- WH1 =	Existing	
- WH2 =	Efficiency Improvement	
- WH3 =	Existing	
- WH4 =	Existing	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	2,580,600	($)
Capital cost distribution:		
- Year 1 =	45	(%)
- Year 2 =	55	(%)
- Year 3 =	0	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$1,161	$1,161	0		0	$0	$0
2018	$1,419	$1,373	212		-42	$0	-$41
2019	$0	$0	-47		9	$0	$9
2020	$0	$0	-239		48	$0	$43
2021	$0	$0	-430		86	$0	$75
2022	$0	$0	-430		86	$0	$73
2023	$0	$0	-430		86	$0	$70
2024	$0	$0	-430		86	$0	$68
2025	$0	$0	-430	0.070	86	$175	$200
2026	$0	$0	-430		86	$0	$64
2027	$0	$0	-430		86	$0	$62
2028	$0	$0	-430		86	$0	$60
2029	$0	$0	-375		75	$0	$50
2030	$0	$0	-321		64	$0	$42
2031	$0	$0	-266		53	$0	$33
2032	$0	$0	-211		42	$0	$26
2033	$0	$0	-156		31	$0	$18
2034	$0	$0	-102		20	$0	$12
2035	$0	$0	-47		9	$0	$5
2036	$0	$0	-47		9	$0	$5
2037	$0	$0	-47		9	$0	$5
2038	$0	$0	-47		9	$0	$5
2039	$0	$0	-47		9	$0	$5
2040	$0	$0	-47		9	$0	$4
2041	$0	$0	-47		9	$0	$4
2042	$0	$0	-47		9	$0	$4
2043	$0	$0	-47		9	$0	$4
2044	$0	$0	-47		9	$0	$4
2045	$0	$0	-47		9	$0	$4
2046	$0	$0	-47		9	$0	$4
2047	$0	$0	-47		9	$0	$3
2048	$0	$0	-47		9	$0	$3
2049	$0	$0	-47		9	$0	$3
2050	$0	$0	-47		9	$0	$3
2051	$0	$0	-47		9	$0	$3
2052	$0	$0	-47		9	$0	$3
2053	$0	$0	-47		9	$0	$3
2054	$0	$0	-47		9	$0	$3
2055	$0	$0	-47		9	$0	$3
2056	$0	$0	-47		9	$0	$3
2057	$0	$0	-47		9	$0	$2
2058	$0	$0	-47		9	$0	$2
2059	$0	$0	-47		9	$0	$2
2060	$0	$0	-47		9	$0	$2

PV Cost ($1000)	$2,534	**PV Energy & Capacity ($1000)**	**20 years**	$883
			30 years	$923
			40 years	$951

	NPV ($1000)	B/C Ratio	Payback Period	Discounted Payback Period
20 years	***-$1,651***	***0.35***	**45 yrs**	**45 yrs**
30 years	***-$1,612***	***0.36***		
40 years	***-$1,584***	***0.38***		

Table 2-4A

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	2-4A	
Syslem load =	Scenario 4	
Whitehorse Generating Unit Status		
- WH1 =	Existing	
- WH2 =	Efficiency Improvement	
- WH3 =	Existing	
- WH4 =	Existing	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	1,177,000	($)
Capital cost distribution:		
- Year 1 =	45	(%)
- Year 2 =	55	(%)
- Year 3 =	0	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$530	$530	0		0	$0	$0
2018	$647	$626	212		-42	$0	-$41
2019	$0	$0	-47		9	$0	$9
2020	$0	$0	-239		48	$0	$43
2021	$0	$0	-430		86	$0	$75
2022	$0	$0	-430		86	$0	$73
2023	$0	$0	-430		86	$0	$70
2024	$0	$0	-430		86	$0	$68
2025	$0	$0	-430	0.070	86	$175	$200
2026	$0	$0	-430		86	$0	$64
2027	$0	$0	-430		86	$0	$62
2028	$0	$0	-430		86	$0	$60
2029	$0	$0	-375		75	$0	$50
2030	$0	$0	-321		64	$0	$42
2031	$0	$0	-266		53	$0	$33
2032	$0	$0	-211		42	$0	$26
2033	$0	$0	-156		31	$0	$18
2034	$0	$0	-102		20	$0	$12
2035	$0	$0	-47		9	$0	$5
2036	$0	$0	-47		9	$0	$5
2037	$0	$0	-47		9	$0	$5
2038	$0	$0	-47		9	$0	$5
2039	$0	$0	-47		9	$0	$5
2040	$0	$0	-47		9	$0	$4
2041	$0	$0	-47		9	$0	$4
2042	$0	$0	-47		9	$0	$4
2043	$0	$0	-47		9	$0	$4
2044	$0	$0	-47		9	$0	$4
2045	$0	$0	-47		9	$0	$4
2046	$0	$0	-47		9	$0	$4
2047	$0	$0	-47		9	$0	$3
2048	$0	$0	-47		9	$0	$3
2049	$0	$0	-47		9	$0	$3
2050	$0	$0	-47		9	$0	$3
2051	$0	$0	-47		9	$0	$3
2052	$0	$0	-47		9	$0	$3
2053	$0	$0	-47		9	$0	$3
2054	$0	$0	-47		9	$0	$3
2055	$0	$0	-47		9	$0	$3
2056	$0	$0	-47		9	$0	$3
2057	$0	$0	-47		9	$0	$2
2058	$0	$0	-47		9	$0	$2
2059	$0	$0	-47		9	$0	$2
2060	$0	$0	-47		9	$0	$2

PV Cost ($1000)	$1,156	**PV Energy & Capacity ($1000)**	**20 years**	$883
			30 years	$923
			40 years	$951

	NPV ($1000)	B/C Ratio	Payback Period	Discounted Payback Period
20 years	***-$272***	***0.76***	**20 yrs**	**45 yrs**
30 years	***-$233***	***0.80***		
40 years	***-$205***	***0.82***		

Table 3-1

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	3-1	
Syslem load =	Scenario 1	
Whitehorse Generating Unit Status		
- WH1 =	Existing	
- WH2 =	Existing	
- WH3 =	Existing	
- WH4 =	Efficiency Improvement	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	4,263,050	($)
Capital cost distribution:		
- Year 1 =	10	(%)
- Year 2 =	40	(%)
- Year 3 =	50	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$426	$426	0		0	$0	$0
2018	$1,705	$1,649	0		0	$0	$0
2019	$2,132	$1,994	1,040		-208	$0	-$195
2020	$0	$0	-395		79	$0	$72
2021	$0	$0	-395		79	$0	$69
2022	$0	$0	-395		79	$0	$67
2023	$0	$0	-395		79	$0	$65
2024	$0	$0	-395		79	$0	$63
2025	$0	$0	-395	0.050	79	$125	$156
2026	$0	$0	-395		79	$0	$59
2027	$0	$0	-395		79	$0	$57
2028	$0	$0	-395		79	$0	$55
2029	$0	$0	-395		79	$0	$53
2030	$0	$0	-395		79	$0	$51
2031	$0	$0	-395		79	$0	$50
2032	$0	$0	-395		79	$0	$48
2033	$0	$0	-395		79	$0	$46
2034	$0	$0	-395		79	$0	$45
2035	$0	$0	-395		79	$0	$43
2036	$0	$0	-395		79	$0	$42
2037	$0	$0	-395		79	$0	$41
2038	$0	$0	-395		79	$0	$39
2039	$0	$0	-395		79	$0	$38
2040	$0	$0	-395		79	$0	$37
2041	$0	$0	-395		79	$0	$36
2042	$0	$0	-395		79	$0	$34
2043	$0	$0	-395		79	$0	$33
2044	$0	$0	-395		79	$0	$32
2045	$0	$0	-395		79	$0	$31
2046	$0	$0	-395		79	$0	$30
2047	$0	$0	-395		79	$0	$29
2048	$0	$0	-395		79	$0	$28
2049	$0	$0	-395		79	$0	$27
2050	$0	$0	-395		79	$0	$26
2051	$0	$0	-395		79	$0	$26
2052	$0	$0	-395		79	$0	$25
2053	$0	$0	-395		79	$0	$24
2054	$0	$0	-395		79	$0	$23
2055	$0	$0	-395		79	$0	$22
2056	$0	$0	-395		79	$0	$22
2057	$0	$0	-395		79	$0	$21
2058	$0	$0	-395		79	$0	$20
2059	$0	$0	-395		79	$0	$20
2060	$0	$0	-395		79	$0	$19

PV Cost ($1000)	$4,070	**PV Energy & Capacity ($1000)**	**20 years**	$886
			30 years	$1,226
			40 years	$1,470

	NPV ($1000)	B/C Ratio	Simple Payback Period	Discounted Payback Period
20 years	***-$3,184***	***0.22***	**No Payback**	**No Payback**
30 years	***-$2,844***	***0.30***		
40 years	***-$2,600***	***0.36***		

Table 3-1A

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	3-1A	
Syslem load =	Scenario 1	
Whitehorse Generating Unit Status		
- WH1 =	Existing	
- WH2 =	Existing	
- WH3 =	Existing	
- WH4 =	Efficiency Improvement	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	2,300,000	($)
Capital cost distribution:		
- Year 1 =	10	(%)
- Year 2 =	40	(%)
- Year 3 =	50	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$230	$230	0		0	$0	$0
2018	$920	$890	0		0	$0	$0
2019	$1,150	$1,076	1,040		-208	$0	-$195
2020	$0	$0	-395		79	$0	$72
2021	$0	$0	-395		79	$0	$69
2022	$0	$0	-395		79	$0	$67
2023	$0	$0	-395		79	$0	$65
2024	$0	$0	-395		79	$0	$63
2025	$0	$0	-395	0.050	79	-$125	-$35
2026	$0	$0	-395		79	$0	$59
2027	$0	$0	-395		79	$0	$57
2028	$0	$0	-395		79	$0	$55
2029	$0	$0	-395		79	$0	$53
2030	$0	$0	-395		79	$0	$51
2031	$0	$0	-395		79	$0	$50
2032	$0	$0	-395		79	$0	$48
2033	$0	$0	-395		79	$0	$46
2034	$0	$0	-395		79	$0	$45
2035	$0	$0	-395		79	$0	$43
2036	$0	$0	-395		79	$0	$42
2037	$0	$0	-395		79	$0	$41
2038	$0	$0	-395		79	$0	$39
2039	$0	$0	-395		79	$0	$38
2040	$0	$0	-395		79	$0	$37
2041	$0	$0	-395		79	$0	$36
2042	$0	$0	-395		79	$0	$34
2043	$0	$0	-395		79	$0	$33
2044	$0	$0	-395		79	$0	$32
2045	$0	$0	-395		79	$0	$31
2046	$0	$0	-395		79	$0	$30
2047	$0	$0	-395		79	$0	$29
2048	$0	$0	-395		79	$0	$28
2049	$0	$0	-395		79	$0	$27
2050	$0	$0	-395		79	$0	$26
2051	$0	$0	-395		79	$0	$26
2052	$0	$0	-395		79	$0	$25
2053	$0	$0	-395		79	$0	$24
2054	$0	$0	-395		79	$0	$23
2055	$0	$0	-395		79	$0	$22
2056	$0	$0	-395		79	$0	$22
2057	$0	$0	-395		79	$0	$21
2058	$0	$0	-395		79	$0	$20
2059	$0	$0	-395		79	$0	$20
2060	$0	$0	-395		79	$0	$19

PV Cost ($1000)	$2,196	**PV Energy & Capacity ($1000)**	**20 years**	$694
			30 years	$1,034
			40 years	$1,278

	NPV ($1000)	B/C Ratio	Simple Payback Period	Discounted Payback Period
20 years	***-$1,502***	***0.32***	**37 yrs**	**No Payback**
30 years	***-$1,162***	***0.47***		
40 years	***-$918***	***0.58***		

Table 4-1

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	4-1	
Syslem load =	Scenario 1	
Whitehorse Generating Unit Status		
- WH1 =	Increased Turbine Flow	
- WH2 =	Existing	
- WH3 =	Existing	
- WH4 =	Existing	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	4,781,700	($)
Capital cost distribution:		
- Year 1 =	45	(%)
- Year 2 =	55	(%)
- Year 3 =	0	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$2,152	$2,152	0		0	$0	$0
2018	$2,630	$2,544	197		-39	$0	-$38
2019	$0	$0	-488		98	$0	$91
2020	$0	$0	-488		98	$0	$88
2021	$0	$0	-488		98	$0	$85
2022	$0	$0	-488		98	$0	$83
2023	$0	$0	-488		98	$0	$80
2024	$0	$0	-488		98	$0	$77
2025	$0	$0	-488	0.150	98	$375	$362
2026	$0	$0	-488		98	$0	$72
2027	$0	$0	-488		98	$0	$70
2028	$0	$0	-488		98	$0	$68
2029	$0	$0	-488		98	$0	$65
2030	$0	$0	-488		98	$0	$63
2031	$0	$0	-488		98	$0	$61
2032	$0	$0	-488		98	$0	$59
2033	$0	$0	-488		98	$0	$57
2034	$0	$0	-488		98	$0	$55
2035	$0	$0	-488		98	$0	$54
2036	$0	$0	-488		98	$0	$52
2037	$0	$0	-488		98	$0	$50
2038	$0	$0	-488		98	$0	$49
2039	$0	$0	-488		98	$0	$47
2040	$0	$0	-488		98	$0	$45
2041	$0	$0	-488		98	$0	$44
2042	$0	$0	-488		98	$0	$43
2043	$0	$0	-488		98	$0	$41
2044	$0	$0	-488		98	$0	$40
2045	$0	$0	-488		98	$0	$38
2046	$0	$0	-488		98	$0	$37
2047	$0	$0	-488		98	$0	$36
2048	$0	$0	-488		98	$0	$35
2049	$0	$0	-488		98	$0	$34
2050	$0	$0	-488		98	$0	$33
2051	$0	$0	-488		98	$0	$32
2052	$0	$0	-488		98	$0	$30
2053	$0	$0	-488		98	$0	$29
2054	$0	$0	-488		98	$0	$29
2055	$0	$0	-488		98	$0	$28
2056	$0	$0	-488		98	$0	$27
2057	$0	$0	-488		98	$0	$26
2058	$0	$0	-488		98	$0	$25
2059	$0	$0	-488		98	$0	$24
2060	$0	$0	-488		98	$0	$23

PV Cost ($1000)	$4,696	**PV Energy & Capacity ($1000)**	**20 years**	$1,606
			30 years	$2,012
			40 years	$2,304

	NPV	B/C Ratio	Simple Payback Period	Discounted Payback Period
20 years	***-$3,090***	***0.34***	**No Payback**	**No Payback**
30 years	***-$2,684***	***0.43***		
40 years	***-$2,392***	***0.49***		

Table 4-1A

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	4-1A	
Syslem load =	Scenario 1	
Whitehorse Generating Unit Status		
- WH1 =	Increased Turbine Flow	
- WH2 =	Existing	
- WH3 =	Existing	
- WH4 =	Existing	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	2,739,000	($)
Capital cost distribution:		
- Year 1 =	45	(%)
- Year 2 =	55	(%)
- Year 3 =	0	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$1,233	$1,233	0		0	$0	$0
2018	$1,506	$1,457	197		-39	$0	-$38
2019	$0	$0	-488		98	$0	$91
2020	$0	$0	-488		98	$0	$88
2021	$0	$0	-488		98	$0	$85
2022	$0	$0	-488		98	$0	$83
2023	$0	$0	-488		98	$0	$80
2024	$0	$0	-488		98	$0	$77
2025	$0	$0	-488	0.150	98	$375	$362
2026	$0	$0	-488		98	$0	$72
2027	$0	$0	-488		98	$0	$70
2028	$0	$0	-488		98	$0	$68
2029	$0	$0	-488		98	$0	$65
2030	$0	$0	-488		98	$0	$63
2031	$0	$0	-488		98	$0	$61
2032	$0	$0	-488		98	$0	$59
2033	$0	$0	-488		98	$0	$57
2034	$0	$0	-488		98	$0	$55
2035	$0	$0	-488		98	$0	$54
2036	$0	$0	-488		98	$0	$52
2037	$0	$0	-488		98	$0	$50
2038	$0	$0	-488		98	$0	$49
2039	$0	$0	-488		98	$0	$47
2040	$0	$0	-488		98	$0	$45
2041	$0	$0	-488		98	$0	$44
2042	$0	$0	-488		98	$0	$43
2043	$0	$0	-488		98	$0	$41
2044	$0	$0	-488		98	$0	$40
2045	$0	$0	-488		98	$0	$38
2046	$0	$0	-488		98	$0	$37
2047	$0	$0	-488		98	$0	$36
2048	$0	$0	-488		98	$0	$35
2049	$0	$0	-488		98	$0	$34
2050	$0	$0	-488		98	$0	$33
2051	$0	$0	-488		98	$0	$32
2052	$0	$0	-488		98	$0	$30
2053	$0	$0	-488		98	$0	$29
2054	$0	$0	-488		98	$0	$29
2055	$0	$0	-488		98	$0	$28
2056	$0	$0	-488		98	$0	$27
2057	$0	$0	-488		98	$0	$26
2058	$0	$0	-488		98	$0	$25
2059	$0	$0	-488		98	$0	$24
2060	$0	$0	-488		98	$0	$23

PV Cost ($1000)	$2,690	**PV Energy & Capacity ($1000)**	**20 years**	$1,606
			30 years	$2,012
			40 years	$2,304

	NPV	B/C Ratio	Simple Payback Period	Discounted Payback Period
20 years	***-$1,084***	***0.60***	**27 yrs**	**No Payback**
30 years	***-$678***	***0.75***		
40 years	***-$386***	***0.86***		

Table 4-4

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	4-4	
Syslem load =	Scenario 4	
Whitehorse Generating Unit Status		
- WH1 =	Existing	
- WH2 =	Existing	
- WH3 =	Existing	
- WH4 =	Efficiency Improvement	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	4,781,700	($)
Capital cost distribution:		
- Year 1 =	10	(%)
- Year 2 =	40	(%)
- Year 3 =	50	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$478	$478	0		0	$0	$0
2018	$1,913	$1,850	254		-51	$0	-$49
2019	$2,391	$2,237	-488		98	$0	$91
2020	$0	$0	-1,184		237	$0	$214
2021	$0	$0	-1,879		376	$0	$329
2022	$0	$0	-1,879		376	$0	$318
2023	$0	$0	-1,879		376	$0	$308
2024	$0	$0	-1,879		376	$0	$298
2025	$0	$0	-1,879	0.400	376	$1,000	$1,055
2026	$0	$0	-1,879		376	$0	$279
2027	$0	$0	-1,879		376	$0	$270
2028	$0	$0	-1,879		376	$0	$261
2029	$0	$0	-1,680		336	$0	$226
2030	$0	$0	-1,482		296	$0	$192
2031	$0	$0	-1,283		257	$0	$161
2032	$0	$0	-1,084		217	$0	$132
2033	$0	$0	-885		177	$0	$104
2034	$0	$0	-687		137	$0	$78
2035	$0	$0	-488		98	$0	$54
2036	$0	$0	-488		98	$0	$52
2037	$0	$0	-488		98	$0	$50
2038	$0	$0	-488		98	$0	$49
2039	$0	$0	-488		98	$0	$47
2040	$0	$0	-488		98	$0	$45
2041	$0	$0	-488		98	$0	$44
2042	$0	$0	-488		98	$0	$43
2043	$0	$0	-488		98	$0	$41
2044	$0	$0	-488		98	$0	$40
2045	$0	$0	-488		98	$0	$38
2046	$0	$0	-488		98	$0	$37
2047	$0	$0	-488		98	$0	$36
2048	$0	$0	-488		98	$0	$35
2049	$0	$0	-488		98	$0	$34
2050	$0	$0	-488		98	$0	$33
2051	$0	$0	-488		98	$0	$32
2052	$0	$0	-488		98	$0	$30
2053	$0	$0	-488		98	$0	$29
2054	$0	$0	-488		98	$0	$29
2055	$0	$0	-488		98	$0	$28
2056	$0	$0	-488		98	$0	$27
2057	$0	$0	-488		98	$0	$26
2058	$0	$0	-488		98	$0	$25
2059	$0	$0	-488		98	$0	$24
2060	$0	$0	-488		98	$0	$23

PV Cost ($1000)	$4,565	**PV Energy & Capacity ($1000)**	**20 years**	$4,421
			30 years	$4,841
			40 years	$5,143

	NPV ($1000)	B/C Ratio	Payback Period	Discounted Payback Period
20 years	***-$144***	***0.97***	**14 yrs**	**25 yrs**
30 years	***$276***	***1.06***		
40 years	***$577***	***1.13***		

Table 4-4A

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	4-4A	
Syslem load =	Scenario 4	
Whitehorse Generating Unit Status		
- WH1 =	Existing	
- WH2 =	Existing	
- WH3 =	Existing	
- WH4 =	Efficiency Improvement	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	2,739,000	($)
Capital cost distribution:		
- Year 1 =	10	(%)
- Year 2 =	40	(%)
- Year 3 =	50	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$274	$274	0		0	$0	$0
2018	$1,096	$1,060	254		-51	$0	-$49
2019	$1,370	$1,281	-488		98	$0	$91
2020	$0	$0	-1,184		237	$0	$214
2021	$0	$0	-1,879		376	$0	$329
2022	$0	$0	-1,879		376	$0	$318
2023	$0	$0	-1,879		376	$0	$308
2024	$0	$0	-1,879		376	$0	$298
2025	$0	$0	-1,879	0.400	376	$1,000	$1,055
2026	$0	$0	-1,879		376	$0	$279
2027	$0	$0	-1,879		376	$0	$270
2028	$0	$0	-1,879		376	$0	$261
2029	$0	$0	-1,680		336	$0	$226
2030	$0	$0	-1,482		296	$0	$192
2031	$0	$0	-1,283		257	$0	$161
2032	$0	$0	-1,084		217	$0	$132
2033	$0	$0	-885		177	$0	$104
2034	$0	$0	-687		137	$0	$78
2035	$0	$0	-488		98	$0	$54
2036	$0	$0	-488		98	$0	$52
2037	$0	$0	-488		98	$0	$50
2038	$0	$0	-488		98	$0	$49
2039	$0	$0	-488		98	$0	$47
2040	$0	$0	-488		98	$0	$45
2041	$0	$0	-488		98	$0	$44
2042	$0	$0	-488		98	$0	$43
2043	$0	$0	-488		98	$0	$41
2044	$0	$0	-488		98	$0	$40
2045	$0	$0	-488		98	$0	$38
2046	$0	$0	-488		98	$0	$37
2047	$0	$0	-488		98	$0	$36
2048	$0	$0	-488		98	$0	$35
2049	$0	$0	-488		98	$0	$34
2050	$0	$0	-488		98	$0	$33
2051	$0	$0	-488		98	$0	$32
2052	$0	$0	-488		98	$0	$30
2053	$0	$0	-488		98	$0	$29
2054	$0	$0	-488		98	$0	$29
2055	$0	$0	-488		98	$0	$28
2056	$0	$0	-488		98	$0	$27
2057	$0	$0	-488		98	$0	$26
2058	$0	$0	-488		98	$0	$25
2059	$0	$0	-488		98	$0	$24
2060	$0	$0	-488		98	$0	$23

PV Cost ($1000)	$2,615	**PV Energy & Capacity ($1000)**	**20 years**	$4,421
			30 years	$4,841
			40 years	$5,143

	NPV ($1000)	B/C Ratio	Payback Period	Discounted Payback Period
20 years	***$1,806***	***1.69***	**9 yrs**	**10 yrs**
30 years	***$2,226***	***1.85***		
40 years	***$2,527***	***1.97***		

Table 5-1

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	5-1	
Syslem load =	Scenario 1	
Whitehorse Generating Unit Status		
- WH1 =	Existing	
- WH2 =	Existing	
- WH3 =	Existing	
- WH4 =	Kaplan Runner	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	10,379,325	($)
Capital cost distribution:		
- Year 1 =	45	(%)
- Year 2 =	55	(%)
- Year 3 =	0	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$4,671	$4,671	0		0	$0	$0
2018	$5,709	$5,522	1,308		-262	$0	-$253
2019	$0	$0	-1,583		317	$0	$296
2020	$0	$0	-1,583		317	$0	$287
2021	$0	$0	-1,583		317	$0	$277
2022	$0	$0	-1,583		317	$0	$268
2023	$0	$0	-1,583		317	$0	$259
2024	$0	$0	-1,583		317	$0	$251
2025	$0	$0	-1,583	0.700	317	-$1,750	-$1,099
2026	$0	$0	-1,583		317	$0	$235
2027	$0	$0	-1,583		317	$0	$227
2028	$0	$0	-1,583		317	$0	$220
2029	$0	$0	-1,583		317	$0	$212
2030	$0	$0	-1,583		317	$0	$206
2031	$0	$0	-1,583		317	$0	$199
2032	$0	$0	-1,583		317	$0	$192
2033	$0	$0	-1,583		317	$0	$186
2034	$0	$0	-1,583		317	$0	$180
2035	$0	$0	-1,583		317	$0	$174
2036	$0	$0	-1,583		317	$0	$168
2037	$0	$0	-1,583		317	$0	$163
2038	$0	$0	-1,583		317	$0	$158
2039	$0	$0	-1,583		317	$0	$152
2040	$0	$0	-1,583		317	$0	$147
2041	$0	$0	-1,583		317	$0	$143
2042	$0	$0	-1,583		317	$0	$138
2043	$0	$0	-1,583		317	$0	$133
2044	$0	$0	-1,583		317	$0	$129
2045	$0	$0	-1,583		317	$0	$125
2046	$0	$0	-1,583		317	$0	$121
2047	$0	$0	-1,583		317	$0	$117
2048	$0	$0	-1,583		317	$0	$113
2049	$0	$0	-1,583		317	$0	$109
2050	$0	$0	-1,583		317	$0	$106
2051	$0	$0	-1,583		317	$0	$102
2052	$0	$0	-1,583		317	$0	$99
2053	$0	$0	-1,583		317	$0	$96
2054	$0	$0	-1,583		317	$0	$93
2055	$0	$0	-1,583		317	$0	$90
2056	$0	$0	-1,583		317	$0	$87
2057	$0	$0	-1,583		317	$0	$84
2058	$0	$0	-1,583		317	$0	$81
2059	$0	$0	-1,583		317	$0	$78
2060	$0	$0	-1,583		317	$0	$76

PV Cost ($1000)	$10,193	**PV Energy & Capacity ($1000)**	**20 years**	$2,648
			30 years	$4,011
			40 years	$4,988

	NPV	B/C Ratio	Simple Payback Period	Discounted Payback Period
20 years	***-$7,544***	***0.26***	**42 yrs**	**No Payback**
30 years	***-$6,182***	***0.39***		
40 years	***-$5,205***	***0.49***		

Table 5-4

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	5-4	
Syslem load =	Scenario 4	
Whitehorse Generating Unit Status		
- WH1 =	Existing	
- WH2 =	Existing	
- WH3 =	Existing	
- WH4 =	Kaplan Runner	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	10,379,325	($)
Capital cost distribution:		
- Year 1 =	45	(%)
- Year 2 =	55	(%)
- Year 3 =	0	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$4,671	$4,671	0		0.0	$0	$0.0
2018	$5,709	$5,522	1,692		-338.5	$0	-$327.4
2019	$0	$0	-1,583		316.6	$0	$296.2
2020	$0	$0	-2,802		560.3	$0	$507.1
2021	$0	$0	-4,020		804.0	$0	$703.9
2022	$0	$0	-4,020		804.0	$0	$680.9
2023	$0	$0	-4,020		804.0	$0	$658.6
2024	$0	$0	-4,020		804.0	$0	$637.1
2025	$0	$0	-4,020	1.000	804.0	$2,500	$2,532.5
2026	$0	$0	-4,020		804.0	$0	$596.1
2027	$0	$0	-4,020		804.0	$0	$576.6
2028	$0	$0	-4,020		804.0	$0	$557.8
2029	$0	$0	-3,672		734.4	$0	$492.8
2030	$0	$0	-3,324		664.7	$0	$431.5
2031	$0	$0	-2,976		595.1	$0	$373.7
2032	$0	$0	-2,627		525.5	$0	$319.2
2033	$0	$0	-2,279		455.9	$0	$267.8
2034	$0	$0	-1,931		386.2	$0	$219.5
2035	$0	$0	-1,583		316.6	$0	$174.0
2036	$0	$0	-1,583		316.6	$0	$168.4
2037	$0	$0	-1,583		316.6	$0	$162.8
2038	$0	$0	-1,583		316.6	$0	$157.5
2039	$0	$0	-1,583		316.6	$0	$152.4
2040	$0	$0	-1,583		316.6	$0	$147.4
2041	$0	$0	-1,583		316.6	$0	$142.6
2042	$0	$0	-1,583		316.6	$0	$137.9
2043	$0	$0	-1,583		316.6	$0	$133.4
2044	$0	$0	-1,583		316.6	$0	$129.0
2045	$0	$0	-1,583		316.6	$0	$124.8
2046	$0	$0	-1,583		316.6	$0	$120.7
2047	$0	$0	-1,583		316.6	$0	$116.8
2048	$0	$0	-1,583		316.6	$0	$113.0
2049	$0	$0	-1,583		316.6	$0	$109.3
2050	$0	$0	-1,583		316.6	$0	$105.7
2051	$0	$0	-1,583		316.6	$0	$102.3
2052	$0	$0	-1,583		316.6	$0	$98.9
2053	$0	$0	-1,583		316.6	$0	$95.7
2054	$0	$0	-1,583		316.6	$0	$92.5
2055	$0	$0	-1,583		316.6	$0	$89.5
2056	$0	$0	-1,583		316.6	$0	$86.6
2057	$0	$0	-1,583		316.6	$0	$83.8
2058	$0	$0	-1,583		316.6	$0	$81.0
2059	$0	$0	-1,583		316.6	$0	$78.4
2060	$0	$0	-1,583		316.6	$0	$75.8

PV Cost ($1000)	$10,193	**PV Energy & Capacity ($1000)**	**20 years**	$10,029
			30 years	$11,392
			40 years	$12,369

	NPV ($1000)	B/C Ratio	Payback Period	Discounted Payback Period
20 years	***-$164***	***0.98***	**14 yrs**	**23 yrs**
30 years	***$1,199***	***1.12***		
40 years	***$2,176***	***1.21***		

Table 6-1

Whitehorse Turbine Uprate Study Project
Economic Analysis
R1 Feb 23, 2017

Uprate option =	6	
Syslem load =	Scenario 1	
Whitehorse Generating Unit Status		
- WH1 =	Efficiency Improvement	
- WH2 =	Efficiency Improvement	
- WH3 =	Existing	
- WH4 =	Existing	
Value of diesel/LNG energy offset =	200	($ per MWh)
Value of added LNG capacity offset =	2,500,000	($ per MW)
Uprate capital cost =	1,986,050	($ per turbine)
Capital cost distribution:		
- Year 1 =	45	(%)
- Year 2 =	100	(%)
- Year 3 =	55	(%)
Discount rate =	3.38	(%)

Year	Capital Expediture ($ 1,000)	PV Cap. Exp. ($ 1,000)	Incremental Thermal Gen. (MWh)	Reduced Added Cap. (MW)	Energy Cost Saving ($ 1,000)	Capital Cost Saving ($ 1,000)	PV Cost Saving ($ 1,000)
2017	$894	$894	0		0	$0	$0
2018	$1,986	$1,921	220		-44	$0	-$42
2019	$1,092	$1,022	-178		36	$0	$33
2020	$0	$0	-795		159	$0	$144
2021	$0	$0	-795		159	$0	$139
2022	$0	$0	-795		159	$0	$135
2023	$0	$0	-795		159	$0	$130
2024	$0	$0	-795		159	$0	$126
2025	$0	$0	-795	0.090	159	$225	$294
2026	$0	$0	-795		159	$0	$118
2027	$0	$0	-795		159	$0	$114
2028	$0	$0	-795		159	$0	$110
2029	$0	$0	-795		159	$0	$107
2030	$0	$0	-795		159	$0	$103
2031	$0	$0	-795		159	$0	$100
2032	$0	$0	-795		159	$0	$97
2033	$0	$0	-795		159	$0	$93
2034	$0	$0	-795		159	$0	$90
2035	$0	$0	-795		159	$0	$87
2036	$0	$0	-795		159	$0	$85
2037	$0	$0	-795		159	$0	$82
2038	$0	$0	-795		159	$0	$79
2039	$0	$0	-795		159	$0	$77
2040	$0	$0	-795		159	$0	$74
2041	$0	$0	-795		159	$0	$72
2042	$0	$0	-795		159	$0	$69
2043	$0	$0	-795		159	$0	$67
2044	$0	$0	-795		159	$0	$65
2045	$0	$0	-795		159	$0	$63
2046	$0	$0	-795		159	$0	$61
2047	$0	$0	-795		159	$0	$59
2048	$0	$0	-795		159	$0	$57
2049	$0	$0	-795		159	$0	$55
2050	$0	$0	-795		159	$0	$53
2051	$0	$0	-795		159	$0	$51
2052	$0	$0	-795		159	$0	$50
2053	$0	$0	-795		159	$0	$48
2054	$0	$0	-795		159	$0	$46
2055	$0	$0	-795		159	$0	$45
2056	$0	$0	-795		159	$0	$43
2057	$0	$0	-795		159	$0	$42
2058	$0	$0	-795		159	$0	$41
2059	$0	$0	-795		159	$0	$39
2060	$0	$0	-795		159	$0	$38

PV Cost ($1000)	$3,837	**PV Energy & Capacity ($1000)**	**20 years**	$2,224
			30 years	$2,886
			40 years	$3,361

	NPV ($1000)	B/C Ratio	Simple Payback Period	Discounted Payback Period
20 years	***-$1,613***	***0.58***	**27 yrs**	**No Payback**
30 years	***-$951***	***0.75***		
40 years	***-$476***	***0.88***		

Appendix G
Photos

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Photo 1 – WH0 Powerhouse

Photo 2 – WH0 Powerhouse (Main Exciters of WH2 in Foreground and WH3 in Background)

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Photo 3 – WH3 Generator

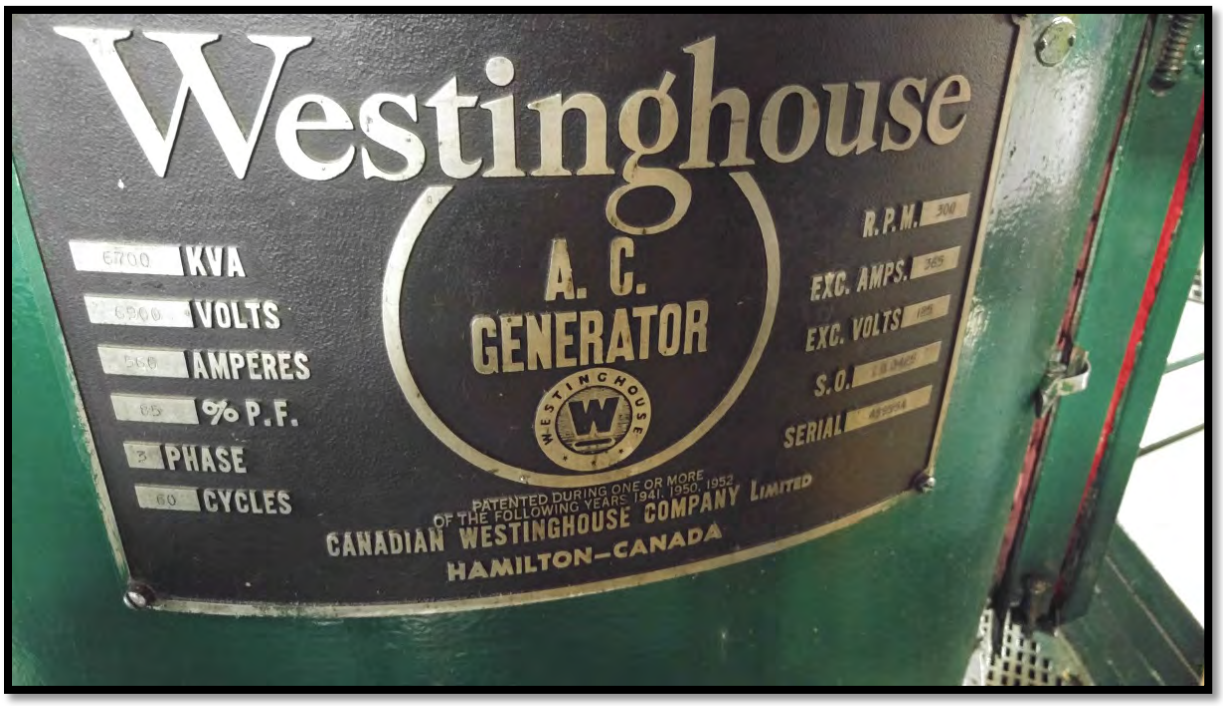

Photo 4 – WH1 Generator Nameplate

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Photo 5 – WH1 Generator Underside

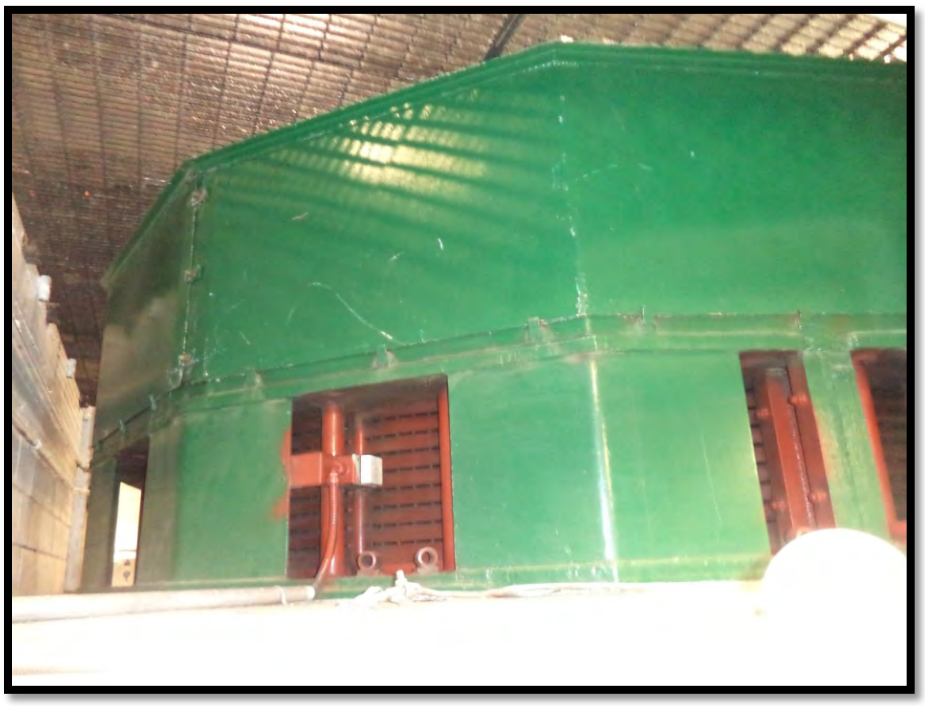

Photo 6 – WH1 Generator Stator Frame

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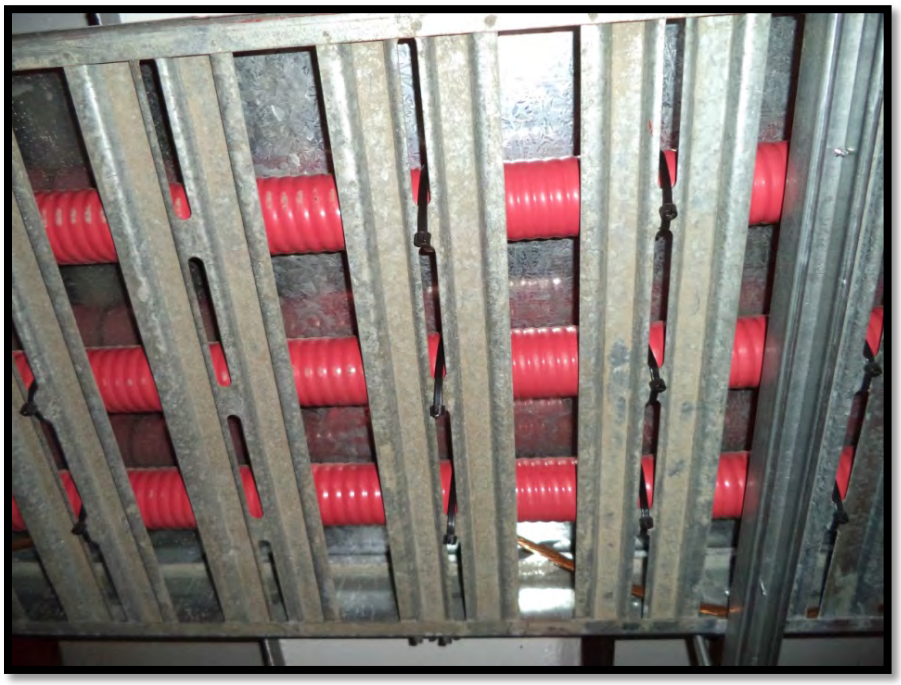

Photo 7 – WH1 Generator Leads

Photo 8 – WH1 Main Exciter (DC Generator) Nameplate

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Photo 9 – WH1 Neutral Grounding Resistor

Photo 10 – WH1 Turbine Nameplate

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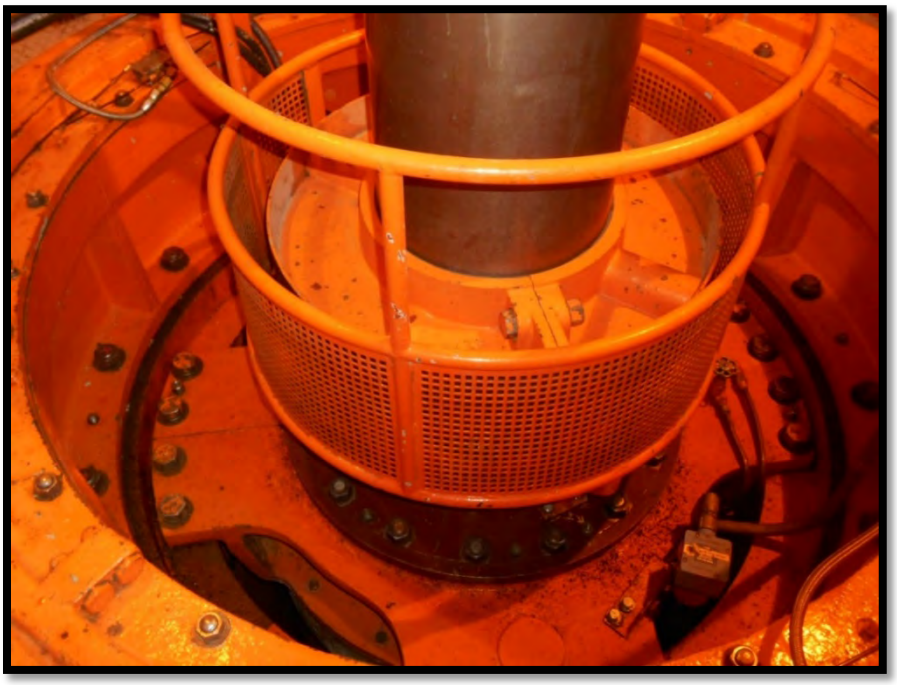

Photo 11 – WH1 Turbine

Photo 12 – WH1 Governor

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Photo 13 – WH1, WH2 and WH3 Generator Control Panels

Photo 14 – WH1, WH2 and WH3 Medium Voltage (6.9 kV) Switchgear

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Photo 15 – WH0 600 V Motor Control Center

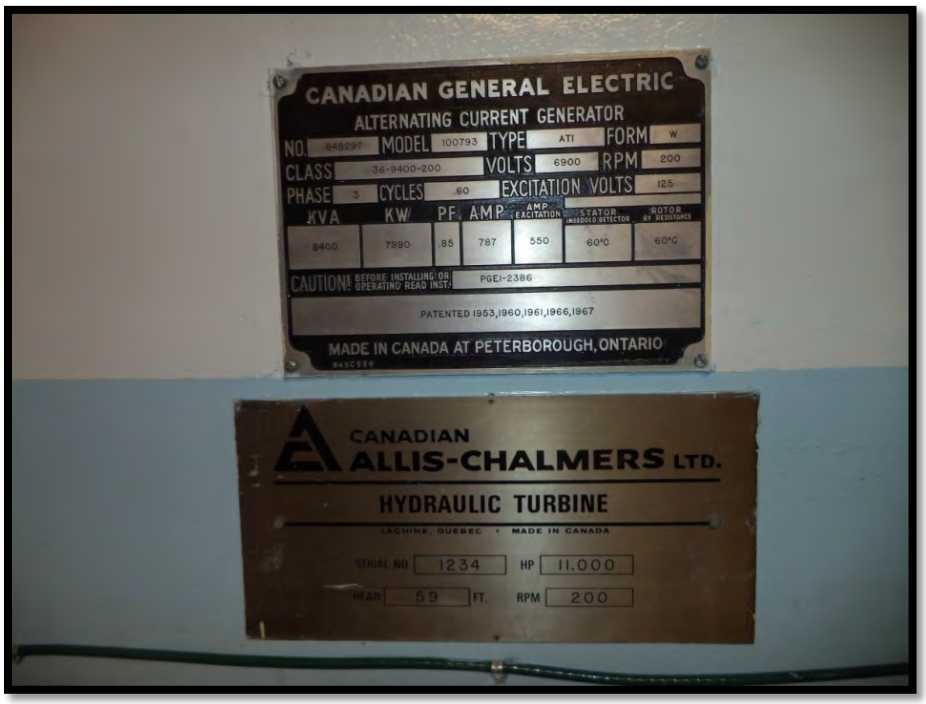

Photo 16 – WH3 Generator and Turbine Nameplate

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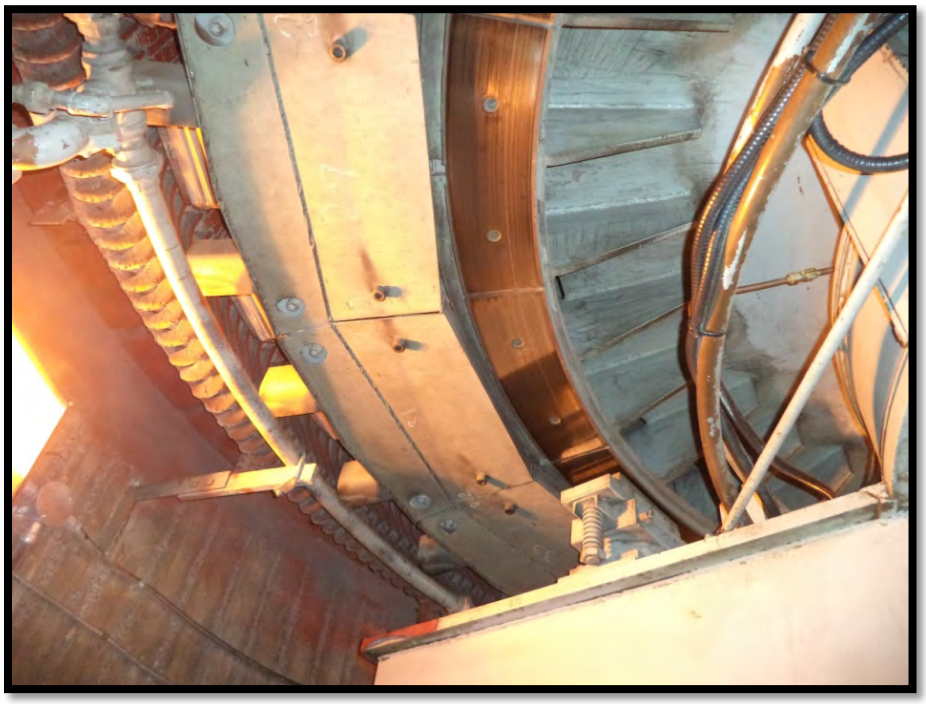

Photo 17 – WH3 Generator Underside

Photo 18 – WH3 Stator Coils and Rotor Poles

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Photo 19 – WH3 Exciter Nameplate

Photo 20 – WH3 Neutral Grounding Resistor

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Photo 21 – WH3 Turbine

Photo 22 – WH3 Governor

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Photo 23 – Dam and WH4 Powerhouse

Photo 24 – W4 Powerhouse with Spillway in Background

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Photo 25 – WH4 Generator Nameplate

Photo 26 – WH4 Generator Leads

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Photo 27 – WH4 Excitation System

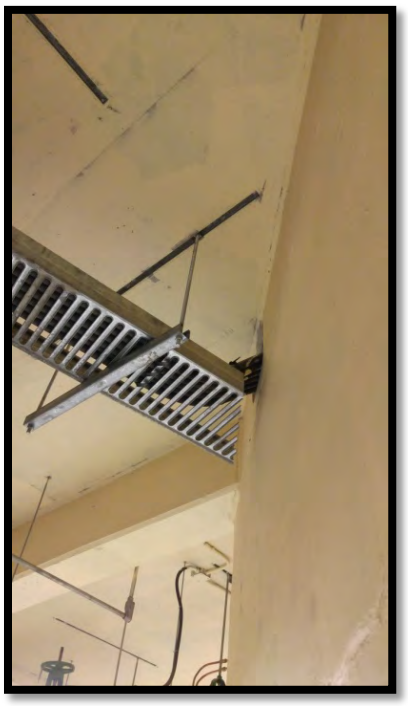

Photo 28 – WH4 Field Leads

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Photo 29 – WH4 Neutral Grounding Resistor

Photo 30 – WH4 Generator Control Panel

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Photo 31 – WH4 Medium Voltage (6.9 kV) Switchgear

Photo 32 – WH3 Motor Control Center

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Photo 33 – WH4 Turbine Nameplate

Photo 34 – WH4 Turbine

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Photo 35 – WH4 Governor (Interior of Cabinet)

Photo 36 – WH4 Draft Tube Door

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REFERENCE: **Application, Tab 5.2.1.10, pages 5-19**

ISSUE: **WH4 Uprate – Servomotor Replacement Project**

QUOTE: "The project involves detailed design, procurement and installation of two new Servomotors for Whitehorse Hydro Unit 4 (WH4) wicket gate operation. Implementation will increase the output of the WH4 unit by allowing full range of operation of the wicket gates; this enhancement adds additional hydraulic generation of 0.9 GWh/year."

"Contracts with [ANDRITZ Hydro] (OEM), L&S Electric (to review documentation and develop a governor commissioning plan) and Hatch (owners engineer) have been finalized. Procurement has not yet been undertaken for testing services and installation of a lifting device."

"Final design is nearing completion and manufacturing is expected to commence in Q3 2020 … Delivery of the Servos is expected by January 2021. Contractor mobilization and installation, testing and commissioning is expected to occur in June 2021. The project is expected to be in service in June 2021."

QUESTION:

a) Please indicate the year in which the existing servomotors were installed and the expected service life at the time of installation.

b) Please explain why YEC decided to pursue this project. For example, were there reliability issues with the existing servomotors? Did the existing servomotors cause reliability issues with WH4? If outages were experienced at WH4 due to the servomotors, please provide the number and duration of outages in the last 10 years, on a per annum basis, and the costs incurred due to these outages.

c) If there were reliability issues with the servomotors, please explain how often YEC carried out tests in the past to assess reliability of the servomotors. If possible, please provide the number of times maintenance was conducted on the servomotors in the last 10 years, on a per annum basis, and the cost of this maintenance work.

d) Please explain how the enhancement proposed in this project adds additional hydraulic generation.

e) Please provide details on the selection process of contractors (specifically ANDRITIZ Hydro, L&S Electric and Hatch) for this project, including how contracts were awarded for this project.

f) Please provide an update on the work currently completed for this project. Is YEC currently on schedule with this project? For example, has final design and manufacturing been completed and is the project still expected to be in service in June 2021?

ANSWER:

(a)

Servo motors are original (1984). The expected service life at time of installation is not known.

(b)

Yukon Energy's (YEC) 10 Year Renewable Electricity Plan has confirmed that the Corporation faces an existing and forecast shortfall in renewable energy until such time that significant new sources of supply are sourced from the Atlin Hydro Expansion and the Moon Lake Pump Storage projects.

A number of smaller scale supply projects, including the replacement of servo-motors on YEC's Whitehorse Hydro #4 (WH4) hydro unit (also referred to as the 'WH4 Uprating Project') are included in the 10 Year Renewable Electricity Plan, in order to provide incremental sources of renewable energy in the short to medium term. The primary benefit of the project is a 0.8 MW increase in maximum output of WH4, resulting in an estimated gain in energy production of 0.9 GWh/yr. at average hydro conditions. The estimated Levelized Cost of Energy (LCOE) of this energy gain is $0.065/kWh under the base case load forecast, and $0.051/kWh under the high load case. This project LCOE compares favourably to the economics of both existing and new thermal and renewable generation options. Secondary benefits include reduced stress levels in the servo-motors, governor and wickets gates/operating ring which will increase reliability and safety during operation.

(c)

The current servo motors were not meeting IEEE code in terms of operation and reliability.

The servo motor is a hydraulic ram that requires little maintenance other than oil and filter changes. The issue with the servo motor on WH4 is not related to frequent failures. The servo is not capable (underpowered) enough to allow the hydro unit to operate at 100% gate opening. The unit if brought to 100% gate opening would be unable to close the wicket gates.

(d)

YEC's WH4 unit is currently limited to 92% gate opening as a result of undersized servo-motors. This limitation results in a reduction of the unit output as compared to the nameplate rating. The proposed project involves replacement of the servo-motors with spring assisted servo-motors that will augment the force provided by the high pressure hydraulic unit (HPU) and overcome the gate stalling issue experienced beyond 92% stroke. The governor gate position limiter will be removed and the WH4 unit will be re-commissioned with the capability to operate at 100% gate opening. The ability to operate at %100 gate opening will increase Energy and Capacity of the unit.

(e)

ANDRITZ Hydro and L&S were selected because they are the Original Equipment Manufacturers (OEM) for the equipment. The OEMs have all proprietary drawings, manuals and expert / familiar staff to perform the modifications that other manufacturers simply would not have. Hatch was selected through an RFP process.

(f)

Final design and manufacturing are complete and the project is expected to be completed by June 2021.

REFERENCE: **Application, Tab 5.3.1, pages 5-21 to 5-25 and 5-35 to 5-42**

ISSUE: **Costs for Deferred Projects Greater Than $1 Million**

PREAMBLE: In this section of its application, YEC outlined the costs for the Aishihik Generating Station Three-Year Licence Renewal and Demand Side Management projects, which were deferred projects incurring costs greater than $1 million. For the Aishihik Generating Station Three Year Licence Renewal Project, YEC indicated that it spent $0.805 million in 2019 and $0.200 million in 2020. For the Demand Side Management Project, YEC indicated that it spent $0.833 million in 2019, forecasted spending $0.375 million in 2020 and forecasted spending $0.894 million in 2021. YEC stated that it reflected these costs in Tables 5.3 to 5.6 in its application, found from pages 5-35 to 5-42. It is not clear how YEC allocated these costs over the previous years and how it plans to allocate these costs in its forecasted years.

QUESTION:

a) Regarding the Aishihik Generating Station Three-Year Licence Renewal Project, please provide a cost breakdown of the $0.805 million and $0.200 million spent in 2019 and 2020 respectively. More specifically, provide the activities conducted and then the cost amount allocated to each activity.

b) Regarding the Demand Side Management Project, please provide:

   i. a cost breakdown of the $0.833 million spent in 2019, a description the activities conducted and the cost amount allocated to each activity; and

   ii. a cost breakdown of forecasted spending on $0.375 million and $0.894 million in 2020 and 2021 respectively, a description of the activities YEC forecasts to conduct and the cost amount allocated to each activity.

ANSWER:

(a)

Please see Table 1 below.

Table 1: Aishihik Generating Station Three-Year Licence Renewal Project Costs

Year	Description	Cost
2019	Compensation-related activities including negotiating compensation with claimants pursuant to the Waters Act and legal support for negotiations	$127,325
2019	Project Management	$125,631
2019	Conducting impact assessment for YESAA Project Proposal	$21,607
2019	Conducting baseline studies and early monitoring in support of development of YESAA Project Proposal and MAMP	$62,144
2019	Assessment and review process activities, including: Development of YESAA Project Proposal, submission of Project Proposal to Designated Office and all activities supporting path through assessment process (e.g. interrogatories), Preparation of Yukon Water Board Application and DFO Fisheries Act Authorizations.	$368,061
2019	Stakeholder Engagement activities, including capacity funding of CAFN for technical review and participation in project activities	$99,704
2019	Accrual of AFUDC	$122
	Total 2019:	**$804,593**
2020	Project Management	$11,445
2020	Assessment and review process activities, including: Yukon Water Board hearing and DFO Fisheries Act Authorizations, activities to complete these processes.	$89,819
2020	Compensation payments under the Yukon Waters Act for the 3-year License Period	$8,700
2020	Accrual of AFUDC	$2,314
	Total 2020:	**$ 112,278**

(b)

(i)

Breakdown of $832,906 costs spent in 2019:

- $385,009 DSM Program Design.

- $433,612 Residential Demand Response Pilot (gross cost; contributions of $365,315 received and separately noted in Table 5.4).

- $14, 285 inCharge maintenance.

(ii)

In 2020, YEC planned to complete the design of a new portfolio of DSM programs as well as incur costs to administer the Residential Demand Response Pilot. The DSM 2020 program was delayed and actual 2020 costs were therefore lower than forecast in the Application. The actual 2020 DSM costs are broken out as follows:

- $571,901 Residential Demand Response Pilot (gross cost; contributions of $488,932 received and recorded as offset to project costs).

- $8,576 HPS light disposal and inCharge admin.

- Total Net Project Cost $91,545.

In 2021, YEC planned to implement the new portfolio of DSM programs as well as continuing the administration of the Residential Demand Pilot. The forecast costs for 2021 have been updated as required, given delays in the program starting in 2020.

The table below provides breakdown for the updated cost for 2021.

Demand Side Management		
DSM Administration	$	25,000
New Program Design Completion	$	300,000
New Program Implementation	$	240,000
Energy Management Tracking	$	-
Peak Smart Pilot (Gross Costs)	$	250,000
Total Gross Project Cost	**$**	**815,000**
Contributions (PeakSmart funding)	$	*(215,000)*
Total Net Project Cost	**$**	**600,000**

Net of contributions, the updated costs for 2020/2021 are $691.545 as compared with $904,000 in the Application.

REFERENCE: **Application, Tab 5.3.1.2, page 5-23, line 14; Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy, page 45**

ISSUE: **Demand Side Management (DSM)**

QUOTE: From page 5-23 of the Application:

"Since that determination the Yukon Government has put in place a Climate Change policy initiative called "Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy" which emphasizes the importance of DSM as a valuable resource to reduce the Yukon's energy and capacity requirements. As part of that policy the government fully expects YEC to pursue a cost-effective DSM program." (footnote removed)

From page 45 of Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy:

"ACTIONS
H26. Provide direction to the Yukon Utilities Board in 2020 to allow Yukon's public utilities to partner with the Government of Yukon to pursue cost-effective demand-side management measures (YDC)

H27. Establish a partnership between the Government of Yukon, YEC Corporation and ATCO Electric Yukon by 2021 that will collaborate on the delivery of energy and capacity demand-side management programs (EMR & YEC)"

QUESTION:

a) Please provide copies of any written communication from the Yukon Government directing YEC to deliver DSM programs.

b) Please provide references to any act, regulation or order in council since the Board issued Order 2018-10 directing YEC to deliver DSM programs or directing the Board to allow YEC to recover the costs of such programs through its rates.

ANSWER:

(a) and **(b)**

Please see OIC 2021-16 which added section 10 to OIC 1995/90, and response to YUB-YEC-1-46 (a to f).

REFERENCE: **Application, Tab 5.3.1.2, page 5-24, line 18**

ISSUE: **Pilot DSM Program**

QUOTE: "YEC faces a capacity shortage under the single contingency (N-1) planning criterion. With this capacity planning context, and mindful of the policy context outlined in the Yukon Government's Climate change strategy, YEC has pursued a pilot program testing internet connected, wifi enabled demand response technology designed to control residential baseboard and hot water heating during winter peak periods to help reduce system peak and reduce reliance on thermal generation such as diesel or natural gas.

The objective of the program is to: evaluate the technical feasibility of the demand response technology; model and test the peak shifting effect of the pilot; test the reliability of the peak shifting effects of the pilot; and evaluate customer acceptance of the demand response events.

The project is managed by YEC with funding support from Atco Electric Yukon (AEY), Yukon Development Corporation (YDC) and Natural Resources Canada (NRCan). Project expenditures of $0.809 million ($0.434 million in 2019 and $0.375 million in 2020) are to be included in rate base, offset by contributions of $0.365 million in 2019, are amortized over 10 years."

QUESTION:

a) Please provide a detailed description of the components of this pilot project. For example, in which areas of Yukon is the project being conducted, and how many customers are included in the pilot? Please provide the forecasted and actual costs to date allocated to each component.

b) Please provide details of the funding amounts provided by AEY, YDC and NRCan, including a description of how YEC and AEY determined the relative amounts to be contributed by each party.

c) Please provide the information and assumptions on which this pilot project is based, including but not limited to:

i. quantity of and electrical demand of the installed water heaters;

ii. percentage of water heaters that could be taking part in the final project;

iii. estimated demand of the water heaters during peak demand periods;

iv. average lifespan of water heaters being used in the pilot program compared to the typical household water heater;

v. the cost of the equipment, including installation cost, included in the pilot;

vi. description of any incentives offered to the participating ratepayers;

vii. potential security concerns for participants' wireless internet systems and measures being implemented to address those concerns; and

viii. estimated frequency and duration of disconnections or service calls resulting from the new equipment and YEC's proposed measures to manage such events.

d) Please provide any analysis carried out by YEC or its program partners comparing the proposed program to direct incentives paid to customers who take their own steps to reduce demand or shift peak demand. If no such analysis has been done, please explain why.

e) Please provide the results of analysis performed by YEC or its program partners examining the costs and benefits of the project relative to any alternatives considered.

ANSWER:

(a)

The Residential Demand Response Pilot will install internet-connected, wifi-enabled electric baseboard thermostats and hot water tank controllers in the homes of residential

electrical customers anywhere on the Yukon Integrated System. The thermostats and hot water tank controllers will be used to temporarily lower the temperature set-point of the homes heat and hot water during a period of peak demand to lower the demand on the grid.

1000 thermostats and 400 hot water tank controllers will be installed as part of the pilot across 400 Yukon residences.
The actual costs to the end of 2020 are $269K in equipment, $149K in labour, $512 in professional services and $8K in expenses. The forecast remaining costs to complete the pilot are $68K labour and $414 professional services, including ongoing licensing and support.

(b)

AEY is providing $300,000, YDC is providing $250,000 and NRCan is providing $650,000. The funding amounts with AEY and YDC were reached through discussion with these organizations. NRCan offers up to 50% of eligible costs in for the demonstration stream of their Smart Grid funding stream.

(c)

(i)

Controllers are being installed on 400 hot water tanks as part of this pilot. The electrical demand of a standard residential hot water tank is estimated to be an average of 4.5kW/unit.

(ii)

No projection has been made as to how many total hot water tanks could take part if this pilot is transitioned into a full program.

(iii)

As the heating elements of the 400 hot water tanks participating in the pilot are at various stages of heating, it is assumed that these tanks would contribute 400kW to the peak demand (1kW/unit).

(iv)

Controllers are being installed on customers' existing typical hot water tanks. Accordingly, the average lifespan of the hot water tanks in the program are the same as a typical hot water tank. YEC does not have detailed data on this expected lifespan at this time.

(v)

The total cost of equipment for this pilot is $269,000 and installation costs are $134,000.

(vi)

There are no financial incentives being paid to participants of the pilot.

(vii)

There was a potential security concern that records of a participant's hot water use and heating could be accessed and constitute a personal privacy breach. For this reason, the supplier of the controllers used in the pilot program were evaluated on the cyber security of their systems and care has been taken to protect any personal information of participants in the program design.

(viii)

It is expected that service calls or disconnections of a customer's heating or hot water are extremely infrequent. In the case that a participant experiences a heating or hot water emergency, a local electrical contractor is kept on retainer to respond. Participants are provided with the contractor's contact information as part of the program.

(d)

This particular pilot was pursued by YEC due to the funding opportunities from NRCan, AEY and YDC largely offsetting the program costs, enabling learnings from the pilot to be applied to future DSM programs at far less than the full project cost. The analysis and design of other DSM programs, such as direct incentives to customers, will now be advanced given OIC 2021/16 directions enabling YEC to recover through rates the costs reasonably incurred to provide or participate in a demand side management program.

(e)

YEC has not performed any analysis of this project relative to alternatives. As discussed in (d) this pilot was pursued as funding was available to do so.

REFERENCE: **Application, Tab 5.3.1.2, page 5-25, line 9**

ISSUE: **LED Streetlight Retrofit Program**

QUOTE: "In addition to the program's specifically developed in response to the Yukon Governments Climate Change initiative, the Board also noted in Order 2018-10 (Para 481) that it "considers that retrofitting streetlights at end of life with LED lights were prudent expenditures. Any LED installations that are not end-of-life conversions must not be included in YEC's rate base." The 2017/18 GRA outlined the basis for the LED Streetlight Replacement program noting that YEC decided to move forward with the retrofit of streetlight assets with LEDs. Streetlights in downtown Dawson and Mayo were retrofit in 2016 with plans to retrofit the remaining streetlights in Faro, Mendenhall and Champagne in 2018. As illustrated in Table 5.3, $0.273 million was added to rate base in 2018." (footnote removed)

QUESTION:

a) Please confirm that all costs added to rate base in 2018 for LED streetlight retrofits were for retrofitting streetlights that were at end of life. If not confirmed, please explain.

b) If part (a) is not confirmed, please separate the $0.273 million into amounts for end-of-life retrofitting and retrofitting of streetlights that were not at end of life.

c) Please confirm that YEC has not added any amounts to rate base for streetlight retrofitting in 2019 and 2020 and does not propose to do so in 2021. If not confirmed, please explain.

d) Are there any remaining streetlights that have not been retrofitted to LEDs? If so, please estimate the percentage of streetlights that have not been retrofitted, the cost of retrofitting the remaining streetlights, and outline YEC's planned timeline for doing so.

ANSWER:

(a) and **(b)**

For clarity, the transfer to rate base in 2018 for $0.273 million was not all related to the streetlight replacement program. The costs breakdown further as follows:

inCharge Program Delivery	$0.180
Streetlight Change Outs	$0.093
	$0.273

inCharge program delivery is the cost to deliver the programs approved by the YUB in Order 2014-06. As a historical DSM cost, this amount will be written off the accounts of YEC and ratepayers will bear no burden.

Not all of the streetlights retrofit were end-end-of-life. As described in response to YUB-YEC-1-81 in the 2017/18 GRA, YEC believes these assets are at or near end of life. This is assumed as the majority of the asset value is historical cost transferred by community i.e. YEC has no visibility on the value of the lamp head separate from the rest of the structure – pole, wiring, civil improvements, etc. Based on past experience with installation costs, YEC estimates $0.006 million in undepreciated capital costs from streetlights replaced. YEC proposes to write off this amount from the streetlight PP&E accounts.

(c)

Costs were added in 2020 for the environmental disposal of the old HPS streetlight heads ($0.008 million).

(d)

There are some high-powered highway lights that have not been retrofit. These lights were not retrofit as the business case of the energy savings did not justify the LEDs required for this application.

REFERENCE: **Application, Tab 5.3.2, page 5-26, line 15; Appendix A to Board Order 2018-10: Reasons for Decision, paragraphs 515 and 516**

ISSUE: **Deferred Costs for Projects Between $100,000 and $1 Million**

QUOTE: From Application page 5-26:

"Mayo and Aishihik Hydro Climate Change Study ($0.638 million in 2020 for expenditures from 2017 to 2020)…"

"Transmission Access Road Program Study ($0.133 million in 2020 and $0.200 million in 2021)…"

From Appendix A to Board Order 2018-10:

"515. For the Mayo and Aishihik climate change study, YEC spent $121,530 prior to 2017 and forecast $160,000 for each of 2017 and 2018. This project will deliver research and modelling to better understand how climate change will impact the Aishihik and Mayo drainages to help inform inputs to YEC's generation model…

516. In response to a UCG IR, YEC indicated that the 35 years of data inflows into YECSIM reflect what was recorded over the 35 years, including any climate change impacts relevant to those years. Given YEC's statement that its YECSIM model includes climate change impacts, the Board finds that YEC has not adequately demonstrated that it is necessary to engage in a separate study specifically on climate change impacts. Accordingly, the Board finds there is no justification for this project and directs YEC to remove these costs from its revenue requirement for each of 2017 and 2018 and not recover the 2016 costs. The Board directs YEC further to reflect this finding in its compliance filing." (emphasis added; footnotes removed)

QUESTION:

a) Please justify the costs for the Mayo and Aishihik Hydro Climate Change Study in this application, given that the Board directed YEC to remove costs associated

with studies on climate change impact in the previous application. Why should the $0.638 million incurred for this study be approved and put into rate base?

b) Please provide a breakdown of the $0.333 million incurred for the Transmission Access Road Program Study. More specifically, please provide the activities conducted by YEC and the cost allocated to each activity.

ANSWER:

(a)

The Mayo and Aishihik Climate Change Study as concluded in 2020 was required to develop an understanding of future climate change impacts on YEC's hydrological system and its hydroelectric generation.

Costs incurred on this project were not included in 2017-18 forecast revenue requirement or rates (i.e., YEC forecast in that application that these costs would remain in WIP).

Now that these costs are included in the forecast revenue requirement under the present application it is important to emphasize why this study is crucial to YEC's understanding of how its hydro facilities may be impacted by climate change. The information before the Board in Order 2018-10 did not adequately reflect why YEC pursued this study.

At a strategic level, Canadian utilities have focused significant attention on understanding the potential long-term impacts of climate change on energy supply, and also on developing strategies to adapt to the expected impacts of climate change in order to mitigate potential impacts to utility operations and ratepayers. As an example, a key requirement of the Canadian Electricity Association's *Sustainable Electricity Company* designation, which YEC achieved in 2016, is the development of a utility-specific climate change adaptation plan. As a hydro-based utility, YEC's focus is first to understand the expected long term impact of Climate Change on its hydro resources, which it critical to long term resource planning, risk mitigation and the development of any required adaptation plans.

In Board Order 2018-10, the Board stated:

> "YEC indicated that the 35 years of data inflows into YECSIM reflect what was recorded over the 35 years, including any climate change impacts relevant to those years. Given YEC's statement that its YECSIM model includes climate change impacts, the Board finds that YEC has not adequately demonstrated that it is necessary to engage in a separate study specifically on climate change impacts."

The YECSIM model data only reflects any impacts due to climate change observed to date by incorporating 35 years of actual historical data. However, the model does not predict or account for the expected future impact of climate change on the inflows. Further, as the timing of impacts of climate change can vary, a 35-year historical dataset does not necessarily adequately reflect the near-term impacts to be expected from climate change.

The future impact of climate change includes changes in the expected amount of precipitation (rain and snow), as well as the impact of glacier melt on the hydrological systems. These impacts directly affect the expected long-term water availability for hydroelectric generation. This is a key assumption for long-term resource planning. The future effects of climate change on hydro availability is a critical variable to evaluate when conducting long-term resource planning for the Yukon Interconnected System. Further, understanding the potential range of event severity due to climate variability is critical for understanding future impacts to system reliability and generation availability.

The project scope included development of a supplemental model, Hydrotel, which produces inflow forecasts that incorporate not only historical actual data, but also future climate change predictions. These predictions can be used in conjunction with YECSIM to understand the long-term generation limitations or behaviour due to future climate change impacts. The project scope was also updated to include an assessment of climate change and glacial melt impact on the Upper Yukon River, enabling the Hydrotel model to be used to forecast expected climate change impacts on all three of YEC's hydroelectric generation facilities.

The project was also partially funded by NSERC, which lessened the costs incurred by YEC to achieve the project objectives.

(b)

The Transmission Access Road Program Study includes the following key phases of activities:

1. Phase 1 activities were focused on completion of a desktop GIS study;

2. Phase 2 activities will focus on field work to confirm the findings of the desktop study undertaken in Phase 1; and

3. Phase 3 includes final reporting to tie the results of desktop GIS study and subsequent field work together.

Phase 1 activities were completed by Tetra Tech in 2020 at a total cost of $87,526. Phase 2 and Phase 3 activities planned for 2021 have been deferred to 2022.

REFERENCE: **Application, Tab 5.4.1.1, page 5-28, line 11 and page 5-30, line 10**

ISSUE: **Enterprise Asset Management (EAM) System Purchase and Implementation Project**

QUOTE: "YEC is undertaking a multi-year process to develop and implement a formal Physical Asset Management Managed System (PAMMS) that will align its practices with the ISO 55000 standard for physical asset management (see Appendix 5.1 for further details on the Asset Management Framework). A key part of the PAMMS initiative is the selection and implementation of an Enterprise Asset Management (EAM) solution suited to the needs of the company. (footnote removed)

The existing Computerized Maintenance Management System (CMMS) does not meet YEC's current or future asset management needs. An EAM system is an enterprise level software application that enables an organization – particularly an asset intensive organization – to manage and optimize its assets throughout the entire asset lifecycle including asset needs identification, asset investment planning and prioritization, advanced asset maintenance management and asset performance tracking." (page 5-28)

"Total costs to complete the project are currently estimated at $4.938 million. The project is expected to be fully implemented in early 2021." (page 5-30)

QUESTION:

a) Please provide a business case for the enterprise asset management system project, including the cost benefit analysis that could be used for a performance measure.

b) Please explain why the existing Computerized Maintenance Management System does not meet YEC's current or future asset management needs.

c) Please provide a cost breakdown of the $4.938 million estimated, specifically the activity that will be completed and the cost amount allocated to that activity.

d) Please explain if any other alternatives were explored by YEC in meeting its asset management needs and, if so, provide the costs of those alternatives.

e) Please provide an update on the work currently completed for this project. Is YEC currently on schedule with this project?

ANSWER:

(a)

The average estimated NPV for the EAM project is $2.87 million over a period of 10 years.[1] A detailed NPV analysis is provided as Attachment 1 to this response.[2] Savings from anticipated tangible benefits are as summarized in the table below. A description of tangible and intangible benefits of the Project are summarized in the discussion that follows.

[1] Assuming weighted average cost of capital of 4.82%; inflation rate of 2.0%; implementation cost allocation of $3.56 million in 2020 and $275,000 in 2021; estimated O&M costs and realized benefits for 10 years from 2021 to 2031, increasing form 2021 onwards from 0% in 2020; 40% in 2021; 80% in 2022 and 100% 2023 onwards.

[2] The total project cost is $ 4.6 million. The NPV evaluation used a project cost of $3.7 million which was at that time the cost looking forward, excluding costs incurred/ committed to date. The increase of $0.9 million is covered by the NPV result.

Table 1: Anticipated Tangible Benefits Summary

Benefits Description	Annual Expenditure	Low % Improvement	High % Improvement	Low Estimated Annual Benefit	High Estimated Annual Benefit
Productivity Gains	$3,055,143[2]	12%	25%	$366,617	$763,786
Inventory Management - Reduced Cost of Procured Parts	$1,153,181	0.5%	3%	$5,766	$34,595
Improved Reliability – Extended Asset Life	$11,770,068[3]	2%	3%	$235,401	$353,102
Improved Reliability - Reduced Diesel Consumption	$156,724	20%	30%	$31,345	$47,017
Improved Reliability - Revenue Recovery	$8,000	20%	30%	$1,600	$2,400
Warranty Claims Improvements	$10,000	100%	200%	$10,000	$20,000
TOTAL ESTIMATED BENEFITS:				**$650,729**	**$1,220,900**

Tangible Benefits:

- **Productivity Gains:** Implementation of an EAM solution is expected to improve YEC's overall maintenance performance and increase efficiency of execution of maintenance works. A study conducted for the power industry[3] has shown that wrench time can increase between 10 – 40% as a result of improvement in maintenance capabilities that are enabled by an EAM. YEC supervisors in respective groups estimate a 10 – 15% productivity improvement for electrical technicians and a 15 – 20% improvement for mechanical technicians. YEC estimates a productivity improvement range of 12 – 25% once all asset classes are fully deployed in the EAM by the end of 2021.

- **Improved Inventory Management and Procurement:** Because of integration of work with material requirements, better inventory visibility will result in forward planning of work and materials will enable YEC to source materials with longer lead times taking advantage of existing contractual agreements that are in place. Other electric utilities have estimated savings of 0.5 - 3% as a result of better contract management for purchases.

[3] Source: Booz & Company.

- **Improved Reliability – Extended Asset Life:** The use of an EAM system for planned maintenance requirements and scheduling can extend asset life and maintain a record of asset health. Organizations that have implemented EAM have reported reductions in long term asset costs of up to 5% by extending asset life. YEC is estimating an expected improvement of 2 – 3% on useful asset life as a result of asset life optimization.

- **Improved Reliability – Reduced Diesel Consumption:** Improved asset maintenance practices are expected to result in reduced outages and therefore a reduction in thermal consumption for backup power during restorations. A reduction of 20 – 30% in controllable outages and related thermal costs could be realized.

- **Improved Reliability – Revenue Recovery:** Utilizing the EAM to enable improved preventative maintenance before the point of asset failure is expected to reduce controllable outage events that cause customers to lose power, by 20 – 30%. This will result in additional revenue from the sale of energy otherwise not delivered.

- **Warranty Claims**: The EAM will record and track warranty periods for assets and parts that are placed into service. Should installed assets or parts require corrective work orders, the EAM will flag when those parts are still under warranty, and eligible for a warranty claim reimbursement. This is expected to increase successful warranty claims by 100 – 200%.

Intangible Benefits:

- **Process Improvement – Standardized Processes:** The EAM standardizes workflows, processes, and procedures related to the entire asset lifecycle; transitioning this knowledge from individuals into institutional knowledge retention. Particularly valuable is knowledge related to proactive maintenance strategies.

- **Availability and Retention of Information:** The EAM will improve access and availability of information (ad hoc and personal documents, corporate documents, etc.), gathered from currently disparate locations into an organized ‘single source of truth’.

- **Contributions to Safety:** Safety procedures can be attached to work orders; ensuring recorded completion of Job Safety Analysis (JSA) procedures and forms, all contributing to a reduced risk of injury.

- **Improved Decision Making:** Improved access to detailed, complete data sets on the assets of the Corporation, which can inform better decision making.

- **Increased Compliance with Regulatory Requirements:** The EAM will serve as the system of record for compliance work fulfilling regulatory requirements. These centralized data sets can be queried for trends or data points that support YEC's rate applications. The EAM will unlock a holistic view of capital projects that will better inform and justify deferral and renewals.

- **Improved Accountability:** Transparent workflows enable simple work order delegation, and managers can easily track the status of work orders. This improves accountability and supports quality control audits.

- **Increased Accuracy in Performance Measurement**: Enabling management to track and report on various performance measures, and trends over time. High value reports can be consolidated into dashboards tailored by audience.

(b)

While YEC's current CMMS allows YEC to track cost and raise reactive work orders, it has significant shortcomings and is not capable of planning and executing planned preventative maintenance work requiring coordinated scheduling of materials and labour requirements, tracking asset condition and criticality, nor does it support the end worker by making equipment records and history easily available.

In 2017, a preliminary market study and RFI were carried out by YEC and Hatch. To assess suitability of Key2Act's (YECs existing CMMS) to support YEC's long term strategic needs, Key2Act was invited to complete the RFI that was distributed to the other viable vendors. As noted, the self-assessment requests that the vendors confirm and demonstrate compliance to a series of functional requirements by answering yes/no and providing details on how their solution addresses each requirement. While Key2Act did not explicitly answer No to any questions, they did leave 14/44 responses blank, citing reasons such as "possibly with configuration" and "likely through customization" with no

additional detail. Specifically, Key2Act was unable to confirm compliance to the following functional requirements detailed in Attachment 1 to this response: F1, F2, F5, F15, F17, F18, F19, F20, F22, F25, F36, F39, F43, and F44.

When contrasted with the other vendor responses which provided substantial detail as to how they would address each requirement, Key2Act's responses illustrate a lack of understanding of this domain.

Additionally, interviews were held with YECs operational, engineering, and IT staff in which they were asked about their experiences with Key2Act. The interviews identified that the solution falls short of meeting YEC's current requirements which has resulted in the development of several stop-gap in-house solutions, and significant duplication of effort. It was also identified that the YEC staff have no confidence in Key2Act's ability to enhance their system to meet YEC's needs.

Based on the results of the self-assessment and the interviews with YEC staff, it was apparent that the Key2Act solution was not only incapable of supporting YEC's long term strategic objectives but that it is also not meeting their current operational needs. For this reason, Key2Act was not invited to submit costing to enhance their system to meet YEC's needs nor were they asked to participate in the solution demonstrations.

(c)

Please see Table 1 below for a breakdown of EAM costs.

Table 1: EAM Implementation Cost Breakdown

Cost Item	Forecast at Completion ($million)
Vendor Selection & Project Initiation	0.809
Application Software Licences	0.578
System Implementation	1.575
Hardware and Facilities	0.390
Internal Resources	0.462
Additional Data Loading (2021)	0.250
Change Management	0.114
Project Management	0.340
Subtotal	***4.518***
Contingency	0.118
Total Project costs	**$4.636**

Note there is a $0.302 million variance from the GRA forecast of $4.93 million. This is due to an error in the GRA forecast for this project.

(d)

Yes. Other software alternatives were explored. A preliminary market survey of EAM solutions was conducted in 2017. An RFI was distributed to 27 vendors in order to better understand the costs associated with implementation and integration.

YEC moved to a formal public tender in 2018. The process was divided into a two-part process including an RFSQ and an invitational request for proposal (iRFP) to be referred to as (RFP) in this report. A total of 9 vendors participated in the RFSQ, and 4 moved on to the detailed RFP. Submissions were scored and ranked based on their submissions, results of demos as well as their respective costs. At the RFP evaluation, vendor submissions for implementation cost ranged from $967k to $1,400k.

(e)

YEC is expecting to go live with the EAM project on March 15, 2021. YEC is currently on schedule with this project.

APPENDIX D – DETAILED NET PRESENT VALUE ANALYSIS

NPV Analysis of EAM Deployment

Assumptions	
Year 1 Implementation %	80%
Year 2 Implementation %	20%
Year 1 Benefits Captured	40%
Year 2 Benefits Captured	80%
Year 3 Benefits Captured	100%
Year 4 and beyond	100%
IRR	4.82%
Inflation %	2%

	NPV	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Costs													
One Time Implementation	($3,646,589)	($3,560,000)	($275,000)										
On-going Support	($1,528,024)		($166,260)	($169,585)	($172,977)	($176,436)	($179,965)	($183,564)	($187,236)	($190,980)	($194,800)	($198,696)	($202,670)
Total Costs	**($5,174,613)**	**($3,560,000)**	**($441,260)**	**($169,585)**	**($172,977)**	**($176,436)**	**($179,965)**	**($183,564)**	**($187,236)**	**($190,980)**	**($194,800)**	**($198,696)**	**($202,670)**
Benefits													
Low Estimated Benefits	$5,597,013		$ 265,498	$ 541,615	$ 690,559	$ 704,370	$ 718,458	$ 732,827	$ 747,483	$ 762,433	$ 777,682	$ 793,235	$ 809,100
Average Estimated Benefits	$8,049,074		$ 381,812	$778,897	$993,094	$1,012,956	$1,033,215	$1,053,879	$1,074,957	$1,096,456	$1,118,385	$1,140,753	$1,163,568
High Estimated Benefits	$10,501,135		$ 498,127	$ 1,016,180	$ 1,295,629	$ 1,321,542	$ 1,347,973	$ 1,374,932	$ 1,402,431	$ 1,430,479	$ 1,459,089	$ 1,488,271	$ 1,518,036
Costs - Benefits													
Low Estimate Cost Benefit	$422,400	($3,560,000)	($175,762)	$372,030	$517,582	$527,934	$538,492	$549,262	$560,248	$571,453	$582,882	$594,539	$606,430
Average Estimate Cost Benefit	$2,874,461	($3,560,000)	($59,448)	$609,312	$820,117	$836,520	$853,250	$870,315	$887,721	$905,476	$923,585	$942,057	$960,898
High Estimate Cost Benefit	$5,326,522	($3,560,000)	$56,867	$846,595	$1,122,652	$1,145,105	$1,168,008	$1,191,368	$1,215,195	$1,239,499	$1,264,289	$1,289,575	$1,315,366

Figure 1: 10 Year Cost Benefits Projection for EAM Project

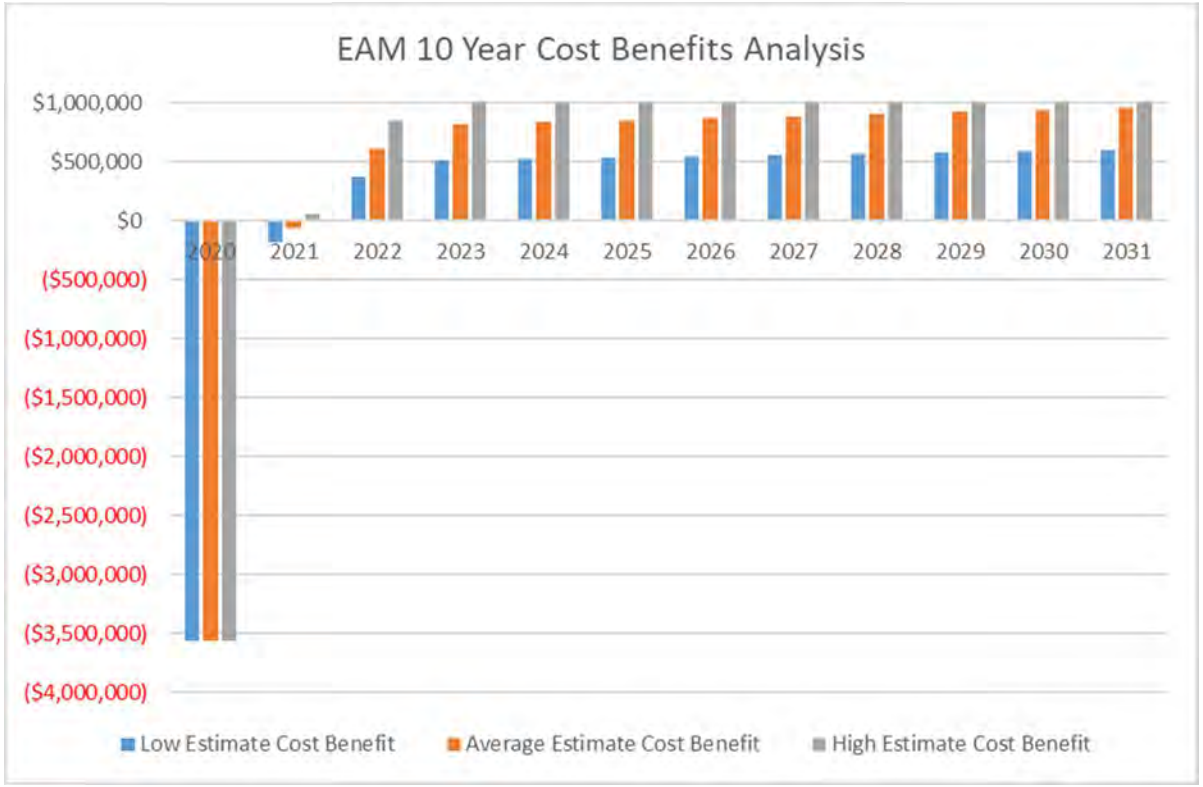

Table 4-1: Functional Requirements

#	Requirement	Description
F1	Alignment with ISO55000, 55001, and 55002	The system should be capable of managing the assets from concept to disposal.
F2	Base CMMS Functionality	The system should be capable of performing the basic maintenance functions for work order planning, execution, closing, and history.
F3	Asset Register	The system should provide a robust asset register.
F4	Critical Asset Identification	The system should enable the assignment of criticality to equipment to be used for prioritization.
F5	Management of Change (MoC) capabilities	The system should be capable of tracking and recording all changes made to equipment, procedures, and work orders by user and time stamp.
F6	Pending work back log	The system should be capable of monitoring the backlog of work to allow for prioritization of scheduling, and to make sure no high priority work is missed.
F7	ContractorProject Work Management	The system should be capable of supporting projects: tracking for schedule, costs and completion as well as history.
F8	KPIs and Reports	The system should support any required reports or KPIs.
F9	Material and Procurement Management	The system should be capable of performing Material management and procurement or integrating with existing systems.
F10	InventorySpares management	The system should be capable of tracking and managing inventory (and spares) as well as attaching parts to work orders and setting levels and allowing automatic reordering.
F11	Mobile Device Support	The system should have a robust mobile device capability to allow execution of work and recording of all required details by the technicians using it.
F12	Standard jobs & task lists	The system should enable common, repeated tasks (either PM or common repairs) to be created and saved including parts and special requirements then can be used when work is required without the need to keep recreating it.
F13	Reliability and related analysis	The system should be capable of tracking and storing the information required to perform reliability analysis.
F14	Asset Equipment History	The system should track all equipment history, work completed, schedule, and costs (for use with reliability and budgeting).
F15	Compatibility with condition monitoring system	The system should be capable of performing condition monitoring through Scada and others systems, with the ability use this information for reliability, and schedule generation.
F16	Manage PM and PdM work procedures	The system should support PM and PdM work procedures (and association to work orders).
F17	PM optimization including Reliability Analysis	The system should be capable of tracking the history of the PMs so it can be analyzed to see if the right work is being done at the right time.

#	Requirement	Description
F18	Support for failure modes and effects analysis (FMEA) and reliability centered maintenance (RCM)	The system should support FMEA and RCM or provide a mechanism to import these analyses from external sources for inclusion in reliability work.
F19	Track and differentiate non-recurring work failures and break downs	The system should monitor break in or break down work for use in reliability analysis.
F20	Track corrective maintenance results against PM and CBM	The system should be capable of tracking corrective maintenance results vs PM and CBM. This is used for PM optimization to ensure the right work is being created by the PM and PdM work orders. If the PM and PdM is being done but no corrective work is being generated these PMs and PdM may need to be adjusted.
F21	Track recurring work types - PM and PdM	The system should be capable of tracking recurring work types. This is used for the reliability functions of the PMs and PdMs. May signal a need for deeper investigation like RCM.
F22	Support for Asset Health Index Calculations	The system should be capable of using the RCA, FMEA and history to provide assets health index calculations.
F23	Work Order Management	Break out of CMMS function
F24	Work Close Out and Feed Back	Break out of CMMS function
F25	Work Order Routing	Break out of CMMS function
F26	Work Planning	Break out of CMMS function
F27	Work Scheduling and Resource Balancing	Break out of CMMS function
F28	Document Management	The system should provide a mechanism for attaching and managing documents. This can be through integration with external document management systems or native functionality within the system.
F29	Decision Analytics	This is part of the reliability functions and IDS functions. The reliability side can predict the life of the equipment and repairs will need to be made. This is information that will also be used by and IDS function to calculate costing.
F30	Asset and project views for business cases for both asset-based and needs-based projects	Part of the decision analytics
F31	Configurable for workflows, policies and processes	This requirement is to ensure the IDS system can facilitate the workflows for approvals and execution to align with the policies and processes of the organization.
F32	Ease of integration	This requirement is to ensure the IDS system can be integrated with the organizations other systems e.g. Finance.
F33	Method of "What if" analysis for investment analysis	The system should provide a mechanism for performing What-If analysis and scenario generation for investment and maintenance decisions.
F34	Asset management planning tools/approach	The system should provide all of the required tools for asset planning through its entire life cycle.
F35	System Architecture options	This requirement aims to establish the vendor solution systems architecture to ensure compatibility with other systems in the organization.
F36	Risk calculation evaluation	The system should support reliability and risk calculations, and analysis
F37	Ease of Customization	The system should be easily configured (and re-configured) to meet the organization's needs.
F38	Ease of use: implementation effort	This requirement aims to understand the effort involved in implementing the system.

#	Requirement	Description
F39	Hardware Support (if applicable)	This requirement aims to establish whether hardware support is part of the offering.
F40	Reporting and Ad-hoc Queries	The system should be support ad-hoc reporting and analytics.
F41	User Customizable Dashboards	The system should support user configurable dashboards.
F42	Financial Software Integration	The system should be capable of integrating with the existing financial information system.
F43	GIS Software Integration	The system should provide a mechanism to overlay EAM data on a GIS layer (through integration or native functionality).
F44	Scada Software Integration	The system should be capable of integrating with the existing Scada system.

REFERENCE: **Application, Appendices 5.1 to 5.6**

ISSUE: **Forecasted Dates Provided for Projects and Studies in These Appendices**

PREAMBLE: In the descriptions for the projects and studies, YEC provided the forecasted completion date. For example, YEC indicated that the forecasted completion date for the Dawson Voltage Conversion was 2022.

QUESTION:

a) For each project or study mentioned in Appendices 5.1 to 5.6, please indicate whether it is still viable for completion on the forecasted date. If not, please explain the reasons for delays on projects.

ANSWER:

(a)

Please see the summary provided below.

Table 1: Summary of projects/ Studies in Appendix 5.1 to Appendix 5.6

Project (Appendices 5.1 to 5.6)	Forecast completion date (Referenced in Appendices 5.1-5.6 of Application)	Still viable for completion on forecast date?	If no, Explain delay
Appendix 5.1: Capital Projects >$1 M Not Impacting Rate Base			
Dawson Voltage Conversion	2023/24	Yes	2020 and 2021 and 2022 are planning years due to significant amount of outages required and project complexity. We expect the project to be in service in 2023
MHO (Mayo A) Generating Station Slope Stability	2022	No	This project will be completed in 2023 as part of a suite of projects to take advantage of mobilization and demobilization costs as well as other synergies that exist.
Replacement of Mayo A Surge Chamber	2023	Yes	

Project (Appendices 5.1 to 5.6)	Forecast completion date (Referenced in Appendices 5.1-5.6 of Application)	Still viable for completion on forecast date?	If no, Explain delay
Stop Log Crane WH Main Spillway	2022	Yes	
Asset Management framework	2022	Yes	
Battery Energy Storage System	2022	Yes	
Pumped Storage	2028	No	Monitoring activities did not commence in 2020 as originally forecast. Initiation of these activities is contingent on securing Federal funding and alignment with First Nations whose Traditional Territories the project is located on.
Southern lake transmission line	2028	Yes	
Whitehorse Interconnection	2022	Yes	
Appendix 5.2: Capital Projects>$100,000 and <$1 M Added to Rate Base			
Dam Safety Program	2021	Yes	
Dam Safety Recommendations	2019, 2020	2019 Yes, 2020 No	As a result of the high water levels, work identified could not be completed. The work will be reprioritized and included in the 2021 DSR action plan.
P126 Boil off gas heat exchanger	2019	Yes	Completed
Wareham Gate Heater	2020	Yes	
Wareham Gate Refurbishment	2020	No	Higher than normal water levels in 2020 resulted in this project to be deferred until 2022. Investments to date will be held in WIP through 2021.
Whitehorse Diesel System Grounding for Generators	2020	Yes	
WH1 and WH2 Design and Installation of Dewatering system	2019	Yes	
WH4 Ventilation	2021	No	Engineering will be finalized in 2021 for installation in 2022.
Alexco Mobile Substation	2020	No	Alexco has had delays in selecting substation location and will not receive the substation

Project (Appendices 5.1 to 5.6)	Forecast completion date (Referenced in Appendices 5.1-5.6 of Application)	Still viable for completion on forecast date?	If no, Explain delay
			until March 2021. This has delayed the in service date.
Line 177 Re Route	2021	Yes	
Minto Mine Substation - NGR	2019	Yes	
Protection and Control Program	2021	Yes	Scope has been reduced in 2021 to allow for additional planning and estimating of activities in 2022 and beyond.
Transmission Line Access	2019, 2020	2019 yes, 2020 No	Activities planned for 2020 were deferred as a result of additional planning required to develop and prioritize the plan moving forward. Activities will resume in 2022. The spending for the project to date will be held in WIP until it is completed.
Van Gorda Substation	2019	Yes	
WAF Transmission Upgrades	2019	Yes	
Customer Extensions	2019, 2020, 2021	Yes	
L355 Voltage Regulator	2020	Yes	
System Improvements for Eagle Gold Mine	2019	Yes	
Communication Upgrades	2019	Yes	
Building Upgrades	2019, 2020	Yes	
Compact Digger Truck	2021	Yes	
Crane Replacement/ Refurbishment	2020, 2021	Yes	
Mayo Earthworks	2020	Please see the note	Preliminary engineering work was done in 2020. Further studies and engineering are required. Also being planned as part of a larger suite of projects to take advantage of synergies and reduce Mob and Demob costs. Any cost spent in 2020 will be held in WIP until the project is completed [potentially in 2022/23].
Mobile Office Unit – IT	2021	Yes	
Vehicle Purchases	2019,2020,2021	Yes	

Project (Appendices 5.1 to 5.6)	Forecast completion date (Referenced in Appendices 5.1-5.6 of Application)	Still viable for completion on forecast date?	If no, Explain delay
FD7 Overhaul	2021	No	Pricing for overhaul has been significantly higher than expected. Business case being performed in 2021 to determine if replacement is more cost effective than refurbishment. Any spending for 2021 business case will be held in WIP and reflected in GRA compliance filing.
Decommissioning on WD3	2019	Yes	
Site Restoration Transmission Lines	2019	Yes	
Appendix 5.3: Deferred Project >$1 M Not Added to Rate Base			
Aishihik Generating Station Long Term Year Water Use License Renewal	2022	Yes	
Whitehorse Rapids Generating Station Water Use Licence Renewal	2025	Yes	
Diesel Retirement Replacement	2023/24	Yes	
Southern Lakes Enhanced Storage Project	2023	Yes	
Mayo Lake Storage Enhancement Project – Including Mayo Lake Outlet Dredging	2023	Yes	
Appendix 5.4: Deferred Projects >$100,000 and <$1 M Added to Rate Base			
IPP Standing Offer Program Implementation	2019	Yes	
Mt Sumanik Wind Feasibility Studies	2020	Yes	
WH2 uprate Engineering	2021	Yes	
Building Condition Reports 2020-2024	2021	Yes	
Business Continuity Plan	2021	Yes	
Mayo and Aishihik Hydro Climate Change	2020	Yes	

Project (Appendices 5.1 to 5.6)	Forecast completion date (Referenced in Appendices 5.1-5.6 of Application)	Still viable for completion on forecast date?	If no, Explain delay
PMF Flood Study	2021	Yes	
Transmission Access Road Program Study	2020, 2021	2020 Yes, 2021 No	2020 will be closed separately. The planned additional phases for 2021 have been deferred to 2022/23 and will be in WIP at end of 2021. YEC is looking at a GIS project in the future and want to ensure that the data collected is compatible with the system of choice.
Whitehorse Diesel Rental Substation improvements	2021	Yes	
10-Year Renewable Electricity Plan	2020	Yes	
Atlin Hydro EPA Preparation	2020	No	2021
Dam Safety Review	2020	No	Project will be completed in 2021, impacts from COVID-19 and high water levels prevented completion in 2020. All assessments are completed and drafts reports submitted.
Appendix 5.5: Deferred Studies >$100,000 <$1 M Not Impacting Rate Base			
EV Infrastructure Project	>2021	Not specified	Given the delays in the rollout of the electric vehicles contemplated in Yukon Government's strategy from the original draft in November 2019, the project is not required to be completed in 2021 and has been delayed.
P125 Trash rack Study	2021	No	To be completed in 2023 in conjunction with the remaining Headgate replacement projects. Synergies with equipment rentals, and a reduction in mob and demob costs is the rationale
Appendix 5.6: Intangible Assets >$100,00 <$1 M Added To Rate Base			
ERP System Upgrades	2020	Yes	

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REFERENCE: **Application, Appendix 5.1-1, page 5.1-2**

ISSUE: **Dawson Voltage Conversion Project**

QUOTE: "Dawson City's two 4.16 kV distribution feeders have reached their practical operating limits, resulting in frequent power outages, constant voltage flicker, and longer fault clearing times. Teshmont Consultants LP conducted a site visit to assess the entire 4.16 kV distribution system to identify protection issues, potential voltage levels, transformer utilization and power flow. The primary issues facing the Dawson distribution system were noted as follows …"

"Teshmont recommended converting the operating voltage of the Dawson City distribution system from 4.16 kV to 12.47 kV in a single stage. Increasing the voltage immediately improves the capacity on the existing conductors, reduces fault current at the primary, reduces voltage drops and decreases energy losses."

QUESTION:

a) Please indicate the year in which these two feeders were installed and the expected service life of the feeders at the time installation.

b) Please explain how often YEC carried out tests on these feeders in the past to assess their reliability and how often maintenance work was required. If possible, please provide the number of times maintenance was conducted on these feeders in the last 10 years, on a per annum basis, and the cost of this maintenance work.

c) Please provide the number and duration of outages resulting from the two Dawson City distribution feeders for each of the last 10 years, on a per annum basis, and the costs incurred due to these outages.

d) Please provide the assessments conducted by Teshmont Consultants LP. Were any other alternatives explored for mitigating the issues on the Dawson distribution system?

ANSWER

(a)

The F1 Breaker was installed in 1978; and the F2 breaker was installed in 1976. The expected service life is 40 years for the wire, pole and insulators.

(b)

These breakers receive 10 year inspections. The estimated cost is $3,500 for this testing. The other feeder assets (i.e., transformers, poles) are typically run to failure. It is noted that studies and engineering are continuing in 2021 and 2022 that will include further data collection and analysis to support the project justification. The project will not be in service until 2023.

(c)

Attachment 1 to this response provides the outage list for F1 and F2. Table 1 below summarizes the total number of outages and duration.

Table 1: Number and Duration of Outages

Year	Total Outages	Outage Hours
2011	8	4.36
2012	11	2.87
2013	12	26.95
2014	7	2.46
2015	20	10.43
2016	12	5.31
2017	21	11.59
2018	9	6.96
2019	25	26.46
2020	19	11.34
	144	**108.73**

Cost associated with the individual outages would be onerous. Studies and engineering are continuing in 2021 and 2022 that will include further data collection and analysis to support the project justification. The project is not planned to be in service until 2023.

(d)

Please see Attachment 1 to this response for the assessment provided by Teshmont LP.

The Dawson Voltage conversion project is set to be in-service in 2023. Temporary measures have been implemented such as increasing the breaker trip settings and fuse sizes, which leads the system to experience different types of issues such as brownouts. An interim solution has been implemented which includes a partial voltage conversion to 12.47 kV which has relieved the load on Dome area. A voltage conversion to 24.94 kV was not considered due to the excessive costs.

YEC Outage Reporting with Parameters

Year	Quarter	Id	Date			(Code) Description	Comment							
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2011	Qtr 1	2011-0019	Jan 23, 2011	Segs: 2	Dawson	(603) Wet Snow			0.62	270	153.0	YUB		
				Dawson	Dawson (Feeder 1)		1/23/2011 2:13:00 AM	1/23/2011 2:44:00 AM	0.52	135	69.7		T	12.47Kv
				Dawson	Dawson (Feeder 2)		1/23/2011 2:13:00 AM	1/23/2011 2:50:00 PM	0.62	135	83.2		T	12.47Kv
		2011-0022	Mar 22, 2011	Segs: 2	Dawson	(503) Defective Equipment/Material			0.78	270	209.2	YUB		
				Dawson	Dawson (Feeder 1)		3/22/2011 2:23:32 PM	3/22/2011 3:10:07 PM	0.78	135	104.8		T	12.47Kv
				Dawson	Dawson (Feeder 2)		3/22/2011 2:23:32 PM	3/22/2011 3:09:57 PM	0.77	135	104.4		T	12.47Kv
		Tot Qtr:2							2.68	540	362.2			
	Qtr 2	2011-0048	Jun 27, 2011	Segs: 1	Dawson	(400) Lightning			0.10	422	40.4	YUB		
				Dawson	Dawson (Feeder 1)		6/27/2011 4:06:05 PM	6/27/2011 4:11:50 PM	0.10	422	40.4		T	12.47Kv
		Tot Qtr:1							0.10	422	40.4			
	Qtr 3	2011-0004	Aug 25, 2011	Segs: 1	Dawson	(202) Transmission Inadvertent			0.60	439	263.5	YUB		
				Dawson	Dawson (Feeder 2)		8/25/2011 12:19:04 PM	8/25/2011 12:55:05 PM	0.60	439	263.5		T	12.47Kv
		2011-0008	Sep 29, 2011	Segs: 1	Dawson	(806) Commissioning Error			0.09	439	39.8	YUB		
				Dawson	Dawson (Feeder 2)		9/29/2011 12:05:01 PM	9/29/2011 12:10:27 PM	0.09	439	39.8		T	12.47Kv
		Tot Qtr:2							0.69	878	303.3			
	Qtr 4	2011-0012	Nov 10, 2011	Segs: 2	Dawson	(806) Commissioning Error			0.14	861	115.3	YUB		
				Dawson	Dawson (Feeder 1)		11/10/2011 11:34:46 AM	11/10/2011 11:42:09 AM	0.12	422	51.9		T	12.47Kv
				Dawson	Dawson (Feeder 2)		11/10/2011 11:34:46 AM	11/10/2011 11:43:26 AM	0.14	439	63.4		T	12.47Kv
		2011-0015	Dec 05, 2011	Segs: 2	Dawson	(603) Wet Snow			0.20	861	165.2	YUB		
				Dawson	Dawson (Feeder 1)		12/5/2011 12:41:00 AM	12/5/2011 12:52:00 AM	0.18	422	77.4		T	12.47Kv
				Dawson	Dawson (Feeder 2)		12/5/2011 12:41:00 AM	12/5/2011 12:53:00 AM	0.20	439	87.8		T	12.47Kv
		2011-0017	Dec 25, 2011	Segs: 2	Dawson	(603) Wet Snow			0.13	861	104.5	YUB		
				Dawson	Dawson (Feeder 1)		12/25/2011 2:05:38 PM	12/25/2011 2:12:29 PM	0.11	422	48.2		T	12.47Kv
				Dawson	Dawson (Feeder 2)		12/25/2011 2:05:38 PM	12/25/2011 2:13:20 PM	0.13	439	56.3		T	12.47Kv
		Tot Qtr:3							0.89	2,583	385.0			
	Tot Yr: 8								4.36	4,423	1,091.0			

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Year	Quarter	Id	Date			(Code) Description	Comment							
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2012	Qtr 1	2012-0010	Mar 30, 2012	Segs: 2	Dawson	(302) Broken Branch			0.14	857	120.5	YUB		
				Dawson	Dawson (Feeder 1)		3/30/2012 1:47:30 PM	3/30/2012 1:55:43 PM	0.14	420	57.5		T	12.47Kv
				Dawson	Dawson (Feeder 2)		3/30/2012 1:47:30 PM	3/30/2012 1:56:09 PM	0.14	437	63.0		T	12.47Kv
		2012-0022	Jan 01, 2012	Segs: 2	Dawson	(603) Wet Snow			0.20	861	166.6	YUB		
				Dawson	Dawson (Feeder 1)		1/1/2012 5:33:18 PM	1/1/2012 5:44:17 PM	0.18	422	77.2		T	12.47Kv
				Dawson	Dawson (Feeder 2)		1/1/2012 5:33:18 PM	1/1/2012 5:45:31 PM	0.20	439	89.4		T	12.47Kv
		2012-0023	Jan 02, 2012	Segs: 2	Dawson	(603) Wet Snow			0.20	861	166.4	YUB		
				Dawson	Dawson (Feeder 1)		1/2/2012 8:26:02 AM	1/2/2012 8:37:21 AM	0.19	422	79.6		T	12.47Kv
				Dawson	Dawson (Feeder 2)		1/2/2012 8:26:02 AM	1/2/2012 8:37:54 AM	0.20	439	86.8		T	12.47Kv
		2012-0024	Jan 03, 2012	Segs: 2	Dawson	(603) Wet Snow			0.16	861	131.0	YUB		
				Dawson	Dawson (Feeder 1)		1/3/2012 1:39:20 AM	1/3/2012 1:48:13 AM	0.15	422	62.5		T	12.47Kv
				Dawson	Dawson (Feeder 2)		1/3/2012 1:39:20 AM	1/3/2012 1:48:42 AM	0.16	439	68.5		T	12.47Kv
		Tot Qtr:4							1.36	3,440	584.6			
	Qtr 3	2012-0001	Sep 04, 2012	Segs: 2	Dawson	(506) Other Equipment Failure			0.08	861	61.9	YUB		
				Dawson	Dawson (Feeder 1)		9/4/2012 5:38:56 AM	9/4/2012 5:42:55 AM	0.07	422	28.0		T	12.47Kv
				Dawson	Dawson (Feeder 2)		9/4/2012 5:38:56 AM	9/4/2012 5:43:34 AM	0.08	439	33.9		T	12.47Kv
		2012-0002	Sep 05, 2012	Segs: 2	Dawson	(300) Tree Contacts			0.12	861	107.1	YUB		
				Dawson	Dawson (Feeder 1)		9/5/2012 6:11:14 PM	9/5/2012 6:18:42 PM	0.12	422	52.5		T	12.47Kv
				Dawson	Dawson (Feeder 2)		9/5/2012 6:11:14 PM	9/5/2012 6:18:42 PM	0.12	439	54.6		T	12.47Kv
		2012-0003	Sep 12, 2012	Segs: 2	Dawson	(300) Tree Contacts			0.12	861	96.9	YUB		
				Dawson	Dawson (Feeder 1)		9/12/2012 11:11:10 PM	9/12/2012 11:17:40 PM	0.11	422	45.7		T	12.47Kv
				Dawson	Dawson (Feeder 2)		9/12/2012 11:11:10 PM	9/12/2012 11:18:10 PM	0.12	439	51.2		T	12.47Kv
		Tot Qtr:3							0.62	2,583	266.0			
	Qtr 4	2012-0004	Oct 25, 2012	Segs: 1	Dawson	(300) Tree Contacts			0.08	401	33.1	YUB		
				Dawson	Dawson (Feeder 1)		10/25/2012 12:53:55 PM	10/25/2012 12:58:52 PM	0.08	401	33.1		T	12.47Kv
		2012-0005	Dec 10, 2012	Segs: 2	Dawson	(603) Wet Snow			0.29	861	245.6	YUB		
				Dawson	Dawson (Feeder 1)		12/10/2012 6:04:33 AM	12/10/2012 6:21:27 AM	0.28	422	118.9		T	12.47Kv
				Dawson	Dawson (Feeder 2)		12/10/2012 6:04:33 AM	12/10/2012 6:21:52 AM	0.29	439	126.7		T	12.47Kv
		2012-0006	Dec 11, 2012	Segs: 3	Dawson	(205) Other Loss of Supply			0.02	1,283	18.8	YUB		

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2012	Qtr 4	2012-0006	Dec 11, 2012	Dawson	Dawson (Feeder 2)		12/11/2012 10:30:06 AM	12/11/2012 10:31:12 AM	0.02	439	8.0		T	12.47Kv
				Dawson	Dawson (Feeder 1)		12/11/2012 10:30:06 AM	12/11/2012 10:30:53 AM	0.01	422	5.5		T	12.47Kv
				Dawson	Dawson (Feeder 1)		12/11/2012 10:31:12 AM	12/11/2012 10:31:57 AM	0.01	422	5.3		T	12.47Kv
		2012-0008	Dec 12, 2012	Segs: 2	Dawson	(603) Wet Snow			0.11	861	86.4	YUB		
				Dawson	Dawson (Feeder 1)		12/12/2012 5:23:19 PM	12/12/2012 5:30:07 PM	0.11	422	47.8		T	12.47Kv
				Dawson	Dawson (Feeder 2)		12/12/2012 5:23:19 PM	12/12/2012 5:28:35 PM	0.09	439	38.5		T	12.47Kv
		Tot Qtr:4							0.90	3,406	383.8			
	Tot Yr: 11								2.87	9,429	1,234.4			
2013	Qtr 1	2013-0001	Jan 13, 2013	Segs: 2	Dawson	(603) Wet Snow			0.24	861	197.4	YUB		
				Dawson	Dawson (Feeder 2)		1/13/2013 11:34:41 PM	1/13/2013 11:48:55 PM	0.24	439	104.1		T	12.47Kv
				Dawson	Dawson (Feeder 1)		1/13/2013 11:34:41 PM	1/13/2013 11:47:57 PM	0.22	422	93.3		T	12.47Kv
		2013-0002	Jan 15, 2013	Segs: 2	Dawson	(603) Wet Snow			0.11	861	92.9	YUB		
				Dawson	Dawson (Feeder 2)		1/15/2013 11:49:36 AM	1/15/2013 11:56:04 AM	0.11	439	47.3		T	12.47Kv
				Dawson	Dawson (Feeder 1)		1/15/2013 11:49:36 AM	1/15/2013 11:56:05 AM	0.11	422	45.6		T	12.47Kv
		2013-0003	Jan 19, 2013	Segs: 2	Dawson	(603) Wet Snow			0.22	861	151.8	YUB		
				Dawson	Dawson (Feeder 2)		1/19/2013 11:12:00 AM	1/19/2013 11:20:00 AM	0.13	439	58.5		T	12.47Kv
				Dawson	Dawson (Feeder 1)		1/19/2013 11:15:00 AM	1/19/2013 11:28:16 AM	0.22	422	93.3		T	12.47Kv
		Tot Qtr:3							1.03	2,583	442.2			
	Qtr 2	2013-0005	Jun 04, 2013	Segs: 2	Dawson	(300) Tree Contacts			0.16	861	130.8	YUB		
				Dawson	Dawson (Feeder 1)		6/4/2013 11:37:46 AM	6/4/2013 11:47:21 AM	0.16	422	67.4		T	12.47Kv
				Dawson	Dawson (Feeder 2)		6/4/2013 11:38:41 AM	6/4/2013 11:47:21 AM	0.14	439	63.4		T	12.47Kv
		2013-0006	Jun 04, 2013	Segs: 1	Dawson	(802) Protection Setting			0.08	422	35.4	YUB		
				Dawson	Dawson (Feeder 1)		6/4/2013 2:00:03 PM	6/4/2013 2:05:05 PM	0.08	422	35.4		T	12.47Kv
		2013-0007	Jun 05, 2013	Segs: 2	Dawson	(802) Protection Setting			12.09	861	10,404.9	YUB		
				Dawson	Dawson (Feeder 1)		6/5/2013 9:35:41 AM	6/5/2013 9:40:33 PM	12.08	422	5,098.2		T	12.47Kv
				Dawson	Dawson (Feeder 2)		6/5/2013 9:35:41 AM	6/5/2013 9:40:58 PM	12.09	439	5,306.7		T	12.47Kv
		Tot Qtr:3							24.56	2,144	10,571.1			
	Qtr 3	2013-0011	Jul 02, 2013	Segs: 2	Dawson	(300) Tree Contacts			0.13	861	107.0	YUB		
				Dawson	Dawson (Feeder 2)		7/2/2013 5:15:01 PM	7/2/2013 5:22:19 PM	0.12	439	53.4		T	12.47Kv

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2013	Qtr 3	2013-0011	Jul 02, 2013	Dawson	Dawson (Feeder 1)		7/2/2013 5:15:01 PM	7/2/2013 5:22:38 PM	0.13	422	53.6		T	12.47Kv
		2013-0012	Aug 08, 2013	Segs: 1	Dawson	(808) Other Human Element			0.11	439	47.4	YUB		
				Dawson	Dawson (Feeder 2)		8/8/2013 11:42:53 AM	8/8/2013 11:49:22 AM	0.11	439	47.4		T	12.47Kv
		2013-0013	Aug 11, 2013	Segs: 1	Dawson	(300) Tree Contacts			0.19	439	83.3	YUB		
				Dawson	Dawson (Feeder 2)		8/11/2013 2:33:02 PM	8/11/2013 2:44:25 PM	0.19	439	83.3		T	12.47Kv
		2013-0015	Sep 08, 2013	Segs: 1	Dawson	(300) Tree Contacts			0.17	439	73.2	YUB		
				Dawson	Dawson (Feeder 2)		9/8/2013 8:04:05 AM	9/8/2013 8:14:05 AM	0.17	439	73.2		T	12.47Kv
		2013-0016	Sep 08, 2013	Segs: 2	Dawson	(0) Unknown			0.11	861	88.5	YUB		
				Dawson	Dawson (Feeder 1)		9/8/2013 6:52:37 PM	9/8/2013 6:58:16 PM	0.09	422	39.7		T	12.47Kv
				Dawson	Dawson (Feeder 2)		9/8/2013 6:52:37 PM	9/8/2013 6:59:17 PM	0.11	439	48.8		T	12.47Kv
		2013-0017	Sep 24, 2013	Segs: 2	Dawson	(0) Unknown			0.30	861	193.3	YUB		
				Dawson	Dawson (Feeder 1)		9/24/2013 4:34:09 PM	9/24/2013 4:42:43 PM	0.14	422	60.3		T	12.47Kv
				Dawson	Dawson (Feeder 2)		9/24/2013 4:33:12 PM	9/24/2013 4:51:23 PM	0.30	439	133.0		T	12.47Kv
		Tot Qtr:6							1.36	3,900	592.7			
	Tot Yr: 12								26.95	8,627	11,606.0			
2014	Qtr 2	2014-0033	Apr 15, 2014	Segs: 2	Dawson	(503) Defective Equipment/Material	Outage caused by a failed Governor PLC for WH4.		0.20	857	161.0	YUB		
				Dawson	Dawson (Feeder 1)		4/15/2014 2:59:50 AM	4/15/2014 3:10:24 AM	0.18	420	74.0		T	4200V
				Dawson	Dawson (Feeder 2)		4/15/2014 2:59:50 AM	4/15/2014 3:11:47 AM	0.20	437	87.0		T	4200V
		2014-0038	May 02, 2014	Segs: 1	Dawson	(500) Equipment Failure	WH4 tripped off at 19.6MW while testing under CSP 14-115. After investigation it was foung that the governor PLC failed. CPU in PLC was replaced.		0.07	439	30.0	YUB		
				Dawson	Dawson (Feeder 2)		5/2/2014 2:49:21 PM	5/2/2014 2:53:27 PM	0.07	439	30.0		T	4200V
		2014-0040	May 18, 2014	Segs: 1	Dawson	(100) Scheduled Outage	Planned power outage to replace C Phase hot tap in Alley between 6th and 7th Avenues.		1.03	439	451.4	YUB		
				Dawson	Dawson (Feeder 2)		5/16/2014 11:48:13 AM	5/16/2014 12:49:55 PM	1.03	439	451.4		T	12.47Kv

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2014	Qtr 2	2014-0049	Jun 24, 2014	Segs: 2	Dawson	(300) Tree Contacts	Outage caused by a tree on L178 at structure 1318 just passed Drury Creek Campground. Note: The area where the tree contacted the power line was an area identified and was contracted by Ace Vegetation to be cleared this summer.		0.12	861	100.4	YUB		
				Dawson	Dawson (Feeder 1)		6/24/2014 4:14:00 PM	6/24/2014 4:21:00 PM	0.12	422	49.2		T	4200V
				Dawson	Dawson (Feeder 2)		6/24/2014 4:14:00 PM	6/24/2014 4:21:00 PM	0.12	439	51.2		T	4200V
		Tot Qtr:4							1.71	2,596	742.9			
	Qtr 3	2014-0081	Aug 04, 2014	Segs: 2	Dawson	(503) Defective Equipment/Material	System was split at S255-52-2 and L170-89-481 for GOI 14-240. Faro was on diesel generation. Carmacks was seperated from the grid and placed on AEY diesel generation. SCC was tying Faro and Mayo together via S255-52-2 when the Northern grid collapsed due to high voltage. After investigation it was found that the breaking resistors in Mayo were non operational and 1.1 MVAR Reactor was open in Mayo. December 05/2014 update; Michael Tilbrook informed SCC that the breaking resistors are now operational and the 1.1 MVAR Reactor is now closed.		0.14	861	116.3	YUB		
				Dawson	Dawson (Feeder 1)		8/4/2014 12:14:00 PM	8/4/2014 12:21:49 PM	0.13	422	55.0		T	4200V
				Dawson	Dawson (Feeder 2)		8/4/2014 12:14:00 PM	8/4/2014 12:22:23 PM	0.14	439	61.3		T	4200V
		2014-0085	Aug 12, 2014	Segs: 2	Dawson	(400) Lightning	Possibly a lightning strike as lightning and generally poor weather was reported at the time of the outage.Faro, Mayo and Dawson were seperated at S255. L170 was isolated at the time for structure/repair/replace.		0.12	861	101.5	YUB		
				Dawson	Dawson (Feeder 1)		8/12/2014 7:12:00 PM	8/12/2014 7:18:51 PM	0.11	422	48.2		T	4200V
				Dawson	Dawson (Feeder 2)		8/12/2014 7:12:00 PM	8/12/2014 7:19:17 PM	0.12	439	53.3		T	4200V
		Tot Qtr:2							0.51	1,722	217.8			
	Qtr 4	2014-0194	Dec 06, 2014	Segs: 1	Dawson	(203) Generation Inadvertent	WH4 Tripped - PLC failure		0.25	459	115.9	YUB		
				Dawson	Dawson (Feeder 2)		12/6/2014 10:07:58 PM	12/6/2014 10:23:07 PM	0.25	459	115.9		T	12.5Kv
		Tot Qtr:1							0.25	459	115.9			
	Tot Yr: 7								2.46	4,777	1,076.6			

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2015	Qtr 1	2015-0027	Jan 16, 2015	Segs: 2	Dawson	(603) Wet Snow	12cm of heavy wet snow with 22k winds at the time of the outage.		0.64	906	575.1	YUB		
				Dawson	Dawson (Feeder 1)		1/16/2015 2:35:36 AM	1/16/2015 3:13:19 AM	0.63	447	281.0		T	4200V
				Dawson	Dawson (Feeder 2)		1/16/2015 2:35:36 AM	1/16/2015 3:14:03 AM	0.64	459	294.1		T	4200V
		Tot Qtr:1							1.27	906	575.1			
	Qtr 2	2015-0098	May 14, 2015	Segs: 2	Dawson	(503) Defective Equipment/Material	Split Cross Arm on structure along L177. Insulator pulled free and contacted Guywire.		0.42	906	281.3	YUB		
				Dawson	Dawson (Feeder 1)		5/14/2015 1:26:06 PM	5/14/2015 1:38:12 PM	0.20	447	90.1		T	4200V
				Dawson	Dawson (Feeder 2)		5/14/2015 1:26:06 PM	5/14/2015 1:51:05 PM	0.42	459	191.1		T	4200V
		2015-0099	May 21, 2015	Segs: 1	Dawson	(506) Other Equipment Failure	DD5 tripped on Low coolant level. P158 52-F2 and S250 52-2 tripped on U/F.		0.13	459	61.5	YUB		
				Dawson	Dawson (Feeder 2)		5/21/2015 2:24:03 PM	5/21/2015 2:32:05 PM	0.13	459	61.5		T	4200V
		2015-0102	May 29, 2015	Segs: 2	Dawson	(400) Lightning	Lightning storm at time of outage. Dawson power restored using Dawson Diesel generation.		0.88	906	714.1	YUB		
				Dawson	Dawson (Feeder 1)		5/30/2015 6:40:30 AM	5/30/2015 7:22:05 AM	0.69	447	309.8		T	4200V
				Dawson	Dawson (Feeder 2)		5/29/2015 11:40:30 PM	5/30/2015 12:33:21 AM	0.88	459	404.3		T	4200V
		2015-0121	Jun 08, 2015	Segs: 2	Dawson	(400) Lightning	Reports of lightning between Dawson and Stewart North. Comms for P158 and S250 went down immediately. Dawson PLT called in to reset RTU - COMMS restored. Once COMMS restored, SCC was able to restore Dawson back to grid power.		0.21	906	187.3	YUB		
				Dawson	Dawson (Feeder 1)		6/8/2015 9:13:20 PM	6/8/2015 9:25:30 PM	0.20	447	90.6		T	4200V
				Dawson	Dawson (Feeder 2)		6/8/2015 9:13:20 PM	6/8/2015 9:25:58 PM	0.21	459	96.6		T	4200V
		2015-0139	Jun 25, 2015	Segs: 2	Dawson	(103) Maintenance	Planned power outage for YEC Electrician and Orbis under CSP 15-253 to change the PLC program and test run the Diesels.		0.55	906	500.3	YUB		
				Dawson	Dawson (Feeder 1)		6/25/2015 3:00:50 AM	6/25/2015 3:33:58 AM	0.55	447	246.8		T	4200V
				Dawson	Dawson (Feeder 2)		6/25/2015 3:00:50 AM	6/25/2015 3:33:58 AM	0.55	459	253.5		T	4200V
		2015-0141	Jun 24, 2015	Segs: 2	Dawson	(901) Wildlife (Bird/Animal)	Northern grid outage caused by a Raven that was discovered in 870S.		0.30	906	270.2	YUB		
				Dawson	Dawson (Feeder 2)		6/24/2015 8:20:16 AM	6/24/2015 8:38:27 AM	0.30	459	139.1		T	4200V
				Dawson	Dawson (Feeder 1)		6/24/2015 8:20:16 AM	6/24/2015 8:37:52 AM	0.29	447	131.1		T	4200V

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2015	Qtr 2	2015-0142	Jun 24, 2015	Segs: 2	Dawson	(203) Generation Inadvertent	Grids were seperated for L170 test and treat repairs. FD1 was on line because YEC Employee had a clearance to make changes to the P158 PLC which had all Dawson Diesels off line. FD1 tripped off causing a Dawson power outage. Cause was a valve cage cooling hi temp alarm.		0.27	906	205.4	YUB		
				Dawson	Dawson (Feeder 2)		6/24/2015 2:20:55 PM	6/24/2015 2:37:01 PM	0.27	459	123.2		T	4200V
				Dawson	Dawson (Feeder 1)		6/24/2015 2:20:55 PM	6/24/2015 2:31:57 PM	0.18	447	82.2		T	4200V
		2015-0143	Jun 25, 2015	Segs: 2	Dawson	(203) Generation Inadvertent	MBH1 tripped off line at 4.3MW. Alarms on MBH1 were, MBH1 non drive end thrust bearing pad #1 Hi temp alarm and MBH1 86M1 Lockout.		0.19	906	169.0	YUB		
				Dawson	Dawson (Feeder 1)		6/25/2015 9:34:53 AM	6/25/2015 9:45:50 AM	0.18	447	81.6		T	4200V
				Dawson	Dawson (Feeder 2)		6/25/2015 9:34:53 AM	6/25/2015 9:46:19 AM	0.19	459	87.5		T	4200V
		Tot Qtr:8							5.27	6,801	2,389.0			
	Qtr 3	2015-0157	Jul 13, 2015	Segs: 2	Dawson	(400) Lightning	Lightning Strike was the cause. Rain and Thunderclouds reported in the area. S250 57-1 grounding switch closed and had to be opened.		0.25	906	225.3	YUB		
				Dawson	Dawson (Feeder 1)		7/13/2015 3:38:50 PM	7/13/2015 3:53:27 PM	0.24	447	108.9		T	4200V
				Dawson	Dawson (Feeder 2)		7/13/2015 3:38:50 PM	7/13/2015 3:54:03 PM	0.25	459	116.4		T	4200V
		2015-0158	Jul 17, 2015	Segs: 2	Dawson	(808) Other Human Element	MH2 Tripped due to hi bearing temperature at 07:12:11. At 07:11:15 there was an MH2 MW Hi Alarm @ 2.70MW as well as 5 Mayo Penstock Hi level alarms between 07:04 and 07:05 that gave the SCC Operator indication that there was an over load issue with MH2.		0.16	906	129.1	YUB		
				Dawson	Dawson (Feeder 1)		7/17/2015 7:12:30 AM	7/17/2015 7:19:48 AM	0.12	447	54.4		T	4200V
				Dawson	Dawson (Feeder 2)		7/17/2015 7:12:30 AM	7/17/2015 7:22:16 AM	0.16	459	74.7		T	4200V
		2015-0159	Jul 17, 2015	Segs: 2	Dawson	(400) Lightning	There were reports of lightning storms in the area at the time of the outage. S256 L177A LED occurred alarm , L177 inst trip Alarm, L177A LED Zone 1Fault , L177A LED ground fault alarm , L177A LEDPhase A alarm, L177A LED 50 trip Alarm, L177B LED trip Alarm , L177B LED A Phase trip alarm , L177B BPhase trip alarm. L176 A freq hi 61.7, L177 A Phase B to Ground Voltage Lo , L177B LED Zone 1 fault alarm .		0.18	906	161.8	YUB		
				Dawson	Dawson (Feeder 1)		7/17/2015 6:13:32 PM	7/17/2015 6:23:57 PM	0.17	447	77.6		T	4200V
				Dawson	Dawson (Feeder 2)		7/17/2015 6:13:32 PM	7/17/2015 6:24:32 PM	0.18	459	84.1		T	4200V
		2015-0167	Jul 26, 2015	Segs: 2	Dawson	(400) Lightning	There were reports of lightning storms in the area at the time of the outage. Diesel DD3 tripped twice as soon as they tried to close P158-52-EF locally.		0.18	906	160.5	YUB		

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				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2015	Qtr 3	2015-0167	Jul 26, 2015	Dawson	Dawson (Feeder 2)		7/26/2015 5:49:55 PM	7/26/2015 6:00:50 PM	0.18	459	83.5		T	4200V
				Dawson	Dawson (Feeder 1)		7/26/2015 5:49:55 PM	7/26/2015 6:00:15 PM	0.17	447	77.0		T	4200V
		2015-0181	Aug 10, 2015	Segs: 1	Dawson	(400) Lightning	Walter Tindal placed S250 SC1 on line ....Lightning is suspected as a storm was reported at the time of the outage. System went back together without incident Bevon Keefer assisted in restoration. DD2 and DD3 stayed on line (Grids Seperated) Feeder 1 stayed closed.		0.14	459	64.0	YUB		
				Dawson	Dawson (Feeder 2)		8/10/2015 7:08:25 PM	8/10/2015 7:16:47 PM	0.14	459	64.0		T	4200V
		2015-0183	Aug 20, 2015	Segs: 2	Dawson	(304) Off-ROW Tree	Suspect tree on the line approx. 170km east of Carmacks. Mike Sage flew the line from Carmacks and discovered an off-ROW tree on the line. Mike removed tree. SCC was able to tie the grids back together at S164. L178 isolated and Faro mine site being fed from FD7.		0.30	906	271.1	YUB		
				Dawson	Dawson (Feeder 1)		8/20/2015 3:25:28 AM	8/20/2015 3:43:10 AM	0.30	447	131.9		T	4200V
				Dawson	Dawson (Feeder 2)		8/20/2015 3:25:28 AM	8/20/2015 3:43:40 AM	0.30	459	139.2		T	4200V
		2015-0189	Sep 06, 2015	Segs: 2	Dawson	(503) Defective Equipment/Material	There was a false fire alarm in P158. This false fire alarm resulted in all Dawson Diesel units locking out and tripped Feeder 1 and Feeder 2.		0.30	906	234.5	YUB		
				Dawson	Dawson (Feeder 1)		9/6/2015 11:23:00 AM	9/6/2015 11:36:00 AM	0.22	447	96.8		T	4200V
				Dawson	Dawson (Feeder 2)		9/6/2015 11:23:00 AM	9/6/2015 11:41:00 AM	0.30	459	137.7		T	4200V
		2015-0193	Sep 15, 2015	Segs: 2	Dawson	(806) Commissioning Error	WH1 tripped offline due to manual input of gate limit. SCC manually entered a gate limit of '99' which was the same value already targeted. Lead Electrician deducted an error in the PLC programming caused the gate to shut when it should not have.		0.10	906	86.6	YUB		
				Dawson	Dawson (Feeder 1)		9/15/2015 1:26:48 PM	9/15/2015 1:32:52 PM	0.10	447	45.2		T	4200V
				Dawson	Dawson (Feeder 2)		9/15/2015 1:26:48 PM	9/15/2015 1:32:13 PM	0.09	459	41.4		T	4200V
		2015-0195	Sep 29, 2015	Segs: 2	Dawson	(304) Off-ROW Tree	Wind gusts up to 70k knocked tree onto power line along L178.		0.13	906	110.0	YUB		
				Dawson	Dawson (Feeder 2)		9/29/2015 9:51:29 AM	9/29/2015 9:59:01 AM	0.13	459	57.6		T	4200V
				Dawson	Dawson (Feeder 1)		9/29/2015 9:51:29 AM	9/29/2015 9:58:31 AM	0.12	447	52.4		T	4200V
		Tot Qtr:9							3.18	7,707	1,443.0			
	Qtr 4	2015-0199	Oct 02, 2015	Segs: 2	Dawson	(503) Defective Equipment/Material	AH3 tripped due to faulty solenoid for the TIV.		0.29	906	256.5	YUB		
				Dawson	Dawson (Feeder 1)		10/2/2015 7:57:53 PM	10/2/2015 8:14:30 PM	0.28	447	123.8		T	4200V
				Dawson	Dawson (Feeder 2)		10/2/2015 7:57:53 PM	10/2/2015 8:15:14 PM	0.29	459	132.7		T	4200V

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2015	Qtr 4	2015-0221	Nov 13, 2015	Segs: 1	Dawson	(603) Wet Snow	Heavy snow was reported in the area at the time of this outage. Lineman suspects line slap from snow falling off the power lines. The grid was tied back together at 11:41:49.		0.15	459	67.2	YUB		
				Dawson	Dawson (Feeder 2)		11/13/2015 8:29:42 AM	11/13/2015 8:38:29 AM	0.15	459	67.2		T	4200V
		Tot Qtr:2							0.71	1,365	323.7			
	Tot Yr: 20								10.43	16,779	4,730.9			
2016	Qtr 1	2016-0007	Jan 15, 2016	Segs: 2	Dawson	(911) Other foreign Interference	Elevator repair personnel hit the emergency stop button for AH1. AH1 tripped off line with approximately 11.5MW of load.		0.18	906	150.1	YUB		
				Dawson	Dawson (Feeder 1)		1/15/2016 9:17:13 AM	1/15/2016 9:27:43 AM	0.18	447	78.2		T	4200V
				Dawson	Dawson (Feeder 2)		1/15/2016 9:17:13 AM	1/15/2016 9:26:37 AM	0.16	459	71.9		T	4200V
		2016-0008	Jan 18, 2016	Segs: 2	Dawson	(601) Extreme Wind	50K winds and heavy snow were reported at the time of this outage.		0.31	906	279.1	YUB		
				Dawson	Dawson (Feeder 1)		1/18/2016 9:41:50 PM	1/18/2016 10:00:04 PM	0.30	447	135.8		T	4200V
				Dawson	Dawson (Feeder 2)		1/18/2016 9:41:50 PM	1/18/2016 10:00:34 PM	0.31	459	143.3		T	4200V
		2016-0010	Jan 25, 2016	Segs: 2	Dawson	(604) Ice/Icing	Suspect power line slap due to the heavy frost/ice built up on the lines. Mild weather reported which caused frost/ice to fall off the lines.		0.42	906	378.3	YUB		
				Dawson	Dawson (Feeder 1)		1/25/2016 6:37:06 PM	1/25/2016 7:01:59 PM	0.41	447	185.4		T	4200V
				Dawson	Dawson (Feeder 2)		1/25/2016 6:37:06 PM	1/25/2016 7:02:19 PM	0.42	459	192.9		T	4200V
		Tot Qtr:3							1.78	2,718	807.6			
	Qtr 2	2016-0092	Jun 30, 2016	Segs: 2	Dawson	(400) Lightning	Heavy lightning and rain reported at the time of the outage.		0.13	906	113.3	YUB		
				Dawson	Dawson (Feeder 2)		6/30/2016 6:58:00 PM	6/30/2016 7:05:45 PM	0.13	459	59.3		T	4200V
				Dawson	Dawson (Feeder 1)		6/30/2016 6:58:00 PM	6/30/2016 7:05:15 PM	0.12	447	54.0		T	4200V
		Tot Qtr:1							0.25	906	113.3			
	Qtr 3	2016-0095	Jul 11, 2016	Segs: 2	Dawson	(400) Lightning	Thunder/lightning storm at the time of the outage.		0.18	906	158.1	YUB		
				Dawson	Dawson (Feeder 1)		7/11/2016 6:45:30 PM	7/11/2016 6:55:45 PM	0.17	447	76.4		T	4200V
				Dawson	Dawson (Feeder 2)		7/11/2016 6:45:30 PM	7/11/2016 6:56:11 PM	0.18	459	81.7		T	4200V
		2016-0099	Jul 12, 2016	Segs: 2	Dawson	(400) Lightning	Thunder/lightning storm Territory wide was the cause of this outage.		0.49	906	337.2	YUB		
				Dawson	Dawson (Feeder 1)		7/12/2016 5:59:10 PM	7/12/2016 6:14:29 PM	0.26	447	114.1		T	4200V
				Dawson	Dawson (Feeder 2)		7/12/2016 5:59:10 PM	7/12/2016 6:28:20 PM	0.49	459	223.1		T	4200V

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2016	Qtr 3	2016-0104	Jul 14, 2016	Segs: 2	Dawson	(400) Lightning	Thunder and lightning storm at the time of the outage.		0.17	906	148.6	YUB		
				Dawson	Dawson (Feeder 1)		7/15/2016 7:44:40 PM	7/15/2016 7:54:00 PM	0.16	447	69.5		T	4200V
				Dawson	Dawson (Feeder 2)		7/15/2016 7:44:40 PM	7/15/2016 7:55:00 PM	0.17	459	79.0		T	4200V
		2016-0105	Jul 15, 2016	Segs: 2	Dawson	(503) Defective Equipment/Material	WH4 Tripped off line at 17.5MW. Cause of the trip was a loose wire on the governor. Loose wire was cold soldered and reconnected.		0.17	906	147.6	YUB		
				Dawson	Dawson (Feeder 1)		7/15/2016 1:51:44 AM	7/15/2016 2:01:00 AM	0.15	447	69.0		T	4200V
				Dawson	Dawson (Feeder 2)		7/15/2016 1:51:44 AM	7/15/2016 2:02:00 AM	0.17	459	78.5		T	4200V
		2016-0107	Jul 15, 2016	Segs: 2	Dawson	(400) Lightning	Severe thunder and lightning storm at the time of the outage.		0.24	906	209.8	YUB		
				Dawson	Dawson (Feeder 1)		7/15/2016 8:06:15 PM	7/15/2016 8:19:53 PM	0.23	447	101.6		T	4200V
				Dawson	Dawson (Feeder 2)		7/15/2016 8:06:15 PM	7/15/2016 8:20:24 PM	0.24	459	108.2		T	4200V
		Tot Qtr:5							2.21	4,530	1,001.3			
	Qtr 4	2016-0138	Nov 29, 2016	Segs: 2	Dawson	(605) Other Adverse Weather	Strong blowing winds mixed with heavy snow fall at the time of the outage.		0.23	906	205.2	YUB		
				Dawson	Dawson (Feeder 2)		11/29/2016 7:59:08 PM	11/29/2016 8:13:02 PM	0.23	459	106.3		T	4200V
				Dawson	Dawson (Feeder 1)		11/29/2016 7:59:08 PM	11/29/2016 8:12:24 PM	0.22	447	98.8		T	4200V
		2016-0140	Dec 12, 2016	Segs: 1	Dawson	(802) Protection Setting	After short investigation it was discovered the breaker settings were set too low. Changed settings from non breaker to hi load setting. Feeder #1 closed and held.		0.09	447	39.7	YUB		
				Dawson	Dawson (Feeder 1)		12/12/2016 12:14:20 PM	12/12/2016 12:19:40 PM	0.09	447	39.7		T	4200V
		2016-0143	Dec 30, 2016	Segs: 2	Dawson	(603) Wet Snow	Heavy snowfall with strong winds were the cause of this outage.		0.27	906	238.9	YUB		
				Dawson	Dawson (Feeder 1)		12/30/2016 12:55:47 AM	12/30/2016 1:11:27 AM	0.26	447	116.7		T	4200V
				Dawson	Dawson (Feeder 2)		12/30/2016 12:55:47 AM	12/30/2016 1:11:45 AM	0.27	459	122.1		T	69Kv
		Tot Qtr:3							1.07	2,259	483.8			
	Tot Yr: 12								5.31	10,413	2,405.9			
2017	Qtr 1	2017-0006	Jan 17, 2017	Segs: 2	Dawson	(706) Other Adverse Environment	Aishihik Plant slowly began to shed load until all three Aishihik units were taken off line. This event was caused by a complete ice build up on the intake - warm weather caused ice to weaken along power canal and eventually break off and plug up intake. Divers and steamer truck needed to remove ice/debris from trashracks. Minto Mine placed on their back up diesel generators until Aishihik plant brought back to service.		0.38	906	342.8	YUB		

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2017	Qtr 1	2017-0006	Jan 17, 2017	Dawson	Dawson (Feeder 1)		1/17/2017 7:34:53 AM	1/17/2017 7:57:13 AM	0.37	447	166.4		T	4200V
				Dawson	Dawson (Feeder 2)		1/17/2017 7:34:51 AM	1/17/2017 7:57:55 AM	0.38	459	176.5		T	4200V
		2017-0007	Feb 01, 2017	Segs: 2	Dawson	(808) Other Human Element	System split at the time of this outage for a structure repair along L178. Voltage spiked when closing in S255-52-2, picking up all of L178 as well as to L170-89-481. It was later determined that the GOI point that was used (L178-89-481) created too many MVAR's as it was later decided that L170-89-754A should have been the GOI point (Less line voltage). Also, as voltage increased rapidly SCC tried to lower voltage with S251 Tap Changer. Tap changer adjusted in wrong direction.		0.31	906	277.3	YUB		
				Dawson	Dawson (Feeder 1)		2/1/2017 11:16:41 AM	2/1/2017 11:34:47 AM	0.30	447	134.8		T	4200V
				Dawson	Dawson (Feeder 2)		2/1/2017 11:16:41 AM	2/1/2017 11:35:18 AM	0.31	459	142.4		T	4200V
		2017-0010	Feb 18, 2017	Segs: 2	Dawson	(501) Electrical Failure	WAFMD system wide outage. Mayo and Haines Jct. were the only locations left with power. WH4 tripped at 18.9MW. After investigation it was determined that a control circuit failed on the exciter.		0.23	906	209.4	YUB		
				Dawson	Dawson (Feeder 1)		2/18/2017 3:08:16 PM	2/18/2017 3:21:57 PM	0.23	447	101.9		T	4200V
				Dawson	Dawson (Feeder 2)		2/18/2017 3:08:16 PM	2/18/2017 3:22:19 PM	0.23	459	107.5		T	4200V
		2017-0014	Feb 28, 2017	Segs: 2	Dawson	(501) Electrical Failure	AH2 tripped on over voltage. After investigation it was determined that AH2 tripped due to all 11 brushes on one of the slip rings being damaged (5 severely). The cause may be due to contamination of fiberglass dust and access to perform regular checks on the Aishihik units.		0.11	906	96.6	YUB		
				Dawson	Dawson (Feeder 1)		2/28/2017 2:47:56 PM	2/28/2017 2:53:56 PM	0.10	447	44.7		T	4200V
				Dawson	Dawson (Feeder 2)		2/28/2017 2:47:53 PM	2/28/2017 2:54:40 PM	0.11	459	51.9		T	4200V
		Tot Qtr:4							2.04	3,624	926.1			
	Qtr 2	2017-0031	Apr 22, 2017	Segs: 2	Dawson	(304) Off-ROW Tree	This outage affected the Northern grid. After flying the lines (L170 and L178) a tree was discovered on L178 across from Little Salmon campground between structures 1166 and 1167. Heavy winds were witnessed/reported at the time of this outage.		0.67	906	367.4	YUB		
				Dawson	Dawson (Feeder 1)		4/22/2017 12:00:54 PM	4/22/2017 12:09:02 PM	0.14	447	60.6		T	4200V
				Dawson	Dawson (Feeder 2)		4/22/2017 12:00:54 PM	4/22/2017 12:41:00 PM	0.67	459	306.8		T	4200V
		2017-0061	Jun 22, 2017	Segs: 2	Dawson	(400) Lightning	The Outage was likely due to Lightning. The Canadian Lightning Danger Map was showing extreme strikes throughout Northern Yukon. Dawson had a Fire Rating of High. Dawson PLT patrolled the line before SCC closed in on Hunker and S250 52-1.		0.26	906	233.9	YUB		

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2017	Qtr 2	2017-0061	Jun 22, 2017	Dawson	Dawson (Feeder 1)		6/22/2017 7:23:40 PM	6/22/2017 7:38:52 PM	0.25	447	113.2		T	4200V
				Dawson	Dawson (Feeder 2)		6/22/2017 7:23:40 PM	6/22/2017 7:39:26 PM	0.26	459	120.6		T	4200V
		2017-0062	Jun 25, 2017	Segs: 2	Dawson	(400) Lightning	Heavy thunder and lightning reported at the time of this outage. PLT's dispatched to fly L178 and L170. Nothing discovered.		0.30	906	262.9	YUB		
				Dawson	Dawson (Feeder 1)		6/25/2017 4:22:30 PM	6/25/2017 4:39:07 PM	0.28	447	123.8		T	4200V
				Dawson	Dawson (Feeder 2)		6/25/2017 4:22:30 PM	6/25/2017 4:40:41 PM	0.30	459	139.1		T	4200V
		2017-0065	Jun 27, 2017	Segs: 2	Dawson	(205) Other Loss of Supply	AH1 tripped due to thrust bearing high temperature alarm. This trip is under investigation.		0.04	906	34.0	YUB		
				Dawson	Dawson (Feeder 1)		6/27/2017 12:19:19 PM	6/27/2017 12:21:33 PM	0.04	447	16.6		T	4200V
				Dawson	Dawson (Feeder 2)		6/27/2017 12:19:17 PM	6/27/2017 12:21:33 PM	0.04	459	17.3		T	4200V
		Tot Qtr:4							1.97	3,624	898.1			
	Qtr 3	2017-0094	Jul 25, 2017	Segs: 2	Dawson	(400) Lightning	Major Lightning/Thunder storms Territory wide. Outage caused by lightning strike in Minto area.		0.05	934	45.9	YUB		
				Dawson	Dawson (Feeder 1)		7/25/2017 7:46:23 PM	7/25/2017 7:49:29 PM	0.05	466	24.1		T	4200V
				Dawson	Dawson (Feeder 2)		7/25/2017 7:46:23 PM	7/25/2017 7:49:11 PM	0.05	468	21.8		T	4200V
		2017-0095	Aug 03, 2017	Segs: 1	Dawson	(503) Defective Equipment/Material	WH4 speed signal failed, WH4 secondary speed device failed which caused the unit to trip off line and shut down.		0.14	468	66.7	YUB		
				Dawson	Dawson (Feeder 2)		8/3/2017 7:40:18 AM	8/3/2017 7:48:51 AM	0.14	468	66.7		T	4200V
		2017-0097	Aug 08, 2017	Segs: 2	Dawson	(802) Protection Setting	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.		0.28	934	258.1	YUB		
				Dawson	Dawson (Feeder 1)		8/8/2017 7:25:01 AM	8/8/2017 7:41:36 AM	0.28	466	128.8		T	4200V
				Dawson	Dawson (Feeder 2)		8/8/2017 7:25:01 AM	8/8/2017 7:41:36 AM	0.28	468	129.3		T	4200V
		2017-0098	Aug 08, 2017	Segs: 1	Dawson	(503) Defective Equipment/Material	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.		0.27	468	127.5	YUB		
				Dawson	Dawson (Feeder 2)		8/8/2017 4:30:17 PM	8/8/2017 4:46:38 PM	0.27	468	127.5		T	4200V

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				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2017	Qtr 3	2017-0099	Aug 09, 2017	Segs: 1	Dawson	(506) Other Equipment Failure	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.		0.23	468	109.7	YUB		
				Dawson	Dawson (Feeder 2)		8/9/2017 4:16:38 AM	8/9/2017 4:30:42 AM	0.23	468	109.7		T	4200V
		2017-0103	Sep 13, 2017	Segs: 2	Dawson	(0) Unknown	S256-52-2 tripped. Attempted a close on S256-52-2, which held. DD2 failed to synch on line and P158-52-EF had to be closed locally.		0.32	934	286.9	YUB		
				Dawson	Dawson (Feeder 1)		9/13/2017 12:50:26 PM	9/13/2017 1:09:50 PM	0.32	466	150.7		T	4200V
				Dawson	Dawson (Feeder 2)		9/13/2017 12:50:26 PM	9/13/2017 1:07:54 PM	0.29	468	136.2		T	4200V
		Tot Qtr:6							1.91	4,206	894.9			
	Qtr 4	2017-0115	Oct 17, 2017	Segs: 1	Dawson	(103) Maintenance	Planned outage to Dawson City Customers to set power poles under work order # C17045.		2.09	468	976.4	YUB		
				Dawson	Dawson (Feeder 2)		10/17/2017 4:00:04 AM	10/17/2017 6:05:15 AM	2.09	468	976.4		T	4200V
		2017-0116	Oct 19, 2017	Segs: 1	Dawson	(103) Maintenance	Planned isolation for Dawson City Customers fed from Feeder #1. Isolation needed to set power poles.		1.89	466	880.6	YUB		
				Dawson	Dawson (Feeder 1)		10/19/2017 4:00:04 AM	10/19/2017 5:53:27 AM	1.89	466	880.6		T	4200V
		2017-0118	Oct 30, 2017	Segs: 2	Dawson	(0) Unknown	AH2 tripped on a 86M Mechanical lockout. No cause determined.		0.21	934	192.9	YUB		
				Dawson	Dawson (Feeder 1)		10/30/2017 11:19:38 AM	10/30/2017 11:31:53 AM	0.20	466	95.1		T	4200V
				Dawson	Dawson (Feeder 2)		10/30/2017 11:19:36 AM	10/30/2017 11:32:08 AM	0.21	468	97.8		T	4200V
		2017-0127	Nov 21, 2017	Segs: 2	Dawson	(604) Ice/Icing	Heavy frost built up on the power lines. Very windy at the time of the outage. Line slap from frost coming off the power lines most likely the cause.		0.15	934	136.2	YUB		
				Dawson	Dawson (Feeder 1)		11/21/2017 4:22:57 PM	11/21/2017 4:31:24 PM	0.14	466	65.6		T	4200V
				Dawson	Dawson (Feeder 2)		11/21/2017 4:22:57 PM	11/21/2017 4:32:00 PM	0.15	468	70.6		T	4200V

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2017	Qtr 4	2017-0128	Nov 21, 2017	Segs: 2	Dawson	(802) Protection Setting	After restoration of the outage at 16:22 S250 RT1 did not go back to normal setpoint automatically. It was at step 9 and should have been step 7. Local lineman changed steps and voltages all returned to normal. Feeder 1 and Feeder 2 both tripped on under voltage.		0.23	934	177.4	YUB		
				Dawson	Dawson (Feeder 1)		11/21/2017 5:34:34 PM	11/21/2017 5:43:44 PM	0.15	466	71.2		T	4200V
				Dawson	Dawson (Feeder 2)		11/21/2017 5:34:34 PM	11/21/2017 5:48:11 PM	0.23	468	106.2		T	4200V
		2017-0129	Nov 24, 2017	Segs: 1	Dawson	(808) Other Human Element	Orbis was working on protection relays and settings in Minto landing and caused S253-52-2 to open on undervoltage. An incident report will be completed		0.13	468	58.5	YUB		
				Dawson	Dawson (Feeder 2)		11/24/2017 4:59:03 PM	11/24/2017 5:06:33 PM	0.13	468	58.5		T	4200V
		2017-0131	Dec 10, 2017	Segs: 2	Dawson	(301) Falling Tree	Tree on the line discovered near Little Salmon area. Faulty indications to S164-52-1 and S164-52-2 delayed restoration to Faro and tying the grid back together.		0.25	934	220.8	YUB		
				Dawson	Dawson (Feeder 2)		12/10/2017 4:13:25 AM	12/10/2017 4:28:12 AM	0.25	468	115.3		T	4200V
				Dawson	Dawson (Feeder 1)		12/10/2017 4:13:25 AM	12/10/2017 4:27:00 AM	0.23	466	105.5		T	4200V
		Tot Qtr:7							5.66	5,138	2,642.9			
	Tot Yr: 21								11.59	16,592	5,362.0			
2018	Qtr 1	2018-0009	Feb 07, 2018	Segs: 2	Dawson	(501) Electrical Failure	Protection and Systems Engineer: Based on what tripped I am about 90% sure that it was the T1 protection that operated. When it operates, it also trips the R1 lockout relay (along with the 52-5 lockout relay, the SC1 lockout relay, and the high-speed grounding switch). The reactor protection only trips the reactor lockout relay, not the rest. Furthermore, the last event logs that I did see from the relay (from November 2017) showed the overcurrent protection on T1 picking up and dropping out multiple times under non-fault conditions. There are some setting changes waiting to be applied that would increase the pickup slightly.		0.21	934	192.0	YUB		
				Dawson	Dawson (Feeder 1)		2/7/2018 12:12:37 PM	2/7/2018 12:24:42 PM	0.20	466	93.8		T	4200V
				Dawson	Dawson (Feeder 2)		2/7/2018 12:12:37 PM	2/7/2018 12:25:12 PM	0.21	468	98.1		T	4200V
		Tot Qtr:1							0.41	934	192.0			

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2018	Qtr 2	2018-0023	Apr 10, 2018	Segs: 2	Dawson	(501) Electrical Failure	TIV closed resulting in AH1 shutdown. After investigation it was determined that the TIV had a stuck Electrical Actuated valve. When looking at the PLC program it showed that a bit called the TIV open_command_latch was not getting turned on. The request for an open should cause this latch to happen. This command is blocked only by a TIV Alarm or a TIV Close command. When operating the TIV it was noted that it immediately went into alarm and then cleared after the TIV fully traveled. This happened in both directions (open or Close). Further investigation showed that at least one of the Atco electrically operated valves was stuck causing a Fail to open Alarm thus allowing water flow when it should not and without the Open Latch signal the TIV was able to drift off of its fully open state. I will try to get the signal from the Open latch bit indicating to our SCADA System for a short term solution. I believe we need to look into some stronger type of operating valves to insure that after sitting for a few months the control power will be strong enough to move the valve. Minto Mine left on their own dieswel generation until Aishihik problem resolved.		0.24	934	219.5	YUB		
				Dawson	Dawson (Feeder 1)		4/10/2018 3:52:46 PM	4/10/2018 4:06:42 PM	0.23	466	108.2		T	4200V
				Dawson	Dawson (Feeder 2)		4/10/2018 3:52:46 PM	4/10/2018 4:07:02 PM	0.24	468	111.3		T	4200V
		2018-0025	Apr 24, 2018	Segs: 1	Dawson	(506) Other Equipment Failure	Operator was switching storage tanks to accommodate LNG truck offload. The send out tank switched to the storage tank and units tripped on low gas pressure. Operations Coordinator working with GP Strategies to rectify problem.		0.13	468	62.4	YUB		
				Dawson	Dawson (Feeder 2)		4/24/2018 7:48:00 AM	4/24/2018 7:56:00 AM	0.13	468	62.4		T	4200V
		2018-0044	May 30, 2018	Segs: 2	Dawson	(400) Lightning	Lightning strike near Callison Substation was cause. Also, Lineman reported burnt transformer and a blown fuse. Replaced transformer and re-fused.		0.19	934	154.4	YUB		
				Dawson	Dawson (Feeder 1)		5/30/2018 7:31:51 PM	5/30/2018 7:40:13 PM	0.14	466	65.0		T	4200V
				Dawson	Dawson (Feeder 2)		5/30/2018 7:31:51 PM	5/30/2018 7:43:19 PM	0.19	468	89.4		T	4200V

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Year	Quarter	Id	Date			(Code) Description	Comment							
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2018	Qtr 2	2018-0075	Jun 20, 2018	Segs: 2	Dawson	(304) Off-ROW Tree	Lost everything on the Northern Grid except Mayo Townsite. MH1 was the only hydro generator online and very overloaded to the point of cycle degradation. L250 fault tripped S249 52-4 and S249 52-5 which effectively disconnected MBH0 from the rest of the grid. Dawson islanded for restoration. The system was delivering very poor power quality to Minto Mine and Faro couldn't synch to the grid due to low Hz. Only MH1 was online. SCC dumped Minto Mine to regain Hz and opened S249 89-17 to bridge back and regain MBH1 for generation. Minto Mine remains on their own diesel power. A leaning structure was found and believed to be the cause. After investigation a tree had fallen onto the structure and caused it to lean. Rick Brooker and Daniel Lafleur dismantled the structure and SCC energized using MBH1. S253 52-1 and 52-2 deadbus closes didn't work. Matt O'Brien closed breakers locally.		0.47	934	416.2	YUB		
				Dawson	Dawson (Feeder 2)		6/20/2018 11:43:18 AM	6/20/2018 12:08:24 PM	0.42	468	195.8		T	12.47Kv
				Dawson	Dawson (Feeder 1)		6/20/2018 11:43:18 AM	6/20/2018 12:11:41 PM	0.47	466	220.4		T	4200V
		Tot Qtr:4							1.83	3,270	852.5			
	Qtr 3	2018-0082	Jul 24, 2018	Segs: 2	Dawson	(501) Electrical Failure	WH3 tripped on an 86E Electrical Fault. The cause of the 86e was		1.77	934	1,645.0	YUB		
				Dawson	Dawson (Feeder 1)		7/24/2018 6:32:07 PM	7/24/2018 8:17:32 PM	1.76	466	818.7		T	4200V
				Dawson	Dawson (Feeder 2)		7/24/2018 6:32:07 PM	7/24/2018 8:18:03 PM	1.77	468	826.3		T	4200V
		2018-0085	Jul 27, 2018	Segs: 1	Dawson	(301) Falling Tree	Earlier today S255-52-1 tripped. Outages in Faro and along L178 were experienced. SCC was just informed that Whitehorse PLT flew the line and the all clear was given to SCC to reenergize the power line. After closing S255-52-1 it tripped immediately. Whitehorse PLT flew the line again and discovered a tree was discovered on the power line just north of Drury Creek. As it was getting too late to remove the tree, L178 was isolated from North of Drury Creek to Faro for the night. The next day (July 28) the tree was removed and L178 was reenergized.		0.19	468	87.1	YUB		
				Dawson	Dawson (Feeder 2)		7/27/2018 8:35:19 PM	7/27/2018 8:46:29 PM	0.19	468	87.1		T	4200V

Year	Quarter	Id	Date			(Code) Description	Comment							
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2018	Qtr 3	2018-0100	Sep 12, 2018	Segs: 2	Dawson	(911) Other foreign Interference	Contractors washing the building at the time all five Dawson Diesel units locked out and both Feeder 1 and Feeder 2 tripped. After investigation by YEC Electrician, he stated " my assumption is that the water from the sprinkler system must have some how got a low pressure. There is a valve which is labeled inspectors test that may have been used. The only two thing that will trip all units and feeders are the emergency shutdown button or the sprinkler system(not the fire alarm). This has happened a few times in the past.		0.35	934	293.5	YUB		
				Dawson	Dawson (Feeder 1)		9/12/2018 2:23:51 PM	9/12/2018 2:45:07 PM	0.35	466	165.2		T	4200V
				Dawson	Dawson (Feeder 2)		9/12/2018 2:23:51 PM	9/12/2018 2:40:18 PM	0.27	468	128.3		T	4200V
		Tot Qtr:3							4.34	2,336	2,025.6			
	Qtr 4	2018-0117	Nov 13, 2018	Segs: 2	Dawson	(304) Off-ROW Tree	Heavy snow and strong winds in the north (Carmacks to Faro). PLT noticed outside ROW trees heavily weighted down by snow. Possible tree contact on L178 may be cause of outage as no other possible cause reported.		0.20	934	179.0	YUB		
				Dawson	Dawson (Feeder 1)		11/13/2018 7:34:00 PM	11/13/2018 7:45:00 PM	0.18	466	85.4		T	4200V
				Dawson	Dawson (Feeder 2)		11/13/2018 7:34:00 PM	11/13/2018 7:46:00 PM	0.20	468	93.6		T	4200V
		Tot Qtr:1							0.38	934	179.0			
	Tot Yr: 9								6.96	7,474	3,249.2			
2019	Qtr 1	2019-0020	Mar 08, 2019	Segs: 2	Dawson	(506) Other Equipment Failure	Outage due to loss of WGO plant generation. Manually Pressure build idle tank @ 30,000L and swap tanks manually until process issues are sorted out.		0.12	934	101.2	YUB		
				Dawson	Dawson (Feeder 1)		3/8/2019 6:04:00 PM	3/8/2019 6:11:00 PM	0.12	466	54.4		T	4200V
				Dawson	Dawson (Feeder 2)		3/8/2019 6:04:00 PM	3/8/2019 6:10:00 PM	0.10	468	46.8		T	4200V
		Tot Qtr:1							0.22	934	101.2			
	Qtr 2	2019-0043	May 31, 2019	Segs: 1	Dawson	(203) Generation Inadvertent	WG3 tripped off with a transmission oil low level.		0.17	468	77.6	YUB		
				Dawson	Dawson (Feeder 2)		5/31/2019 11:49:54 AM	5/31/2019 11:59:51 AM	0.17	468	77.6		T	4200V
		2019-0048	Jun 08, 2019	Segs: 2	Dawson	(400) Lightning	Caused by lightning strike in Dawson area. Lots of lightning strikes reported at the time of the outage. Outage duration prolonged due to COMMS issues in the North.		0.42	934	388.4	YUB		
				Dawson	Dawson (Feeder 1)		6/8/2019 7:33:00 PM	6/8/2019 7:57:50 PM	0.41	466	192.9		T	4200V
				Dawson	Dawson (Feeder 2)		6/8/2019 7:33:00 PM	6/8/2019 7:58:04 PM	0.42	468	195.5		T	4200V

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2019	Qtr 2	2019-0062	Jun 30, 2019	Segs: 2	Dawson	(400) Lightning	Multiple lightning strikes.		1.12	934	1,011.8	YUB		
				Dawson	Dawson (Feeder 1)		6/30/2019 2:15:51 PM	6/30/2019 3:18:37 PM	1.05	466	487.5		T	4200V
				Dawson	Dawson (Feeder 2)		6/30/2019 2:15:51 PM	6/30/2019 3:23:04 PM	1.12	468	524.3		T	4200V
		2019-0064	Jun 25, 2019	Segs: 1	Dawson	(400) Lightning	Lightening Strike.		2.22	468	1,037.4	YUB		
				Dawson	Dawson (Feeder 2)		6/25/2019 1:20:00 PM	6/25/2019 3:33:00 PM	2.22	468	1,037.4		T	4200V
		Tot Qtr:4							5.38	2,804	2,515.2			
	Qtr 3	2019-0077	Jul 22, 2019	Segs: 2	Dawson	(400) Lightning	S164 L170 Zone 2 Phase distance 21A 175km @ 340A 20:55:59 Suspected lightning. Possible two lightning events. One at 20:49:15 near Minto Landing and one at 20:55:59 near L170.		0.26	934	223.4	YUB		
				Dawson	Dawson (Feeder 1)		7/22/2019 8:49:16 PM	7/22/2019 9:02:14 PM	0.22	466	100.7		T	4200V
				Dawson	Dawson (Feeder 2)		7/22/2019 8:49:16 PM	7/22/2019 9:05:00 PM	0.26	468	122.7		T	4200V
		2019-0085	Aug 06, 2019	Segs: 1	Dawson	(101) Customer Requested	GOI 19-497 return to normal Install Openers		0.05	466	23.0	YUB		
				Dawson	Dawson (Feeder 1)		8/6/2019 2:40:00 AM	8/6/2019 2:42:58 AM	0.05	466	23.0		T	4200V
		2019-0086	Aug 06, 2019	Segs: 1	Dawson	(101) Customer Requested	GOI 19-497 planned outage to install switch		0.11	466	52.7	YUB		
				Dawson	Dawson (Feeder 1)		8/6/2019 1:56:34 AM	8/6/2019 2:03:21 AM	0.11	466	52.7		T	4200V
		2019-0087	Aug 07, 2019	Segs: 1	Dawson	(101) Customer Requested	G O I 19_499 start switching at 2 am installed grounds for work being done on the Caisiar BLDG		3.35	466	1,561.1	YUB		
				Dawson	Dawson (Feeder 1)		8/7/2019 2:00:00 AM	8/7/2019 5:21:00 AM	3.35	466	1,561.1		T	4200V
		2019-0090	Aug 06, 2019	Segs: 2	Dawson	(301) Falling Tree	A tree fell on the line – Broke insulators and cross arms – had to operate several local breakers to get the Hospital and as many customers back on the grid as possible		3.80	934	1,792.0	YUB		
				Dawson	Dawson (Feeder 2)		8/6/2019 2:35:46 PM	8/6/2019 6:23:35 PM	3.80	468	1,777.0		T	4200V
				Dawson	Dawson (Feeder 1)		8/6/2019 3:13:05 PM	8/6/2019 3:15:01 PM	0.03	466	15.0		T	4200V
		2019-0100	Aug 29, 2019	Segs: 1	Dawson	(503) Defective Equipment/Material	Feeder 1 isolation Required to fix Gang Switch S7905		0.04	466	18.0	YUB		
				Dawson	Dawson (Feeder 1)		8/29/2019 12:42:00 AM	8/29/2019 12:44:19 AM	0.04	466	18.0		T	4200V

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2019	Qtr 3	2019-0101	Aug 28, 2019	Segs: 1	Dawson	(103) Maintenance	PP 34 S7905 gang switch center phase had a hot spot on arcing horn. Isolated feeder 1 and potential test and installed grounds open and close gang switch.		1.55	466	722.3	YUB		
				Dawson	Dawson (Feeder 1)		8/28/2019 11:47:00 PM	8/29/2019 1:20:00 AM	1.55	466	722.3		T	4200V
		2019-0104	Sep 17, 2019	Segs: 1	Dawson	(103) Maintenance	IBEX doing porcelain cutout replacement on feeder one starting in alley behind 2 ave and queen street to Harper street pp 55 pp52 pp50 pp all 3 phase transformer		1.00	50	50.0	YUB		
				Dawson	Dawson (Feeder 1)		9/17/2019 7:30:00 AM	9/17/2019 8:30:00 AM	1.00	50	50.0		T	4200V
		2019-0109	Sep 14, 2019	Segs: 2	Dawson	(506) Other Equipment Failure	The cause of the trip was a momentary loss of 24vdc power supply to the Dawson plant, "fire alarm panel B." In Figure 1, a loss in 24vdc to relays FFT, FET1, and FET2 will cause a trip to be sent to F1, F2, DD1, DD2, DD3, DD4, and DD5.		0.15	934	136.8	YUB		
				Dawson	Dawson (Feeder 2)		9/14/2019 10:41:07 AM	9/14/2019 10:49:26 AM	0.14	468	64.9		T	4200V
				Dawson	Dawson (Feeder 1)		9/14/2019 10:41:07 AM	9/14/2019 10:50:23 AM	0.15	466	72.0		T	4200V
		2019-0110	Sep 18, 2019	Segs: 1	Dawson	(103) Maintenance	; Ibex porcelaine cut out change on feeder 2		2.00	61	122.0	YUB		
				Dawson	Dawson (Feeder 2)		9/18/2019 9:30:00 AM	9/18/2019 11:30:00 AM	2.00	61	122.0		T	4200V
		2019-0111	Sep 18, 2019	Segs: 1	Dawson	(103) Maintenance	Dawson feeder 1 cut out replacement on 3 phase bank		1.00	61	61.0	YUB		
				Dawson	Dawson (Feeder 1)		9/18/2019 5:00:00 PM	9/18/2019 6:00:00 PM	1.00	61	61.0		T	4200V
		2019-0112	Sep 18, 2019	Segs: 1	Dawson	(103) Maintenance	Ibex porcelaine cut out replacement Dawson feeder 2 residential		3.00	53	159.0	YUB		
				Dawson	Dawson (Feeder 2)		9/18/2019 1:30:00 PM	9/18/2019 4:30:00 PM	3.00	53	159.0		T	4200V
		Tot Qtr:12							16.70	5,357	4,921.4			
	Qtr 4	2019-0123	Nov 06, 2019	Segs: 2	Dawson	(802) Protection Setting	S250-52-1 switch was in Dawson Protection Mode causing S250-52-2 to trip at lower settings		0.97	934	887.7	YUB		
				Dawson	Dawson (Feeder 1)		11/5/2019 3:43:55 PM	11/5/2019 4:40:00 PM	0.93	466	435.6		T	4200V
				Dawson	Dawson (Feeder 2)		11/5/2019 3:43:55 PM	11/5/2019 4:41:53 PM	0.97	468	452.1		T	4200V
		2019-0124	Nov 05, 2019	Segs: 2	Dawson	(802) Protection Setting	S250-52-1 switch was in Dawson Protection Mode causing S250-52-2 to trip at lower settings		0.25	934	224.3	YUB		
				Dawson	Dawson (Feeder 2)		11/5/2019 12:44:57 PM	11/5/2019 12:59:03 PM	0.24	468	110.0		T	4200V
				Dawson	Dawson (Feeder 1)		11/5/2019 12:44:57 PM	11/5/2019 12:59:40 PM	0.25	466	114.3		T	4200V
		2019-0131	Nov 19, 2019	Segs: 1	Dawson	(603) Wet Snow	Local Lineman reports lots of snow on lines. Suspect line slap.		0.29	466	136.0	YUB		
				Dawson	Dawson (Feeder 1)		11/19/2019 6:32:40 PM	11/19/2019 6:50:11 PM	0.29	466	136.0		T	4200V

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2019	Qtr 4	2019-0132	Nov 20, 2019	Segs: 2	Dawson	(603) Wet Snow	Heavy snowfall in the area. Suspected line slap		0.15	934	130.4	YUB		
				Dawson	Dawson (Feeder 1)		11/20/2019 8:53:03 AM	11/20/2019 9:01:03 AM	0.13	466	62.1		T	4200V
				Dawson	Dawson (Feeder 2)		11/20/2019 8:53:03 AM	11/20/2019 9:01:48 AM	0.15	468	68.2		T	4200V
		2019-0133	Nov 20, 2019	Segs: 2	Dawson	(603) Wet Snow	Heavy snowfall in the area.		0.12	934	110.3	YUB		
				Dawson	Dawson (Feeder 1)		11/20/2019 12:23:07 PM	11/20/2019 12:30:02 PM	0.12	466	53.7		T	4200V
				Dawson	Dawson (Feeder 2)		11/20/2019 12:23:07 PM	11/20/2019 12:30:22 PM	0.12	468	56.5		T	4200V
		2019-0136	Nov 21, 2019	Segs: 2	Dawson	(604) Ice/Icing	Thick Frost on the lines		0.11	934	103.5	YUB		
				Dawson	Dawson (Feeder 1)		11/21/2019 1:41:22 PM	11/21/2019 1:47:47 PM	0.11	466	49.8		T	4200V
				Dawson	Dawson (Feeder 2)		11/21/2019 1:41:22 PM	11/21/2019 1:48:15 PM	0.11	468	53.7		T	4200V
		2019-0137	Nov 25, 2019	Segs: 2	Dawson	(604) Ice/Icing	lines in Dawson are all thick covered with Snow and Frost		0.26	934	240.9	YUB		
				Dawson	Dawson (Feeder 1)		11/25/2019 3:50:23 AM	11/25/2019 4:05:39 AM	0.25	466	118.6		T	4200V
				Dawson	Dawson (Feeder 2)		11/25/2019 3:50:23 AM	11/25/2019 4:06:04 AM	0.26	468	122.3		T	4200V
		2019-0138	Nov 25, 2019	Segs: 2	Dawson	(604) Ice/Icing	Heavy frost buildup on power lines. Frost falling off causing line slap.		0.12	934	110.5	YUB		
				Dawson	Dawson (Feeder 1)		11/25/2019 10:24:26 AM	11/25/2019 10:31:32 AM	0.12	466	55.1		T	4200V
				Dawson	Dawson (Feeder 2)		11/25/2019 10:24:26 AM	11/25/2019 10:31:32 AM	0.12	468	55.4		T	4200V
		Tot Qtr:8							4.16	7,004	1,943.6			
	Tot Yr: 25								26.46	16,099	9,481.4			
2020	Qtr 1	2020-0004	Jan 31, 2020	Segs: 2	Dawson	(604) Ice/Icing	Breaker opened at Stewart North @ 14:20. Cause likely related to snow loading on the lines, reset all alarms in control room, opened S250-57-1, reset express feeder, and put sync condenser S250-52-SC1 online.		0.13	939	123.4	YUB		
				Dawson	Dawson (Feeder 1)		1/31/2020 2:18:24 PM	1/31/2020 2:26:04 PM	0.13	429	54.8		T	4200V
				Dawson	Dawson (Feeder 2)		1/31/2020 2:18:24 PM	1/31/2020 2:26:28 PM	0.13	510	68.6		T	4200V
		2020-0007	Feb 07, 2020	Segs: 2	Dawson	(203) Generation Inadvertent	Comms failure led to system wide cascade event Tripped Minto and requested Eagle transfer to their own generation. Minto made decision to stay on their own generation for the night.		1.67	939	1,354.0	YUB		
				Dawson	Dawson (Feeder 1)		2/7/2020 7:42:29 PM	2/7/2020 8:52:58 PM	1.17	429	504.0		T	4200V
				Dawson	Dawson (Feeder 2)		2/7/2020 7:42:29 PM	2/7/2020 9:22:29 PM	1.67	510	850.0		T	4200V

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2020	Qtr 1	2020-0008	Feb 13, 2020	Segs: 2	Dawson	(203) Generation Inadvertent	WH4 trip (excitor problems)		0.15	939	139.6	YUB		
				Dawson	Dawson (Feeder 1)		2/13/2020 2:00:31 PM	2/13/2020 2:09:09 PM	0.14	429	61.7		T	4200V
				Dawson	Dawson (Feeder 2)		2/13/2020 2:00:31 PM	2/13/2020 2:09:41 PM	0.15	510	77.9		T	4200V
		Tot Qtr:3							3.40	2,817	1,617.0			
	Qtr 2	2020-0011	Apr 07, 2020	Segs: 1	Dawson	(203) Generation Inadvertent	High LEL during offload at LNG Facility tripped all three WG units and all four on line YM rental units.		0.17	510	88.0	YUB		
				Dawson	Dawson (Feeder 2)		4/7/2020 8:37:18 AM	4/7/2020 8:47:39 AM	0.17	510	88.0		T	4200V
		2020-0018	May 29, 2020	Segs: 2	Dawson	(503) Defective Equipment/Material	Fire pump testing in P158 proved that the bypass switch for the fire system is not working correctly. Dan entered an equipment issue for this.		0.04	939	33.4	YUB		
				Dawson	Dawson (Feeder 1)		5/29/2020 8:22:54 AM	5/29/2020 8:24:50 AM	0.03	429	13.8		T	4200V
				Dawson	Dawson (Feeder 2)		5/29/2020 8:22:54 AM	5/29/2020 8:25:12 AM	0.04	510	19.5		T	4200V
		Tot Qtr:2							0.24	1,449	121.3			
	Qtr 3	2020-0028	Jul 05, 2020	Segs: 2	Dawson	(400) Lightning	Lightening strike L171		0.47	939	434.0	YUB		
				Dawson	Dawson (Feeder 1)		7/5/2020 7:06:44 PM	7/5/2020 7:33:34 PM	0.45	429	191.9		T	4200V
				Dawson	Dawson (Feeder 2)		7/5/2020 7:04:50 PM	7/5/2020 7:33:19 PM	0.47	510	242.1		T	4200V
		2020-0029	Jul 11, 2020	Segs: 2	Dawson	(301) Falling Tree	Tree on L178.		0.60	939	560.9	YUB		
				Dawson	Dawson (Feeder 1)		7/11/2020 2:03:04 PM	7/11/2020 2:38:26 PM	0.59	429	252.9		T	4200V
				Dawson	Dawson (Feeder 2)		7/11/2020 2:03:04 PM	7/11/2020 2:39:18 PM	0.60	510	308.0		T	4200V
		2020-0032	Jul 25, 2020	Segs: 2	Dawson	(400) Lightning	Heavy lightning storm reported at the time of the outage.		0.19	939	171.0	YUB		
				Dawson	Dawson (Feeder 2)		7/25/2020 2:52:52 PM	7/25/2020 3:03:58 PM	0.19	510	94.4		T	4200V
				Dawson	Dawson (Feeder 1)		7/25/2020 2:52:52 PM	7/25/2020 3:03:35 PM	0.18	429	76.6		T	4200V
		2020-0035	Jul 27, 2020	Segs: 2	Dawson	(400) Lightning	Lightning was reported in the area at the time of the outage. No other cause reported/discovered.		0.17	939	156.2	YUB		
				Dawson	Dawson (Feeder 1)		7/27/2020 7:09:44 PM	7/27/2020 7:19:31 PM	0.16	429	70.0		T	4200V
				Dawson	Dawson (Feeder 2)		7/27/2020 7:09:44 PM	7/27/2020 7:19:53 PM	0.17	510	86.3		T	4200V
		2020-0037	Jul 30, 2020	Segs: 1	Dawson	(100) Scheduled Outage	Planned power outage under GOI 20-416.		0.11	429	47.8	YUB		
				Dawson	Dawson (Feeder 1)		7/30/2020 1:00:11 AM	7/30/2020 1:06:52 AM	0.11	429	47.8		T	4200V
		Tot Qtr:5							2.92	4,185	1,369.8			

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2020	Qtr 4	2020-0061	Oct 26, 2020	Segs: 2	Dawson	(601) Extreme Wind	Strong southerly winds at +90kmph knocked down many trees in southern Yukon causing damage to power lines, transformers and PT's.		0.49	939	445.4	YUB		
				Dawson	Dawson (Feeder 1)		10/26/2020 2:54:58 PM	10/26/2020 3:22:39 PM	0.46	429	197.9		T	4200V
				Dawson	Dawson (Feeder 2)		10/26/2020 2:54:58 PM	10/26/2020 3:24:05 PM	0.49	510	247.5		T	4200V
		2020-0068	Nov 15, 2020	Segs: 2	Dawson	(203) Generation Inadvertent	Vaporizer on LNG skid tripped off due to low gas temp, cut fuel to WG0 and tripped the units. S249-52 -10 did not close on SCADA commands, Mayo PLT. needed to close in locally.		0.24	939	223.8	YUB		
				Dawson	Dawson (Feeder 1)		11/15/2020 4:00:27 PM	11/15/2020 4:14:32 PM	0.23	429	100.7		T	4200V
				Dawson	Dawson (Feeder 2)		11/15/2020 4:00:27 PM	11/15/2020 4:14:56 PM	0.24	510	123.1		T	4200V
		2020-0069	Nov 17, 2020	Segs: 2	Dawson	(506) Other Equipment Failure	Cause was S250-T1MVA exceeded.		0.50	939	465.8	YUB		
				Dawson	Dawson (Feeder 1)		11/17/2020 6:16:42 PM	11/17/2020 6:46:28 PM	0.50	429	212.8		T	4200V
				Dawson	Dawson (Feeder 2)		11/17/2020 6:16:42 PM	11/17/2020 6:46:28 PM	0.50	510	253.0		T	4200V
		2020-0072	Dec 02, 2020	Segs: 2	Dawson	(301) Falling Tree	This was the 6th tree caused outage along L178 this year. Tree discovered just north of Little Salmon.		0.13	939	124.2	YUB		
				Dawson	Dawson (Feeder 1)		12/2/2020 3:51:40 AM	12/2/2020 3:59:36 AM	0.13	429	56.7		T	4200V
				Dawson	Dawson (Feeder 2)		12/2/2020 3:51:40 AM	12/2/2020 3:59:36 AM	0.13	510	67.4		T	4200V
		2020-0073	Dec 04, 2020	Segs: 2	Dawson	(304) Off-ROW Tree	Outage currently under investigation. No cause discovered. Possibly a tree contact as it was very windy and snowing.40-60km/hr. Note that Minto Mine breaker S254-52-F1 tripped not S254-52-TR (S254-52-F1 not in database. Had to use S254-52-TR for outage tracking purposes). Also, had to enterS258 -52-3 breaker for Eagle Gold		0.25	939	227.5	YUB		
				Dawson	Dawson (Feeder 1)		12/4/2020 10:53:16 AM	12/4/2020 11:07:26 AM	0.24	429	101.3		T	4200V
				Dawson	Dawson (Feeder 2)		12/4/2020 10:53:16 AM	12/4/2020 11:08:07 AM	0.25	510	126.2		T	4200V
		2020-0074	Dec 14, 2020	Segs: 2	Dawson	(501) Electrical Failure	The three LNG units tripped, as a result the Breakers at P158, S250 and Mayo opened and YM10 and YM13 tripped. The reason for the LNG trip is under investigation. After further investigation it was determined that a ground fault on WG1 resulted in all three LNG units tripping off line.		0.13	939	115.2	YUB		
				Dawson	Dawson (Feeder 2)		12/14/2020 7:17:46 AM	12/14/2020 7:25:20 AM	0.13	510	64.3		T	4200V
				Dawson	Dawson (Feeder 1)		12/14/2020 7:17:46 AM	12/14/2020 7:24:53 AM	0.12	429	50.9		T	4200V
		2020-0078	Dec 22, 2020	Segs: 2	Dawson	(604) Ice/Icing	Heavy frost/snow accumulation on L177 causing line slap.		0.13	939	114.4	YUB		

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Year	Quarter	Id	Date			(Code) Description	Comment								
				Locations		Feeder/Line	Start DateTime	End DateTime	OutageHrs	Cust	Cust Hours	Resp	T/D	Voltage
2020	Qtr 4	2020-0078	Dec 22, 2020	Dawson	Dawson (Feeder 1)		12/22/2020 4:58:09 PM	12/22/2020 5:06:00 PM	0.13	429	56.1		T	4200V
				Dawson	Dawson (Feeder 2)		12/22/2020 4:58:09 PM	12/22/2020 5:05:00 PM	0.11	510	58.2		T	4200V
		2020-0079	Dec 26, 2020	Segs: 2	Dawson	(501) Electrical Failure	S253-521 had lost its SF6 as burst disc had ruptured. This had happened the night before. Through testing the breaker was determined to be the fault.		0.26	939	218.0	YUB		
				Dawson	Dawson (Feeder 1)		12/26/2020 4:46:29 PM	12/26/2020 5:02:09 PM	0.26	429	112.0		T	4200V
				Dawson	Dawson (Feeder 2)		12/26/2020 4:46:29 PM	12/26/2020 4:58:57 PM	0.21	510	106.0		T	4200V
		2020-0081	Dec 20, 2020	Segs: 2	Dawson	(604) Ice/Icing	Suspected line slap due to frost built up on L177 power lines.		0.46	939	294.0	YUB		
				Dawson	Dawson (Feeder 1)		12/20/2020 10:39:02 AM	12/20/2020 11:06:29 AM	0.46	429	196.3		T	4200V
				Dawson	Dawson (Feeder 2)		12/20/2020 10:39:02 AM	12/20/2020 10:50:32 AM	0.19	510	97.7		T	4200V
		Tot Qtr:9							4.77	8,451	2,228.3			
	Tot Yr: 19								11.34	16,902	5,336.4			
2021	Qtr 1	2021-0004	Jan 18, 2021	Segs: 2	Dawson	(604) Ice/Icing	Windy and wet snow at the time of the outage. Also lots of frost built up on power lines. Possible line slap.		0.08	939	66.8	YUB		
				Dawson	Dawson (Feeder 1)		1/18/2021 5:09:54 PM	1/18/2021 5:13:50 PM	0.07	429	28.1		T	4200V
				Dawson	Dawson (Feeder 2)		1/18/2021 5:09:57 PM	1/18/2021 5:14:30 PM	0.08	510	38.7		T	4200V
		Tot Qtr:1							0.14	939	66.8			
	Tot Yr: 1								0.14	939	66.8			
Tot All:145									108.88	112,454	45,640.5			

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Teshmont
Leaders in Power Delivery Engineering

Yukon Energy Corporation
Dawson City Distribution System Study

Dawson City Feeders 1 & 2

Voltage Conversion of Dawson City Distribution

Prepared by:

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Disclaimer

This report was prepared under the supervision of Teshmont Consultants LP ("Teshmont"), whose responsibility is limited to the scope of work as shown herein. Teshmont disclaims responsibility for the work of others incorporated or referenced herein.

Revision History

Revision Number	Date Released	Prepared by	Reviewed by	Comments
Rev00	2018 November 29	MM	KLV, DPK	Issued for Review.
Rev01	2018 December 05	KLV	DPK	Revised as per comments received from YEC on 2018 December 04. Issued for review.
Rev02	2018 December 17	MM, KLV	DPK	Revised as per comments received from YEC on 2018 December 14. Inserted Appendix F. Issued for review.

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Executive Summary

Dawson City's 4.16 kV distribution system has currently reached its practical operating limits resulting in frequent power outages and longer fault clearing times. This report is intended to study the system, identify deficiencies, and recommend remedial action.

Following the field visit by the Senior Distribution Engineer, the entire distribution system was analyzed to identify the issues with protection, voltage levels, transformer utilization, and power flow including losses.

The complete distribution system study has concluded the causes of the issues faced by the Dawson City Distribution System to be:

- Inadequate protective settings (due to load growth) have increased outage frequency and fault clearing times resulting in poor quality of power to the customers.
- Inadequate available fault currents at the end of the feeders resulting in potential safety concerns due to protective devices failing to operate.
- Poor feeder end voltages limiting secondary conductor lengths and forcing underutilization of transformation capacity, resulting in increased life cycle costs.

This report recommends converting the operating voltage of the Dawson City distribution system from 4.16 kV to 12.47 kV in a single stage, including the implementation of revised protection coordination at a total cost of $833,000.00 (with a 30 year Net Present Value of +$26,000, 28 year payback and a quantifiable benefit /cost ratio of 1.03). The implementation of these recommendations would successfully mitigate all the issues identified above.

Since the cost savings realized through project implementation outweigh the interest cost savings through deferral, an early in service date of October 31st, 2019, is strongly recommended.

1. Introduction

The Yukon Energy Corporation's (YEC) Dawson City distribution system currently operates at 4.16 kV primary voltage.

Due to the increased electrical load in Dawson City over the years, there have been multiple instances of feeder breaker trips and blown fuses resulting in an elevated outage frequency.

Over the past few years, several system studies have been initiated which were never completed nor implemented. The YEC staff in Dawson City has been forced to implement certain short-term solutions to handle the system issues that have created their own adverse side effects such as safety concerns, prolonged outage durations, and poor power quality.

The electrical distribution system in Dawson City is very much in need of a comprehensive review to evaluate the long-term solutions and to make necessary recommendations ensuring safety, quality, and reliability for YEC customers.

The rural distribution system (industrial and residential), which is fed from the 12.47 kV Hunker Feeder from Callison Station, is not experiencing significant operational issues other than inadequate generation capacity to supply the industrial load. This is outside the scope of this report, however, YEC is currently handling this issue through customer owned generation and proposed new generation at Callison Station.

2. Dawson City Electrical Distribution System

2.1. Current State of the Dawson City Distribution System

The Dawson City distribution system currently consists of two (2) three-phase 4.16 kV feeders, Feeder #1 and Feeder #2, exiting out of the Dawson Diesel Generating Station's (DDGS) 4.16 kV bus. Under lightly loaded operating conditions, the DDGS 4.16 kV bus is energized by a 12.47 kV express feeder from Callison Station via a 12.47 kV – 4.16 kV, 4/5/6 MVA step down transformer located within the station fence. To handle an event of the loss or inadequate supply capacity, there is sufficient back up diesel generators connected to the 4.16 kV bus through normally open breakers. One (1) or more diesel generators can be synchronized for parallel operation as needed.

Callison Station has a single 5.6 MVA, 66 kV – 12.47 kV transformer and switchgear for two (2) energized feeders, one (1) spare cell, and a bus tie cell (for future). The two (2) energized 12.47 kV feeders are on an overhead double-circuit line picking up the Dawson City and Rural load. The top (express) circuit feeds the DDGS 4.16 kV bus through the step-down transformer. The bottom circuit (Hunker Feeder) services the Dome area and the rural industrial/residential loads. There is an existing 1500 kVA, 12.47 kV to 4.16 kV platform mounted step-down transformer (disconnected from both HV and LV sides) located at the south end of the Dawson City. The originally intended purpose of this transformer was to pick up Dawson City essential loads via the Hunker Feeder in an emergency situation.

All transformers mentioned above have spares stored in Callison Station yard.

As a temporary measure to handle the increasing town load, the YEC staff has increased breaker trip settings and fuse sizes, which leads the system to experience different type of issues such as longer fault clearing times (resulting in "brownouts"), protective device and inconvenience of seasonal settings. These are typical symptoms of a 4.16 kV system approaching the practical limitations.

As an interim solution to handle the increasing rural load, a partial voltage conversion to 12.47 kV has relieved the 4.16 kV load on Feeder #2 (Dome area). The YEC Operating Staff is very pleased with the performance of this smaller scale voltage conversion.

2.2. Major Issues Currently Faced by the Dawson City Distribution System

The recent and ongoing new commercial developments (including multi-family residential) within the Dawson City have increased at an alarming rate for a 4.16 kV system that is primarily meant for urban residential distribution. Please see Appendix A. This has forced the Dawson City distribution system to approach the practical operational limits of a 4.16 kV system on short notice.

Based on comments made by some major customers, the fluorescent lights start flickering and the LED lights turn off just prior to an outage. These brownouts appear to be a very common occurrence in Dawson City, especially the past few years.

The entire Dawson City distribution system relies solely on the integrity of the DDGS 4.16 kV bus and the integrity of cables feeding Feeder #1, Feeder #2, and the spare feeder regardless of the source of supply (either the diesel generators or the 12.47 kV express feeder through the step-down transformer or combination of both). The 5 kV Rubber Insulated Neoprene Jacketed (RINJ) feeder cables were very popular in the 1960's (with an original life expectancy of 20-30 years from the installation date) and are very near the end of their serviceable life now. Some Canadian Utilities have started replacement programs for this type of cable in the 1990's.

In addition, it is very evident that the distribution transformers in the system are considerably underutilized, which further increases the losses. The main reason for this underutilization is the rapid voltage drop of a loaded 4.16 kV feeder with distance resulting in very poor input voltage to distribution transformers that limits the maximum allowable secondary lengths significantly.

2.3. General Observations:

- Most of the overhead plant (except the distribution transformers and lightening arresters) is relatively new and built suitable for 12.47 kV operation. Conversion to 24.9 kV would require some minor modifications to the distribution plant, however, major modifications would be required to Callison station.
- While the vast majority of the transformers in the system are only suitable for single 4.16 kV operation, all recent transformer additions have been dual voltage, rated for future 12.47 kV conversion, which is YEC's current direction.
- All the 3-phase pad mounted transformers on the "Essential Services Underground Distribution Loop" are dual voltage, 4.16/12.47 kV rated. All the underground cables within this loop are rated to 25 kV. The essential loads include the two (2) transformers (one (1) in service and the other as an energized spare) feeding the hospital, the transformer feeding the museum, and the transformer feeding the wastewater treatment plant (WWTP).
- The local operating staff is diligent in building all new additions to the plant to be compatible with future 12.47 kV conversion.
- The utilization factors of the distribution transformers are very low (20%-30% of rated capacity), which is not their most efficient range of operation. There is no evidence of using load diversity in determining transformation capacity.
- The YEC staff has observed that customers are requesting much larger service sizes than required by the type of load. They even doubt whether the customers are using proper methodology as per Canadian Electrical Code (CEC) for demand calculations. See Appendix D.
- Due to the tight timelines, some service connections are being built prior to design approvals. The preferred process flow is: Service Request -> Planning & Protection study -> Design -> Construction -> "As built" plan updates.

2.4. Potential Causes of the Dawson 4.16kV Distribution System Issues

Downtown Dawson distribution Feeder # 1 and Feeder #2's voltages at the DDGS 4.16 kV bus are 4.22 kV, which represents 122 V, based on a 120 V reference. However, towards the very end of the feeder, the primary voltage drops down to 4.00 kV, which represents 115 V, based on a 120 V reference. Please see Appendix B. The secondary conductor lengths are typically selected based on a 4.0 V (3.5%) voltage drop, so any customer in Downtown Dawson could have a voltage range of 111 V – 122 V at the service entrance with maximum system and secondary load.

- Under normal operating conditions, YEC is obligated to maintain the CSA voltage ranges, which are 110/220 V-125/250 V for 120/240 V single-phase, 112/194 V-125/216 V for 120/208 V three-phase and 318/550 V-360/625 V for 347/600 V three-phase service entrances [2]. Under emergency operating conditions, these limits may be 106/212 V-127/254 V, 110/190 V-127/220 V and 306/530 V-367/635 V for 347/600 V, respectively. Please note the percentage voltage tolerances are the same regardless of the 3-phase secondary voltage.

- Based on current load. Downtown Dawson's 4.16 kV system may not meet the voltage criteria at certain customers' service entrances at maximum rating.
- Further additions of load, especially far away from the station, would force shorter maximum allowable secondary conductor lengths and eventually become practically impossible to meet the CSA voltage criteria above.
- Due to the reduced maximum allowable secondary lengths, more than required transformation will have to be added to the already underutilized transformation capacity.

Downtown Dawson's distribution Feeder #1 and Feeder #2 available fault currents at the DDGS 4.16 kV bus are 7264 A three-phase and 9510 A single-line to ground (SLG). Please see Appendix B. However, toward the very end of the feeder, the available fault currents drop down to 1406 A three-phase and 985 A SLG. The very high fault currents at the source and rapid drop of fault current with distance is an inherent issue with 4.16 kV systems.

- As the load increases, the protective settings have to be increased to avoid nuisance trips due to high load currents and cold load pickup.
  - For example, Feeder #1 and Feeder #2's loads are peaking at 200 A and 138 A, respectively, in January and February. To allow a minimum cold load pickup factor of 2.0, the feeder protective settings need to be set at 400 A and 300 A, respectively, making the protective reach unacceptably low for a 4.16 kV system.
- Further increase in load (which was very evident during the field trip) will force these settings to go higher, reducing the protective reach criteria to unsafe levels. Higher protective settings, reduced protective reach, and significantly increased operating times, which will cause the collapsed voltage (caused by the faults) last for a longer period, very noticeable to the customers prior to operation (brownouts).
  - This is the reason the customers are experiencing fluorescent lights flickering/LED lights turning off prior to an outage and eventual reduction of life expectancy of non-incandescent lighting and constant kVA loads such as motors.
  - If this situation were to continue, customer complaints/damage claims on premature failure of equipment/devices will potentially rise to an alarming level.
  - These very low reaches run the risk of the feeders staying energized without clearing especially under fault conditions involving ground. This is a major safety concern with excessively loaded 4.16 kV systems seeking immediate corrective action.
- The protective settings at DDGS have no room left for safe increases in the future, so the 4.16 kV system has reached the maximum practical limit. The fundamental reason for this situation is that the fault currents are approaching the load current levels that make the protective devices feed the fault as opposed to clearing it. The effect of the fault impedance is very significant on 4.16 kV, as compared to a 12.47 kV system (theoretically nine (9) times).
- The 4.16 kV system is suitable for urban residential distribution with limited electric heat and shorter feeder lengths. There are no viable solutions left to prolong the 4.16kV operation in the Dawson City Distribution System.
  - Increased load currents contribute to significant increase in line losses (I^2R) and low voltage issues, especially when there are large loads at the end of the feeder. Since the available hydro generation is limited, the incremental load due to the losses may cost as high as three (3) times the revenue rate.

- If the source and the line capacity were strengthened to extend the useable life of 4.16 kV, the available fault currents at the beginning of the feeder would increase to undesirable levels, causing other operational issues. The steep drop in voltage and available short-circuit currents would still continue to be an issue at 4.16 kV voltage level.

2.5. Solutions to the Issues with the Dawson City Distribution System

Downtown Dawson Distribution system's major issues are the inadequate system strength, protection coordination, voltage, and capacity to match the type/size of loading. The existing 4.16 kV system has already outlasted its serviceable life and some key system components are reaching the end of their life expectancy. Corrective action providing a long-term solution is required immediately.

The status quo is not a viable solution. Due to excessive cost, a voltage conversion to 24.94 kV can be eliminated as a viable option.

The 4.16 kV to 12.47 kV voltage conversion, accompanied by appropriate protection coordination and new feeder ties, will resolve the immediate safety/operational issues and provide a reasonably long-term solution to the City of Dawson distribution system as follows.

- Since the total load kVA remains the same, increasing the voltage by a factor of three (3) will reduce the load current by a factor of three (3). This will increase the capacity of the lines by the same factor, deferring potential conductor upgrades required for the near future.
- The reduction of the load currents will decrease the line losses significantly, reducing the kVA demand at the source, and resulting in a reduction in the requirement for supplementary diesel generation only when the Synchronous Condenser is not in operation, eventually lowering operational costs.

The voltage conversion will reduce the line voltage drop significantly, resulting in much more desirable primary voltages at the end of the feeder. The post conversion primary voltages throughout the system would be 12,380 V or better, which represents 119.1 V on 120 V reference. Please see Appendix B.

- This would allow a 7.1 V (or 5.9%) voltage drop across the secondary conductors to meet minimum CSA service entrance voltage requirements.
  - The recommended secondary lengths can be increased by approximately by 70% without violating the CSA voltage limit criteria.
  - This would mean less transformation (increasing the utilization factor) and more secondary, reducing the proposed voltage conversion cost and future expansion costs.
  - Although it may appear the increased secondary conductor lengths contribute to more losses, it actually is offset by the improved efficiency of the replacement transformers and therefore disregarded in the calculations.
  - The voltage profiles have been generated using off load taps of the Callison 66 kV – 12.47 kV transformer at nominal position, which are adequate for this analysis. However, the 12.47kV voltage profiles can be further improved by optimal use of those tap positions.

The voltage conversion will also reduce the fault currents at the beginning of the feeder down to 2597 A three-phase and 3304 A SLG, however, the fault currents will now decrease at a much lower rate than at 4.16 kV. The lowest available short-circuit current anywhere in the 12.47 kV system is 2306 A three-phase and 2077 A SLG.

- Due to the reduction in load currents and through proper sectionalizing, the 12.47 kV protective device settings can be reduced significantly. This will improve the protection coordination and

increase the protective reach significantly (as high as 5 – 7 times based on the protection coordination study) due to the better-sustained short-circuit levels with distance at 12.47 kV.

- This will eliminate the safety concern of the line remaining energized during high impedance faults.
- Better coordination between protective devices and ease of troubleshooting would reduce outage durations.
- Faster fault clearing times would resolve the "brownout" issues.

The proposed feeder configuration eliminates funnelling the total City of Dawson electricity consumption through ageing DDGS bus/breakers and the RINJ cables approaching the end of serviceable life. This will also immediately address the potential reliability issues associated with load increases due to rapid development. The implementation of appropriate protection coordination and the addition of feeder ties will significantly improve the steady state and transient reliability.

3. Evaluation of Voltage Conversion Options

3.1. Single Stage Dawson City Distribution System Full Voltage Conversion

In Service Date (ISD) of October 31st, 2019 (Option #1) - Cost = $833,000, Net Present Value (NPV) = $26,000 (Please see Appendix E, Appendix E and Appendix E.

- Convert 4.16 kV Feeder #1 to 12.47 kV and connect to the express feeder from Callison Station – ISD October 31st, 2019.
  - Construct one (1) span of 12.47 kV primary just outside the DDGS to energize Feeder #1 at 12.47 kV at the existing riser pole location.
  - The electrical load within the DDGS will remain at 4.16 kV, fed through the step-down transformer.
  - Replace all the single 2.4 kV rated transformers with 2.4/7.2 kV dual voltage rated units.
  - Replace all the lightening arresters with 9 kV Metal Oxide Varistor (MOV) units. This task needs to be completed just prior to the voltage conversion due to reduced margin of protection provided at 4.16 kV operation. The 9 kV arresters are meant for 12.47 kV systems designed for 95 kV Basic Impulse Insulation Level (BIL), whereas the 4.16 kV system has been designed only for 60 kV BIL.
  - Change the few remaining underrated dropouts and insulators as needed for 12.47 kV operation.
- Convert 4.16 kV Feeder #2 to 12.47 kV and connect to the express feeder from Callison Station - ISD October 31st, 2019.
  - Connect the 12.47 kV express feeder and Feeder #2 at the corner of 8th Avenue and Craig Street.
  - In addition to the transformer and arrester replacements, this would require removal of a short section of 4.16 kV underbuilt circuit just outside the station and splicing out a dead span at the time of voltage conversion. This would be an opportunity to resolve clearance issues and to remove obsolete poles within this section.
- Decommission 4.16 kV Feeder #1, Feeder #2, and spare, including cables, terminations, and transition assemblies, since they are no longer required.

- Salvage the platform mounted step-down transformer at the south end of the town and the spare stored at Callison Station. The line segment feeding this transformer shall be used to create the feeder tie point.
- Add a normally closed in-line disconnect switch on the 12.47 kV express circuit from Callison at the south corner of Dawson City, just north of the Klondike Hwy - ISD October 31st, 2019.
- Add a normally open feeder tie switch between the 12.47 kV circuits from Callison Station immediately on the load side of the line switch above - ISD October 31st, 2019.
- Connect the risers of Hunker feeder at the first pole south side of Klondike Highway near south end of the city.
- Switch #7908 at the corner of King Street and Fifth Avenue shall remain open.
- Implement protection coordination recommendations on both feeders - ISD October 31st, 2019.
    - The normal supply for the entire City of Dawson shall be the present 12.47 kV Express Feeder from Callison Station.
    - In addition to being the existing supply for the industrial and rural residential load, the bottom 12.47 kV circuit (Hunker Feeder) will have sufficient capacity and voltage to back up the new Downtown Feeder (old Express Feeder) via the new feeder tie.
    - The existing feeder protection relay for the 12.47 kV Hunker Feeder can be retained with appropriate overcurrent setting changes.
    - The existing differential and distance protection for the Express Feeder will require to be replaced with feeder overcurrent protection, similar to the Hunker Feeder, with appropriate settings.
    - In-line fuses or sectionalizers will be required at the three tie-in points between the main 12.47 kV feeder and the existing downtown distribution. These locations are along the back lane of Craig Street at 5th Avenue, 6th Avenue and 8th Avenue.
- The existing diesel generators will remain as an additional contingency and a peak shaving resource in event of the loss or inadequacy of the 12.47 kV supply.
    - In this mode, the transformer outside the station will step the 4.16 kV up to 12.47 kV.

At the client's request, a sample work plan has been added for option #1 (Appendix E) for illustration purposes only.

3.2. Two Stage Dawson City Distribution System Full Voltage Conversion

Stage 1 ISD of October 31st, 2019, and Stage 2 ISD of October 31st, 2021 (Option #2) - Cost = $843,000, Net Present Value (NPV) = -$700 (Please see Appendix Eand Appendix E)

- Convert entire 4.16 kV Feeder #1 and approximately 1/3 of Feeder #2 to 12.47 kV and connect to the express feeder from Callison Station - ISD October 31st, 2019.
    - Construct one (1) span of 12.47 kV primary just outside the DDGS to energize Feeder #1 at 12.47 kV at the existing riser pole location.
    - The electrical load within the DDGS will remain at 4.16 kV, fed through the step-down transformer.
    - Replace all the single-phase 2.4 kV rated transformers with 2.4/7.2 kV dual voltage rated units.
    - Replace all the lightning arresters 9 kV Metal Oxide Varistor (MOV) units.

- Convert a portion of 4.16kV Feeder #2 to 12.47kV and connect to Feeder #1 at the corner of 6th Avenue and the back lane of Craig Street. - ISD October 31st, 2019.
  - The 4.16 kV Feeder #2 and #3(spare) risers, and the 4.16 kV underbuilt along the back lane of Craig Street will remain to pick up the remaining Feeder #2 load.
  - Remove solid blades of the switch #7981 and construct a dead span between 4.16 kV and 12.47 kV.
- Remove the risers of switch #7908 and place a permanent hold card. Construct a dead span between 12.47 kV and 4.16 kV.
- Salvage the platform mounted step-down transformer at the south of the city and the spare. The line segment feeding this transformer shall be used to create the feeder tie point.
- Add a normally closed in-line disconnect switch on the 12.47 kV express circuit from Callison at the south corner of Dawson City, just north of the Klondike Hwy - October 31st, 2019.
- Add a normally open feeder tie switch between the 12.47 kV circuits from Callison station immediately on the load side of the line switch above - ISD October 31st, 2019.
- Connect the risers of Hunker feeder at the first pole south side of Klondike Highway near south end of the city.
- Implement protection coordination recommendations on both feeders similar to Option #1's description - ISD October 31st, 2019.
- The existing diesel generators will remain as described in Option #1.
- Convert the remainder of 4.16 kV Feeder #2 to 12.47 kV and connect to the Feeder #1 at the corner of 8th Avenue and Craig Street. - ISD October 31st, 2021.
- Remove all dead spans and reinstate the switches #7908 and #7981 back to their original mode of operation at 12.47 kV. - ISD October 31st, 2021.

3.3. Two Stage Dawson City Distribution System Full Voltage Conversion Using the Platform Mounted Step-Down Transformer

Stage 1 ISD October 31st, 2019, and Stage 2 ISD October 31st, 2021, (Option #3) - Cost = $849,000, Net Present Value (NPV) = -$5,500 (Please see Appendix Eand Appendix E)

- Convert the entire 4.16 kV Feeder #1 and approximately 1/3 of Feeder #2 to 12.47 kV and connect to the express feeder from Callison Station. – ISD October 31st, 2019.
  - Construct one (1) span of 12.47 kV primary just outside the DDGS to energize Feeder #1 at 12.47 kV at the existing riser pole location.
  - The electrical load within the DDGS will remain at 4.16 kV, fed through the step-down transformer.
  - Replace all the single 2.4 kV rated transformers with 2.4/7.2 kV dual voltage rated units.
  - Replace all the lightening arresters with 9 kV Metal Oxide Varistor (MOV) units.
- Convert a portion of 4.16 kV Feeder #2 to 12.47 kV and connect to Feeder #1 at the corner of 6th Avenue and the back lane of Craig Street. – ISD October 31st, 2019.
  - In addition to the transformer and arrester replacements, this would require removal of a short section of 4.16 kV underbuilt circuit just outside the station.
  - This would be an opportunity to resolve clearance issues and to remove obsolete poles within this section.

- Remove the risers of switch #7908 and place a permanent hold card. Construct a dead span between the 12.47 kV and 4.16 kV.
- Remove the solid blades of switch #7981 and construct a dead span between the 4.16 kV and 12.47 kV.
- Decommission 4.16 kV Feeder #1, Feeder #2, and spare, including cables, terminations, and transition assemblies, since they are no longer required.
- Test and connect the platform mounted step-down transformer, located at the south end of the town, to feed the unconverted 4.16 kV portion of Feeder #2. The transformer shall be protected by standard NEMA fuses as per protection coordination study.
- Add a normally closed in-line disconnect switch on the 12.47 kV express circuit from Callison at the south corner of Dawson City, just north of the Klondike Hwy - ISD October 31st, 2019.
- Add a normally closed feeder tie switch between the 12.47 kV circuits from Callison station immediately on the load side of the line switch above - ISD October 31st, 2019.
- The open risers of Hunker feeder at the first pole south side of Klondike Highway near south end of the city shall remain open.
- Implement protection coordination recommendations on both feeders similar to the Option #1 description - ISD October 31st, 2019.
- The existing diesel generators will remain as described in Option #1.
- Convert the remainder of 4.16 kV Feeder #2 to 12.47 kV and connect to Feeder #1 at the corner of 8th Avenue and Craig Street. The platform mounted step-down transformer and the spare located in Callison Station shall be salvaged. - ISD October 31st, 2021.
- Remove all dead spans and reinstate switches #7908 and #7981 back to their original mode of operation at 12.47kV. - ISD October 31st, 2021.

Between the two (2) stages of either Option #2 or #3, the Downtown Dawson City distribution system will have two (2) different operating voltages. The two (2) systems are constructed to the same standard, making them visually near identical. (Some utilities build 4.1 6kV systems with reduced clearances and they are visually recognizable.)

- The safety concern due to the two (2) different operating voltages has been addressed by the addition of a dead span.
- New staff may get confused initially due to the two (2) operating voltages, however, proper orientation addresses this issue.
- Once Stage 2 is implemented, Option #2 and option #3 will provide a system similar to Option #1.

It is highly recommended that Stage 2 not be deferred in either Option 2 or 3. Actually, the cost savings realized through project implementation outweighs the interest cost savings through deferral.

Table 3–1: Benefits and Constraints

	Option #1: Single Stage Full Voltage Conversion (ISD October 31st, 2019)	Options #2 & #3: Two Stage Full Voltage Conversion (Stage 1 ISD October 31st, 2019, & Stage 2 ISD October 31st, 2021)
Benefits	• Provides a good system backup through tie points and diesel generation from the ISD. • The downtown system losses are reduced by 20.8kW from the ISD. • Overall NPV is positive which means the cost savings from quantifiable benefits will pay for the project in less than 30 years (28 years precisely).	• This option allows a more convenient spread of capital expenditure and resource allocation.
Constraints	• This option allows lesser flexibility in spreading of capital expenditure and resource allocation.	• Between the two (2) stages, certain customers on the 4.16 kV system lack an alternate supply increasing outage times during maintenance. • The inconvenience of having two (2) different voltage systems in the city. This could lead to confusion for new staff. • Continued higher system losses in unconverted area. • This option runs the risk of Stage 2 deferral due to unforeseen financial constraints and prioritization of projects.

4. Conclusions and Recommendations

The status quo (do nothing) is not considered as an option.

Option #2 leaves the unconverted part of Feeder #2 in a worse situation than its current state for two (2) years due to lack of operational feeder ties. Maintenance work performed on de-energized 4.16 kV plant would result in prolonged outages.

Option #3 is functionally similar to Option #2, however, due to the smaller size of the platform mounted transformer, the available feeder end fault currents would be lowered, worsening the issues on the remaining 4.16 kV system. In addition, the cost is higher Option #2. The only favorable feature of Option #3 as compared to Option #2 is the independence of the DCGS main bus and the feeder cables.

Option #1 has the lowest implementation cost and provides the best Net Present Value (NPV) and is the only option with a positive NPV, among numerous unquantified other benefits. It also will provide a long-term solution right away.

Based on the analysis above, Option #1 is recommended.

Following the implementation of Option #1, it is strongly recommended to follow the methodology of determining transformation capacity as explained in Appendix D.

Although not included in the alternatives in this report, a complete long-term solution with further improved reliability may include the following, subject to the availability of capital funds and resources:

- A new 12.47 kV feeder out of Callison Station to exclusively pick up the Hunker industrial load.
  - The available spare feeder position in the switchgear cabinet may be used for this purpose.

- Estimated cost would be approximately $50,000, providing a great benefit/cost ratio.

- Addition of a second bank at Callison Station.
  - This will provide firm capacity (with full contingency) to the station.
  - The spare transformer stored at the station is converted to an “Energized Spare”.

5. References

Articles:

[1] Virginie Letschert, Michael McNeil, Jing Ke, Puneeth Kalavase, Mahesh Sampat (EMS International Consulting Inc.) “Energy Efficiency Potential for Distribution Transformers in the APEC Economies”, December 2013.

[2] ATCO Electric Customer Metering and Services Guide – Section 1.8 – Voltage Operating Conditions

Website: http://www.atcoelectric.com/Services/Industrial-Customers/Documents/Customer%20Metering%20and%20Service%20Guide.pdf

Standards:

[3] CSA C802.3 – 15, Efficiency Values for Transformers.

[4] CSA C22.1 – 18, Canadian Electrical Code – Section 8 – Circuit Loading and Demand Factors.

[5] CSA C22.3 No. 01 – 15, Overhead Systems – Section 5 – Clearances, Separations and Spacings.

Appendix A

Recent and Current Load Growth in Downtown Dawson Area

Appendix A
Recent and Current Load Growth in Downtown Dawson Area

The following loads have been added recently and are being added to the City of Dawson distribution system:

- A 20-unit apartment building on 2nd Avenue.
  This load is being served at 120/208 V via a 3x100 kVA overhead transformer bank.

- Water Treatment Plant on 5th Avenue between Turner & Dugas Streets.
  This load is being served at 120/20 8V via a 3x100 kVA overhead transformer bank.

- An 8-unit apartment building on 6th Avenue between Queen and King Streets.
  This load is being served at 120/208 V via a 3x50 kVA overhead transformer bank.

- Parks Canada 600 A Service at 302 Front Street.
  This load is being served at 120/208 V via a 3x50 kVA overhead transformer bank.

- Four Plex on 2nd Avenue between York and Duke Streets.
  This load is being served at 120/240 V single-phase overhead transformer.

- Duplex with 4 meters on 4th Avenue between York and Duke Streets.
  This load is being served at 120/240 V single-phase overhead transformer.

The following loads have been added recently and are being added to the Hunker Feeder on the rural distribution system:

- Hunker mine 800 A Service at 347/600 V via a 3x100 kVA overhead transformer bank.

- YTG Airport Shop 800 A Service at 120/208 V via a 225 kVA pad mount transformer.

At the time of the field visit there was a lot of construction happening within the city all of which adds to the electric heat load. This is a very stressful to a 4.16 kV system approaching its practical limits.

Appendix B

Voltage Profiles, Fault Analysis, and Load Flow Results

Existing Fault Levels At Dawson City Generating Station 4.16 kV Bus

Project:		ETAP		Page:	1
Location:		16.2.0C		Date:	2018-11-05
Contract:				SN:	TESHMONT-3
Engineer:				Revision:	Base
Filename:	DawsonCompNetwork		Study Case: SC	Config.:	Cfg_FI1

SHORT- CIRCUIT REPORT

Fault at bus: **P158 Bus**

Prefault voltage = 4.300 kV = 100.00 % of nominal bus kV (4.300 kV)
= 99.43 % of base kV (4.325 kV)

Contribution		3-Phase Fault		Line-To-Ground Fault					Positive & Zero Sequence Impedances Looking into "From Bus"			
From Bus ID	To Bus ID	% V From Bus	kA Symm. rms	% Voltage at From Bus Va	Vb	Vc	kA Symm. rms Ia	3I0	% Impedance on 100 MVA base R1	X1	R0	X0
P158 Bus	Total	0.00	7.264	0.00	88.69	87.00	9.510	9.510	3.94E+001	1.78E+002	1.14E+001	5.93E+001
1-5	P158 Bus	3.90	0.998	3.34	91.05	91.33	0.854	0.000	4.11E+002	1.27E+003		
2-163	P158 Bus	2.28	0.640	1.95	91.28	90.76	0.548	0.000	5.88E+002	1.99E+003		
Bus1	P158 Bus	0.00	0.000	51.92	52.93	101.62	0.515	1.544 *			5.19E+001	3.68E+002
# P158-T1 Primary	P158 Bus	17.71	2.101	23.00	90.02	87.35	2.728	2.795	1.95E+002	6.01E+002	4.16E+001	2.01E+002
# P158-T1 Tertiary	P158 Bus	9.08	1.051	53.30	55.74	101.76	2.622	5.173 *	3.91E+002	1.20E+003	2.18E+001	1.09E+002
DD1	P158 Bus	103.37	0.717	103.37	103.37	103.37	0.645	0.000	7.40E+001	1.85E+003		
DD2	P158 Bus	103.37	0.896	103.37	103.37	103.37	0.806	0.000	5.92E+001	1.48E+003		
DD3	P158 Bus	103.37	0.923	103.37	103.37	103.37	0.830	0.000	5.75E+001	1.44E+003		
1-5C	1-5	4.97	0.274	4.26	90.88	91.72	0.235	0.000	1.31E+003	4.51E+003		
1-7	1-5	5.61	0.688	4.80	90.79	91.94	0.589	0.000	5.54E+002	1.79E+003		
L1-5	1-5	103.37	0.036	103.37	103.37	103.37	0.031	0.000	5.34E+003	3.56E+004		
2-278	2-163	8.28	0.626	7.09	90.30	92.96	0.536	0.000	5.68E+002	2.01E+003		
L2-163	2-163	103.37	0.015	103.37	103.37	103.37	0.012	0.000	1.33E+004	8.90E+004		
S250 12.5 kV Bus	P158-T1 Primary	48.83	1.078	54.81	89.23	93.58	0.971	0.143	1.16E+002	3.28E+002	1.82E+002	6.04E+002
# P158-T1 Tertiary	P158-T1 Primary	9.08	0.359	53.30	55.74	101.76	0.044	0.814 *	3.47E+002	9.84E+002	2.18E+001	1.09E+002

# Indicates fault current contribution is from three-winding transformers
* Indicates a zero sequence fault current contribution (3I0) from a grounded Delta-Y transformer

Existing Fault Levels At 4.16 kV Feeder #1 End

Project:		ETAP		Page:	1
Location:		16.2.0C		Date:	2018-11-05
Contract:				SN:	TESHMONT-3
Engineer:				Revision:	Base
Filename:	DawsonCompNetwork		Study Case: SC	Config.:	Cfg_FI1

SHORT- CIRCUIT REPORT

Fault at bus: 1-128

Prefault voltage = 4.160 kV = 100.00 % of nominal bus kV (4.160 kV)
= 96.19 % of base kV (4.325 kV)

Contribution		3-Phase Fault		Line-To-Ground Fault					Positive & Zero Sequence Impedances Looking into "From Bus"			
From Bus ID	To Bus ID	% V From Bus	kA Symm. rms	% Voltage at From Bus Va	Vb	Vc	kA Symm. rms Ia	3I0	% Impedance on 100 MVA base R1	X1	R0	X0
1-128	Total	0.00	1.450	0.00	121.97	116.84	0.985	0.985	5.91E+002	6.59E+002	1.28E+003	1.72E+003
1-116	1-128	14.21	1.378	13.45	118.43	114.81	0.952	0.985	6.46E+002	6.72E+002	1.28E+003	1.72E+003
L1-128	1-128	100.00	0.087	100.00	100.00	100.00	0.039	0.000	2.19E+003	1.46E+004		
1-90	1-116	29.26	1.324	28.04	114.60	112.54	0.928	0.985	5.73E+002	6.09E+002	1.11E+003	1.50E+003
1-143	1-116	14.25	0.021	13.47	118.43	114.82	0.010	0.000	7.79E+003	5.18E+004		
L1-116	1-116	100.00	0.044	100.00	100.00	100.00	0.020	0.000	3.71E+003	2.48E+004		

# Indicates fault current contribution is from three-winding transformers
* Indicates a zero sequence fault current contribution (3I0) from a grounded Delta-Y transformer

Existing Fault Levels At 4.16 kV Feeder #2 End

Project:		ETAP		Page:	1
Location:		16.2.0C		Date:	2018-11-05
Contract:				SN:	TESHMONT-3
Engineer:				Revision:	Base
Filename:	DawsonCompNetwork	Study Case:	SC	Config.:	Cfg_FI1

SHORT- CIRCUIT REPORT

Fault at bus: **2-177**

Prefault voltage = 4.160 kV = 100.00 % of nominal bus kV (4.160 kV)
= 96.19 % of base kV (4.325 kV)

Contribution		3-Phase Fault		Line-To-Ground Fault					Positive & Zero Sequence Impedances Looking into "From Bus"			
From Bus ID	To Bus ID	% V From Bus	kA Symm. rms	% Voltage at From Bus Va	Vb	Vc	kA Symm. rms Ia	3I0	% Impedance on 100 MVA base R1	X1	R0	X0
2-177	Total	0.00	1.406	0.00	121.17	112.34	1.013	1.013	6.51E+002	6.41E+002	1.19E+003	1.60E+003
2-196	2-177	26.51	1.381	26.11	114.42	109.12	1.001	1.013	6.71E+002	6.44E+002	1.19E+003	1.60E+003
L2-177	2-177	100.00	0.031	100.00	100.00	100.00	0.015	0.000	6.10E+003	4.07E+004		
2-202	2-196	26.54	0.007	26.13	114.42	109.13	0.003	0.000	2.14E+004	1.42E+005		
2-204	2-196	28.95	1.376	28.53	113.80	108.85	0.998	1.013	4.67E+002	5.11E+002	8.71E+002	1.18E+003

# Indicates fault current contribution is from three-winding transformers
* Indicates a zero sequence fault current contribution (3I0) from a grounded Delta-Y transformer

Post Voltage Conversion Fault Levels at the Step-Up Transformer 12.47 kV Primary Outside Dawson City Generating Station

Project:
Location:
Contract:
Engineer:
Filename: DawsonUpgraded

ETAP
16.2.0C

Study Case: SC-12.47kV

Page: 1
Date: 2018-11-16
SN: TESHMONT-3
Revision: Hydro
Config.: Cfg_FI1

SHORT- CIRCUIT REPORT

Fault at bus: **P158-T1 Primary**

Prefault voltage = 12.470 kV = 100.00 % of nominal bus kV (12.470 kV)
= 96.25 % of base kV (12.955 kV)

Contribution		3-Phase Fault		Line-To-Ground Fault					Positive & Zero Sequence Impedances Looking into "From Bus"			
From Bus ID	To Bus ID	% V From Bus	kA Symm. rms	% Voltage at From Bus Va	Vb	Vc	kA Symm. rms Ia	3I0	% Impedance on 100 MVA base R1	X1	R0	X0
P158-T1 Primary	Total	0.00	2.597	0.00	89.61	88.51	3.304	3.304	3.59E+001	1.61E+002	1.30E+001	6.22E+001
S250 12.5 kV Bus	P158-T1 Primary	37.81	1.276	44.29	87.00	93.29	1.184	0.349	1.10E+002	3.18E+002	1.73E+002	5.76E+002
1-5	P158-T1 Primary	0.51	0.387	0.42	89.51	88.71	0.324	0.000	1.84E+002	1.09E+003		
2-163	P158-T1 Primary	0.28	0.235	0.23	89.55	88.62	0.196	0.000	3.03E+002	1.80E+003		
# P158 Bus	P158-T1 Primary	12.40	0.479	20.02	87.70	87.89	0.772	1.067	5.32E+001	8.95E+002	3.75E+001	1.93E+002
# P158-T1 Tertiary	P158-T1 Primary	6.20	0.239	52.94	52.69	98.71	0.837	1.889 *	1.06E+002	1.79E+003	2.18E+001	1.09E+002
# S250 69 kV Bus	S250 12.5 kV Bus	59.56	0.554	64.07	88.21	91.32	0.505	0.126	1.10E+002	4.84E+002	6.85E+001	3.43E+002
# S250-SC1 Bus	S250 12.5 kV Bus	60.36	0.502	79.63	73.33	100.22	0.495	0.224 *	8.32E+001	5.40E+002	3.86E+001	1.93E+002
H5-1726	Hunker Creek	37.84	0.220	44.31	87.00	93.30	0.184	0.000	2.19E+002	1.23E+003		
1-5C	1-5	0.65	0.112	0.54	89.48	88.76	0.093	0.000	5.79E+002	3.78E+003		
1-7	1-5	0.72	0.264	0.61	89.46	88.79	0.221	0.000	2.73E+002	1.60E+003		
L1-5	1-5	100.00	0.012	100.00	100.00	100.00	0.010	0.000	5.34E+003	3.56E+004		
2-278	2-163	1.01	0.230	0.85	89.40	88.90	0.192	0.000	3.05E+002	1.84E+003		
L2-163	2-163	100.00	0.005	100.00	100.00	100.00	0.004	0.000	1.34E+004	8.91E+004		
Bus1	P158 Bus	12.40	0.000	55.10	54.05	98.53	0.245	0.735 *			5.20E+001	3.69E+002
# P158-T1 Tertiary	P158 Bus	6.20	0.717	52.94	52.69	98.71	0.217	2.464 *	6.29E+001	1.57E+003	2.18E+001	1.09E+002
DD1	P158 Bus	100.00	0.608	100.00	100.00	100.00	0.532	0.000	7.41E+001	1.85E+003		
DD2	P158 Bus	100.00	0.760	100.00	100.00	100.00	0.664	0.000	5.93E+001	1.48E+003		
DD3	P158 Bus	100.00	0.783	100.00	100.00	100.00	0.684	0.000	5.76E+001	1.44E+003		

# Indicates fault current contribution is from three-winding transformers
* Indicates a zero sequence fault current contribution (3I0) from a grounded Delta-Y transformer

Post Voltage Conversion Fault Levels at 12.47 kV Feeder #1 End

Project:	ETAP	Page:	1
Location:	16.2.0C	Date:	2018-11-22
Contract:		SN:	TESHMONT-3
Engineer:		Revision:	Hydro
Filename: Dawson-3taps	Study Case: SC-1end	Config.:	Cfg_FI1

SHORT- CIRCUIT REPORT

Fault at bus: **1-128**

Prefault voltage = 12.470 kV = 100.00 % of nominal bus kV (12.470 kV)
= 91.44 % of base kV (13.637 kV)

Contribution		3-Phase Fault		Line-To-Ground Fault					Positive & Zero Sequence Impedances Looking into "From Bus"			
From Bus ID	To Bus ID	% V From Bus	kA Symm. rms	% Voltage at From Bus Va	Vb	Vc	kA Symm. rms Ia	3I0	% Impedance on 100 MVA base R1	X1	R0	X0
1-128	Total	0.00	2.036	0.00	96.27	101.83	2.077	2.077	7.49E+001	1.75E+002	9.06E+001	1.59E+002
1-116	1-128	6.90	2.008	9.61	94.64	100.63	2.059	2.077	7.66E+001	1.77E+002	9.06E+001	1.59E+002
L1-128	1-128	100.00	0.029	100.00	100.00	100.00	0.020	0.000	1.98E+003	1.32E+004		
1-90	1-116	14.43	1.984	20.15	92.91	99.36	2.043	2.077	6.67E+001	1.72E+002	7.34E+001	1.36E+002
1-143	1-116	6.91	0.008	9.61	94.63	100.63	0.005	0.000	7.02E+003	4.68E+004		
L1-116	1-116	100.00	0.016	100.00	100.00	100.00	0.011	0.000	3.35E+003	2.24E+004		

# Indicates fault current contribution is from three-winding transformers
* Indicates a zero sequence fault current contribution (3I0) from a grounded Delta-Y transformer

Post Voltage Conversion Fault Levels at 12.47 kV Feeder #2 End

Project:	ETAP	Page:	1
Location:	16.2.0C	Date:	2018-11-22
Contract:		SN:	TESHMONT-3
Engineer:		Revision:	Hydro
Filename: Dawson-3taps	Study Case: SC-2end	Config.:	Cfg_FI1

SHORT- CIRCUIT REPORT

Fault at bus: **2-298**

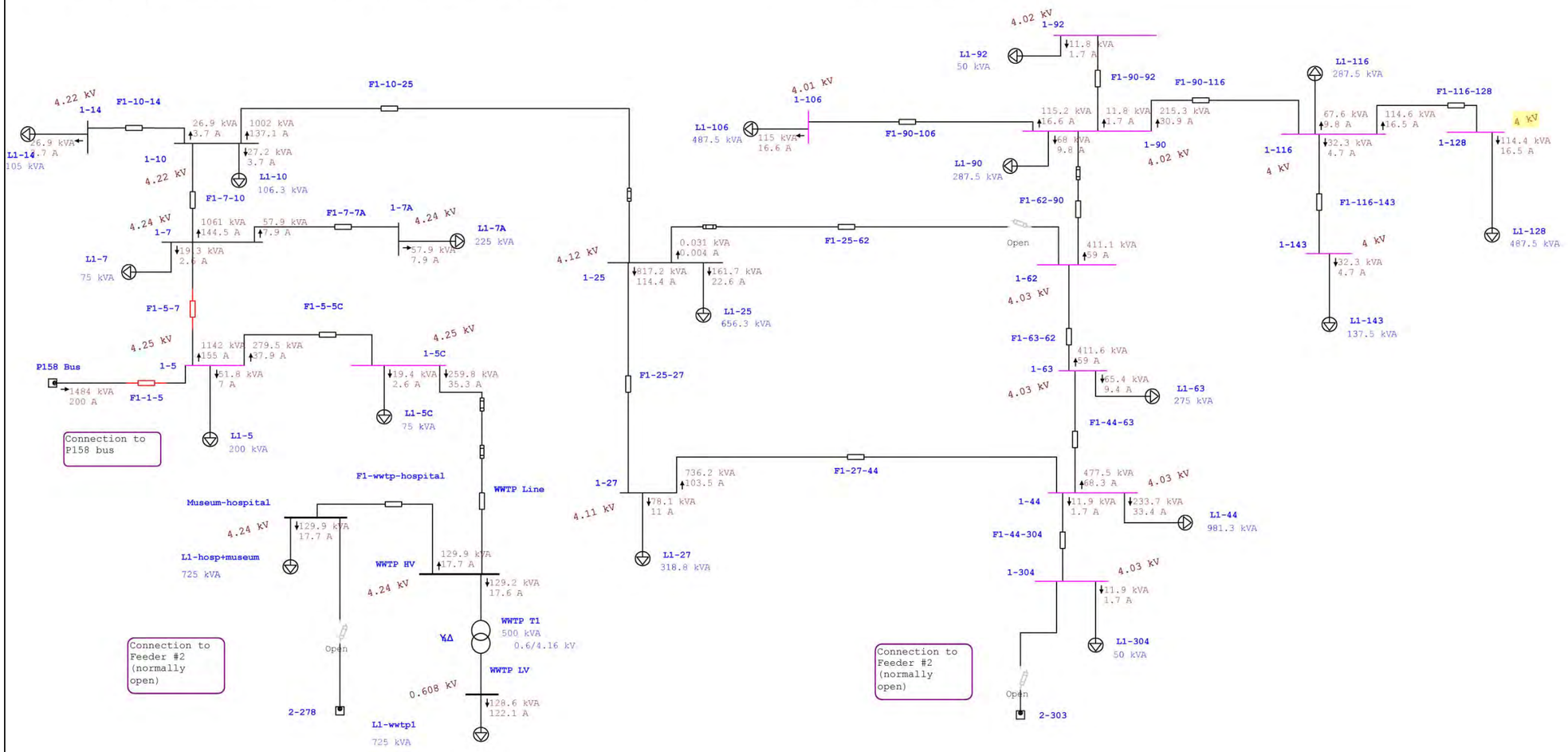
Prefault voltage = 12.470 kV = 100.00 % of nominal bus kV (12.470 kV)
= 91.44 % of base kV (13.637 kV)

Contribution		3-Phase Fault		Line-To-Ground Fault					Positive & Zero Sequence Impedances Looking into "From Bus"			
From Bus ID	To Bus ID	% V From Bus	kA Symm. rms	% Voltage at From Bus Va	Vb	Vc	kA Symm. rms Ia	3I0	% Impedance on 100 MVA base R1	X1	R0	X0
2-298	Total	0.00	2.342	0.00	91.26	97.35	2.633	2.633	4.93E+001	1.58E+002	4.85E+001	1.04E+002
2-303	2-298	3.03	2.324	4.63	90.71	96.76	2.620	2.633	4.99E+001	1.59E+002	4.85E+001	1.04E+002
L2-300	2-298	100.00	0.018	100.00	100.00	100.00	0.013	0.000	3.21E+003	2.14E+004		
2-238	2-303	4.54	1.412	6.97	90.47	96.43	1.607	1.643	7.90E+001	2.56E+002	6.46E+001	1.54E+002
L2-303	2-303	100.00	0.020	100.00	100.00	100.00	0.015	0.000	2.76E+003	1.84E+004		
1-44	1-304	3.98	0.890	6.06	90.51	96.60	0.997	0.991	1.11E+002	4.10E+002	1.19E+002	2.51E+002
L1-304	1-304	100.00	0.003	100.00	100.00	100.00	0.002	0.000	1.93E+004	1.29E+005		

# Indicates fault current contribution is from three-winding transformers
* Indicates a zero sequence fault current contribution (3I0) from a grounded Delta-Y transformer

One-Line Diagram - OLV1=>Feeder1Ntwk (Load Flow Analysis)

Existing 4.16 kV Feeder #1 Voltage Profile



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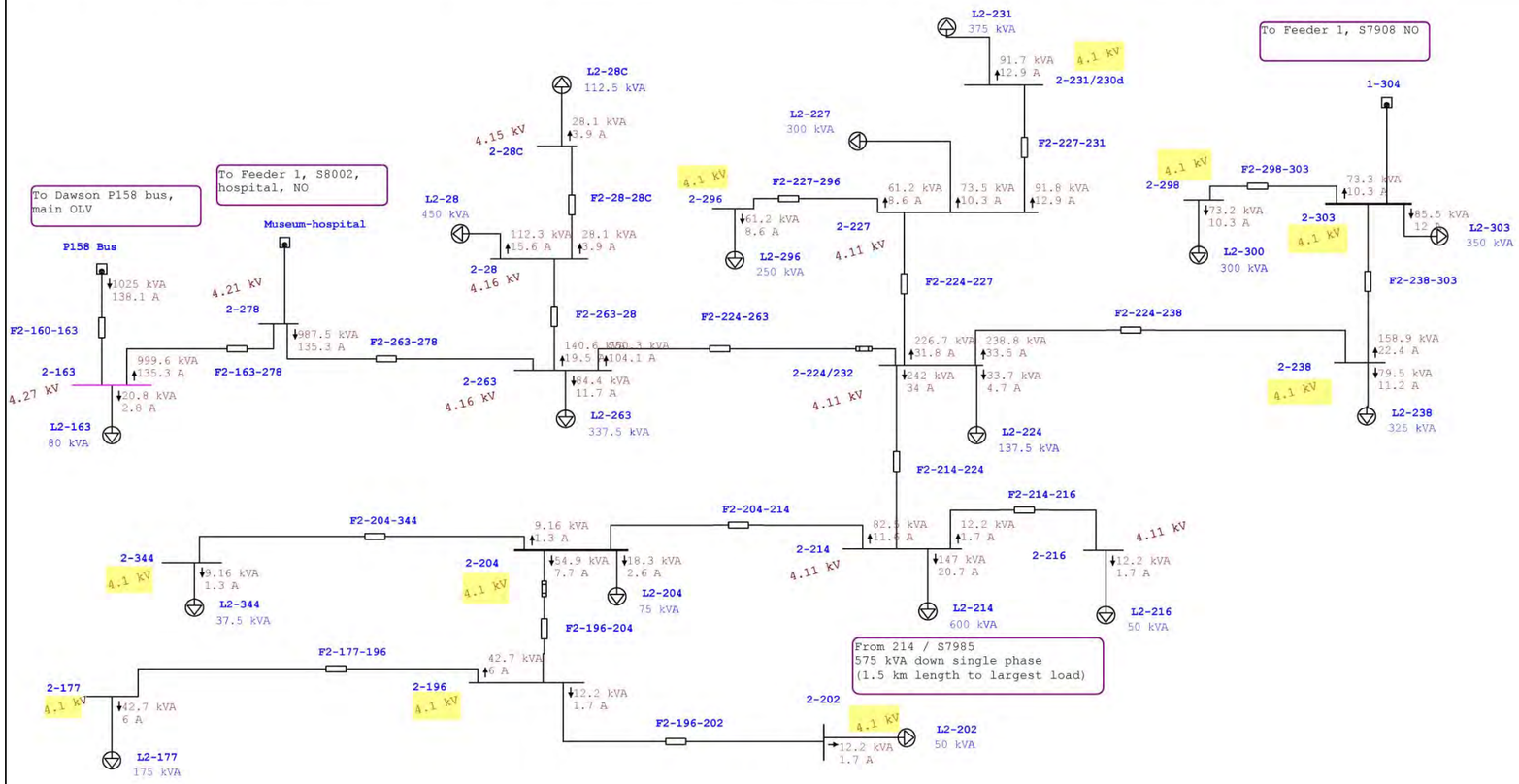
One-Line Diagram - OLV1=>Feeder2 (Load Flow Analysis)

Existing 4.16 kV Feeder #2 Voltage Profile



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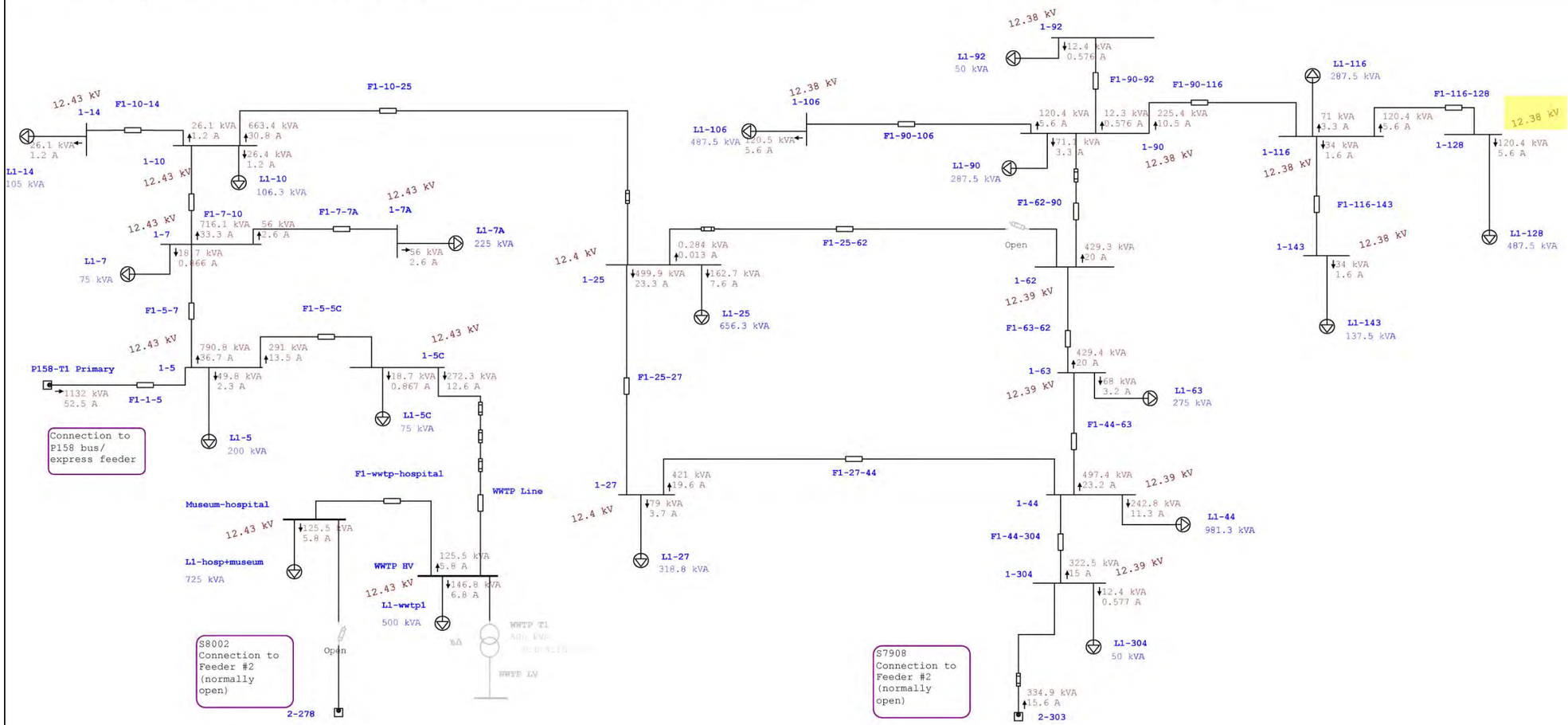
One-Line Diagram - OLV1=>Feeder1-Ntwk (Load Flow Analysis)

Post Voltage Conversion 12.47 kV Feeder #1 Voltage Profile



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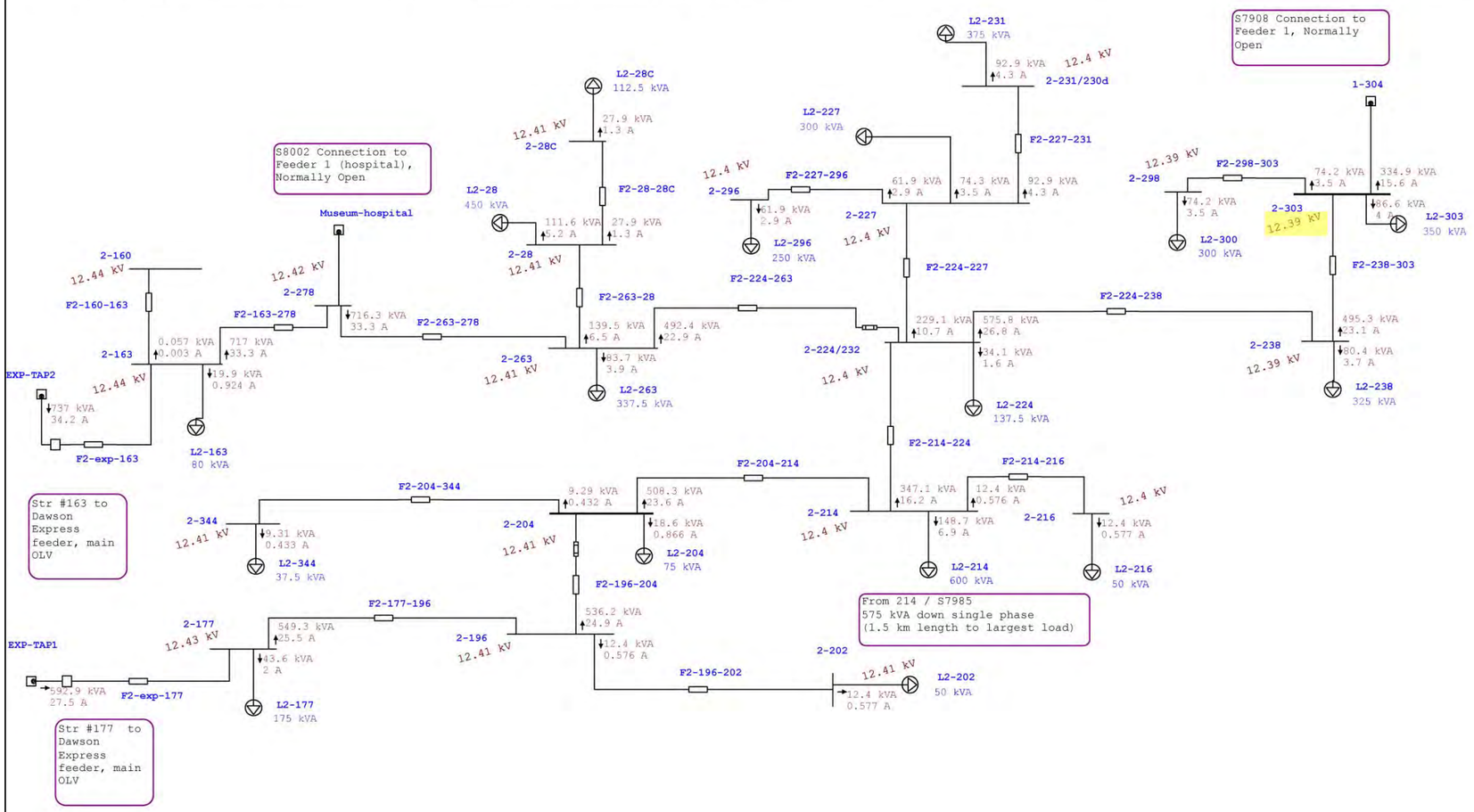
One-Line Diagram - OLV1=>Feeder2-Ntwk (Load Flow Analysis)

Post Voltage Conversion 12.47 kV Feeder #2 Voltage Profile



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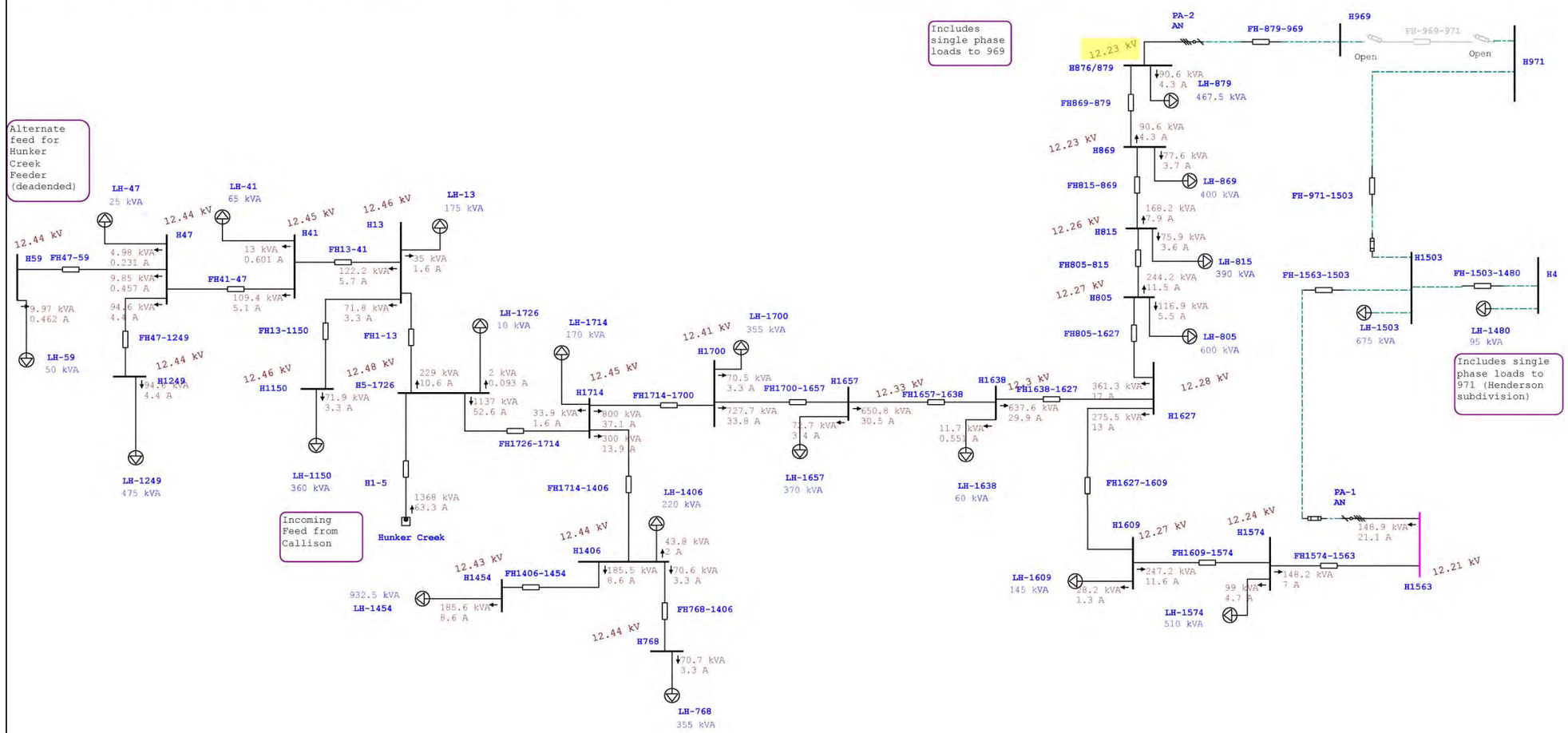
One-Line Diagram - OLV1=>HunkerCreek (Load Flow Analysis)

Post Voltage Conversion 12.47 kV with Hunker Feeder as Backup



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Total System Losses with Existing 4.16 kV Dawson City

Project:		ETAP		Page:	18
Location:		16.2.0C		Date:	2018-11-20
Contract:				SN:	TESHMONT-3
Engineer:				Revision:	Base
Filename:	DawsonCompNetwork		Study Case: LF	Config.:	Cfg_FI1

Branch Losses Summary Report

	From-To Bus Flow		To-From Bus Flow		Losses		% Bus Voltage		Vd % Drop
Branch ID	MW	Mvar	MW	Mvar	kW	kvar	From	To	in Vmag
F1-1-5	-1.430	-0.435	1.440	0.441	9.7	6.3	102.2	103.0	0.76
F1-5-5C	0.289	0.086	-0.288	-0.086	0.4	0.2	102.2	102.1	0.15
F1-5-7	1.092	0.334	-1.088	-0.332	3.6	2.3	102.2	101.9	0.37
WWTP Line	0.270	0.081	-0.269	-0.080	0.6	0.4	102.1	101.8	0.26
F1-7-7A	0.056	0.016	-0.056	-0.016	0.0	0.0	101.9	101.9	0.02
F1-7-10	1.014	0.310	-1.010	-0.308	3.6	2.3	101.9	101.5	0.39
F1-10-14	0.026	0.008	-0.026	-0.008	0.0	0.0	101.5	101.5	0.02
F1-10-25	0.959	0.293	-0.938	-0.279	20.6	13.3	101.5	99.1	2.39
F1-25-27	0.783	0.234	-0.780	-0.232	2.5	1.6	99.1	98.7	0.35
F1-25-62	0.000	0.000	0.000	0.000	0.0	0.0	99.1	99.1	0.00
F1-27-44	0.705	0.211	-0.694	-0.203	11.5	7.4	98.7	97.0	1.76
F1-44-63	0.458	0.134	-0.458	-0.134	0.4	0.3	97.0	96.9	0.09
F1-44-304	0.011	0.003	-0.011	-0.003	0.0	0.0	97.0	97.0	0.01
F1-62-90	0.394	0.116	-0.394	-0.115	0.7	0.4	96.8	96.6	0.18
F1-63-62	-0.394	-0.116	0.395	0.116	0.4	0.3	96.8	96.9	0.12
F1-90-92	0.011	0.003	-0.011	-0.003	0.0	0.0	96.6	96.6	0.00
F1-90-106	0.111	0.032	-0.110	-0.032	0.2	0.1	96.6	96.4	0.20
F1-90-116	0.207	0.061	-0.206	-0.060	0.7	0.4	96.6	96.2	0.34
F1-116-128	0.110	0.032	-0.110	-0.032	0.2	0.1	96.2	96.1	0.16
F1-116-143	0.031	0.009	-0.031	-0.009	0.0	0.0	96.2	96.2	0.01
F2-28-28C	0.027	0.008	-0.027	-0.008	0.0	0.0	99.9	99.9	0.02
F2-263-28	-0.135	-0.039	0.135	0.039	0.2	0.1	99.9	100.0	0.14
F2-160-163	-0.977	-0.296	0.981	0.298	4.1	2.6	102.5	103.0	0.47
F2-163-278	0.957	0.290	-0.946	-0.283	10.6	6.9	102.5	101.3	1.25
F2-177-196	-0.041	-0.012	0.041	0.012	0.0	0.0	98.5	98.6	0.11
F2-196-202	0.012	0.003	-0.012	-0.003	0.0	0.0	98.6	98.6	0.01
F2-196-204	-0.053	-0.015	0.053	0.015	0.0	0.0	98.6	98.6	0.01
F2-204-214	-0.079	-0.023	0.079	0.023	0.1	0.0	98.6	98.7	0.13
F2-204-344	0.009	0.003	-0.009	-0.003	0.0	0.0	98.6	98.6	0.01
F2-214-216	0.012	0.003	-0.012	-0.003	0.0	0.0	98.7	98.7	0.01
F2-214-224	-0.232	-0.068	0.232	0.068	0.2	0.1	98.7	98.8	0.10
F2-224-227	0.218	0.064	-0.217	-0.063	0.2	0.1	98.8	98.7	0.10
F2-224-238	0.229	0.067	-0.229	-0.067	0.4	0.3	98.8	98.6	0.19
F2-224-263	-0.712	-0.208	0.719	0.213	7.9	5.1	98.8	100.0	1.21

Total System Losses with Existing 4.16 kV Dawson City

Project:		ETAP		Page:	19
Location:		16.2.0C		Date:	2018-11-20
Contract:				SN:	TESHMONT-3
Engineer:				Revision:	Base
Filename:	DawsonCompNetwork		Study Case: LF	Config.:	Cfg_FI1

Branch ID	From-To Bus Flow		To-From Bus Flow		Losses		% Bus Voltage		Vd % Drop
	MW	Mvar	MW	Mvar	kW	kvar	From	To	in Vmag
F2-227-231	0.088	0.026	-0.088	-0.026	0.1	0.0	98.7	98.6	0.08
F2-227-296	0.059	0.017	-0.059	-0.017	0.0	0.0	98.7	98.7	0.08
F2-238-303	0.153	0.045	-0.152	-0.044	0.1	0.1	98.6	98.6	0.07
F2-263-278	-0.935	-0.276	0.946	0.283	10.6	6.9	100.0	101.3	1.25
F2-298-303	-0.070	-0.021	0.070	0.021	0.0	0.0	98.5	98.6	0.04
SST1	0.000	0.000	0.000	0.000			103.0	103.0	0.00
FH1-13	0.219	0.061	-0.219	-0.061	0.2	-0.4	99.7	99.6	0.10
FH1726-1714	1.086	0.314	-1.084	-0.311	2.1	2.7	99.7	99.4	0.26
H1-5	-1.307	-0.375	1.307	0.375	0.1	0.0	99.7	99.7	0.01
FH13-41	0.117	0.032	-0.117	-0.033	0.1	-1.1	99.6	99.5	0.13
FH13-1150	0.069	0.020	-0.069	-0.020	0.0	-0.5	99.6	99.6	0.03
FH41-47	0.105	0.029	-0.105	-0.030	0.0	-0.3	99.5	99.4	0.03
FH47-59	0.010	0.002	-0.010	-0.003	0.0	-0.5	99.4	99.4	0.00
FH47-1249	0.090	0.026	-0.090	-0.026	0.0	-0.3	99.4	99.4	0.03
FH768-1406	-0.067	-0.020	0.067	0.019	0.0	-0.3	99.4	99.4	0.01
FH805-815	0.234	0.066	-0.233	-0.067	0.1	-0.2	98.0	98.0	0.06
FH805-1627	-0.345	-0.099	0.345	0.099	0.3	-0.1	98.0	98.1	0.09
FH815-869	0.161	0.045	-0.161	-0.047	0.4	-1.2	98.0	97.7	0.24
FH869-879	0.087	0.025	-0.087	-0.025	0.0	-0.2	97.7	97.7	0.01
FH1406-1454	0.177	0.051	-0.177	-0.052	0.1	-0.6	99.4	99.3	0.05
FH1714-1406	-0.287	-0.083	0.287	0.082	0.1	-0.3	99.4	99.4	0.05
FH1574-1563	-0.142	-0.041	0.142	0.038	0.3	-3.6	97.6	97.8	0.24
FH1609-1574	-0.237	-0.065	0.237	0.064	0.4	-1.5	97.8	98.0	0.20
FH1627-1609	-0.264	-0.072	0.264	0.071	0.2	-0.6	98.0	98.1	0.10
FH1638-1627	-0.610	-0.170	0.611	0.171	0.7	0.5	98.1	98.3	0.15
FH1657-1638	-0.622	-0.174	0.623	0.175	1.2	0.9	98.3	98.5	0.26
FH1700-1657	-0.692	-0.195	0.696	0.198	3.5	3.1	98.5	99.2	0.66
FH1714-1700	-0.763	-0.218	0.765	0.219	1.5	1.5	99.2	99.4	0.26
F1-wwtp-hospital	-0.125	-0.036	0.125	0.036	0.0	0.0	101.8	101.8	0.00
Dawson EF	1.322	-0.248	-1.308	0.266	13.6	17.6	100.4	99.7	0.70
L177	0.000	0.000	0.015	-3.033	15.0	-3032.7	102.5	100.0	2.49
WWTP T1	0.144	0.044	-0.144	-0.042	0.4	1.8	101.8	101.2	0.59
S250-T1	0.000	0.000	0.000	0.647	1.2	5.9	99.5	100.0	0.45
S250-T1	0.000	0.000	0.001	-0.641			99.5	99.7	0.16
T1	-1.322	0.248	1.325	-0.235	2.7	13.4	100.4	103.0	2.59
T1	0.000	0.000	0.000	0.000			100.4	103.0	2.58

Total System Losses with Existing 4.16 kV Dawson City

Project:		ETAP		Page:	20
Location:		16.2.0C		Date:	2018-11-20
Contract:				SN:	TESHMONT-3
Engineer:				Revision:	Base
Filename:	DawsonCompNetwork		Study Case: LF	Config.:	Cfg_FI1

133.9	-2939.2

Total System Losses with Post Voltage Conversion 12.47 kV Dawson City

Project:		ETAP		Page:	20
Location:		16.2.0C		Date:	2018-11-19
Contract:				SN:	TESHMONT-3
Engineer:				Revision:	Base
Filename:	Dawson-3taps		Study Case: LF	Config.:	Cfg_FI1

Branch Losses Summary Report

Branch ID	From-To Bus Flow		To-From Bus Flow		Losses		% Bus Voltage		Vd % Drop
	MW	Mvar	MW	Mvar	kW	kvar	From	To	in Vmag
F1-1-5	-1.095	-0.284	1.096	0.285	0.7	0.4	99.7	99.8	0.07
F1-5-5C	0.279	0.081	-0.279	-0.081	0.0	0.0	99.7	99.7	0.02
F1-5-7	0.768	0.189	-0.768	-0.189	0.2	0.1	99.7	99.7	0.03
WWTP Line	0.261	0.076	-0.261	-0.076	0.1	-0.1	99.7	99.7	0.03
F1-7-7A	0.054	0.016	-0.054	-0.016	0.0	0.0	99.7	99.7	0.00
F1-7-10	0.696	0.168	-0.696	-0.168	0.2	0.1	99.7	99.6	0.03
F1-10-14	0.025	0.007	-0.025	-0.007	0.0	-0.1	99.6	99.6	0.00
F1-10-25	0.645	0.153	-0.644	-0.153	1.0	0.4	99.6	99.5	0.18
F1-25-27	0.488	0.108	-0.488	-0.108	0.1	0.0	99.5	99.5	0.02
F1-25-62	0.000	0.000	0.000	0.000	0.0	-0.3	99.5	95.1	0.00
F1-27-44	0.412	0.086	-0.412	-0.086	0.4	0.0	99.5	99.3	0.11
F1-44-63	0.478	0.139	-0.478	-0.139	0.0	0.0	99.3	99.3	0.01
F1-44-304	-0.299	-0.121	0.299	0.121	0.0	0.0	99.3	99.4	0.02
F1-62-90	0.412	0.120	-0.412	-0.120	0.1	0.0	99.3	99.3	0.02
F1-63-62	-0.412	-0.120	0.412	0.120	0.1	0.0	99.3	99.3	0.01
F1-90-92	0.012	0.003	-0.012	-0.003	0.0	0.0	99.3	99.3	0.00
F1-90-106	0.116	0.034	-0.116	-0.034	0.0	-0.2	99.3	99.3	0.02
F1-90-116	0.216	0.063	-0.216	-0.063	0.1	-0.1	99.3	99.3	0.04
F1-116-128	0.116	0.034	-0.116	-0.034	0.0	-0.2	99.3	99.2	0.02
F1-116-143	0.033	0.009	-0.033	-0.010	0.0	0.0	99.3	99.3	0.00
F2-28-28C	0.027	0.008	-0.027	-0.008	0.0	-0.1	99.5	99.5	0.00
F2-263-28	-0.134	-0.039	0.134	0.039	0.0	-0.1	99.5	99.5	0.02
F2-160-163	0.000	0.000	0.000	0.000	0.0	-0.1	99.7	99.7	0.00
F2-163-278	0.687	0.205	-0.686	-0.205	0.6	0.3	99.7	99.6	0.10
F2-exp-163	-0.706	-0.211	0.706	0.211	0.1	0.0	99.7	99.7	0.01
F2-177-196	0.519	0.179	-0.518	-0.179	0.8	0.2	99.7	99.6	0.16
F2-exp-177	-0.561	-0.192	0.561	0.192	0.1	0.0	99.7	99.7	0.01
F2-196-202	0.012	0.003	-0.012	-0.003	0.0	-0.1	99.6	99.6	0.00
F2-196-204	0.506	0.176	-0.506	-0.176	0.1	0.0	99.6	99.5	0.01
F2-204-214	0.480	0.168	-0.479	-0.168	0.4	0.1	99.5	99.5	0.09
F2-204-344	0.009	0.003	-0.009	-0.003	0.0	-0.1	99.5	99.5	0.00
F2-214-216	0.012	0.003	-0.012	-0.003	0.0	-0.1	99.5	99.5	0.00
F2-214-224	0.325	0.123	-0.325	-0.123	0.1	0.0	99.5	99.4	0.02
F2-224-227	0.220	0.064	-0.220	-0.064	0.0	0.0	99.4	99.4	0.01

Total System Losses with Post Voltage Conversion 12.47 kV Dawson City

Project:		ETAP		Page:	21
Location:		16.2.0C		Date:	2018-11-19
Contract:				SN:	TESHMONT-3
Engineer:				Revision:	Base
Filename:	Dawson-3taps		Study Case: LF	Config.:	Cfg_FI1

Branch ID	From-To Bus Flow		To-From Bus Flow		Losses		% Bus Voltage		Vd % Drop
	MW	Mvar	MW	Mvar	kW	kvar	From	To	in Vmag
F2-224-238	0.543	0.192	-0.543	-0.192	0.3	0.1	99.4	99.4	0.05
F2-224-263	-0.471	-0.142	0.471	0.142	0.4	0.1	99.4	99.5	0.09
F2-227-231	0.089	0.026	-0.089	-0.026	0.0	-0.1	99.4	99.4	0.01
F2-227-296	0.059	0.017	-0.059	-0.017	0.0	-0.2	99.4	99.4	0.01
F2-238-303	0.465	0.169	-0.465	-0.169	0.1	0.0	99.4	99.4	0.02
F2-263-278	-0.686	-0.205	0.686	0.205	0.6	0.3	99.5	99.6	0.10
F2-298-303	-0.071	-0.021	0.071	0.021	0.0	-0.1	99.4	99.4	0.00
SST1	0.000	0.000	0.000	0.000			103.0	103.0	0.00
Dawson EF	-0.007	-0.307	0.008	0.305	0.7	-1.8	99.7	100.1	0.34
Dawson EF1	-0.554	0.115	0.554	-0.115	0.1	0.0	99.7	99.7	0.01
Dawson EF2	-1.260	-0.096	1.261	0.096	0.4	0.5	99.7	99.8	0.04
FH1-13	0.221	0.061	-0.220	-0.062	0.2	-0.4	100.1	100.0	0.10
FH1726-1714	1.092	0.315	-1.090	-0.313	2.1	2.7	100.1	99.8	0.26
H1-5	-1.315	-0.377	1.315	0.377	0.1	0.0	100.1	100.1	0.01
FH13-41	0.118	0.032	-0.118	-0.033	0.1	-1.1	100.0	99.8	0.13
FH13-1150	0.069	0.020	-0.069	-0.020	0.0	-0.5	100.0	99.9	0.03
FH41-47	0.105	0.030	-0.105	-0.030	0.0	-0.3	99.8	99.8	0.03
FH47-59	0.010	0.002	-0.010	-0.003	0.0	-0.5	99.8	99.8	0.00
FH47-1249	0.091	0.026	-0.091	-0.027	0.0	-0.3	99.8	99.8	0.03
FH768-1406	-0.068	-0.020	0.068	0.019	0.0	-0.3	99.7	99.8	0.01
FH805-815	0.235	0.067	-0.235	-0.067	0.1	-0.2	98.4	98.3	0.06
FH805-1627	-0.347	-0.100	0.347	0.099	0.3	-0.1	98.4	98.5	0.09
FH815-869	0.162	0.046	-0.161	-0.047	0.4	-1.2	98.3	98.1	0.24
FH869-879	0.087	0.025	-0.087	-0.025	0.0	-0.2	98.1	98.1	0.01
FH1406-1454	0.178	0.051	-0.178	-0.052	0.1	-0.6	99.8	99.7	0.05
FH1714-1406	-0.288	-0.083	0.288	0.083	0.1	-0.3	99.8	99.8	0.05
FH1574-1563	-0.143	-0.042	0.143	0.038	0.3	-3.6	97.9	98.2	0.24
FH1609-1574	-0.238	-0.066	0.239	0.064	0.4	-1.5	98.2	98.4	0.20
FH1627-1609	-0.266	-0.072	0.266	0.072	0.2	-0.7	98.4	98.5	0.11
FH1638-1627	-0.613	-0.171	0.614	0.172	0.7	0.5	98.5	98.6	0.15
FH1657-1638	-0.625	-0.175	0.627	0.176	1.2	0.9	98.6	98.9	0.26
FH1700-1657	-0.696	-0.196	0.700	0.199	3.5	3.1	98.9	99.5	0.67
FH1714-1700	-0.768	-0.219	0.769	0.220	1.5	1.5	99.5	99.8	0.26
F1-wwtp-hospital	-0.120	-0.035	0.120	0.035	0.0	0.0	99.7	99.7	0.00
L177	-1.356	-3.689	1.408	0.968	51.3	-2721.3	95.1	100.0	4.90
S250-T1	1.356	3.689	0.000	-2.836	34.2	170.9	95.1	100.0	0.55
S250-T1	0.000	0.000	-1.322	-0.682			95.1	100.1	0.62

Total System Losses with Post Voltage Conversion 12.47 kV Dawson City

Project:		ETAP		Page:	22
Location:		16.2.0C		Date:	2018-11-19
Contract:				SN:	TESHMONT-3
Engineer:				Revision:	Base
Filename:	Dawson-3taps		Study Case: LF	Config.:	Cfg_FI1

Branch ID	From-To Bus Flow		To-From Bus Flow		Losses		% Bus Voltage		Vd % Drop
	MW	Mvar	MW	Mvar	kW	kvar	From	To	in Vmag
T1	-2.356	-0.381	2.365	0.424	8.5	42.7	99.8	103.0	3.23
T1	0.000	0.000	0.000	0.000			99.8	102.7	2.89
					113.1	-2511.8			

Appendix C

Voltage Conversion Area Maps (Options 1, 2, and 3)

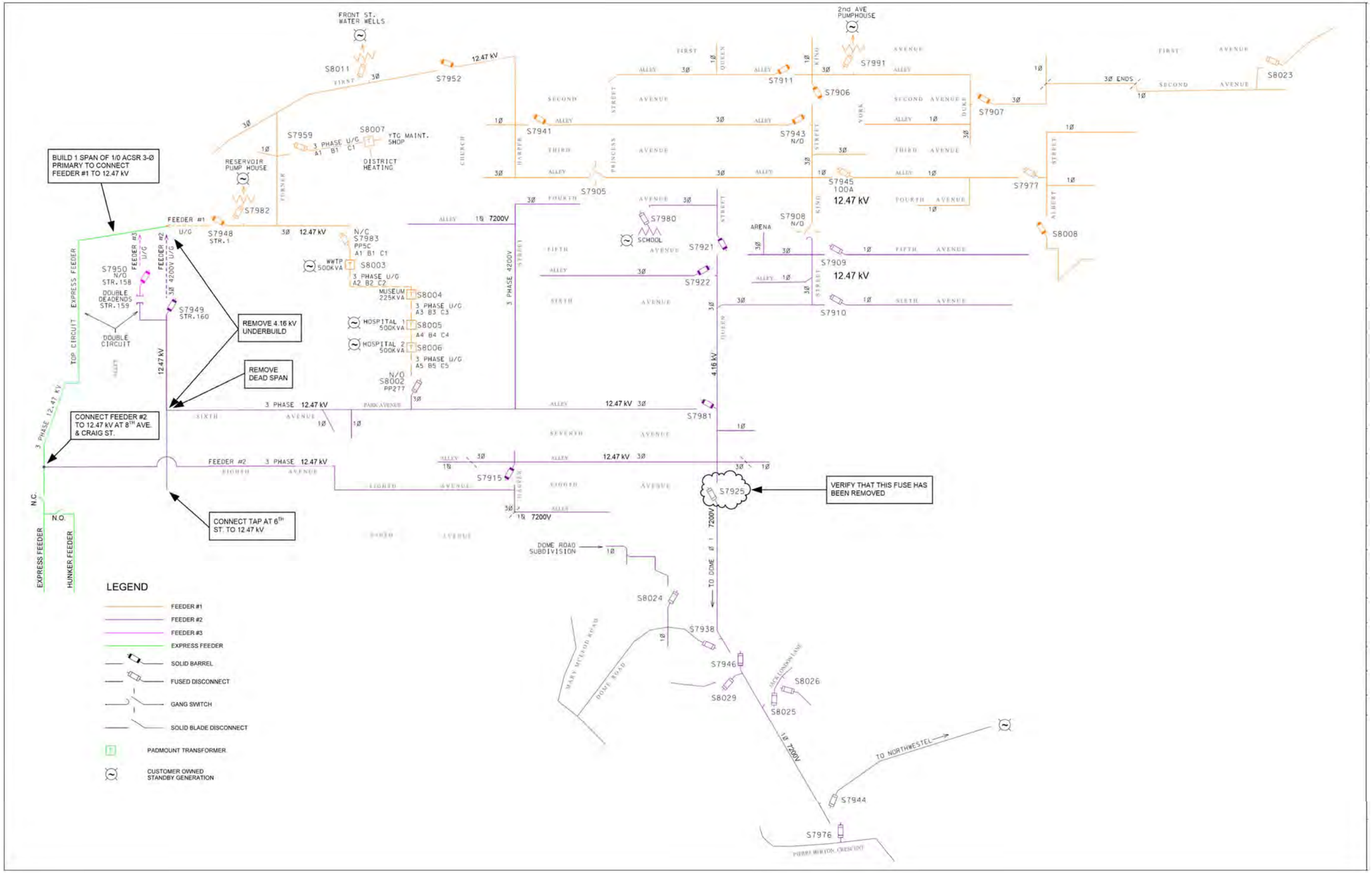

Figure C–1: Dawson City 12.47 kV Voltage Conversion Option #1

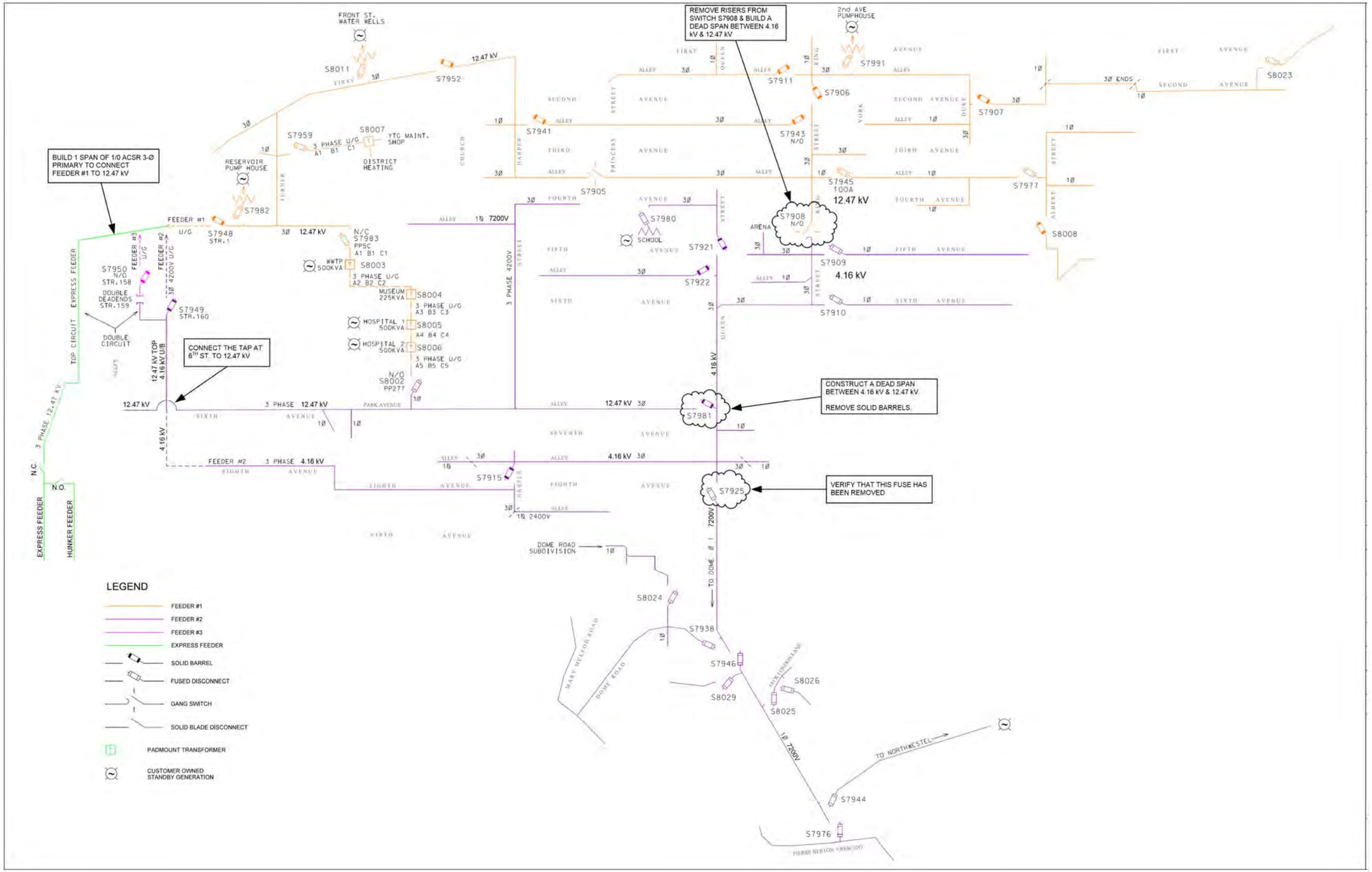

Figure C–2: Dawson City 12.47 kV Voltage Conversion Option #2

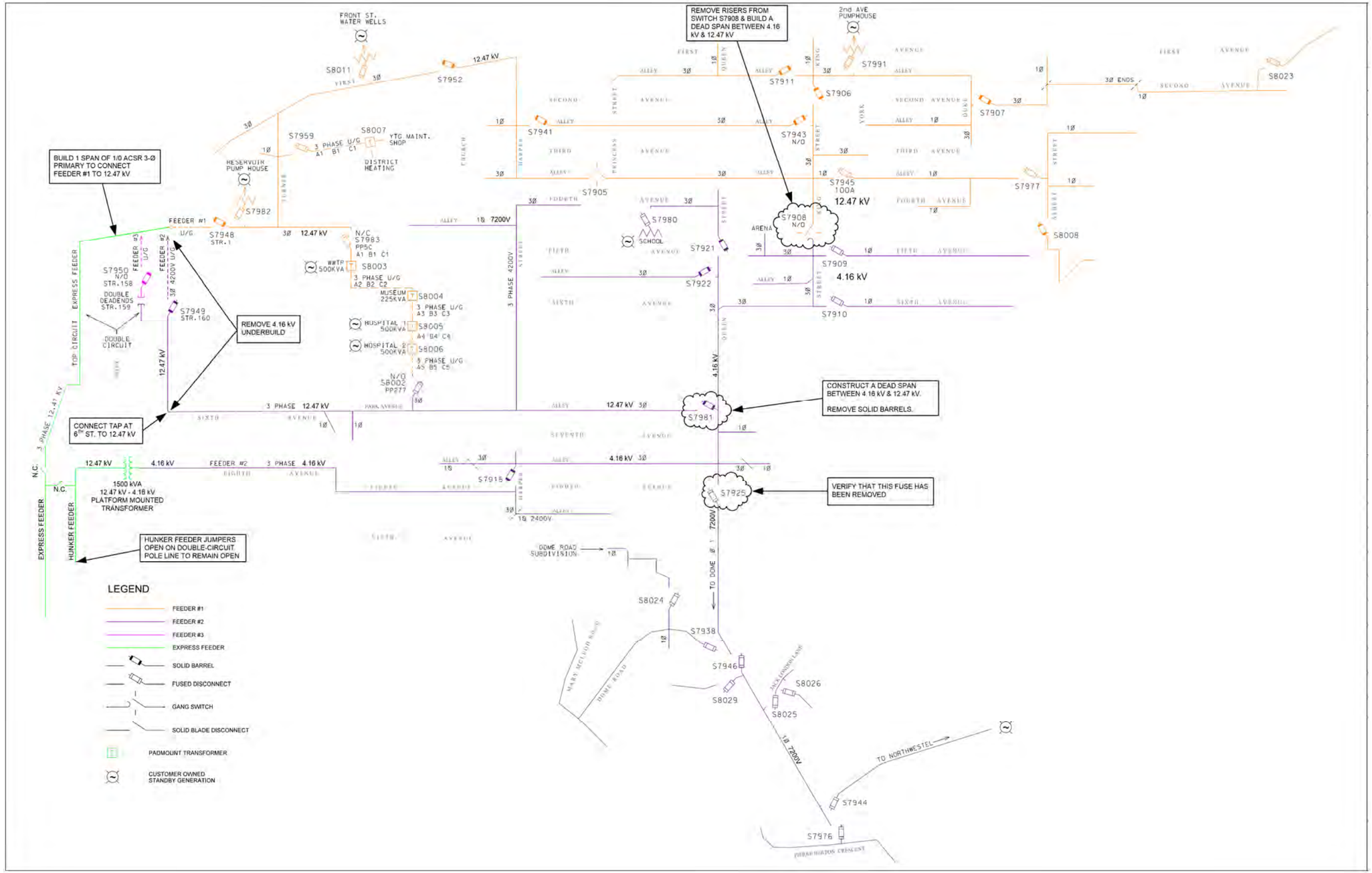

Figure C–3: Dawson City 12.47 kV Voltage Conversion Option #3

Appendix D

Sample Load Estimate and Transformer Efficiency Calculations

Appendix D
Sample Load Estimate and Transformer Efficiency Calculations

Currently, YEC is oversizing the transformation capacity for loads. This report recommends better approach to select transformation capacity to reduce life cycle cost of owning distribution plant.

The overhead transformers can handle 30% overload in summer and 90% overload in winter without sacrificing normal life expectancy. This extra cushion can be used to allow for load growth and to be confident in sizing the transformers more aggressively. It's recommended YEC to keep in track of similar existing loads and develop reasonable diversity factors to get a better handle of transformer capacity utilization factors.

Sample CEC load calculations for an apartment or similar building:

For a new 20-unit apartment building, the section 8 – 202 of Canadian Electrical Code (CEC) applies. This would be a very conservative approach for a commercial residential dwelling.

Assumptions:

- Exterior dimensions of the building is 40' x 150', two storey
- Common area 20% of total square footage
- Coin operated laundry in common area
- Electric baseboard heat
- Dedicated 40 gallon HWT (3000 W) in each unit
- The load is predominantly resistive so, unity power factor = 1.0

Confirmation of unit and common area sizes:

- Total square footage = 40x150x2 =12000 ft^2
- Common area = 0.2*12000 = 2400 ft^2
- Square footage of each unit = (12000-2400)/20 = 480 ft^2 (44.6m^2) on average

Each Dwelling Unit (excluding electric heat):

As per CEC, section 8 – 202:

i) Basic load for the first 45 m^2 = 3.5 kW

ii) N/A

iii) N/A

iv) N/A

v) Electric Range = 6.0 kW

vi) Water heater = 3.0 kW (HWT @ 100%)

vii) N/A

Total Power consumed except electric heat = 3.5+6.0+3.0 =12.5 kW

Additional load not located in the dwellings (Connected to the common area panel):

- Washer and dryer = 5.0 kW
- Outside plugs/alarm system = 3.2 kW (8 plugs, block heater only)
- Common area/exterior LED lighting = 0.5 kW
- Subtotal = 8.7 kW
- Total space heating load (@10 W/ft^2) = 120 kW

As per CEC section 8-202(3), load at the customer service entrance

= 1.0*12.5 + 0.65 * 12.5*2 + 0.40*12.5*2 + 0.25*12.5*15 + 1.0* 10 + 0.75 *(120-10) + 0.75*8.7

= 184.65 kW

Calculated current at 120/208 Service = 184.65/(3*0.120) = 512 A (Customer may request a 600 A)

The above number was calculated as per CEC representing the worst-case scenario. In reality, 60% - 70% adjustment factor is used by the utility is very common to size the transformation.

As a general rule, for an apartment building;

- Size the secondary to match the panel rating.
- Size the transformation to 60%-70% of the customer's estimated demand.
- Keep in track of similar actual loads to get a better handle on the above diversity factor.

Based on the above calculations, the transformation capacity required = 0.7*184.65 kVA= 130 kVA

3x50 kVA overhead transformer bank is required.

Similar building being constructed on 2nd Avenue is served by a 3x100 kVA overhead transformer bank. Clearly, this single load addition is not 10% of current city demand. Therefore, 3x50 kVA bank should have been a better choice.

Demand calculation for other commercial services such as schools, hotels and hospitals are also performed as per CEC.

The following calculations analyze transformer life cycle costs under different utilization factors.

YEC Distribution Transformer Efficiency Evaluation

Transformer Rating (kVA)	15	25	50	75	100	167
Canadian Manufacturer agreed efficiency at 50% FL	98.20%	98.41%	98.63%	98.84%	98.94%	98.94%
Assumed load factor where maximum efficiency occurs	0.43	0.43	0.43	0.43	0.43	0.43
Cost of energy ($/kWH)	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20
Cost of transformer	$2,000	$2,500	$3,000	$3,500	$4,000	$4,500
Loss evaluation						
Calculated Total Losses at 50% FL (watts)	135	199	343	435	530	885
Calculated No Load Losses (watts)	57	84	146	185	225	376
Calculated Full Load losses (watts)	310	457	788	1000	1219	2035
Load Losses at 10%FL (watts)	3	5	8	10	12	20
Load Losses at 15%FL(watts)	7	10	18	23	27	46
Load Losses at 20%FL(watts)	12	18	32	40	49	81
Load Losses at 30%FL(watts)	28	41	71	90	110	183
Load Losses at 40%FL (watts)	50	73	126	160	195	326
Load Losses at 50%FL(watts)	78	114	197	250	305	509
Load Losses at 60%FL(watts)	112	165	284	360	439	733
Load Losses at 70%FL(watts)	152	224	386	490	597	997
Load Losses at 80%FL(watts)	199	292	504	640	780	1303
Load Losses at 100%FL(watts)	310	457	788	1000	1219	2035
Load Losses at 130%FL(watts)	525	772	1331	1690	2060	3439
Efficiency evaluation						
Efficiency at 10%FL	96.12%	96.56%	97.02%	97.47%	97.68%	97.68%
Efficiency at 15%FL	97.22%	97.53%	97.87%	98.19%	98.34%	98.34%
Efficiency at 20%FL	97.73%	97.99%	98.26%	98.52%	98.65%	98.65%
Efficiency at 30%FL	98.14%	98.35%	98.58%	98.79%	98.90%	98.90%
Efficiency at 40%FL	98.25%	98.45%	98.66%	98.86%	98.96%	98.96%
Efficiency at 50%FL	98.23%	98.43%	98.65%	98.85%	98.95%	98.95%
Efficiency at 60%FL	98.16%	98.37%	98.59%	98.80%	98.91%	98.91%
Efficiency at 70%FL	98.04%	98.27%	98.50%	98.73%	98.84%	98.84%
Efficiency at 80%FL	97.91%	98.15%	98.40%	98.64%	98.76%	98.76%
Efficiency at 100%FL	97.61%	97.88%	98.17%	98.44%	98.58%	98.58%
Efficiency at 130%FL	97.10%	97.43%	97.78%	98.11%	98.27%	98.27%
Simple 30yr ife cycle operating cost evaluation						
Under current 10%, 15%, 20% loading conditions	$3,420	$5,036	$8,678	$11,021	$13,428	$22,425
On a 20%, 30%, 40% loading cycle	$4,606	$6,782	$11,687	$14,843	$18,085	$30,201
On a 30%, 50%, 60% loading cycle	$6,842	$10,073	$17,359	$22,048	$26,863	$44,861
On a 30%, 50%, 70% loading cycle	$7,551	$11,117	$19,158	$24,332	$29,646	$49,509
On a 40%, 60%, 80% loading cycle	$9,351	$13,767	$23,724	$30,131	$36,711	$61,307
On a 50%, 80%, 100% loading cycle	$13,332	$19,628	$33,824	$42,958	$52,340	$87,408
On a 70%, 100%, 130% loading cycle	$20,367	$29,984	$51,671	$65,626	$79,958	$133,531
Simple 30yr ife cycle total cost evaluation						
Under current 10%, 15%, 20% loading conditions	$5,420	$7,536	$11,678	$14,521	$17,428	$26,925
On a 20%, 30%, 40% loading cycle	$6,606	$9,282	$14,687	$18,343	$22,085	$34,701
On a 30%, 50%, 60% loading cycle	$8,842	$12,573	$20,359	$25,548	$30,863	$49,361
On a 30%, 50%, 70% loading cycle	$9,551	$13,617	$22,158	$27,832	$33,646	$54,009
On a 40%, 60%, 80% loading cycle	$11,351	$16,267	$26,724	$33,631	$40,711	$65,807
On a 50%, 80%, 100% loading cycle	$15,332	$22,128	$36,824	$46,458	$56,340	$91,908
On a 70%, 100%, 130% loading cycle	$22,367	$32,484	$54,671	$69,126	$83,958	$138,031

Simple 30 year ife cycle cost savings by improved transformer utilization factor

	Single t/f	3Ø Bank
Using 15kVA instead of 25kVA(20%-30%-40%)	$929	$2,787
Using 15kVA instead of 50kVA(30%-50%-70%)	$2,126	$6,379
Using 15kVA instead of 75VA(40%-60%-80%)	$3,170	$9,511
Using 15kVA instead of 100kVA(70%-100%-130%)	-$4,939	-$14,816
Using 25kVA instead of 75VA(30%-50%-60%)	$1,948	$5,843
Using 25kVA instead of 100kVA(40%-60%-80%)	$1,161	$3,484
Using 3x25kVA instead of 3 banks; 2- 3x75kVA(50%-80%-100%)		$20,745
Using 3x50kVA instead of 3 banks; 2 - 3x100kVA + 3x50kVA(50%-80%-100%)		$29,131

LEGEND	
Data	
Calculated	

The above calculations assume the following:

- The transformer efficiency maximizes around 40% - 45% of capacity, which is very typical for overhead distribution transformers.
- Cost of losses is calculated at $0.20/kWh, which is a reasonable weighted average between revenue rate and the cost of diesel generation.
- The yearly load cycle consist of 4 months of winter, 2months each of spring/fall (with 75% of winter loading) and 4 months of summer (50% of winter loading).

Although downsizing 2.4/7.2 kVA existing transformers is not justified by the cost savings however, improved utilization of them through reduction of excess transformation is well justified.

The replacement transformers shall have better utilization factors as included in the cost calculations.

Although the overhead transformers can handle significant overload without sacrificing normal life expectancy, it increases the life cycle cost beyond economical limits. The most economical life cycle cost is achieved when the transformers are loaded between 50% and 100% of capacity during the yearly load cycle.

Appendix E

Cost Estimates

Appendix E
Cost Estimates

The unit costs below are used in cost estimates. Salvage labor and material credit nearly cancel each other and disregarded in the calculation.

Replacement of 15 kVA single-phase transformer c/w 9 kV arrester:

- Cost of the transformer $1,800.00
- Cost of arrester & risers and misc. $ 200.00
  - Total material $2,000.00
  - Material overhead (25%) $ 500.00
- Cost of labor 10 hours @ $120/hour $1,200.00
  - Total labor and material cost $3,700.00

Replacement of 25kVA, 50kVA, 75kVA and 100kVA single-phase transformers may be priced at 4000, $4500, S5200, $6000 respectively.

Option #1 Cost Estimate:

Rebuild/Make ready cost:

Add 36 – 15 kVA transformers @ $3,700/ea.	= $133,200.00
Add 30 – 25 kVA transformers @ $4,000/ea.	= $120,000.00
Add 47 – 50 kVA transformers @ $4,500/ea.	= $211,500.00
Add 04 – 75 kVA transformers @ $5,200/ea.	= $ 20,800.00
Add 03 – 25 kV Single pole disconnects (in line for express feeder)	= $ 3,000.00
Add 01 – 25 kV Gang operated switch (for the feeder tie)	= $ 10,000.00
Add 02 spans of overhead 1/0 ACSR primary	= $ 2,000.00
Add 20 spans of overhead 1/0 triplex secondary	= $ 16,000.00
Add 10 spans of overhead 4/0 quadraplex secondary	= $ 15,000.00
Replace 25 arresters on dual voltage transformers with 9kV units	= $ 12,500.00
Remove obsolete primary	= $ 8,000.00
Remove 3 sets of 4 kV RINJ cable and terminations	= $ 3,000.00
Add 03 – 40’ to 50’ Class 3 poles	= $ 9,000.00
Make ready cost (Labor & material)	**= $ 564,000.00**

Voltage Conversion labor including overheads **= $ 60,000.00**

Protection coordination labor and material (Both 12 kV circuits)	**= $ 70,000.00**
Total of all costs above	**= $ 694,000.00**
Add 20% contingency	**= $ 138,800.00**
Total Conversion Cost	**= $ 832,800.00 (In 2019 $'s)**

Note: There was no salvage credit allowed for the 4160 V rated distribution transformers. The salvage value of the transformer approximately balances out the salvage labor cost, which adds up to zero.

There are 187 overhead distribution transformers with ratings ranging from 10 kVA to 100 kVA would be replaced only with 117 units ranging from 15 kVA to 75 kVA, significantly improving the utilization factor. The voltage conversion reduced the load currents, which reduces the line losses significantly.

30-year life cycle operating cost savings by better utilization of transformers (assuming doubled utilization factor) as per Appendix D

= (6x3420+57x5036+96x8678+14x11021+14x13428) – (36x4606+30x6782+47x11687+4x14843)

= $1,482,946 - $977,937

=$505,009 over 30 years

=$16,834/year transformer life cycle cost savings

As per pre conversion and post conversion load flow studies, the overall system losses are reduced by 20.8kW (= 133.9kW – 113.1kW). This is due to reduction of load currents at the higher distribution voltage.

Average cost savings due to reduced losses = 20.8x24x365x0.20 = $36,442/year

Option #2 Cost Estimate:

Deferred conversion cost:

Add 06 – 15 kVA transformers @ $3,700/ea.	= $22,200.00
Add 10 – 25 kVA transformers @ $4,000/ea.	= $40,000.00
Add 10 – 50 kVA transformers @ $4,500/ea.	= $45,000.00
Removal of some RINJ cable and some primary	= $ 5,000.00
Voltage conversion labor	= $20,000.00
Protection Coordination Labor and Material	= $10,000.00
Total of above	**= $142,200.00**

Add 20% contingency	**= $ 28,440.00**
Total deferred Conversion Cost	**= $ 170,640.00 (to 2021)**

Cost incurred in 2019 = $832,800.00 - $ 170,640.00 = $662,160.00

Cost incurred in 2021 = $170,640 + $10,000 for extra crew mobilization/demobilization cost
= $180,640

Approximately only 2/3 of the cost savings are realized in the first two years due to partial conversion. Cost savings on transformer life cycle and reduced system losses are approximately $11,223 and $24,295 respectively.

Option #3 Cost Estimate:

Cost incurred in 2019 = Option 2 cost in 2019 + $5000.00 to test and energize the platform mount transformer
= $662,160 + $5000
= $667,160

The deferred conversion cost is the same as Option #2.
Cost incurred in 2021 = $180,640

Approximately only 2/3 of the cost savings are realized in the first two years due to partial conversion. Cost savings on transformer life cycle and reduced system losses are approximately $11,223 and $24,295 respectively.

Key financial levers for options:

Based on above calculations, assuming a 5% corporate discount rate for YEC, and applying the quantifiable benefits of the voltage conversion against the cost, the following financial levers were determined:

Option #1

Total Cost	**= $832,800**
Net Present Value (NPV)	**= $ 25,840**
Breakeven period	**= 28 years**
Benefit/Cost ratio	**= 1.03**

Internal Rate of Return (IRR) **= 5.31%**

Option #2

Total Cost **= $842,800**

Net Present Value (NPV) **= - $ 709**

Breakeven period **= N/A**

Benefit/Cost ratio **= 1.00**

Internal Rate of Return (IRR) **= 4.99%**

Option #3

Total Cost **= $847,800**

Net Present Value (NPV) **= -$ 5471**

Breakeven period **= N/A**

Benefit/Cost ratio **= 0.99**

Internal Rate of Return (IRR) **= 4.93**

Appendix F

Sample Work Plan

Appendix F
Sample Work Plan

As per request from YEC, a sample work plan for Option #1 has been developed (for illustration purposes only) as follows. The timelines of activities are highly dependent on YEC's internal processes, budgetary requirements and the resource allocation to the project and therefore are not included. The In Service date (ISD) may be deferred by a few months and/or timelines may be spread out as required. The following activities shall be completed in the order of priority. Live line work may be substituted as fit.

1. **Technical and Financial Approval of Project:**

Obtain approval for this project and commit required funds. The high-level planning cost estimates and key financial levers in this report may deviate based on the degree of optimization of design.

2. **Complete Detailed Distribution Design and Protection Package:**

Based on the concepts provided by this report and the distribution standards used, complete a detailed design including protection, which shall include the following steps:

- Complete inspection of entire distribution plant to Identify requirements for 12kV operation below.
  - Insulator, dropout, cable voltage rating upgrades.
  - Single voltage rated transformers requiring replacement and dual Voltage transformers that can remain.
  - Overhead plant compliance of CAN CSA C-22.3 No. 01, latest revision.
  - Underground/ above-ground plant compliance of CAN CSA C-22.3 No. 07, latest revision.
- Obtain loading information of each distribution transformer. Customer billing information may be used for this purpose.
- Determine the optimum location/size of replacement distribution transformers and associated secondary conductor reconfiguration/upgrades/additions.
- Incorporate Distribution Protection Coordination hardware requirements in the design.

The inspection, voltage rating upgrades and CSA Standard compliance above are mandatory. Please note the design optimization has been taken in to account in the cost estimates and key financial lever calculations therefore, may result in cost overruns if not followed.

The Distribution protection study including settings shall be ready at this stage.

3. **Complete "Make Ready Work" for Voltage Conversion:**

While the distribution system still operating at 4.16kV, the following tasks shall be completed. At the client's discretion, the work may be performed on energized plant following approved work procedures minimizing outages to the customers.

- Upgrade all insulators, dropouts and primary cables to suit 12.47/7.2kV operation.
- Ensure the entire distribution plant comply with the latest applicable CSA standards above. Voltage conversion is considered as a 'Significant Modification" of the system and at the time of implementation, the affected plant shall meet applicable CSA standards wherever "reasonably practicable". No "Grand parenting Clauses" shall apply.

- Replace all overhead 2.4kV single rated distribution transformers with 2.4kV/7.2kV dual voltage rated units. Ensure all three-phase transformers are 4.16kV/12.47kV dual voltage rated. Ensure the voltage selector switch is set for 4.16kV system operation.
- The existing lightning arresters may remain on the overhead system until voltage conversion.
- Ensure all parking stand and elbow arresters (if any) in the underground system are rated at 9kV. Ensure normally open points in the underground system are adequately protected for "surge doubling effect" from both normal and alternate feed sides.
- Install distribution protection hardware recommended by the protection coordination study. All reclosers/sectionalizers shall be bypassed until the voltage conversion stage unless they are field resettable for both 4.16kV and 12.47kV operations.
- The existing 4.16kV riser cables and the 4.16kV underbuilt circuit along the back lane of Craig Street may remain until the voltage conversion is complete.

4. Complete the Voltage Conversion:

This step would require multiple partial system outages. The outage durations depend on construction crew capacity and methodology employed. There are three major branches of the Dawson City Distribution System tapped off the three-phase 'back bone" line along the back lane of Craig Street at 4th Avenue, 6th Avenue and 8th Avenue respectively. At each tap, sectionalizing equipment is to be installed. To minimize customer outage durations, the client may schedule the voltage conversion on one tap at a time. Each of these taps is called a "section" hereafter.

- Convert the first section to 12.47kV operation.
  - To minimize the outage time, de-energize a portion of a section (starting from the tap sectionalizing device) at a time.
  - Keep the unconverted area energized at 4.16kV during this period following proper safety procedures such as dead spans, non-reclosing etc.
  - Change out all lightning arresters on the de-energized portion of the section to 9kV units (this task may have been completed during the "make ready" stage as long as the voltage conversion is completed prior to the next forecasted thunderstorm).
  - Set the voltage selector switches of all transformers within this portion of the section to 7.2kV (single phase) or 12.47kV (three phase) as appropriate.
  - Connect the recloser/sectionalizer risers. Ensure 12.47kV protection settings are applied.
  - Energize the portion of the section at 12.47kV.
- Convert the rest of the section to 12.47kV operation repeating similar procedure.
- Remove the 4kV under-built circuit along the back lane of Craig Street and convert the 4.16kV load on this circuit to 12.47kV.

REFERENCE: **Application, Appendix 5.1, page 5.1-3**

ISSUE: **MH0 (Mayo A) Generation Station Slope Stability Project**

QUESTION:

a) Please provide a cost breakdown of the $1,500,000 cost for this project. More specifically, identify the activities YEC forecasts to conduct and the cost amount allocated to those activities.

ANSWER:

(a)

This project has been deferred to 2023 to allow for further engineering and planning.

REFERENCE: **Application, Appendix 5.1, page 5.1-3**

ISSUE: **Replacement of Mayo A Surge Chamber Project**

QUOTE: "The Mayo A surge chamber is at end life and must be replaced before there is a catastrophic failure. An engineering study is being undertaken in 2021 to determine solutions and further work is forecast in 2022."

QUESTION:

a) Please indicate the year in which the Mayo A surge chamber was installed and the expected service life at the time of installation.

b) Please explain how often YEC carried out tests on this chamber in the past to assess its reliability and how often maintenance work was required. If possible, please provide the number of times maintenance was conducted on this chamber in the last 10 years, on a per annum basis, and the cost of this maintenance work.

c) Please describe the nature of the catastrophic failure that could occur in the Mayo A surge chamber.

d) Please provide details on the engineering study that will be conducted on the chamber.

ANSWER:

(a)

The surge chamber was Installed in 1952. Expected service life unknown.

(b)

A reliability test was performed in 2018; annual maintenance consists of visual inspection and confirmation of heating functionality prior to winter.

Maintenance was performed twice (2019/2020)

- The 2019 cost was $142; and
- The 2020 cost was $21,212.

(c)

The nature of the catastrophic failure that could occur is unknown.

(d)

An engineering study will be completed to determine options and a recommendation for the replacement of the surge chamber.

REFERENCE: **Application, Appendix 5.1, page 5.1-4**

ISSUE: **Stop Log Crane WH Main Spill Way Project**

QUOTE: "The stop log crane at the Whitehorse hydro main spill way is critical infrastructure that is required for installing stop logs, including in emergency situations. Furthermore, cranes are subject to annual inspection by regulation. The stop log crane is aging and is experiencing a number of issues. Several structural fasteners are showing signs of rusting and possible fatigue … Due to the age and design of this unit, any parts required to facilitate this repair will have to be independently sourced and/or manufactured."

QUESTION:

a) Please indicate the year in which the stop log crane was installed and the expected service life at the time of installation.

b) Please clearly describe what work will be done, as part of this project in 2021, that is covered by the $200,000 cost. Are further costs, beyond the $200,000 in 2021, anticipated in the near future for the stop log crane?

ANSWER:

(a)

The estimated installation date is 1958 as part of the original infrastructure. The expected service life of an exterior crane is 20 years.

(b)

Assessment and engineering work will be completed in 2021 and has yet to begin. This information will be used for project planning and estimating. The crane replacement project will commence in 2022.

REFERENCE: **Application, Appendix 5.1, page 5.1-4**

ISSUE: **Asset Management Framework Project**

QUOTE: "YEC is proceeding in a staged manner. Asset Management Framework costs to the end of 2019 were $2.064 million, with $1.560 million of forecast expenditures in 2020 and $1.196 million of forecast expenditures in 2021. Project costs will remain in WIP at the end of 2021 as activities for the 5-year program remain ongoing in 2022. Costs for EAM system purchase and implementation are addressed separately (see Section 5.4.1)."

QUESTION:

a) Please confirm that this is a separate project from and in addition to the Enterprise Asset Management (EAM) in Section 5.4.1.1 in the Application. (IR 66) Why are they separated into two projects?

b) Please explain why it costs $4.82 million to develop a framework for managing capital assets.

c) Please provide a cost breakdown for this project. More specifically, provide the activities YEC has included in its forecasts and the cost amount allocated to those activities.

d) Please provide the results of analysis performed by YEC examining the costs and benefits of this project, including a comparison to any alternatives considered by YEC for this project.

ANSWER:

(a)

EAM implementation is a separate project from Asset Management Framework (AMF) and PAMMS.

The AMF project involves development of a governance model as it applies to lifecycle management of YEC assets cradle to grave. It is aligned with ISO 55000, the international standard on Asset Management, and involves the development of a managed system. This system includes policy, processes, procedures pertaining to the management of assets. Attachment 1 to this response provides the ISO 55000 standard.

The EAM tool is a component of the AMF. The EAM projects is a software tool project primarily used for planning maintenance work at YEC.

(b)

The objective of this 5-year project is to develop and implement a formal Asset Management Framework at YEC. Project deliverables include the following activities:

- Implementation of an AMF and governance model consisting of policies, procedure, and process;
- Completion of the asset hierarchy and naming convention;
- Asset data collection;
- Maintenance philosophy, and methodology;
- Refinement, Development and documentation of Maintenance Manuals (Maintenance plans and instructions);
- Development of Asset Management Plans (AMPs) which include YEC's hydro, protection and control, diesel, substation, dam, transmission, and distribution assets;
- Maintenance Repair and Operations (MRO) parts warehousing process and procedure development and implementation;
- Organizational change management procedures and processes; and
- Project management methodologies, processes and procedures.

(c)

Please see the cost breakdown provided in the table below.

Asset Management Project Budget March 2018		
Subject Area	**Total**	
Strategy and Planning	$	58
Whole Life Cost Justification	$	81
Lifecycle Delivery	$	3,015
Asset Information	$	645
Organizaion and People	$	228
Risk and Review	$	422
Project Management and Overhead	$	426
Subtotal	**$**	**4,875**
Contingency	$	608
Total	**$**	**5,482**

(d)

There was no formal cost/ benefit analysis or NPV business case study performed on the Asset Management Framework (AMF) project as the benefits are qualitative.

Successful execution of the proposed the AMF project is expected to deliver the following benefits to YEC:

- Organizational sustainability;
- Knowledge transfer;
- Operational Efficiencies;
- Long Term Capital Planning certainty;
- Regulatory Approval certainty;
- Managing the risk of project deferral; and
- Continuous improvement.

These benefits are discussed in further detail below.

Organizational Sustainability

Without a managed system, strategic items that are implemented are typically on someone's desktop or filed away where other employees have little to no access. A managed system prevents this, and information is stored and managed in a structure, such that any one employee can leave the company and the information is available and managed.

Knowledge capture / lasting change

The outcome of the development of the AMF (collaboratively developing and documenting roles and responsibilities, processes, and procedures) establishes documented business practices for YEC and ensures that the AMF becomes a persistent part of the culture and is resilient to potential risks such as turnover of key staff.

Operational Efficiencies

Utilities that have implemented Asset Management programs based on the ISO 55000 standard have achieved operational savings in the range of 15-25%[1]. While Management has not quantified the expected cost savings that will result from implementation of the proposed Asset Management framework, savings are expected to arise from of the following:

- Efficiency improvements in the planning and execution of maintenance work;
- Capital efficiency improvements through the prioritization of investments according to asset criticality, condition and risk;
- Optimization of relative expenditures on operating costs (e.g., maintenance) vs capital expenditures (asset refurbishment or replacement); and
- Efficiency improvements from improved availability and management of documentation and data related to assets.

[1] From presentation "Strategic Asset Management Delivering Value across the Organization", presented by The Institute of Asset Management CEATI Strategic Asset Management Planning conference, Vancouver 2017.

Long Term Capital Planning certainty

The proposed Asset Management program will deliver comprehensive data and supporting analysis on the condition of YEC's key assets, which will be used to support and justify YEC's long term Sustaining Capital plans and associated long term financing requirements. This data is critical for the evaluation of YEC's future capital needs by the YEC Board, Shareholder and Yukon Government.

Regulatory Approval certainty

Information on the condition of key assets can be used to demonstrate the prudency of YEC's Sustaining Capital investments to the Yukon Utilities Board (YUB). This results in YECs ability to deliver on its Capital Program consistently.

Managing the risk of project deferral

Upon project completion YEC will have information at hand to make well informed decision about an asset. Also, the maintenance program will be improved such that the overall lifecycle of an asset is longer than expected. This results in a flatter Capital program over a longer period of time, extending asset life as well as a reduction in equipment failures.

Continuous improvement

A managed system, by definition, deploys a Plan, Do, Check and Act process. The process, when followed, reviews existing systems, identifies improvement opportunities and where cost effective, defines actions to ensure that the "Status Quo" is challenged. This process is significant and allows an organization to become more efficient in its operations.

INTERNATIONAL STANDARD

ISO 55000

First edition
2014-01-15

Corrected version
2014-03-15

Asset management — Overview, principles and terminology

Gestion d'actifs — Aperçu général, principes et terminologie

Reference number
ISO 55000:2014(E)

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Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular the different approval criteria needed for the different types of ISO documents should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. ISO shall not be held responsible for identifying any or all such patent rights. Details of any patent rights identified during the development of the document will be in the Introduction and/or on the ISO list of patent declarations received (see www.iso.org/patents).

Any trade name used in this document is information given for the convenience of users and does not constitute an endorsement.

For an explanation on the meaning of ISO specific terms and expressions related to conformity assessment, as well as information about ISO's adherence to the WTO principles in the Technical Barriers to Trade (TBT) see the following URL: Foreword - Supplementary information

The committee responsible for this document is Project Committee ISO/PC 251, *Asset management*.

This corrected version of ISO 55000:2014 incorporates the correction of the numbering of definitions 3.2.4 to 3.2.7 and corresponding cross-references.

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Introduction

0.1 Purpose

This International Standard provides an overview of asset management and asset management systems (i.e. management systems for the management of assets). It also provides the context for ISO 55001 and ISO 55002.

International cooperation in the preparation of these standards has identified common practices that can be applied to the broadest range of assets, in the broadest range of organizations, across the broadest range of cultures.

0.2 Relationship with other standards

ISO 55001, ISO 55002 and this International Standard relate to a management system for asset management, which is referred to as an "asset management system" throughout the three standards.

ISO 55001, ISO 55002 and this International Standard can be used in combination with any relevant sector or asset type-specific asset management standards and technical specifications. ISO 55001 specifies requirements for an asset management system, while the other standards detail sector-specific, asset-specific or activity-specific technical requirements or give guidance on how ISO 55001 should be interpreted and applied within a specific sector or to particular asset types.

0.3 Target audience

This International Standard is primarily intended for use by:

— those considering how to improve the realization of value for their organization from their asset base

— those involved in the establishment, implementation, maintenance and improvement of an asset management system

— those involved in the planning, design, implementation and review of asset management activities; along with service providers.

0.4 Benefits of the standards

The adoption of ISO 55001, ISO 55002 and this International Standard enables an organization to achieve its objectives through the effective and efficient management of its assets. The application of an asset management system provides assurance that those objectives can be achieved consistently and sustainably over time.

Annex A provides additional information on areas related to asset management activities.

Annex B shows the relationship between key elements of an asset management system.

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Asset management — Overview, principles and terminology

1 Scope

This International Standard provides an overview of asset management, its principles and terminology, and the expected benefits from adopting asset management.

This International Standard can be applied to all types of assets and by all types and sizes of organizations.

NOTE 1 This International Standard is intended to be used for managing physical assets in particular, but it can also be applied to other asset types.

NOTE 2 This International Standard does not provide financial, accounting or technical guidance for managing specific asset types.

NOTE 3 For the purposes of ISO 55001, ISO 55002 and this International Standard, the term "asset management system" is used to refer to a management system for asset management.

2 Asset management

2.1 General

The factors which influence the type of assets that an organization requires to achieve its objectives, and how the assets are managed, include the following:

— the nature and purpose of the organization;

— its operating context;

— its financial constraints and regulatory requirements;

— the needs and expectations of the organization and its stakeholders.

These influencing factors need to be considered when establishing, implementing, maintaining and continually improving asset management.

Effective control and governance of assets by organizations is essential to realize value through managing risk and opportunity, in order to achieve the desired balance of cost, risk and performance. The regulatory and legislative environment in which organizations operate is increasingly challenging and the inherent risks that many assets present are constantly evolving.

The fundamentals of asset management and the supporting asset management system introduced in this International Standard, when integrated into the broader governance and risk framework of an organization, can contribute tangible benefits and leverage opportunities.

Asset management translates the organization's objectives into asset-related decisions, plans and activities, using a risk based approach.

2.2 Benefits of asset management

Asset management enables an organization to realize value from assets in the achievement of its organizational objectives (see 2.5.3.4). What constitutes value will depend on these objectives, the nature and purpose of the organization and the needs and expectations of its stakeholders. Asset management

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supports the realization of value while balancing financial, environmental and social costs, risk, quality of service and performance related to assets.

The benefits of asset management can include, but are not limited to the following:

a) **improved financial performance**: improving the return on investments and reducing costs can be achieved, while preserving asset value and without sacrificing the short or long-term realization of organizational objectives;

b) **informed asset investment decisions**: enabling the organization to improve its decision making and effectively balance costs, risks, opportunities and performance;

c) **managed risk**: reducing financial losses, improving health and safety, good will and reputation, minimizing environmental and social impact, can result in reduced liabilities such as insurance premiums, fines and penalties;

d) **improved services and outputs**: assuring the performance of assets can lead to improved services or products that consistently meet or exceed the expectations of customers and stakeholders;

e) **demonstrated social responsibility**: improving the organization's ability to, for example, reduce emissions, conserve resources and adapt to climate change, enables it to demonstrate socially responsible and ethical business practices and stewardship;

f) **demonstrated compliance**: transparently conforming with legal, statutory and regulatory requirements, as well as adhering to asset management standards, policies and processes, can enable demonstration of compliance;

g) **enhanced reputation**: through improved customer satisfaction, stakeholder awareness and confidence;

h) **improved organizational sustainability**: effectively managing short and long-term effects, expenditures and performance, can improve the sustainability of operations and the organization;

i) **improved efficiency and effectiveness**: reviewing and improving processes, procedures and asset performance can improve efficiency and effectiveness, and the achievement of organizational objectives.

2.3 Assets

An asset is an item, thing or entity that has potential or actual value to an organization. The value will vary between different organizations and their stakeholders, and can be tangible or intangible, financial or non-financial.

The period from the creation of an asset to the end of its life is the asset life (see 3.2.2). An asset's life does not necessarily coincide with the period over which any one organization holds responsibility for it; instead, an asset can provide potential or actual value to one or more organizations over its asset life, and the value of the asset to an organization can change over its asset life.

An organization may choose to manage its assets as a group, rather than individually, according to its needs, and to achieve additional benefits. Such groupings of assets may be by asset types, asset systems, or asset portfolios.

2.4 Overview of asset management

2.4.1 General

An organization's top management, employees and stakeholders should implement planning, control activities (e.g. policies, processes or monitoring actions) and monitoring activities, to exploit opportunities and to reduce risks to an acceptable level.

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Asset management involves the balancing of costs, opportunities and risks against the desired performance of assets, to achieve the organizational objectives. The balancing might need to be considered over different timeframes.

Asset management enables an organization to examine the need for, and performance of, assets and asset systems at different levels. Additionally, it enables the application of analytical approaches towards managing an asset over the different stages of its life cycle (which can start with the conception of the need for the asset, through to its disposal, and includes the managing of any potential post disposal liabilities).

2.4.2 Fundamentals

Asset management is based on a set of fundamentals.

a) **Value**: Assets exist to provide value to the organization and its stakeholders.

   Asset management does not focus on the asset itself, but on the value that the asset can provide to the organization. The value (which can be tangible or intangible, financial or non-financial) will be determined by the organization and its stakeholders, in accordance with the organizational objectives.

   This includes:

   1) a clear statement of how the asset management objectives align with the organizational objectives;

   2) the use of a life cycle management approach to realize value from assets;

   3) the establishment of decision-making processes that reflect stakeholder need and define value.

b) **Alignment**: Asset management translates the organizational objectives into technical and financial decisions, plans and activities.

   Asset management decisions (technical, financial and operational) collectively enable the achievement of the organizational objectives.

   This includes:

   1) the implementation of risk-based, information-driven, planning and decision-making processes and activities that transform organizational objectives into asset management plans (see 2.5.3.4);

   2) the integration of the asset management processes with the functional management processes of the organization, such as finance, human resources, information systems, logistics and operations;

   3) the specification, design and implementation of a supporting asset management system.

c) **Leadership**: Leadership and workplace culture are determinants of realization of value.

   Leadership and commitment from all managerial levels is essential for successfully establishing, operating and improving asset management within the organization.

   This includes:

   1) clearly defined roles, responsibilities and authorities;

   2) ensuring that employees are aware, competent, and empowered;

   3) consultation with employees and stakeholders regarding asset management.

d) **Assurance**: Asset management gives assurance that assets will fulfil their required purpose.

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The need for assurance arises from the need to effectively govern an organization. Assurance applies to assets, asset management and the asset management system.

This includes:

1) developing and implementing processes that connect the required purposes and performance of the assets to the organizational objectives;

2) implementing processes for assurance of capability across all life cycle stages;

3) implementing processes for monitoring and continual improvement;

4) providing the necessary resources and competent personnel for demonstration of assurance, by undertaking asset management activities and operating the asset management system.

2.4.3 The relationship of the asset management system to asset management

An asset management system is used by the organization to direct, coordinate and control asset management activities. It can provide improved risk control and gives assurance that the asset management objectives will be achieved on a consistent basis. However, not all asset management activities can be formalized through an asset management system. For example, aspects such as leadership, culture, motivation, behaviour, which can have a significant influence on the achievement of asset management objectives, may be managed by the organization using arrangements outside the asset management system. The relationship between key asset management terms is shown in Figure 1.

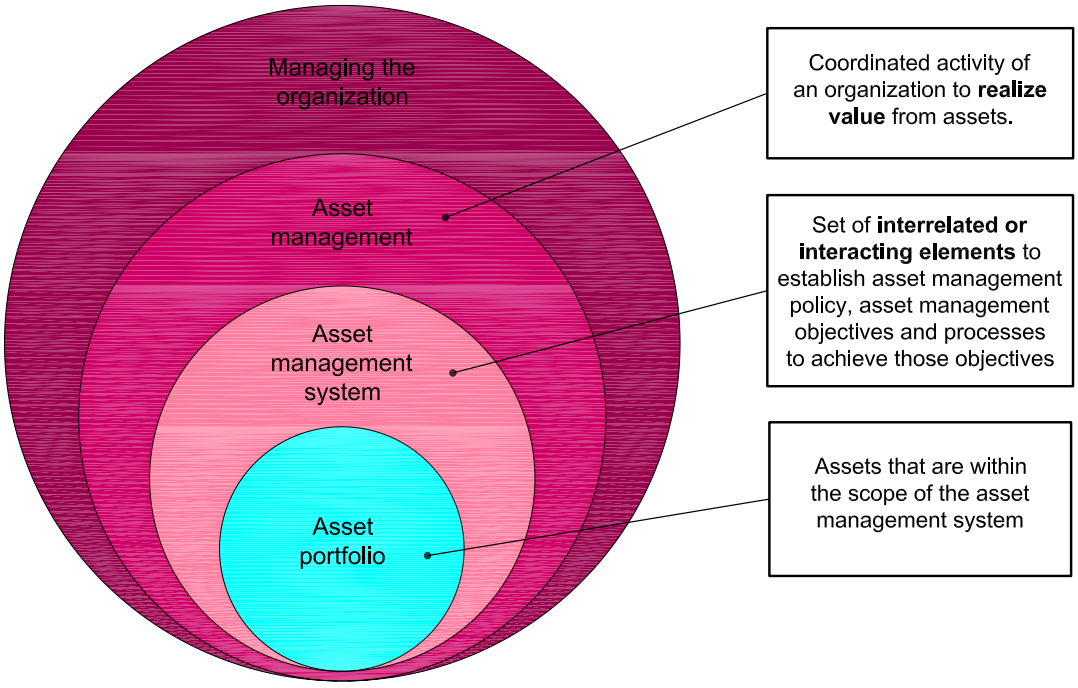

Figure 1 — Relationships between key terms

2.5 Overview of the asset management system

2.5.1 General

An asset management system is a set of interrelated and interacting elements of an organization, whose function is to establish the asset management policy and asset management objectives, and the processes, needed to achieve those objectives (see 3.4.3). In this context, the elements of the asset management

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system should be viewed as a set of tools, including policies, plans, business processes and information systems, which are integrated to give assurance that the asset management activities will be delivered.

Asset management requires accurate asset information, but an asset management system is more than a management information system. Asset management interacts with many functions of an organization. The assets themselves can also support more than one function and more than one functional unit within the organization. The asset management system provides a means for coordinating contributions from and interaction between these functional units within an organization.

The asset management plan can enable an organization to create a link, if needed, between its asset management system (such as described by ISO 55001, ISO 55002 and this International Standard) and a variety of specific, technical asset management requirements. These specific, technical requirements are given in standards both inside and outside the ISO environment, and at the international, regional or national standardization levels; such standards provide information on strategies and tactics, as well as specific design, construction, material or process requirements. The definitions given in 3.4 refer specifically to the asset management system described in this International Standard; some of these terms may be defined differently for a specific, technical standard.

The establishment of an asset management system is an important strategic decision for an organization. ISO 55001 specifies the requirements of an asset management system, but does not specify the design of the system. ISO 55002 provides guidance on the design and operation of an asset management system.

2.5.2 Benefits of an asset management system

An asset management system provides a structured approach for the development, coordination and control of activities undertaken on assets by the organization over different life cycle stages, and for aligning these activities with its organizational objectives.

a) Creating an asset management system provides benefits in itself.

   The process of implementing an asset management system can require significant time effort and expense; however, the organization does not need to wait until the entire system is fully operational to begin accruing benefits. The benefits, or quick wins, in areas such as risk reduction, opportunity identification or process improvement can be identified early in the implementation, and can be exploited to demonstrate returns and gain stronger stakeholder support.

   — Asset management is data intensive and new tools and processes are often necessary to collect, assemble, manage, analyse and use asset data. The creation and use of these tools can stimulate and improve organizational knowledge and decision making.

   — The process of creating an asset management system brings new perspectives to the organization and new ideas on value creation from the use of assets. These new perspectives can also stimulate improvements in other organizational functions, such as purchasing, finance, human resources and information technology.

   — The creation of an asset management system is usually cross-functional and based on life cycle considerations; this can provide a focal point for addressing the issues of functional integration of the organization and life cycle planning.

b) Top management benefits from new insights and cross functional integration.

   An asset management system can help in gaining an understanding of assets, their performance, the risks associated with managing assets, investment needs, and asset value as an input to decision making and organizational strategic planning.

   — Top management should recognize the need to improve communication and interaction across functions. An asset management system inherently supports this interaction. It ensures that assets are managed in an integrated manner, and asset value is improved.

   — An asset management system supports a long-term and sustainable approach to decision making.

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— An asset management system provides an ideal framework for the identification, understanding and integration of the many technical standards, codes, guidelines and best practices that affect the organization's assets, and support the implementation of asset management.

— An asset management system supports energy management, environmental management and other activities related to sustainability.

c) Financial functions benefit from improved data and linkages.

Integration of an organization's strategic asset management plan (SAMP) (see 2.5.3.4 and 3.3.2), with its long-term financial plans can enable the balancing of short-term financial needs with the needs of medium-term activity plans, and with the much longer-term plans that some assets require.

— Robust financial information, based on integrated processes between the asset management and finance functions, is an important benefit of the asset management system. The linkage of asset management information to financial information is an important contribution of the asset management system to the financial function. This interaction supports improved assessment of the financial position and funding requirements of the organization in relation to its assets.

— The organization's risk-based decision making processes can become more effective by addressing asset and financial risks together, and by balancing performance, costs and risks.

— An effective taxonomy, which may be a feature of the asset management system, can enable an integrated financial and technical view of assets and asset systems.

d) Many parts of the organization benefit from an asset management system.

An asset management system touches many parts of the organization:

— the organization's human resources function may work with its asset management system on the development of competency models, training programs and processes for coaching and mentoring; these developments benefit both functions;

— some asset data comes from control systems, which are often isolated from other information systems. Integration of this data through the asset management system can provide new asset information, leading to improved organizational decision making;

— communicating with employees, suppliers and contracted service providers about the asset management system can result in improvements in the quality of asset information; it will also increase awareness amongst individuals, inside and outside of the organization, of their role in asset management decision making and the value of the activities they are undertaking;

— the asset management system can stimulate creativity and innovation by supporting people who understand the importance of asset management and are motivated to work towards achieving the asset management objectives.

2.5.3 Elements of an asset management system

2.5.3.1 General

An asset management system impacts the whole organization, including its stakeholders and external service providers, and can use, link or integrate many of the organization's activities and functions that would otherwise be managed or operated in isolation. The process of establishing an asset management system requires a thorough understanding of each of its elements and the policies, plans and procedures that integrate them.

The asset management system requirements described in ISO 55001 are grouped in a way that is consistent with the fundamentals of asset management:

— context of the organization (ISO 55001:2014, Clause 4);

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— leadership (ISO 55001:2014, Clause 5);

— planning (ISO 55001:2014, Clause 6);

— support (ISO 55001:2014, Clause 7);

— operation (ISO 55001:2014, Clause 8);

— performance evaluation (ISO 55001:2014, Clause 9);

— improvement (ISO 55001:2014, Clause 10).

2.5.3.2 Context of the organization

When establishing or reviewing its asset management system, an organization should take into account its internal and external contexts. The external context includes the social, cultural, economic and physical environments, as well as regulatory, financial and other constraints. The internal context includes organizational culture and environment, as well as the mission, vision and values of the organization. Stakeholder inputs, concerns and expectations are also part of the context of the organization. The influences of stakeholders are key to setting rules for consistent decision making and also contribute to the setting of organizational objectives, which in turn, influence the design and scope of its asset management system.

2.5.3.3 Leadership

Top management is responsible for developing the asset management policy and asset management objectives and for aligning them with the organizational objectives. Leaders at all levels are involved in the planning, implementation and operation of the asset management system. Top management should create the vision and values that guide policy, practice and actively promote these values inside and outside the organization. Top management also defines the responsibilities, accountabilities and asset management objectives and strategies, which create the environment for the asset management system. Leaders should lend their authority to supporting the asset management system, and should ensure its alignment to other management systems within the organization through appropriate organizational design.

Top management and leaders at all levels are responsible for ensuring that appropriate resources are in place to support the asset management system. These resources include appropriate funding, adequate and competent human resources, and information technology support.

Leaders should recognize and resolve conflicts between the internal culture of the organization and the performance of its asset management system.

Top management and leaders at all levels are responsible for communicating the organization's asset management objectives and the importance of its asset management system to all employees, customers, suppliers, contractors and other stakeholders. Communication should be two-way, with leaders being open to receiving information aimed at improving the asset management system from all levels.

2.5.3.4 Planning

The organizational objectives provide the overarching context and direction to the organization's activities, including its asset management activities. The organizational objectives are generally produced from the organization's strategic level planning activities and are documented in an organizational plan (see 3.1.15).

NOTE 1 The organizational plan can be referred to by other names, e.g. the corporate plan.

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The principles by which the organization intends applying asset management to achieve its organizational objectives should be set out in an asset management policy (see 3.1.18). The approach to implementing these principles should be documented in a strategic asset management plan (SAMP) (see 3.3.2).

NOTE 2 A strategic asset management plan can be referred to by other names, e.g. an asset management strategy.

An organization's SAMP should be used to guide the setting of its asset management objectives, and to describe the role of the asset management system in meeting these objectives. This includes the structures, roles and responsibilities necessary to establish the asset management system and to operate it effectively. Stakeholder support, risk management and continuous improvement are important issues to be addressed in the establishment and operation of the asset management system. The SAMP can have a timeframe that extends beyond the organization's own business planning timeframe, requiring the asset management system to address the complete lifetimes of the assets.

The organization should also use its SAMP to guide its asset management system in the development of its asset management plans (i.e. in establishing what to do). The asset management plans themselves should define the activities to be undertaken on assets, and should have specific and measurable objectives (e.g. timeframes and the resources to be used). These objectives can provide the opportunity for alignment of operating plans with the organizational plan and any unit level business plans.

Aligning the asset management objectives with the organizational objectives, as well as linking asset reports to financial reports, can improve the organization's effectiveness and efficiency, The linking of asset reports to financial reports can also improve and clarify the assessment of the financial status and long-term funding requirements of the organization.

2.5.3.5 Support

The asset management system will require collaboration among many parts of the organization. This collaboration often involves the sharing of resources. Coordinating these resources and applying, verifying and improving their use should be objectives of the asset management system. It should also promote awareness of the asset management objectives across the whole organization.

The asset management system provides information to support the development of asset management plans and the evaluation of their effectiveness. Asset information systems can be extremely large and complex in some organizations, and there are many issues involved in collecting, verifying and consolidating asset data in order to transform it into asset information. Creating, controlling, and documenting this information is a critical function of the asset management system.

The asset management system should specify the competency requirements for personnel involved in asset management. The implementation, maintenance, evaluation and improvement of these competencies normally requires close cooperation with the organization's human resource management system. These two systems should be mutually supportive.

2.5.3.6 Operation

The organization's asset management system can enable the directing, implementation and control of its asset management activities, including those that have been outsourced. Functional policies, technical standards, plans and processes for the implementation of the asset management plans should be fed back into the design and operation of the asset management system.

Operation of the asset management system can sometimes require planned changes to asset management processes or procedures, which can introduce new risks. Risk assessment and control in the context of managing change is an important consideration in operating an asset management system.

When an organization outsources some of its asset management activities, this should not remove those outsourced activities from the control of the organization's asset management system. In situations where interacting activities are outsourced to different service providers, the responsibilities and complexity of control will be increased.

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2.5.3.7 Performance evaluation

The organization should evaluate the performance of its assets, its asset management and its asset management system. Performance measures can be direct or indirect, financial or non-financial.

Asset performance evaluation is often indirect and complex. Effective asset data management and the transformation of data to information (see 2.5.3.5) is a key to measuring asset performance. Monitoring, analysis and evaluation of this information should be a continuous process. Asset performance evaluations should be conducted on assets managed directly by the organization and on assets which are outsourced.

Asset management performance should be evaluated against whether the asset management objectives have been achieved, and if not, why not. Where applicable, any opportunities that arose from having exceeded the asset management objectives should also be examined, as well as any failure to realize them. The adequacy of the decision-making processes should be examined carefully.

The performance of the asset management system should be evaluated against any objectives set specifically for the system itself (either when it was established, or following previous evaluations). The primary purpose of evaluating the system should be to determine whether it is effective and efficient in supporting the organization's asset management. Periodic audits should be used to evaluate the performance of the asset management system; these may be complemented by self-assessments.

The results of performance evaluations should be used as inputs into management reviews.

2.5.3.8 Improvement

An organization's asset management system is likely to be complex and continually evolving to match its context, organizational objectives and its changing asset portfolio. Continual improvement is a concept that is applicable to the assets, the asset management activities and the asset management system, including those activities or processes which are outsourced.

Opportunities for improvement can be determined directly through monitoring the performance of the asset management system, and through monitoring asset performance.

Nonconformities or potential nonconformities of the asset management system can also be identified through management reviews and internal or external audits. The nonconformities require corrective action and the potential nonconformities require preventive action.

Of particular importance are asset-related incidents or emergency situations, for which emergency response planning and business continuity planning for identified risks should be addressed by the asset management system. All such incidents, including unanticipated events, should be investigated and reviewed to see if any improvements are needed to the asset management system, to prevent their recurrence and to mitigate their effects.

Improvements should be risk assessed prior to being implemented.

2.6 Integrated management systems approach

Using an integrated management systems approach allows an organization's asset management system to be built on elements of its other management systems, such as for quality, environment, health and safety, and risk management. Building on existing systems can reduce the effort and expense involved in creating and maintaining an asset management system. It can also improve integration across different disciplines and improve cross-functional coordination.

Organizations that have implemented an integrated systems approach have demonstrated the benefits of the integrated approach and shortened the time to implementation of each new system. The integrated approach, in addition to reducing cost, reduces risks and improves acceptance of each new system.

Asset management, because it touches so many parts of the organization, is a natural candidate for an integrated systems approach.

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3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

3.1 General terms

3.1.1
audit
systematic, independent and documented *process* (3.1.19) for obtaining audit evidence and evaluating it objectively to determine the extent to which the audit criteria are fulfilled

Note 1 to entry: An audit can be an internal audit (first party) or an external audit (second party or third party), and it can be a combined or integrated audit (combining two or more disciplines).

Note 2 to entry: "Audit evidence" and "audit criteria" are defined in ISO 19011.

3.1.2
capability
<asset management> measure of capacity and the ability of an entity (system, person or *organization* (3.1.13)) to achieve its *objectives* (3.1.12)

Note 1 to entry: *Asset management* (3.3.1) capabilities include *processes* (3.1.19), resources, *competences* (3.1.3) and technologies to enable the effective and efficient development and delivery of *asset management plans* (3.3.2) and *asset life* (3.2.2) activities, and their *continual improvement* (3.1.5).

3.1.3
competence
ability to apply knowledge and skills to achieve intended results

3.1.4
conformity
fulfilment of a *requirement* (3.1.20)

3.1.5
continual improvement
recurring activity to enhance *performance* (3.1.17)

3.1.6
documented information
information required to be controlled and maintained by an *organization* (3.1.13) and the medium on which it is contained

Note 1 to entry: Documented information can be in any format and media and from any source.

Note 2 to entry: Documented information can refer to:

— the *management system* (3.4.2), including related *processes* (3.1.19);

— information created in order for the organization to operate (documentation);

— evidence of results achieved (e.g. records, key performance indicators).

3.1.7
effectiveness
extent to which planned activities are realized and planned results achieved

3.1.8
incident
unplanned event or occurrence resulting in damage or other loss

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3.1.9
monitoring
determining the status of a system, a *process* (3.1.19) or an activity

Note 1 to entry: To determine the status, there may be a need to check, supervise or critically observe.

Note 2 to entry: For the purposes of asset management, monitoring may also refer to determining the status of an asset. This is typically referred to as "condition monitoring" or "performance monitoring".

3.1.10
measurement
process (3.1.19) to determine a value

3.1.11
nonconformity
non-fulfilment of a *requirement* (3.1.20)

Note 1 to entry: Nonconformity can be any deviation from asset *management system* (3.4.2) requirements, or from relevant work standards, practices, procedures, legal requirements, etc.

3.1.12
objective
result to be achieved

Note 1 to entry: An objective can be strategic, tactical or operational.

Note 2 to entry: Objectives can relate to different disciplines (such as financial, health and safety, and environmental goals) and can apply at different levels (such as strategic, organization-wide, project, product and *process* (3.1.19)).

Note 3 to entry: An objective can be expressed in other ways, e.g. as an intended outcome, a purpose, an operational criterion, an *asset management* (3.3.1) objective or by the use of other words with similar meaning (e.g. aim, goal, or target).

Note 4 to entry: In the context of *asset management systems* (3.4.3), asset management objectives are set by the *organization* (3.1.13), consistent with the *organizational objectives* (3.1.14) and asset management *policy* (3.1.18), to achieve specific measurable results.

3.1.13
organization
person or group of people that has its own functions with responsibilities, authorities and relationships to achieve its *objectives* (3.1.12)

Note 1 to entry: The concept of organization includes, but is not limited to, sole-trader, company, corporation, firm, enterprise, authority, partnership, charity or institution, or part or combination thereof, whether incorporated or not, public or private.

3.1.14
organizational objective
overarching *objective* (3.1.12) that sets the context and direction for an *organization's* (3.1.13) activities

Note 1 to entry: Organizational objectives are established through the strategic level planning activities of the organization.

3.1.15
organizational plan
documented information (3.1.6) that specifies the programmes to achieve the *organizational objectives* (3.1.14)

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3.1.16
outsource (verb)
make an arrangement where an external *organization* (3.1.13) performs part of an organization's function or *process* (3.1.19)

Note 1 to entry: An external organization is outside the scope of the *management system* (3.4.2), although the outsourced function or process is within the scope if its activities influence the effectiveness of the *asset management system* (3.4.3).

3.1.17
performance
measureable result

Note 1 to entry: Performance can relate either to quantitative or qualitative findings.

Note 2 to entry: Performance can relate to the management of activities, *processes* (3.1.19), products (including services), systems or *organizations* (3.1.13).

Note 3 to entry: For the purposes of *asset management* (3.3.1), performance can relate to *assets* (3.2.1) in their ability to fulfil *requirements* (3.1.20) or *objectives* (3.1.12).

3.1.18
policy
intentions and direction of an *organization* (3.1.13) as formally expressed by its *top management* (3.1.23)

3.1.19
process
set of interrelated or interacting activities which transforms inputs into outputs

3.1.20
requirement
need or expectation that is stated, generally implied or obligatory

Note 1 to entry: "Generally implied" means that it is custom or common practice for the *organization* (3.1.13) and *stakeholders* (3.1.22) that the need or expectation under consideration is implied.

Note 2 to entry: A specified requirement is one that is stated, for example in *documented information* (3.1.6).

3.1.21
risk
effect of uncertainty on *objectives* (3.1.12)

Note 1 to entry: An effect is a deviation from the expected — positive and/or negative.

Note 2 to entry: Objectives can relate to different disciplines (such as financial, health and safety, and environmental goals) and can apply at different levels (such as strategic, organization-wide, project, product and *process* (3.1.19)).

Note 3 to entry: Risk is often characterized by reference to potential "events" (as defined in ISO Guide 73:2009, 3.5.1.3) and "consequences" (as defined in ISO Guide 73:2009, 3.6.1.3), or a combination of these.

Note 4 to entry: Risk is often expressed in terms of a combination of the consequences of an event (including changes in circumstances) and the associated "likelihood" (ISO Guide 73:2009, 3.6.1.1) of occurrence.

Note 5 to entry: Uncertainty is the state, even partial, of deficiency of information related to, understanding or knowledge of, an event, its consequence, or likelihood.

[SOURCE: ISO Guide 73:2009, 1.1]

3.1.22
stakeholder
person or *organization* (3.1.13) that can affect, be affected by, or perceive themselves to be affected by a decision or activity

Note 1 to entry: A "stakeholder" can also be referred to as an "interested party".

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3.1.23
top management
person or group of people who directs and controls an *organization* (3.1.13) at the highest level

Note 1 to entry: Top management has the power to delegate authority and provide resources within the organization.

Note 2 to entry: If the scope of the *management system* (3.4.2) covers only part of an organization, then top management refers to those who direct and control that part of the organization. If multiple *asset management systems* (3.4.3) are employed, the systems should be designed to coordinate efforts.

3.2 Terms relating to assets

3.2.1
asset
item, thing or entity that has potential or actual value to an *organization* (3.1.13)

Note 1 to entry: Value can be tangible or intangible, financial or non-financial, and includes consideration of *risks* (3.1.21) and liabilities. It can be positive or negative at different stages of the *asset life* (3.2.2).

Note 2 to entry: Physical assets usually refer to equipment, inventory and properties owned by the organization. Physical assets are the opposite of intangible assets, which are non-physical assets such as leases, brands, digital assets, use rights, licences, intellectual property rights, reputation or agreements.

Note 3 to entry: A grouping of assets referred to as an *asset system* (3.2.5) could also be considered as an asset.

3.2.2
asset life
period from *asset* (3.2.1) creation to asset end-of-life

3.2.3
life cycle
stages involved in the management of an *asset* (3.2.1)

Note 1 to entry: The naming and number of the stages and the activities under each stage usually vary in different industry sectors and are determined by the *organization* (3.1.13).

3.2.4
asset portfolio
assets (3.2.1) that are within the scope of the *asset management system* (3.4.3)

Note 1 to entry: A portfolio is typically established and assigned for managerial control purposes. Portfolios for physical hardware might be defined by category (e.g. plant, equipment, tools, land). Software portfolios might be defined by software publisher, or by platform (e.g. PC, server, mainframe).

Note 2 to entry: An asset management system can encompass multiple asset portfolios. Where multiple asset portfolios and asset management systems are employed, *asset management* (3.3.1) activities should be coordinated between the portfolios and systems.

3.2.5
asset system
set of *assets* (3.2.1) that interact or are interrelated

3.2.6
asset type
grouping of *assets* (3.2.1) having common characteristics that distinguish those assets as a group or class

EXAMPLE Physical assets, information assets, intangible assets, *critical assets* (3.2.7), enabling assets, linear assets, information and communications technology (ICT) assets, infrastructure assets, moveable assets.

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3.2.7
critical asset
asset (3.2.1) having potential to significantly impact on the achievement of the *organization's* (3.1.13) *objectives* (3.1.12)

Note 1 to entry: Assets can be safety-critical, environment-critical or *performance-critical* (3.1.17) and can relate to legal, regulatory or statutory *requirements* (3.1.20).

Note 2 to entry: Critical assets can refer to those assets necessary to provide services to critical customers.

Note 3 to entry: *Asset systems* (3.2.5) can be distinguished as being critical in a similar manner to individual assets.

3.3 Terms relating to asset management

3.3.1
asset management
coordinated activity of an *organization* (3.1.13) to realize value from *assets* (3.2.1)

Note 1 to entry: Realization of value will normally involve a balancing of costs, *risks* (3.1.21), opportunities and *performance* (3.1.17) benefits.

Note 2 to entry: Activity can also refer to the application of the elements of the *asset management system* (3.4.3).

Note 3 to entry: The term "activity" has a broad meaning and can include, for example, the approach, the planning, the plans and their implementation.

3.3.2
strategic asset management plan
SAMP
documented information (3.1.6) that specifies how *organizational objectives* (3.1.14) are to be converted into *asset management* (3.3.1)*objectives* (3.1.12), the approach for developing *asset management plans* (3.3.3), and the role of the *asset management system* (3.4.3) in supporting achievement of the asset management objectives

Note 1 to entry: A strategic asset management plan is derived from the *organizational plan* (3.1.15).

Note 2 to entry: A strategic asset management plan may be contained in, or may be a subsidiary plan of, the organizational plan.

3.3.3
asset management plan
documented information (3.1.6) that specifies the activities, resources and timescales required for an individual *asset* (3.2.1), or a grouping of assets, to achieve the *organization's* (3.1.13)*asset management* (3.3.1)*objectives* (3.1.12)

Note 1 to entry: The grouping of assets may be by *asset type* (3.2.6), asset class, *asset system* (3.2.5) or *asset portfolio* (3.2.4).

Note 2 to entry: An asset management plan is derived from the *strategic asset management plan* (3.3.2).

Note 3 to entry: An asset management plan may be contained in, or may be a subsidiary plan of, the strategic asset management plan.

3.3.4
preventive action
action to eliminate the cause of a potential *nonconformity* (3.1.11) or other undesirable potential situation

Note 1 to entry: This definition is specific to *asset management* (3.3.1) activities only.

Note 2 to entry: There can be more than one cause for a potential nonconformity.

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Note 3 to entry: Preventive action is taken to prevent occurrence and to preserve an *asset's* (3.2.1) function, whereas *corrective action* (3.4.1) is taken to prevent recurrence.

Note 4 to entry: Preventive action is normally carried out while the asset is functionally available and operable or prior to the initiation of functional failure.

Note 5 to entry: Preventive action includes the replenishment of consumables where the consumption is a functional *requirement* (3.1.19).

[SOURCE: ISO 9000:2005, 3.6.4, modified – Note 3 to entry has been modified; Notes 1, 4 and 5 have been added]

3.3.5
predictive action
action to monitor the condition of an *asset* (3.2.1) and predict the need for *preventive action* (3.3.4) or *corrective action* (3.4.1)

Note 1 to entry: Predictive action is also commonly referred to as either "condition monitoring" or "performance monitoring".

3.3.6
level of service
parameters, or combination of parameters, which reflect social, political, environmental and economic outcomes that the *organization* (3.1.13) delivers

Note 1 to entry: The parameters can include safety, customer satisfaction, quality, quantity, capacity, reliability, responsiveness, environmental acceptability, cost and availability.

3.4 Terms relating to asset management system

3.4.1
corrective action
action to eliminate the cause of a *nonconformity* (3.1.11) and to prevent recurrence

Note 1 to entry: In the case of other undesirable outcomes, action is necessary to minimize or eliminate the causes and to reduce the impact or prevent recurrence. Such actions fall outside the concept of corrective action, in the sense of this definition.

3.4.2
management system
set of interrelated or interacting elements of an *organization* (3.1.13) to establish *policies* (3.1.18) and *objectives* (3.1.12) and *processes* (3.1.19) to achieve those objectives

Note 1 to entry: A management system can address a single discipline or several disciplines.

Note 2 to entry: The system elements include the organization's structure, roles and responsibilities, planning, operation, etc.

Note 3 to entry: The scope of a management system may include the whole of the organization, specific and identified functions of the organization, specific and identified sections of the organization, or one or more functions across a group of organizations.

3.4.3
asset management system
management system (3.4.2) for *asset management* (3.3.1) whose function is to establish the asset management *policy* (3.1.18) and asset management *objectives* (3.1.12)

Note 1 to entry: The asset management system is a subset of asset management.

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Annex A
(informative)

Information on asset management activities

Relevant asset management subject areas addressed by other published international, regional, or national standards include, but are not limited to, the following:

— data management;

— condition monitoring;

— risk management;

— quality management;

— environmental management;

— systems and software engineering;

— life cycle costing;

— dependability (availability, reliability, maintainability, maintenance support);

— configuration management;

— tero-technology;

— sustainable development;

— inspection;

— non-destructive testing;

— pressure equipment;

— financial management;

— value management;

— shock and vibration;

— acoustics;

— qualification and assessment of personnel;

— project management;

— property and property management;

— facilities management;

— equipment management;

— commissioning process;

— energy management.

Users of ISO 55001, ISO 55002 and this International Standard should also refer to such standards wherever possible, to ensure consistent delivery of asset management throughout their organization.

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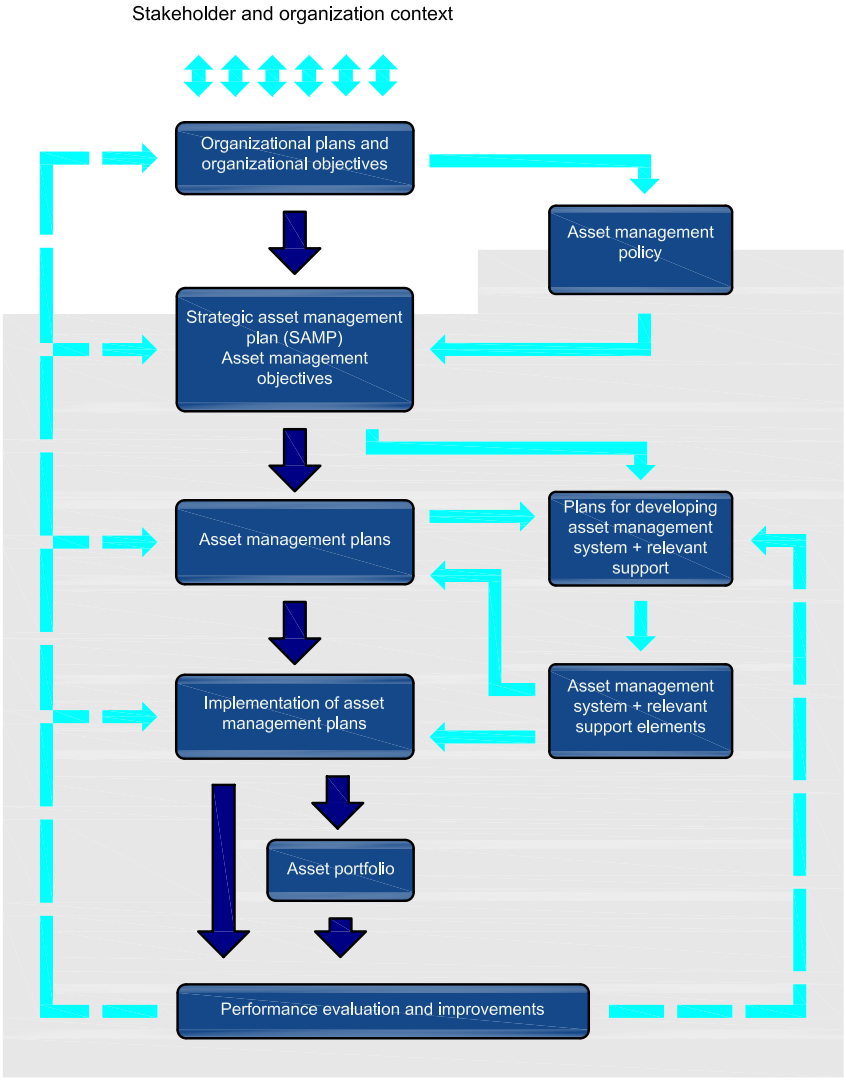
Annex B
(informative)

Relationship between key elements of an asset management system

Figure B.1 shows the relationship between key elements of an asset management system.



NOTE The grey highlighted box designates the boundary of the asset management system.

Figure B.1 — Relationship between key elements of an asset management system

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Gestion d'actifs — Systèmes de management — Exigences

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Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular the different approval criteria needed for the different types of ISO documents should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

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The committee responsible for this document is Project Committee ISO/PC 251, *Asset management*.

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Introduction

This International Standard specifies the requirements for the establishment, implementation, maintenance and improvement of a management system for asset management, referred to as an "asset management system".

This International Standard can be used by any organization. The organization determines to which of its assets this International Standard applies.

This International Standard is primarily intended for use by:

— those involved in the establishment, implementation, maintenance and improvement of an asset management system;

— those involved in delivering asset management activities and service providers;

— internal and external parties to assess the organization's ability to meet legal, regulatory and contractual requirements and the organization's own requirements.

The order in which requirements are presented in this International Standard does not reflect their importance or imply the order in which they are to be implemented.

Further guidance regarding the application of the requirements within this International Standard is provided in ISO 55002.

General information on asset management, and information on the terminology applicable to this International Standard, is provided in ISO 55000. Organizations can find that consideration of the principles will assist the development of asset management in their organization.

This International Standard applies the definition of "risk" given in ISO 31000:2009 and ISO Guide 73:2009. In addition, it uses the term "stakeholder" rather than "interested party".

This International Standard is designed to enable an organization to align and integrate its asset management system with related management system requirements.

Annex A provides additional information on areas related to asset management activities.

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Asset management — Management systems — Requirements

1 Scope

This International Standard specifies requirements for an asset management system within the context of the organization.

This International Standard can be applied to all types of assets and by all types and sizes of organizations.

NOTE 1 This International Standard is intended to be used for managing physical assets in particular, but it can also be applied to other asset types.

NOTE 2 This International Standard does not specify financial, accounting or technical requirements for managing specific asset types.

NOTE 3 For the purposes of ISO 55000, ISO 55002 and this International Standard, the term "asset management system" is used to refer to a management system for asset management.

2 Normative reference

The following documents, in whole or in part, are normatively referenced in this document and are indispensable for its application. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

ISO 55000:2014, *Asset management — Overview, principles and terminology*

3 Terms and definitions

For the purposes of this document, the terms and definitions given in ISO 55000 apply.

4 Context of the organization

4.1 Understanding the organization and its context

The organization shall determine external and internal issues that are relevant to its purpose and that affect its ability to achieve the intended outcome(s) of its asset management system.

Asset management objectives, included in the strategic asset management plan (SAMP), shall be aligned to, and consistent with, the organizational objectives.

4.2 Understanding the needs and expectations of stakeholders

The organization shall determine:

— the stakeholders that are relevant to the asset management system;

— the requirements and expectations of these stakeholders with respect to asset management;

— the criteria for asset management decision making;

— the stakeholder requirements for recording financial and non-financial information relevant to asset management, and for reporting on it both internally and externally.

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4.3 Determining the scope of the asset management system

The organization shall determine the boundaries and applicability of the asset management system to establish its scope. The scope shall be aligned with the SAMP and the asset management policy. When determining this scope, the organization shall consider:

— the external and internal issues referred to in 4.1;

— the requirements referred to in 4.2;

— the interaction with other management systems, if used.

The organization shall define the asset portfolio covered by the scope of the asset management system.

The scope shall be available as documented information.

4.4 Asset management system

The organization shall establish, implement, maintain and continually improve an asset management system, including the processes needed and their interactions, in accordance with the requirements of this International Standard.

The organization shall develop a SAMP which includes documentation of the role of the asset management system in supporting achievement of the asset management objectives.

5 Leadership

5.1 Leadership and commitment

Top management shall demonstrate leadership and commitment with respect to the asset management system by:

— ensuring that the asset management policy, the SAMP and asset management objectives are established and are compatible with the organizational objectives;

— ensuring the integration of the asset management system requirements into the organization's business processes;

— ensuring that the resources for the asset management system are available;

— communicating the importance of effective asset management and of conforming to the asset management system requirements;

— ensuring that the asset management system achieves its intended outcome(s);

— directing and supporting persons to contribute to the effectiveness of the asset management system;

— promoting cross-functional collaboration within the organization;

— promoting continual improvement;

— supporting other relevant management roles to demonstrate their leadership as it applies to their areas of responsibility;

— ensuring that the approach used for managing risk in asset management is aligned with the organization's approach for managing risk.

NOTE Reference to "business" in this International Standard can be interpreted broadly to mean those activities that are core to the purposes of the organization's existence.

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5.2 Policy

Top management shall establish an asset management policy that:

a) is appropriate to the purpose of the organization;

b) provides a framework for setting asset management objectives;

c) includes a commitment to satisfy applicable requirements;

d) includes a commitment to continual improvement of the asset management system.

The asset management policy shall:

— be consistent with the organizational plan;

— be consistent with other relevant organizational policies;

— be appropriate to the nature and scale of the organization's assets and operations;

— be available as documented information;

— be communicated within the organization;

— be available to stakeholders, as appropriate;

— be implemented and be periodically reviewed and, if required, updated.

5.3 Organizational roles, responsibilities and authorities

Top management shall ensure that the responsibilities and authorities for relevant roles are assigned and communicated within the organization.

Top management shall assign the responsibility and authority for:

a) establishing and updating the SAMP, including asset management objectives;

b) ensuring that the asset management system supports delivery of the SAMP;

c) ensuring that the asset management system conforms to the requirements of this International Standard;

d) ensuring the suitability, adequacy and effectiveness of the asset management system;

e) establishing and updating the asset management plan(s) (see 6.2.2);

f) reporting on the performance of the asset management system to top management.

6 Planning

6.1 Actions to address risks and opportunities for the asset management system

When planning for the asset management system, the organization shall consider the issues referred to in 4.1 and the requirements referred to in 4.2 and determine the risks and opportunities that need to be addressed to:

— give assurance that the asset management system can achieve its intended outcome(s);

— prevent, or reduce undesired effects;

— achieve continual improvement.

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The organization shall plan:

a) actions to address these risks and opportunities, taking into account how these risks and opportunities can change with time;

b) how to:

— integrate and implement the actions into its asset management system processes;

— evaluate the effectiveness of these actions.

6.2 Asset management objectives and planning to achieve them

6.2.1 Asset management objectives

The organization shall establish asset management objectives at relevant functions and levels.

When establishing its asset management objectives, the organization shall consider the requirements of relevant stakeholders and of other financial, technical, legal, regulatory and organizational requirements in the asset management planning process.

The asset management objectives shall:

— be consistent and aligned with the organizational objectives;

— be consistent with the asset management policy;

— be established and updated using asset management decision-making criteria (see 4.2);

— be established and updated as part of the SAMP;

— be measurable (if practicable);

— take into account applicable requirements;

— be monitored;

— be communicated to relevant stakeholders;

— be reviewed and updated as appropriate.

The organization shall retain documented information on the asset management objectives.

6.2.2 Planning to achieve asset management objectives

The organization shall integrate the planning to achieve asset management objectives with other organizational planning activities, including financial, human resources and other support functions.

The organization shall establish, document and maintain asset management plan(s) to achieve the asset management objectives. These asset management plan(s) shall be aligned with the asset management policy and the SAMP.

The organization shall ensure that the asset management plan(s) take(s) into account relevant requirements coming from outside the asset management system.

When planning how to achieve its asset management objectives, the organization shall determine and document:

a) the method and criteria for decision making and prioritizing of the activities and resources to achieve its asset management plan(s) and asset management objectives;

b) the processes and methods to be employed in managing its assets over their life cycles;

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c) what will be done;

d) what resources will be required;

e) who will be responsible;

f) when it will be completed;

g) how the results will be evaluated;

h) the appropriate time horizon(s) for the asset management plan(s);

i) the financial and non-financial implications of the asset management plan(s);

j) the review period for the asset management plan(s) (see 9.1);

k) actions to address risks and opportunities associated with managing the assets, taking into account how these risks and opportunities can change with time, by establishing processes for:

— identification of risks and opportunities;

— assessment of risks and opportunities;

— determining the significance of assets in achieving asset management objectives;

— implementation of the appropriate treatment, and monitoring, of risks and opportunities.

The organization shall ensure that its asset management related risks are considered in the organization's risk management approach including contingency planning.

NOTE See ISO 31000 for further guidance on risk management

7 Support

7.1 Resources

The organization shall determine and provide the resources needed for the establishment, implementation, maintenance and continual improvement of the asset management system.

The organization shall provide the resources required for meeting the asset management objectives and for implementing the activities specified in the asset management plan(s).

7.2 Competence

The organization shall:

— determine the necessary competence of person(s) doing work under its control that affects its asset performance, asset management performance and asset management system performance;

— ensure that these persons are competent on the basis of appropriate education, training, or experience;

— where applicable, take actions to acquire the necessary competence, and evaluate the effectiveness of the actions taken;

— retain appropriate documented information as evidence of competence;

— periodically review current and future competency needs and requirements.

NOTE Applicable actions can include, for example: the provision of training to, the mentoring of, or the re-assignment of currently employed persons; or the hiring or contracting of competent persons.

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7.3 Awareness

Persons doing work under the organization's control, who can have an impact on the achievement of the asset management objectives, shall be aware of:

— the asset management policy;

— their contribution to the effectiveness of the asset management system, including the benefits of improved asset management performance;

— their work activities, the associated risks and opportunities and how they relate to each other;

— the implications of not conforming to the asset management system requirements.

7.4 Communication

The organization shall determine the need for internal and external communications relevant to assets, asset management and the asset management system including:

— on what it will communicate;

— when to communicate;

— with whom to communicate;

— how to communicate.

7.5 Information requirements

The organization shall determine its information requirements to support its assets, asset management, asset management system and the achievement of its organizational objectives. In doing this:

a) the organization shall include consideration of:

   — the significance of the identified risks;

   — the roles and responsibilities for asset management;

   — the asset management processes, procedures and activities;

   — the exchange of information with its stakeholders, including service providers;

   — the impact of quality, availability and management of information on organizational decision making;

b) the organization shall determine:

   — the attribute requirements of identified information;

   — the quality requirements of identified information;

   — how and when information is to be collected, analysed and evaluated;

c) the organization shall specify, implement and maintain processes for managing its information;

d) the organization shall determine the requirements for alignment of financial and non-financial terminology relevant to asset management throughout the organization;

e) the organization shall ensure that there is consistency and traceability between the financial and technical data and other relevant non-financial data, to the extent required to meet its legal and regulatory requirements while considering its stakeholders' requirements and organizational objectives.

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7.6 Documented information

7.6.1 General

The organization's asset management system shall include:

— documented information as required by this International Standard;

— documented information for applicable legal and regulatory requirements;

— documented information determined by the organization as being necessary for the effectiveness of the asset management system, as specified in 7.5.

NOTE The extent of the documented information for an asset management system can differ from one organization to another due to:

— the size of organization and its type of activities, processes, products and services;

— the complexity of processes and their interactions;

— the competence of persons;

— the complexity of the asset(s).

7.6.2 Creating and updating

When creating and updating documented information the organization shall ensure appropriate:

— identification and description (e.g. a title, date, author, or reference number);

— format (e.g. language, software version, graphics) and media (e.g. paper, electronic);

— review and approval for suitability and adequacy.

7.6.3 Control of documented information

Documented information required by the asset management system and by this International Standard shall be controlled to ensure:

a) it is available and suitable for use, where and when it is needed;

b) it is adequately protected (e.g. from loss of confidentiality, improper use, or loss of integrity).

For the control of documented information, the organization shall address the following activities, as applicable:

— distribution, access, retrieval and use;

— storage and preservation, including preservation of legibility;

— control of changes (e.g. version control);

— retention and disposition.

Documented information of external origin determined by the organization to be necessary for the planning and operation of the asset management system shall be identified, as appropriate, and controlled.

NOTE Access implies a decision regarding the permission to view the documented information only, or the permission and authority to view and change the documented information, etc.

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8 Operation

8.1 Operational planning and control

The organization shall plan, implement and control the processes needed to meet requirements, and to implement the actions determined in 6.1, the asset management plan(s) determined in 6.2, and the corrective and preventive actions determined in 10.1 and 10.2 by:

— establishing criteria for the required processes;

— implementing the control of the processes in accordance with the criteria;

— keeping documented information to the extent necessary to have confidence and evidence that the processes have been carried out as planned;

— treating and monitoring risks using the approach described in 6.2.2.

8.2 Management of change

Risks associated with any planned change, permanent or temporary that can have an impact on achieving the asset management objectives, shall be assessed before the change is implemented.

The organization shall ensure that such risks are managed in accordance with 6.1 and 6.2.2.

The organization shall control planned changes and review the unintended consequences of changes, taking action to mitigate any adverse effects, as necessary.

8.3 Outsourcing

When the organization outsources any activities that can have an impact on the achievement of its asset management objectives, it shall assess the associated risks. The organization shall ensure that outsourced processes and activities are controlled.

The organization shall determine and document how these activities will be controlled and integrated into the organization's asset management system. The organization shall determine:

a) the processes and activities that are to be outsourced (including the scope and boundaries of the outsourced processes and activities and their interfaces with the organization's own processes and activities);

b) the responsibilities and authorities within the organization for managing the outsourced processes and activities;

c) the processes and scope for the sharing of knowledge and information between the organization and its contracted service provider(s);

When outsourcing any activities, the organization shall ensure that:

— the outsourced resources meet the requirements of 7.2, 7.3 and 7.6;

— the performance of the outsourced activities is monitored in accordance with 9.1.

9 Performance evaluation

9.1 Monitoring, measurement, analysis and evaluation

The organization shall determine:

a) what needs to be monitored and measured;

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b) the methods for monitoring, measurement, analysis and evaluation, as applicable, to ensure valid results;

c) when the monitoring and measuring shall be performed;

d) when the results from monitoring and measurement shall be analysed and evaluated.

The organization shall evaluate and report on

— the asset performance;

— the asset management performance, including financial and non-financial performance;

— the effectiveness of the asset management system.

The organization shall evaluate and report on the effectiveness of the processes for managing risks and opportunities.

The organization shall retain appropriate documented information as evidence of the results of monitoring, measurement, analysis and evaluation.

The organization shall ensure that its monitoring and measurement enables it to meet the requirements of 4.2.

9.2 Internal audit

9.2.1 The organization shall conduct internal audits at planned intervals to provide information to assist in the determination on whether the asset management system:

a) conforms to:

— the organization's own requirements for its asset management system;

— the requirements of this International Standard;

b) is effectively implemented and maintained.

9.2.2 The organization shall:

a) plan, establish, implement and maintain an audit programme(s), including the frequency, methods, responsibilities, planning requirements and reporting. The audit programme(s) shall take into consideration the importance of the processes concerned and the results of previous audits;

b) define the audit criteria and scope for each audit;

c) select auditors and conduct audits to ensure objectivity and the impartiality of the audit process;

d) ensure that the results of the audits are reported to relevant management; and

e) retain documented information as evidence of the results of the implementation of the audit programme and the audit results.

9.3 Management review

Top management shall review the organization's asset management system, at planned intervals, to ensure its continuing suitability, adequacy and effectiveness.

The management review shall include consideration of:

a) the status of actions from previous management reviews;

b) changes in external and internal issues that are relevant to the asset management system;

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c) information on the asset management performance, including trends in:

— nonconformities and corrective actions;

— monitoring and measurement results;

— audit results;

d) asset management activity;

e) opportunities for continual improvement;

f) changes in the profile of risks and opportunities.

The outputs of the management review shall include decisions related to continual improvement opportunities and any need for changes (see 8.2) to the asset management system.

The organization shall retain documented information as evidence of the results of management reviews.

10 Improvement

10.1 Nonconformity and corrective action

When a nonconformity or incident occurs in its assets, asset management or asset management system the organization shall:

a) react to the nonconformity or incident, and, as applicable:

— take action to control and correct it;

— deal with the consequences;

b) evaluate the need for action to eliminate the causes of the nonconformity or incident, in order that it does not occur or recur elsewhere, by:

— reviewing the nonconformity or incident;

— determining the causes of nonconformity or incident;

— determining if similar nonconformities exist, or could potentially occur;

c) implement any action needed;

d) review the effectiveness of any corrective action taken; and

e) make changes (see 8.2) to the asset management system, if necessary.

Corrective actions shall be appropriate to the effects of the nonconformities or incident encountered.

The organization shall retain documented information as evidence of:

— the nature of the nonconformities or incident and any subsequent actions taken;

— the results of any corrective action.

10.2 Preventive action

The organization shall establish processes to proactively identify potential failures in asset performance and evaluate the need for preventive action.

When a potential failure is identified the organization shall apply the requirements of 10.1.

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10.3 Continual improvement

The organization shall continually improve the suitability, adequacy and effectiveness of its asset management and the asset management system.

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Annex A
(informative)

Information on asset management activities

Relevant asset management subject areas addressed by other published international, regional, or national standards include, but are not limited to, the following:

— data management;

— condition monitoring;

— risk management;

— quality management;

— environmental management;

— systems and software engineering;

— life cycle costing;

— dependability (availability, reliability, maintainability, maintenance support);

— configuration management;

— tero-technology;

— sustainable development;

— inspection;

— non-destructive testing;

— pressure equipment;

— financial management;

— value management;

— shock and vibration;

— acoustics;

— qualification and assessment of personnel;

— project management;

— property and property management;

— facilities management;

— equipment management;

— commissioning process;

— energy management.

Users of ISO 55000, ISO 55002 and this International Standard should also refer to such standards wherever possible, to ensure consistent delivery of asset management throughout their organization.

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Foreword

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The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular the different approval criteria needed for the different types of ISO documents should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

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For an explanation on the meaning of ISO specific terms and expressions related to conformity assessment, as well as information about ISO's adherence to the WTO principles in the Technical Barriers to Trade (TBT) see the following URL: Foreword - Supplementary information

The committee responsible for this document is Project Committee ISO/PC 251, *Asset management*.

This corrected version of ISO 55000:2014 incorporates the correction of the numbering of subclause 7.3.2.

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Introduction

This International Standard provides guidance for the application of a management system for asset management, referred to as an "asset management system", in accordance with the requirements of ISO 55001.

This International Standard contains explanatory text necessary to clarify the requirements specified in ISO 55001 and provides examples to support implementation. It does not provide guidance for managing specific asset types.

This International Standard provides guidance for use by:

— those involved in the establishment, implementation, maintenance and improvement of an asset management system;

— those involved in delivering asset management activities and service providers.

General information on asset management, and information on the terminology applicable to this International Standard, is provided in ISO 55000.

Annex A provides additional information on areas related to asset management activities.

Annex B shows the relationship between key elements of an asset management system.

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Asset management — Management systems — Guidelines for the application of ISO 55001

1 Scope

This International Standard provides guidance for the application of an asset management system, in accordance with the requirements of ISO 55001.

This International Standard can be applied to all types of assets and by all types and sizes of organizations.

NOTE 1 This International Standard is intended to be used for managing physical assets in particular, but it can also be applied to other asset types.

NOTE 2 This International Standard does not provide financial, accounting or technical guidance for managing specific asset types.

NOTE 3 For the purposes of ISO 55000, ISO 55001 and this International Standard, the term "asset management system" is used to refer to a management system for asset management.

2 Normative references

The following documents, in whole or in part, are normatively referenced in this document and are indispensable for its application. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

ISO 55000:2014, *Asset management — Overview, principles and terminology*

ISO 55001:2014, *Asset management — Management systems — Requirements*

3 Terms and definitions

For the purposes of this document, the terms and definitions given in ISO 55000 apply.

4 Context of the organization

4.1 Understanding the organization and its context

4.1.1 Overview

4.1.1.1 The asset management system forms an integrated part of the organization's management system and has a prescribed structure. It should fit in and result from:

— the organizational objectives;

— the organizational plan.

The asset management system includes:

a) the asset management policy (see 5.2);

b) the asset management objectives (see 6.2);

c) the strategic asset management plan (SAMP);

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d) the asset management plan(s) (see 6.2.2), which are implemented in:

— operational planning and control;

— supporting activities;

— control activities;

— other relevant processes.

Figure B.1 shows the relationship between the key elements of an asset management system, together with the related clauses in ISO 55001.

The scope of an organization's asset management system and the outputs from its asset management activities should be used to set out the approach to enable the delivery of its organizational objectives. The requirements for the scope and context of an organization's asset management system are given in ISO 55001:2014, Clause 4.

The organizational objectives provide the overarching context and direction to the organization's activities, including its asset management activities. The organizational objectives are generally produced from the organization's strategic level planning activities and are documented in an organizational plan.

NOTE 1 The organizational plan can be referred to by other names, e.g. the corporate plan.

The principles by which the organization intends applying asset management to achieve its organizational objectives should be set out in an asset management policy. The approach to implementing these principles should be documented in a strategic asset management plan (SAMP).

NOTE 2 A strategic asset management plan can be referred to by other names, e.g. an asset management strategy.

The SAMP should document the relationship between the organizational objectives and the asset management objectives, and should define the framework required to achieve the asset management objectives.

The links between the organizational plan and the SAMP should be two-way, and should be developed through an iterative process. For example, the organizational objectives should not be developed in isolation from the organization's asset management activities. Asset capability and performance, as well as the outputs from asset management activities (e.g. the asset management plan(s)), are key inputs into establishing realistic and achievable organizational objectives.

4.1.1.2 In developing its SAMP, the organization should:

a) consider the expectations and requirements of stakeholders;

b) consider activities that could extend beyond the organization's routine planning timeframe, and which should be subject to regular review;

c) clearly document the processes to establish its asset-related decision-making criteria.

The SAMP should be a high level plan that contains the asset management objectives. It should be used to develop the asset management plan(s), which should set out the asset level activities. The asset management plan(s) can be cascaded in large organizations or in organizations with complex asset portfolios.

4.1.1.3 All parts of the asset management system should be scalable, e.g. for small organizations, the organizational plan could be a single document that includes separate sections for:

a) the organizational objectives;

b) the SAMP;

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c) the asset management plan(s).

Alternatively, the organizational plan could be kept separate from the SAMP, which could include the asset management plan(s) as a sub-section, or all three plans could be kept separately. While it is necessary to distinguish between the SAMP and the asset management plan(s), it is not a requirement of ISO 55001 to create separate documents for each.

The concept of ensuring alignment and consistency between the organizational objectives, the asset management policy, the SAMP, the asset management objectives and the asset management plan(s), should reinforce within the organization that asset level activities support the delivery of the organizational objectives. It is important that this alignment is communicated to ensure that stakeholders at all levels understand why asset activities and asset management activities are implemented.

4.1.2 Understanding the organization and its context

4.1.2.1 When establishing or reviewing an asset management system, it is important to ensure that the approach is consistent and aligned with the external and internal contexts of the organization, since these can significantly influence the design and scope of the asset management system.

4.1.2.2 Evaluating the organization's external context can include, but is not limited to, the following issues:

a) the social and cultural, political, legal, regulatory, financial, technological, economic, competitive and natural environment, whether international, national, regional or local;

b) key drivers and trends having impacts on the objectives of the organization;

c) relationships with, and perceptions and values of, external stakeholders.

4.1.2.3 Evaluating the organization's internal context can include, but is not limited to, the following issues:

a) governance requirements;

b) organizational structure, roles, accountabilities and authorities;

c) policies, objectives, and the strategies that are in place to achieve them;

d) capabilities, understood in terms of resources and knowledge (e.g. capital, time, people, systems and technologies);

e) information systems, information flows and decision-making processes (both formal and informal);

f) relationships with, and perceptions and values of, internal stakeholders;

g) the organization's culture;

h) standards, guidelines and models adopted by the organization;

i) the form and extent of contractual relationships;

j) risk management plans;

k) asset management practices and other management systems, plans, process(es) and procedure(s);

l) integrity and performance of the assets and asset systems;

m) feedback from the investigation of previous asset and asset system failures, incidents, accidents and emergencies;

n) assessing the ability of the asset management system to achieve the intended outcomes of the organizational objectives;

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o) feedback from previous self-assessments, internal audits, third party reviews and certification reviews.

4.2 Understanding the needs and expectations of stakeholders

4.2.1 The organization should identify and review the stakeholders that are relevant to asset management and the needs and expectations of these stakeholders.

4.2.2 Internal stakeholders can include the following:

a) employees within the organization;

b) groups within the organization, i.e. functional groups (e.g. engineering, accounting, maintenance, operations, purchasing, receiving, logistics) or other groups (e.g. safety delegates);

c) shareholders, management consortiums, owners.

4.2.3 External stakeholders can include the following:

a) customers, users, suppliers, service providers and contractors;

b) non-governmental organizations, including civil society organizations, consumer organizations and the media with an interest in issues related to asset management;

c) government organizations, government agencies, regulatory authorities, and politicians at all levels of government;

d) investors or taxpayers;

e) local communities;

f) those in society interested in social, financial, environmental or other forms of sustainability;

g) financial institutions, rating agencies, and insurers;

h) employee representatives.

4.2.4 Stakeholders' needs and expectations should be documented and communicated. This may be captured in a statement of stakeholders needs within the SAMP and should reference any mandatory requirements, as well as the expectations of different stakeholder groups. The organization should consider a means of tracking how current the information is, and the methods involved for its collection. When engaging with stakeholders to determine their needs and expectations, the organization can use the list of contexts given in 4.1.2 to frame the discussions.

One objective of asset management is to enable the organization to meet the service needs of the customers and users of its asset(s). The organization should measure the levels of service (see 6.2.1) that its assets deliver, and analyse these against the requirements and expectations of its customers and users. A level of service review process can be a useful approach to understand the expectations of customers and users.

Stakeholders are likely to make judgments about the organization's asset management and its asset management outputs and outcomes, based on their perceptions. These can vary due to differences in values, needs, assumptions, concepts and concerns, as they relate to the issues under discussion. Since the views of stakeholders can have a significant impact on the organization's asset-related decisions, it is important that their perceptions are determined, recorded, and taken into account in the organization's decision-making process.

Understanding how asset-related decisions are made is an important part of asset management. The criteria for decision making are influenced by the needs of external and internal stakeholders, by the asset management policy and by the risk attitude of the organization. The external and internal stakeholders' input to establishing decision-making criteria is important for setting priorities and resolving conflicting

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requirements. Decision-making criteria should be appropriate to the importance and complexity of the decisions being made. Decision-making criteria should be used to evaluate competing options to meet asset management objectives and develop asset management plans. The criteria can be expressed in a number of ways, to support quantitative, semi-quantitative or qualitative decisions. The processes to establish the decision-making criteria that guide asset management should be clear and documented.

The level of detail needed when reporting to stakeholders will vary from one stakeholder to another, depending on the scope of the organization's activities and on the complexity of the assets being managed. The detail should only disclose proprietary information as appropriate for the stakeholders receiving the information.

Stakeholders generally need to be informed about the decisions that can affect them and might need to provide input into decisions that can have an impact on them. Failure to both communicate and consult in an appropriate way about asset management activities can in itself constitute a risk, because it could later prevent an organization from fulfilling its objectives.

It is important that the terminology used in communicating with stakeholders is consistent and aligned with other functions in the organization, and in accordance with legal requirements, where applicable. This is particularly necessary when communicating financial information.

4.3 Determining the scope of the asset management system

Based on the outcomes of reviews of its context and stakeholders (see 4.1 and 4.2), the organization should define (or review) the boundaries of the asset management system, and establish its scope.

The boundaries and applicability of the asset management system should be captured in a statement of scope (which may be included in the SAMP). It should be communicated to all relevant stakeholders, both internal and external to the organization. The detail will be influenced by the size of the organization and the scale and complexity of the asset portfolio covered by the asset management system. It should clearly show what is considered inside and outside scope.

The scope should consider:

a) the assets, asset portfolio(s), their boundaries and interdependencies;

b) which other organizations are involved in meeting the organization's asset management system requirements (including the requirements of ISO 55001), e.g. through the outsourcing of asset management activities or activities related to life cycle stages;

c) the organizational aspects, e.g. which parts or functions of the organization are involved;

d) the organization's period of responsibility (e.g. where the management of assets is contracted out for a set period of time), including its residual liabilities beyond the operation or use of the asset (e.g. where an organization remains accountable for risks beyond its use of an asset, such as a chemical plant asset owner that retains liability for ground contamination);

e) the interactions with other parts of the organization's management system (e.g. for quality or environmental management), which can require defining the boundaries, functions, and responsibilities of each part of the management system.

4.4 Asset management system

In the initial development of the asset management system, the organization should outline how it will establish, implement, maintain and improve the system. An initial review of the organization's current processes against the requirements of ISO 55001 will determine the areas that need to be developed to support the functioning of a compliant asset management system.

The asset management system should not stand alone. A factor of successful asset management is the ability to integrate asset management processes, activities and data with those of other organizational functions, e.g. quality, accounting, safety, risk and human resources. Where possible, existing business

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processes should be leveraged to avoid unnecessary new work and duplication of existing work and data. These interactions with the existing processes need to be clearly communicated to all involved.

Consideration should be given to how to prioritize what to develop first, as there is usually a limit on resources available. The review can guide the organization in formulating plan(s) for implementing and prioritizing improvements to its asset management system.

An appropriate starting point is the establishment of an asset management policy, which often helps to provide focus for the organization and to identify its intentions. Following this, the organization should develop its SAMP.

It is important to be aware of, and to clarify, any variations in terminology between ISO 55000 and the terminology used in the organization's common practice.

Compliance with all the requirements of ISO 55001 should be considered as achieving only the minimum starting point for an effective asset management system and should not be seen as the final goal.

5 Leadership

5.1 Leadership and commitment

Asset management leadership can be demonstrated by top management through positively influencing the organization (and in its execution of all the requirements of ISO 55001, and specifically the requirements of ISO 55001:2014, 5.1). Top management may appoint an individual to oversee the development, implementation, operation and continual improvement of an asset management system, however, it is important that ownership and accountability for asset management remains at the top management level.

Top management commitment to asset management can be demonstrated by:

a) making reference to asset management principles in communications;

b) engagement in setting the objectives and measures of success for the people responsible for the asset management system:

   — by setting priorities for these objectives;

   — by allocating appropriate resources for the achievement of these objectives;

c) establishing a strong collaborative work culture that is focused on delivering the asset management objectives;

d) using asset management related decision-making criteria for capital expenditures and other decisions;

e) supporting asset management related improvement activities;

f) supporting a management-development track that encourages and rewards time spent in roles associated with asset management and operation of the asset management system;

g) monitoring the asset management system performance and ensuring corrective or preventive actions, including opportunities for continual improvement;

h) assuring that asset management is considered at the same level of importance as safety, quality, environment, etc.;

i) addressing asset related risks and incorporating them into the organization's risk management processes;

j) aligning asset management and the asset management system to other organizational functions through collaboration on achieving the organizational objectives;

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k) aligning asset management and the asset management system to other organizational practices and management systems, e.g. including the organization's approach to risk management.

5.2 Policy

The asset management policy is a short statement that sets out the principles by which the organization intends to apply asset management to achieve its organizational objectives. The asset management policy should be authorized by top management and thereby demonstrate commitment to asset management.

The policy should set out the organization's commitments and expectations for decisions, activities and behaviour concerning asset management. It should be aligned to and demonstrate support for the organizational objectives. For example, an organizational objective to reduce capital investment could result in an asset management policy statement for adopting risk-based approaches to capital investment.

Examples of asset management policy principles may include commitments for:

a) guiding principles for asset management activities, e.g. service delivery objectives are to guide asset management practices and decisions;

b) adherence to applicable laws, legislation and regulations;

c) the provision of resources to deliver on asset management objectives and the structure or working of the organization to achieve the organizational objectives, e.g. asset planning and management is to be integrated with corporate and business planning, budgetary and reporting processes;

d) the decision-making criteria to be used, e.g. asset management decisions are to be based on evaluations of alternatives that take into account life cycle costs, benefits and risks of the asset;

e) reporting on asset and asset management performance;

f) long-term objectives, sustainable outcomes and stakeholder requirements;

g) continual improvement of the asset management system.

It is not necessary for the policy to be captured in a discrete document; it can be contained in other high level organizational policies or documents, e.g. it may be included in the SAMP. The important point is that it is communicable to the organization. If this can be demonstrated, a separate asset management policy document may not be required.

There should be processes in place to review and update the asset management policy, and to ensure that if the organization's external or internal context changes, the actions necessary to update the policy are also triggered.

5.3 Organizational roles, responsibilities and authorities

The responsibilities and authorities of key functions should be defined (see ISO 55001:2014, 5.3). This should include both internal and outsourced roles and responsibilities. The interfaces between organizational functions should be clearly established. This becomes more important in an outsourced environment.

It should be clear which role is responsible for which activity. This can be achieved through the development of job descriptions, or through including asset management responsibilities in existing job descriptions, or through the production of a documented organizational chart.

When assigning internal roles, consideration should be given to the following:

a) an individual's experience and competence (see 7.2);

b) support for the role through training and mentoring;

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c) other workload requirements and their variability, which could impact the individual's ability to deliver on asset management related objectives;

d) the individual being able to demonstrate an understanding of what the responsibilities mean in the context of their role (e.g. this can be achieved through the signed acceptance of a job description).

In small or medium-sized organizations, multiple asset management functions may be assigned to one individual. This does not change the need to communicate this to other stakeholders, or to clarify the responsibility of the individual.

For contractors and external service providers, their responsibilities and the competence required should be documented in the scope or elsewhere in contracts.

6 Planning

6.1 Actions to address risks and opportunities for the asset management system

The organization should determine the actions that are necessary for addressing risks when planning for its asset management system (see also ISO 55001:2014, 6.1). In this International Standard, it is assumed that the term "risk" also includes opportunities (see ISO 55000:2014, 3.1.21). The overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to manage such risks to an acceptable level, and to provide an audit trail for the management of risks. The intent is for the organization to ensure that the asset management system achieves its objectives, prevents or reduces undesired effects, identifies opportunities, and achieves continual improvement.

When addressing risks in the asset management system, the organization should determine the risk assessment criteria (e.g. likelihood and consequence, and risk attitude) within asset management decision making for its asset management system (see 4.2). A risk matrix may be used as part of this process.

The approach of managing risks associated with the asset management system should be aligned with the organization's risk management approach and, where appropriate, this may include business continuity planning and contingency planning. The organization should consider how managing risks in its asset management system relate to other risk management processes in the organization (see 4.3).

The organization should determine and plan actions, and provide adequate resources, to address its asset management system risks. For example, asset management risks could be incorporated into an organization's divisional and project risk registers, with appropriate escalation mechanisms if they cannot be addressed at the level at which they are raised.

The organization should integrate the actions identified to address these risks into the implementation plan for the asset management system.

The organization should be able to demonstrate how it has evaluated the effectiveness of the actions that it has taken to manage the risks identified in relation to the organizational objectives and decision-making criteria.

6.2 Asset management objectives and planning to achieve them

6.2.1 Asset management objectives

6.2.1.1 The asset management objectives, derived as part of the SAMP, provide the essential link between the organizational objectives and the asset management plan(s) that describe how those objectives are going to be achieved. The asset management objectives transform the required outcomes (product or service) to be provided by the assets, into activities typically described in the asset management plan(s).

The asset management objectives should be tailored to suit each organization's needs, which may include addressing subsets of objectives (e.g. for the asset management system, asset portfolios, the

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asset system and at asset level), and can vary for different functions carried out to meet stakeholder requirements. The organization should consider information or data from sources internal and external to the organization, including contractors, key suppliers, regulators or other stakeholders.

Asset management objectives should be specific, measurable, achievable, realistic and time-bound (i.e. "SMART" objectives). They can be both quantitative measurements (e.g. mean time between failure) and qualitative measurements (e.g. customer satisfaction).

The organization should consider the monitoring, measuring, analysing and evaluating needed to drive and support its decision making on improvement actions. When deciding what to measure, how to measure, what to analyse, etc., it is important for the organization to understand what type of behaviour and actions it wants to achieve from the asset management objectives before implementing them. The asset management objectives should be aligned to the organizational objectives and should promote collaboration with stakeholders.

6.2.1.2 During the development of its asset management objectives, the organization should:

a) review risks, including the potential impacts from the failure of

   — assets, or

   — the asset management activities on achieving asset management objectives, individually or in combination;

b) review the importance of assets related to their intended outcomes, objectives and product or service requirements;

c) check the applicability of the asset management objectives during the asset management planning process.

6.2.1.3 Typical issues, amongst others, that are addressed by objectives include the following:

a) for asset management:

   — total cost of ownership;

   — net present value;

   — return on capital employed;

   — performance against plan;

   — certification of the asset management system, or the assessment of asset management maturity (by benchmarking);

   — customer satisfaction scores;

   — society or reputation survey results;

   — environmental impact, e.g. carbon costs;

   — level of service;

b) for asset portfolios:

   — return on investment (or return on capital employed, or return on asset);

c) for asset systems:

   — asset system availability;

   — asset system performance (e.g. uptime, efficiency);

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— unit cost of product or service;

d) for assets:

— reliability (mean time/distance between failures);

— asset condition, performance, or health score;

— life cycle costs;

— life expectancy;

— asset energy performance.

For large or complex asset management systems, the organization might also need to establish objectives for the asset management system itself.

6.2.1.4 Monitoring the performance of the organization's asset management, in terms of how well the asset management objectives and hence the organizational objectives are being met, is an important part of the asset management system (see 9.1). Deviations in performance should be used as inputs to revise the asset management objectives.

Asset management objectives should be subject to regular management review (see 9.3) and such reviews should inform the continuous improvement process (see 10.3).

6.2.2 Planning to achieve asset management objectives

6.2.2.1 The organization should develop an asset management plan(s) to define the activities that will be implemented and the resources that will be applied to meet the asset management objectives and consequently the organizational objectives. An asset management plan(s) provides the direction to, and expectations for, an individual asset or for a portfolio, group or class of assets.

An asset management plan(s) should be documented at a level that is appropriate to the organization and the degree of sophistication in its asset management approach. There is no set formula for what should be included or how it should be structured, however, it is common practice for such an asset management plan(s) to contain a rationale for asset management activities, operational and maintenance plans, capital investment (overhaul, renewal, replacement and enhancement) plans, and financial and resource plans, often based on a review of earlier achievements.

For some organizations, this may be captured in a single document, while for other organizations, multiple asset management plans may be appropriate. For example, a small municipality may produce one asset management plan for all of its assets, whereas a large rail organization may provide multiple plans for each asset class (e.g. stations, track, infrastructure), or a utility may provide multiple plans for different locations.

Asset management plan(s) should be developed to appropriate time horizons for the organization. The time horizons should meet the organization's needs and take account of the organization's period of responsibility and the life of its assets.

There can be benefits in developing the first asset management plan(s) as an interim plan as quickly as possible, using existing information. It helps the organization to understand the strengths and weaknesses of current asset management practices and to identify priorities for the development of future plan(s). It can also help avoid embarking on ambitious data collection exercises before needs are fully understood.

It is important for the organization to commit the resources that are identified in the asset management plan(s) as being necessary, in order to achieve its planned objectives. Implementation of the asset management plan(s) is an iterative process that involves resolving conflicts between what is planned and what can be afforded in terms of financial constraints. Once the financial implications arising from the asset management plan(s) have been quantified, linkages need to be established between the asset

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management plan(s) and the financial plans of the organization, and decisions should be made jointly about financial allocations.

Asset management plan(s) should be reviewed periodically to ensure continual alignment with the asset management objectives. Planning should also consider solutions that do not require additional assets to achieve the organizational objectives (e.g. it can be preferable to change demand for products or services by changing pricing rather than building new assets or providing more services).

There should be a regular assessment of the ability of the SAMP to support the achievement of the asset management objectives. The intent is to determine what the mismatch or gaps are and where they exist. This analysis should be used as input to management review and to an improvement process for the asset management system.

A risk ranking process can determine which assets have a significant potential to impact on the achievement of the asset management objectives, i.e. which are the critical assets.

6.2.2.2 When developing or reviewing asset management plan(s), the organization should consider:

a) who should be responsible for developing and implementing the asset management plan(s) and their continual improvement: writing the asset management plan(s) internally is useful for ensuring better commitment to the asset management planning process, however, resources and capabilities can be such that external support is required; it is important that staff are familiar with the objectives and approach, and have the opportunity to learn from the project when external resources are used;

b) who will read the asset management plan(s), what they will want to know and need to know: a tiered approach to asset management plan development can assist in targeting several user groups, e.g. the executive summary aimed at top management and the general public, the main body of the plan at top management and key stakeholders, and appendices for more technical information for service providers;

c) the environments in which the assets are operating or are intended to operate and the activities that are being performed either on individual assets, on various components, where inter-dependencies exist or combinations of activities occur on the same asset, or on multiple assets (i.e. whether this activity on this asset is worthwhile and, if so, when);

d) activity program requirements, which will typically also involve operational planning activities and implementation (see Clause 8);

e) the performance of the assets and the intended outcomes expected from implementation of asset management plan(s) in enabling the organization to achieve its asset management objectives;

f) whether appropriate resources and funding is available;

g) applicable standards.

6.2.2.3 The organization should ensure that its assets are capable of delivering the required products or services and achieving its organizational objectives.

The organization should be able to create and demonstrate a link between the actions that address the risks and the organization's approach to risk management and business continuity planning.

When planning processes to manage risk in the asset management system, the organization should consider adopting a structured method for identifying, analysing and evaluating risk (see 6.1). An example method is provided below.

a) Classify assets and define the scope: prepare a list of asset systems and their constituent assets, and gather information about them, including the management and control activities which affect the assets' performance; define the scope and limits of the individual asset risk assessments (see 4.3).

b) Identify risks: create a table of potential events and their causes, ensuring that the identification process includes risks to the delivery of the organizational objectives.

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c) Identify risk controls that exist (or are proposed for planned assets and planned activities).

d) Analyse risks using appropriate process.

e) Evaluate the level of risk: estimate the likelihood and consequences for each potential event, based on the asset management decision-making criteria (see 4.2) and the risk management criteria (see 6.1). The effectiveness of any existing risk controls, and the likelihood and consequences of their failure, should also be considered.

f) Evaluate the level of risk over time: where appropriate, establish whether the identified risks will change over time, and how this will affect their consequences.

g) Evaluate the tolerability of the risks: decide whether planned or existing controls (if any) are sufficient to keep the risks under control and to meet any legal, statutory and other asset management requirements.

h) Determine the treatment of the risks: establish whether the risks will be treated by addressing them directly, avoiding, reducing, tolerating or transferring them.

6.2.2.4 The organization's method to identify, analyse and evaluate risk in the asset management system should be documented appropriately (see 7.6). The documentation of the risk management process in the asset management system may include the completion of a risk register, or another recording mechanism appropriate to the organization's risk management approach.

The organization should document the risks associated with asset management and incorporate risks critical to the achievement of the asset management objectives in its risk register. Larger organizations may need to use divisional or project risk registers, with appropriate escalation mechanisms if the risks cannot be addressed at the level at which they are raised.

The organization should establish governance arrangements for risk management in the asset management system (see 6.1). This includes audit of the risk management approach (see 9.2), and the review of risks by top management (see 9.3).

Where asset life cycle activities or asset management activities are outsourced as part of the organization's asset management approach, the organization should ensure that the asset management system includes control and management of risk (see 8.3).

Asset management plan(s) should consider the risks during the organization's period of responsibility, including any residual liabilities beyond the period of operation or use of the asset.

In the process of continual improvement, the organization should consider the risks that can change with time and how these could impact the asset management system in the future and plan to manage them. For example, asset deterioration related risks can change the asset management risks over time (e.g. corrosion of a pipeline), or currency exchange related risks can impact capital investments.

Standard risk management practices tend to overlook events that are very low probability/high consequence as not worth considering in detail. For example, extreme weather events do not occur often, but when they happen, asset managers tend to be inadequately prepared.

It is important that there be an additional dimension in the risk analysis to include the capability of the asset system to monitor and continually assess the probability of these rare, but potentially catastrophic, events. While the probability of such events can be very low, the organization should establish systems of monitoring indicators to identify when circumstances change abruptly, so that it can implement processes early to mitigate against them.

The organization should apply a common methodology for determining the financial implications of the asset management plan(s). Asset management planning should take into account the difference between the economic and technical aspects of assets.

Life cycle cost, which may include capital expenditure, financing and operational costs, should be considered in the decision-making process (see 4.2). The development of an asset management plan can

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involve making decisions that have short- and long-term effects. It can also involve consideration of all the asset's life cycle stages, and the potential impacts of a decision at one stage on a later stage.

When making asset management decisions, the organization should use a methodology that evaluates options of investing in new or existing assets, or operational alternatives (which could include, for example, financial solutions that do not require assets). Consideration should be given to the different effects of capital expenditure, operational expenses and any resulting pricing impacts upon the organization's products and services.

NOTE See ISO 31000 for further information on risk management and IEC 31010 for guidance on risk assessment techniques.

7 Support

7.1 Resources

During the development and implementation of the asset management system, including the asset management objectives and asset management plan(s), the organization should determine the required resources. The organization should map its available resources to its planned activities to determine any gaps. This gap analysis can be used as an input to determining options for resourcing the activities. This analysis applies across all asset management activities, could be extensive and can require prioritization and programme planning of many projects to close these gaps.

It is possible that a resourcing analysis, for the reconciliation of available budgets with funding, could determine that not all proposed asset management activities can be resourced as proposed. An iterative process to reconcile proposed activities with available resources should be used, and the criteria and processes for prioritizing asset management activities should be decided and the asset management plan(s) be revised to reflect the available resourcing and the timing that the resource is assigned.

In determining options for resourcing the activities, the organization should consider both internal and external resources. For human resources, options available can be affected by organizational policy and strategic plans on human resources, contracting-out or outsourcing. For non-human resources, availability of resources should include consideration of procurement options (e.g. lease, hire, purchase or otherwise acquire). Both human and other resourcing needs can be influenced by the nature and duration of the activities (e.g. one-off versus on-going).

In some organizations, these activities can require that other parts of the organization provide additional resources in order to support the primary asset management activity (e.g. additional staff). Those responsible for implementing the asset management activity should ensure that they have coordinated effectively, so that all parts of the organization are resourced appropriately.

Any tools, facilities or equipment that are required for the delivery and control of asset management activities should be defined and managed as assets, at a level of detail appropriate to their function and purpose.

7.2 Competence

7.2.1 Competency in asset management should be addressed at all levels of the organization in a way that ensures alignment between roles and levels and not just for those considered to be asset managers. For example, a competent trades person should be able to demonstrate clear competency in specific asset management related tasks (e.g. condition rating) and also have an understanding of the relationship of what they do to the asset management activities others undertake (e.g. the input of the condition rating activity into the determination of remaining useful asset life).

7.2.2 The organization should determine the competences required for all asset management roles and responsibilities, and the awareness, knowledge, understanding, skills and experience needed to fulfil them. The organization should map its current competences to its required competences to determine any gaps. This gap analysis can be used to develop asset management competency improvement and

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training plans, and enable the organization to incorporate specific asset management competences into its organizational competency framework, as considered appropriate.

For example, the gap analysis and the resulting competency improvement and training plans may include the following:

a) the assessment of competences for the role(s), responsibility(ies) and accountability(ies) to be undertaken for all stakeholders;

b) alignment to the organizational objectives as well as its asset management policy, asset management objectives, SAMP and asset management plan(s);

c) the creation of personal development programmes that identify the training, education, development and other support needed to attain the required competence;

d) the provision of training and mentoring, including the selection of suitable methods and materials;

e) knowledge and job sharing;

f) succession and knowledge management plans;

g) the hiring or contracting of competent persons;

h) the training of target groups;

i) documentation and monitoring of the training received;

j) the evaluation of the training received against defined training needs and requirements, in order to verify conformity with asset management system requirements.

All persons assigned roles and accountabilities within the organization that can have an impact on the asset management system should have those roles and accountabilities communicated to them, be provided with the training, education, development and other support needed to perform their role, and be able to demonstrate the competences required.

7.2.3 The organization should recognize that there is interdependency between its asset management competences, its organizational design and business processes. When undertaking a competency gap analysis, it should also consider undertaking a gap analysis of its organizational design and business processes and develop appropriate improvement plans, as necessary. For example, the organization could find it has competent asset managers that are disconnected from its business planning and budgeting function, which could impede its long range planning and investment decision making. Alternatively, the organization could discover that the majority of its asset management competences exist within one individual, with no effective succession and knowledge management plans (a situation requiring urgent remedial action).

The organization should:

a) establish appropriate and effective processes for managing the competence of persons undertaking asset management work that affects its asset and asset management performance;

b) consider linking these processes to its existing human resource management and competency improvement processes;

c) establish processes to periodically review and update the asset management competency improvement and training plans.

In the event that the organization decides to outsource any aspect of the asset management system, the organization should ensure that the external resource providers can demonstrate competency against the required activities. The organization should, depending on the criticality of the activity, validate claims of competency, and have a process to ensure that any third party resource provider continues to provide competent resources.

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7.3 Awareness

7.3.1 Persons working under the organization's control should have appropriate awareness of the organization's asset management system and activities. Such persons can include staff, contractors, internal or external service providers, and suppliers. They should be aware of the asset management policy and the following:

a) why asset management is important to the organization;

b) the implications of changes in the operation of the organization (e.g. if the organization makes changes to its operational processes or performance objectives, those persons with accountability for the asset management system should be aware of any resulting impacts);

c) their contribution to the effectiveness of the asset management system, including the benefits of improved asset management system performance;

d) asset management related risk consequences (actual or potential) of their work activities, their behaviour, and the asset management benefits of improved personal performance and how they relate to each other;

e) their roles, responsibilities and authorities as well as the importance of their contribution in meeting the requirements of the asset management policy and the asset management system;

f) how well the organization is performing in meeting its objectives.

The specific awareness needs of any stakeholder should be determined by their role and its relationship to the organization meeting its asset management objectives. The need for awareness of some areas can apply to only a limited group of individuals, e.g. those directly involved in a particular function, such as plant maintenance.

7.3.2 The level of organizational awareness can be improved, for example, by the following:

a) a consultation process with staff throughout the organization concerning the establishment, operation, improvement and changes to the asset management system;

b) discussion of asset management in the organization's newsletters, briefings, introduction programme or journals (including new employee orientation);

c) inclusion of asset management articles on relevant web pages;

d) inclusion of asset management as a topic in staff and management team meetings;

e) briefings for top management;

f) briefing key suppliers and distributors on the organization's asset management arrangements.

7.4 Communication

7.4.1 General

Asset management activities carried out by the organization should be communicated to relevant stakeholders periodically, in a coordinated way, as an integral part of the organization's asset management activity and asset management system.

7.4.2 Communication plan

The organization should develop communication plan(s) with consideration of:

a) building awareness of the asset management requirements and expectations;

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b) developing an understanding of how the implementation of the asset management system can impact stakeholders;

c) promoting engagement with stakeholders to embrace transparency and create accountability for the asset management system;

d) managing, informing and influencing stakeholders who can directly impact the asset management plans and the achievement of the asset management objectives.

7.4.3 Communication plan content

The content of the communication plan(s) may include the following:

a) the benefits of implementing an activity, project, programme, or asset modification or augmentation, and how these improvements are expected to collectively or individually impact stakeholders and the organization;

b) any improvement schedules, including key milestones, who will be involved, and for how long;

c) any resource specific communications, including statements of the asset management system expectations;

d) the who, why, when and what of communicating, including how well the organization is performing against its organizational objectives and the contribution asset management is making to this performance;

e) if appropriate, what external and internal knowledge is needed for the stakeholders to make informed contributions or decisions, or provide informed feedback;

f) the representative who is best suited to deliver specific communications;

g) the format to be used for the communications;

h) the feedback and reporting processes.

7.5 Information requirements

7.5.1 The organization should determine the information needs related to its assets, asset management and its asset management system.

The organization should use a systematic approach to identify the necessary asset information and establish the appropriate information repositories. For example, the organization should undertake a needs analysis, establish priorities, review system development options and data collection strategies, plan the creation of information repositories and data collection, then implement as appropriate.

NOTE ISO 55001 addresses information-related requirements in the following three subclauses:

— ISO 55001:2014, 7.5, which addresses the determination of required information;

— ISO 55001:2014, 7.6, which addresses the requirements for control over information;

— ISO 55001:2014, 9.1, which addresses the determination of requirements for information needed for performance reporting and evaluation.

7.5.2 In general, the organization should consider its asset information requirements related to the following areas:

a) strategy and planning (e.g. corporate service levels and objectives, asset strategy(ies), demand management strategy and plans);

b) process (e.g. process performance objectives and indicators, asset related processes and procedures);

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c) technical and asset physical properties (e.g. asset attributes, ownership, design parameters, vendor information, physical location, condition, in service dates);

d) service delivery and operations (e.g. service levels, performance objectives, asset performance characteristics, future operational requirements, demand management objectives);

e) maintenance management (e.g. historical asset failures, betterment or replacement dates, future maintenance requirements);

f) performance management and reporting (e.g. asset performance data, continuous improvement objectives, regulatory reporting);

g) financial and resource management (e.g. historical cost, depreciation, asset replacement value, date of acquisition, materiality, capitalization rules, asset classification/hierarchies, life cycle costing analysis, useful lives of assets, residual value and any residual liabilities);

h) risk management;

i) contingency and continuity planning;

j) contract management (e.g. asset related contractual information, vendor information, service objectives, third party agreements).

7.5.3 When determining its information requirements the organization should consider:

a) the value of the information to enable decision making and its quality relative to the cost and complexity of collecting, processing, managing and sustaining the information;

b) the need to align its information requirements to suit the level of risk that an asset, or managing it, poses;

c) the participation of relevant stakeholders to determine the types of information required to support decision making as well as to ensure the completeness, accuracy and integrity of the necessary information;

d) the establishment and continual improvement of controls, specifications and level of accuracy for data;

e) the determination, assignment and periodic review of accountabilities for the stewardship of specific information;

f) the establishment of competences required to collect, interpret, utilize and report information;

g) the alignment of information requirements for different levels and functions within the organization: this includes the ability to have vertical alignment of the information from top management down into the operational areas, as well as horizontal alignment between asset management, financial management and risk management functions, by using a common terminology for financial and non-financial information;

h) the alignment of financial and non-financial terminology (it should be recognized that for some types of organizations, e.g. government type agencies, there are provisions that make their functional areas independently accountable for their own domain terminology: in such cases, a common terminology is unlikely to be achievable, however, conflicting terminology should be resolved where possible and documented);

i) the need for financial information regarding assets to be appropriate, consistent and traceable, and to reflect the technical and operational reality of the assets (e.g. completeness, accuracy, proper valuation and presentation, including ownership, is achieved through employing identifiable and auditable accounting records that are linked to the technical asset records);

j) the establishment of data collection processes from internal and external stakeholders (including contracted service providers);

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k) the data flow and integration of information sources to planning, operational and reporting technology systems, appropriate for the size, complexity and capability of the organization (e.g. in more sophisticated asset management technology systems, specific data may be kept in separate asset registers);

l) its ability to maintain the appropriate quality and timeliness of the information (as the collection of data can be costly, the organization should prioritize data that is identified as strategically or operationally important).

7.6 Documented information

In establishing its documented information needs, the organization should consider the identification and definition of documented information that will be managed and maintained over the life cycle, taking into account its period of responsibility for the assets. The organization should also consider the requirement to maintain this documented information for any defined period beyond the disposal of the assets, in accordance with its business, legal and regulatory requirements. The controls put in place should be adequate for the type of information in supporting the asset management activity.

The organization should determine the documented information required to ensure effectiveness of its asset management system and asset management activity. Different types of documented information can address elements of the asset management system, asset management or a specific asset. The information required can differ from one organization to another and should be proportional to the complexity of the assets and the asset management activity.

When creating and updating documented information, an organization should determine if appropriate controls are in place to ensure that the information is appropriate; these controls are necessary to ensure that the personnel supporting the asset management activity are using the approved, accurate, most up to date information.

8 Operation

8.1 Operational planning and control

8.1.1 The organization should establish operational planning and control processes in order to support the effective delivery of the activities contained within the asset management plan(s). The processes should identify who is responsible for the planning and how the defined activities will be executed, including how risks arising during the planning and execution will be managed and controlled. (ISO 55001:2014, Clause 8, defines the requirements for the operational planning and control of both asset management and the asset management system).

8.1.2 In implementing the processes and actions, the following criteria, amongst others, should be considered:

a) roles and responsibilities;

b) procedures;

c) resource allocation;

d) competency development.

8.1.3 Control mechanisms for the processes and actions can include elements such as the following:

a) process performance measures;

b) internal audit criteria and schedules.

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The implementation of the processes and actions should produce documentation to enable verification that the process steps were followed as designed and the expected output of the process is achieved, e.g. this could include signed completed work orders.

8.1.4 The organization should implement those processes and actions needed to address its risks (see 6.2). This should be done by establishing the criteria for risk management processes, controlling implementation of these processes based on the defined criteria, and keeping documentation that demonstrates the risk management processes have been executed as planned.

The organization should have the capability to determine emerging risks and to consider their impacts on its asset management objectives. The asset management system should enable the organization to consider and plan changes that affect its assets or asset management with sufficient time to act if required.

Implementation should involve an iterative process to achieve a balance between cost, risk and performance, to resolve conflicts between what is planned and what can be achieved, while taking into account the constraints faced by the organization.

8.2 Management of change

8.2.1 Internal or external changes affecting assets, asset management or the asset management system can impact on the organization's ability to achieve its asset management objectives. These changes should be evaluated and mitigating actions should be taken prior to implementation. The organization should review the consequences associated with both planned and unplanned changes and take the necessary action to mitigate any foreseen adverse effects.

8.2.2 The organization's considerations should address changes that include, but are not limited to, the following:

a) organizational structures, roles or responsibilities;

b) asset management policy, objectives or plans;

c) process(es) or procedure(s) for asset management activities;

d) new assets, asset systems or technology (including obsolescence);

e) factors external to the organization (including new legal and regulatory requirements);

f) supply chain constraints;

g) demands for products and services, contractors or suppliers;

h) demands on resources, including competing demands.

8.2.3 The organization should have the capability to make evidence-based decisions on proposed changes and the ability to consider scenarios systematically across the entire organization.

Risks associated with a change should be considered in relation to their impact on asset management and the asset management system. This should include unintentional consequences that occur to other parts of the organization, as a result of a change, e.g. the impact of resource constraints due to changes in service delivery requirements.

8.3 Outsourcing

8.3.1 Outsourcing is a common method for an organization that prefers to perform certain asset management activities not by itself, but by an external or internal service provider. When these activities influence the achievement of the asset management objectives, these should be part of the asset management system, and should be documented.

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8.3.2 The organization should formalize the relationship (e.g. through a contract, service level agreement or other appropriate commercial mechanism) for:

a) the governance of the outsourced activities, including responsibilities and authorities within the organization for managing the outsourced asset management processes and activities;

b) the processes and activities that are outsourced, with a description of the scope and boundaries, their interfaces with the organization and its control, quality, timelines, consultation requirements, financing, feedback and improvement opportunities;

c) the processes for the (bidirectional) exchange of information, knowledge, people, processes and technology at the start of the agreed period;

d) the processes for monitoring the activities of the assigned service provider(s);

e) the processes for sharing of knowledge, information and data, between the organization and its service provider(s);

f) the process of handing back the asset management activity from the service provider(s), including the required state of the asset and associated information.

8.3.3 Any asset management objectives, processes and activities that are outsourced should be controlled by the organization to provide assurance that performance is as planned. The performance of outsourced activities should be subject to a regular management reviews to ensure that they are adequately controlled.

The more extensively an organization chooses to outsource the delivery of its asset management, the greater will be the degree of control and integration into the asset management system that it will need to exert over the service provider(s), in order to give assurance that delivery of the SAMP will be achieved. The extent of outsourcing could require a service provider to establish its own asset management system that is aligned with the organization's asset management objectives.

8.3.4 The organization should consider the ownership and protection of intellectual property and corporate knowledge (including that generated during the outsourcing) when outsourcing asset management activities.

When outsourcing any life cycle activities and asset management activities, the organization should consider the risks and impacts on its assets, asset management and asset management system.

The organization should consider what potential risks cannot be transferred, even if the related asset management activities are transferred (e.g. damage to its reputation). A corresponding control over those risks should be maintained within the organization.

9 Performance evaluation

9.1 Monitoring, measurement, analysis and evaluation

9.1.1 General

9.1.1.1 The organization should develop processes to provide for the systematic measurement, monitoring, analysis and evaluation of the organization's assets, asset management system and asset management activity on a regular basis. In the development of these processes (and any associated procedures) the following should be taken into account:

a) setting of performance metrics and associated indicators, e.g. condition or capacity indicators;

b) confirmation of compliance with the requirements;

c) examination of historical evidence;

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d) the use of documented information to facilitate subsequent corrective actions and decision making.

9.1.1.2 The processes should also reference the asset management policy and objectives.

More specifically the processes for monitoring performance should address:

a) the setting of performance metrics, including qualitative and quantitative measurements (financial and non-financial) that are appropriate to the needs of the organization;

b) the extent to which the organization's asset management policy and objectives are met;

c) the evaluation of compliance with legal and regulatory requirements, and any other requirements to which the organization subscribes;

d) identifying when the monitoring and measuring should take place;

e) the ability to aggregate and report information to those accountable for the asset management system and asset activities (see 7.5, bullet g));

f) the quality, reliability and completeness of the financial and non-financial asset information;

g) enabling top management to make statements on the organization's ability to manage its assets (see 4.2);

h) the performance of activities outsourced to external providers;

i) assessing the performance of the asset management processes, procedures and functions;

j) proactive indicators that are related to performance of the assets, asset management system, and activities (e.g. capacity or condition indicators);

k) reactive measures of performance to monitor failures, incidents, non-conformities (including near misses and false alarms) and other historical evidence of deficient asset management system and activity performance;

l) recording the data and results of monitoring and measurement, sufficient to facilitate subsequent corrective action analysis.

9.1.1.3 A set of performance indicators should be developed to measure the asset management activity and its outcomes. Measurements can be either quantitative or qualitative, financial and non-financial. Indicators should provide useful information to determine both successes and areas requiring corrective action or improvement. The organization should consider the relationship and alignment between performance indicators.

9.1.1.4 The asset management system should employ data from monitoring and measurement to identify patterns and obtain information regarding its performance. These data should be used to evaluate whether the organization's policy and objectives are being achieved, as well as identifying corrective actions and areas for improvement.

Documented information on all periodic evaluations and their results should be maintained.

The organization should analyse and, at planned intervals, evaluate the outcomes from the monitoring and measurement.

The performance of activities outsourced to external service providers should be monitored and be based on the evaluation of reported results, audits performed by the organization, or independent auditor's reports.

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9.1.2 Evaluation of the performance of the asset portfolio and asset management processes

9.1.2.1 The organization should conduct evaluations of its assets and asset management activity in order to ensure their continuing suitability, adequacy and effectiveness.

The evaluations should address the possible need for changes to policy, objectives, strategies, and other elements of the asset management system, e.g. in the light of reviews, changing circumstances, the commitment to continual improvement.

Evaluations can take the form of internal or external audits, or self-assessments. The frequency and timing of evaluations should be determined by the organization or can be determined by laws and regulations, depending on the size, nature and legal status of the organization. When setting the frequency of condition or performance monitoring and the parameters for measurement, the organization should consider, at a minimum, the costs of monitoring, the risks of failure or nonconformity, and potential deterioration mechanisms and deterioration rates. They might also be influenced by the requirements of stakeholders.

9.1.2.2 An evaluation of the organization's assets and asset management activity should verify whether:

a) the organization's asset management policy, strategies, objectives and asset management processes accurately reflect its priorities and requirements (i.e. the organizational objectives);

b) the persons doing work under the control of the organization are competent;

c) its procedures are effective and up-to-date;

d) processes have been clearly defined, documented and effectively implemented and complied with;

e) there are processes for on-going training and awareness;

f) the organization's assets and asset management fulfil their required function;

g) the organization's asset management is appropriate to the level of risk faced by the organization;

h) the asset management plan(s) and processes have been effectively communicated to relevant stakeholders;

i) persons doing work under the organization's control understand their roles and responsibilities;

j) change control processes are in place and operate effectively;

k) any changes (internal or external) that impact the organization are reviewed in relation to the asset management activities.

9.1.2.3 Outcomes from the evaluation should include evidence of whether:

a) there is proactive management and governance of the organization's asset management;

b) people are trained and competent;

c) there is operational planning and control of asset management;

d) the organization's asset management activities are in compliance with its processes;

e) significant changes in the organization have been reflected in the organization's asset management processes in a timely manner.

Documented information relating to all periodic evaluations and their results should be maintained as evidence.

9.1.2.4 In the context of continual improvement, the organization can acquire knowledge on new asset management technology and practices, including new tools and techniques (e.g. development of

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reliability and predictive technologies during the procurement of new assets or the design of modified assets). This should be evaluated to establish its potential benefit to the organization.

9.1.2.5 To ensure that reported information used for monitoring has the same meaning with respect to different functions in the organization, common financial and non-financial terminology should be used in reports. Because cost plays such an important role in reflecting asset related performance, it may be useful to have a shared set of classification systems, hierarchical structures, and a common understanding of how asset portfolios, asset systems and individual assets are broken down for life cycle management purposes.

The change in future value of the assets and the risk profile should be evaluated in both a financial context and a non-financial context. The evaluation team should include stakeholders from relevant disciplines.

9.1.2.6 Monitoring should ensure that there is consistency and traceability between technical asset information and accounting records. In addition, monitoring should address the following key aspects of the data registration process.

a) a uniform technical, operational and financial glossary;

b) a technical, operational and financial linkage, which is consistent and traceable to the assets and their components at a predefined level of detail;

c) adequate and accurate financial and non-financial data and information of technical and operational events that have a potential impact on financial reporting.

This monitoring in the financial reporting system should be done at a level suitable to the risk, complexity and value of the assets. An asset breakdown structure can be used to identify the individual components of an asset, to enable the organization to take into account the significance of the value of the components in relation to the asset, and to determine the differences between the technical and economic lives of the components.

9.2 Internal audit

9.2.1 The organization should conduct internal audits at planned intervals to ensure the asset management system conforms to its requirements (and to the requirements of ISO 55001).

It is essential to conduct internal audits of the asset management system, particularly in relation to critical assets and asset systems, to ensure that the asset management system is achieving its objectives and plans and is identifying opportunities for improvement. Internal audits of the asset management system should be conducted at planned intervals to determine and provide information to top management on the appropriateness and effectiveness of the asset management system, as well as to provide the basis for setting objectives for continual improvement.

9.2.2 The organization should establish an audit process to direct the planning and conduct of audits, and to determine the audits needed to meet its objectives. The process should be based on the organization's activities, its risk assessments, the results of past audits, and other relevant factors.

Internal audits should be based on the full scope of the asset management system, however, it is not necessary for each audit to cover the entire system. Audits may be divided into smaller parts provided the audit programme ensures that all organizational units, functions, activities and system elements and the full scope of the asset management system are audited within the auditing period designated by the organization. In deciding the scope of an audit, it is good practice to consider the risk associated with both the asset management system and the assets. This can aid the relevance of an audit and help to objectively reassess the risk areas.

The results of an internal audit of an asset management system can be used to correct or prevent specific nonconformities, as an input for continual improvement, and to provide input for management review.

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Internal audits of the asset management system may be performed by personnel from within the organization or by external persons selected by the organization, working on its behalf. In either case, the persons conducting the audit should be competent and in a position to do so impartially and objectively. In smaller organizations, auditor independence can be demonstrated by an auditor being free from responsibility for the activity being audited.

Audits should support learning and improvement of the asset management system. To achieve this, the audits should focus on the performance of the asset management processes, as opposed to the performance of persons within the processes. Attention should be paid to examples of good practice and improvement opportunities. At the same time, audits should also determine system deficiencies, by checking conformity of practice and the asset management system with each other and to the requirements of ISO 55001.

9.2.3 Self-assessment can be helpful in driving continual improvement. Self-assessments should evaluate the viability and suitability of the asset management policy, objectives and plans to ensure they are consistent with each other, suitable, adequate, and achievable. This requires assessment of the following:

a) assumptions related to the organization's asset management;

b) the organization's process(es) and procedure(s), methods, tools and techniques;

c) the availability and allocation of funds and resources.

The self-assessment process should encourage participants to identify opportunities for continual improvement. Active participation, understanding and support of the organization's employees are important in conducting a self-assessment review.

9.3 Management review

9.3.1 Top management should review the organization's assets, asset management system and asset management activity, as well as the operation of its policy, objectives and plans, at planned intervals, to ensure their suitability, adequacy and effectiveness.

The review should also consider whether the asset management policy continues to be appropriate for the organization's purpose. It should establish new or updated asset management objectives for continual improvement, appropriate to the coming period, and consider whether changes are needed to any elements of the assets, asset management processes and the asset management system.

9.3.2 Inputs to management reviews should include:

a) the status of actions from previous management reviews;

b) changes in external and internal issues that are relevant to the asset management system, including changing circumstances (including developments in legal, regulatory and other requirements related to asset management), changes in technology, and changes in market requirements;

c) information on the asset management performance, including trends in:

   1) nonconformities and corrective actions, including evaluations of performance in addressing incident investigations, corrective actions and preventive actions;

   2) monitoring and measurement results including:

      i) the results of communication, participation and consultation with employees and other stakeholders (including complaints);

      ii) the performance of the assets, asset management processes and the asset management system, including trends apparent from nonconformities and corrective actions, the results of monitoring and measurement, and audit findings;

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iii) the results of other evaluations of the assets or asset management system, e.g. condition or capacity;

iv) evaluations of compliance with applicable legal and regulatory requirements and with other requirements to which the organization subscribes;

v) audit results;

d) asset management activities;

e) opportunities for continual improvement;

f) changes in the profile of risks and opportunities;

g) asset performance and condition.

9.3.3 Management reviews provide top management with an opportunity to evaluate the continuing suitability, adequacy and effectiveness of the assets, asset management, and asset management system. The management review should cover the scope of the asset management system and the asset management activity, although it is not necessary to review all elements at once and the review process may take place over a period of time.

Reviews of the implementation and outcomes by top management should be regularly scheduled and evaluated. While ongoing system reviews are advisable, formal reviews should be structured and appropriately documented and scheduled on a suitable basis. Persons who are involved in implementing the asset management system and allocating its resources should be involved in the management reviews.

9.3.4 The outputs from management reviews should include decisions and actions relating to improvements in asset management system and activity including:

a) variations to the scope, policy and objectives;

b) criteria for asset management decision making;

c) updates to performance requirements;

d) resources including financial, human and physical resources;

e) changes to controls and how their effectiveness is measured, including roles, responsibilities and authorities.

9.3.5 The organization should retain documented information as evidence of the results of management reviews and should communicate the results of management reviews to relevant stakeholders. It should also take appropriate action based on the results, while managing any changes (see 8.2).

Management reviews should also cover aspects of the asset management system and activities, if any, that are outsourced to external service providers. Relevant information from management reviews should be communicated to specific employees, external service providers or other stakeholders.

Relevant outputs from management reviews should be used by top management during reviews of the organizational plan.

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10 Improvement

10.1 Nonconformity and corrective action

10.1.1 General

The organization should be aware that nonconformities (including failures) can occur in its assets, asset management activity and asset management system. The organization should establish plans and processes to control nonconformities and their associated consequences, to minimize any adverse effects on the organization and on stakeholder needs and expectations. This can be accomplished by documenting and reviewing past nonconformities, evaluating how the consequences were dealt with, and by determining methodologies to prevent future nonconformity.

Corrective actions are actions taken to address the root cause(s) of identified non-conformances, or incidents, in order to manage their consequences, and to prevent or reduce the likelihood of recurrence. Aspects to be considered in establishing and maintaining corrective action processes should include:

a) the identification and execution of corrective measures, both for the short term and the long term;

b) the evaluation of any impact on risk identification and assessment results, including any need to update risk identification, assessment and control report(s);

c) the recording of any required changes in processes or procedures resulting from the corrective action or risk identification, assessment and control, and execution of these changes.

10.1.2 Processes for the investigation of asset-related nonconformities and incidents

The organization should establish, implement and maintain process(es) (and their associated procedure(s)) for the handling and investigation of nonconformities, functional failures, and incidents associated with assets, asset systems and the asset management system. These process(es) should define the significant criteria for the investigation of non-conformities or incidents and the necessary responsibilities and authorities (for all the actions listed in ISO 55001:2014, 10.1).

10.1.3 Processes for implementing corrective actions

The organization should establish, implement and maintain process(es) for instigating corrective action(s) for eliminating the causes of nonconformities or incidents identified from investigations, evaluations of compliance and audits, to avoid their recurrence.

Any corrective actions taken and their timings should be commensurate with the risk(s) encountered. Where a corrective action identifies new or changed risks, or the need for new or changed process(es), procedure(s) or other arrangements to control life cycle activities, the proposed actions should be risk assessed prior to implementation (see 8.2).

The organization should monitor the timely close-out or completion and the effectiveness of the corrective action(s). Documented information should be kept on the corrective actions taken.

The organization should ensure that any necessary changes arising from corrective actions are made to the asset management system (see 8.2).

10.2 Preventive action

Preventive actions, which may include predictive actions, are those taken to address the root cause(s) of potential failures or incidents, as a proactive measure, before such incidents occur. The organization should establish, implement and maintain process(es) for initiating preventive or predictive action(s). Elements to be considered in establishing and maintaining preventive action processes include:

a) the use of appropriate sources of information;

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b) the identification of any potential failures;

c) the use of an appropriate methodology;

d) the initiation and implementation of preventive action;

e) the recording of any changes in processes and procedures resulting from the preventive action;

f) assessment of the preventive action;

g) the input to the asset management plan(s) from preventive actions;

h) the need to keep documented information on the preventive or predictive actions.

10.3 Continual improvement

10.3.1 Opportunities for improvement should be identified, assessed and implemented across the organization as appropriate, through a combination of monitoring and corrective actions for the assets, asset management, or asset management system. Continual improvement should be regarded as an ongoing iterative activity, with the ultimate aim of delivering the organizational objectives. It should not be interpreted as cyclic (e.g. annual) improvement in asset performance parameters just because they can be achieved.

10.3.2 Continual improvement can be organized as a top-down or bottom-up process, or as a combination. The organization should establish, implement and maintain process(es) for determining opportunities and assessing, prioritizing and implementing actions to achieve continual improvement and reviewing their subsequent effectiveness. These processes may include:

a) non-conformity and corrective action (see 10.1), in particular failure and incident investigation (see 10.1.2);

b) preventive action (see 10.2);

c) trends in performance (see 9.1);

d) evaluation of compliance (see 9.1.1);

e) internal and external audits (see 9.2);

f) management review (see 9.3);

g) stimulating employees to come forward with suggestions;

h) management of change (see 8.2).

10.3.3 The organization should actively seek and acquire knowledge about new asset management-related technology and practices, including new tools and techniques; these should be evaluated to establish their potential benefit to the organization and be incorporated into the asset management system as appropriate. Examples include:

a) active participation in professional bodies and industry associations;

b) conferences, seminars, publications, (online) forums, journals;

c) benchmarking and technology transfer initiatives, and competitor check-ups;

d) engaging specialist organizations;

e) research and development;

f) consultation of suppliers and clients.

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10.3.4 Although the opportunities for improvement can be widely different in size and effect, the approach for processing them may consist of the following steps:

a) identification of improvement needs and potential;

b) evaluation of options;

c) estimation and determination of financial and non-financial consequences;

d) risk assessment and management of change (see 8.2) aspects;

e) links with decision-making criteria (see 4.2);

f) selection and execution;

g) tracking of outcomes and review.

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Annex A
(informative)

Information on asset management activities

Relevant asset management subject areas addressed by other published international, regional, or national standards include, but are not limited to, the following:

— data management;

— condition monitoring;

— risk management;

— quality management;

— environmental management;

— systems and software engineering;

— life cycle costing;

— dependability (availability, reliability, maintainability, maintenance support);

— configuration management;

— tero-technology;

— sustainable development;

— inspection;

— non-destructive testing;

— pressure equipment;

— financial management;

— value management;

— shock and vibration;

— acoustics;

— qualification and assessment of personnel;

— project management;

— property and property management;

— facilities management;

— equipment management;

— commissioning process;

— energy management.

Users of ISO 55000, ISO 55001 and this International Standard should also refer to such standards wherever possible, to ensure consistent delivery of asset management throughout their organization.

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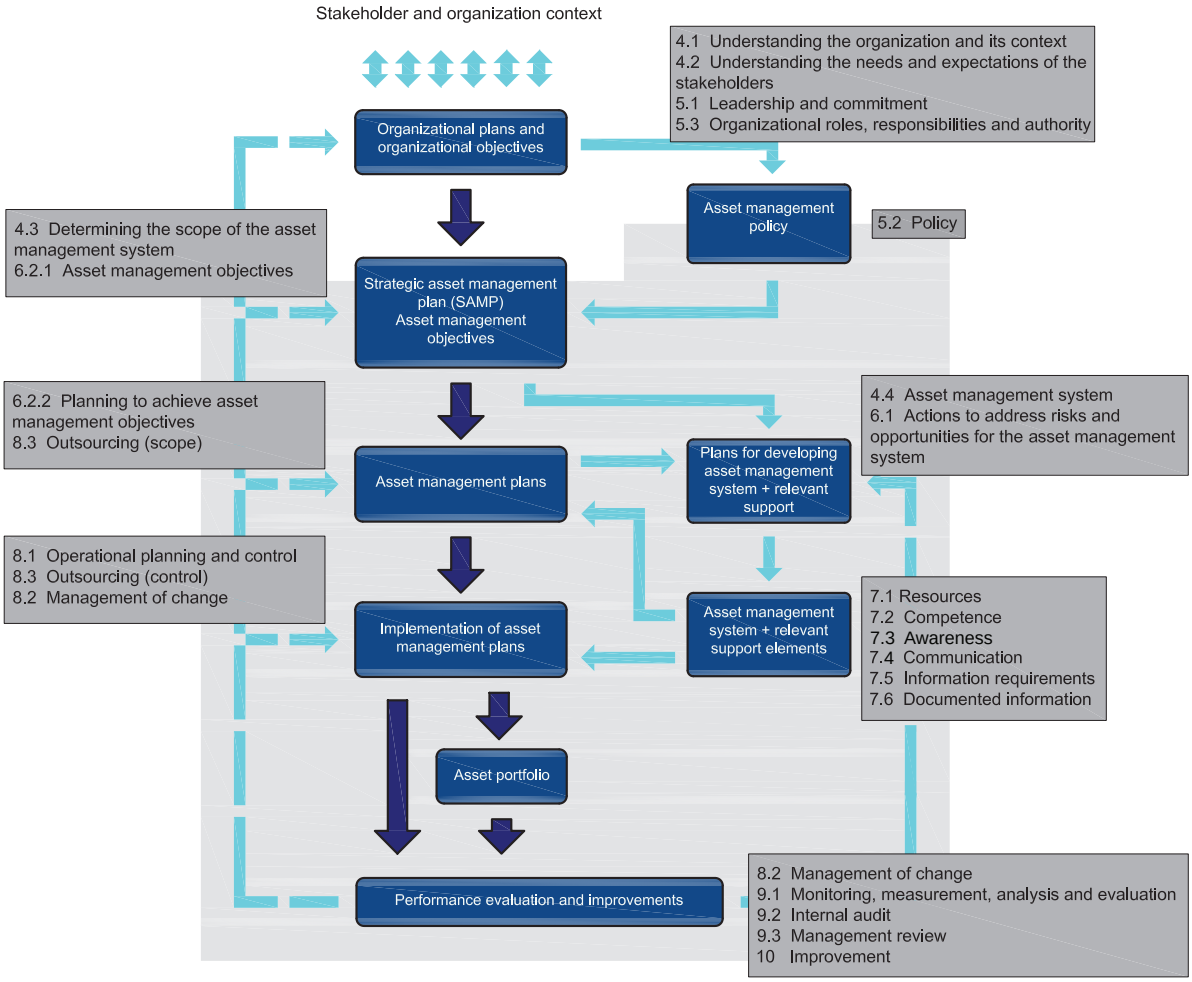
Annex B
(informative)

Relationship between key elements of an asset management system

Figure B.1 shows the relationship between the key elements of an asset management system, together with the related clauses in ISO 55001.



NOTE 1 Only the primary connections are shown to avoid over complexity.

NOTE 2 This does not aim to repeat the distinction between asset management and an asset management system: it is a connections view showing directions of influence.

NOTE 3 The grey highlighted box designates the boundary of the asset management system.

Figure B.1 — Relationship between key elements of an asset management system

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REFERENCE: **Application, Appendix 5.1-2, page 5.1-5; Appendix A to Board Order 2018 10: Reasons for Decision, paragraph 463**

ISSUE: **Battery Energy Storage System Project**

QUOTE: From Appendix 5.1-2, page 5.1-5:

"In Order 2018-10 regarding the 2017/18 GRA the Board noted its view that the estimated costs for 4 MW of battery storage did not compare favourably on a dollar per MW basis with the LNG third engine or the 20 MW thermal plant. Further, concern was noted that the technology was not tested, and shown demonstrated benefits, in northern climates. Given the costs and unproven nature of the technology in a northern environment, the Board determined the project was not viable and absent NRCan funding it was risky to undertake the project." (footnote removed)

From Appendix A to Board Order 2018-10:

"Further, the Board is of the view that, at this time, the technology used for battery storage has not been tested in northern climates such as Yukon and has not been shown to provide the benefits outlined by YEC in such jurisdictions. The Board finds that, given the costs and unproven nature of the technology in a northern environment, the project is not viable. If YEC did not have funding from NRCan, it was risky to undertake the project, considering that even the initial costs in the test years are forecast at over $9 million dollars. For these reasons, the Board finds that expenditures on such a project are not warranted. As a result, the Board denies the inclusion of costs associated with the battery energy storage project in the revenue requirement for the test years and directs YEC to reflect this finding in its compliance filing."

QUESTION:

a) Please provide the results of analysis performed by YEC examining the costs and benefits of the project relative to any alternatives considered by YEC.

b) Please identify how YEC has addressed the Board's concerns in Board Order 2018-10 with respect to the project's viability, benefits and expenditures.

c) If this project is approved by the Government of Yukon in 2021, please provide the current estimate of when YEC intends to add costs related to this project to its proposed rate base, e.g., in a future GRA.

ANSWER:

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

The Battery Energy Storage System (BESS) project is planned to come into service in the latter part of 2022. It will remain in WIP during 2021 and not affect 2021 GRA revenue requirement.

The BESS project has been designated in OIC 2020/180 as a "regulated project" under Part 3 of the Public Utilities Act, and the Minister has referred to the YUB for review the YEC Application for an energy project certificate and an energy operation certificate for this project. The Board's review and report to the Minister will be completed before YEC undertakes any final commitments to proceed with this project.

Yukon Energy addressed the Board's concerns regarding this project through feasibility assessment by Hatch Engineering of the technology application in the Yukon climate and securing $16.5 million of federal grant funding towards development of this project as described in the GRA section referenced in this question.

The BESS will provide 7.2 MW dependable capacity [reduction of four diesel rentals] to reduce Yukon Energy's need to rely on rental of diesel generators during the winter months to address N-1 capacity shortfalls. The BESS will also provide other benefits, including: an operating reserve that reduces thermal generation requirements; enhanced blackstart capability; opportunities for diesel-peak shifting; and other system benefits. These benefits are forecast in the Part 3 Application to result in net ratepayer savings when compared to the use of diesel rentals which would be necessary should the Project not proceed, i.e., over the life of the Project the net present value (2022$) of the net YEC costs is $27.751 million compared to the net present value of benefits of $40.426 million for reduced diesel rental costs and reduced thermal generation fuel costs (see a copy below of Table 4-3 from the Part 3 Application). This indicates the BESS project will benefit

Yukon ratepayers (present value savings of $12.676 million). The BESS is expected to assist in YIS grid stability and reduce thermal generation and GHGs – benefiting both the environment and Yukon ratepayers.

Table 1: Annual Ratepayer Impacts from BESS (20 MW/ 40 MWh)
[Copy of Table 4-3 from YEC's Part 3 Application for the BESS Project]

	BESS Annual Costs ($000)				BESS Annual Savings ($000)				
$000	Annual Capital Cost	Annual Operating Cost [excl. recharging]	Annual Net Recharging Cost [15% return loss plus 3% idling loss]	Total Annual Costs	Avoided Diesel Rental Costs	Annual Savings from Operating Reserve Use	Annual Savings from Peak Shifting	Total Annual Savings	Net Annual Ratepayer Savings (Costs) ($000)
	A	B	C	D=A+B+C	E	F	G	H=E+F+G	I=H-D
Year 1	$1,530	$652	$82	$2,264	$1,216	$1,125	$11	$2,351	$87
Year 2	$1,492	$665	$84	$2,240	$1,265	$1,147	$11	$2,423	$182
Year 3	$1,454	$678	$85	$2,217	$1,315	$1,170	$11	$2,496	$280
Year 4	$1,416	$691	$87	$2,194	$1,368	$1,193	$11	$2,573	$379
Year 5	$1,378	$704	$89	$2,171	$1,423	$1,217	$12	$2,651	$481
Year 6	$1,340	$717	$91	$2,148	$1,480	$1,242	$12	$2,733	$585
Year 7	$1,302	$731	$92	$2,126	$1,539	$1,267	$12	$2,817	$691
Year 8	$1,264	$745	$94	$2,104	$1,600	$1,292	$12	$2,904	$801
Year 9	$1,226	$759	$96	$2,082	$1,664	$1,318	$12	$2,994	$912
Year 10	$1,189	$774	$98	$2,061	$1,731	$1,344	$13	$3,088	$1,027
Year 11	$1,151	$789	$100	$2,040	$1,800	$1,371	$13	$3,184	$1,144
Year 12	$1,113	$804	$102	$2,019	$1,872	$1,398	$13	$3,284	$1,265
Year 13	$1,075	$820	$104	$1,999	$1,947	$1,426	$13	$3,387	$1,388
Year 14	$1,037	$835	$106	$1,978	$2,025	$1,455	$14	$3,493	$1,515
Year 15	$999	$851	$108	$1,959	$2,106	$1,484	$14	$3,604	$1,645
Year 16	$961	$868	$111	$1,939	$2,190	$1,514	$14	$3,718	$1,779
Year 17	$923	$885	$113	$1,920	$2,278	$1,544	$15	$3,836	$1,916
Year 18	$885	$902	$115	$1,902	$2,369	$1,575	$15	$3,958	$2,057
Year 19	$847	$919	$117	$1,884	$2,463	$1,606	$15	$4,085	$2,201
Year 20	$810	$937	$120	$1,866	$2,562	$1,638	$15	$4,216	$2,350
NPV	**$16,318**	**$10,147**	**$1,286**	**$27,751**	**$22,647**	**$17,612**	**$167**	**$40,426**	**$12,676**

Notes:

1 2021 assumed as Year 1. Capital costs (Table 3-4) and operating costs (Table 3-5) each escalated 2% for one year inflation.

2 YEC WACC at 4.794% per 2021 GRA (real WACC with 2% inflation at 2.739%) is used for all net present values (NPVs).

3 Annual Capital Cost includes depreciation (20 year life) and return on mid-year rate base at YEC WACC of 4.794%.

4 Annual Net Recharging Cost assumes diesel generation for N-1 dependable capacity and operating reserve recharge losses, 75% LNG and 25% hydro for other recharge losses (peak shifting saving already addresses these losses), and hydro for idling losses.

5 Avoided Diesel Rental Costs assumes $168,896 per MW (2022$) and 7.2 MW (4 rental units) of dependable capacity.

REFERENCE: **Application, Appendix 5.1, page 5.1-6**

ISSUE: **Pumped Storage**

QUOTE: "Federal funding was identified as a critical requirement for this project to keep the project affordable for customers and to minimize risks."

QUESTION:

a) Does YEC have an estimate of the total cost for this project, if completed? If so, please provide a cost breakdown of the costs for this project. More specifically, provide the activities YEC forecasts to conduct and the cost amount allocated to those activities. If not, please explain why not.

b) Has YEC identified potential federal funding for this project? If so, please provide an overview of the funding YEC hopes to obtain and the status of efforts to do so.

c) Please provide the results of analysis performed by YEC examining the costs and benefits of the project relative to any alternatives considered by YEC.

d) Please comment on how an isolated electrical system running out of generation capacity can benefit over the short, medium and long term from energy storage within the isolated system.

e) Given the inefficiencies of storage systems and the current operating frequencies and duration for thermal generation in the Yukon, please comment on whether it is reasonable to use thermal generation to charge a storage facility.

ANSWER:

(a)

As outlined in the 10-Year Renewable Electricity Plan, the total cost for the Moon Lake Pumped Storage is estimated to be $280,000,000. A breakdown of the cost estimate can be found in Appendix F, Table 4.1 of the 10-Year Renewable Electricity Plan. [This Plan is provided in Attachment 1 to CW-YEC-1-36(a).]

(b)

YEC is working with Yukon government and the First Nations whose Traditional Territory the project is located on to secure Federal funding for the work required in the planning phase of the Moon Lake project. An application has been submitted for initial funding for project planning, but no confirmation has been received to date on its approval status from the Federal government. Material work on the project will not be undertaken until Federal funding is secured for these activities.

(c)

The 10-Year Renewable Electricity Plan analyzed a number of alternative resources to meet the Yukon's energy and capacity demands. The Moon Lake pumped storage project with federal funding has the most competitive Levelized Cost of Capacity (LCOC) compared to alternatives, as reviewed in Table 3 in the 10-Year Renewable Electricity Plan (see response to "a" above). Dependable capacity was the key element needed in resources to address the capacity shortfall and expected load growth, while providing additional benefits of seasonal energy storage.

(d)

The proposed pumped storage would enable the YIS to secure renewable dependable capacity sufficient to remove the sizeable N-1 dependable capacity shortfall forecast for the medium and long-term that would otherwise require reliance on rental and/or new permanent thermal generation capacity. The project would also utilize summer surplus renewable energy on the YIS, and (through the related transmission development) enhance prospects for sale of surplus renewable summer energy to the Skagway cruise ship tourist activity. Key factors related to pumped storage and YIS summer surplus renewable energy include the following:

- Today YEC has excess water in summer at WGS and have to spill;

- It is forecast that YEC will have 40 GWh of SOP IPP energy added to the grid, and all of the summer energy related to these IPPs is expected to increase spill at Whitehorse dam; and

- Pumped storage will utiltize this summer surplus and enable it to be redeployed to the winter, directly reducing thermal generation requirements.

(e)

YEC does not anticipate recharging the pumped storage system with thermal energy but would instead use surplus wind, solar and summer Whitehorse generation (which is currently spilled). Moon Lake is also expected to provide inflows and energy generation. Having a seasonal pumped storage facility would allow Whitehorse Generating Station to run at 100% capacity in the summer and shift this energy to the winter, reducing the thermal requirements in the Yukon.

REFERENCE: **Application, Appendix 5.1, page 5.1-7**

ISSUE: **Southern Lakes Transmission Line and Whitehorse Interconnection Projects**

QUESTION:

a) Does YEC have an estimate of the total costs for these two projects, if completed? If so, please provide cost breakdowns for the projects. More specifically, provide the activities YEC forecasts to conduct and the cost amount allocated to those activities. If not, please explain why not.

ANSWER:

(a)

As stated in the 10-Year Renewable Electricity Plan, the full cost of the Southern Lakes Transmission Line project is estimated at $166,000,000. The methodology for creating this cost estimate for the transmission project is presented in Section 3 of the Transmissions Options Evaluation Study, completed for the 2016 Resource Plan.[1] Specifically, Options 4 and 10, presented in Table 4 of this study. The full cost of the Whitehorse Interconnection Project is estimated to be $7.7 million, for the components as shown in the table below.

Element	Cost Estimate
Whitehorse S150 & P126 Upgrades	$3 million
L151 Reroute	$0.5 million
Riverside Substation S171 Upgrades	$3.5 million
Subtotal:	$7 million
Contingency (10%)	$0.7 million
Total Interconnection Upgrades Cost:	$7.7 million

[1] For further details see the following: https://yukonenergy.ca/media/site_documents/Appendix_5.21_Transmission_Options_Evaluation_(Midgard_2016).pdf.

REFERENCE: **Application, Appendix 5.2, page 5.2-1**

ISSUE: **Dam Safety Program Project**

QUOTE: "A full dam safety review (DSR) is performed every 5 years by an external consultant as recommended by the Canadian Dam Association (CDA) … Spending in 2021 is required to address 2020 DSR outcomes and priorities identified for 2021. Some of the high priority items that will be addressed include:

- Wareham dam spillway design
- Warning and danger signage around the six dams
- Public safety around Marsh Lake"

QUESTION:

a) Please confirm that the $300,000 cost for 2021 is for the work included in the bullet list. If confirmed, please break down the $300,000 cost into the three projects.

b) Please explain what "public safety around Marsh Lake" entails.

c) Is the cost of performing the dam safety review included in YEC's revenue requirement? If so, please provide a reference to where that is described in YEC's Application.

d) Was a competitive process used to retain an external consultant to perform the review? If not, why not? If so, please describe the process, including the number of quotes or proposals received and details of the successful vendor.

ANSWER:

(a)

The $300,000 cost is broken out as follows:

- Warning/danger signage - $50,000;
- Public safety around Marsh Lake - $150,000;
- Emergency Preparedness Plan and Operational MS - $25,000; and
- Canyon Lake control structure repairs - $75,000.

(b)

The work includes the development of a public safety plan, signage and safety boom installation.

(c)

Yes, Dam Safety Program cost is included in the 2021 test year revenue requirements as part of rate base. No amortization expense is included for 2021 test year as the project is forecast to be closed by end of 2021.

The project is listed in Appendix 5.2: Capital Projects >$10,000 and < $1 million added to Rate Base and also included in Table 5.2-1 “Projects Included in 2021 Rate Base”.

(d)

A competitive RFP process was initiated. Eight proposals were received evaluated and awarded based on total score based on best overall proposal which included evaluating technical ability and price. Ecora Engineering was selected as the successful proponent.

REFERENCE: **Application, Appendix 5.2, page 5.2-2**

ISSUE: **Dam Safety Recommendations 2017-18**

QUOTE: "2019 spending included required maintenance around the Marsh Lake control structure, and replacement of Whitehorse piezometers; while planned 2020 activities include replacement of the Mayo Lake Dam wood planking, Wareham Dam seismic upgrades, and the implementation of a public safety plan at the Marsh Lake control structure."

QUESTION:

a) Please provide a cost breakdown for 2019 and 2020 spending by the work items listed in the quote above.

b) Please explain why each of the work items listed in the quote above were required to be done in 2019 and 2020.

c) Was the work scheduled to be done in 2020 completed? If not, please explain why and provide an update on the status of the work.

ANSWER:

(a)

A breakdown of 2019 and 2020 spending is outlined in the table below.

	2019 (+)	2019 (+)	2020 (+)
	Total Cost (+)	Cust Connect Contract (+)	Total Cost (+)
P16-026) Dam Safety Recommendations - (-)	272,274.92		124,011.21
(C18053) Dam Safety Recommendations -Closed	172,735.64		
(C19601) DSR-WH Spillway Drainage -Closed	560.66		.00
(C19602) DSR-Marsh Lake Sheet Pile Isla -Closed	3,521.28		
(C19603) DSR-Marsh Lake Boat Lock -Closed	3,214.03		
(C19604) DSR-Mayo Replace Wall Planking -Open	24,377.73		3,405.32
(C19605) DSR-Wareham Dam 2007 Seismic -Open	23,164.62		38,988.33
(C19606) DSR-P125 Stability of stoplogs -Closed	76.82		
(C19607) DSR-Aishihik GS Contingency Pl -Closed	2,999.61		
(C19608) DSR-Aishihik CLCS Non-Conforma -Closed	3,735.98		
(C19609) DSR-WH Embankmt Piexometer Rep -Closed	3,804.16		
(C19610) DSR-EPP/OMS and Other Support -Closed	25,323.16		42,803.25
(C19611) DSR-Owner Cost -Closed	6,978.60		
(C19612) Dam Safety Management Program -Closed	977.86		3,475.35
(C19613) Dam Safety Inspection -Closed			35,338.96
(C19614) WRGS Seismic Study -Closed	804.77		

The total actual spend for 2020 was $124,011 (compared to the forecast of $0.300 million in the GRA). The remainder was to be applied to the Mayo Wall Planking construction, the Wareham Dam Seismic Upgrades construction, and the Public Safety Plan. The Mayo Wall Planking and the Wareham Dam Seismic Upgrades were deferred due to the high water levels in both Mayo Lake and Wareham Lake. The Public Safety Plan was deferred until the completion of the 2020 Dam Safety Review.

These 3 projects are identified as part of Dam Safety Review and will be completed.

(b)

Items listed for 2019/2020 were generated from Dam Safety Inspection (performed yearly) and the Dam Safety Review of 2015.

(c)

Mayo Lake Planking not completed due to high water levels. Currently YEC is waiting for lower water levels to drop such that the planking can be replaced safely.

Wareham Dam Seismic Upgrades were also not completed due to high water levels. This work will now be completed as part of other Wareham Dam projects currently being planned.

Public Safety Plan was not completed due to the fact that YEC is waiting for results from the 2020 Dam Safety Review for inclusion into the Public Safety Plan.

REFERENCE: **Application, Appendix 5.2, page 5.2-2**

ISSUE: **P126 LNG Boil-Off Gas Heat Exchanger Project**

QUOTE: "Prior to decommissioning of the Mirrlees diesel generators, LNG boil off gas was piped to P126 and burned in the P126 plant boiler and/or dissipated through the WD1 jacket water heat exchanger. With retirement and removal of the three Mirrlees gensets at the Whitehorse Diesel Plant (P126) there was a requirement to replace this heat dissipation function and to design, supply and install a new heat exchanger at the plant to dissipate extra heat from the combustion of LNG boil off gas. Work related to the installation of the heat exchanger included hiring an owners engineer to prepare design, drawings and specifications for the new heat exchanger, piping, a new pump with VFD, and a temperature sensing device, and provide mechanical and electrical drawings and technical specifications for equipment and piping installation for tendering the construction work."

PREAMBLE: The Board requires additional information regarding how removal of the Mirrlees generators necessitates a new heat dissipation function and heat exchanger.

QUESTION:

a) Were the P126 plant boiler and WD1 jacket water heat exchanger removed or decommissioned when the diesel generators were decommissioned?

b) Please explain why removal of the diesel generators necessitates installation of a new heat exchanger.

ANSWER:

(a)

P126 boiler was not removed. WD1 Jacket and water heat exchanger were removed when the diesel generators were decommissioned.

(b)

New heat exchanger was installed to dissipate heat from the boil off gas from the LNG site. The diesel cooling system previously dissipated heat prior to removal.

REFERENCE: **Application, Appendix 5.2, page 5.2-2**

ISSUE: **Wareham Gate Heating Project**

QUOTE: "The Wareham Gate Heating project replaced an old and ineffective heating system on both Wareham Spillway Gates. The new system is designed to keep both spillway gates operational through the winter. Passing flows during outages and times of high inflows is a critical function of the spillway."

QUESTION:

a) Please indicate the year in which the original heating system was installed and the expected service life at the time of installation.

b) Please describe the frequency and duration of periods during which the Wareham spillway gates were out of operation during the winter over the last ten years, on a per annum basis.

c) Please describe the effect of those periods on available capacity.

ANSWER:

(a)

The original heating system was installed in circa 1990. The expected service life is unknown.

(b)

Due to the extreme cold weather at Mayo keeping the gates operational is problematic. Prior to the repair of the gate heat and installation of the bubbler system in 2015 the spill gates required steaming at least 1-2 times per year to keep them operational.

(c)

There is no effect on available capacity.

The installation of the Mayo B facility (2011) required an increase to the Wareham forebay level, i.e., the layout of the penstock to Mayo B instituted a higher Wareham forebay level to run one or both units[1]. The higher operating forebay reduces the time to start spilling if the hydro is shutdown; and the higher forebay requirements have required increased availability and operability of the Wareham spill gates. Additional gate heat and sealing of the gates was required to accomplish this.

[1] The high point in the penstock (PI2) limits the variations in the forebay.

REFERENCE: **Application, Appendix 5.2, page 5.2-4**

ISSUE: **WH4 Ventilation**

QUOTE: "The WH4 plant is overheating during the summer. Given that YEC is adding additional capacity to the WH4 hydro unit with new servo motors in 2021, removing the restriction placed on output by the overheating issue will enable the extra capacity to be used reliably throughout the year."

QUESTION:

a) Please describe the work to be done as part of this project and break down the $750,000 cost to the work items comprising this project. In your response, provide any assumptions on how the $750,000 cost was derived.

b) Please describe the frequency and duration of outages at WH4 resulting from overheating over the last ten years, on a per annum basis.

ANSWER:

(a)

The project was forecast to be completed in 2021. It will now be completed in 2022 and therefore will not be part of the test year revenue requirement. A breakdown of project costs is not available at this time.

(b)

Outages were avoided by limiting the output. Summer output was limited to ~80% due to the overheating.

REFERENCE: **Application, Appendix 5.2, page 5.2-7**

ISSUE: **L355 Voltage Regulator Project**

QUOTE: "Atco Electric Yukon (AEY) has reported low voltage levels (below CSA standards) at the AEY Haines Junction substation, which is supplied from Aishihik via distribution line L355. The project identified the voltage profile of L355, determined the appropriate location and settings of voltage regulators, and completed all installation and commissioning work.

QUESTION:

a) Please explain the frequency at which AEY is experiencing low voltage levels.

b) Please provide the voltage levels prescribed in CSA standards and the voltage levels experienced at the Haines Junction substation.

ANSWER:

(a)

The low voltages at the AEY Haines Junction substation occur during periods of high load. Most frequently during the winter months.

(b)

The nominal voltage at the point of sale and purchase should not vary by more than +/- 6% as per CAN3-C235-83 (reaffirmed in 2015). On two previous occasions, the incoming voltage to the Haines Junction substation has dipped as low as 6.4% and 10% below nominal.

REFERENCE: **Application, Appendix 5.2, page 5.2-9, footnotes**

ISSUE: **Building Upgrades**

QUOTE: "[7]There are many exterior works, including roofing, heat trace, metal or wood cladding, structural or building envelope work or windows and doors. A variety of work is required to be done on staff housing, offices and plants.

[8] Numerous Heating Ventilation and Air Conditioning (HVAC) issues have been identified. The intent is to group the HVAC work requirements into annual tenders seeking contractor to do works within the communities required.

[9] Flooring issues identified relate to removal of warn carpeting or sealing of foundation flooring to alleviate any potential radon into the workplace.

[10] A majority of electrical panels are at end of life or currently overloaded and need to be replaced.

[11] A stepdown transformer is required for the Aishihik office plant as the existing one has exceeded its life expectancy."

QUESTION:

a) Please provide the costs for the work items listed in footnote 7 and explain why each is necessary.

b) Please describe the issues and problems with the existing HVAC systems and equipment and the proposed remedies and forecast cost of those remedies.

c) Please provide and comment on the results of any testing done for radon in YEC's buildings and the forecast cost of replacing flooring in those buildings.

d) Are the electrical panels currently experiencing problems or issues leading to safety concerns or excessive maintenance costs? Please explain.

e) Please provide the estimated cost of replacing the panels.

f) Is the existing stepdown transformer currently experiencing problems or issues leading to safety concerns or excessive maintenance costs? Please explain.

g) Please provide the estimated cost of replacing the stepdown transformer.

ANSWER:

(a)

Exterior Works planned for 2019 included replacement of metal cladding and joint sealers at two offices and a hydro plant, roofing replacement at a staff house and office trailer, and the installation of an ice melt system in the concrete ramp at the WH4 hydro plant. The roofing replacement of the Faro staff house was completed during Q3; other planned work was deferred to 2020 due to the need for further investigation, contractor availability, or further inspection determined the work not to be required and it was removed from the scope.

Total costs incurred in 2019 for exterior work was $11,989.

(b)

The consultant identified number of HVAC units that were at end of lifecycle. YEC deemed it prudent to proactively replace these now, rather than waiting for them to breakdown. Run-to-failure is not a principled approach to managing this class of asset. This equipment is critical during heating season so any failures in winter would likely entail higher costs for call-outs, overtime, etc.

Planned HVAC Retrofits for 2019 involved the replacement of furnaces, boilers, ventilation, or fan coils at a number of locations including offices, generation plants, and staff houses. HVAC work was completed in Q4 at the Aishihik plant, Dawson and Faro offices, Mayo staff house, Kulan warehouse, and Whitehorse IT & drafting trailers. Total costs allocated to HVAC work in 2019 were $68,709.

(c)

Radon testing results did not indicate any areas high zone for radon. The flooring works being undertaken consequently do not relate to radon but relate to the end of life of the existing product in place.

Flooring Replacement was completed as planned at the main office and a staff house in Dawson. The quotes for replacement of the carpet in the Whitehorse main office came in higher than expected, however, this was offset by removing the flooring replacement in the electrician's trailer from the scope of work. Work planned for 2020 includes flooring replacement at staff houses in Faro and Mayo.

Total costs allocated to flooring work in 2019 was $86,014.

(d)

Some panels are reaching end of life and some are fully loaded requiring a larger panel installation. Works identified within BCR were to be addressed internally if possible. The panels that were replaced were deemed priority for load and life cycling purposes.

(e)

The estimated cost for replacing the panels was $18,250.

(f)

An internal inspection was undertaken and it was determined that this stepdown transformer is not currently overloaded, will not be taking on any more load and could have significant useful life remaining if not operated at a high load. Although it is exceeding its life expectancy the transformer will be monitored and replaced when it starts showing signs of failure or requires additional load.

(g)

The cost estimate to replace the stepdown transformer in 2013 was $9,800.

REFERENCE: **Application, Appendix 5.2, page 5.2-9**

ISSUE: **Compact Digger Truck**

QUOTE: "The purchase of a 4 to 5 ton chassis compact digger truck for use in Dawson will substantially decrease risks for workers and ensure greater efficiency in day to day work; including providing improvements in outage response times. Servicemen currently use an attachable bucket that goes on the side of the digger boom for many types of work from street light maintenance, service work, trouble call response, and new construction. The bucket is heavy and difficult to attach/detach. In a trouble call scenario this can also be time consuming and increase trouble call response time leading to frustration and potential unsafe working conditions."

QUESTION:

a) On average, how many times per year is the bucket attached to and removed from the digger boom, how many service personnel does it typically take to attach the bucket, and how long does it typically take to do so?

b) Please use the answers to part (a) to estimate the annual incremental cost of not purchasing a new digger truck.

c) In the past five years, have any injuries or safety concerns been reported by service personnel as a result of having to attach the bucket? If so, please explain.

d) Please provide the models and website links (with purchase prices) for the models of compact digger trucks being considered. Please also include YEC's comments on which model(s) are preferable and why.

ANSWER:

(a)

It is practice to remove the bucket if the boom is to be used for lifting. This can include being used for poles, transformers, and wire. Frequency of removing and re-attaching the bucket to the digger boom can range from multiple times per day to just a few times per week depending on the tasks being completed. It is estimated that there can be between 250 and 400 change overs per year.

Dawson PLT's are often in a working alone situation due the district requirements. This can lead to the bucket being attached/re-attached by one PLT. This can be difficult to do as the bucket alone weighs over 100 lbs and can be difficult to handle. Slippery conditions can also add a degree of difficulty to this work.

For one person working alone this can take 15-20 minutes, and with two people it can take about 10 minutes. The digger takes about twice as long to set up as does a compact bucket truck.

(b)

Two separate options to purchasing a new digger truck are noted: (1) renting a bucket truck; and (2) continuing to operate in the same manner:

1. **Rental Option:** YEC could rent bucket truck for the busy season at a cost of $5000-6000 a month for 6 months. This would total about $30,000 - $36,000 per year. However, rentals are difficult to procure locally and would likely need to be mobbed/ de-mobbed from a southern province. Mob cost are about $6000 each way.

2. **Status Quo:** This option would result in more pressure on, and maintenance for, the Whitehorse large bucket truck. YEC would continue to incur unnecessary travel costs, over time and contractor use. The bucket truck travels to Dawson an estimated 10 times per year, a round trip of 1,064 km. Having the compact bucket truck in Dawson would not eliminate all of these trips but would increase the capacity of Dawson PLT's and greatly reduce trips to Dawson. The closest bucket truck is in Whitehorse which leaves us more exposed to outages in Dawson.

(c)

No Injuries have been recorded in the past five years.

(d)

YEC has received information from four vendors regarding the purchase of a compact bucket truck. Table 1 that follows provides a comparison of the information received. Attachment 1 provides the information and specs received from each vendor.

- In comparing the four units YEC has concluded that the Altec AT41M (rank #1) would be the best selection for YEC. Altec is a reputable name when it comes to bucket trucks. It is the same make of the bucket YEC currently owns (smaller model). The AT41M has the best work height of all the comparable units. The rear two step access makes the bucket very accessible. The truck is a “single Cab” which keeps the overall length short and is ideal for the alley ways in Dawson. This truck comes ready to work with all necessary boom testing, strobe lights and compartment lights. The price of this unit is $187,975. This unit will be ready in June which is months sooner than the Versalift below.

- The next most comparable unit is the Versalift VST 40-I (rank #2). This truck comes on the same chassis and the base price is $167,500. Although this unit is $20k lower cost it does not have all of the features of the Altec AT41M and will require upgrades to be ready for work (e.g., inadequate strobes, no compartment lighting, no go light).

YEC will release a public RFP in 2021 to ensure optimal pricing and fit for service.

Table 1: Summary of Options Reviewed & Vendor Information

Bucket Truck Comparison				
Model	AT41M - Altec	LTM40 Terex Hi_Ranger	ETI ETC40MH	VST40-I Versalift
Supplier	Altec BC	Comercial BC	Falcon equipment BC	Custom truck Alberta
Price	$187,975	$261,000	$209,000	$167,500
Condition	New	New	New	New
Ready Date	Jun-21	late to end of year 2021	Available now	Fall 2021
		Truck Spec		
Chasis	Ford 550	Ford 550 super cab	Ford 550 super cab	Ford 550
4X4	yes	yes	yes	yes
HP	330	330	330	330
Transmission	AUTO	AUTO	AUTO	AUTO
Engine	6.7L power stroke diesel	6.7L power stroke diesel	6.7L power stroke diesel	6.7L power stroke diesel
GVWR	19,500 LBS	19,500 LBS	19,500 LBS	19,500 LBS
Unit Spec				
Boom	Altec model AT41M telescopic articulating aerial device with continuous rotation and ISO-Grip insulating system at boom tip	New Terex Hi-Ranger LTM40 Articulating / Telescoping Aerial Device	2019 ETI ETC40MH Continuous Rotation/ Fiberglass Inner Boom	Versalift VST-40-I, Insulated 40Ft. 4 In Telescopic Aerial Platform Lift, 360 Degree Continuous Rotation Including Slip Rings
Working Hieght	45.8 ft	44.5 ft	44'10"	45.4 ft
Side Reach	30.1 feet	30.7 ft	27'5"	30'2"
Material handling	jib/winch, hydraulically articulating, top mounted, round	Top mount, Removable Jib /Winch	Hydraulic Jib and Winch Package	Hydraulic Dual Arm Articulating Jib Pole And Winch Package
Lifting eye capacity	1000Lbs	800Lb	1000lbs	Jib up to 1000 lb
Elevator	No	No	No	No
Platform	Single 1-Man Platform, Fiberglass, 24" x 30" x 42", End Mount, 180 Degree Rotation	One (1) person, end mounted Platform 24 x 30 x 42:	24x30	1 man Side Mounted Closed Heavy-Duty One-Step 24 In. X 30 In. X 42 In.
Platform Steps	2	Includes one outside access step with slip-resistant surface.	2	Cable Access Step At Rear And Side Access.
Platform cover	yes	yes	yes	yes
Platform Liner	yes 50 kv rating	yes 50 kv rating	yes	Yes
Hydraulic tool outlet	1 set	2 sets	1 set	1 set
Engine start/stop	yes	yes	yes	yes
Out Riggers	Modified A-frame primary outriggers with fixed shoes and safety interlock system	Model 438506 Standard Duty Low Profile A-Frame Outriggers:	A-frame shaped between cab and body	Sub Frame Mounted Main A-Frame Outriggers With Pivot Feet,
Body / other				
Body (lots of detail in spec's)	Standard altec fiber glass body details in W.O documents	Brand FX BFXB 84T Line Body with C2 Walk-Up Details in W.O	steel standard	Dakota Bodies 132” Long X 40” High X 94” Wide Service Body:
Hitch	T-60 style pintle hitch	Assumed…	Assumed	Typical hitch reciever
Out rigger pads	Wood outrigger pads	Wood outrigger pads	Dica compisite	Compisite
Bin Lights	Complete LED FMVSS lighting package	LED Flexglo Compartment Lighting * Top & Sides of Doors	Light in every compartment with master switch in cab	none
More strobe light	4-Corner strobes, amber LED	Truck-Lite 60122Y LED amber oval strobe light offering dual or quad flashing patterns.		none
Strobe light	Strobes, amber LED, with brush guard, installed on post at front of body,	Amber strobe light with 6" lens and mounting bracket.	Amber strobe on post at DS	Strobes in Grill
Light bar	none	Strip LED lighting mounted in loadbed both sides Extruded aluminum drip rails mounted above lighting	none	none
Trailer plug	6-Way trailer receptacle, pin type	6-Way trailer receptacle, pin type	6-Way trailer receptacle, pin type	6-Way trailer receptacle, pin type
Search Light	Go Light	Golight Stryker Search Light	no	no
	Secondary stowage system			
		Prowatt 3000 Inverter		
			7	
		Aluminum ladder rack mounted on the street side compartment top		No Hose Cover

January 19, 2021

Company: Yukon Energy

Customer Contact: Matt Noseworthy

Altec Account Manager: Richard Merinsky 604-358-0148

Unit / Body Specifications

- Altec model AT41M telescopic articulating aerial device with continuous rotation and ISO-Grip insulating system at boom tip
  working height: 45.8 ft
  side reach: 30.1 ft
- Single one man platform, 180 degree rotation
- Material handling jib/winch, hydraulically articulating, top mounted, round
- Two (2) platform steps
- Platform cover
- Platform liner
- One set of hydraulic tool outlets at the boom tip
- Engine start/stop with secondary stowage system
- Jib stick, 36 in L, non-extension dependent, non-certified
- Modified A-frame primary outriggers with fixed shoes and safety interlock system
- Temperature Sight Gauge
- Small aerial service body with side access, 29 inch long tailshelf
- T-60 style pintle hitch
- Wood outrigger pads
- Complete LED FMVSS lighting package
- 4-Corner strobes, amber LED
- Strobes, amber LED, with brush guard, installed on post at front of body, one (1) each side
- 6-Way trailer receptacle, pin type
- Secondary stowage system
- Standard Altec warranty: one (1) year parts, one (1) year labor, ninety (90) days travel and limited lifetime structural.

Chassis Specifications

- Ford F550
  4x4 drivetrain
  84 inch CA
  6.7L Power Stroke diesel
  330 HP engine rating
  Automatic transmission
  GVWR 19,500 lb

Options

FOB Surrey, BC

Quick-turn Unit – Delivery June 2021

Price:	$ 187,975.00
Options:	$ 0
Delivery:	$ FOB Surrey, BC
Total: (Excluding Taxes)	$ 187,975.00

www.altec.com for additional models and information. Quote valid for 45 days; Price does not reflect any local, state, or Federal Excise Taxes (F.E.T.). For additional accessories or details contact your Altec Account Manager.

NEW EQUIPMENT SALES | 800.958.2555 | SALES@ALTEC.COM | ALTEC.COM

Quote Number: 826303 - 1
Altec, Inc.

January 19, 2021
Our 92nd Year

Ship To:
Yukon Energy

Bill To:

Attn:
Phone:
Email:

Altec Quotation Number: 826303 - 1
Account Manager: Richard Merinsky
Technical Sales Rep:

Item	Description	Qty
	Unit	
1.	Altec Model AT41M Articulating Telescopic Aerial Device with a fiberglass upper boom and fiberglass insulator in the articulating arm and proportional joystick upper controls. Built in accordance to ALTEC's standard specifications and to include the following features:	1

A. Ground to Bottom of Platform Height: 40.8 feet at 7.3 feet from centerline of rotation (12.45 m at 2.21 m)
B. Working Height: 45.8 feet (13.96 m)
C. Maximum reach to edge of platform with Upper Boom Non- overcenter: 30.1 feet (at 17.3 feet platform height)
D. Upper boom extension: 110 inches
E. Continuous rotation
F. Articulating Arm: Articulation is from -3 to 82 degrees. Insulator provides 19 inches of isolation.
G. Compensation System: By raising the articulating arm only, the telescopic boom maintains its relative angle in relation to the ground. The work position is achieved through a single function operation.
H. Upper Boom: Articulation is from -25 to 85 degrees. The fiberglass section provides a minimum of 10.9 inches of isolation in the upper boom (when retracted and 42.3 inches when extended).
I. Platform leveling is achieved by a hydraulic master-slave leveling system. This lifetime system is very low maintenance.
J. The dielectrically tested, insulating upper control system includes the following boom tip components that can provide an additional layer of secondary electrical contact protection.
Control Handle: A single handle controller incorporating high electrical resistance components that is dielectrically tested to 40 kV AC with no more than 400 microampers of leakage. The control handle is green in color to differentiate it from other non-tested controllers. The handle also includes an interlock guard that reduces the potential for inadvertent boom operation.
Auxiliary Control Covers: Non-tested blue silicon covers for auxiliary controls.
Control Console: Non-tested non-metallic control console plate.
Boom Tip Covers: Non-tested non-metallic boom tip covers. The covers are not

Altec

Quote Number: 826303 - 1
Altec, Inc.

Item	Description	Qty
	dielectrically tested, but they may provide some protection against electrical hazards.	
	K. Hydraulic system: Open center (full pressure), maximum flow 6 GPM, maximum operating pressure 3,000.	
	L. Dielectric rating: Category C, 46 kV and below	
	M. Unit is painted with a powder coat paint process which provides a finish-painted surface that is highly resistant to chipping, scratching, abrasion and corrosion. Paint is electrostatically applied to the inside as well as outside of fabricated parts then high temperature cured prior to assembly ensuring maximum coverage and protection.	
	N. Manuals: Two (2) Operator's and two (2) Maintenance/ Parts manuals containing instructional markings indicating hazards inherent in the operation of an aerial device.	
	O. Unit meets or exceeds ANSI 92.2 standards.	
2.	Pedestal	1
3.	Single 1-Man Platform, Fiberglass, 24" x 30" x 42", End Mount, 180 Degree Rotation	1
4.	No Platform Elevator	1
5.	Platform Mounted Single Handle Controls	1
6.	Material Handling Jib/Winch, Hydraulically Articulating, Top Mounted, Round (ARM Jib)	1
7.	One (1) Platform Step - located on the side of the platform nearest the elbow in the stowed position	1
8.	Platform Cover - soft vinyl, 24 x 30 inches (610 x 762 mm)	1
9.	Platform Liner, 24 x 30 x 42 inches (610 x 762 x 1067 mm), 50 kV Rating	1
10.	Hydraulic Tool Circuit at Platform: One set of quick disconnect couplings at the boom tip for open center tools.	1
11.	Engine Start/Stop & Secondary Stowage System: 12 VDC powered motor and pump assembly for temporary operation of the unit in a situation wherein the primary hydraulic source fails. Electric motor is powered by the chassis battery. This feature allows the operator to completely stow the booms, platform, and outriggers. Secondary Stowage & Start/Stop is activated with an air plunger at the platform or momentary switch at the lower control station and outriggers.	1
12.	Jib Stick, 36" L, non-extension, non certified, grey in color	1
13.	Slip Ring: Required for engine start/stop, secondary stowage system, and throttle control options	1
14.	Outriggers, Primary, Modified A-Frame With Integrated Subbase, 30"-34" Chassis Height, Electric Interlock, No Valves On Legs, 114" Spread, Fixed Shoe (AT37/41 M/ME/P/PE/S/SE)	1
15.	Winch load line swivel hook	1
16.	Altec Unit Powder Painted White	1

Altec

Quote Number: 826303 - 1
Altec, Inc.

Item	Description	Qty
	Unit & Hydraulic Acc.	
17.	Scuff Pad, 24" x 30", No Step (For use with Platform Liner)	1
18.	Electric Outrigger Controls for one (1) set of outriggers, drive hydraulic outrigger control valves. Durable weather proof sealed electronic switches mounted in aluminum boxes located at the rear of the unit unless otherwise specified.	1
19.	Steel Reservoir, 15 gallon capacity, triangular, 17" L x 17" W x 24" H, and includes breather caps and dipsticks	1
20.	Temperature Sight Gauge	1
21.	HVI-22 Hydraulic Oil (Standard).	25
22.	Standard Pump For PTO	1
23.	Electric Shifted PTO	1
24.	Standard PTO/Transmission Functionality for Small Ford and Dodge Chassis	1
	Body	
25.	Altec LGSS-132-84 (81) Low-Side General Service Body With Step:	1

- **A.** Steel Body
- **B.** Steel Structural Channel Crossmembers And Smooth Floor With Ladder-Style Understructure
- **C.** 132" Body Length
- **D.** 94" Body Width
- **E.** 40" Body Compartment Height
- **F.** 20" Body Compartment Depth
- **G.** 24" From Body Floor To Compartment Tops
- **H.** Finish Paint Entire Body Altec White
- **I.** Undercoat Applied Under The Body
- **J.** 5.5" Drop-In Wooden Cargo Retaining Board At Rear Of Body
- **K.** 5.5" Drop-In Wooden Retaining Board At Top Of Side Access Step
- **L.** Stainless Steel Rotary paddle Latches With Locks
- **M.** Gas Props On All Vertical Doors
- **N.** Chains On All Horizontal Doors
- **O.** Standard Master Body Locking System
- **P.** Hotstick Shelf Extending Full Length Of Body On Streetside
- **Q.** Two (2) Hotstick Brackets Installed On Streetside.
- **R.** One Chock Holder On Each Side of Body With Retaining Lip In Fender Panel
- **S.** 1st Vertical (SS) - 34" W - One (1) Outrigger Housing And Two (2) Adjustable Shelves With Removable Dividers On 4 Inch Centers
- **T.** 2nd Vertical (SS) - 24" W - Two (2) Adjustable Shelves With Removable Dividers On 4 Inch Centers
- **U.** 1st Horizontal (SS) - 50" W - One (1) Fixed Shelf With Removable Dividers On 4 Inch Centers On Bottom of Compartment
- **V.** Rear Vertical (SS) - 24" W - Six (6) Locking Swivel Hooks On An Adjustable Rail (1-4-1)
- **W.** 1st Vertical (CS) - 34" W - One (1) Outrigger Housing And Two (2) Adjustable Shelves With Removable Dividers On 4 Inch Centers

Altec

Quote Number: 826303 - 1
Altec, Inc.

Item	Description	Qty
X.	2nd Vertical (CS) - 24" W - Gripstrut Access Steps With Two (2) Sloped Grab Handles, Vented Battery Storage	
Y.	1st Horizontal (CS) - 50" W - One (1) Adjustable Shelf With Removable Dividers On 4 Inch Centers And One (1) Fixed Shelf With Removable Dividers On 4 Inch Centers On Bottom Of Compartment	
Z.	Rear Vertical (CS) - 24" W - Six (6) Locking Swivel Hooks On An Adjustable Rail (1-4-1)	
AA.	Body Floor Cut-Out For AT41M/ME/P/PE Aerial Device Near Front Of Body	
AB.	Steel Tailshelf, 29" L x 94" W, With Rear Cross Storage And Drop Down Doors	
	Body and Chassis Accessories	
26.	ICC (Underride Protection) Bumper Installed At Rear	1
27.	Combination 2 Ball (10 000 LB MGTW) and Rigid Pintle Hitch (16 000 LB MGTW with 3 000 LB MVL), 4-Bolt, Buyers BH82000	1
28.	Set Of Eye Bolts for Trailer Safety Chain, installed one each side of towing device mount.	1
29.	Rigid Step Mounted Beneath Side Access Steps (Installed To Extend Approx. 2" Outward)	1
30.	Platform Rest, Rigid with Rubber Tube	1
31.	Boom Rest for a Telescopic Unit	1
32.	Wood Outrigger Pad, 19" x 19" x 2.5", With Rope Handle	2
33.	Outrigger Pad Holder, 20" L x 20" W x 5" H, Fits 19.5" x 19.5" x 4" And Smaller Pads, Bolt-On, Bottom Washout Holes, 3/4" Lip Retainer	2
34.	Pendulum Retainers For Outrigger Pad Holders	2
35.	Mud Flaps With Altec Logo (Pair)	1
36.	Wheel Chocks, Rubber, 9.75" L x 7.75" W x 5.00" H, with 4" L Metal Hairpin Style Handle (Pair)	1
37.	Slope Indicator Assembly (Pair) For Machine With Outriggers	1
38.	Safety Harness & 4.5 FT Lanyard (Medium To X-large)	1
39.	Driveaway Safety Kit	1
40.	Vinyl manual pouch for storage of all operator and parts manuals	1
	Electrical Accessories	
41.	Lights and reflectors in accordance with FMVSS #108 lighting package. (Complete LED, including LED reverse lights)	1
42.	4-Corner Strobes, Amber, LED, Two (2) Surface Mounted Lights In Grille, Two (2) Round Lights At Rear	1

Quote Number: 826303 - 1
Altec, Inc.

Item	Description	Qty
43.	Remote Spot Light, LED, Permanent Mount with Wireless Dash Mounted Controls and Programmable Wireless Remote	1
44.	Strobe Beacon, Amber LED, With Brush Guard, Installed On Post At Front Of Body, One (1) Each Side (Standard) (Federal Signal #420221-02)	1
45.	Dual Tone Back-Up With Outrigger Motion Alarm	1
46.	PTO Hour Meter, Digital, with 10,000 Hour Display	1
47.	6-Way Trailer Receptacle (Pin Type) Installed At Rear	1
48.	Ford Upfitter Switches (Supplied with Chassis)	1
49.	Power Distribution Module Is A Compact Self-Contained Electronic System That Provides A Standardized Interface With The Chassis Electrical System. (Includes Operator's Manual)	1
50.	Install secondary stowage system.	1
51.	Install Remote Start/Stop system in Final Assembly.	1
52.	Install Outrigger Interlock System	1
53.	Heavy Duty Secondary Stowage Pump	1
54.	PTO Indicator Light Installed In Cab	1
	Finishing Details	
55.	Powder Coat Unit Altec White	1
56.	Finish Paint Body Accessories Above Body Floor Altec White	1
57.	Altec Standard; Components mounted below frame rail shall be coated black by Altec. i.e. step bumpers, steps, frame extension, pintle hook mount, dock bumper mounts, D-rings, receiver tubes, accessory mounts, light brackets, under-ride protection, etc. Components mounted to under side of body shall be coated black by Altec. i.e. Wheel chock holders, mud flap brackets, pad carriers, boxes, lighting brackets, steps, and ladders.	1
58.	Additional Black Undercoating, Applied per Altec Standard	1
59.	Apply Non-Skid Coating to all walking surfaces	1
60.	English Safety And Instructional Decals	1
61.	Vehicle Height Placard - Installed In Cab	1
62.	Placard, HVI-22 Hydraulic Oil	1
63.	Dielectric test unit according to ANSI requirements.	1
64.	Stability test unit according to ANSI requirements.	1
65.	Focus Factory Build	1

Altec

Quote Number: 826303 - 1
Altec, Inc.

Item	Description	Qty
66.	Inbound Freight	1
67.	Stock Unit	1
68.	Stock Unit Sold To Customer	1
	Chassis	
69.	Altec Supplied Chassis	1
70.	2022 Model Year	1
71.	Ford F550	1
72.	4x4	1
73.	84 Clear CA (Round To Next Whole Number)	1
74.	Regular Cab	1
75.	Chassis Cab	1
76.	Chassis Color - White	1
77.	Chassis Wheelbase Length - 169	1
78.	Ford 6.7L Power Stroke Diesel	1
79.	330 HP Engine Rating	1
80.	Ford Torqshift 10-Speed Automatic Transmission (w/PTO Provision)	1
81.	GVWR 19,500 LBS	1
82.	7,500 LBS Front GAWR	1
83.	14,706 LBS Rear GAWR	1
84.	225/70R19.5 Front Tire	1
85.	225/70R19.5 Rear Tire	1
86.	Hydraulic Brakes	1
87.	Park Brake In Rear Wheels	1
88.	Ford E/F250-550 Single Horizontal Right Side Exhaust	1
89.	63C - Aft Axle Frame Extension	1
90.	98R - Operator Commanded Regeneration (OCR)	1
91.	No Idle Engine Shut-Down Required	1
92.	50-State Emissions	1

Quote Number: 826303 - 1
Altec, Inc.

Item	Description	Qty
93.	Clean Idle Certification	1
94.	Ford 40 Gallon Fuel Tank (Rear)	1
95.	Ford 7.2 Gallon DEF Tank (Mid Mount)	1
96.	AM/FM Radio	1
97.	Bluetooth	1
98.	Air Conditioning	1
99.	Cruise Control	1
100.	Keyless Entry	1
101.	Power Door Locks	1
102.	Power Windows	1
103.	Tilt Steering Wheel	1
104.	Block Heater	1
105.	Limited Slip Rear Axle	1
106.	Power Mirrors with Heated Glass	1
107.	Trailer Brake Controller (Factory Installed)	1
108.	Vinyl Split Bench Seat	1
	Additional Pricing	
109.	Standard Altec Warranty: One (1) year parts warranty, one (1) year labor warranty, ninety (90) days warranty for travel charges, limited lifetime structural warranty	1

Altec Industries, Inc.

BY _____

Hannah Elizabeth Bridges

Notes:

We Wish To Thank You For Giving Us The Pleasure
And Opportunity of Serving You

UTILITY EQUIPMENT AND BODIES SINCE 1929

Commercial
591 Chester Road
Delta, British Columbia
Phone: (604) 526-6126
Fax: (604) 526-1746

Quotation

Customer: Yukon Energy – Sample Spec

Quote Date:

Contact:
Phone:
Email:

Salesperson: Adam Lowe

QUANTITY	DESCRIPTION	Quote Number: Sample
	AERIAL DEVICE	
1	One (1) New Terex Hi-Ranger LTM40 Articulating / Telescoping Aerial Device providing a working height of 44.5 ft (13.6 m) and a side reach of 30.7 ft (9.4 m) with a platform. Unit will be mounted behind the cab. Design Criteria: * Design criteria is in accordance with current industry and engineering standards applicable and accepted for structural and hydraulic design. Platform Leveling: * Leveling is provided by a master/slave cylinder system. * A control a both the upper and lower control is provided. Upper Controls: * "Control-Plus" single stick controller (4-function) * Non-metallic control handle * Dielectrically tested for limited secondary protection between the valve and handle. * May provide limited secondary protection for operator depending on condition and cleanliness. * Not rated for electrical protection, although it may provide limited secondary protection. * Not intended to replace safe work practices or primary protection such as cover-up and personal protection equipment. * Enable lever must be actuated before operation. * Controls lower boom lift, upper boom lift, boom extension and rotation. Insulated Engine Stop / Start: * Controlled from platform and lower control station. Lower Control: * Individual control levers are located in an accessible location on the turntable. * The lower controls activate boom lift, boom extension, platform leveling, and rotation. * An upper/lower control selector provides override of platform controls, along with an emergency stop. Lower Boom: * Constructed of high strength, rectangular steel tube with a rectangular bi-axial epoxy resin filament wound, high strength fiberglass insert providing an insulation gap of 12 inches. * The lower boom articulation is from -5 to 90 degrees. Upper Boom: * Aerial device upper boom is constructed of high strength steel. * The upper boom has an articulation of -20 to 80 degrees * A boom rest with a cam style tie down strap is provided. Second Section Boom: * The second section boom is constructed of high strength filament wound fiberglass.	

QUANTITY	DESCRIPTION	Quote Number: Sample

* Extension of the second section is accomplished by a hydraulic cylinder.
* The upper boom has a total insulation gap of 14 inches retracted and 61 inches extended for end mount platform.
* (Note: Side mount platform will be reduced by 12 inches.)
* Tapered non-metallic rollers mounted at the end of the second section boom support the fiberglass boom under load minimizing scratches and abrasions. The sides of the fiberglass boom are supported and guided by non-metallic rollers to reduce tracking.

Lower Boom Cylinder:
* Single, threaded end gland design, double acting hydraulic lift cylinder equipped with integral holding valves.

Upper Boom Cylinder:
* A double acting hydraulic lift cylinder equipped with integral holding valve is provided.

Extension Cylinder:
* The boom cylinder is of threaded end gland design.
* The cylinder is equipped with integral holding valves to prevent creep and hold the boom is position in the event of hose failure.

Boom Interlock:
* To operate the boom the outriggers must be extended.

Pedestal:
* The pedestal is of welded high-strength steel construction.
* The pedestal top plate is machined from a single piece of plate.
* The top plate bearing surface is pre-machined and inspected after weld to provide a flat mounting surface for the rotation bearing.

Turntable:
* The turntable is constructed of side plates with an offset configuration to provide maximum strength.
* The steel bottom plate has provisions for attaching the outer race of the rotation bearing.

Continuous Unrestricted Rotation:
* A hydraulic rotary manifold provides a rotating oil distribution system for continuous and unrestricted rotation.
* One 3/8 inch hydraulic port is available for options.
* Self-locking worm gear rotation drive is provided and equipped with bi-directional motor.
* A 7/8 inch external hex shaft allows for manual rotation.
* A minimum 4-channel electric collector ring is provided.

Rotation Bearing:
* The rotation bearing is a heavy-duty "shear ball" bearing with external gear teeth utilizing polished alloy steel balls.
* Both the inner and outer races are made from high-strength alloy steel and are heat treated to provide maximum life.
* High strength grade 8 bolts attach the inner and outer races to the pedestal and turntable.

ANSI & CSA Rating:
* Aerial device is designed as a Category C machine and is dielectrically tested and rated for operation up to 46,000 volts AC per ANSI/SIA A92.2-2009 and CSA C225-10.

Hydraulic System:
* Full pressure, open center hydraulic system.
* A 20 gallon external hydraulic oil reservoir is provided with a 60 mesh filler screen, baffles, 100 mesh suction screen with bypass, clean out access hole, dip stick and shut off valve.
* A spin on type 10 micron return line filter is provided.
* A relief is also provided.
* Hydraulic hoses are equipped with permanent type fittings.

Miscellaneous:
* All metallic components of the complete aerial device are prime painted.
* The fiberglass upper boom, boom inserts, platforms, and covers are white.
* Two complete manuals providing operation and maintenance procedures, and a replacement parts listing.

QUANTITY	DESCRIPTION	Quote Number: Sample
	* Warning decals provided with unit.	
1	Pedestal * Sized for F550 Super cab Chassis	
1	Platform 24 x 30 x 42: * One (1) person, end mounted, fiberglass platform with a rated capacity up to 400 lbs. * Includes one outside access step with slip-resistant surface. * A safety harness with lanyard.	
1	Hydraulic Platform Rotator: * For end mount platform. * Allows 180-degrees hydraulic rotation and is controlled at the upper controls.	
1	Insulated Platform Liner with Step for 24" x 30" x 42" Platform: * Tested at 50 KV AC.	
1	Vinyl Platform And Control Cover For 24" x 30" Platform: * Waterproof with internal elastic cord around edge and external elastic cord around control cover.	
1	Dual Hydraulic Tool Outlets At Platform With Flow Control: * Installed at the platform to accommodate two open center hydraulic tools. * Provides 5 GPM at 2250 psi at engine idle.	
1	Auxiliary Power: * Allow the operation of any function for a time period limited by the battery life. *Includes 12 volt electric motor for use on a 12 volt chassis. Note: This includes a switch for activation at pedestal for electric or air function.	
1	Platform Rest Saddle with a padded rest. * Provides platform support during road travel	
1	Top mount, Removable 800 lb. Jib/Winch * Levels with platform. * Hydraulic articulation from -20 to 70 degrees. * 51" load radius from the platform shaft. * Manual extension 17". * Maximum jib capacity of 800 lb. * Includes up to 65' of 3/8" winch rope and hook. * Low profile stowed position of 16" and the boom can still utilize its full range of motion down to -40 degrees. * Poppet valve protection of fiberglass boom. Stops boom operation if jib contacts fiberglass boom. * Jib/winch is removable and comes with ship loose socket to store the jib/winch when removed (placed during installation) *King post attached to jib. Low profile socket when jib removed to minimize interference and overall height.	
1	Model 438506 Standard Duty Low Profile A-Frame Outriggers: * Hydraulic double acting outriggers including integral holding valves. * 135.8 " Spread pin to pin and 147.8 " to outside of pads at 3.1 " penetration and 32 " frame height. * 7 " x 12 " Stabilizer pads.	
1	Control For 1-Set Of Outriggers (Open center systems): * Recessed at rear of truck each side for ease of view for outrigger placement. * Includes switches and alarm for outrigger in motion alarm.	
1	Mounting Kit: * Behind cab mount for use with (1) set of outriggers and tie plates.	
1	SAG Light opening in outrigger leg for 1 set of Outriggers: * Includes wiring and switch. * Opening only, no light.	
1	Sight Gauge With Thermometer:	

QUANTITY	DESCRIPTION	Quote Number: Sample
	* Mounted within an aluminum body to protect sight tube. * Installed on end of hydraulic oil reservoir. * Thermometer has a range of 0-300 degrees Fahrenheit.	
1	Pump for systems requiring 8 gallons per minute: *Fixed displacement vane pump providing 5 gallons per minute at 950 engine rpm and 8 gallons per minute at 1370 engine rpm with a 98% PTO. * Typically used for transmissions required an elevated speed for PTO operation. Note: LTM product 6 gallons per minute at 900 engine RPM.	
1	Metric and Imperial Load Chart	
	UTILITY BODY	
1	Brand FX BFXB 84T Line Body with C2 Walk-Up – 53130-0007 * Overall Pack Length 132" * Overall Width 94" * Floor Width 58" * Overall Height 48 1/2" * Mounting Height: 30" * Pack Depth 18" * Stainless Steel Hinges and Slam Locks * Vinyl Covered S/S cable door stops * Non Skid Compartment Tops * Full length Aluminum Drip Rail * Clear Vinyl Rock Guards * Automotive grade Bubble gasket * One piece Molded Doors with Automotive finish both sides * Recessed Door Jambs * Flow through Ventilation System * Hot-stick Door Street Side Street Front Compartment * (5) Locking Swivel Hooks 2-1-2 mounted high * (5) Locking Swivel Hooks 2-1-2 mounted Low * Outrigger Cutout Street Front Compartment #2 * 3 Adjustable Shelves with Dividers * Dri-Dek Compartment Liner Street Horizontal Compartment * 1 Adjustable Shelf * Dri-Dek Compartment Liner Street Rear Compartment * 3 Adjustable Shelves * Dri-Dek Compartment Liner Curb Side Front * 3 Adjustable Shelves with Dividers * Dri-Dek Compartment Liner * Outrigger Cutout Curb Front #2 * Walk-Up Stairs – Grip-strut * Access to Deck Curb Horizontal * Fixed Shelf on either side of three pull-out drawers * Fixed Shelf on bottom with Dividers	

QUANTITY	DESCRIPTION	Quote Number: Sample
	* Dri-Dek Compartment Liner Curb Rear Compartment * (5) Locking Swivel Hooks 2-1-2 mounted high * (5) Locking Swivel Hooks 2-1-2 mounted Low * Dri-Dek Compartment Liner LED Flexglo Compartment Lighting * Top & Sides of Doors Wheel Well Liners – Aluminum. Fully covering Fiberglass in front, behind and on top of Wheel Wells * Extends under Verticals by 3 inches Wheel Chock Holders * Mounted Curbside at Fenders Aluminum ladder rack mounted on the street side compartment top	
	INSTALLATION & ACCESSORIES	
1	Install Aerial Device Behind Cab And Install All Associated Components: * Final test and inspect completed unit including stability and dielectric testing per manufacturers requirements, ANSI/SIA A92.2-2001 and CSA C225-10.	
1	Hose and fittings to connect the hydraulic system from the oil reservoir to the pump and unit.	
1	Miscellaneous Shop Supplies.	
1	Commercial Custom Aerial Boom Rest * Heavy Gauge Steel Construction	
2	Stainless Steel Grounding Point * 3/4" Stainless Steel round bar * Welded to bottom of outrigger leg	
1	Outrigger controls protection cover * Controls to be enclosed with Aluminum box to protect them from tire and road debris	
30	Hydraulic Oil * ESSO Univis HVI 13	
1	Power take off, 6-bolt, with indicator light for automatic transmission.	
1	Relocate factory DEF Tanks * Required procedure on Ford F550 chassis	
1	Rear towing Recovery Eyes 50,000 pound capacity - used in pairs only * Closed eye 1 1/2" diameter hole * Material - 1" 50,000 PSI steel * One (1) Left & One (1) Right - vertical orientation * Mounted directly to frame rail * 5" W X 16" L * Engineered rating - see 2285-1	
1	Heavy Duty Aluminum Checker Plate Deck	
4	Deck "D" Rings * Welded to cross members * Flush mount	
1	Aluminum Tail Shelf * Checker plate top surface	

QUANTITY	DESCRIPTION	Quote Number: Sample
	* Aluminum grab handle mounted on top surface	
1	Vise bracket that fits vertical in a pocket. * 2 inch receiver * Mounted at curb side of Tailshelf	
1	Set chassis parameters * Programming of the Multi-Plex circuits * Writing the programming for the ECU * Program Throttle and PTO * Program Stop/Start * Program all safety controls.	
1	License Plate Lamp * LED * Meets SAE J587 * Complete with bracket	
1	VMAC Throttle Commander * Maintains rpm over engine torque loads * 12-Volt activated * 3 preset programmable rpm settings	
1	Wired-Rite system for chassis.	
1	Truck-Lite LED 7-lamp DOT Lighting Package: * Complies with CMVSS 108 * Includes required lights, junction box and wiring harness	
1	Golight Stryker Search Light * Wireless Remote Controlled Operation * 370° Rotation x 135° Tilt * 500,000 Candle Power, 5.5 Amps * UV Ray and Saltwater Resistant * Integrated 12V DC High-Torque Motors * Weatherproof for Land and Sea Applications * Waterproof Remote Transmitters * R.F. Programmable Super Heterodyne Receiver * 5-Year Limited Warranty * Mounted on hood of vehicle	
2	Amber strobe light with 6" lens and mounting bracket. * Mounted on Boom rest behind Cab * 360 degree visibility	
2	Truck-Lite 60122Y LED amber oval strobe light offering dual or quad flashing patterns. * Flush mounted at rear of body * Switched in Cab	
2	Strip LED lighting mounted in loadbed both sides Extruded aluminum drip rails mounted above lighting	
1	Back-up alarm to sound when the vehicle is shifted into reverse.	
1	Prowatt 3000 Inverter is designed for high power and industrial applications. Its high surge output is ideal for heavy-duty loads or multiple smaller AC loads. It can often be used in place of a generator for large intermittent loads. Product Features * 3000 watts maximum, 5000 watt surge capability * Built-in LED display for DC volts and amps * Supports addition of external AC outlets	

QUANTITY	DESCRIPTION	Quote Number: Sample
	* Single GFCI receptacle for safe operation and hardwire AC connections * Heavy duty terminals for trouble-free battery connection * Includes ON/OFF remote switch * Two year warranty	
1	400 Amp fuse Product Features * DC rated, UL listed high current Class-T fuse * Protective clear removable cover protects against inadvertent contact * Dual post design to reduce arcing * Easy to change, user replaceable fuses	
1	Battery Interconnect * 12V * 100 Amp * Uni-Directional /w aux start	
2	Duplex GFI Outlet * Mounted in NEMA 4 Junction Box	
1	Inverter/Battery Cable Package * Required to connect the Vehicle Batteries with the Inverter * Includes all necessary Hardware	
1	Bin Heater mounted in SS2 – with switch in cab Engine coolant type – provide air access via 3” holes to SS1 & Hot stick shelf.	
1	Paint completed Unit one solid colour (white) * Aerial unit powder coated Terex White * Fiberglass service body to be white Gelcoat * Cargo area to be coated with spray-on non-slip coating * Side pack tops to non-slip coated * Front surface of outriggers to be coated with spray on coating * Body under carriage, rear hitch assembly and bottom side of front outrigger sub frame to be undercoated with petroleum based coating	
2	Level indicator, inclinometer, +/- 5 Degrees.	
2	Mud Flap * Plain Black - 24" x 30" * Includes mounting hardware	
1	One pair of anti-sail brackets for mud flaps.	
1	Cone Holder * Deck Mounted.	
2	Outrigger Pads - wood * 24" x 24" x 2"	
2	Outrigger Pad Holder * For Single Outrigger Pads - 24" X 24" * Mounted under body in close proximity to the Outriggers	
2	Wheel Chock * Standard Rubber Type	
1	DOT Triangle Reflector Kit.	
1	First Aid Kit – BC Level 1 * Ship loose.	

QUANTITY	DESCRIPTION	Quote Number: Sample
2	5lb ABC Fire Extinguisher * Includes mounting bracket. *Ship loose – customer to install	
1	CMVSS Inspection. * Scale Ticket * Road Test * Fuel Truck.	
1	Dielectric Testing to CSA Standards * Fibreglass Boom Sections only * Auxiliary Jibs not included	
1	Stability Testing to CSA standards * Weight studies will be provided for customer approval prior to start of assembly.	
1	Orientation of Completed Unit with Customer * This is for the customers personnel * Certified Trainer reviews the operation of the new unit with crew * Safety items are discussed * Maintenance schedules are discussed * Classroom discussion followed up with a hands on Orientation Session * Orientation is performed on Customers Site * Up to one day in length.	
1	Chassis (Customer Supplied) * Quote is based on clear frame back of cab, customer supplied chassis. * Quote does not include any modification to chassis including but not limited to suspension modifications, axle relocation, relocation of batteries, air brake components, fuel tanks or other items not covered by this quotation. * Prior to order we required a detailed chassis specification provided by original manufacturer to confirm suitability of vehicle.	
	CHASSIS	
1	Ford F550 Super Cab 4x4 Chassis * 84" CA * 6.7 Liter Diesel Engine * 6 speed Automatic Transmission * 4.88:1 ratio differential * 19,500 GVWR * Customer supplied Specifications	

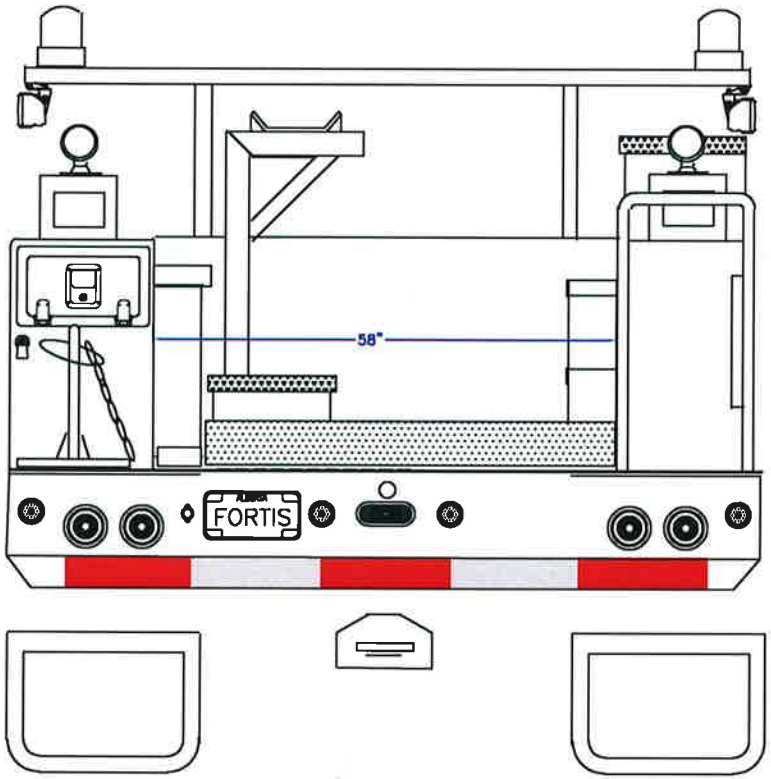
Budgetary price per unit: $261,000.00

Customer must fill out the information below before the order can be processed…

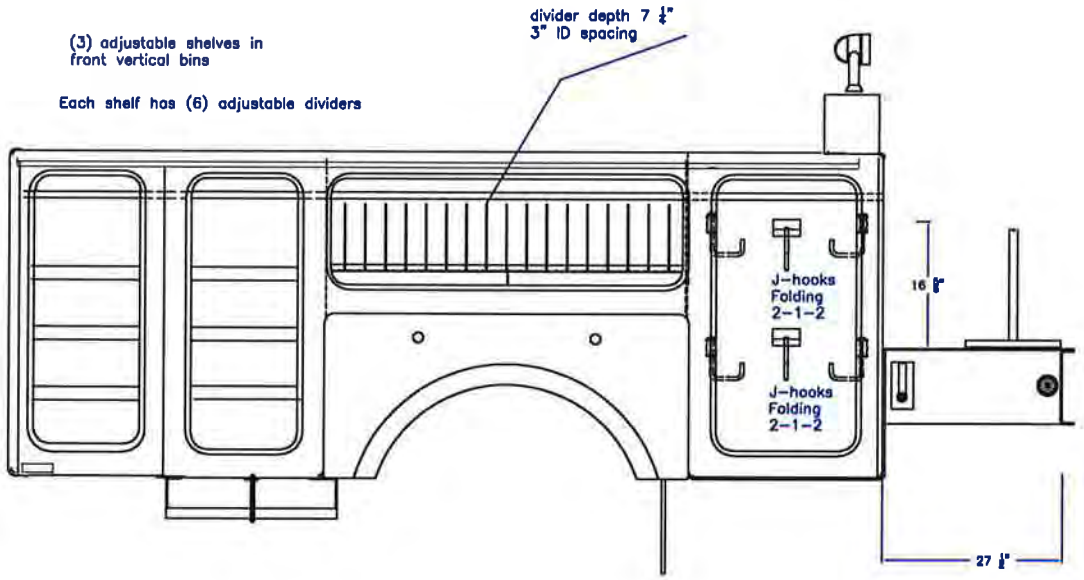
Accepted by:	
Date:	
P.O. number:	

- Quote is valid for 15 days from date of quote.
- All prices are in Canadian Funds.
- Quoted price does not include any applicable taxes.
- Terms are Due upon Receipt unless prior credit arrangements are made at the time of order.
- FOB Yukon.

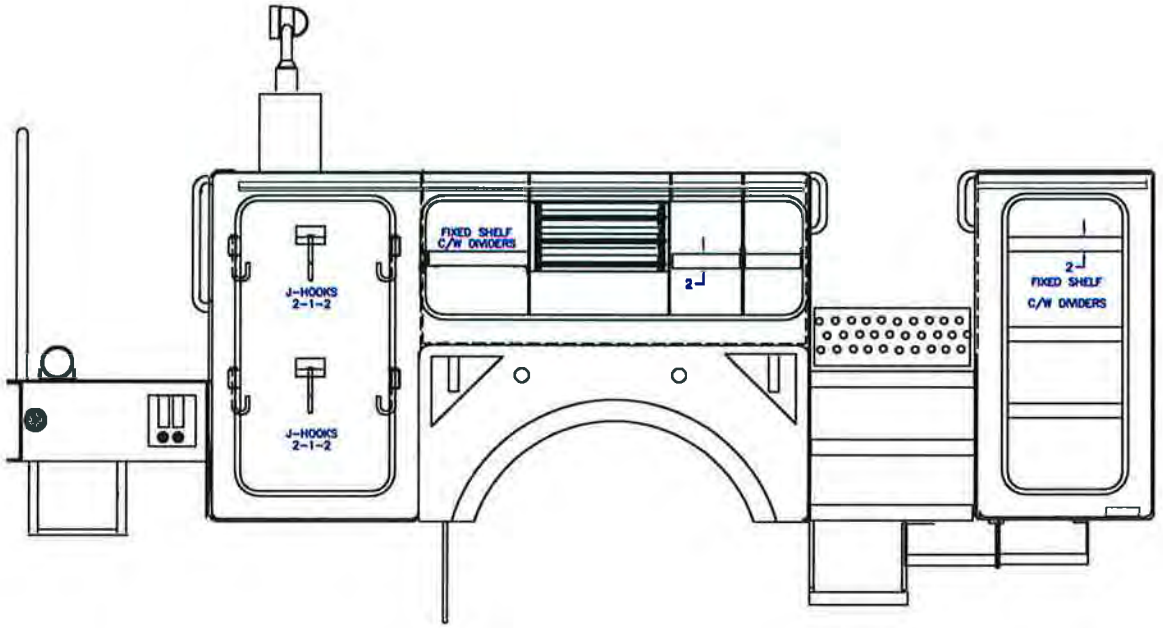
- Please note if chassis is furnished, it is as a convenience and terms are Net Due on Receipt of Chassis.



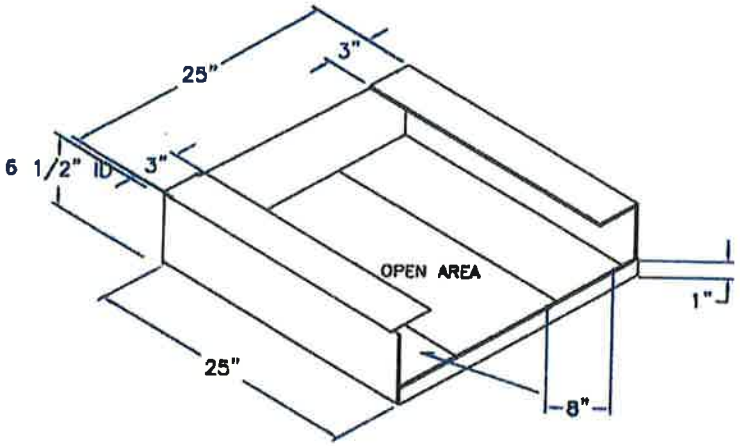
REAR VIEW 84" C-A
Nov. 21 / 19



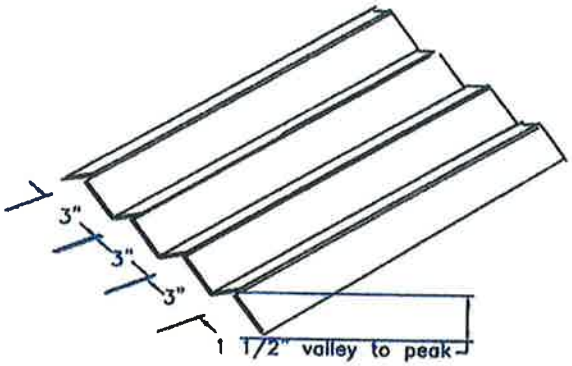
STREET SIDE
Nov. 25/19



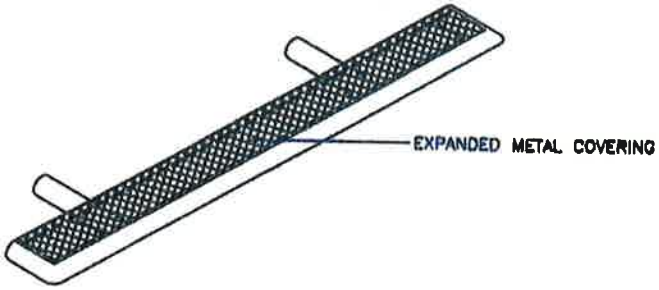
CURB SIDE
Nov. 21/19



OUTRIGGER PAD HOLDER
3/16" Aluminum

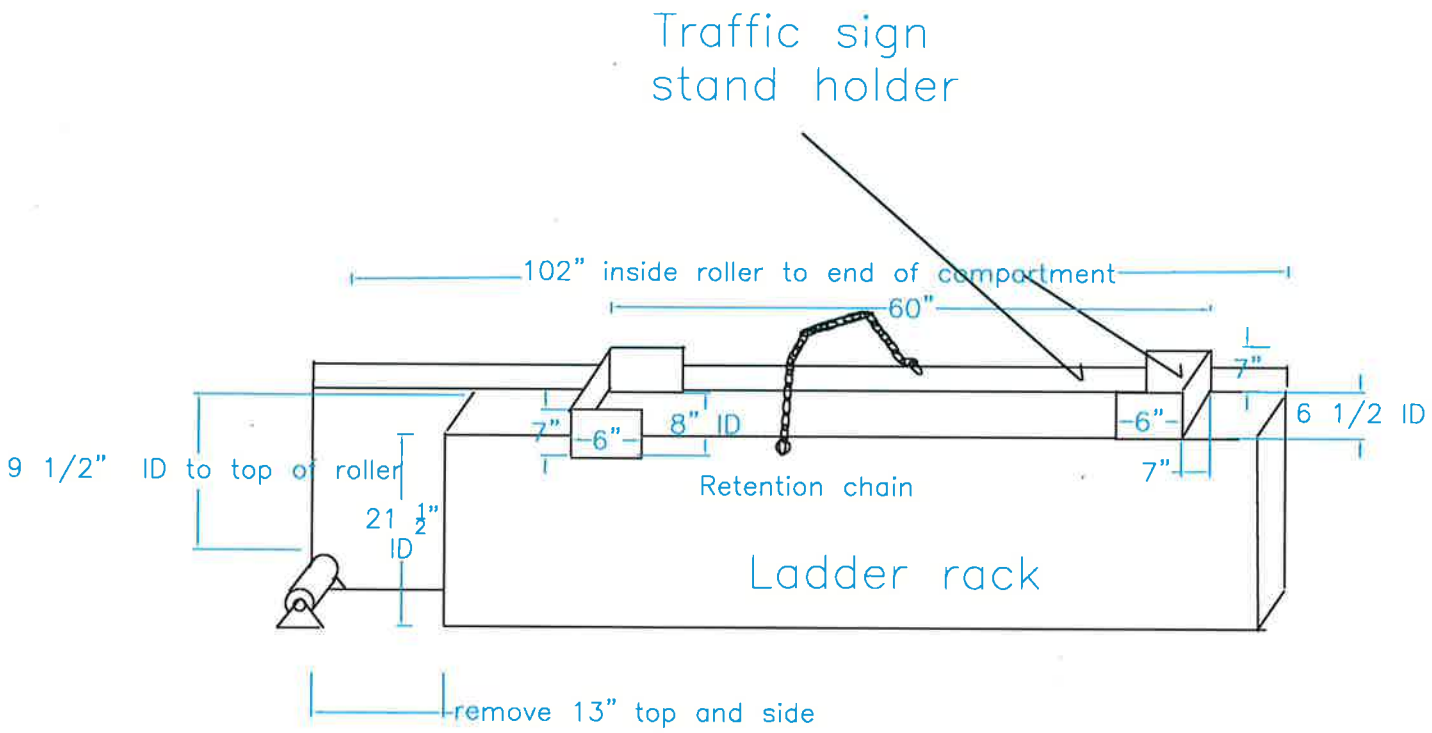


STREETSIDE HOTSTICK TUBE TRAY
1/8" Aluminum



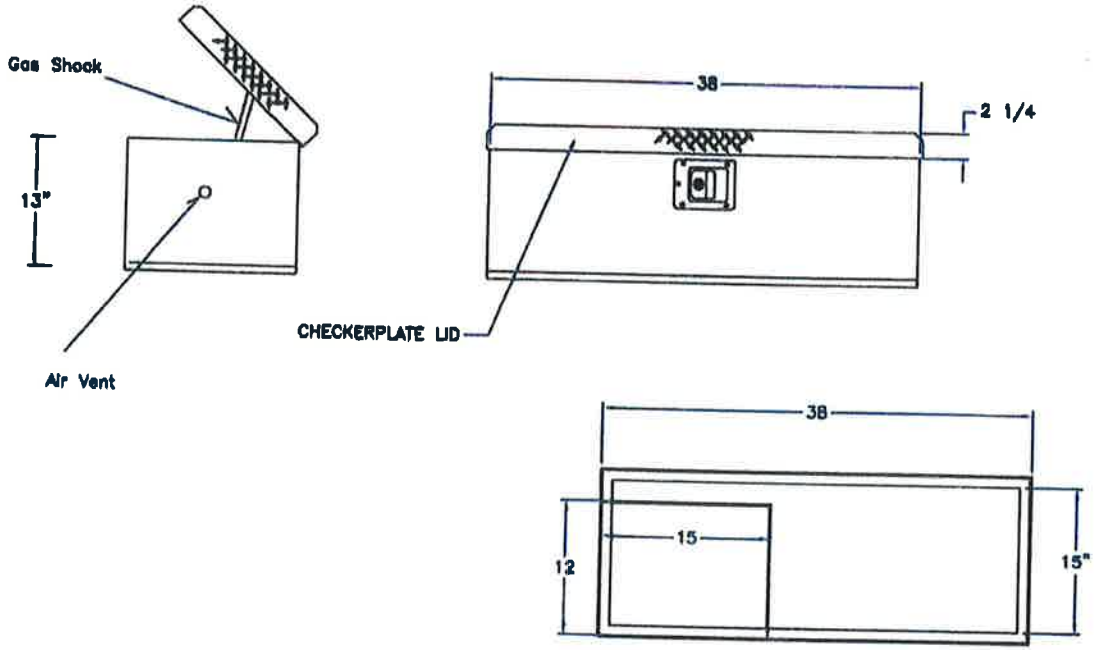
RUNNING BOARDS

Drawing #1
Nov. 10 / 17



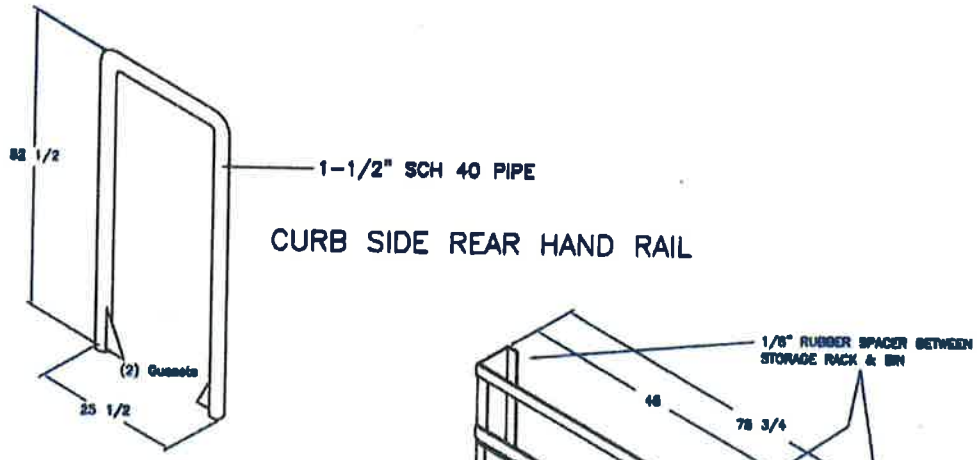
Drawing #2

Oct. 29 / 18
Revised March 03 / 2019



Chain saw Box
1/8" ALUMINUM

Drawing# 3
Nov. 10 /17



CURB SIDE REAR HAND RAIL

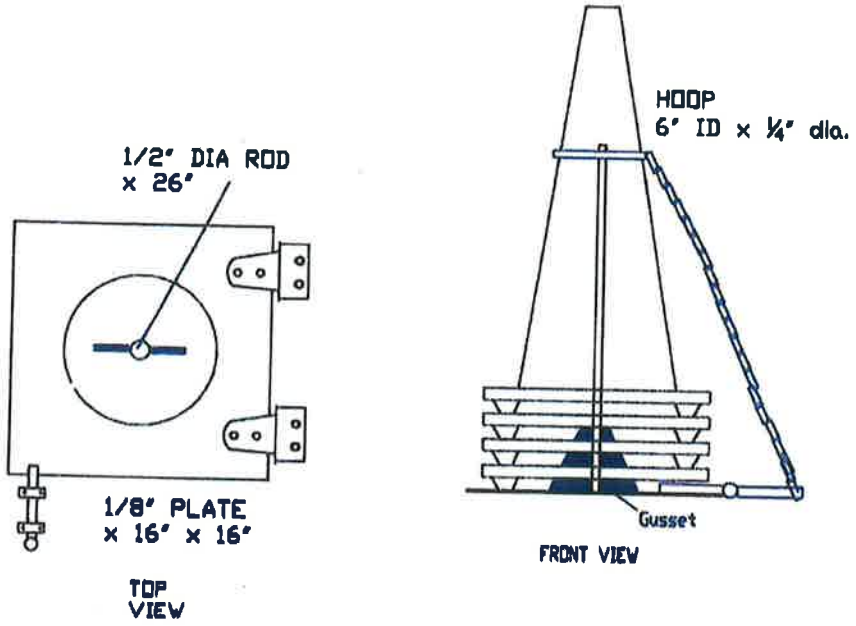
WIRE RACK

(TO BE CONSTRUCTED FROM 1/8" ALUMINUM)

Measurements in Inches

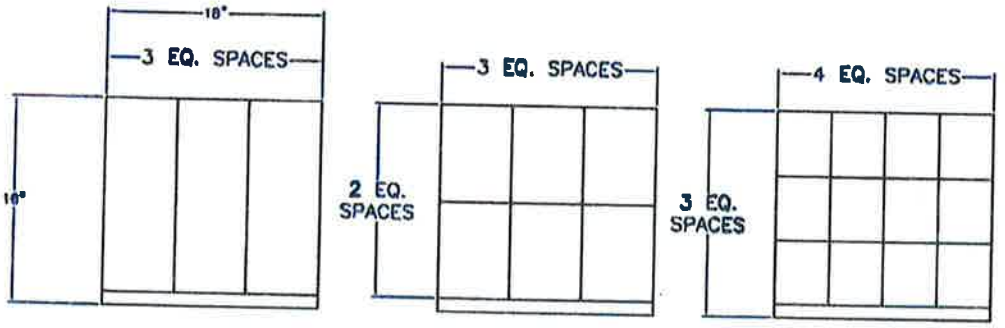
Drawing #4

Nov. 09 / 17



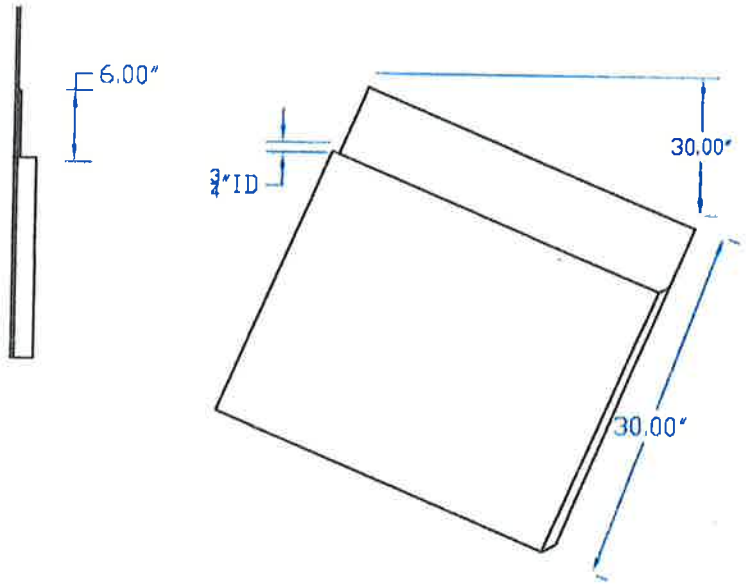
Cone Holder

Drawing #5
Nov. 10 / 17

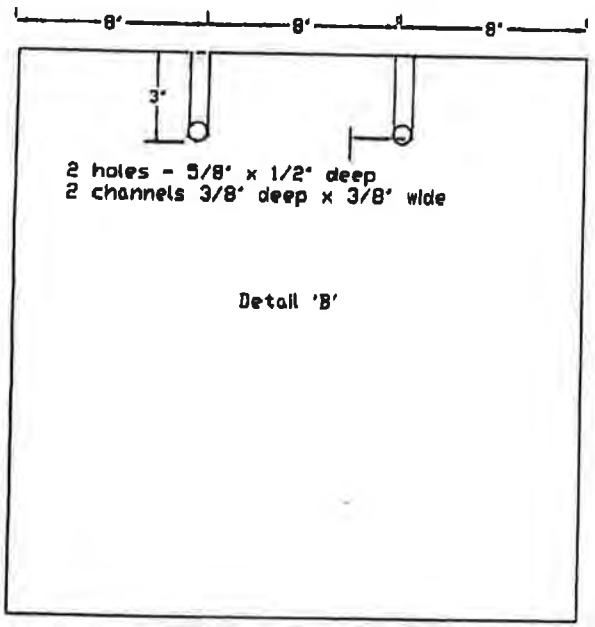


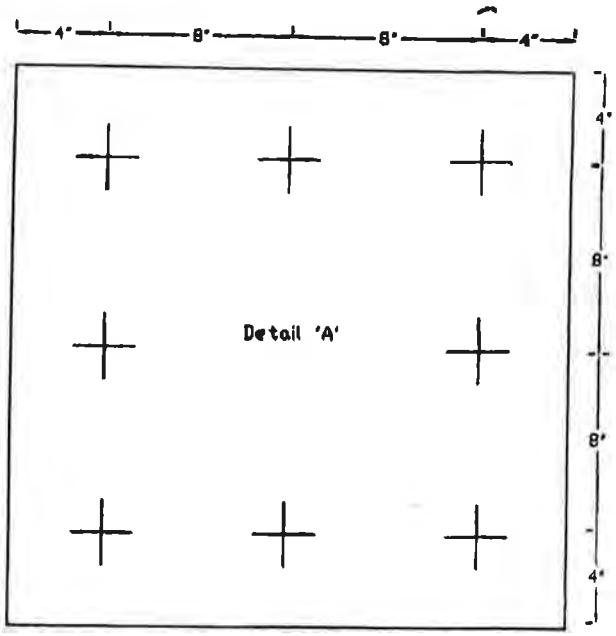
Drawer height 3"

Drawing #6
Nov. 09 / 17



Drawing# 7
Envelope sign holder
Aug. 16, 2017
rev. May 16, 2018





Requirements

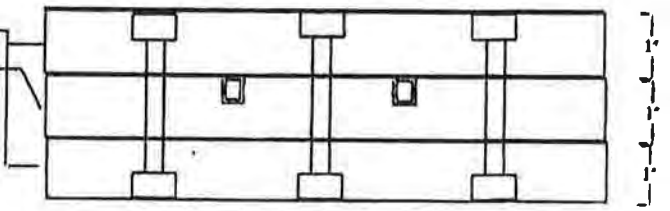
2 - 1" x 24" x 24" plywood with 8 holes, centered as in Detail 'A'.
Drill 8 holes 9/16" x depth of plywood.

1 - 1" x 24" x 24" plywood drilled and channeled as in detail 'B'
Then drill 8 holes 9/16" x depth of plywood as in detail 'A'.

8 - Hex Bolts 1/2" by 2 3/4".

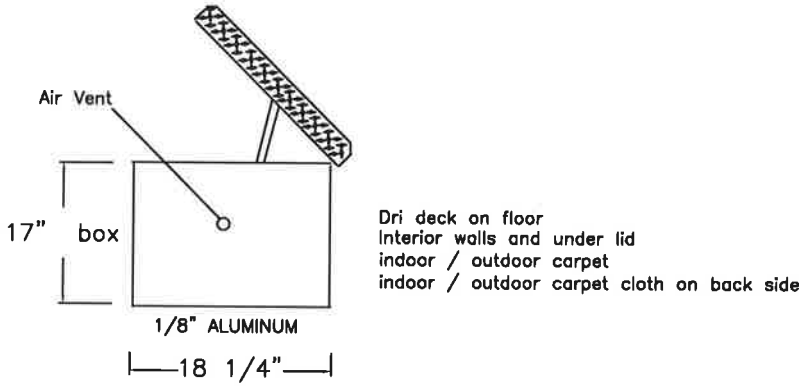
1 - Piece of rope, 3/8" with knots at each end. Long enough to press knot into each hole run up channel and leave approximately 11" outside for a handle

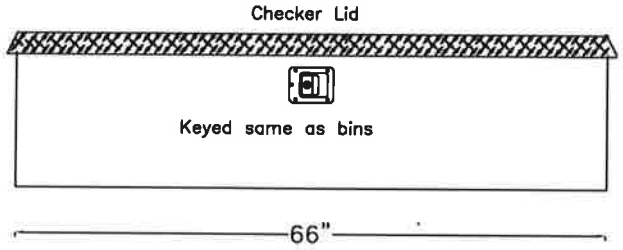
- Allpieces of wood to be glued together.
- All weathered sides of wood to have Thompsons Weather Seal applied.



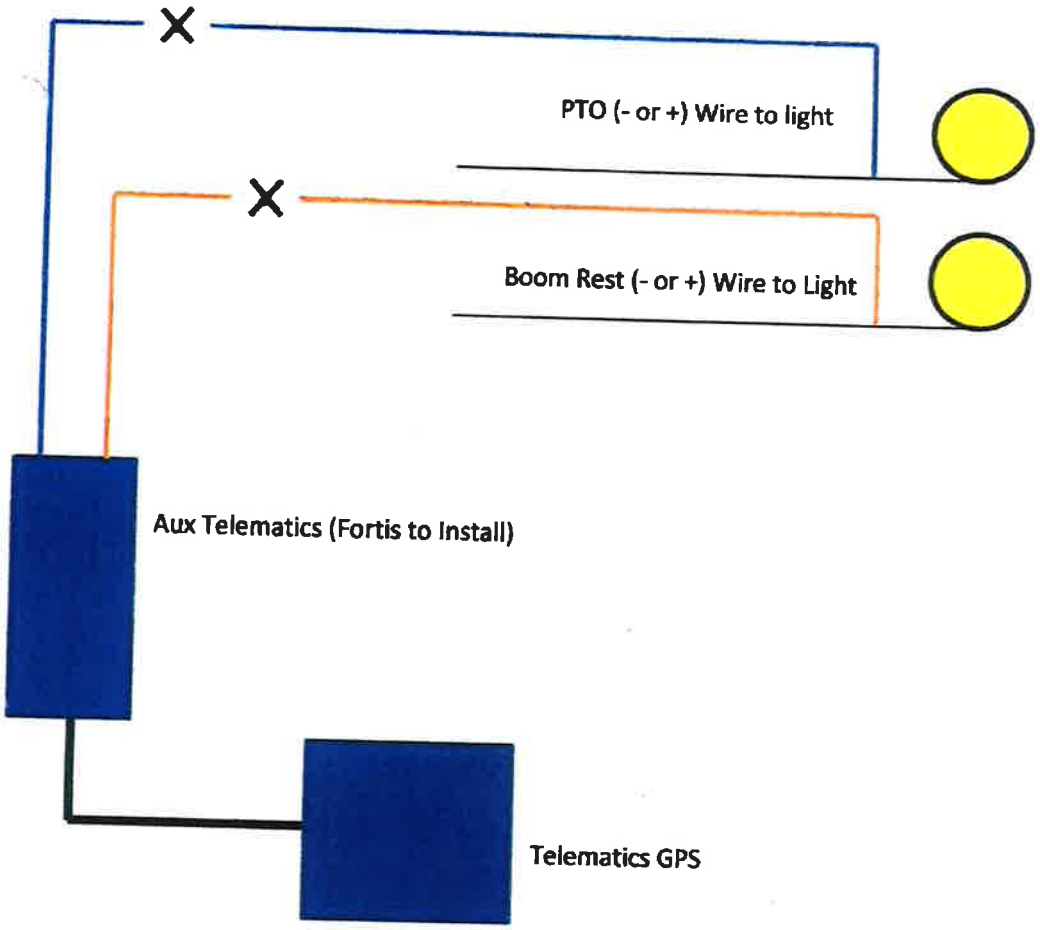
Detail 'C'

OUTRIGGER PADS
rev. 10/25/2000





Rubber Cover Bin



Supply 2 wires for boom out of rest wiring and PTO engaged wiring

PTO engaged wiring shall be supplied as a **BLUE** wire off the ground or positive wire from the PTO IQ light on the dash. Run wire to the OBD reader area, Fortis Techs will make connection to Telematics; ensure that wire is labeled **"Telematics PTO".**

Boom out of rest wiring shall be supplied as an ORANGE wire off the ground or positive wire from the Boom out of rest IQ light in the dash. Run wire to the OBD reader area, Fortis Techs will make connection to Telematics; ensure that wire is labeled **"Telematics boom out of rest".**

Our Telematics system can run on both positive and ground signals

Versalift VST-40-MHI Aerial
Ford F550 4x4

CHASSIS SPECS & BODY SPECS

Cab And Chassis:
Ford F-550 4X4 Cab And Chassis With A CA Of 84”
GVWR: 19,500 Lbs.
6.7L 4V OHV Power Stroke V8 Turbo Diesel Engine
Torqshift 6-Speed Automatic Transmission
4.88 Limited Slip Axle.
Air Conditioning.
Engine Block Heater
225/70RX19.5G BSW Traction Tires.
Radio: AM/FM Stereo Includes 4 Speakers.
HD Vinyl 40/20/40 Slit Bench Seat
Trailer Brake Controller
Operator Commanded Regeneration
Painted Oxford White.

Dakota Bodies 132” Long X 40” High X 94” Wide Service Body:
30 Inch Aluminum Tread Plate Platform Extension
LED Lighting Package Installed In Tail Shelf.
Cable Access Step At Rear And Side Access.
Two (2) Chrome Grab Handles At Side Access And
Two (2) Pool Type Grab Rails At Rear Tail Shelf.
Wheel Chock Storage And Outrigger Pad Holders.
Push/Pull Rod Lock System
40” High Street Side Compartments As Follows
1st Vertical: Two (2) Adjustable Shelves With Dividers And Cutout For Outrigger
2nd Vertical: Two (2) Adjustable Shelves With Dividers
Horizontal: One (1) Removable Shelf With Dividers
Rear Vertical: Two (2) Adjustable Shelves With Dividers
Hot Stick Shelf With Rear Access Door.
40” High Curbside Compartments As Follows
1st Vertical: Two (2) Adjustable Shelves With Dividers And Cutout For Outrigger
2nd Vertical: Grip Strut Access Steps To Bed Area With Removable Composite Side Gate.
Horizontal: One (1) Adjustable Shelf With dividers
Rear Vertical: Five (5) fixed material hooks 1-3-1

EQUIPMENT SPECS

Versalift VST-40-I, Insulated 40Ft. 4 In Telescopic Aerial Platform Lift, 45Ft. 4 In Working Height With A Horizontal Reach Of 30 Ft.2 In. To Include The Following Items:

Standard Platform Capacity Of 400 Lbs
Right Hand Single Stick Control.
Hydraulic Platform Rotator.
Hydraulic Dual Arm Articulating Jib Pole And Winch Package For Up To 1,000 Lbs. Capacity, Including Insulated Jib Pole
360 Degree Continuous Rotation Including Slip Rings
Six GPM Open Center Hydraulic System With A 3000 PSI Operating Pressure
Side Mounted Telescopic Upper Boom Allows Low Stowing Of Platform.
ANSI A92.2 Requirements For Category C 46KV And Below.
Chassis Insulating System (Fiberglass Lower Boom Insert) Providing 12 In. Insulation Gap And Including Accommodations To Bridge Insulation Gap For Testing Per ANSI 92.2
Electrogard And Inner Boom Finished With White Urethane Paint Over A White Gel Coat.
Non-Lube Bearings Used Throughout.
One Set Of Hydraulic Tool Outlets With Pressure Limit Valve. Valve Can Be Adjusted From 1000 To 2500 PSI.
Sub Frame Mounted Main A-Frame Outriggers With Pivot Feet, Two Control Valves, And A Selector Valve.
Outrigger Boom Interlock System For Main Outriggers
Integral Reservoir With A 17-Gallon Capacity And Dual Sight Gauges.
Side Mounted Closed Heavy-Duty One-Step 24 In. X 30 In. X 42 In.
Fiberglass Platform Including Platform Liner And Vinyl Cover.
Individual Full Pressure Controls At The Turret Actuate All Boom Functions And Is Equipped With A Selector Valve To Override Upper Controls
12 Volt DC Backup Pump Providing Power To All Boom Functions.
2 speed Throttle Control.
Start/Stop at upper controls
Safety Harness And Lanyard
Two Operator Manuals And Service Manuals

888-684-8146 www.customtruck.com

ASK ABOUT THE CUSTOMIZED AND FLEXIBLE LEASING & FINANCING SOLUTIONS AVAILABLE FROM CUSTOM TRUCK CAPITAL

DISCLAIMER: Speci ications are believed to be correct, but may contain errors and/or omissions. Pictures are representative and may not be identical.

PRICE: $167,500.00 CAD Plus applicable taxes

Ex Works: Calgary, Alberta

QUOTE NUMBER: Yukon Energy

EXPIRATION DATE: Jan 31, 2021

VST-36/40/47/52-I

Insulated Articulated/Telescopic Aerial Device

- **WORKING HEIGHT:** Up to 56 ft 6 in (17.2 m) with Standard Pedestal
- **HORIZONTAL REACH:** Up to 30 ft 9 in (9.4 m)
- **PLATFORM CAPACITY:** Up to 600 lbs (272 kg)
- **JIB CAPACITY (Optional):** Up to 1000 lbs (454 kg)

MORE PAYLOAD THAN THE COMPETITION

JIB & WINCH OPTIONAL

TruGuard® STANDARD

VST-40-I shown with Material Handling option.

LOWER TRUE COST OF OWNERSHIP

VERSALIFT®

7601 Imperial Drive | Waco, Texas 76712 | 254.399.2100 | VERSALIFT.com

VST-36/40/47/52-I

Insulated Articulated/Telescopic Aerial Device

VERSALIFT

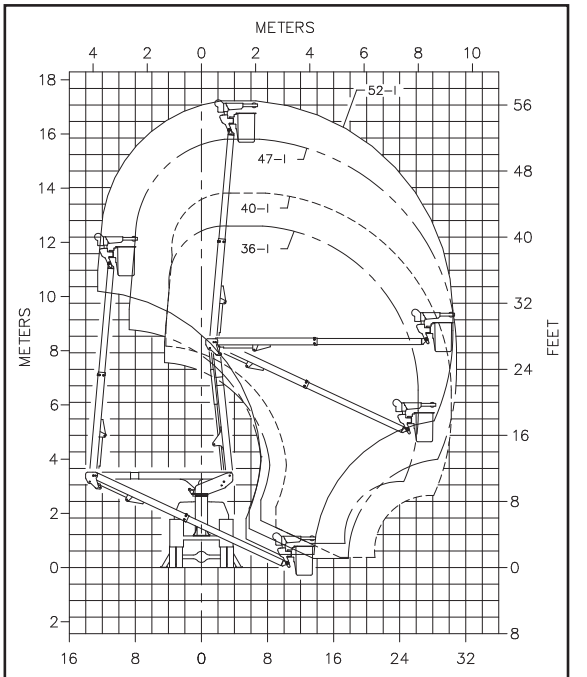
	VST-36-I	VST-40-I	VST-47-I	VST-52-I
GENERAL SPECIFICATIONS: (Based on 40 in Frame)				
Horizontal Reach	26 ft 2 in (8.0 m)	30 ft 2 in (9.2 m)	30 ft 9 in (9.4 m)	30 ft 4 in (9.3 m)
Maximum Platform Capacity	600 lbs (272 kg)	600 lbs (272 kg)	600 lbs (272 kg)	600 lbs (272 kg)
Inner Boom Extension	79 in (2.0 m)	103 in (2.6 m)	103 in (2.6 m)	53 in (1.35 m)
Outer/Inner Boom Articulation	-25° to +85°	-25° to +85°	-25° to +85°	-25° to +85°
Lower Boom Articulation	0° to +87°	0° to +87°	0° to +84°	0° to +84°
Rotation	360° Continuous	360° Continuous	360° Continuous	360° Continuous
WITH STANDARD PEDESTAL:				
Height to Bottom of Platform	36 ft 4 in (11.1 m)	40 ft 4 in (12.3 m)	46 ft 10 in (14.3 m)	51 ft 6 in (15.7 m)
Working Height	41 ft 4 in (12.6 m)	45 ft 4 in (13.8 m)	51 ft 10 in (15.8 m)	56 ft 6 in (17.2 m)
Stowed Travel Height	10 ft 6 in (3.2 m)	10 ft 6 in (3.2 m)	11 ft 0 in (3.4 m)	11 ft 6 in (3.5 m)
INSULATION GAP:				
Upper Boom Fully Retracted	46 in (1.2 m)	46 in (1.2 m)	52 in (1.3 m)	64 in (1.6 m)
Upper Boom (Extended 12+ inches)	46 in (1.2 m)	46 in (1.2 m)	64 in (1.6 m)	64 in (1.6 m)
Lower Boom	12 in (305 mm)	12 in (305 mm)	12 in (305 mm)	12 in (305 mm)

HYDRAULIC SYSTEM:

Operating Pressure	3000 psi (207 bar)
Flow Rate	6 gpm (22.7 lpm)
System Type	Open Center

OPTIONS:

- Auxiliary Outriggers
- Second Set of Tool Power Ports
- Platform Elevator
- Various Pedestal Heights
- Automatic Boom Latch
- Backup 12-Volt Pump
- Hydraulic Jib/Winch (Reduces Platform Capacity 100 lbs)
- Jib up to 1000 lb (454 kg) capacity



VST-36/40/47/52-I REACH

Note: Specifications on units may vary or change without prior notification due to option selections.

REV. 03/20

VERSALIFT is a leading manufacturer of bucket trucks, digger derricks and cable placers. Customers in the electric utility, telecommunications, forestry and sign, light & traffic industries experience a lower true cost of ownership by choosing Versalift. Our equipment is engineered to be lighter, while keeping the designs simple, which provides advantages like less unscheduled maintenance, greater payloads and ease of maintenance. Versalift has the lowest recall rate in the industry making it the smarter and most reliable choice. Versalift aerial lifts are the only units to feature the patented TruGuard® safety system, which provides additional protection to linemen in the bucket. Versalift is a Time Manufacturing Company, and together with Aspen Aerials has more than 1,400 employees worldwide.

REV. 03/19

VERSALIFT | 7601 Imperial Drive | Waco, Texas 76712 | 254.399.2100 | VERSALIFT.com

FALCON

FALCONEQUIP.COM

LOCATION: **SURREY, BC**

CLASSIFICATION: **FALCON DEMO**

2019 FORD F-550

TRANSMISSION: Automatic
ENGINE: 6.7L 4 Valve OHV Power Stroke Diesel
KMS: 10
GVW: 19,500 lbs
WHEELBASE: 192"

T2265

VIN #: IFDOX5HT7KEG25813

2019 ETI ETC40MH

Material Handler
45' Working Height
30' Ground to Bottom of Bucket
27' 5" Side Reach with End Mount Bucket
Hydraulic Jib and Winch Package
Continuous Rotation/ Fiberglass Inner Boom
Hoses Inside Boom Are Contained in a Cat Trac
400 lb Bucket Capacity/ 18 Gallon Oil Reservoir
Light in every compartment with master switch in cab
Backup Alarm and camera

$209,000.00

FALCON

Prepared for: Mr. Monty Smith
Office: 604-888-5066

2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930

Client Proposal

Prepared by:
Chenn Bergen
Office: 604-532-9921
Quote ID: MontyX5H
Date: 08/15/2019

Prepared for: Mr. Monty Smith

Prepared by: Chenn Bergen
08/15/2019

Dams Ford Lincoln Sales Ltd. | 19330 Langley Bypass Surrey British Columbia | V3S7R2

2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

Warranty

Standard Warranty

Basic			
Distance	37,283 miles	Months	36 months
Powertrain			
Distance	62,139 miles	Months	60 months
Corrosion Perforation			
Distance	Unlimited miles	Months	60 months
Roadside Assistance			
Distance	62,139 miles	Months	60 months
Accessories			
Distance	37,283 miles	Months	36 months

Prices and content availability as shown are subject to change and should be treated as estimates only. Actual base vehicle, package and option pricing may vary from this estimate because of special local pricing, availability or pricing adjustments not reflected in the dealer's computer system. See salesperson for the most current information.

Prepared for: Mr. Monty Smith

Prepared by: Chenn Bergen
08/15/2019

Dams Ford Lincoln Sales Ltd. | 19330 Langley Bypass Surrey British Columbia | V3S7R2

2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

As Configured Vehicle

Code	Description	MSRP
Base Vehicle		
X5H	Base Vehicle Price (X5H)	$61,249.00
Packages		
663A	Order Code 663A *Includes:* *- Cloth 40/20/40 Split Bench Seat w/Recline* *Includes fold down centre armrest with 2 cupholders, lift up centre-seat with locking storage, powerpoint, driver's side manual lumbar and 4-way adjustable driver and passenger headrests.* *- Radio: Premium AM/FM Stereo w/MP3 Player* *Includes 7 speakers, digital clock and SiriusXM satellite radio with 6 month prepaid subscription.* *- SYNC Communications & Entertainment System* *Voice-activated. Includes USB port, 911 Assist, steering wheel mounted controls and microphone in headliner.*	N/C
Powertrain		
99T	Engine: 6.7L 4V OHV Power Stroke V8 Turbo Diesel B20 *Includes transmission mounted live drive and stationary mode PTO, 27 litre (7.2 gallon) plastic urea tank, exhaust brake, B20 capability, urea gauge and intelligent oil life monitor.* *Includes:* *- Dual 78-AH 750 CCA Batteries* *- Rapid-Heat Supplemental Cab Heater* *- Dual Extra Heavy-Duty Alternators (Total 377-Amps)* *- 4.2" LCD Display in Centre-Stack*	$9,450.00
44W	Transmission: TorqShift 6-Speed Automatic *(6R140). Includes SelectShift and tow/haul mode.*	N/C
X8L_	4.88 Axle Ratio w/Limited Slip w/99T/68M	N/C
68M	GVWR: 8,845 kgs (19,500 lbs) Payload Package *Includes upgraded frame, upgraded rear-axle, low deflection/high capacity rear springs and 14,706 lbs. max rear GAWR. Note: See Super Duty Supplemental Reference Manual for further details on GVWR.*	$700.00
Wheels & Tires		
TGK	Tires: 225/70Rx19.5G BSW Max Traction #2 *Includes 4 traction tires on the rear and 2 traction tires on the front. Not recommended for over the road applications; could incur irregular front tire wear and/or NVH. Optional spare is BSW traction #2.*	$320.00
64D	Wheels: 19.5" Forged Polished Aluminum	$820.00

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Prepared for: Mr. Monty Smith

Prepared by: Chenn Bergen
08/15/2019

Dams Ford Lincoln Sales Ltd. | 19330 Langley Bypass Surrey British Columbia | V3S7R2

2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

As Configured Vehicle (cont'd)

Code	Description	MSRP
	Includes Ford oval centre hub ornaments.	
Seats & Seat Trim		
3	Cloth 40/20/40 Split Bench Seat w/Recline *Includes fold down centre armrest with 2 cupholders, lift up centre-seat with locking storage, powerpoint, driver's side manual lumbar and 4-way adjustable driver and passenger headrests.*	Included
Other Options		
PAINT	Monotone Paint Application	STD
192WB	192" Wheelbase	STD
213	4x4 Electronic-Shift-On-The-Fly *Includes auto-manual locking hubs and rotary control located on instrument panel.*	$200.00
98R	Operator Commanded Regeneration (OCR)	$290.00
18A	Upfitter Interface Module *Includes the UIM pre-installed and interface cables (2- 3' blunt cut cables with connectors). Note: The Upfitter Interface Module (UIM) is an electronic control module that provides output signals for aftermarket equipment (such as lift buckets, cranes, motors, salt spreaders, snow plows, etc.) via customer programmable logic based on switch inputs and vehicle CAN bus messages. The operation of such equipment is limited to the load parameters of the UIM. The UIM does not come pre-programmed for use. It must be configured by the upfitter for aftermarket equipment. The UIM provides output signals only, and is not intended to directly power any aftermarket device. Customer must use external relays to drive any equipment. Ford Motor Company is not responsible for debugging or verifying the function of the customer created UIM program files. It is the responsibility of the upfitter to ensure proper function of the software created to complete their upfit.*	$400.00
41P	Transfer Case Skid Plates	$200.00
43C	110V/400W Outlet *Includes 1 in-dash mounted outlet.*	$250.00
18B	Platform Running Boards	$490.00
585	Radio: Premium AM/FM Stereo w/MP3 Player *Includes 7 speakers, digital clock and SiriusXM satellite radio with 6 month prepaid subscription. Includes:* *- SYNC Communications & Entertainment System* *Voice-activated. Includes USB port, 911 Assist, steering wheel mounted controls and microphone in headliner.*	Included
166	Carpet Delete *Replaced with black flooring.*	N/C
Interior Colors		

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Prepared for: Mr. Monty Smith

Prepared by: Chenn Bergen
08/15/2019

Dams Ford Lincoln Sales Ltd. | 19330 Langley Bypass Surrey British Columbia | V3S7R2

2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

As Configured Vehicle (cont'd)

Code	Description	MSRP
3S_02	Medium Earth Grey	N/C
Primary Colors		
Z1_01	Oxford White	N/C
SUBTOTAL		$74,369.00
Destination Charge		$1,900.00
TOTAL		$76,269.00

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Prepared for: Mr. Monty Smith

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08/15/2019

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2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

Pricing Summary - Single Vehicle

	MSRP
Vehicle Pricing	
Base Vehicle Price	$61,249.00
Options & Colours	$13,120.00
Upfitting	$0.00
Destination Charge	$1,900.00
Subtotal	$76,269.00
Pre-Tax Adjustments	
Description	
Air Excise Tax	$100.00
Total	$76,369.00

Customer Signature

Acceptance Date

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Prepared for: Mr. Monty Smith

Prepared by: Chenn Bergen
08/15/2019

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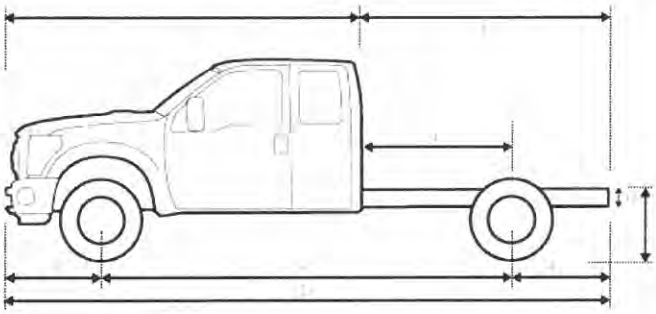
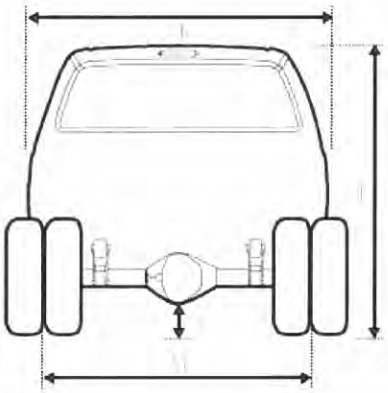
2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

Vehicle Dimension and Performance Summary

Performance predictions in this report represent an estimate of vehicle performance based on standard operating conditions. Variations in customer equipment, load configuration, ambient conditions, and/or operator driving techniques can cause significant variations in vehicle performance. These values are not representative of results that may be shown in actual dynamometer tests. This report should therefore be used as a guide for comparative vehicle performance.





Dimensions

A	Front of Bumper to Front Axle	38.30 in.
B	Front Bumper to Back of Cab (BBC)	146.30 in.
C	Wheelbase (WB)	192.00 in.
D	Overall Length (OAL)	277.40 in.
E	Back of Cab to Rear Axle (CA)	84.00 in.
F	Back of Cab to End of Frame	131.20 in.
G	Rear Axle to End of Frame (AF)	47.20 in.
H	Frame Section Height	N/A
I	Rear Frame Height Unloaded	34.30 in.
I	Rear Frame Height Loaded	28.60 in.
J	Cab Height	81.80 in.
K	Body Width	80.00 in.
L	Maximum Ground Clearance	N/A
L	Minimum Ground Clearance	8.20 in.
M	Front Tread	74.80 in.
M	Rear Tread	74.00 in.

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Prepared for: Mr. Monty Smith

Prepared by: Chenn Bergen
08/15/2019

Dams Ford Lincoln Sales Ltd. | 19330 Langley Bypass Surrey British Columbia | V3S7R2

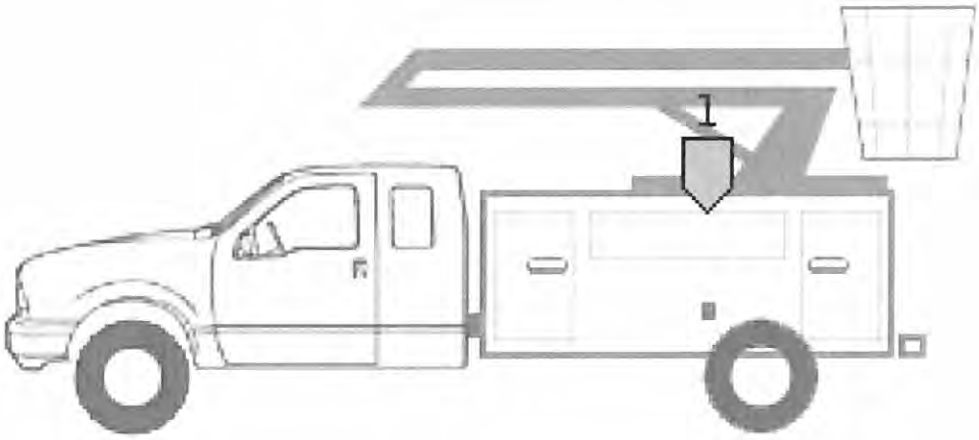
2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

Vehicle Dimension and Performance Summary (cont'd)

Body Specs

Truck body style:	Aerial Device
Cab to body gap:	3.00 in.
Body length:	10.70 ft
Body tare weight:	3,460 lbs
Body width:	96 in.
Body height from ground:	120 in.
Centre gravity (from front):	64.10 in.



Weight

GVW	Front Axle	Rear Axle	Totals
Chassis	5,009 lbs	3,381 lbs	8,390 lbs
Body	306 lbs	3,154 lbs	3,460 lbs
Occupants Weight	600 lbs	300 lbs	900 lbs
1 Max Payload - (Max Payload)	585 lbs	6,165 lbs	6,750 lbs
TOTAL	**6,500 lbs**	**13,000 lbs**	**19,500 lbs**

Ratings	Front Axle	Rear Axle	GVWR
GAWR	**6,500 lbs**	**14,706 lbs**	**19,500 lbs**
Wheels/Tires	7,500 lbs	15,000 lbs	
Suspension	6,500 lbs	15,000 lbs	
Axle	7,000 lbs	14,706 lbs	
Legal Axle Limit	0 lbs	0 lbs	

Prices and content availability as shown are subject to change and should be treated as estimates only. Actual base vehicle, package and option pricing may vary from this estimate because of special local pricing, availability or pricing adjustments not reflected in the dealer's computer system. See salesperson for the most current information.

Prepared for: Mr. Monty Smith

Prepared by: Chenn Bergen
08/15/2019

Dams Ford Lincoln Sales Ltd. | 19330 Langley Bypass Surrey British Columbia | V3S7R2

2019 F-550 Chassis 4x4 SD Super Cab 192" WB DRW XLT (X5H)

Price Level: 930 | Quote ID: MontyX5H

Vehicle Dimension and Performance Summary (cont'd)

Start, Grade and Speed

Start	Ratio	Desired	Calculated
Start grade capability in 1st gear	3.97	15.00 %	42.71 %
Start grade capability in reverse	3.13	15.00 %	33.62 %
Grade	**Ratio**	**Desired**	**Calculated**
Maximum grade in 4th gear	1.15	3.00 %	13.00 %
Maximum grade in 5th gear	0.86	3.00 %	9.71 %
Maximum grade in 6th gear	0.67	3.00 %	7.63 %
Speed		**Desired**	**Calculated**
Top Speed (level grade)		75 mph	88 mph
To meet your requirement you need a maximum axle ratio of 5.74			
Top Speed on 3.0% grade		55 mph	
To meet your requirement you need a maximum of 122 hp			
Cruise Speed		60 mph	65 mph
Engine RPM at desired cruise speed			2,121 rpm

Variables in Use

Rear axle ratio:	4.88/4.88	Governed RPM:	3,120 rpm
Tire size:	225/70R19.5 (645 rev/mile)	Frontal Area:	40.44 Sq.Ft.
Gross Vehicle Weight (GVW):	19,500 lbs	Cruising RPM	2,300 rpm
Clutch engagement torque:	375 ft.lbs.	Worst road surface	Typical Highway
Torque conversion ratio:	1.90	Final Drive Ratio:	0.67
Peak engine torque:	750 ft.lbs.	Drag Coefficient	0.80
Engine Power:	330 hp @ 2,600 rpm		

Prices and content availability as shown are subject to change and should be treated as estimates only. Actual base vehicle, package and option pricing may vary from this estimate because of special local pricing, availability or pricing adjustments not reflected in the dealer's computer system. See salesperson for the most current information.

Prepared for: Mr. Monty Smith

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Price Level: 930 | Quote ID: MontyX5H

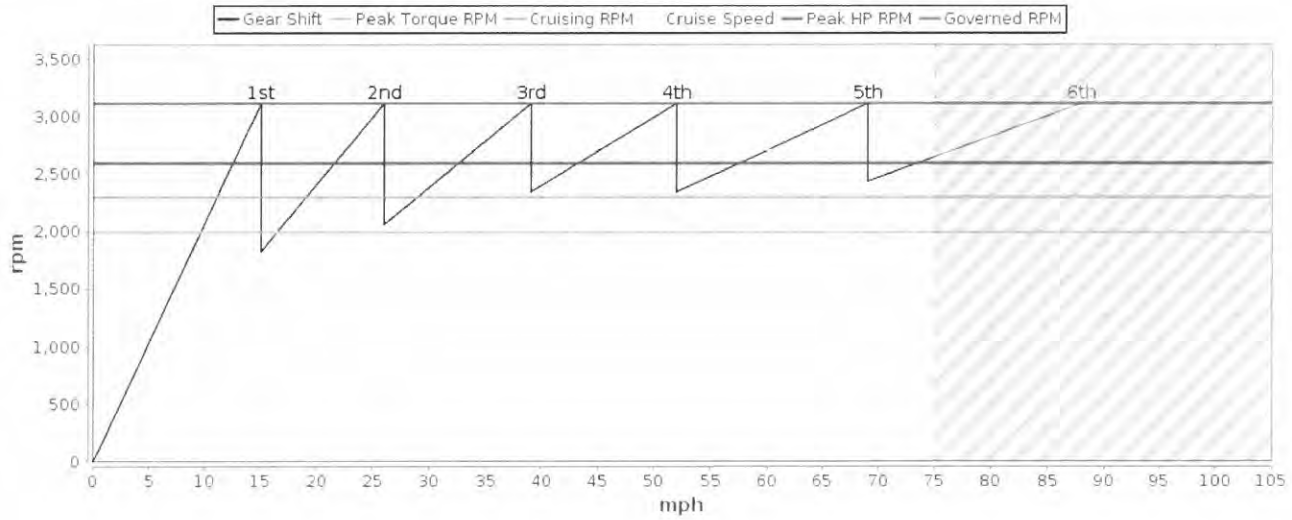
Vehicle Dimension and Performance Summary (cont'd)

Shift Chart

Shift Chart displays mathematical geared speed.

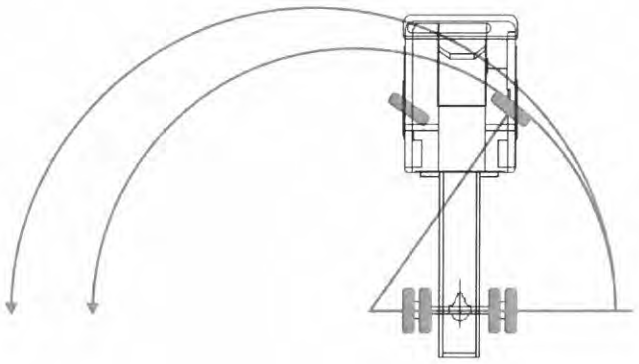
Diesel engines use Governed RPM for shift points.

Gas engines use Peak Torque RPM for shift points.



Turning Radius

Turning Radius	27.10 ft



Prices and content availability as shown are subject to change and should be treated as estimates only. Actual base vehicle, package and option pricing may vary from this estimate because of special local pricing, availability or pricing adjustments not reflected in the dealer's computer system. See salesperson for the most current information.

REFERENCE: **Application, Appendix 5.2, page 5.2-9**

ISSUE: **Crane Replacement/Refurbishment**

QUOTE: "During an annual crane inspection, three YEC cranes (Aishihik service building, P127 powerhouse, & P127 stop log hoist) were identified as needing significant structural, electrical, and mechanical repairs in order remain in acceptable working condition. 2020 spending will provide for a detailed assessment of each crane to determine an engineered plan for replacement or refurbishment as required. Actual construction activities are planned for 2021."

QUESTION:

a) Are the cranes being repaired or replaced with mobile or fixed cranes? If they are mobile cranes, how many mobile cranes does YEC have available at the specified locations? Please comment on the possibility of other cranes being used in place of the cranes to be repaired or replaced.

b) Please explain what is entailed in the assessments of the cranes, who will carry out the assessments and why the assessment of three cranes will cost $165,000.

c) Please confirm that the $400,000 forecast cost for 2021 is the estimated cost to repair or replace all three cranes. If not confirmed, please explain.

d) What is the estimated full replacement cost of the three cranes?

e) When did the three cranes enter service, and what is their expected service life?

ANSWER:

(a) and **(e)**

To clarify, the three cranes in the quote provided refer to the following equipment:

These two cranes entered service on the following dates:

- Whitehorse Spillway: 1958 (capacity: 20t);
- P127 (WH4) Whitehorse Powerhouse crane: 1984 (capacity: 80T); and
- Aishihik Powerhouse: 1975 (capacity: 38t/5t).

The typical life span on all crane hoists is 20-25 years. With major overhauls, the typical lifespan can potentially extend by an additional 20-25 years (and the process can be repeated). The steel and the concrete structure itself has a typical lifespan of 50 years and a major overhaul can be undertaken to extend its life.

Fixed cranes are proposed. YEC currently has 25 mobile cranes, however, the lifting capacity of mobile cranes is far less than the fixed cranes.[1]

(b)

The value reported in the GRA for 2020 was a forecast; actual work completed resulted in an actual value of $155,296. 2020 Crane works included asset assessment and capital corrective works. The assessment work was conducted on three cranes:

- WH4 Powerhouse Crane;
- WHS Whitehorse Spillway Crane, and
- Aishihik Service Building Crane.

Total value of assessment work was $51,750. The scope of the assessment work is as follows:

[1] The lift capacity of service truck cranes is about 2,000 lbs at 3 ft. radius. Large PLT trucks have greater capacity and can lift up to 20,000 lbs. YEC Digger Derricks in Mayo, Dawson and Whitehorse have this capacity.

WHS Spillway Crane Whitehorse:

- **Structural Assessment:** Measurement of structural members; Engineer assessment of structural members, welds, joints, bolts and rivets; Determination of current crane capacity and life cycle stage.

- **Mechanical Assessment:** Examination of gearing, couplings, drive trains, and power transfer systems (involving disassembly).

- **Electrical/Controls Assessment:** Engineer assessment of controls, motors, switching, wiring etc.; Testing of electric motors and panels; Determination of current condition and life cycle stage.

WH4 Powerhouse Crane – Whitehorse

- **Structural Assessment:** Measurement of structural members; Engineer assessment of structural members, welds, joints, bolts and rivets; Determination of current crane capacity and life cycle stage.

- **Mechanical Assessment:** Servicing of internal couplings (disassembly required).

- **Electrical Assessment** Disassembly and internal inspection of resistor cubicles and panels.

Aishihik Service Building Crane

- **Mechanical Assessment:** Disassembly and inspection of internal couplings, gearcase.

As the contractor was on site already, YEC had them address a number of deficiencies on the cranes. The value of this work was $103,500 and included repair/replacement of various components:

- Braking systems;

- Cables;

- Electrical components; and

- Control systems.

Additionally, the repair scope included addressing recommendations on the inspection of numerous mobile cranes at YEC ($30,000). Both the inspections and repair works were completed by Kone Crane.

(c)

No. The $400k is for Major capital repairs including:

- An engineered assessment on replacement of the Whitehorse Stop Log crane;

- Retrofit to the Aishihik Service Building Crane Auxiliary Hoist Drum Replacement; and

- A 5 Ton Electric Chain Hoist Replacement for the Aishihik surge chamber unit that is damaged and non-serviceable.

These major works are approximately 80% of the total budget. The remaining $80k of budget relates to addressing safety considerations for other cranes.

(d)

Unknown at this time; cost will be based on an engineered solution, followed by an RFP cost estimate and review.

REFERENCE: **Application, Appendix 5.2, page 5.2-9**

ISSUE: **Mayo Earthworks Project**

QUOTE: "A number of issues at and around the Mayo Hydro facilities have been identified. These include slope instability and erosion issues near access roads (Mayo A, Mayo B, and Wareham dam), both powerhouse buildings, surge tank, and both substations. During 2019 a complete site inventory of civil issues was undertaken to identify and prioritize issues. The inspection highlighted several required projects to improve roads, make culvert installations and secure embankments. 2020 spending developed a detailed work plan for identified issues including a geotechnical assessment, topographic survey, detailed engineering design (including drawings and specifications), construction methodology, and project scope, schedule & budget development."

QUESTION:

a) Please confirm that 2020 spending was only on development of the work plan for the Mayo earthworks project. If not confirmed, please explain.

b) When does YEC propose to undertake the works required to remediate the identified issues and what is the estimated cost of those works?

c) Please describe the safety issues and or threats to infrastructure caused by the issues identified.

ANSWER:

(a)

Spending was only on the work plan for the Mayo Earthworks project. Please see response to YUB-YEC-1-65.

(b)

The project will begin in 2022 and stretch in 2023. Costs not identified as of yet.

(c)

Current issues are: erosion at edges of roads that will increase hazards for drivers; and erosion of slopes that cause landslides that could increase and potentially impact access safety or equipment.

REFERENCE: **Application, Appendix 5.2, page 5.2-10**

ISSUE: **New Mobile Office Unit – IT**

QUOTE: "The existing IT trailer houses five offices and a closed storage space. It is aging and requires additional O&M support each year. The project involves replacement of the aging, undersized IT trailer with a larger unit able to accommodate eight office spaces and storage. Additional office spacing would allow for staff expansion as a less costly solution than building onto the main building."

QUESTION:

a) What was the original cost of the existing IT trailer, when did it enter service and what was its expected service life?

b) How many YEC personnel currently use the IT trailer, and what is the typical number of personnel occupying the trailer at any time?

c) What is the estimated annual O&M cost associated with the IT trailer, and what is the estimated annual O&M if a new trailer is purchased?

ANSWER:

(a)

YEC is unable to locate the original cost of the existing IT trailer or the original expected service life. According to the Atco tag on the building, the unit was factory constructed in 1991.

(b)

Excluding Covid-19 pandemic limitations, five employees normally occupy this space on a full-time basis, with an additional one employee using it on a part-time basis.

(c)

The estimated annual O&M cost associated with the IT trailer is $8,500. The estimated annual O&M on a new trailer would be expected to be less than $8,500.

REFERENCE: **Application, Appendix 5.2, page 5.2-10**

ISSUE: **Vehicle Purchases**

QUOTE: "Fleet vehicles were historically replaced at regular intervals based simply on age and mileage. YEC has recently adopted a replacement policy that considers more comprehensive criteria when assessing specific vehicles to be replaced each year. The forecast amounts for 2019 include the purchase of pickup trucks with service bodies, including a 2 tonne mechanical operator's vehicle (the current 1 tonne vehicles did not have sufficient chassis to do the work safely), and forecast 2020 acquisitions focused on vehicles based in Dawson and Mayo due to the higher cost of local repair services. 2021 costs are to replace aging/ high mileage vehicles that are incurring greater O&M costs to maintain."

QUESTION:

a) For each of the last five years (actual) and 2021 (forecast), please provide the number of vehicles replaced and the average age and average mileage of those vehicles.

b) Please provide YEC's estimate of the average annual maintenance cost of vehicles in its fleet based on the number of years the vehicle has been in service, beginning at one year and ending with the age of the oldest vehicle replaced in the last five years.

ANSWER:

(a)

Please see the table below for the requested information:

YEC Vehicle Replacement 2017-2021				
Year	# of Vehicles replaced (additional vehicle(s) added to fleet)	Average Mileage of vehicles replaced	Average Age of vehicle being replaced (Years)	Notes
2017	2 (2)	216683	10	Added 2 additional vehicles to inventory - Digger Truck & Pool vehicle. Blown Transmission in PLT truck reduced Average age of vehicle being replaced
2018	1 (1)	197465	11	Added 1 additional vehicle to inventory - PLT's vehicle
2019	3	182003	13.6667	Ambulance (unit # 54) was replaced driving up average age
2020	4 (1)	211172	9.25	Added 1 additional vehicle to inventory - Electrician's vehicle
2021	6	196126	11.2	Unit # 113 being replaced due to rollover/writeoff accident, not factored in averages. Please note Average mileage will increase before replacemnent vehicles are obtained

(b)

The question is unclear; the table below shows annual maintenance cost by vehicle category: >= 1 ton and < 1 ton as well as the number of units in the fleet during that year. The cost per unit for >1T shows more variability, in part due to the nature of the equipment. This category includes large utility equipment such as bucket trucks, crane trucks and diggers. By their nature, the maintenance requirements of the attached equipment, i.e., cranes can be variable with respect to timing and amount. Cranes are required by law to be inspected by certified inspectors and the recommendations of the inspector must be complied with or the unit will be tagged out from service.

	2016		2017		2018		2019		2020	
	Maintenance Cost	# units	Maintenance Cost	# units	Maintenance Cost	# units	Maintenance Cost	# units	Maintenance Cost	# units
Service Vehicles > 1T	$83,855	25	$146,892	26	$146,428	26	$222,068	27	$146,340	27
Service Vehicles < 1T	$58,860	26	$65,535	27	$57,722	27	$59,125	27	$75,603	28

1

REFERENCE: **Application, Appendix 5.2, page 5.2-10**

ISSUE: **Water Improvement Upgrades**

QUOTE: "The cooling water and potable water systems in the YEC main corporate office have experienced pre-mature piping failure and select cooling coil leaks for at least the past 10 years. An external engineering firm was engaged to assess the current systems and provide recommendations to address the issues. The project will implement those recommendations including the installation of a particulate filter, a VFD drive for the existing pump, a heat exchanger, new cooling water piping and valves, and fan coil drip pans with leak detection."

QUESTION:

a) What was the cause of the problems experienced with the office water systems? Please describe how the proposed work will prevent similar problems in the future.

ANSWER:

(a)

An assessment was undertaken by Stantec in 2019 to assess the identified failures related to the cooling water and potable water systems in the YEC main corporate office. This identified two potential reasons for the failures: (1) the first was that the well water is possibly slightly corrosive towards the piping (not likely to form scale in the piping); and (2) the second is that excessive flow velocities are present in sections of the piping.

Work completed to address these concerns included the following:

- New pex piping;
- New filtration system from well water to building;
- Installation of lead/standby pumps with integral variable speed drives and sensors self-modulating to meet pressure set points;

- Installation of chemical pot feeder;

- Revising control valves to 3rd floor fan coils; and

- Supplying of VFD and Pressure sensor for domestic water.

REFERENCE: **Application, Table 5.2-1, page 5-33**

ISSUE: **Other Projects Under $100K**

QUESTION:

a) Please provide more details on the "Other projects under $100K" line item in Table 5.2.1. What were these projects associated with? Why were they required?

ANSWER:

(a)

Projects under $100k include various small projects under the generation, transmission, distribution and general plant and equipment functions. Detailed business cases are typically not provided for these projects in the GRA application given small cost magnitude within the forecast capital costs for the test year, i.e., collectively all such small projects in Table 5.2-1 account for $915k in 2021 forecast capital works (with 71% under "General Plant & Equipment").

The following is noted regarding the nature of the projects:

- **Generation –** Includes small projects that relate to maintenance of generation facilities such as insulation, water level sensor upgrades, stairways, etc.

- **Transmission –** Includes small projects that relate to maintenance of transmission facilities such as substation protection and control minor upgrades.

- **Distribution –** Includes small projects that relate to maintenance of distribution facilities including distribution upgrades and land management and easement project.

- **General Plant and Equipment –** The majority of projects under general plant have annual blanket costs such as operations tools and equipment, fencing upgrades, IT equipment and replacements, etc.

REFERENCE: **Application, Appendix 5.2, page 5.2-11**

ISSUE: **FD7 Overhaul Project**

QUOTE: "Faro Diesel #7 (FD7) is located at the Faro Diesel Plant and uses as 12 cylinder Caterpillar Model 3612 diesel engine as its prime mover (vintage 1992). The unit was used when purchased by YEC from a mining operation; however, the complete service history for the unit is not known (YEC has registered 28,624 operating hours). A conditional assessment for the engine was undertaken in 2016 by MPR Associates and a follow-up inspection was undertaken by Finning in May 2016. The inspection focused on items identified in the MPR report and included a more fulsome mechanical inspection that included: removal, measurement and inspection of piston/ rings; inspection of camshaft segments and filter assemblies; measurement of heads and valves and connect rod bearings. One cylinder lining was found cracked and replaced during the inspection. Due to the significant wear found on the inspected parts, it was recommended that a complete overhaul of the unit be undertaken."

QUESTION:

a) Please indicate the number of hours FD7 was in operation for the last 10 years.

b) If the overhaul is completed as proposed, does YEC expect the annual operating hours for the unit to increase, decrease or stay the same? Please explain.

c) What is the estimated purchase and installation price to completely replace FD7?

d) Were any alternatives to this project considered? If not, please explain why not. If so, please provide details of the results of this consideration.

e) Please provide a breakdown of the work proposed to be done on FD7 and the estimated cost of each component.

ANSWER:

(a)

Please see Table 1 below which provides FD7 running hours for the past 10 years. This also provides for 2014 to 2020 the hours available for operation.

Table 1: FD7 Running Hours and Hours Available for Operation

Year	Running Hours	Available for Operation
2011	573.40	
2012	263.60	
2013	599.20	
2014	204.60	8,705.94
2015	208.90	8,589.79
2016	114.50	8,433.76
2017	202.40	8,390.61
2018	173.40	8,176.99
2019	496.50	8,671.70
2020	427.30	8,721.54
2021 to date	66.73	
Total	**3,330.53**	**59,690.33**

(b)

With the overhaul complete the annual operating hours for the unit are expected to stay the same.

YEC's dispatch utilizes renewable energy first on the generation dispatch. YEC Faro generation is lower than LNG, rentals, Whitehorse and Dawson thermal assets in the stacking order. FD7 provides community backup during unplanned events as well as planned maintenance work.

(c)

Replacement cost for FD7 is estimated at $4-5 million.

(d)

The option for a replacement unit has been considered and will be reviewed through a business case assessment. Discoveries during OH's are a project risk and do increase the cost to repair. The condition of the block may necessitate a replacement of the component (block) resulting in a substantial increase in cost. These costs can equal or exceed the replacement cost.

(e)

As indicated in response to YUB-YEC-1-65, pricing for this overhaul was significantly higher than expected when the GRA forecast was prepared. Therefore, a business case is being performed in 2021 to determine if replacement is more cost effective than refurbishment. Any spending for 2021 business case will now be held in WIP and reflected in GRA compliance filing.

The original work proposed to be done on FD7 in the GRA included disassembly of engine; cleaning and inspection of all parts and components and reassembly of engine, including:

- Installation of all must-do parts[1] (includes main, rod, & cam bearings);
- Exchange components including:
    - Cylinder Heads;
    - Turbocharger Complete;
    - Cylinder Liners;
    - Pistons (Including Rings, Retainers, Pins, Bearing shafts);
    - Fuel Injectors;
    - water, oil and fuel lines;
    - valve train;
    - air lines;
    - instrument panel and wiring (where applicable);
    - front & rear gear train; and
    - aftercooler and exhaust.

The OH quote is high level and does not provide individual component costs.

[1] "Must-Do Parts" are seals, gaskets, bearings, plugs, pins, springs and other minor parts necessary in a standard complete in-frame overhaul.

REFERENCE: **Application, Appendix 5.1, page 5.1-1 and Appendix 5.3, page 5.3-1**

ISSUE: **Projects Not Impacting Rate Base and Deferred Projects**

QUOTE: "Appendix 5.1 provides project summaries for capital projects with spending over the period from 2019 to 2021 exceeding $1 million that remain in WIP at the end of 2021 (and therefore do not affect the 2021 GRA revenue requirement)."

"Deferred expenditure test year spending on major projects (i.e., expenditures over $1 million) retained in WIP is focused on projects required to address sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance), investments to ensure sufficient dependable capacity for the integrated grid, and continued planning expenditures to meet other potential future generation and transmission requirements."

QUESTION:

a) Please explain why there are two different appendixes (5.1 and 5.3) for projects held in WIP and what the purpose of each of those appendixes is.

b) Please confirm that no costs for projects listed in Appendix 5.1 and Appendix 5.3 have been added to YEC's rate base or revenue requirement for 2021. If not confirmed, please explain and provide a breakdown of all costs for these projects that YEC is proposing to add to rate base.

c) Please explain the rational for YEC's "Not Impacting Rate Base" and "Deferred Projects" categories. At some point, will YEC put the costs of projects currently listed as "Not Impacting Rate Base" into the rate base?

d) Please provide YEC's capitalization policy.

ANSWER:

(a) through **(c)**

Appendices 5.1 and 5.3 review Major Projects (i.e., projects with forecast costs exceeding $1 million) for PPE (Appendix 5.1) and deferred costs (Appendix 5.3) that are forecast to remain in WIP during the 2021 test year. The purpose of these appendices is to clearly identify major projects with costs that will not affect forecast test year rate base and therefore do not require detailed review at this time for the purpose of the 2021 GRA Application. Accordingly, it is confirmed that no costs for projects listed in these appendices have been added to rate base or revenue requirement for 2021.

The rationale generally for the “Not Impacting Rate Base” category is to identify clearly project costs that are not added to rate base or revenue requirement for 2021. It is expected that the costs for projects in WIP will at some point after 2021 (e.g., when brought into service or closed) be brought into rate base.

To clarify further, information on individual projects with costs that remain in WIP is provided in separate appendices for each category (Appendix 5.1 for Major Projects that are capital works, Appendix 5.3 for Major Projects that are deferred studies, and Appendix 5.5 for deferred studies with costs between $100,000 and $1 million).

(d)

Please see Attachment 1 to this response. The policy is unchanged from the version reviewed during the 2017/18 proceeding.

YUKON ENERGY	Finance Accounting Practice FX-Appendix	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Finance	Property, Plant and Equipment Definitions
		ISSUED:	REVIEW DATE:	APPROVED BY:
		January 1, 2021	January 1, 2024	Chief Financial Officer

1.0 Purpose

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

2.0 Definitions

1. ***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.

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, , acceptance and commissioning costs.

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 rate-regulated 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 PP&E category. A unit of property is defined as that which is independently operational, readily separable 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 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. ***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. 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)

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

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

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

12. ***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.

REFERENCE: **Application, Appendix 5.3, page 5.3-2**

ISSUE: **Aishihik Generating Station (AGS) Long-Term Water Use Licence Renewal Project**

QUOTE: "The planned long term AGS Water Use Licence renewal project and related costs were initially reviewed as part of the 2017/18 GRA. At that time, it was noted that the total forecast budget for the project was $3.569 million spread over five years (2015-2019) … The deferred costs forecast in the Application include spending in WIP increasing from $4.957 million at the end of 2018 to $7.918 million by the end of 2021. The project is forecast to be complete by the end of 2022."

QUESTION:

a) Please break down the $7.918 million cost for this project into the various components of the project and provide a description of why each component is necessary for the project to proceed.

b) Please explain why the total cost of this project has increased from $3.569 million in the 2017-18 GRA to $7.918 million in the current application.

c) Please provide a description of each new cost item and each cost item that has increased since the previous GRA, along with a description of why the new cost item or the increased cost is necessary.

d) Please include an explanation of why YEC's initial cost estimate was less than half of the current estimate and the measures YEC has implemented or plans to implement to improve its ability to forecast the costs of projects like this.

e) Please describe the actions YEC has taken throughout the duration of this project and the actions YEC plans to implement moving forward to control and minimize the costs of this project.

ANSWER:

(a)

The $7.918 million cost noted in Appendix 5.3 of the Application provided forecast project costs to the end of 2021, including 2020 forecasts. These costs now need to be updated to reflect revised forecast costs for 2020, 2021 and 2022.

As set out in Table 1 below – costs forecast to the end of 2021 are now expected to be $0.871 million higher than forecast in the Application. See Table 2 (response to (b) and (c) below) for updated forecast costs to the end of 2022.

Table 1: Project Costs - 2018 WIP to 2021 WIP

	2018 WIP Actual Cost	2019 Actual Cost	2020 Actual Cost	Forecast 2021	Total
Project Management	$276,268	$1,247	$152,946	$200,000	$630,461
CAFN Compensation & Stakeholder Engagement	$705,319	$2,373	$1,012,811	$350,000	$2,070,503
Impact Assessment Studies	$3,748,543	$94,741	$406,438	$ -	$4,249,722
Early Monitoring	$ -	$226,900	$258,049	$65,000	$549,949
Permitting processes	$40,218	$182,847	$303,625	$325,000	$851,690
Aishihik Advisory Committee	$186,851	$4,648	$4,935	$ -	$196,434
Future AFUDC*	$ -	$ -	$ -	$240,000	$240,000
Project Total:	**$4,957,199**	**$512,755**	**$2,138,804**	**$1,180,000**	**$8,788,758**

*Note: Previous AFUDC accruals for actuals 2018WIP, 2019 and 2020 are embedded within each category total

Set out below are descriptions of the various cost components (and why they are necessary for the project is as follows):

- Project management costs are primarily YEC internal costs related to work on planning and executing the project. These costs are required to move the project forward and coordinate the various working groups and deliverables.

- CAFN Compensation and stakeholder engagement costs are related to the following:

    1. Engagement with the CAFN, including funding the Champagne and Aishihik Community Advisory Committee (CACAC);
    2. Compensation to the CAFN to be approved by the Yukon Water Board;
    3. Negotiation costs to reach a reconciliation agreement with the CAFN;
    4. Capacity funding to CAFN to support participation in the project technical review and development of the Monitoring and Adaptive Management Plan and
    5. Public engagement activities.

  YEC deemed it prudent to engage the CAFN at the beginning of the current water use license renewal process, given that the facility is located within the CAFN's traditional territory. 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.

- Impact assessment studies costs are related to the planning and execution of the environmental and social impact assessment studies in preparation for the YESAB and Yukon Water Board applications. These costs are required to be able to prepare the Project Proposal for the YESAB Designated Office and develop a Monitoring & Adaptive Management Plan for the Yukon Water Board application.

- Early monitoring costs are related to early monitoring carried out to address issues relevant to CAFN, YESAB and regulators (including requirements from 3-year license to support 25-year renewal).

- Permitting process costs are required to complete the regulatory activities which are mandatory to achieve the primary objective of the project (obtaining a 25-year water use license for the facility). They include: 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).

- Aishihik Advisory Committee (AAC) costs related to funding the activities of the AAC from 2015 to 2018. The AAC's role was to provide ongoing advice and feedback as Yukon Energy and CAFN developed the necessary regulatory applications. In addition, the AAC worked to reconcile potential opposing interests and values of the YEC, CAFN, external stakeholders, and public related to the use of Aishihik Lake.

(b), **(c)**, **(d)** and **(e)**

As noted, the $7.918 million cost provided in Appendix 5.3 of the Application relates to forecast costs only to the end of 2021. Appendix 5.3 noted that the project is now forecast to be complete by end of 2022.

Table 2 below compares:

(a) the forecast cost breakdown provided during the 2017/18 GRA[1] to complete the 25-year licence renewal; and
(b) the updated forecast costs to complete this project by the end of 2022.

The updated forecast costs of $9,388,758 to complete the project include 2020 and 2021 costs that are $0.871 million higher than the forecast reviewed in Appendix 5.3 of the 2021 GRA (see Table 1 above) plus $600,000 forecast costs for 2022 (the 2021 GRA did not provide any forecast for this project's costs after 2021).

[1] The response to YUB-YEC-1-77(a) in the 2017-18 GRA proceeding provided a cost breakdown for $3.149 million, excluding compensation costs to CAFN. Table 2 includes the added $0.42 million (as required for the $3.569 million 2017-18 GRA forecast) under CAFN Compensation and Stakeholder Engagement.

Table 2: 2017/18 GRA Forecast compared to Updated Forecast to end of 2022 – Aishihik Relicensing Project Costs

	Forecast cost to end of 2022	2017/18 GRA Forecast Cost Sept, 2015 budget	Variance	Cost Drivers
Project Management	$730,460	$553,000	$177,460	Additional project management required to provide project management services over extended project timeline and coordinate/attend increased number of technical subgroups.
CAFN Compensation & Stakeholder Engagement	$2,145,503	$804,000	$1,761,083	$500,000 Chemi Narrows compensation payment (requirement from 2002 relicensing process, adjusted to this compensation in the Three Year Licence) was not included in initial budget. Significant additional engagement and collaboration requirements beyond those anticipated in the initial budget, including increased capacity funding for CAFN.
Impact Assessment Studies	$4,249,722	$1,759,000	$2,490,722	Additional studies and technical work beyond that anticipated in the initial budget. drove higher costs, particularly during shared study planning process with CAFN plus added costs due to extended time for studies.
Early Monitoring	$564,949	$-	$564,949	Engagement with CAFN and YG revealed requirement for early monitoring programs (as well as requirements from 3-year license to support 25-year renewal) not anticipated in the initial budget. Some items raised for consideration or requested by external parties to be part of the MAMP were required to be piloted to ensure commitments over long term are effective and achievable. In order to address assessment and permitting risk, elements initiated to evaluate impact for

				the long-term license requirements.
Permitting processes	$1,001,690	$300,000	$701,690	Collaborative approach with external parties as directed in Three Year Licence drove an increase in the MAMP scope. Specific information on the MAMP is required for the Water Board; accordingly, scope increases drove additional supporting technical work to complete the processes.
Aishihik Advisory Committee	$196,434	$153,000	$43,434	Increased scope of committee activities per input from committee members; Additional accrual of AFUDC due to project extended timeline.
2021 & 2022 AFUDC	$500,000	$-	$500,000	Additional accrual of AFUDC due to project extended timeline and increased budget.
Project Total:	**$9,388,758**	**$3,569,000**	**$6,239,338**	

Explanation as to why the total cost has increased as described in Table 2, and why the initial cost estimate provided in the 2017-18 GRA was less than half the current estimate, requires review of the context for the 2017-18 GRA forecast including Champagne and Aishihik First Nations' (CAFN) historic grievances relating to the facility and other key factors affecting the relicensing of the Aishihik Generating Station.

Background re: 2017-18 Cost Forecast

The 2017-18 GRA filing addressed a project that was to remain in WIP for the test years and therefore did not affect the revenue requirement during the test years. When the GRA was filed in June 2017, the relicensing process was still at an early stage of development. The forecast cost provided in the GRA reflected a preliminary budget approved by the YEC Board in September 2015.

However, the 2017-18 GRA filing noted that the last Aishihik licence renewal (2002) cost approximated $8.791 million. That cost reflected protracted processes related to stakeholder engagement, first nation compensation, environmental assessment, and the Yukon Water Board. These processes underscored major issues CAFN had with the Aishihik facility dating back well before Yukon Energy acquired these assets from Canada in 1987.

The initial 2015 budget assumed that these issues would not once again cause similar protracted time and cost problems if a shared work plan approach for the relicensing assessment studies was adopted between Yukon Energy and CAFN (and other stakeholders).

In that regard, the 2017-18 GRA filing recognized that the Aishihik hydro facility has had long term impacts on CAFN, that Yukon Energy and CAFN were working in partnership on proposed terms and conditions for the new Aishihik water license, and that in January of 2016 Yukon Energy and CAFN entered into a Protocol Agreement which established shared objectives, procedures and governance of the new relationship.

During the 2017/2018 GRA Application process, when YEC forecast the project to be completed by the end of 2019 (when the then existing water use licence expired), YEC identified in YUB-YEC-1-77 that the forecast costs could not be accurately estimated at the time given the material uncertainties relating to the First Nation and regulatory issues surrounding this project. This was clearly articulated as follows:

> "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."

Experience during 2017 through 2018 confirmed that the uncertainties and issues surrounding this project since its inception remained. It became evident during this time that considerably more time and costs would be required than forecast in the initial budget. This experience revealed amongst other things the challenges that CAFN and YEC faced in trying to carry out the shared work plan.

As reviewed below - because of these difficulties and other related matters --, Yukon Energy had to suspend its 25 year relicensing project in early 2019 in order to secure a three year licence renewal while reconciliation discussions between the Yukon government and CAFN relating to amongst other things CAFN's historical grievances were ongoing.

Overview of Key Factors for Cost & Schedule Change

In summary, the two key factors accounting for the added time and cost requirements for this project are:

- The long-standing concerns of Champagne and Aishihik First Nations (CAFN) with regard to this facility's origins and ongoing impacts; and

- The Yukon Government's decision by early 2019 to engage in negotiation of an agreement with CAFN to address issues of concern including reconciliation.

Overlaying the above key factors is the critical importance of the AGS facility (and its successful relicensing) for the Yukon Integrated System and the strong interest that Yukon Energy has in establishing an improved long-term relationship with CAFN. See Appendix A to this response for summary of the key features of the Aishihik facility.

CAFN's Longstanding Concerns

Yukon Energy was aware of CAFN's long standing and ongoing concerns related to the AGS. These concerns were front and center in the 2002 renewal process and they have not abated.

To try to deal with these issues -- at the start of the current AGS relicensing in 2016 -- Yukon Energy and CAFN worked together to develop a shared work plan for the AGS long term licence renewal through implementation of a Protocol Agreement.

- Through the Protocol Agreement the parties agreed to work together, on a without prejudice basis, to pursue common objectives for the AGS Water Licence renewal.

- The Protocol Agreement (2016) did not expand CAFN's rights under the Final Agreement, but it confirmed that CAFN retained the right to participate freely in the regulatory review and Government consultation processes (i.e., under *YESAA* and the *Waters Act*) and to oppose any or all parts of what may be proposed.

- The shared work planning process provided a framework for extensive engagement with CAFN and other relevant stakeholders that commenced in 2016 and extended throughout the Project planning phase until the fall of 2018. This

included Yukon Energy and CAFN working jointly to direct the consulting team regarding the Project work plan and schedule, including the scope of the baseline studies, a structured decision making process to jointly attempt to determine a preferred operating regime, and the opportunity to review and comment on initial Project Proposal draft documentation.

- The shared work planning process under the Protocol Agreement ended in October 2018 as the parties were unable to obtain consensus regarding the operating range for Aishihik Lake. Due to the impending licence renewal deadline Yukon Energy proceeded with preparing and filing a YESAA Project Proposal that reflected key elements of Water Use Licence HY99-011. CAFN indicated that it was not in agreement with Yukon Energy's decision to move ahead with its preferred operating alternative.

The above experience between 2016 and the end of 2018 resulted in a greatly expanded and prolonged impact assessment study and CAFN engagement processes that delayed initiation of required YESAA evaluation and subsequent permitting activities. YEC attempted to move ahead by the start of 2019 with its 25-year YESAA Project Proposal – but - as outlined below - work on this project had to be deferred to address a three-year short-term relicensing project.

Yukon Government Reconciliation Discussions – Three Year Licence

Yukon Energy brought forward the AGS Relicensing Project Proposal in February 2019 for a three-year renewal term. This was done to allow the YG and YEC to engage with CAFN on reconciliation related issues including historic grievances CAFN had with the Aishihik facility and to avoid a lapse in Yukon Energy's water use licence for the AGS and termination of Yukon's encumbering rights related to this project under the CAFN Final Agreement.[2]

The three year licence approved by the Yukon Water Board in early 2020 outlined a number of additional regulatory requirements for the 2020-2022 period that have driven added costs for completion of the long-term relicensing project. The regulatory requirements included: additional collaborative monitoring and studies during the three

[2] Due to delays in filing the YESAA Project Proposal to accommodate Yukon Government discussions with Champagne and Aishihik First Nations (CAFN), Yukon Energy had to address material risks that the regulatory review timelines could extend beyond 2019.

year licence; development of a collaborative downstream monitoring and adaptive management plan; and reporting on collaboration with CAFN and other parties in relation to the required monitoring and adaptive management specified in the licence.

After the three year licence renewal was secured in early 2020, Yukon Energy engaged in a further collaborative process with CAFN and YG to develop a Monitoring and Adaptive Management Plan (MAMP) for the long-term licence renewal. Concurrently, CAFN, YG and Yukon Energy continue to work on concluding a reconciliation agreement to address long-standing issues of mutual interest. These activities were also not anticipated in the initial September 2015 project budget, and result in further material schedule extensions and cost increases.

At the time of filing this IR response, negotiations for the reconciliation agreement have substantively progressed, but have yet to be concluded.

In summary, the use of a collaborative process with CAFN from 2016 to 2018, prior to the 2019 filing and over 2020 and 2021 has led to very material increases in effort and related costs to date and a significantly longer process than originally envisioned.

The only way to reduce costs would have been to reduce the level of collaboration with CAFN regarding the relicensing process and avoid the 3-year renewal requirement by completing the 25-year relicensing proposal in accordance with the initial schedule. However, in the context of the Water Use Licence and a Yukon government led agreement process with CAFN related to this project and other outstanding issues, this was not feasible – and any such option would not have had any assurance that the end result would have secured the required licence.

YEC plans to conduct a comprehensive ‘lessons learned’ analysis prior to the initiation of similar future relicensing projects in order to increase the estimation of project costs by increasing the accuracy of estimated technical effort and engagement requirements.

Appendix A: Importance of AGS for the Yukon Integrated System

The Aishihik Generating Station (AGS) is a critical asset for the Yukon Integrated System (YIS); and ensuring that the regulatory instruments required for its ongoing operation are sustained is an essential requirement and responsibility for Yukon Energy.

- The AGS provides the only material annual storage in the Yukon and load following power, after non-dispatchable generation resources (e.g., any existing wind or run-of-river hydro generation facilities) have been utilized.

- Under long-term average water conditions, the AGS supplies approximately 25% of the total annual YIS generation – and about 40% of annual YIS winter generation concentrated in the months from November through May when peak YIS loads occur and run-of-river hydro supplies are constrained.

- The AGS also provides 37 MW of dependable capacity[3] to the YIS, which is more than one quarter of Yukon Energy's maximum generation capacity.

- Cessation or reduction of AGS operation would require that the current generation capability of AGS be replaced with some other source of energy that could be relied upon during the winter months. No such renewable alternative is in place today.

- Prior to planning, permitting and development of any new alternative generation capability, including renewable supply options, YEC would need to rely on existing thermal generation to replace the energy supplied currently by the AGS. Reliance on thermal generation to replace AGS hydro generation would have ongoing and very significant added generation operation costs (for fuel and non-fuel O&M) as well as added GHG emissions.[4]

[3] Dependable capacity, expressed in MW, is the maximum generation output that a resource can reliably provide in a specific timeframe, typically during the period of greatest demand. YEC defines dependable capacity as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months (November to February) based on the inflows in the five driest inflow years in history.

[4] Implications are discussed at a high level in Appendix 6C of YEC's 2020 YESAB Project Proposal, which provides estimates of added capital and O&M costs as well as added GHG emissions associated with an alternative (Alternative 7) that removes AGS storage capability as proposed by CAFN and limits operating to the pre AGS Aishihik Lake LSL and FSL levels, i.e., the high added capital costs (+$100 million), O&M costs (~$12 million per year long-term average for thermal generation) and GHG emissions (+32 kt/year CO2e long-term average) for this alternative compared with the existing licence under 2021 grid loads and grid configuration which still retains run-of-river hydro generation benefits from the AGS.

- Yukon Energy assessments also indicate that the 37 MW of AGS dependable capacity would also likely need to be replaced with new thermal generation capacity in order to maintain dependable winter supply capability, which would require time for planning and permitting and a capital cost for new thermal generation capacity in excess of $100 million (a significantly higher capital cost would be required for similar new dependable renewable capacity even if such an alternative was available in the near to medium term).

In light of the above considerations, renewal of the AGS water use licence under terms substantially similar to the 2002 water use licence has been (and continues to be) considered the only reasonable option for Yukon Energy to pursue at this time.

REFERENCE: **Application, Appendix 5.3, page 5.3-3**

ISSUE: **Whitehorse Generating Station Water Use Licence Renewal Project**

QUOTE: "The existing water use licence for the Whitehorse Rapids Generating Station (WRGS) expires at end of 2025 and must be renewed in order to ensure ongoing, lawful operation of the WRGS hydro facilities. This is a multi-year project to renew the existing long-term project authorizations for the WRGS Hydro Plants and associated infrastructure. Project activities include conducting required baseline studies (e.g. environmental, socio-economic, engineering), and undertaking environmental and socio-economic effects assessment, First Nation engagement and consultation, other stakeholder engagement as required to submit a YESAA project proposal to the Whitehorse Designated Office. Project activities will also include completing the YESAA review process, the water use renewal process with the Yukon Water Board, and Fisheries Act Authorization (DFO) regulatory process."

QUESTION:

a) Is the $260,000 cost for 2021 the full expected cost of this project? If not, please provide the full expected cost of this project along with a breakdown of that cost into individual cost components. Please also include a description of why each cost component is a necessary part of the project.

b) What measures is YEC undertaking to ensure that the cost of this project does not increase by a similar magnitude as the costs for the Aishihik licence renewal?

c) What efforts have been made to streamline planning work for the Southern Lakes Enhanced Storage to avoid duplication with this water licence renewal project?

ANSWER:

(a)

No. The estimated cost of the full project is approximately $5,000,000. A detailed workplan and budget will be developed as part of the project initiation work in 2021.

(b)

YEC plans to conduct a “lessons learned’ exercise regarding the Aishihik licence renewal to identify areas for improvement and lessons to apply to the Whitehorse generating station renewal.

(c)

The scope of the assessment and permitting for the Southern Lakes Enhanced Storage Project will include an examination primarily of the storage component of the Whitehorse Rapids Generating Station operations. The subsequent water use licence renewal for the whole facility and operations, including an extension to the term of the project authorizations, will have a broader scope. It is expected that most of the issues that will be examined during the assessment and permitting for the Enhanced Storage Project will be able to stand as evidence for the assessment and permitting for the long-term licence renewal and will effectively limit the scope of the water use licence renewal project to primarily those things that were not otherwise assessed during the Enhanced Storage Project just a few years earlier. Accordingly, it is anticipated that redundancy will be minimized and the scope of the water relicensing project will be reduced via the work done on the Enhanced Storage Project.

REFERENCE: **Application, Appendix 5.3, page 5.3-3 to 5.3-4**

ISSUE: **Diesel Retirement Replacement Project**

QUOTE: "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. YEC 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 given the need to maintain reliable service and to address an ongoing and growing dependable capacity shortfall.

The 2016 Resource Plan identified a new 20 MW greenfield diesel plant as one of the preferred options for addressing the dependable capacity shortfall gap in a cost effective manner in the near term. The YUB reviewed planning for the project during the 2017/18 GRA, and noted it was not persuaded that the project was the only way to address the predicted capacity shortfall, and that YEC should not proceed with the project without a detailed business case that considers the alternatives to the project.

Following the Board's direction in Order 2018-10, YEC proceeded with the additional work as required to evaluate project alternatives. This included identifying and evaluating a number of options for a new 20 MW thermal plant. In October 2019, it was determined that considering the results of the technical, environmental and socio- economic research, as well as public feedback, YEC would focus potential options to add or replace capacity at existing generation facilities on an incremental basis as diesel engines are retired.

This includes consideration of the following near term activities:

- Installation of 5 MW of thermal capacity at the Whitehorse Diesel Plant (P126);

- Replacement of 5.1 MW of diesel to be retired at the Faro Diesel Plant with a 5 MW diesel unit;

- Retirement of the existing 2.5 MW of diesel capacity in Dawson City with installation of 2.5 MW of diesel capacity at the Callison Substation.

Efforts in 2020 have focused on preliminary engineering and finalizing a procurement strategy, defining vendor contracts and milestones, and updating the overall project schedule.

The deferred costs forecast in the Application assume that the project continues, with spending in WIP increasing from $0.041 million at the end of 2018 to $6.395 million by the end of 2021. Dependable capacity from these projects is expected to be available by winter 2023/24. In the interim, YEC will continue to rent diesel generators each winter to ensure an adequate supply of back-up power in case of an emergency."

QUESTION:

a) Is the $6.395 million estimate for the end of 2021 the full estimated cost of this project? If not, please provide the full estimated cost.

b) Please provide a breakdown of the $6.395 million into the various components of this project, including a description of why each component is required.

c) Please provide the results of the analysis YEC carried out to compare the costs and benefits of the various alternatives considered in response to the Board's finding that it "requires a detailed evaluation of alternatives to this project included in the business case."

ANSWER:

(a)

The full cost of the project is estimated to be $45 million.

(b)

Subsequent to the submission of the Application the project cost for 2021 has been adjusted to $1,920,000 based on updated project planning. This change will be reflected in YEC's Compliance Filing.

A breakdown of all actual costs from 2018 WIP to 2020, and forecast 2021 costs, is shown in Table 1 below.

Table 1: Estimated Project Costs

	Actuals - 2018WIP	**Actuals - 2019**	**Actuals - 2020**	**2021 Forecast**
Feasibility Engineering	$6,775	$349,724	$238,654	$-
Preliminary Engineering & Procurement	$-	$-	$86,101	$1,100,000
Assessment & Permitting	$-	$20,541	$78,166	$220,000
Public & First Nations Engagement	$-	$98,764	$-	$50,000
Project Management	$33,897	$78,758	$50,914	$500,000
AFUDC	$334	$6,437	$21,947	$50,000
Total	**$41,006**	**$554,224**	**$475,783**	**$1,920,000**

(c)

The use of a 20 MW greenfield thermal plant as the reference point for comparison was originally based on the findings of the 2016 Resource Plan, which included a 20 MW greenfield diesel plant in the recommended portfolio to address the forecast N-1 dependable capacity shortfall on the Yukon Integrated System (YIS). The initial analysis did not assess options (including requirements) involving replacement and/or addition of diesel units at existing plant facilities on the YIS, and assumed a need to rely primarily on new thermal generation to address the N-1 dependable capacity shortfall.

Ongoing Yukon Energy review and consultation on 20 MW plant options, including potential addition of units at the Whitehorse diesel plant, indicated a wide range of concerns regarding development of a new large greenfield diesel plant – as well as higher costs and uncertainties if similar scaled development was to be focused at the existing Whitehorse diesel plant. The resultant reconsideration of the new thermal generation recommended in the 2016 Resource Plan led to increased reliance on short-term diesel rentals to address the near-term capacity shortfall and provide time to assess a wider range of options.

Ongoing review of YEC diesel facilities at Faro, Dawson and Mayo indicated site-specific requirements and opportunities that needed to be addressed when assessing optimum overall new diesel unit planning on the YIS to address forecast N-1 dependable capacity shortfalls. For example, assessments indicated a potential need to relocate diesel capacity required at Dawson and Mayo for reasons unrelated to the N-1 dependable capacity deficit, with resultant opportunities in each case (including planned retirement of two units at Dawson in 2023) to provide cost-effective new diesel capacity to the YIS. Recent studies also highlighted opportunities to provide new cost-effective incremental diesel capacity at the existing Faro diesel plant where a unit is planned to be retired in 2023. The Whitehorse diesel plant also provides ongoing opportunities to replace the three retired Mirrlees diesel units.

Updated resource plans also separately identified potential renewable generation options that could significantly reduce the need to rely primarily on new thermal generation to address the forecast N-1 dependable capacity shortfall.

Based on the above reviews, the 2016 Resource Plan has now been superseded by YEC's 10 Year Renewable Electricity Plan, which includes the development of 12.5 MW of replacement diesel capacity at three different existing plant sites (Faro, Dawson and Whitehorse) in the recommended portfolio of projects as well as planning for potential development of a major pumped storage dependable capacity option and a near-term Atlin Hydro Expansion dependable capacity project. Therefore, the development of a new 20 MW greenfield thermal plant is no longer a relevant option for current planning given the Corporation's current business plan as reflected in the 10 Year Renewable Electricity Plan, i.e., developing 20 MW of new thermal generation today would be inconsistent with consideration of the renewable pumped storage option combined with the Atlin Hydro Expansion project.

The 12.5 MW of diesel retirement replacement now being planned involves three separate diesel plant projects, each with its own cost prudence assessment based on plant site requirements and options. Economic assessment for each facility focuses on levelized cost of capacity (LCOC) for each option, given the need to provide dependable capacity that is not expected to have material long term average levels of thermal energy generation. Ongoing cost experience with rented diesels provides a benchmark to assess an option to development of new permanent diesel replacement capacity.

REFERENCE: **Application, Appendix 5.3, page 5.3-4**

ISSUE: **Southern Lakes Enhanced Storage Project (Marsh Lake Storage Project)**

QUOTE: "Forecast MLSEP project costs and actual expenditures were reviewed in detail in the 2012/13 and the 2017/18 GRAs. The 2012/13 GRA, identified the project as a relatively small project, with earliest in-service assumed in 2014 (first full year 2015) at a capital cost (2010$) of $10.5 million, with mitigation design (shoreline erosion and surface water) expected to comprise about one-half of this total cost (actual costs for mitigation were stated in the 2012/13 GRA as an item that at that time could not be known with any certainty). In the 2017/18 GRA, forecast total project costs increased to $15.377 million ($9.795 million forecast for effects assessment; $0.300 million forecast for YESAA assessment and permitting; and $7.127 million forecast for mitigation implementation).

"YEC completed an additional round of engagement in 2019 to confirm the level of support for the project. This included engagement with local residents in the Southern Lakes area, and Yukoners generally; as well as a further round of First Nations engagement to confirm the position of the affected First Nations (Carcross/Tagish First Nation, Kwanlin Dun First Nation and Ta'an Kwach'an Council). Prior to the end of 2020, YEC will make a determination regarding whether to advance the project to the YESAA assessment phase.

The deferred costs forecast in the Application assumes that the project continues, with spending in WIP increasing from $7.319 million at the end of 2018 to $9.379 million by the end of 2021. Potential in service for the Project is 2023."

QUESTION:

a) Please provide an update on the status of this project including but not limited to the outcome of First Nations and public engagement and YEC's decision on whether to proceed with this project.

b) If YEC is proceeding with this project, please provide:

i. updated cost forecasts along with detailed explanations for any cost increases relative to the forecast provided in 2017-18;

ii. a detailed work plan for completion of the project, including timing for individual components of the project;

iii. a breakdown of the costs forecast for the various work components comprising the project, including all plans for shoreline erosion and property owner septic upgrades and other mitigations;

iv. steps YEC is taking to prevent cost increases for the project; and

v. results of analysis performed by YEC examining the costs and benefits of the project relative to any alternatives considered by YEC.

ANSWER:

(a)

In 2019 and early 2020 YEC conducted a final round of public engagement regarding the project. Based on the results of this engagement and the estimated economics of the project, YEC's Board of Directors decided to advance the project into the next stage: preparing a proposal to submission to the YESAA Designated Office.

(b)

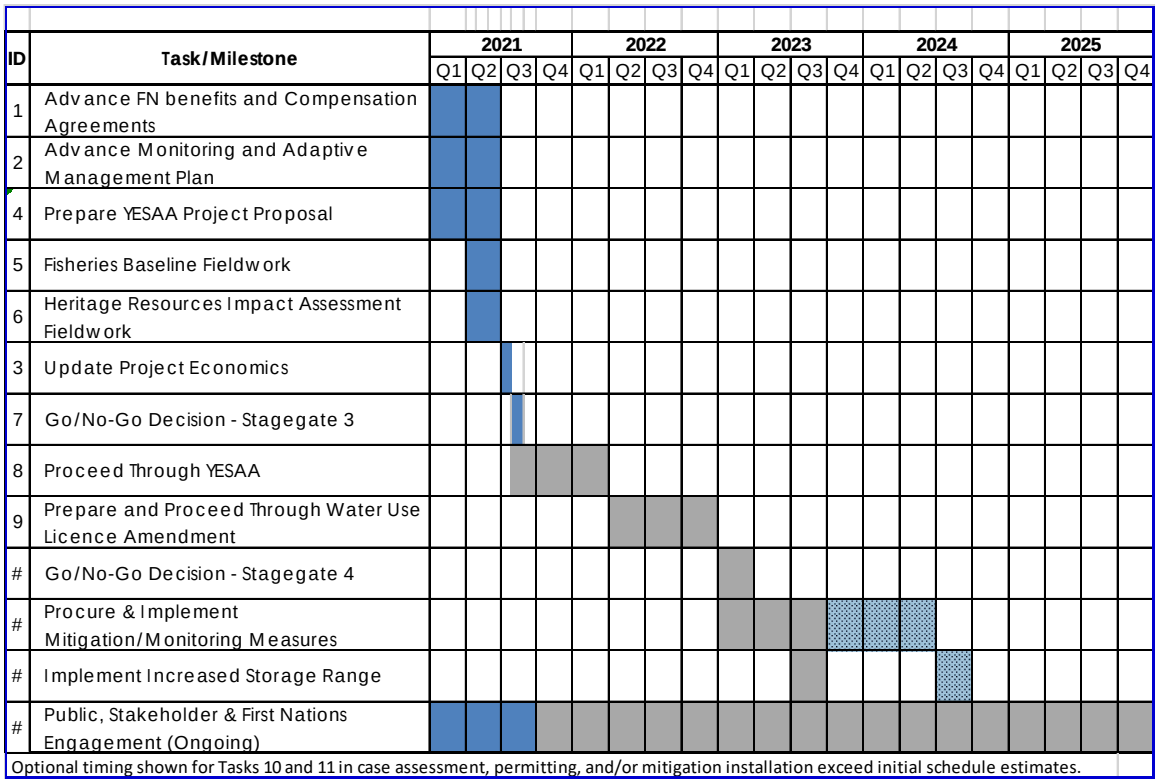
(i)

The current total project cost estimate is $17.1 million.

(ii)

The current workplan as outlined below includes collaboration with impacted First Nations who contribute to the development of the Monitoring & Adaptive Management Plan and

conducting required fieldwork such as the Heritage Resources Impact Assessment. This workplan will inform the finalization of the overall project timeline.



ID	Task/Milestone	2021				2022				2023				2024				2025			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	Advance FN benefits and Compensation Agreements																				
2	Advance Monitoring and Adaptive Management Plan																				
4	Prepare YESAA Project Proposal																				
5	Fisheries Baseline Fieldwork																				
6	Heritage Resources Impact Assessment Fieldwork																				
3	Update Project Economics																				
7	Go/No-Go Decision - Stagegate 3																				
8	Proceed Through YESAA																				
9	Prepare and Proceed Through Water Use Licence Amendment																				
#	Go/No-Go Decision - Stagegate 4																				
#	Procure & Implement Mitigation/Monitoring Measures																				
#	Implement Increased Storage Range																				
#	Public, Stakeholder & First Nations Engagement (Ongoing)																				

Optional timing shown for Tasks 10 and 11 in case assessment, permitting, and/or mitigation installation exceed initial schedule estimates.

(iii)

The estimated cost components are provided in the table below.

($000's)	Forecast Total Project Costs
Concept Definition & Baseline Studies (2009-2012)	4,305
Preliminary Effects Assessment (2013-2014)	1,229
Mitigation Design & Consultation (2015-2020)	2,234
Additional Engagement & Assessment Prep (2020-2021)	1,314
Assessment & Permitting	800
Project Implementation (Mitigation construction)	7,200
Total Estimated Project Costs	**17,082**

(iv)

YEC is working to confirm mitigation plans for impacted properties and refine estimates to ensure costs are fully understood before moving forward with the project. Using a stagegate approach to assess a "go" or "no go" decision after more information is known from the results of the YESAA assessment will enable a decision to be made regarding the project with refined information on the economics.

(v)

An updated analysis of the Project economics was completed in early 2020 using the estimated Project costs available at the time. The added water storage is forecast to produce an additional ~6.5 GWh/year of winter energy, which would reduce thermal generation costs for ratepayers.

From an economic perspective, the Project provides energy at a levelized cost of $0.17/kWh over an economic life of 25 years (WACC of 5.9%) which compares favorably to the marginal cost of thermal generation (blend fuel price of $0.184/kWh in 2021 GRA forecast).

Given the favorable economics of the SLESP, the Project was included in the recommended project portfolio from both the 2016 Resource plan and the 2020 10 Year

Renewable Electricity Plan, as a near term project to increase the support of cost effective winter energy on the YEC system.

REFERENCE: **Application, Appendix 5.3, page 5.3-6**

ISSUE: **Mayo Lake Storage Enhancement Project**

QUOTE: "In 2018, Northwest Hydraulic Consultants (NHC) was retained to provide a technical assessment regarding whether sediment remediation steps in the Mayo Outlet Channel were feasible and cost effective. This assessment determined that removal of a coffer dam remnant in the outlet channel would improve flow in the near term and, through scouring activity, could potentially also remove the sediment from the channel; if required, as a next step, dredging the channel upstream of the coffer dam could improve hydraulic benefit for power generation. YEC has subsequently proceeded with preparing a YESAA assessment for the project (including the two-phase outlet channel work) which is targeted to be filed with the Mayo Designated Office before the end of 2020.

The deferred costs forecast in the Application assume that the project continues, with spending in WIP increasing from $3.373 million at the end of 2018 to $4.621 million by the end of 2021. Provided licencing processes commence in late 2020/early 2021, potential in service of the amended licence would be in 2023. Work to remove the coffer dam remnant would then proceed as a separate project."

QUESTION:

a) A detailed work plan for completion of the project, including timing for individual components of the project;

b) A total forecast costs for the project and a breakdown of the costs forecast for the various work components comprising the project;

c) Steps YEC is taking to prevent cost increases for the project; and

d) Results of analysis performed by YEC examining the costs and benefits of the project relative to any alternatives considered by YEC.

ANSWER:

(a)

The estimated work plan for completion of the project is shown below. This is subject to FNNND's confirmation of ability to complete review as proposed.

Task	Proposed Completion Date
Assessment and Permitting	
Baseline Studies	Ongoing
YESAA Assessment	
Project Proposal reviewed by FNNND completed	March 1, 2021
FNNND Chief & Council reconfirmation of support to submit	March 15, 2021
File of YESAA Project Proposal	March 31, 2021
Issuance of Decision Document[1]	November 18, 2021
Water Use Licence	
File Water Use License Amendment Application	June 1, 2021
Receipt of amended Water Use License[2]	March 2022
Fisheries Act Authorization	
File Request for Fisheries Act Authorization	June 30, 2021
Receipt of Fisheries Act Authorization[3]	July 2022
Consultation and Engagement	
Consultation and Engagement with FNNND[4]	Ongoing through assessment and permitting
Engineering	
Boat Ramp Extension Design	December 2021
Construction and Implementation	
Boat Ramp Extension	May 2022
Phase 1 Dredging (Cofferdam Removal)	August 2022
Phase 2 Dredging (if required)[4]	2025/2026

Assumptions:

1. Assuming a DO filing no later than March 31, 2021 and that the DO will take maximum time at each stage.
2. Assuming a filing to the Yukon Water Board for a Water Use License amendment no later than June 1, 2021.
3. Assuming a filing to Fisheries and Oceans Canada no later than June 30, 2021.
4. Phase 2 Dredging is dependent on the results of the Phase 1 Dredging. Following the Phase 1 Dredging, two to three years of monitoring will be conducted to monitor results of Phase 1 Dredging and determine if Phase 2 Dredging is required.

(b)

The total forecast costs to project completion are shown below.

Task	Forecast at Completion
Planning (Pre-YESAA)	$4.5M
Assessment & Licensing	$500k
Phase 1 Dredging	$1.1M
Phase 2 Dredging (if required)	$6.5M to $9.7M
Overall Project Total	**$6.1M to $15.8M**

(c)

YEC continues to employ project management practices to manage budget and scope, including review of project costs and benefits at each stage of decisions.

(d)

An economic analysis has examined the project value based on a capital investment amortization period of 45 years and 65 years, across several project scenarios. Three scenarios were run for each of the project added storage ranges (0.5 m and 1 m) with different Phase 2 dredging disposal options, and for each of the 45 year and 65 year project life assumptions. The project life is based on the durability of the proposed dredging and the expected frequency of the future channel dredging:

- A 65 year project life is based on the fact that the control structure has existed since the early 1950s (approximately 70 years) and that this duration would be a reasonable estimate of the expected life of the proposed dredging.

- A more conservative case uses a shorter, 45-year project life in the instance that dredging is required more frequently.

The 2019 estimated levelized cost of energy (LCOE) for the matrix of cases is presented below. As can be seen from the results, the project has a competitive LCOE under even the most conservative of the scenario (45 year project life, 0.5 m storage range extension) when compared to the marginal cost of natural gas generation (approximately $0.18/kWh). Updated LCOE analysis will be provided for the 2021 regulatory submissions.

Project Life	Added Storage Assumption (m)	LTA Added Winter Energy (GWh/yr)	Phase 1 Dredging Only LCOE ($/kWh)	Phase 1 + Phase 2 Dredging LCOE ($/kWh)	
				Lake Disposal	Land Disposal
45 years	0.5	~3.7	$0.05	$0.11	$0.13
	1	~6.3	$0.03	$0.07	$0.08
65 years	0.5	~3.7	$0.05	$0.09	$0.11
	1	~6.3	$0.03	$0.06	$0.07

1

REFERENCE: **Application, Appendix 5.4, page 5.4-2**

ISSUE: **IPP Standing Offer Program Implementation**

QUOTE: "YEC and ATCO Electric Yukon (AEY) are responsible for implementing the Yukon Government's Independent Power Producers (IPP) Policy … The project is to be closed in 2020 with total expenditures of $232,039 to be amortized over five years. The Standing Offer Program (SOP) was developed based on the model used in British Columbia and required development of the following key documents: (1) SOP Program Guide; (2) SOP Program Rules); (3) SOP Application Process; (4) SOP Application Form; (5) Interconnection Standards; and (6) Electricity Purchase Agreement Template."

QUESTION:

a) Please provide a summary of the legislative requirements, any policy directives or government directives which support the statement "YEC and ATCO Electric Yukon (AEY) are responsible for implementing the Yukon Government's Independent Power Producers (IPP) Policy".

b) Please explain what YEC means when they say the project will be "closed" in 2020. Does this mean it will be completed, cancelled or put on hold?

c) Please provide a copy of the documentation for the British Columbia model used by YEC as well as the "key documents" listed in the quote above.

d) Please provide a breakdown of the project components comprising the $232,039.

ANSWER:

(a)

The referenced statement simply reflects the direction by YG in the IPP policy that YEC and AEY are the two public utilities responsible for implementing all contracts and connections with IPPs as required to implement the Yukon Government's IPP Policy.[1]

(b)

In this instance, the term "closed" means that the project will be completed.

(c)

Please see Attachment 1 to this response which provides relevant documents for the YEC SOP program. Attachment 2 to this response provides documentation for the British Columbia model that is available from BC Hydro's website.

(d)

Please see Table 1 below for the actual cost breakdown for project components, which include an increase in actual over forecast of $50k. The following is noted:

1. ATCO's Legal costs to develop the Standing Offer Program rules were cost shared.

2. DLA Piper provided legal services to YEC regarding review the SOP Rules, development of the Electricity Purchase Agreement template, development of systemic responses to address initial inquiries from three early SOP applicants; and developing additional documents to support the EPA such as a Lenders Consent Agreement.

[1] Yukon's IPP Policy is available at the following link: https://yukon.ca/sites/yukon.ca/files/emr/emr-yukon-independent-power-production-policy.pdf.

3. Teshmont developed the System Interconnection Guidelines which is a foundational technical document providing guidance and requirement to the SOP proponent to connect to the grid.

4. Info session food reflects costs for an information session for interested IPP Proponents held on April 25, 2019.

Table 1: IPP Standing Offer Program Implementation Costs

ATCO Electric Yukon - PO		154,949.64
DLA Piper (Canada) LLP		76,984.88
Teshmont Consultants LP		36,985.00
AFUDC		10,244.82
Info Session Food		528.38
Labour		224.51
Orbis Engineering Field Service Ltd.		139.32
	$	280,056.55

STANDING OFFER PROGRAM APPLICATION FORM

Standing Offer Program Application Form

[Revised: January 2019]

General Instructions

- For the purposes of this Standing Offer Application Form, capitalized terms not otherwise defined herein shall have the meaning given thereto in the SOP Rules available at the "Documents" page of the SOP Website located at www.yukon.ca/standingoffer.

- To complete the Application Form, fill out each field that is represented by a blue box. Use drop down menus to make selections, where provided.

- A Developer should be fully responsive to each instruction, as applicable to the Developer and its Project. If a Developer is in any doubt as to the requirements contained in these instructions, it should seek clarification from the SOP Administrator at the address specified in Section 9 of the Rules.

- When completed, name the Application Form "Application" and save in Adobe ("PDF") format for inclusion in the electronic copy of your Application submission.

- Name the Exhibits according to the labelling of Exhibits in the Application Form and save the Exhibits in PDF, MS Excel or MS Word format for inclusion in the electronic copy of your Application submission. Insert "N/A" for Exhibits not applicable to your Project.

- Yukon Energy Corporation and/or ATCO Electric Yukon reserves the right to request additional information in relation to any information requested in this Application Form.

Application Submission Instructions

To apply for the Standing Offer Program, the Developer must submit the following:

- a scanned copy of the completed Standing Offer Program Application signed by the Developer with applicable Exhibits, in electronic form; and

- if required, a scanned copy of the completed Confidentiality and Compliance Agreement signed by the Developer (if not previously submitted with a pre-application meeting or preliminary assessment request);

by email to the SOP Administrator at IPPAdministrator@gov.yk.ca or delivered on one (1) disk or USB flash drive to:

Yukon Government
Energy Branch
206A Lowe Street
Whitehorse, Yukon, Y1A 2C6
Attention: SOP Administrator

by email to YEC at IPP@yec.yk.ca or delivered on one (1) disk or USB flash drive to:

Yukon Energy Corporation
#2 Miles Canyon Road
Box 5920, Whitehorse, Yukon Y1A 6S7
Attention: President

by email to AEY at AEY_SOP@atco.com or delivered on one (1) disk or USB flash drive to:

ATCO Electric Yukon
Standing Offer Program
100 – 1100 Front Street
Whitehorse, Yukon Y1A 3T4
Attention: Manager

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1. DEVELOPER

1.1 Developer Information

Project name:

Developer's full legal name:

Address:	City:	Province:	Country:	Postal Code:
Developer/Project website address:				
Main Contact Person (All Correspondence and Agreements will be sent to the Main Contact Person)				
First name:		Last name:		
Title:		Email:		
Phone:	Alternate Phone:		Fax:	
Alternate Contact Person (Optional)				
First name:		Last name		
Title:		Email:		
Phone:	Alternate Phone:		Fax:	

1.2 Developer Identity

Form of organization (e.g., corporation, general partnership, limited partnership, joint venture, local government, public institution, etc.):

Jurisdiction in which the Developer is incorporated or formed:	Date of incorporation or formation: incorporated or formed (YYYY-MMM-DD):	Incorporation (or similar) number:

Member Details

Member's full name:

Form of organization (e.g., corporation, general partnership, limited partnership, joint venture, local government, public institution, etc.):

Jurisdiction in which the Developer is incorporated or formed:	Date of incorporation or formation: incorporated or formed (YYYY-MMM-DD):	Incorporation (or similar) number:
Date of registration in Yukon (YYYY-MMM-DD):		Registration number:

1.3 Project of Ownership Structure

Provide an organization chart that shows all direct and indirect owners to the ultimate controlling owner(s) of the Project.

☐ Included and named Exhibit 1.

1.4 Project Team

Provide a list of Project development team members including key outside contractors and consultants. Add additional rows if necessary.

Team Member	Role

1.5 Conflict of Interest

As required under Yukon Energy Corporation's and/or ATCO Electric Yukon's Contractor Standards for Ethical Conduct, the Developer must provide on its own behalf and on behalf of each member of the Developer's team a declaration in relation to the potential to be in an actual, apparent or deemed conflict of interest as a result of entering into an EPA with Yukon Energy Corporation and/or ATCO Electric Yukon, as described in Section 3.15 of the Rules.

Complete the Conflict of Interest Statement Form.

☐ Included and named Exhibit 2.

2. PROJECT INFORMATION

2.1 Project Description

(a) Provide a short, general description of the Project		
(b) Provide the Nameplate Capacity of each new generator		
Generator	MW	
Total (MW)		
Comments		
(c) Location		
Project Region:	Nearest Community:	
The approximate latitude and longitude of the project site is (in degrees minutes seconds)	Latitude (99°99'99" North):	
	Longitude (99°99'99" West):	
Parcel Identifier Number	Ownership Status	Describe if "Other"
Provide a geographical map of the Project location ☐ Included and named Exhibit 3.		
Provide the expected layout of the key facilities comprising the Project ☐ Included and named Exhibit 4.		
Is the Project described in the Application located on the same site or in the vicinity of a Project Cluster?		

Does the Project share any facilities with a Project Cluster?	
If "Yes" to either of the above two questions:	
i) Does any project that is part of a Project Cluster have an EPA with Yukon Energy Corporation and/or ATCO Electric Yukon or another party?	
ii) Complete Project Clusters Supplementary Information available on the Documents page of the SOP Website. ☐ Included and named Exhibit 5.	
Does any part of the Project require access to a Yukon Energy Corporation and/or ATCO Electric Yukon right of way?	
(d) The Target COD for the project is (YYYY-MMM-DD):	
(e) The requested Term of the EPA for the Project is (years):	
(f) Provide the Project schedule ☐ Included and named Exhibit 6	
(g) Total estimated Project energy volume	

Month	Average monthly energy output (MWh)
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

Total:	

Provide calculations supporting the average monthly energy output.

☐ Included and named Exhibit 7.

(h) Project Type

The energy delivered to Yukon Energy Corporation and/or ATCO Electric Yukon under the EPA must be Eligible Clean Energy. Select the Project type:

☐ Biomass ☐ Geothermal	☐ Hydro ☐ Solar	☐ Wind

2.2 Generation Technology

(a) Describe the complete generation process that converts raw fuel into electricity. If necessary, include diagrams in Exhibit 8.

☐ Included and named Exhibit 8.

Provide the location and date of initial operation for at least one generation plant that is using the same generation technology proposed for the Project:	Date of initial operation (YYYY-MMM-DD):

2.3 Existing and Previous Electricity Purchase Agreements

(a)	Is the Project currently subject to an EPA with Yukon Energy Corporation and/or ATCO Electric Yukon?	
(b)	Has the Project ever previously been subject to an EPA with Yukon Energy Corporation and/or ATCO Electric Yukon?	
	If "Yes", describe and provide the effective date of termination of the EPA (YYYY-MMM-DD):	
	Did the Project reach commercial operation while the EPA was in effect?	
(c)	Is the Project currently subject to an EPA with a party other than Yukon Energy Corporation and/or ATCO Electric Yukon?	

If "Yes", describe and provide the EPA (pricing information may be kept confidential). ☐ Included and named Exhibit 9.

2.4 Preliminary Feasibility Assessment

Has a preliminary feasibility assessment of the Project and/or the Developer as described in Section 5.2 of the Rules been conducted?	

3. PERMITS, SITE CONTROL AND ZONING

The Developer must comply with all laws, statutes and regulations relating to the Project whether federal, provincial and/or municipal and must obtain all permits, licenses and approvals required for the development, construction and operation of the Project. The following list is not a complete list of all permits, licenses and approvals required for any Project. Developers are solely responsible for determining the permitting and other legal requirements for their Projects.

The information provided by the Developer in response to this part of the Application should address all parts of the Project site (including all areas where the generating facility and related access roads, transmission lines and other Project facilities will be built).

Yukon Energy Corporation and/or ATCO Electric Yukon may request the Developer to provide confirmation from the relevant regulatory authority that a permit or approval is not required for a Project.

☐ If requested, included and named Exhibits 10-13.

3.1 Supplementary Information

(a) Are any of the permits, licenses and approvals for the Project under appeal or judicial review?

If "Yes", describe:

(b) Is there any outstanding order, judgment, litigation or other proceeding with respect to the Project?

If "Yes", describe:

(c) Is there any significant opposition to the Project?

If "Yes", describe:

4. INTERCONNECTION

(a) Has a System Impact Study application been submitted to Yukon Energy Corporation and/or ATCO Electric Yukon?

(b) Have any other interconnection studies been completed for this Project?

If "Yes", provide the study.

(c) Point of Interconnection (e.g. nearest substation), if known:

(d) Interconnection voltage level (kV):

(e) Interconnection to:

(f) Describe the proposed point of delivery of energy to Yukon Energy Corporation and/or ATCO Electric Yukon on the Distribution System or the Transmission System.

5. FIRST NATIONS

Describe all First Nations consultations and engagement conducted relative to the Project. Provide a copy of all executed agreements with First Nations with respect to the Project. Include any letters of support from First Nations for the Project, if available.

☐ Included and named Exhibit 14.

6. REPRESENTATIONS, WARRANTIES AND COVENANTS

The Developer represents, warrants, and covenants with Yukon Energy Corporation and/or ATCO Electric Yukon as follows and understands that Yukon Energy Corporation and/or ATCO Electric Yukon is relying on these representations, warranties and covenants in deciding whether to offer an EPA to the Developer:

6.1 The Developer has reviewed carefully and fully understands the Rules, the Standard Form EPA and all related documents posted to the SOP Website and has taken legal, accounting, engineering and other professional advice as the Developer considers necessary for it to understand its rights and obligations under the EPA if an EPA is offered to the Developer.

6.2 In preparing and submitting this Application, the Developer has not relied on any information given to it by Yukon Energy Corporation and/or ATCO Electric Yukon, whether orally, in writing, electronically or in any other form whatsoever, except information disclosed in the Rules, the SOP Website or advised in writing by the SOP Administrator.

6.3 In consideration for Yukon Energy Corporation and/or ATCO Electric Yukon reviewing the Developer's Application, the Developer agrees to the terms, conditions and exclusions and limitations of liability set out in the Rules in effect at the time the Application was submitted.

6.4 The information contained in the Application is true and correct in all material respects and there is no material information omitted from the Application that makes the information in the Application misleading or inaccurate in any material respect.

6.5 The Developer is duly incorporated, organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation, is registered or otherwise lawfully authorized to carry on business in Yukon, and has full power, capacity and authority to own its assets and to carry on its business as now conducted and to enter into and to perform its obligations under the EPA if an EPA is offered to the Developer. If the Developer is a joint venture or partnership, this representation is true and correct for each of the participants in the joint venture or partnership.

6.6 No actions have been taken or authorized by the Developer or any other person to initiate proceedings for, or in respect of, the bankruptcy, insolvency, liquidation, dissolution or winding-up of the Developer or to appoint a receiver, liquidator, trustee or assignee in bankruptcy in respect of the Developer.

6.7 No appropriation, expropriation or seizure of all or any portion of the Project, or the assets required to construct, operate or maintain the Project, is pending or threatened.

6.8 Neither the signing of the EPA, nor the carrying out of the Developer's obligations under the EPA will: (i) constitute or cause a breach of, default under, or violation of, the constating documents or bylaws of the Developer, any permit, franchise, lease, license, approval or agreement to which the Developer is a party, or any other covenant or obligation binding on the Developer or affecting any of its properties, (ii) cause a lien or encumbrance to attach to any of the assets included in the Project (as defined in the Standard Form EPA), other than a security interest granted in respect of financing the design, construction or operation of the Project, or (iii) result in the acceleration, or the right to accelerate, any obligation under, or the termination of, or the right to terminate, any permit, franchise, lease, license, approval or agreement related to the Project.

6.9 In consideration for Yukon Energy Corporation and/or ATCO Electric Yukon reviewing the Developer's Application, the Developer agrees that: (A) Yukon Energy Corporation and/or ATCO Electric Yukon has

no liability to the Developer or any affiliates of the Developer for any failure by Yukon Energy Corporation and/or ATCO Electric Yukon prior to the effective date of an EPA to adequately consult with, and/or accommodate, any First Nations in relation to: (i) any decision to offer or not to offer an EPA to the Developer, (ii) the Project, (iii) the Developer's Plant, or (iv) the interconnection of the Developer's Plant to the Transmission System or the Distribution System (excluding matters arising on Yukon Energy Corporation's and/or ATCO Electric Yukon's side of the point of interconnection to the Transmission System or Distribution System); and (B) Yukon Energy Corporation's and/or ATCO Electric Yukon's liability, if any, for any failure by Yukon Energy Corporation and/or ATCO Electric Yukon after the effective date of an EPA to adequately consult with, and/ or accommodate any First Nations in relation to the foregoing matters will be determined in accordance with the EPA as if it was still in effect notwithstanding any expiry, termination, declaration by any order of a court or regulatory authority that the EPA is invalid, void or unenforceable, or any other means by which the EPA ceases to be in effect.

6.10 The Developer has read carefully, and it is in compliance with, the Yukon Energy Corporation and/or ATCO Electric Yukon Contractor Standards for Ethical Conduct which is current at the time of the Application. The Yukon Energy Corporation and/or ATCO Electric Yukon Contractor Standards for Ethical Conduct is available on the SOP Website.

7. SIGNATURES

If Developer is a corporation, use the following signature block

[Full legal name of Developer]
Signature:
Name:
Title:
Date (YYYY-MMM-DD):

If Developer is a limited partnership, use the following signature block

[Full legal name of Developer]
limited partnership, by its general partner,
[Full legal name of general partner]
Signature:
Name:
Title:
Date (YYYY-MMM-DD):

If Developer is a general partnership, use the following signature block

[Full legal name of Developer]
a general partnership, by its partners:
[Full legal name of Partner] Partner 1:
Signature:
Name:
Title:
Date (YYYY-MMM-DD):

If Developer is a joint venture, use the following signature block

[Full legal name of Developer]
a joint venture, by its members:
[Full legal name of JV Member] JV Member 1:
Signature:
Name:
Title:
Date (YYYY-MMM-DD):

8. LIST OF EXHIBITS MARKED FOR INCLUSION

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Independent Power Producers Pre-APPLICATION

Applicant Information

Organization Name:
Primary Contact:
Primary Address (Written notifications will be delivered to this address)
Doing business as (Please identify if you are a Society, a body corporate, a Yukon First Nation, Development Corporation, Partnership, or Limited Partnership, including your business/society number if applicable):
Applicant background (Please describe the experience of your organization, including the experience of team members, in deploying renewable projects of this type):
Conflict of Interest (Please declare whether or not any member of the project team, or anyone involved in the project is a Government of Yukon public servant or a board member or employee of an organization involved in the public utility sector (YDC, YEC, ATCO)):

Project Description Summary (Please include reference to geographic locations, relevant coordinates, resource type (wind/solar/biomass/geothermal), nameplate generating capacity, distance to transmission lines, and any other relevant information.).
Status of Project (Please describe work completed to date in support of project deployment, including any economic or technical feasibility assessments, community consultation, detailed engineering, the procurement of land, environmental assessment approvals, water licenses or other regulatory approvals, and/or community consultation).
Please include any relevant materials, such as completed feasibility studies, approvals, or other documentation necessary to support the project description or status provided above.

EXHIBIT "C"

STATEMENT OF PROJECT CHANGES FORM

Project Name: _____

Developer Name: _____

Date of Application: _____

The undersigned hereby represents and warrants to the Utility that:

☐ There have been no changes to the Project and/or the Developer since the date of the Application.

☐ The following is a complete list of changes to the Project and/or the Developer since the date of Application.

DATED this ___ day of _____, 20__.

DEVELOPER:

Signature: _____

Name: _____

Title: _____

EXHIBIT "E"

CONFLICT OF INTEREST STATEMENT FORM

Project Name: _____

Developer Name: _____

The Developer declares on its own behalf and on behalf of each member of the Developer's Team that:

1. this declaration is made to the best of the knowledge of the Developer and, with respect to relationships of each member of the Developer's Team, to the best of the knowledge of that member;

2. the Developer and the members of the Developer's Team have reviewed the Contractor Standards for Ethical Conduct as set out in Exhibit "F" to the SOP Rules;

3. the following is:

   (a) a full disclosure of all members of the Developer's Team who have been directors, officers or employees of the Government of Yukon or ***[insert the applicable Utility]*** or its subsidiaries at any time in the two years preceding the date of this disclosure;

   (b) a full disclosure of all known relationships the Developer and each member of the Developer's Team has, or has had, with:

      i. the Government of Yukon or ***[insert the applicable Utility]*** or its subsidiaries;

      ii. any current directors, officers or employees, as applicable, of the Government of Yukon or ***[insert the applicable Utility]*** or its subsidiaries;

      iii. any former directors, officers or employees, as applicable, of the Government of Yukon or ***[insert the applicable Utility]*** or its subsidiaries, who ceased to hold such position within two years from the date of this disclosure; and

      iv. any other person who, on behalf of the Government of Yukon or ***[insert the applicable Utility]*** or its subsidiaries, has participated in or been involved in the design of the Standing Offer Program under the SOP Rules or any past competitive energy acquisition process of the the Government of Yukon or ***[insert the applicable Utility]*** or its subsidiaries; and

   (c) a full description of the actions that the Developer has undertaken or offers to undertake to address any actual, perceived or potential conflict of interest or unfair advantage arising from the relationships disclosed pursuant to subsections 3(a) and (b) above; and

4. if no such relationships are disclosed by the Developer, the Developer is not aware of any former directors, officers or employees as described in subsection 3(a) above nor any relationships between the Developer or any member of the Developer's Team, and any of the persons described in subsection 3(b) above, and the Standing Offer Program Application has not been/is not being prepared with any involvement from any of those persons.

5. Disclosures pursuant to section 3 above are as follows:

Name of Member of Developer's Team (e.g. John Smith)	Name of Party with Relationship (e.g. employee name)	Details of the Nature of the Relationship with • (e.g. John Smith was a • employee from [date] to [date])

6. For the purposes of this Conflict of Interest Statement Form, capitalized terms not otherwise defined herein shall have the meaning given thereto in the SOP Rules available at the "Documents" page of the SOP Website located at *www.yukon.ca/standingoffer* and:

"**Developer's Team**" means:

(a) all persons who have been involved in the preparation of the Developer's Proposal; and

(b) all persons who the Developer proposes to perform work or services under any resulting Electricity Purchase Agreement.

7. The Developer has undertaken or offers to undertake the following actions to address any actual, perceived or potential conflict of interest or unfair advantage arising from the relationships disclosed pursuant to subsections 3(a) and (b) above:

[insert agreed actions]

DATED this ___ day of _____, 20__.

[DEVELOPER]

By:

Name: _____

Title: _____

EXHIBIT "F"

CONTRACTOR STANDARDS FOR ETHICAL CONDUCT

STANDARDS

1. At all times in the course of its performance of the Contract, the Contractor will conduct itself with fairness, integrity and honesty.

2. At all times during the term of the Contract, the Contractor will avoid any actual, or apparent conflict of interests, in which its interests outside of the Contract (including any engagements the Contractor may have with third parties), and its obligations to • under the Contract and these Standards conflict.

3. The Contractor will promptly disclose to • in writing, to the best of its knowledge, any actual or apparent conflicts between its interests and those of • during the term of the Contract, including:

   (a) the name of any current director, officer or employee of • who is an Owner, or representative of the Contractor;

   (b) any business relationship that the Contractor or any of its Owners or officers has with a director or officer of • or with an employee of • who may have actual or apparent involvement in any • procurement process, or the Contract; and

   (c) the name of any director, officer or employee of • who is connected by frequent or close association to the Contractor, any of its Owners or officers, or any representatives of the Contractor who may have actual or apparent involvement in any • procurement process, or the performance or administration of the Contract.

   For the purposes of this section, •'s interests include non-economic considerations such as reputation.

4. In addition to disclosure required above, the Contractor will take any steps reasonably required by • to address or mitigate any actual or apparent conflict of interest.

5. Subject to the terms of the Contract, the Contractor will keep confidential all non-public, confidential information provided to it by • or developed during performance of the Contract. The Contractor will not use that information for any purpose unrelated to performance of its obligations under the Contract.

6. If • gives the Contractor access to any • property during the term of the Contract, the Contractor will use that property solely for purposes of the Contract.

7. The Contractor will not attempt to secure preferential treatment with • by offering gifts, entertainment, or benefits to •'s directors, officers or employees. Reasonable gifts, entertainment, or benefits common to business relationships, **[as described in the • Code of Conduct]**, are acceptable.

8. Unless the Contractor has the express permission of •, the Contractor will not solicit or recruit any • employee during the term of the Contract. This obligation does not prevent the Contractor from

hiring a • employee who responds to a public and broadly issued job advertisement without prompting or encouragement from the Contractor.

9. The Contractor must treat its employees and subcontractors performing work under the Contract respectfully and in a manner free of discrimination and harassment. The Contractor will provide those employees and subcontractors with a safe and healthy workplace.

10. The Contractor and its employees and subcontractors must treat individuals they encounter in the course of performing work under the Contract respectfully and in a manner free of discrimination and harassment.

11. When the Contractor is participating in any public discussions or taking a position of leadership in other organizations, it must not represent itself as a spokesperson of • unless • has specifically retained or instructed the Contractor to act in that capacity.

12. Contractors who would like further information or advice on the application of these Standards are encouraged to speak to **[name of representative]**'s contract representative.

13. A Contractor's failure to adhere to the provisions of these Standards may be a breach of Contract and could result in termination of the Contract.

DEFINITIONS

"•" means **[*insert applicable utility*]** or any of its subsidiaries that has entered into the Contract;

"Contract" means a contract with • in which these Standards are included directly or by reference as a terms or condition;

"**Contractor**" means the contractor, consultant, supplier or business associate who has a Contract; and

"**Owner**" means any person who, individually or together with relatives, directly or indirectly owns 20% or more of the voting rights of the Contractor.

EXHIBIT "G"

CONFIDENTIALITY AND COMPLIANCE AGREEMENT

THIS CONFIDENTIALITY AND COMPLIANCE AGREEMENT (the "**Agreement**") is made as of the ____ day of _____, 20__.

BETWEEN:

[SELLER], a corporation incorporated under the laws of _____
("**Seller**")

-and-

[UTILITY], a corporation incorporated under the laws of the Yukon
("**Utility**")

(individually, a "**Party**" or collectively, the "**Parties**")

WHEREAS:

Utility and Seller wish to enter into discussions, which may include negotiations concerning an electricity purchase agreement (an "**EPA**"), pursuant to the Government of Yukon's Standing Offer Program ("**SOP**").

NOW THEREFORE, in consideration of the Parties entering into this Agreement and the mutual promises and agreements contained in this Agreement, the Parties agree as follows:

1. DEFINITIONS

1.1 "**Confidential Information**" means any of the Seller's confidential technical or financial information provided by the Seller to Utility in confidence in connection with the SOP and/or any related EPA with express written notice to Utility of the confidential nature of the information, whether such confidential information is provided orally, in writing, electronically or by any other media, but excluding any executed and delivered EPA or related securities delivered thereunder or any agreement collateral thereto, and also excluding information that:

(a) is or becomes in the public domain, other than as a result of a breach of this Agreement by Utility;

(b) is known to Utility before disclosure to it by the Seller, or becomes known to Utility thereafter by way of disclosure to Utility by any other person who, to Utility's knowledge, is not under an obligation of confidentiality with respect thereto; or

(c) is, or has been, disclosed by the Seller to any government authority in connection with any permit, approval or tenure for any project proposed by the Seller in the SOP and any information that is directly related to or that is based on or derived from that information, other than any financial information relating to the Seller or any such project;

1.2 "**Affiliate**" has the meaning given in the Standard Form Electricity Purchase Agreement for the SOP;

1.3 "**Discussions**" means discussions, including negotiations, whether orally, in writing, electronically or by any other media, between the Parties pertaining to the SOP and/or any related EPA from the effective date of this Agreement to the termination of such discussions or an EPA, if any, between the Parties is fully executed and delivered, whichever shall first occur and "discussions" includes but is not limited to, the Seller's questions and Utility's responses thereto in the Q & A process under the SOP and any preliminary assessment of eligibility for the SOP provided by Utility to the Seller;

1.4 "**SOP Rules**" means the SOP Rules available on the SOP Website at *www.Yukon.ca/apply-independent-power-producer*, as amended or replaced from time to time.

2. CONFIDENTIALITY OBLIGATION

2.1 **Confidentiality Obligation**. Utility shall treat as confidential, and shall not disclose to any third person, Confidential Information, and both Parties shall treat as confidential and shall not disclose to any third person, all or any part of the Discussions, provided however that the foregoing obligations, and nothing in this Agreement, prevents or restricts:

(a) disclosure of the fact that Discussions, if any, are occurring, or have occurred, and/or the fact that this Agreement exists and the general nature hereof:

(b) in the case of Utility, disclosures of the Discussions and/or Confidential Information:

(i) to any ministers, deputy ministers, servants or employees of the Yukon Territory; and

(ii) to Utility's directors, officers, employees, subsidiaries, consultants and advisors;

provided that each of the foregoing to whom Discussions and/or Confidential Information is disclosed is advised of the confidential nature thereof;

(c) in the case of Utility, disclosure of Discussions and/or Confidential Information in any regulatory proceeding, whether in respect of an EPA entered into with the Seller pursuant to the SOP or in respect of other matters, to the extent that Utility considers disclosure necessary or desirable to support its position in any such proceeding, provided that, to the extent reasonably practicable, Utility gives reasonable notice to the Seller before making disclosure, and, to the extent requested by the Seller, requests the relevant tribunal to treat all or any part of the disclosure as confidential or to limit its further disclosure;

(d) in the case of Utility, disclosure:

(i) of the Seller's questions and Utility's response thereto under the SOP without attribution to the Seller;

(ii) to a third person of Confidential Information that was known by that third person before disclosure thereof by Utility, including information that originated from that third person or that the Seller or any other person has given to the third person, in each case as indicated on the face of any document or as acknowledged by the Seller; and

(iii) such information as Utility considers necessary to provide any publicly available report on the conduct and outcome of the SOP, including the Seller's participation in the SOP and conclusion of an EPA with the Seller (if applicable), the location and capacity of any project proposed by the Seller, and the energy associated with any project proposed by the Seller;

(e) in the case of the Seller, disclosure of Discussions to its directors, officers, employees and affiliates, consultants and advisors, provided that each of the foregoing to whom Discussions are disclosed is advised of the confidential nature thereof and undertakes in writing to respect such confidentiality on the terms of this Agreement, provided that the Seller shall give to Utility, at its request, a copy of each such undertaking;

(f) without limiting Utility's disclosure rights under section 2.1(c) above, disclosures required to be made by Utility or the Seller by an order of a court or tribunal or under any law, regulatory requirement or requirement of any stock exchange that is binding upon it, provided that, (i) to the extent reasonably practicable, the Party making such disclosure gives reasonable notice to the other Party before making the disclosure, and (ii) limits the disclosure to that required by the applicable order, law, or regulatory or stock exchange requirement;

(g) disclosures in any legal proceedings for the enforcement of this Agreement and/or any EPA or in the defense of any legal proceedings brought by any third person(s) against either or both the Parties in any way relating to the SOP; or

(h) disclosures of the Discussions and/or Confidential Information by agreement or consent of both Parties.

2.2 **Disclosures of EPA**. Disclosure of any executed EPA, or any summary thereof or information contained therein, will be governed by the EPA.

2.3 **[Freedom of Information and Protection of Privacy Act**. The Seller acknowledges that Utility is subject to the Yukon *Access to Information and Protection of Privacy Act* and associated regulations, and agrees that Utility's non-disclosure obligations under this Agreement are subject to the provisions of that legislation, as the same may be amended or replaced from time to time.]

2.4 **Term**. Utility's obligation of confidentiality with respect to Confidential Information expires three years after the date hereof.

3. PROGRAM RULES BINDING

The Seller acknowledges and agrees that it is bound by, and will comply with, the terms and conditions of the SOP Rules.

4. MISCELLANEOUS

4.1 **Liability Exclusion**. No Party will be liable to the other Party in connection with any breach of this Agreement for any indirect, incidental or consequential damages, including loss of profits.

4.2 **Governing Law**. This Agreement shall be interpreted, governed and construed under the laws of Yukon and the law of Canada applicable therein as if it were executed, and to be performed wholly, within Yukon.

4.3 **Equitable Relief**. Each Party agrees that in the event of a breach of this Agreement, or to prevent a breach or contemplated breach, by that party, the other Party shall be entitled to equitable relief, including injunction and specific performance, in addition to all other remedies available at law or equity.

4.4 **Entire Agreement**. The Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof and supersedes and cancels all prior agreements and communications relative to such subject matter.

4.5 **No Implied Terms**. No terms or conditions whatsoever may be implied in this Agreement.

4.6 **Amendments**. This Agreement shall not be modified, except by a written agreement dated after that date of this Agreement and signed by both Parties.

4.7 **Assignment**. This Agreement may not be assigned by either Party without the prior written consent of the other Party.

4.8 **Enurement**. This Agreement is binding upon and enures to the benefit of the Parties and their respective successors and permitted assigns.

4.9 **Execution in Counterparts**. This Agreement may be executed in counterparts, and each counterpart shall for all purposes be an original, and all such counterparts shall together constitute one and the same Agreement.

4.10 **Facsimile Signature**. This Agreement may be executed and delivered by signatures transmitted by facsimile or other electronic means.

4.11 **Relationship**. Entering into this Agreement shall in no way be construed to:

(a) preclude in any way either Party from pursuing any business opportunities;

(b) establish any relationship between Utility and the Seller with respect to such business opportunities; or

(c) establish any other relationship between Utility and the Seller with respect to any project proposed by the Seller under the SOP.

[Remainder of page left intentionally blank]

IN WITNESS WHEREOF, the Parties have entered into this Agreement effective as of the date first above written.

[UTILITY]

By: _____

Name:
Title:

[SELLER]

By: _____

Name:
Title:

STANDING OFFER PROGRAM

RULES

January 2019

For more information, please contact:

Standing Offer Program
Yukon Energy Corporation
#2 Miles Canyon Road
Box 5920
Whitehorse, Yukon, Y1A 6S7
IPP@yec.yk.ca

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STANDING OFFER PROGRAM RULES

1. INTRODUCTION

The Government of Yukon (**YG**) issued the *Independent Power Production Policy* in October 2015 as reviewed and updated by the YG in October, 2018 (**IPP Policy**). One of the key elements of the IPP Policy was to create a framework for the Standing Offer Program (**SOP**) designed by YG to achieve the following principles:

(a) encourage the development of new, small and renewable energy Projects in Yukon by multiple Developers interconnecting into the Yukon Integrated System (**YIS**) or the Watson Lake Grid (**WLG**);

(b) streamline the process for the sale by such Projects of electricity to Yukon Energy Corporation (**YEC**) on the YIS or to ATCO Electric Yukon (**AEY**) on the WLG (YEC and AEY being the Utilities);

(c) provide for a Standard Form Electricity Purchase Agreement (**Standard Form EPA**), being the contract for the sale by such Projects of electricity by the Developer to the applicable Utility;

(d) decrease transaction costs for Developers and the Utilities participating under the SOP; and

(e) achieve the policy objectives of the IPP Policy in a manner which is cost-effective for ratepayers.

These Standing Offer Program Rules (**Rules**) have been developed by YG together with the Utilities in accordance with the IPP Policy to establish the Application Process governing the SOP as well as the SOP eligibility requirements, standards, applicable EPA term or duration and purchase price for energy delivered under the SOP. By OIC, YG has required that the Utilities implement the SOP in accordance with these Rules and YG will perform certain administrative functions contemplated by these Rules.

The IPP Policy supports the principles established in the *Energy Strategy for Yukon* released by YG in January 2009. YG intends to review the IPP Policy every 2 years. YG may make any amendments to the IPP Policy at any time. The Utilities are authorized to make any amendments to these Rules (including any Reference Documents) and the Standard Form EPA at any time to support the SOP and IPP Policy. Prior to making any amendments to the IPP Policy including any amendments that may require the Utilities to make corresponding amendments to these Rules (including any Reference Documents) or the Standard Form EPA, YG shall consult with the Utilities. Neither YG nor the Utilities shall have any obligation to consult with any Developers or potential applicants regarding such amendments or potential amendments. All such amendments made by YG or the Utilities (including, without limitation, amendments to the applicable purchase price) shall apply to any Developer or potential applicant which has not signed an EPA with a Utility in accordance with these Rules at the time of such amendments, whether or not such Developer has been registered in the SOP Queue. Such amendments shall not affect any EPA that has been entered into by a Developer prior to the amendment.

Capitalized terms used but not otherwise defined in these Rules have the meaning given to such term in the Glossary at the end of these Rules.

Actions of YG under the IPP Policy and these Rules may be carried out by any department or agency of YG, including YDC.

2. APPLICATION PROCESS OVERVIEW

The Application Process is comprised of the following phases each of which are described in greater detail in these Rules below:

(a) **Pre-Application Phase** – The Pre-Application Phase shall commence upon submission by the Developer to the YG and the applicable Utility of the Pre-Application Form and other documents outlined in more detail in Section 5.1 below. During the Pre-Application Phase, YG will conduct a Pre-Application Completeness Review to assess whether the potential applicant and Project will be able to meet the eligibility requirements and are prepared to submit a complete Application to the Utility. Following the results of such review by YG, the Utility will complete the assessment on a preliminary basis and shall have the right to reject any potential applicant and Project which, in the Utility's Discretion, will not be able to meet the eligibility requirements.

(b) **Preliminary Feasibility Assessment Phase** – During this phase, the potential applicant may conduct more detailed Project assessment, commence the process required to receive the YESAB Adequacy Confirmation, if required, and may, at its cost, initiate a System Interconnection Study with the Utility.

(c) **Application Phase** – During this phase, a potential applicant that:

(i) is issued a Preliminary Eligibility Approval by the Utility under the Pre-Application Phase; and

(ii) has received the YESAB Adequacy Confirmation for its Project, if required,

shall be entitled to submit an Application outlined in more detail in Section 5.3 below and the applicable Utility will complete the Application Review. Following the Application Review by the Utility, the Utility will either retain or reject the Application. The applicant and the Utility will commence the System Interconnection Study, at the applicant's cost, if not already completed in the Preliminary Feasibility Assessment Phase.

(d) **EPA Execution Phase** – During this phase, if the Utility has retained the Developer's Application, the Utility may make an offer of an EPA to the Developer at which point the Developer must sign the EPA, failing which the Utility's offer of an EPA will be withdrawn.

YG and the Utilities make no representations or warranties as to the amount of time that will be required to complete these phases, whether each such party will complete all or any such phases or whether any potential applicant will be successful or rejected in this Application Process. Rejection of an applicant or a potential applicant may be determined by the applicable Utility in its Discretion in accordance with these Rules. Potential applicants are advised to read these Rules carefully and retain their own financial, engineering, legal and other technical advisors in the event they wish to participate in the Application Process.

3. ELIGIBILITY REQUIREMENTS

To be eligible for the SOP, the Developer and the Project must meet the eligibility requirements outlined below. The satisfaction of such eligibility requirements will be reviewed in each of the Pre-Application Phase and the Application Phase as follows:

(a) **Pre-Application Phase Eligibility Assessment** - During the Pre-Application Phase, YG will conduct a Pre-Application Completeness Review to assess whether the potential applicant and Project will be able to meet the eligibility requirements and are prepared to submit a complete application to the Utility. Following the results of such review by YG, the Utility will complete the assessment on a preliminary basis and shall have the right to reject any potential applicant and Project which, in the Utility's Discretion, will not be able to meet the eligibility requirements.

(b) **Application Phase Eligibility Assessment** - During the Application Phase, the applicable Utility to which the Application has been made as contemplated in Section 5.3 below will conduct an assessment of whether the Developer and Project meet the eligibility requirements and such Utility shall have the right to reject any Developer and the Project which, in such Utility's Discretion, do not meet the eligibility requirements. For clarity, this assessment will be conducted by YEC in respect of Projects to be interconnected into the YIS and by AEY in respect of Projects to be interconnected into the WLG. References to a Utility below means such applicable Utility having the authority to assess eligibility requirements for a specific Project.

3.1 Generation Technology

The generation technologies and energy sources must be proven to be reliable, as determined by the applicable Utility in its Discretion. Developers will be required to provide all such information as the Utility determines is necessary to assess such reliability. New generation technologies may be considered from time to time by the Utilities in their Discretion.

3.2 Eligible Energy

Energy delivered to a Utility under the EPA must be Eligible Clean Energy.

3.3 Location and System Constraints

Projects must be located in Yukon and connecting to the YIS or the WLG.

If a Developer proposes that a Project be located in part of the YIS or WLG which is in an area where a Utility has system constraints, it is anticipated that any such constraints can be addressed through System Upgrades which will become part of the System Upgrade Costs and paid for by the Developer; provided, however, that the Utilities shall have the right to reject a Project if it is proposed to be located in part of the YIS or WLG which is in an area where a Utility has system constraints.

3.4 System Wide Limits

The following system-wide limits (**System-wide Limits**) for all EPAs entered into under the SOP have been established by YG in order to meet the policy objectives of the SOP, while observing the technical limitations of each of the YIS and WLG:

System/Grid	System-Wide Limit
YIS	20,000 MWh/year
WLG	2,100 MWh/year

The Utilities shall have no Discretion to exceed the System-wide Limits contemplated above.

Each Developer shall submit the annual energy volume which is expected to be generated by the Project determined based on the maximum number of MWh which the applicable Project would generate assuming that it generated in accordance with the Nameplate Capacity after taking into account a reasonable capacity factor for the applicable Eligible Clean Energy source (the **Project Energy Volume**). A Project will be rejected if the total of the Project Energy Volume for the applicable Project together with the Project Energy Volumes of all other projects registered in the SOP Queue or contracted under signed EPAs (without duplication) would result in the Utility exceeding the System-wide Limit set out above for YIS or WLG, as applicable. The Utility shall have the right to reject or modify a Developer's proposed Project Energy Volume where it determines in its Discretion that it is not reasonable. The Utility may request any additional information it requires to assess the reasonableness of Project's Nameplate Capacity or expected generation specified in the Application, including verification by a qualified Yukon registered professional engineer.

Such System-wide Limits may be increased or decreased from time to time by YG in accordance with changes to the IPP Policy and in consultation with the Utilities. In the event that the System-wide Limits are, at any time, decreased, any Developer that has not executed an EPA shall be subject to having their Application rejected if the total of the Project Energy Volume for the applicable Project together with the Project Energy Volumes of all other projects registered in the SOP Queue or contracted under signed EPAs (without duplication) would result in the Utility exceeding the revised System-wide Limit set out above for YIS or WLG, as applicable. In such circumstances, the Utility may determine, in its Discretion, which Projects shall have their Application rejected and such Discretion may be exercised without regard to, among other things, the date on which a Developer has submitted its Application relative to other Applications. Neither YG nor the Utilities shall have any liability to a Developer or any other Person resulting from such rejection of an Application.

YG will maintain the SOP Website which shall contain updates of (i) each Project (including the applicable Developer, the Project Energy Volumes and Target Developer's COD for the Project) for which a Utility has entered into an EPA and (ii) the SOP Queue which shall specify each Project (including the applicable Developer, the Project Energy Volumes and Target Developer's COD for the Project) which has been registered by a Utility under the Application Process. The order in which a Project is placed in the SOP Queue shall not grant a priority to any Project over another Project in the SOP Queue and the Utilities shall have no liability to a Developer or any other Person resulting from the entering into of an EPA for a Project that was registered in the SOP Queue after another Project. Utilities have the right to work with, evaluate or otherwise negotiate with any Developer individually or simultaneously with multiple Developers and regardless of the order of the applicable Projects in the SOP Queue. Once an EPA has been entered into in respect of a Project, such Project shall be removed from the SOP Queue.

Developers are expected to review the SOP Website for available energy volumes in the System-wide Limits. Neither YG nor the Utilities represent or warrant that the available energy volume posted on the SOP Website for System-wide Limits will be or remain available at the time Developers submit an Application or at any time during the Application Process. Developers are encouraged to contact the applicable Utility prior to submitting an Application to verify available energy volumes in the System-wide Limits.

The applicable Utility shall have the Discretion to close, at any time, the SOP Queue for YIS or WLG at which time the applicable Utility shall not accept further Applications from Developers, and, in such case, the Utilities shall have no liability to a Developer or any other Person resulting from such closure of the SOP Queue.

3.5 Project Size

Where a Project is located on the YIS, such Project may have multiple generators and must have a combined total Nameplate Capacity between 30 kW up to and including 2000 kW. Where a Project is located on the WLG, such Project may have multiple generators and must have a combined total Nameplate Capacity between 30 kW up to and including 500 kW. Such limits shall also apply to each eligible Project in a Project Cluster.

The Utility shall have no Discretion to allow a Project to exceed the limits contemplated above.

3.6 Project Clusters

Project Clusters are permitted, provided that each Project within a Project Cluster must have a separate Revenue Meter.

3.7 Yukon Incentives

A Project is not eligible for the SOP if the Project has a reasonable expectation of receiving future funding from the Micro-gen Program or other generation program with the YG; provided that, for clarity, receipt by a Project of funding under the Micro-gen Program or other generation program with the YG prior to an Application under the SOP shall not make such Project ineligible for the SOP.

3.8 Permits, Site Control and Zoning

The Application Form identifies the permits, site control and evidence of zoning that are key or standard eligibility requirements that must be satisfied by the Project.

3.8.1 Permits

If the Project is an assessable activity under YESAA, (i) prior to the Application to the Utility, the Developer must have received the YESAB Adequacy Confirmation; and (ii) prior to the execution of the EPA, the Developer must have obtained all Regulatory Agency Authorizations for the Project.

The EPA may establish certain minimum permits, licenses and approvals required under applicable laws for the EPA to be effective and whether such permits are required prior to execution of the EPA or will be required to be satisfied as a condition precedent to the EPA becoming effective. However, neither the provisions of the EPA nor any other

communication with the Utility will be construed as the Utility advising the Developer in any manner whatsoever on the nature or extent of the permits, licenses and approvals required under applicable laws by the Developer and the Developer will be solely responsible for securing all such permits, licenses and approvals required under applicable laws prior to the EPA becoming effective.

3.8.2 Site Control

The Developer must demonstrate that it has obtained the right to use the site for the Project (including, unless otherwise acceptable to the Utility in its Discretion, all areas where the generating facility and related access roads, transmission lines and other Project facilities will be built) for a period generally consistent with the Term of the EPA or a shorter period if acceptable to the Utility in its Discretion.

3.8.3 Zoning

If local government land use requirements apply to all or any part of the Project site (including all areas where the generating facility and related access roads, transmission lines and other Project facilities will be built), that part of the Project site must be appropriately zoned for the applicable Project use.

Where the Project forms part of a Project Cluster, the Utility may require the Developer to provide evidence that the permits, site control and zoning requirements are satisfied for the entire Project Cluster.

3.9 Public Utility Status

The Project must not be owned, in whole or in part, by a "public utility" for purposes of the *Public Utilities Act* (Yukon).

3.10 Target Developer's Commercial Operation Date

The Target Commercial Operation Date (**Target Developer's COD**) submitted by the Developer in the Application must be:

(a) a reasonable estimate of the date on which the Project is expected to achieve COD with considerations for the SOP application review process, and the results of the System Interconnection Study; and

(b) unless otherwise agreed to by the Utility, not later than three years following signing the EPA.

The Utility may request any additional information it requires to assess the reasonableness of the Target Developer's COD for the Project. If the Utility determines, in its Discretion, that the Target Developer's COD is not achievable, the Utility may reject the Application.

3.11 Projects Behind a Utility Customer Load

Projects located Behind a Utility Customer Load are not eligible to apply under the SOP.

3.12 Previous, Current and Future EPAs with the Utilities

If the Utility previously signed an EPA with respect to a Project, that Project is eligible for the SOP, provided that (i) the Project did not achieve commercial operation while the original EPA was in effect, and (ii) the original EPA has been terminated in accordance with its terms and all other post-termination conditions and restrictions in that EPA have been satisfied.

The Utility may determine in its Discretion whether or not a Project submitted to the SOP constitutes the same project as a project for which an EPA was previously signed with the Utility. Factors the Utility may consider include, but are not limited to, the location, permits, licenses and site tenure, and the Developer (including ownership structure) of the Project submitted to the SOP, relative to the prior project.

If a Project is determined to be part of a Project Cluster, and the Utility has entered into an EPA(s) for generation from any project in that Project Cluster:

(a) where the Project is located on the YIS, the Project is eligible for the SOP provided each Project in that Project Cluster has a Nameplate Capacity between 30 kW up to and including 2000 kW; and

(b) where the Project is located on the WLG, the Project is eligible for the SOP provided each Project in that Project Cluster has a Nameplate Capacity between 30 kW up to and including 500 kW.

If the Utility accepts an Application from a Project that is part of a Project Cluster, the Developer shall be required to pay for all System Upgrades and New Interconnection Facilities which the Utility requires to address any constraints or limitations on the delivery of energy resulting from such Project Cluster identified in the System Interconnection Study.

3.13 Environmental Attributes

All Environmental Attributes for the energy delivered to the Utility under the EPA must be transferred to the Utility. The value of the Environmental Attributes is included in the price paid for energy delivered under the SOP and is not paid separately to the Developer.

3.14 EPAs with Third Parties

A Project is not eligible for the SOP if there are any agreements with a third party or parties for the purchase and sale of electricity, or any Environmental Attributes or other ancillary services from such electricity, from any generator in the Project. Any such third party agreements must be terminated prior to submitting an Application for the SOP.

3.15 Conflicts of Interest

The Developer must not be in or have the potential to be in an actual, apparent or deemed conflict of interest as a result of entering into an EPA with the Utility. The Developer must inform the Utility, by completing and submitting a Conflict of Interest Statement form, of any disclosures required under the Utility's Contractor Standards for Ethical Conduct and any potential conflicts of interest it may have with the Utility or the Utility's directors, officers or employees. The Conflict of Interest Statement Form and the Utility's Contractor Standards for Ethical Conduct are

attached to these Rules as Exhibit "E" and Exhibit "F", respectively, and can also be found at the "Documents" page of the SOP Website.

If the Developer has any directors, officers, owners (with 20 per cent or more direct or indirect ownership in the Developer or its affiliates), or Project team members who have been directors, officers or employees of YG or the applicable Utility or its subsidiaries at any time in the two years preceding the submission of the Application, the Utility will deem there to be a conflict of interest.

The applicable Utility will review the Conflict of Interest Statement Form and each shall determine, in its Discretion, whether there is any actual, apparent or deemed conflict of interest.

3.16 Interconnection

All Projects must be interconnected to the YIS or the WLG directly through a New Interconnection Facility. Projects that would require the Utility to transmit energy other than directly to either the YIS or the WLG through the New Interconnection Facilities are not eligible for the SOP.

In the case of Projects to be interconnected to a portion of the YIS owned by AEY, AEY shall own the New Interconnection Facilities and the Developer shall be required to enter into an Interconnection Agreement with AEY. In such case, YEC shall coordinate with AEY development of the New Interconnection Facilities by AEY and the Developer shall not coordinate such activities/work directly with AEY unless otherwise agreed to by the Utilities.

The System Interconnection Study will be completed by the Utility at the Developer's cost in accordance with these Rules, whether completed during the Preliminary Feasibility Assessment Phase or during the Application Phase.

Whether the System Interconnection Study is completed during the Preliminary Feasibility Assessment Phase or during the Application Phase, following completion of such study and review and assessment of the same by the Utility, the Utility shall have the right to reject such Developer and the Project if the Utility determines in its Discretion that a Project is not technically feasible.

3.17 Consultation

Notwithstanding YG's duty to consult with First Nations, Developers are required to engage with any applicable First Nations and residents of applicable communities to seek their views and inputs early in the process. Developers must document their engagement efforts, including keeping reports, logs, letters of support, and correspondence. Developers will be responsible for all consultation with applicable First Nations and residents of applicable communities in respect of the Project, including the New Interconnection Facilities and System Upgrades. Other than in respect of System Upgrades, the Utilities shall have no responsibility for such consultation in respect of the Projects, nor will the Utilities have any obligation to assess the adequacy of such consultation by the Developer.

YG and the Utilities strongly encourage all Developers to confirm they have all of the necessary permits or permit amendments in place and to obtain information on any consultation with First Nations that may be required in relation to the Project.

4. ENERGY PRICE AND LINE LOSSES

All payments under an EPA will be administered by the applicable Utility entering into the EPA. All EPAs with Developers of Projects proposing to interconnect to the YIS shall be entered into with YEC and all EPAs with Developers of Projects proposing to interconnect to the WLG shall be entered into with AEY.

4.1 Purchase Price for Energy

The purchase price for energy (the **Energy Price**) per kWh delivered under an EPA shall be determined as follows:

(a) for an EPA with a Developer in which the Project is interconnected to the YIS, the Energy Price for the initial calendar year shall be equal to applicable Base Fuel Price determined for such EPA in accordance with Section 4.2 below and thereafter the Energy Price for a particular calendar year shall be determined by increasing the Energy Price paid in the immediately preceding calendar year by 50% of the percentage increase, if any, in the CPI in such preceding calendar year; and

(b) for an EPA with a Developer in which the Project is interconnected to the WLG, the Energy Price for the initial calendar year shall be equal to applicable Base Fuel Price determined for such EPA in accordance with Section 4.2 below and thereafter the Energy Price for a particular calendar year shall be determined by increasing the Energy Price paid in the immediately preceding calendar year by 100% of the percentage increase, if any, in the CPI in such preceding calendar year.

The Energy Price is the only amount payable by the Utility. There is no additional payment for Environmental Attributes, for environmental certification (as defined in the Standard Form EPA) or any other expenses.

4.2 Calculation of Base Fuel Price

The applicable **Base Fuel Price** means the following amount determined by the Utilities:

(a) **YIS EPA** - for an EPA with a Developer in which the Project is interconnected to the YIS, the Base Fuel Price is to be equal to the YEC's average blended fuel price per kWh for thermal generation most recently approved by the YUB before the date on which the EPA takes effect; and

(b) **WLG EPA** - for an EPA with a Developer in which the Project is interconnected to the WLG, the Base Fuel Price is to be expressed in cents per kWh and will be equal to the weighted average cost of fuel purchased by AEY for the purpose of producing electricity by means of thermal generation for the five years immediately preceding the date on which the EPA takes effect divided by the weighted average heat rate for the plant for the five years immediately preceding the date on which the EPA takes effect and, if applicable, shall account for any reduction in the maintenance, capital or other costs arising from the displacement of thermal generation as a result of the electricity generated by the Project.

4.3 Seasonal Adjustment on YIS

For Developers of Projects proposing to interconnect to the YIS, the escalated Energy Price referred to in Section 4.1 may be further adjusted based upon the month when the energy is delivered to establish the payment price for each kWh of energy delivered to the POI. The monthly delivery adjustments are contained in the Standard Form EPA.

4.4 Line Losses

The price described above applies to the quantity of energy delivered at the Point of Interconnection (**POI**) adjusted for Line Losses. Developers shall be responsible for all Line Losses between (i) the POI and (ii) the point of interconnection between the New Interconnection Facilities and the YIS or WLG, as applicable. As the applicable Revenue Meter is located at the POI, the calculation of Line Losses is based on the formula to be established in the EPA, if and when executed, based on the System Interconnection Study.

5. APPLICATION PROCESS AND REVIEW

All aspects of the application process and review contemplated below shall be administered by YG and (i) YEC in respect of Developers of Projects proposing to interconnect to the YIS and (ii) AEY in respect of Developers of Projects proposing to interconnect to the WLG.

The Application Process must be completed sequentially in the following phases, the purpose of which is to ensure that Projects that are being advanced to the Application Phase have been well scoped, appropriate study work has been conducted and the Utility's assessment of such Project in the Application Phase is streamlined so as to minimize the administrative burden on the Utilities and the Developers.

The phases of this Application Process (outlined in Figure 1 at the end of this Section 5) are:

(a) Pre-Application Phase;

(b) Preliminary Feasibility Assessment Phase;

(c) Application Phase; and

(d) EPA Execution Phase.

5.1 Pre-Application Phase

The Pre-Application Phase shall commence upon submission by the Developer to the YG and the applicable Utility of the Pre-Application Form and, if required by either party, the completed Confidentiality and Compliance Agreement signed by the Developer. The Pre-Application Form and the Confidentiality and Compliance Agreement form are attached to these Rules and can also be found at the "Documents" page of the SOP Website. The applicable Utility shall have the right to reject any Developer and the Project which, in the Utility's assessment, has failed to submit a fully completed Pre-Application Form and, if required, the signed Confidentiality and Compliance Agreement.

5.1.1 Pre-Application Completeness Review by YG

YG will conduct a preliminary assessment of whether the potential applicant and Project will be able to meet the eligibility requirements and are properly prepared to submit a complete application to the Utility (the **Pre-Application Completeness Review**). YG shall assess the information which is available to YG including through the Pre-Application Form and advise the applicable Utility if the Pre-Application Completeness Review has been satisfied.

5.1.2 Preliminary Eligibility Approval by the Utility

Prior to proceeding to the Preliminary Feasibility Assessment Phase, a potential applicant shall require confirmation from the applicable Utility that it may proceed (a **Preliminary Eligibility Approval)**. The applicable Utility shall have the right to not issue such Preliminary Eligibility Approval to any potential applicant and Project which YG has advised has not satisfied the Pre-Application Completeness Review or which otherwise, in the Discretion of the Utility, will not be able to meet the eligibility requirements. Notwithstanding that a Utility issues a Preliminary Eligibility Approval to a potential applicant, such Utility reserves the right to reject at any time any potential applicant and the Project which such Utility subsequently determines, in its Discretion, will not be able to meet the eligibility requirements.

Potential applicants should be careful to include complete and accurate information in this Pre-Application Phase as any variance between the information received and assessed in this preliminary assessment and the information contained in an Application or actual Project conditions may result in a final decision that is different from the preliminary assessment. As set out in Section 1 of these Rules, the Utilities may amend the SOP Rules at any time. A change in the SOP Rules may also result in a final decision that is different from the preliminary assessment.

The preliminary assessment by YG and the Utility in the Pre-Application Phase is based on the information provided to YG and the Utility and the SOP Rules in effect at the date of the preliminary assessment. A preliminary assessment is not binding on YG or either Utility and shall in no way give any potential applicant any rights in the Application Process or any right to enter into an EPA with the Utility.

5.1.3 Pre-Application Meeting

Potential applicants to the SOP are strongly encouraged to request a meeting or conference call with YG and the applicable Utility at any time prior to submitting a Pre-Application Form. The purpose of the pre-application meeting is to review the SOP Rules, the Application Process, the Standard Form EPA, the interconnection requirements and study costs, First Nations consultation requirements and other matters required to facilitate the Application Process, such as available energy volume within the System-wide Limits, basic interconnection information and other topics that may be the subject of a preliminary assessment. To arrange a pre-application meeting or conference call, Developers should submit a request for such meeting by email to the SOP Administrator at *IPPAdministrator@gov.yk.ca*. The SOP Administrator shall then coordinate with the Utility.

5.2 Preliminary Feasibility Assessment Phase

A potential applicant that is issued a Preliminary Eligibility Approval by the Utility shall be entitled to proceed to the Preliminary Feasibility Assessment Phase. The purpose of this phase is to facilitate more detailed Project assessment by the potential applicant. Potential applicants are strongly encouraged to contact the Utility early in the planning process to discuss the interconnection concept and feasibility for their Project.

During this phase, the potential applicant may conduct more detailed Project assessment, commence the process required to receive the YESAB Adequacy Confirmation, if required, and may, at its cost, initiate a System Interconnection Study with the Utility.

During this phase, the Utility shall have the right to reject any potential applicant and Project which, in the Utility's assessment, is not technically feasible.

5.3 Application Phase

A potential applicant that is issued a Preliminary Eligibility Approval and has received the YESAB Adequacy Confirmation, if required, for its Project shall be entitled to proceed to the Application Phase described below.

5.3.1 Submitting an Application

To apply for the SOP, the Developer must submit the following:

- a completed Application signed by the Developer, with applicable exhibits, in electronic form; and
- if required by either the Developer or the applicable Utility, a completed Confidentiality and Compliance Agreement signed by the Developer (if not previously submitted with a pre-application meeting or preliminary assessment request),

by email to the SOP Administrator and the applicable Utility in accordance with Section 9 of these Rules or by designated upload site specified by the SOP Administrator.

The Application Form and Confidentiality and Compliance Agreement are attached to these Rules and can also be found at the "Documents" page of the SOP Website.

5.3.2 Application Review

(a) **Completeness Review** – Upon receipt of the Application, the Utility will provide the Developer with a written acknowledgement and will perform a completeness review to ensure that it has all the information required to proceed with the Application Review. At a minimum, the Developer will have submitted the following in order to commence the Application Review:

- a signed Application;
- all exhibits marked for inclusion by the Developer;
- if required, a signed Confidentiality and Compliance Agreement; and

- the YESAB Adequacy Confirmation, if required.

The Utility reserves the right to require additional information and/or documents including verification as to the good standing of the Developer before commencing the Application Review. The Utility may reject the Application in the event the Developer fails to provide such additional information and/or documents.

In the event the Application is incomplete, the Utility may request additional information or clarification from the Developer. Depending upon how much information is missing from the Application, the Utility will either (1) keep the Application and request submission of the missing information subject to Section 5.7 of these Rules or (2) reject the Application.

The Utility will notify the Developer in writing upon completion of the completeness review.

(b) **Eligibility Review and Application Review** – The Utility will perform an eligibility review and the Application Review.

An eligibility review assesses whether the Developer and the Project meet, or will be able to meet, the eligibility requirements described in Section 3 of these Rules. Except in respect of Outstanding Permits described below, the Utility will reject an Application that has not met the eligibility requirements upon submission of the Application.

The Utility recognizes that the eligibility requirements in Section 3 of these Rules require that all necessary permits, licenses or approvals have been received by the Developer and that receipt of certain of such permits, licenses or approvals may not be achievable by the time of submission of the Application (**Outstanding Permits**). Accordingly, the Utility has the right to conduct the Application Review notwithstanding that such Outstanding Permits have not been received by the Developer and require that such Outstanding Permits be received prior to the EPA becoming effective. Where a Project is an assessable activity under YESAA, in no circumstances will the Application Review commence prior to the Developer receiving the YESAB Adequacy Confirmation.

In the event the Utility is unable to confirm the Project's eligibility under the SOP, the Utility may request additional information or clarification from the Developer. Depending upon how much information is missing from the Application, the Utility will either (1) keep the Application and request submission of the missing information subject to Section 5.7 of these Rules or (2) reject the Application.

The Utility will notify the Developer in writing of the results of the Application Review and whether the Application is retained or rejected following completion of this step.

(c) **Registration Under the Available System-wide Limits** – For each Application that is retained following completion of the steps described in Section 5.3.2(b) of these Rules, the Utility will notify YG and YG shall register the Project (including the applicable Developer, the Project Energy Volumes and Target Developer's COD for the Project) in the SOP Queue on the SOP Website. The Utility will notify the Developer in writing upon completion of the registration by YG, provided that neither YG nor the Utility make any representation or warranty that such registration provides the Developer any right to enter into an EPA.

5.3.3 Review of System Interconnection Study

(a) For each Application that is retained following completion of the steps described in Section 5.3.2 of these Rules, the Utility will, at the Developer's cost, conduct the System Interconnection Study, unless such System Interconnection Study has been previously completed by the Utility for the Developer during the Preliminary Feasibility Assessment Phase under Section 5.2 of these Rules. The Developer must file a complete System Interconnection Study application with the Utility for the System Interconnection Study and pay the applicable study fees specified by the Utility within 28 Days following the request by the Utility, or the Application may be rejected. The Utility shall not be required to perform or commit to perform any work relating to the System Interconnection Study unless and until the Developer has paid in advance the estimated amount of such costs required by the Utility delivered a complete System Interconnection Study application.

(b) If the Developer submits a System Interconnection Study application with a Plant Capacity and Nameplate Capacity or other material information that is not the same as the Plant Capacity and Nameplate Capacity or other information described in the Application, the Application will be rejected.

(c) Upon completion of the System Interconnection Study, the Utility will review the System Interconnection Study to determine whether the Utility is ready to support the Project's interconnection to the YIS or WLG, as applicable. Without limiting any other rights of the Utility to reject an Application under these Rules, the Utility may reject an Application if the System Interconnection Study indicates that the proposed New Interconnection Facilities and System Upgrades are not capable of being completed at least 90 Days prior to the Target Developer's COD specified by the Developer in the Application.

(d) Developers should note that a System Interconnection Study may become out-of-date and invalid if further studies or steps are not commenced within the time required by the Utility.

(e) The Developer shall notify the Utility and other Governmental Authorities, including YESAB and other permitting or licensing agencies, having jurisdiction over the Project of any changes to the Project arising from the System Interconnection Study or other work completed since the submission of the original Application or the YESAB Adequacy Confirmation. In such case, the Developer will be required to submit a Statement of Project Changes to the Utility and the Utility will determine whether the Application needs to be re-submitted by the Developer for review based on the nature of any changes submitted in the Statement of Project Changes. If the Developer is required to re-submit the Application, the Utility shall notify YG that the Application has been rejected and YG shall remove the Developer and the Project from the SOP Queue.

5.4 EPA Execution Phase

Provided (i) the Developer's Application has not been rejected following completion of the steps described in Section 5.3 of these Rules and (ii) where a Project is an assessable activity under YESAA, the Developer has received such Regulatory Agency Authorizations for the Project, the Developer shall be entitled to proceed to the EPA Execution Phase described below.

5.4.1 EPA Preparation

The following shall apply to the EPA preparation:

(a) The Utility expects that the Standard Form EPA will not be modified except as may be necessary for a Project. (See Section 7.2 of these Rules)

(b) Developers are encouraged to carefully review the Standard Form EPA prior to submitting an Application. The Utility will not consider any changes proposed by Developers to the Standard Form EPA in their Application or otherwise. The Utility may reject an Application that contains proposed changes to the Standard Form EPA.

(c) The Utility may advise the Developer of required changes to the Standard Form EPA based on a review of the Application. The Utility then expects to provide the Developer with a draft EPA for the Developer's review and comment. If required, the Utility may also exchange subsequent drafts with the Developer. Once the Utility sends a draft EPA to the Developer, the Developer is expected to provide its response and comments to the Utility within a commercially reasonable period of time. Failure to do so may result in rejection of the Application.

(d) For each Application that is retained following completion of the steps described above in this Section 5.4.1:

(i) the Utility will request that the Developer completes and submits a Statement of Project Changes that identifies any changes to any information in the Application; and

(ii) the Utility will prepare a final draft EPA and present it to the Developer for review and comment.

The Developer is required to submit such a Statement of Project Changes and provide comments on the final draft EPA within a commercially reasonable period of time or the Application may be rejected.

5.4.2 EPA Offer and Acceptance

(a) After completion of the process described in Section 5.4.1 of these Rules, including the filing of all required documents, the Utility will send the Developer either an offer of an EPA or a notice of rejection of the Application.

(b) If the Developer wishes to accept the offer of an EPA, the Developer must sign the EPA and deliver it to the Utility at the address specified in Section 9 of these Rules. If the Developer has not delivered the signed EPA within 28 days following the offer, the Utility's offer of an EPA may be withdrawn upon notice by the Utility.

(c) Subject to Section 5.4.2(d) of these Rules, the Utility will send a fully signed EPA to the Developer after receipt by the Utility of the signed EPA from the Developer.

(d) The Utility may withdraw an offer of an EPA, without liability, at any time prior to delivery of the fully-signed EPA to the Developer.

5.5 Amending Applications

Developers may amend an Application at any time prior to delivery of an offer of an EPA by the Utility to the Developer. Any such amendment may extend the Utility's Application review and EPA offer timelines.

Developers should note that any amendments that may result in a change to a System Interconnection Study may invalidate or impact the System Interconnection Study. If the System Interconnection Study is impacted (as determined by the Utility) or the Project Energy Volume available from the Project is impacted prior to execution of an EPA by both the Utility and the Developer, the Application may be rejected.

5.6 Withdrawing Applications

Developers may, by written notice to the Utility, withdraw a submitted Application, without liability, at any time prior to signing an EPA; provided that Developers shall remain liable for all costs incurred by the Utility under Sections 5.2, 5.3.3, 6.1 and 6.5 of these Rules.

5.7 Request for Further Information/Meetings

The Utility may, but is not required to, request further information, clarification or verification concerning an Application or other communication received from a Developer. Failure to respond to such a request within 28 Days after the date of the request may result in rejection of an Application. The Utility may telephone or meet with any Developer or group of Developers at any time prior to or following submission of any Application or Applications.

5.8 Due Diligence and Consultation

The Utility may, but is not required to, undertake any investigation or inquiries and/or undertake any consultation with any Governmental Authority or any other Person or group as the Utility considers necessary in its Discretion with respect to a Developer, a Project, and/or an Application and may, in reviewing an Application, consider any information received as a result of such investigation, inquiry and/or consultation.

5.9 Rejecting Applications

The Utility may accept or reject any Application and may decide to offer or not to offer an EPA to a Developer at its Discretion. The Utility may reject an Application at any stage in the Application Review process notwithstanding any prior decision by the Utility in the Application Review process or prior completion of any step in the Application Review process. Without limiting any other rights of the Utilities to reject an Application under these Rules, the reasons for rejection of an Application and/or a decision not to offer an EPA to a Developer may include, but are not limited to:

(a) an incomplete Application;

(b) an Application does not meet the eligibility requirements set out in Section 3 of these Rules;

(c) failure to respond to a request by the Utility for additional information, failure to respond to or accept Project-specific EPA changes requested by the Utility and/or failure to file a System Interconnection Study application or Statement of Project Changes within the required time limits;

(d) a System Interconnection Study becomes invalid at any time prior to execution of an EPA by both the Utility and the Developer;

(e) a System Interconnection Study indicates that the proposed New Interconnection Facilities and System Upgrades are not capable of being completed at least 90 Days prior to the Target Developer's COD specified by the Developer in the Application;

(f) an Application proposes Standard Form EPA amendments that are not acceptable to the Utility, in its Discretion;

(g) an Application for a Project that the Utility determines requires material Standard Form EPA amendments or that is too complex to be an appropriate Project for the SOP;

(h) an Application for a Project that will result in any costs being borne by the Utility that are not acceptable to the Utility;

(i) a Developer fails to pay costs required to be paid by it in accordance with these Rules;

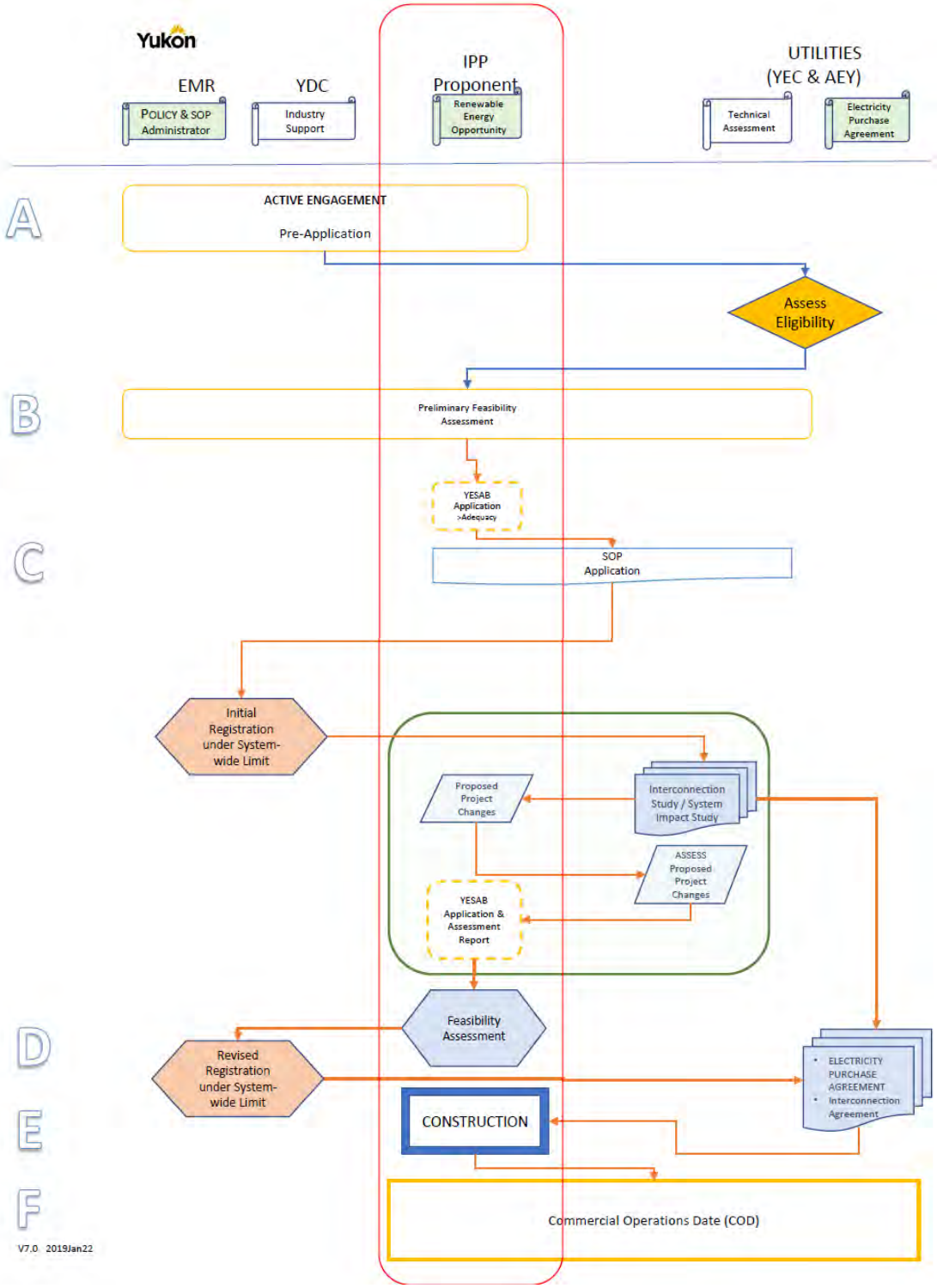
(j) an Application in respect of which any of the information included in the Application is not satisfactory to the Utility in any respect; or

(k) an Application in respect of which the Utility determines that the Developer has, or by entering into an EPA, would have, an actual, apparent, or deemed conflict of interest.

If the Application is rejected, the Developer can request an information meeting with the Utility to discuss the reasons for the rejection.

A rejected Application can be resubmitted at a later date provided the deficiencies or issues noted as reasons for rejection have been addressed. A rejected Application will have its Project Energy Volume deregistered from the SOP Queue.

Figure 1 – Application Process



6. INTERCONNECTION

All aspects of the interconnection process shall be administered by YEC for Projects on the YIS or AEY for Projects on the WLG. All inquiries should be directed to the applicable Utility in accordance with Section 9 of these Rules.

INTERCONNECTION REQUEST PROCESS

6.1 Interconnection Requirements

All generators connected to the YIS or WLG are required to meet the applicable Utility's technical interconnection requirements. In order to determine these requirements and assess the impacts to the Utility's system from the proposed interconnection for the purpose of identifying the required network upgrades, technical studies, including a System Interconnection Study, must be performed. These studies provide cost estimates of the required upgrades. Following the completion of these studies, the Utilities may adjust the Target Developer's COD proposed by any Developer for a Project.

The System Interconnection Study will be completed by the Utility at the Developer's cost in accordance with these Rules. Following completion of the System Interconnection Study and review and assessment of the same by the Utility, the Utility shall have the right to reject such Developer, the Project and the applicable Application (if the Developer has proceeded to the Application Phase) set out in Section 3.16 of these Rules.

6.2 Direct Interconnections

All Projects are required to be directly interconnected to the Transmission System or Distribution System. A valid System Interconnection Study is required for all Projects. The Plant Capacity in the System Interconnection Study must be equal to the Plant Capacity in the Application and EPA.

All interconnection studies are a part of the interconnection process. For further information regarding the System Interconnection Study referred to above, please contact the applicable Utility at the address described in Section 9 of these Rules.

6.3 Early Contact and System Interconnection Study Timing

Developers are strongly encouraged to contact the Utility early in the planning process to discuss the interconnection concept and feasibility for their Project.

As previously noted, a System Interconnection Study may become invalid if further studies or further steps are not commenced within the time required by the Utility. Accordingly, the Utilities recommend Developers file their System Interconnection Study application with the Utility at the time they submit their Application.

6.4 Interconnection Issues

For questions related to interconnection including the process for completion of a System Interconnection Study, please contact the applicable Utility in accordance with Section 9 of these Rules.

Complete details on the interconnection process can be found at:

https://yukonenergy.ca/energy-in-yukon/standing-offer-program

RESPONSIBILITY FOR COSTS

6.5 Interconnection Study Costs

The Developer will be responsible for the costs of the System Interconnection Study and any other studies required for the interconnection of the Project to the YIS or WLG, as applicable. The Developer shall be required to pay the Utility, in advance, the estimated costs of such studies. The Utility and the Developer will true up such costs to actuals within a reasonable period of time following completion of the studies.

6.6 Transmission Costs

Subject to the provisions of Section 4.4 respecting Line Losses, the Developer will not be responsible for the cost to transmit power sold under the EPA from the POI.

6.7 New Interconnection Facilities Costs and Ownership

The Developer will be responsible for all New Interconnection Facilities Costs. An estimate of these costs will be provided in the System Interconnection Study. The Developer shall be required to pay the Utility, in advance, the estimated costs of the New Interconnection Facilities. The Utility shall not be required to perform or commit to perform any work relating to the New Interconnection Facilities unless and until the Developer has paid in advance the estimated amount of such costs required by the Utility in respect of the New Interconnection Facilities. The Utility and the Developer will true up such costs to actuals within a reasonable period of time following completion of the New Interconnection Facilities.

The Utility will construct (or cause to be constructed), own and operate the New Interconnection Facilities. All New Interconnection Facilities located within the service area of a Utility will be owned by such Utility and will become part of the YIS or WLG, as applicable. For certainty, in respect of Projects to be interconnected to a portion of the YIS which is the service area of AEY, AEY shall own the New Interconnection Facilities and YEC shall coordinate with AEY development of the New Interconnection Facilities by AEY.

6.8 System Upgrade Costs and Ownership

The Developer will be responsible for all costs of the System Upgrade Costs. An estimate of these costs will be provided in the System Interconnection Study. The Developer shall be required to pay the Utility, in advance, the estimated costs of the System Upgrade Costs. The Utility shall not be required to perform or commit to perform any work relating to the System Upgrade Costs unless and until the Developer has paid in advance the estimated amount of such costs required by the Utility in respect of the System Upgrade Costs. If such amounts are paid in advance by the Developer, the Utility and the Developer will true up such costs to actuals within a reasonable period of time following completion of the System Upgrade Costs.

The Utility will construct (or cause to be constructed), own and operate the System Upgrades. All System Upgrades located within the service area of a Utility will be owned by such Utility and will become part of the YIS or WLG, as applicable. For certainty, in respect of Projects to be

interconnected to a portion of the YIS which is the service area of AEY, AEY shall own the System Upgrades constructed in the service area of AEY, and YEC shall coordinate with AEY development of the System Upgrades by AEY.

6.9 Cost Sharing of New Interconnection Facilities and System Upgrade Costs

In the event that a new Developer connects to existing New Interconnection Facilities which were paid for by one or more other Developers (the **Prior Developers**) within the five years prior to the date of the new Developer's Commercial Operation Date, such new Developer will be required to pay to the Utility a share of the costs paid by such Prior Developers for such New Interconnection Facilities and/or any System Upgrades, such share to be determined by the Utility in its Discretion. The Utility will pay such amount paid by the new Developer to the Prior Developers.

6.10 Revenue Meters

The Utility shall be responsible to install and maintain an appropriate revenue class Revenue Meter for the Project which is tested and sealed and approved for revenue purposes by Measurement Canada. The costs of such Revenue Meter shall be included in the New Interconnection Facilities and paid for by the Developer. An estimate of these costs will be provided in the System Interconnection Study. The Revenue Meter shall be located at the POI between the Developer's Project and the New Interconnection Facilities installed by or on behalf of the Utility and installed in accordance with the Utility's revenue metering requirements. Disputes in respect of the accuracy of such meter shall be resolved in accordance with the EPA.

7. ELECTRICITY PURCHASE AGREEMENT

Developers of Projects (i) proposing to interconnect to the YIS shall enter into the EPA with YEC and (ii) proposing to interconnect to the WLG shall enter into the EPA with AEY. All aspects of the Standard Form EPA will be administered by the applicable Utility and references to a Utility below means such Utility.

7.1 Standard Form EPA

The Standard Form EPA is in the form attached to these Rules and is also available at the "Documents" page of the SOP Website.

The Standard Form EPA is based on a "standard" type of Project and Developer. For example, the Standard Form EPA assumes that the Project consists of a new generator that has a direct and independent interconnection through the New Interconnection Facilities to YIS or WLG, as applicable, and will have a Revenue Meter that measures output only from the Project and no other electricity generators. The Standard Form EPA also assumes that the Developer is a corporation. If a Project is part of a Project Cluster, separate EPAs shall be required in respect of each Project within the Project Cluster.

7.2 EPA Changes

The Utility does not anticipate that any changes will be necessary to the Standard Form EPA with respect to any Application, however, if determined by the Utility in its Discretion due to the technical aspects of the Project, the Utility may change the Standard Form EPA as required based on the information in the Application.

As outlined in Section 5.4.1 of these Rules, Developers are encouraged to carefully review the Standard Form EPA prior to submitting an Application. The Utility, in its Discretion, shall have the right to reject any changes proposed by Developers to the Standard Form EPA in their Application or otherwise. The Utility may reject an Application that contains proposed changes to the Standard Form EPA which are not acceptable to the Utility, in its Discretion.

7.3 EPA Term

Developers may elect a single term under an EPA of up to the following number of years for the applicable Eligible Clean Energy:

Eligible Clean Energy	Term Limit
Wind	25 years
Hydro	40 years
Geothermal	40 years
Biomass	20 years
Solar	25 years

After the term of the EPA expires, the Utility will determine whether it is prepared to enter into negotiations with the owner of the Project regarding a new EPA for the Project. The Utility's determination will be based on its need for the electricity, prevailing market conditions, energy price, and power procurement practices at the time. If the Utility wishes to enter into a new EPA for the Project, the Utility expects that the price it offers for energy will assume that all initial capital costs for the Project have been recovered during the term of original EPA. The Utility shall not be required to enter into a renewal or new EPA and the terms of the prior EPA shall not limit the terms on which the Utility may negotiate such renewal or new EPA.

8. ADDITIONAL RULES

8.1 Costs

Developers are responsible for all costs incurred by them in connection with the SOP and this Application Process, including the costs of preparing an Application and any other submission required under the SOP, all System Interconnection Study costs and the execution and delivery of any EPA.

8.2 Nature of Process

The SOP is not a call for tenders. No legal offer, legal contract or legal duties (including any duty of fairness) or obligations of any kind whatsoever, whether express or implied, are intended to be created by or under these Rules, or by the filing of an Application, or the acceptance of an Application for review, or the review of an Application, or in any other manner whatsoever under or in connection with the SOP except for those arising under an EPA that has been signed and delivered by both the Developer and a Utility. A Utility shall have no liability whatsoever for the actions of YG or the other Utility.

8.3 Waiver

A Utility may waive any provision of these Rules, including any of the eligibility requirements, in respect of any Project which proposes to interconnect into the Distribution System or Transmission System owned by such Utility where the Utility determines in its Discretion that

such waiver would be consistent with the objectives of the SOP or is otherwise in the public interest or the ratepayers' interest. A waiver by a Utility in respect of one Project shall not bind any Utility in respect of any other Project.

8.4 Program Suspension/Cancellation

The Utilities may cancel or suspend the SOP at any time, without any liability of either YG or the Utilities to any Developer or to any other Person, where the Utilities are required to cancel or suspend the SOP by YG or as the Utilities may determine is required by the IPP Policy, the SOP OIC or any amendments thereto.

8.5 Program Amendments

As noted above, YG intends to review the IPP Policy every 2 years. YG may make any amendments to the IPP Policy at any time. The Utilities are authorized to make any amendments to these Rules (including any Reference Documents) and the Standard Form EPA at any time to support the SOP and IPP Policy all in accordance with Section 1 to these Rules.

8.6 No Liability

Neither YG nor the Utilities (including its affiliates, and their respective directors, officers, employees, contactors, subcontractors, consultants, agents and representatives) has any liability of any nature or kind whatsoever to any Person in connection with the SOP or the administration of the SOP, or information provided with respect to, or in the course of, the SOP, or the acceptance, rejection, or review of any Application, or any other decision, assessment, determination, statement, act or omission whatsoever, whether negligent or not, relating to the SOP or its administration.

8.7 Unsolicited Information Not Considered

The Utilities are not required to consider any information with respect to an Application that is not contained in the Application, or any written response to a request from a Utility for further information, clarification or verification.

8.8 Ownership of Documents

All Applications and all documents filed with an Application and all other submissions by a Developer under or in relation to the SOP will be retained by, and become the property of the applicable Utility, provided however that the applicable Utility shall not thereby acquire any ownership interest in intellectual property embedded therein.

8.9 Other Utility Power Procurement Processes

A Utility may at any time reject an Application for a Project that is the subject of a submission in any other Utility power procurement process.

8.10 Filing Requirements

If the last day for completing any act required or contemplated under these Rules falls on a day that is a Saturday, Sunday or other day recognized as a statutory holiday in Yukon, the time for

completing that act will be extended to the next day that is not a Saturday, Sunday or other day recognized as a statutory holiday in Yukon.

9. COMMUNICATION UNDER SOP

9.1 General

Communication from Developers should originate from the contact person(s) specified in the Application. Developers may change their contact persons by notice to the SOP Administrator and the applicable Utility. Developers should communicate in writing (which may include email). Developers should note that any questions or communications submitted and subsequent answers by YG and/or the Utilities respecting the SOP may be posted by YG on the SOP Website.

To avoid any potential misunderstandings and for administrative ease, Developers shall not contact the YG or the Utilities in respect of the SOP except (a) in the case of YG, through the SOP Administrator, and (b) in the case of each Utility, through the designated Utility contact person, as set out below:

(a) to the SOP Administrator

by email to: *IPPAdministrator@gov.yk.ca*

or by mail to: Yukon Government
Energy Branch
Box 2703 (EMR-206)
Whitehorse, Yukon, Y1A 2C6
Attention: SOP Administrator

(b) to YEC

by email to: *IPP@yec.yk.ca*

or by mail to: Yukon Energy Corporation
Standing Offer Program
#2 Miles Canyon Road
Box 5920
Whitehorse, Yukon, Y1A 6S7
Attention: President

(c) to AEY

by email to: *AEY_SOP@atco.com*

or by mail to: ATCO Electric Yukon
Standing Offer Program
100-1100 Front St
Whitehorse, Yukon, Y1A 3T4
Attention: Manager

YG may change the SOP Administrator at any time. The SOP Administrator and each Utility may change their contact persons at any time by notice to Developers.

10. REFERENCE DOCUMENTS

The following Reference Documents are attached to these Rules and can also be found at the "Documents" page of the SOP Website.

EXHIBIT "A"	Pre-Application Form
EXHIBIT "B"	Application Form
EXHIBIT "C"	Statement of Project Changes Form
EXHIBIT "D"	Standard Form EPA
EXHIBIT "E"	Conflict of Interest Statement Form
EXHIBIT "F"	Contractor Standards for Ethical Conduct
EXHIBIT "G"	Confidentiality and Compliance Agreement

GLOSSARY – STANDING OFFER PROGRAM RULES

All references to section numbers are to sections of these Rules, not the Application Form or Standard Form EPA, unless otherwise expressly stated.

1. **AEY** and **ATCO Electric Yukon** means Yukon Electrical Company Limited, doing business as ATCO Electric Yukon.

2. **Application** means the Application Form for a Project as submitted by the Developer to the Utility together with all amendments thereto filed by the Developer and all supporting documents and information filed by the Developer with the Utility with respect to the Project, including the System Interconnection Study or other studies required by the Utility and Statement of Project Changes.

3. **Application Form** means the form titled "Standing Offer Program Application Form" in the form attached to these Rules and which is also available at the "Documents" page of the SOP Website.

4. **Application Phase** means the Application Phase described in Section 5.3 of these Rules.

5. **Application Process** means all 4 phases of the process described in these Rules being the Pre-Application Phase, Preliminary Feasibility Assessment Phase, Application Phase and EPA Execution Phase.

6. **Application Review** means the review process conducted by the Utility once a completed Application has been received, as outlined in Section 5.3.1 of these Rules.

7. **Base Fuel Price** has the meaning given to it in Section 4.2 of these Rules.

8. **Behind a Utility Customer Load** means a Project with an indirect interconnection to the YIS or WLG through a facility of a Utility customer which purchases power from the Utility.

9. **Commercial Operation Date** or **COD** has the meaning given in the Standard Form EPA.

10. **CPI** means the "Canada All Items (Not Seasonally Adjusted)" Consumer Price Index as published by Statistics Canada or any successor agency thereto.

11. **Day** means any calendar day including Saturday, Sunday or Yukon statutory holiday.

12. **Developer** means the developer or owner of a Project that submits an Application under the SOP.

13. **Discretion** (whether or not capitalized) means sole, absolute and unfettered discretion unless these Rules expressly state otherwise.

14. **Distribution System** means the distribution, protection, control and communication facilities in the Yukon that are or may be used in connection with, or that otherwise relate to, the transmission of electrical energy at 35 kV or less, and includes all additions and modifications thereto and repairs or replacements thereof.

15. **Eligible Clean Energy** means wind, hydro, geothermal, biomass and solar energy sources permitted under the IPP Policy for the SOP generated by a Project located in Yukon which is directly connected into the YIS or the WLG through the New Interconnection Facilities.

16. **Energy Price** has the meaning given to it in Section 4.1 of these Rules.

17. **Environmental Attributes** has the meaning given to that term in the Standard Form EPA.

18. **EPA** means an electricity purchase agreement offered to a Developer under the Standing Offer Program.

19. **EPA Execution Phase** means the EPA Execution Phase described in Section 5.4 of these Rules.

20. **First Nation** means any one of the 14 First Nations in the Yukon.

21. **Governmental Authority** means any federal, territorial, local or foreign government or any of their boards or agencies, or any regulatory authority.

22. **Interconnection Agreement** means an agreement with a Utility for the interconnection of the Project to the New Interconnection Facilities.

23. **IPP Policy** means the documents entitled the *Independent Power Production Policy* released in October 2015 by YG, as amended in October, 2018, as may be further amended by YG from time to time.

24. **kV** means kilovolt.

25. **kW** means kilowatt.

26. **kWh** means kilowatt-hour.

27. **Line Losses** means losses of electricity associated with the transmission and transformation of energy and other electricity, if applicable.

28. **Micro-gen Program** means a Yukon program that allows residents of Yukon to offset their electrical consumption by connecting small-scale (less than 50 kW) renewable energy technologies to their homes or businesses while remaining connected to Yukon's electrical grid.

29. **MVA** means megavolt ampere.

30. **MW** means megawatt.

31. **MWh** means megawatt-hour.

32. **Nameplate Capacity** means the aggregate of the nameplate capacities of all the generators included in the Project. For each generator, nameplate capacity is expressed in kW and consistent with the equipment manufacturer's maximum rated generating capacity. Where the nameplate capacity is expressed in MVA, the nameplate capacity will be multiplied by the power factor stated on a generator's nameplate to determine the nameplate capacity in MW.

33. **New Interconnection Facilities** means those additions, modifications and upgrades required to interconnect the Project to the YIS or WLG, as applicable, identified in the System Interconnection Study (and as further refined in subsequent interconnection studies, if required by the Utility) and approved by the Utility, but excluding any System Upgrades. All New Interconnection Facilities become part of the YIS or WLG once the facility becomes operational.

34. **New Interconnection Facilities Costs** means all costs for the design, engineering, procurement, construction, installation and commissioning of the New Interconnection Facilities. See Section 6.7 of these Rules.

35. **OIC** means Order in Council.

36. **Outstanding Permits** means the Outstanding Permits described in Section 5.3.2(b) of these Rules.

37. **Permits** means permits, certificates, licences, approvals and other authorizations issued by any Governmental Authorities as may be required for the design, construction, ownership, operation, maintenance and decommissioning of (i) the Project and (ii) the New Interconnection Facilities.

38. **Person** means an individual, body corporate, firm, partnership, joint venture, trust, legal representative or other legal entity.

39. **Plant Capacity** means the Nameplate Capacity of the generators for a new project or a portion of the Nameplate Capacity of the generators that is allocated to the SOP where a new generator is added to existing project, expressed in kW.

40. **Point of Interconnection** or **POI** means the point at which the Project interconnects with the New Interconnection Facilities.

41. **Pre-Application Phase** means the Pre-Application Phase described in Section 5.1 of these Rules.

42. **Pre-Application Completeness Review** means the review conducted by YG in accordance with Section 5.1.1 of these Rules.

43. **Preliminary Eligibility Approval** means the preliminary eligibility assessment approval by the Utility issued pursuant to Section 5.1.2 of these Rules.

44. **Preliminary Feasibility Assessment Phase** means the Preliminary Feasibility Assessment Phase described in Section 5.2 of these Rules.

45. **Prior Developers** has the meaning given to it in Section 6.9 of these Rules.

46. **Project** means an electrical generation facility and includes all land and interests in land, buildings, equipment and material related to the generation facility as required for the generation and delivery of electrical energy to the point of delivery under the EPA. In the case of a Project that consists of incremental new generation, the "Project" for the purposes of the SOP consists of the new generator(s) and related facilities that are added to an existing generating facility.

47. **Project Cluster** means two or more existing or proposed Projects that a Utility determines in its Discretion are so closely related to each other that they should be considered a project cluster for the purposes of the SOP. A Utility will generally determine that a Project Cluster exists where the existing or proposed Projects have the following characteristics (although the Utility may conclude otherwise in its Discretion): (i) have common direct or indirect ownership or control; (ii) have common development timelines; (iii) are being developed by the same or an affiliated developer; (iv) are located in close proximity (e.g., in same watershed); and/or (v) share any tenures, permits, facilities or other infrastructure such as roads, power lines, interconnection facilities.

48. **Project Energy Volume** has the meaning given in Section 3.4 of these Rules.

49. **Reference Documents** means the documents listed in Section 10 of these Rules.

50. **Regulatory Agency Authorizations** means the issuance of those Permits which are specified as required for the Project in the YESAB assessment report recommendation to proceed issued in respect of the Project.

51. **Revenue Meter** means a meter that measures energy output and/or consumption for purposes of calculating payments under an EPA and that meets the requirements specified in the EPA.

52. **Rules** has the meaning given in Section 1 of these Rules.

53. **SOP** means the Standing Offer Program as described in these Rules.

54. **SOP Administrator** means the person appointed by YG to act as the SOP Administrator for the purposes of these Rules.

55. **SOP OIC** means that Order in Council issued by YG on January 24, 2019 regarding, among other things, the Standing Offer Program.

56. **SOP Queue** means the SOP queue maintained by YG on the SOP Website which shall specify each Project (including the applicable Developer, the Project Energy Volumes and Target Developer's COD for the Project) which has been registered by a Utility under the Application Process. The SOP Website shall maintain separately from the SOP Queue information for each Project (including the applicable Developer, the Project Energy Volumes and Target Developer's COD for the Project) for which a Utility has entered into an EPA. YG reserves the right to modify the information it maintains in the SOP Queue at any time.

57. **SOP Website** means the website with respect to the Standing Offer Program maintained by YG located at *www.Yukon.ca/apply-independent-power-producer*.

58. **Standard Form EPA** means the Standard Form Electricity Purchase Agreement in the form attached to these Rules and which is also available at the "Documents" page of the SOP Website.

59. **Standing Offer Program** and **SOP** means the Standing Offer Program as described in these Rules.

60. **Statement of Project Changes** means a Statement of Project Changes in the form attached to these Rules and which is also available at the "Documents" page of the SOP Website.

61. **System Interconnection Study** means a detailed interconnection study which evaluates the impact of a proposed Project on the reliability of the Utility's system and provides a planning-level estimate of the required System Upgrades and New Interconnection Facilities and associated costs.

62. **System Upgrades** means those additions, modifications and upgrades to the YIS or WLG, as applicable, identified in the System Interconnection Study (and as further refined in subsequent interconnection studies) determined by the Utility to be "interconnection network upgrades" under the applicable policies of the Utility, but excluding New Interconnection Facilities.

63. **System Upgrade Costs** means all costs for the design, engineering, procurement, construction, installation and commissioning of System Upgrades. See Section 6.8 of these Rules.

64. **System-wide Limits** has the meaning given in Section 3.4 of these Rules.

65. **Target Developer's Commercial Operation Date** or **Target Developer's COD** means the date when the Developer expects the Project to achieve COD as specified by the Developer in the Application.

66. **Term** means the term of the EPA as specified by the Developer in the Application.

67. **Transmission System** means the transmission, substation, protection, control and communication facilities owned and operated by a Utility in Yukon, and includes all additions and modifications thereto and repairs or replacements thereof.

68. **Utility** means YEC or AEY, as applicable, and **Utilities** means both such parties.

69. **WLG** means the Watson Lake Grid owned and operated by AEY.

70. **YDC** means Yukon Development Corporation.

71. **YEC** means Yukon Energy Corporation.

72. **YESAA** means the *Yukon Environmental and Socio-economic Assessment Act*, SC 2003, c 7.

73. **YESAB** means the Yukon Environmental and Socio-economic Assessment Board.

74. **YESAB Adequacy Confirmation** means, where required, the confirmation by the YESAB under YESAA that a Developer's proposal for the Project is adequate and ready to be advanced to the evaluation stage.

75. **YG** means the Government of Yukon.

76. **YIS** means the Yukon Integrated System, which is the composite of Yukon Energy's grid assets and connected AEY generation, transmission and distribution assets.

ELECTRICITY PURCHASE AGREEMENT

BETWEEN

[SELLER]

- and -

[UTILITY]

[PROJECT NAME]

(YUKON STANDING OFFER PROGRAM)

Dated the ___ day of ____, 20__

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[UTILITY]

STANDARD FORM ELECTRICITY PURCHASE AGREEMENT

STANDING OFFER PROGRAM

THIS ELECTRICITY PURCHASE AGREEMENT ("**EPA**") is made as of the __ day of ____, 20__

BETWEEN:

[SELLER], a corporation incorporated under the laws of _____ ("**Seller**")

- and -

[UTILITY], a corporation incorporated under the laws of the Yukon ("**Buyer**")

WHEREAS:

A. The Government of Yukon issued the *Energy Strategy for Yukon* in January 2009 and in October 2015 issued the *Independent Power Production Policy* as reviewed and updated in October, 2018 (the "**IPP Policy**") as part of the strategy's priority action to "update and develop a policy framework for electricity that emphasizes efficiency, conservation and renewable energy". The IPP Policy created a framework for the development of the Standing Offer Program. In support of the objectives of the IPP Policy, the Government of Yukon issued the SOP OIC and, together with the Utilities, developed the SOP Rules;

B. Seller has proposed the development of the Project on the Electrical Grid pursuant to the Standing Offer Program and such Project has been reviewed and approved in accordance with the SOP Rules; and

C. This EPA is being entered into by the Parties in respect of the Project under the Standing Offer Program in accordance with the SOP Rules.

NOW THEREFORE Seller and Buyer agree as follows:

ARTICLE 1
DEFINITIONS, INTERPRETATION AND SCHEDULES

1.1 Definitions and Interpretation

The definitions and certain principles of interpretation that apply to this EPA are set out in Schedule "A".

1.2 Schedules

The following Schedules attached hereto are incorporated into and made a part of this EPA:

Schedule "A"	-	Definitions and Interpretation
Schedule "B"	-	Project Description

Schedule "C"	-	Form of Annual Operating Plan
Schedule "D"	-	System Interconnection Study Report
Schedule "E"	-	Monthly Energy Shortfall Payment
Schedule "F"	-	Termination Payment
Schedule "G"	-	System Interconnection Guidelines
Schedule "H"	-	Joint Operating Procedure
Schedule "I"	-	Delivery Time Adjustment Table

ARTICLE 2
CONDITIONS PRECEDENT AND TERM

2.1 Conditions Precedent

(a) Except as provided in this Section, this EPA has no legal force until the Conditions Precedent described in Schedule "B" are satisfied by Seller or waived by Buyer. The Conditions Precedent may only be waived by Buyer by notice in writing to Seller.

(b) Seller will:

(i) seek to satisfy each of the Conditions Precedent on or before the Condition Date;

(ii) keep Buyer informed of any circumstances which may result in any of those Conditions Precedent not being satisfied in accordance with their terms; and

(iii) promptly notify Buyer upon satisfaction of any of those Conditions Precedent and provide such supporting evidence as may be reasonably required by Buyer.

(c) If the Conditions Precedent are not satisfied or waived on or before the Condition Date, or it becomes apparent that the Conditions Precedent will not, in the reasonable opinion of Buyer, be satisfied by the Condition Date, the Conditions Precedent will be taken to have failed and Buyer shall be entitled to terminate this EPA, in which event each Party shall release the other from any and all claims, damages, costs, expenses or liabilities whatsoever incurred by it and its Affiliates in relation this EPA provided that (i) Seller shall remain liable for all costs incurred by Buyer in respect of the System Interconnection Study Report, System Upgrade Costs or New Interconnection Facilities Costs and (ii) otherwise each Party shall be responsible for its own costs incurred by it in connection with this EPA.

(d) Section 2.1(a) does not apply to this Article 2, Section 3.5 and Articles 10, 11, 12, 13 and 15 which shall be in full force and effect from the date of this EPA.

2.2 Term

Subject to Section 2.1, this EPA shall commence on the Effective Date and continues for the period specified in Schedule "B", unless it is terminated earlier in accordance with this EPA.

ARTICLE 3
CONSTRUCTION AND OPERATION

3.1 Construction and Operation Costs, Liabilities and Actions

Seller will be fully responsible for the permitting, design, engineering, construction, Interconnection, commissioning, operation, maintenance, reclamation and decommissioning of the Seller's Plant and shall be responsible for all costs, expenses, liabilities and other obligations associated with such activities.

3.2 Standard of Construction and Operation

Except as otherwise consented to in writing by Buyer, such consent not to be unreasonably withheld, conditioned or delayed, Seller will ensure that the location, design, engineering, construction, Interconnection, commissioning, operation and maintenance of the Seller's Plant, are and will be carried out at all times during the Term:

(a) in accordance with the description of the Seller's Plant in Schedule "B" and the information in the Application in all material respects;

(b) in compliance with the Project Standards; and

(c) by qualified and experienced individuals.

The Parties shall conduct their respective operations in accordance with the Joint Operating Procedure.

3.3 Project Changes

Without Buyer's prior written consent, not to be unreasonably withheld, conditioned or delayed Seller will not make any change to:

(a) the Seller's Plant as described in Schedule "B"; or

(b) any other aspects of the Seller's Plant or the information in any System Interconnection Study Report completed for Seller's Plant prior to the Effective Date which would require changes by Buyer to the System Upgrades where such change would increase Buyer's liability for any costs or otherwise increase the obligations or risks of Buyer with respect to the Seller's Plant or any other project.

Seller acknowledges that Buyer may require, as a condition of its consent to any change described in this Section, that Seller agree in writing to reimburse Buyer for any reasonable incremental liability for any losses, costs and damages incurred by Buyer or any third party, with respect to the Seller's Plant or any other project, as a result of any change described in this Section. Buyer may also require that Seller provide performance assurance or security to Buyer in order to ensure that Buyer has no financial exposure in respect of such reimbursement obligation.

3.4 Development Progress Reports

Seller will deliver a Development Progress Report to Buyer on each January 1, April 1, July 1 and October 1 after the Effective Date until Seller's COD. Buyer shall be entitled to request such

additional information as it may reasonably require from time to time in respect of Seller's development of Seller's Plant.

3.5 Responsibility for Upgrade Costs

Seller will be responsible for and shall pay Buyer for all System Upgrade Costs and New Interconnection Facilities Costs in accordance with the following:

(a) the System Interconnection Study Report sets out Buyer's estimate of System Upgrade Costs and the New Interconnection Facilities Costs. Seller shall (i) pay to Buyer in advance an amount equal to such estimate of System Upgrade Costs and New Interconnection Facilities Costs ("**Upgrade Costs Advance**") and/or (ii) provide such other security in form, substance and amount as may be acceptable to Buyer in its Discretion to secure the obligation of Seller to pay such costs ("**Upgrade Costs Security**"). Buyer shall not be required in any circumstances to accept Upgrade Costs Security except in its Discretion. Buyer shall not be required to perform any work or incur any System Upgrade Costs or New Interconnection Facilities Costs where Buyer determines in its Discretion that the amount of Upgrade Costs Advance it has received together with any Upgrade Costs Security is not sufficient to adequately secure the obligation of Seller to pay all System Upgrade Costs and New Interconnection Facilities Costs and Seller shall forthwith provide to Buyer such additional Upgrade Costs Advance and/or Upgrade Costs Security as may be reasonably required by Buyer;

(b) Buyer will exercise Good Industry Practice to perform, or cause to be performed, the work required in respect of the System Upgrades and the New Interconnection Facilities for the Project. Buyer shall be entitled to draw upon the Upgrade Costs Advance and Upgrade Costs Security from time to time in its Discretion to satisfy any System Upgrade Costs and New Interconnection Facilities Costs as and when incurred by Buyer; and

(c) notwithstanding the estimate of System Upgrade Costs and New Interconnection Facilities Costs provided by Buyer to Seller contemplated in Section 3.5(a) or the amount of any Upgrade Costs Advance and Upgrade Costs Security provided by Seller, Seller shall be responsible for and shall pay Buyer the actual System Upgrade Costs relating to the System Upgrades incurred by Buyer. Following the completion of the System Upgrades and the payment in full by Seller of all System Upgrade Costs incurred by Buyer for such work, Buyer shall release to Seller any undrawn portion of the Upgrade Costs Advance and Upgrade Costs Security**.**

3.6 Metering

As part of the System Upgrades and New Interconnection Facilities, Buyer will install and maintain an appropriate Meter installation at the POI, and ensure that such Meter is tested and sealed according to any Measurement Canada standards. Seller will allow Buyer to access the Seller's Plant as may be necessary from time to time to install and maintain the Meter at the POI. If there is any dispute regarding the accuracy of the Meter, either Party may give notice to the other Party of the dispute. In that case, the Parties will resolve the matter in accordance with the *Electricity and Gas Inspection Act* (Canada).

3.7 Insurance

Seller will, at its cost, obtain and maintain (a) policies of commercial general liability insurance with a per occurrence limit of liability not less than $5,000,000, and (b) property insurance, with limits of liability and deductibles consistent with those a prudent owner of a facility similar to the Seller's Plant would maintain and those the Facility Lender may require. All commercial general liability policies must include Buyer, its directors, officers, employees and agents as additional insureds and must contain a cross liability and severability of interest clause. All policies of insurance must include a waiver of subrogation in favour of Buyer. All policies of insurance must be placed with insurers that have a minimum rating of A- (or equivalent) by A.M. Best Company and are licensed to transact business in the Yukon and must be endorsed to provide to Buyer 30 days' prior written notice of cancellation, non-renewal or any material amendment that results in a reduction in coverage. Seller will give Buyer a copy of the insurance certificate(s) for the insurance required to be maintained by Seller under this Section not more than 30 days after the effective date of coverage and promptly upon renewal thereafter. Seller will be responsible for the full amount of all deductibles under all insurance policies required to be maintained by Seller under this Section.

3.8 Seller's COD

(a) Except with Buyer's prior written consent, Seller's COD may not occur earlier than 90 days prior to Target Seller's COD.

(b) Buyer will not be required to incur any incremental expense or other liability of any kind to enable Seller's COD to occur prior to Target Seller's COD.

3.9 Change in Target Seller's COD

If the estimated date for completing the System Upgrades or the New Interconnection Facilities as required to achieve Buyer's COD is later than 90 days prior to the Target Seller's COD, Buyer shall provide notice to Seller of such delay and, provided Seller is not responsible for any delay in completing the System Upgrades or the New Interconnection Facilities (including a failure to pay amounts contemplated in Section 3.5), upon Seller's written request that the Target Seller's COD be postponed, Buyer will postpone the Target Seller's COD to the estimated date for completing the System Upgrades and the New Interconnection Facilities plus 90 days.

3.10 No Liability For Delay

Buyer shall exercise reasonable commercial efforts to achieve Buyer's COD prior to Target Buyer's COD. Buyer will have no liability under this EPA for delays in completion of (a) any System Upgrades or the New Interconnection Facilities, or (b) other work undertaken by Buyer or any of Buyer's Affiliates on the Seller's Plant side of the POI, in each case howsoever arising.

3.11 Outages

(a) **Notice of Seller's Outage** - Seller will notify Buyer of any Outages in Seller's Plant, or changes in any such Outages, by delivering to Buyer an Outage Notice or revised Outage Notice:

(i) promptly in the case of a Forced Outage or a Maintenance Outage;

(ii) not less than 90 days in advance of any Planned Outage, or such shorter time period with Buyer's written consent, such consent not to be unreasonably withheld, delayed or conditioned; and

(iii) promptly in the case of any changes to the duration, start time or end time of any Outage.

(b) **Notice of Buyer's Outage** - In addition to Buyer's reporting requirements under Section 4.8(d), Buyer will notify Seller of any Planned Outages that will result in a Buyer's Distribution/Transmission Constraint or changes in any such Planned Outages, by delivering to Seller an Outage Notice or revised Outage Notice:

(i) not less than 90 days in advance of any such Planned Outage, or such shorter time period with Seller's written consent, such consent not to be unreasonably withheld, delayed or conditioned; and

(ii) promptly in the case of any changes to the duration, start time or end time of any Outage.

(c) **Coordination and Scheduling of Outages -** Seller will coordinate all Planned Outages or Maintenance Outages with Buyer's maintenance schedule or other requirements where such schedule or requirements are publicly available or otherwise notified to Seller.

3.12 Annual Operating Plan

On or before October 31 in each year during the Term, Seller will provide to Buyer its Annual Operating Plan, including any required update to the then current Annual Operating Plan, for the 12-month period commencing on January 1 of the next year. Seller will promptly provide Buyer with a revised Annual Operating Plan from time to time upon Seller becoming aware of any expected material change in the original Annual Operating Plan for that period. The Parties agree the Annual Operating Plan is provided for planning purposes and does not guarantee or limit the quantity or timing of Delivered Energy to the POI.

ARTICLE 4
PURCHASE AND SALE OBLIGATIONS

4.1 Energy prior to Buyer's COD

Subject to satisfaction of all obligations of Seller under this EPA, upon the occurrence of Seller's COD but prior to the occurrence of Buyer's COD, Buyer will not be obligated to purchase, or accept delivery from Seller of, any Energy, provided if Buyer does accept, in its sole discretion, delivery of Energy at the POI, Buyer will pay for such Energy accepted by Buyer prior to Buyer's COD in accordance with Section 5.1.

4.2 Energy after Buyer's COD

From and after Buyer's COD for the remainder of the Term, Seller will sell and deliver all Energy to Buyer at the POI and Buyer will, subject to Sections 4.3 and 4.4, purchase and accept delivery of all Delivered Energy. Buyer will pay for Delivered Energy from and after Buyer's COD in accordance with Section 5.1.

4.3 Limit on Delivered Energy and Capacity

Notwithstanding the foregoing provisions of this Article 4:

(a) in any hour, Buyer will not be obligated at any time to purchase or accept delivery from Seller at the POI of any Energy generated in excess of the Seller's Plant Capacity in such hour (as measured in KWh) and no amount will be payable by Buyer for Delivered Energy in excess of the Seller's Plant Capacity in such hour, whether prior to or after COD, and regardless of whether Buyer consented to and accepted delivery of such Energy at the POI;

(b) in any calendar year, Buyer will not be obligated to purchase or accept delivery from Seller at the POI of any Energy generated in excess of the Project Energy Volume and no amount will be payable by Buyer for Delivered Energy in any such calendar year in excess of the Project Energy Volume in such calendar year, whether prior to or after COD, and regardless of whether Buyer consented to and accepted delivery of such Energy at the POI; and

(c) in determining the total amount of Delivered Energy for a year, month, hour or any other time period under this EPA for any purpose, the amount of Delivered Energy in each hour of such time period will not exceed the Seller's Plant Capacity in such hour, even if Seller delivered to the POI Energy in excess of such amounts, or the Seller's Plant was capable of generating Energy in excess of such amounts.

4.4 Distribution/Transmission Constraints

Buyer will not be in breach or default of its obligations under Sections 4.1, 4.2 or 5.1 if Buyer is not able to accept delivery of Energy at the POI as a result of a Distribution/Transmission Constraint. Buyer will have no liability with respect to a Distribution/Transmission Constraint, except as set out in Section 4.8, if applicable.

4.5 Exclusivity

(a) Seller will not at any time during the Term commit, sell or deliver any Energy (or related Environmental Attributes) to any Person other than Buyer under this EPA. Seller will not use any Energy (or related Environmental Attributes) for any purpose whatsoever except for sale to Buyer under this EPA. These prohibitions do not apply if, and for so long as, Buyer is in breach of its obligations under Section 4.2.

(b) Seller shall not be entitled to interconnect a generating facility to the Seller's Plant and transmit electricity via the Seller's Plant to the POI.

4.6 Custody, Control, Risk of and Title To Energy

Custody, control, risk of, and title to, all Energy (including any Delivered Energy exceeding the limits set out in Section 4.3 even where Buyer has not paid for such excess Delivered Energy) shall pass from Seller to Buyer at the POI. Seller will ensure that all Energy delivered to Buyer under this EPA is free and clear of all liens, claims, charges and encumbrances.

4.7 Line Losses

Seller will be responsible for all Line Losses, costs and liabilities relating to the transmission of Energy and other electricity, if applicable, from the POI to the interconnection point between the New Interconnection Facilities and the Electrical Grid. Such Line Losses shall be determined in accordance with the Line Loss Methodology.

4.8 Distribution/Transmission Constraint

(a) If, in any month after Buyer's COD, Seller is unable to deliver Energy at the POI or Seller's ability to deliver Energy at the POI is reduced solely as a result of a continuous Distribution/Transmission Constraint which exceeds 30 minutes in duration and which:

(i) is not caused by a Planned Outage by Buyer of the Distribution System or Transmission System;

(ii) is not caused by an event beyond the reasonable control of Buyer; and

(iii) is not caused by Seller, the Seller's Plant or anything on Seller's side of the POI;

(a "**Non-Permitted Distribution/Transmission Constraint**") then, notwithstanding that Buyer is excused under Section 4.4 from its obligations under Section 4.2, Buyer shall pay Seller, for each calendar month in which the Non-Permitted Distribution/Transmission Constraint has occurred, the Monthly Energy Shortfall Payment calculated in accordance with Schedule "E" less any costs Seller avoided or, acting reasonably, could have avoided during the Non-Permitted Distribution/Transmission Constraint.

(b) Buyer will not be required to pay any Monthly Energy Shortfall Amount under this Section in any of the following circumstances:

(i) during any period specified as a Seller's Outage in any Outage Notice, revised Outage Notice or in the Annual Operating Plan or during any other period where the Seller's Plant would otherwise not have been operating;

(ii) during any period when either Party is or would be excused, in accordance with Section 14.1, from its obligation to deliver or to accept delivery of Energy as a result of Force Majeure; or

(iii) if Seller has not provided Buyer with an Annual Operating Plan in accordance with Section 3.12 for the year in which the Non-Permitted Distribution/Transmission Constraint occurs.

(c) Seller will maintain accurate and complete Records of all costs Seller avoided or, acting reasonably, could have avoided during the Non-Permitted Distribution/Transmission Constraint and will report all such costs to Buyer and provide Buyer with all information required to calculate such costs.

(d) Buyer will give Seller notice of all Distribution/Transmission Constraints in each month which individually exceed 30 minutes in duration when it provides its monthly statements in accordance with Section 5.3.

(e) In the event of a Dispute by the Parties in respect of the amount of any Monthly Energy Shortfall Amount, the matter shall be resolved in accordance with Article 12.

4.9 Buyer Dispatch/Turn-Down Right

(a) Buyer may at any time during the Term deliver notice to Seller requiring Seller to Dispatch/Turn-Down and Seller will promptly comply with any such direction except to the extent that any operational, technical or regulatory constraint prevents or limits Seller's ability to comply with such direction.

(b) For each hour of the applicable Dispatch/Turn-Down, Buyer will pay Seller an amount equal to:

(i) the price payable for post-COD Delivered Energy under Section 5.1 multiplied by (A) the aggregate of the duration of the applicable Dispatch/Turn-Down (measured as a fraction determined as the aggregate number of minutes in such Dispatch/Turn-Down period divided by 60) multiplied by (B) an amount equal to the positive difference, if any, of (1) the "Non-Permitted Distribution / Transmission Constraint Hourly Deemed Energy" set out in Table E-1 of Schedule "E" for the applicable calendar month less (2) the amount of Delivered Energy in such hour of Dispatch/Turn-Down (the positive difference being the "**Dispatch/Turn-Down Deemed Energy**"); less

(ii) any costs Seller avoided or, acting reasonably, could have avoided during the period of the Dispatch/Turn-Down.

(c) Buyer will not be required to pay any amount in respect of Dispatch/Turn-Down Deemed Energy under this Section in any of the following circumstances:

(i) during any period specified as a Seller's Outage in any Outage Notice, revised Outage Notice or in the Annual Operating Plan or during any other period where the Seller's Plant would otherwise not have been operating;

(ii) during any period when either Party is or would be excused, in accordance with Section 14.1, from its obligation to deliver or to accept delivery of Energy as a result of Force Majeure;

(iii) if Seller has not provided Buyer with an Annual Operating Plan in accordance with Section 3.12 for the year in which the Dispatch/Turn-Down occurs;

(iv) during any other hour when the Seller's Plant would otherwise not have been operating if there had been no Dispatch/Turn-Down notice; or

(v) where Buyer's requirement for Seller to Dispatch/Turn Down is the result of the operation of the Seller's Plant in a manner inconsistent with Section 3.2.

(d) Where Buyer requires the Dispatch/Turn-Down as result of a Non-Permitted Distribution/Transmission Constraint, Section 4.8 will apply.

4.10 Electric Service to Seller

If at any time Buyer delivers electrical energy to service Seller's Plant Load, then such electrical energy shall be accounted and paid for separately under the applicable agreement for such electricity energy services and will not be netted off of Delivered Energy for the purposes of determining amounts payable by Buyer in accordance with Section 5.1.

ARTICLE 5
PRICE AND PAYMENT TERMS

5.1 Energy Price

In each billing period, Seller shall pay to Buyer, for each KWh of Delivered Energy, the Energy Price calculated in accordance with Schedule "B".

5.2 No Further Payment

The amount payable by Buyer as specified in Section 5.1 is the full and complete payment and consideration payable by Buyer for Delivered Energy and for Environmental Attributes.

5.3 Statements and Payment

(a) **Statements**

(i) Buyer will, by the 15th day of each month after the Buyer's COD, deliver to Seller a statement for the preceding month. The statement must indicate, among other things:

(A) the amount of, and price payable for, Delivered Energy for that month;

(B) any amount owing by Buyer in respect of a Non-Permitted Distribution/Transmission Constraint pursuant to Section 4.8;

(C) any Final Amounts owing by either Party to the other Party.

Where there has been any Delivered Energy purchased by Buyer in the period prior to Buyer's COD, the first statement following Buyer's COD shall also account for all amounts payable by Buyer to Seller for such period prior to Buyer's COD. The statement must set out in reasonable detail the manner by which the statement and the amounts shown thereon were computed and be accompanied by sufficient data to enable Seller, acting reasonably, to satisfy itself as to the accuracy of the statement.

(ii) Either Party may give notice to the other Party of an error, omission or disputed amount on a statement within 36 months after the statement was first issued together with reasonable detail to support its claim. After expiry of that 36 month period, except in the case of willful misstatement, fraud or concealment, amounts on a previously issued statement will be considered accurate and amounts which were omitted will be considered to be nil, other than amounts disputed in accordance with this Section within the 36 month period, which will be resolved in accordance with this EPA.

(iii) If Seller gives notice to Buyer of an error, omission or disputed amount on a statement as described in Section 5.3(a)(ii), Seller may direct Buyer to promptly produce new statements for the relevant month(s). The new statements will show the undisputed amount and disputed amount each in a separate statement or will otherwise separate the amounts in a single statement in a manner acceptable to Seller, acting reasonably.

(b) **Payment**

(i) Within 30 days after receipt of a statement delivered under Section 5.3(a), and subject to Section 5.5, Buyer will pay to Seller or Seller will pay to Buyer the amount set out in the statement, except to the extent Seller in good faith disputes all or part of the statement by notice to Buyer as described in Section 5.3(a)(ii).

(ii) If Seller disputes any portion of a statement, the applicable Party must pay the undisputed net amount payable by it pursuant to the statement or, if applicable, the new statement of the undisputed amount described in Section 5.3(a)(iii).

(iii) The Parties will endeavor to resolve any error, omission or disputed amount on a statement amount within 30 days of the notice described in Section 5.3(a)(ii).

(iv) Any amount required to be paid in accordance with this EPA, but not paid by either Party when due, will accrue interest at an annual rate equal to the Prime Rate plus 2%, compounded monthly. Any disputed amount that is found to be payable will be deemed to have been due within 30 days after the date of receipt of the statement which included or should have included the disputed amount.

(c) **Payment Calculations**

(i) For the purpose of all payment calculations under this EPA:

(A) all payment calculations will be rounded to the nearest cent; and

(B) Energy will be expressed in KWh rounded to two decimal places.

(ii) For the purpose of all payment calculations under this EPA, where CPI is to apply, if Statistics Canada (or the then recognized statistical branch of the Canadian Government):

(A) computes, at any time after the Effective Date, the CPI on a basis different to that employed at the Effective Date, then the CPI will be converted using the appropriate formula recommended by Statistics Canada (or the then recognized statistical branch of the Canadian Government);

(B) at any time ceases to publish or provide the CPI, then the provisions of Section 2.7 of Schedule "A" will apply;

(C) has not published the CPI for a relevant period at the time Buyer is required to provide Seller with a statement, Seller will prepare the invoice based on the CPI in effect at the time the invoice is issued and

when the CPI for the relevant period is published, Buyer will recalculate the invoice amounts in the next succeeding invoice and will include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation; or

(D) recalculates the CPI within 36 months after an invoice affected by that CPI calculation has been issued, then Buyer will recalculate the invoice amounts for the relevant period in the next succeeding invoice and will include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation.

5.4 Taxes

All dollar amounts in this EPA do not include any value added, consumption, commodity or similar taxes, including GST and any successor thereto, which, if applicable, will be added to each statement and paid by Buyer.

5.5 Set-off

If Buyer and Seller each owe the other an amount under this EPA in the same month, then such amounts with respect to each Party will be aggregated and the Parties may discharge their obligations to pay through netting, in which case the Party, if any, owing the greater aggregate amount will pay to the other Party the difference between the amounts owed, provided that this Section applies only to any purchase price for Delivered Energy and any Final Amount owing by either Party to the other Party. Except as otherwise expressly provided herein, each Party reserves all rights, counterclaims and other remedies and defenses which such Party has, or may be entitled to, arising from or related to this EPA.

5.6 Change in Law and GRA Cost Recovery

(a) If at any time after the Effective Date:

(i) the costs to Buyer of complying with its obligations under this EPA are, as a result of one or more Changes in Law, increased or decreased (including, for greater certainty, any increase of the obligations or risks of Buyer with respect to the Seller's Plant, but excluding any increase of the obligations or risks of Buyer with respect to the System Upgrades or New Interconnection Facilities); or

(ii) the costs to Buyer of complying with its obligations under this EPA which were of a category or type previously recovered under a General Rate Application are determined under a General Rate Application to no longer be approved for recovery from Buyer's customers in such General Rate Application;

then, to the extent that Buyer would not have incurred such costs except for the Seller's Project and/or the entering into of this EPA, the amount payable by Buyer as specified in Section 5.1 shall be adjusted by the amount necessary to reflect those changed costs which Buyer is unable to recover from Buyer's customers in a General Rate Application.

(b) For each relevant event in Section 5.6(a)(i) or 5.6(a)(ii), Buyer shall provide Seller with a statement setting out such information as is reasonably necessary to demonstrate that such an event has occurred, the reasonableness and necessity of the measures taken by

Buyer in relation to the event, its efforts to mitigate the costs associated with such event including reasonable efforts of Buyer to recover such costs from its customers in a General Rate Application, the nature and extent of any increase or decrease in the amount payable by Seller as specified in Section 5.1, and any such other information as may be reasonably requested by Seller.

(c) If in Seller's view there has been a Change in Law that may decrease Buyer's costs, Seller may request Buyer to demonstrate how such Change in Law has affected its costs under this EPA by providing the applicable information contemplated in Section 5.6(b).

(d) The payments between the Parties shall thereafter be adjusted effective as of the date such event in Section 5.6(a)(i) or 5.6(a)(ii) affects the costs of Buyer hereunder.

(e) If there is any Dispute between the Parties with respect to this Section 5.6, including as to the appropriate increase or decrease in any payments between the Parties under this Agreement, the Dispute shall be resolved in accordance with Article 12.

ARTICLE 6
ENVIRONMENTAL ATTRIBUTES

6.1 Environmental Attributes

Seller hereby transfers, assigns and sets over to Buyer all right, title and interest in and to the Environmental Attributes. Seller will ensure that all Environmental Attributes transferred to Buyer under this EPA are free and clear of all liens, claims, charges and encumbrances. Seller shall use commercially reasonable efforts to (i) provide information reasonably requested by Buyer in relation to such Environmental Attributes, including as may be required to allow Buyer to verify or certify that such Environmental Attributes exist or have been created and (ii) assist in having Seller's Plant certified, licensed, qualified or approved under any rules, regulations, programs or applicable Laws of any Governmental Authority or independent certification agency in respect of Environmental Attributes, provided that Buyer shall pay Seller all costs reasonably incurred by Seller in respect of the same. Any failure by Seller to exercise such commercially reasonable efforts under this Section 6.1 is a "material default" for the purposes of this EPA, and Buyer may terminate this EPA under Section 9.1(j).

ARTICLE 7
EPA ADMINISTRATION, RECORDS AND AUDITS

7.1 Records

Each of Buyer and Seller will prepare and maintain all Records, or duplicates of such Records, at Buyer's head office or local Yukon office or the Seller's Plant, as applicable, or following the expiry of the Term or the earlier termination of this EPA, at such other location as may be agreed in writing between the Parties, for a period of not less than 7 years from the date on which each such Record is created. The Audit Parties may take copies of such Records for the purposes of an inspection or audit under Section 7.2.

7.2 Inspection and Audit Rights

For the sole purpose of verifying:

(a) compliance with this EPA;

(b) the accuracy of statements, supporting information and calculations delivered by a Party under this EPA;

(c) the qualification of the Seller's Plant and the Energy for the Environmental Certification; or

(d) the liability of Seller for System Upgrades Costs and New Interconnection Facilities Costs,

Buyer or Seller, as applicable, will, on reasonable prior written notice from either Party desiring to conduct an audit, provide the Audit Parties with prompt access during normal business hours to (i) in respect of Buyer, Buyer's records solely relating to this EPA, or (ii) in respect of Seller, Seller's Plant and all records relating to the Seller's Plant, including any Seller Confidential Information, as applicable, to enable the Audit Parties to conduct an inspection or audit thereof. The Audit Parties will exercise any access and audit rights under this Section in a manner that minimizes disruption to the operation of the Party subject to the audit. The audit rights contained in this Section 7.2 shall be subject to the limitations set forth in Section 5.3.

7.3 Seller Consents

Seller will promptly provide any consents required to enable any of the Audit Parties to make enquiries with any Governmental Authority or any Person administering the Environmental Certification concerning any or all of the following: (a) the qualification of the Seller's Plant and the Energy for Environmental Certification, the status of the Environmental Certification and copies of any audits, inspections or reports prepared in connection with the Environmental Certification; and (b) compliance by Seller with Laws and Permits applicable to the Seller's Plant.

ARTICLE 8
FIRST NATION CLAIMS

8.1 Notification of First Nation Claim

Given the ownership and location of the Project, Seller and Buyer do not expect any First Nation Claims. However, if Buyer or Seller receives or obtains evidence of a First Nations Claim, it will notify the other Party as soon as practicable.

8.2 Obligation to Consult

If Buyer receives, obtains evidence or becomes aware of a First Nations Claim, it may direct Seller, at Seller's cost, to:

(a) consult with the First Nations making the First Nation Claim, or, if requested by Buyer, assist Buyer in the consultation process;

(b) take any measures Seller deems necessary to address, prevent, mitigate, compensate or otherwise accommodate any Potential Impacts provided the measures are consented to in advance by Buyer and the First Nations making the First Nation Claim; and

(c) provide regular written reports to Buyer concerning Seller's compliance with this Section, as may be reasonably requested by Buyer.

8.3 Seller Termination for First Nation Claim

At any time prior to Buyer's COD, if:

(a) within 60 days of Buyer receiving, obtaining evidence or becoming aware of a First Nations Claim, Buyer does not make a direction to Seller as contemplated in Section 8.2;

(b) Buyer notifies Seller in writing that it will not make a direction to Seller as contemplated in Section 8.2; or

(c) after consultation with the First Nations making the First Nation Claim it becomes clear that the measure(s) necessary for Seller to resolve the First Nation Claim or to address, prevent, mitigate, compensate or otherwise accommodate any Potential Impacts would, in Seller's discretion, impose a commercially unreasonable cost on Seller, or would require the consent of Buyer under this EPA or agreement by Buyer to amend this EPA in order to address any Potential Impacts and such consent or agreement to amend is not provided within 60 days after Seller's request to Buyer,

then Seller may terminate this EPA on notice to Buyer. Such termination will be effective 30 days after the date of delivery of such notice of termination unless otherwise agreed by the Parties. A termination by Seller under this Section will, for all purposes of this EPA, be treated in the same manner as a termination by Seller under Section 9.3(c) of this EPA (including the obligations of Seller under Section 9.7). The termination of this EPA is the exclusive remedy to which Seller may be entitled to if Seller elects to terminate this EPA under this Section.

8.4 Buyer Termination for First Nation Claim

At any time prior to Buyer's COD, if Buyer receives, obtains evidence or becomes aware of a First Nations Claim, Buyer may, at its sole discretion, terminate this EPA on notice to Seller. Such termination will be effective 30 days after the date of delivery of such notice of termination unless otherwise agreed by the Parties. Upon a termination by Buyer under this Section 8.4, Seller shall reimburse Buyer for costs or liabilities described in Sections 9.7(a), (b) and (c). The reimbursement by Seller of such costs or liabilities, the indemnification by Seller contemplated in Section 8.5 and the termination of this EPA are the exclusive remedies to which Buyer may be entitled to if Buyer elects to terminate this EPA under this Section.

8.5 Seller Indemnity for First Nation Claim

Seller shall indemnify and hold Buyer and its Affiliates harmless from any and all claims, damages, costs, expenses, or liabilities whatsoever incurred by Buyer and its Affiliates in relation to such First Nation Claim and such indemnity shall survive termination of this EPA.

ARTICLE 9
TERMINATION

9.1 Termination by Buyer

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Buyer may have under this EPA or at law or in equity in respect of any of the following events, Buyer may terminate this EPA by notice to Seller if:

(a) Seller's COD does not occur within 730 days following Target Seller's COD for any reason whatsoever (including Force Majeure), provided that Buyer may terminate this EPA under this provision only if Buyer delivers a termination notice prior to Seller's COD; or

(b) at any time after Buyer's COD, Seller fails to deliver at least an average of 25% of the aggregate Projected Monthly Energy as set out in Schedule "E" to Buyer over all hours in a period of 730 continuous days for any reason whatsoever (including Force Majeure, a Distribution/Transmission Constraint), but excluding a Non-Permitted Distribution/ Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or

(c) at any time after Buyer's COD, Buyer is unable to accept delivery of Energy at the POI for a period of 730 continuous days due to Force Majeure invoked by Buyer or a Distribution/ Transmission Constraint other than a Non-Permitted Distribution/ Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or

(d) Seller breaches Section 4.5; or

(e) Seller fails to complete any application, payment, filing, study, document or other step in the process for interconnecting the Seller's Plant to the Distribution System, Transmission System or New Interconnection Facilities, as applicable, in accordance with the requirements of, and within the time limits, including any cure periods, specified by Buyer, and such failure could reasonably be expected to have an adverse impact on Buyer or any third party; or

(f) any System Interconnection Study Report completed after the Effective Date contains information that is inconsistent with the description of the Seller's Plant in Schedule "B" and Seller has not received Buyer's consent under Section 3.3 for the change to Schedule "B"; or

(g) Seller is Bankrupt or Insolvent; or

(h) Seller, as a result of an act or omission of Seller, ceases to be exempt from regulation as a "public utility" as defined in the *Public Utilities Act* with respect to the Seller's Plant and the sale of Energy to Buyer under this EPA, and the loss of such exemption could reasonably be expected to have an adverse effect on the benefit to Buyer of this EPA; or

(i) an amount due and payable by Seller to Buyer under this EPA remains unpaid for 30 days after its due date and such default has not been cured within 30 days after Buyer has given notice of the default to Seller; or

(j) Seller is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by Buyer to Seller of the default Seller has cured the default or, if the default cannot be cured within that 30 day period, Seller demonstrates to the reasonable satisfaction of Buyer that Seller is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time. A "material default" includes any purported Assignment of this EPA without the consent of Buyer.

Any termination pursuant to this Section will be effective immediately upon delivery of the notice of termination to Seller.

9.2 Notice of Termination Event

Seller will notify Buyer promptly if Seller is Bankrupt or Insolvent or if there is a material risk that Seller will become Bankrupt or Insolvent or if Seller has defaulted under any agreement with a Facility Lender or if any Permit or land tenure agreement for the Seller's Plant is terminated or expires.

9.3 Termination by Seller

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Seller may have under this EPA or at law or in equity in respect of any of the following events, Seller may terminate this EPA by notice to Buyer if:

(a) after Buyer's COD, Buyer has not accepted delivery of Energy for a period of 730 continuous days due to an event described in Section 4.4 or any event of Force Majeure and Seller is not entitled to receive any payment pursuant to Section 4.8 in respect of that period; or

(b) the Seller's Plant has suffered major damage where the cost to repair the damage exceeds the net present value (using the Present Value Rate) of the expected revenues under the EPA for the remainder of the Term less the net present value (using the Present Value Rate) of the estimated operating and maintenance costs for the Seller's Plant for the remainder of the Term; or

(c) Seller has been unable to achieve Seller's COD for a period of 730 days after Target Seller's COD or has been unable to deliver Energy to the POI for a period of 730 continuous days after Seller's COD in either case solely as a result of Force Majeure invoked by Seller or a Distribution/Transmission Constraint other than a Non-Permitted Distribution/Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or

(d) Buyer is Bankrupt or Insolvent; or

(e) except where an amount has been disputed in the manner specified in Section 5.3(a)(ii), an amount due and payable by Buyer to Seller under this EPA remains unpaid for 30 days

after its due date and such default has not been cured within 30 days after Seller has given notice of the default to Buyer; or

(f) Buyer is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by Seller to Buyer of the default Buyer has cured the default or, if the default cannot be cured within that 30 day period, Buyer demonstrates to the reasonable satisfaction of Seller that Buyer is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time.

Any termination pursuant to this Section will be effective immediately upon delivery of the notice of termination to Buyer.

9.4 Termination by Buyer for Convenience

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Buyer may have under this EPA or at law or in equity in respect of any of the following events, Buyer may terminate this EPA for convenience upon 90 days prior notice to Seller.

9.5 Effect of Termination

Upon expiry of the Term or earlier termination of this EPA in accordance with its terms:

(a) the Parties may pursue and enforce any rights and remedies permitted by law or equity in respect of any prior breach or breaches of this EPA and may enforce any liabilities and obligations that have accrued under this EPA prior to the expiry of the Term or the date of termination or that are stated to arise on termination of this EPA, subject to any express restrictions on remedies and limitations or exclusions of liability set out in this EPA;

(b) both Parties will remain bound by Section 3.5 with respect to the satisfaction of residual obligations for the period prior to termination or that are specified to arise on, or continue following, termination, and Sections 12.1 and 13.1 associated with Delivered Energy prior to termination of this EPA; and

(c) Seller will remain bound by Sections 7.1 and 7.2 for a period of 36 months following expiry or termination of this EPA;

and, in all such cases, both Parties will remain bound by any other provisions necessary for the interpretation and enforcement of the foregoing provisions.

9.6 Buyer Payment on Termination

If Seller terminates this EPA under any of Sections 9.3(d), 9.3(e) or 9.3(f) or Buyer terminates this EPA for convenience under Section 9.4, Buyer will pay to Seller an amount equal to the applicable Termination Payment due at the time of termination determined in accordance with Schedule "F".

9.7 Seller Payment on Termination

If Buyer terminates this EPA on or before 90 days after Seller's COD or Seller terminates this EPA on or before Buyer's COD under any of Sections 9.3(a), 9.3(b) or 9.3(c), Seller will, within 30 days after receipt of an invoice from Buyer, reimburse Buyer for:

(a) all System Upgrade Costs and New Interconnection Facilities Costs incurred by Buyer, or which Buyer has become contractually obligated to pay, prior to the termination of the EPA including System Upgrade Costs and New Interconnection Facilities Costs Seller would otherwise be responsible for under Section 3.5;

(b) any incremental liability for System Upgrade Costs and New Interconnection Facilities Costs which Buyer will incur as a result of the termination of this EPA; and

(c) any System Upgrade Costs and New Interconnection Facilities Costs which Seller is responsible for under any reimbursement agreement pursuant to Section 3.3.

9.8 Calculation and Payment

Buyer will pay any amount which it owes under Section 9.6 within 30 Business Days after the date of delivery of an invoice by Seller to Buyer. Any amounts owing by Seller to Buyer under this EPA will be netted against any amount owing by Buyer to Seller under Section 9.6.

9.9 Exclusive Remedies

Payment by Buyer of the amount determined under Section 9.6 is the exclusive remedy to which Seller is entitled, and Buyer's limit of liability, for termination of this EPA by Seller pursuant to any of Sections 9.3(d), 9.3(e) or 9.3(f). Subject to Section 9.4 and 9.7, termination of this EPA is the exclusive remedy to which Buyer or Seller, as the case may be, is entitled if Buyer or Seller elects to exercise its right to terminate this EPA under any of Section 9.1, 9.3(a), 9.3(b) or 9.3(c). For greater certainty, subject to Section 9.4 and 9.7, Seller will not be required to pay any termination payment on termination by Buyer of this EPA. Neither Party will have any right to terminate this EPA except as expressly set out herein.

ARTICLE 10
REPRESENTATIONS AND WARRANTIES

10.1 Seller's Representations

Seller represents and warrants to Buyer, and acknowledges that Buyer is relying on those representations and warranties in entering into this EPA, as follows:

(a) Seller is a corporation formed under the laws of _____, is validly existing and is in good standing under the laws of ____, is lawfully authorized to carry on business in _____, and has full corporate power, capacity and authority to enter into and to perform its obligations under this EPA;

(b) this EPA constitutes a valid and binding obligation of Seller enforceable against Seller in accordance with its terms; and

(c) this EPA has been duly authorized, executed and delivered by Seller.

10.2 Buyer's Representations

Buyer represents and warrants to Seller, and acknowledges that Seller is relying on those representations and warranties in entering into this EPA, as follows:

(a) Buyer is a corporation formed under the laws of the Yukon, is validly existing and is in good standing under the laws of the Yukon, is lawfully authorized to carry on business in the Yukon, and has full corporate power, capacity and authority to enter into and to perform its obligations under this EPA;

(b) this EPA constitutes a valid and binding obligation of Buyer enforceable against Buyer in accordance with its terms; and

(c) this EPA has been duly authorized, executed and delivered by Buyer.

ARTICLE 11
LIABILITY LIMITATIONS

11.1 Limit of Liability

Buyer's liability for damages for any failure to take or pay for Delivered Energy under this EPA is limited to the amount payable by Buyer for that Delivered Energy under Article 5, amounts owing under Sections 4.8 and any interest thereon calculated under this EPA.

11.2 Consequential Damages

Neither Party will be liable to the other Party for any special, incidental, exemplary, punitive or consequential damages with respect to, arising out of, relating to or in any way connected with a Party's performance or non-performance under this EPA.

ARTICLE 12
DISPUTES

12.1 Dispute Resolution Procedure

Any dispute, controversy or claim arising out of or relating to this EPA ("**Dispute**") shall be exclusively and finally resolved in accordance with the dispute resolution procedure set forth in this Article 12 (the "**Dispute Resolution Procedure**").

12.2 Commencement of the Dispute Resolution Procedure

The Parties shall make reasonable efforts to first resolve any Dispute. If a Dispute cannot be resolved by the Parties, then either Party may initiate the Dispute Resolution Procedure by giving notice of the Dispute to the other Party (the "**Notice of Dispute**"). The Notice of Dispute shall contain a brief statement of the nature of the Dispute, set out the relief requested, and request that the Dispute Resolution Procedure be commenced.

12.3 Negotiations

Upon the submission of a Notice of Dispute pursuant to Section 12.2, each of the Parties shall refer the Dispute to a designated senior management executive with the authority to negotiate a

settlement of the Dispute for that Party (the "**Senior Management Executives**"). The Senior Management Executives of the Parties shall attempt to resolve the Dispute within 30 days from the date on which the Notice of Dispute was issued, or such longer period as the Senior Management Executives may otherwise unanimously agree. If the Senior Management Executives unanimously agree upon a resolution of the Dispute, such resolution shall be memorialized in a written settlement agreement mutually acceptable to the Parties and shall be binding on the Parties.

12.4 Arbitration

If a Dispute is not resolved by Senior Management Executives within 30 days from receipt of a Notice of Dispute (or such longer period as the Senior Management Executives may otherwise agree in writing), the Dispute shall, at the request of either Party, be resolved by binding arbitration under the Rules of Arbitration of the International Chamber of Commerce (the "**ICC Rules**"), except to the extent of conflicts between the ICC Rules and the provisions of this EPA, in which event the provisions of this EPA shall prevail. The following provisions shall apply to an arbitration commenced pursuant to this Section 12.4:

(a) the number of arbitrators shall be one;

(b) the place, or legal seat, of the arbitration shall be Whitehorse, Yukon;

(c) the language to be used in the arbitral proceedings shall be English;

(d) all awards issued by the arbitrator shall be final, non-appealable and binding on the Parties. Any award may be filed in any court of competent jurisdiction and may be enforced by a Party as a final judgment in such court. The Parties expressly waive, to the maximum extent permitted by law, any right of appeal of any award or reference of any matter to any court, other than as may be necessary to recognize or enforce an award;

(e) the arbitrator shall be guided by the International Bar Association's Rules on the Taking of Evidence in International Commercial Arbitration;

(f) the Parties shall request that the arbitrator render its final award within 12 months of the commencement of the arbitration, or as soon as possible thereafter, provided that no award shall be invalid if it is not rendered within the time period herein specified;

(g) any award for monetary damages shall be made and payable in Canadian Dollars and may include interest from the date of any breach or violation of this EPA until paid in full at the rate determined by the arbitrator;

(h) the Parties agree that any arbitration carried out hereunder shall be kept private and confidential, and that the existence of the proceedings and any element of it (including all awards, the identity of the Parties and all witnesses and experts, all materials created for the purposes of the arbitration, all testimony or other oral submissions, and all documents produced by a Party that were not already in the possession of the other Party) shall be kept confidential, except (i) with the consent of the Parties, (ii) to the extent disclosure may be lawfully required in bona fide judicial proceedings relating to the arbitration, (iii) where disclosure is lawfully required by a legal duty, and (iv) where such information is already in the public domain other than as a result of a breach of this clause. The Parties

also agree not to use any information disclosed to them during the arbitration for any purpose other than in connection with the arbitration;

(i) where a Dispute relates to the EPA, the Parties shall agree to consolidate the matters in Dispute under such agreements in a single arbitration;

(j) the Parties agree that during the resolution of a Dispute pursuant to this Article 12, the Parties shall continue to perform their obligations under this EPA, provided that such performance shall be without prejudice to the rights and remedies of the Parties and shall not be read or construed as a waiver of a Party's right to claim for recovery of any loss, costs, expenses or damages suffered as a result of the continued performance of this EPA; and

(k) each Party will be responsible for its own costs under this Article 12, subject to the award of an arbitrator.

ARTICLE 13
CONFIDENTIALITY

13.1 Confidentiality

(a) **Additional Confidentiality Obligation** - During the Term and for two years thereafter:

(i) Buyer will treat as confidential, and will not disclose to any third Person, Seller Confidential Information, and

(ii) Seller will treat as confidential, and will not disclose to any third Person, Buyer Confidential Information.

(b) **Disclosure of Confidential Information** - Notwithstanding Section 13.1(a) above:

(i) Seller may also disclose Buyer Confidential Information and Buyer may disclose Seller Confidential information in the following circumstances:

(A) disclosures expressly authorized under this EPA or otherwise set out in this EPA;

(B) disclosures to enable a Party to fulfill its obligations under the EPA;

(C) disclosure in any arbitration or legal proceedings for the enforcement of the EPA;

(D) disclosure to the Party's directors, officers, employees, Facility Lenders, consultants and advisors, and purchasers of the Environmental Attributes, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality;

(E) subject to Section 13.1(b)(ii)(D), disclosure required to be made by a Party by an order of a court, a regulatory agency or a tribunal or under any law, regulatory requirements or any requirement of any stock exchange that is binding upon a Party, provided that (i) to the extent

reasonably practicable, the Party intending to make such disclosure gives reasonable notice to the other Party before make the disclosure, and (ii) limits the disclosure to that required by the applicable order, Laws or regulatory or stock exchange requirement;

(F) disclosure to a third Person if such information was known by that third Person before disclosure by Buyer or Seller, as the case may be, provided the third Person did not know of the information as a result of a breach of the non-disclosure obligations in this EPA; or

(G) disclosure with the consent of Buyer, in the case of Buyer Confidential Information, or Seller, in the case of Seller Confidential Information.

(ii) Buyer may disclose Seller Confidential Information in the following circumstances:

(A) disclosure to Buyer's Affiliates or to a third Person, and their respective employees, consultants and advisors, for the purpose of reselling or marketing any Energy, including disclosure of Seller Confidential Information by such Affiliate or third Person to those who have purchased or may purchase the Energy;

(B) for purposes other than those described in Section 13.1(b)(i), to Buyer's Affiliates and to any directors, officers, employees, consultants and advisors of any Affiliates, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality;

(C) to any ministers, deputy ministers, servants or employees of the Yukon or the federal government, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality; or

(D) disclosure in any regulatory proceeding, whether related to this EPA or not, to the extent that Buyer considers disclosure is necessary or desirable to support its position in such proceeding.

ARTICLE 14
FORCE MAJEURE

14.1 Force Majeure

(a) If there is a Force Majeure affecting a Party's ability to perform an obligation under this EPA, and that Party wishes to declare a Force Majeure, that Party will promptly notify the other Party of the Force Majeure. The notice of Force Majeure must identify the nature of the Force Majeure, the date the Force Majeure commenced, the expected duration of the Force Majeure, and the particular obligations affected by the Force Majeure. If (i) a notice of Force Majeure is provided in accordance with this Section, (ii) the event in question is in fact an event of Force Majeure as defined in this EPA, and (iii) the event of Force Majeure commenced on the commencement date in the notice of Force

Majeure, then the Force Majeure will be deemed to have been invoked as of the commencement date stated in the notice.

(b) Neither Party will be in default of any obligation under this EPA if a Party is unable to perform that obligation due to an event or circumstance of Force Majeure, provided notice is delivered in accordance with this Section and the circumstances are, in fact, an event or circumstance of Force Majeure.

(c) Subject to any limitations expressly set out in this EPA, the time for performance of such obligation will be extended by the number of days that Party is unable to perform such obligation as a result of the event or circumstance of Force Majeure. The Party invoking Force Majeure will make commercially reasonable efforts to promptly remove the Force Majeure and will promptly respond to any inquiry from the other Party regarding the efforts being undertaken to remove the Force Majeure and will give prompt notice of the end of the Force Majeure.

ARTICLE 15
GENERAL PROVISIONS

15.1 Independence

The Parties are independent contractors, and nothing in this EPA or its performance creates a partnership, joint venture or agency relationship between the Parties.

15.2 Enurement

This EPA enures to the benefit of the Parties, their successors and their permitted assigns.

15.3 Assignment

(a) Seller may not assign this EPA except with the prior consent of Buyer, which consent may not be unreasonably withheld, conditioned or delayed provided such Assignment is to a Facility Lender. Any Assignment (other than an Assignment to a Facility Lender) is subject to the assignee entering into and becoming bound by this EPA, assuming all the obligations and liabilities of Seller under this EPA arising both before and after the Assignment, and providing the representations and warranties set out in Section 10.1 effective as at the time of Assignment, and Seller not being in default under this EPA. Unless agreed to in writing by Buyer, Seller shall remain jointly and severally liable with the assignee for all obligations of Seller under this EPA.

(b) Any request by Seller for Buyer's consent under Section 15.3(a) must be delivered to Buyer not less than 30 days before the date of the proposed Assignment. A request under this Section must be accompanied by such information as reasonably required by Buyer to assess the request for consent including the name, address and ownership structure of the assignee, details of any consultation with First Nations that may be impacted by the Seller's Plant or the Assignment with respect to the proposed Assignment, list of the directors and officers of the assignee and information concerning the assignee's operations, experience and financial status.

(c) If Seller seeks consent to Assign this EPA to a Facility Lender, Buyer may require, as a condition of its consent to the Assignment, that Seller and the Facility Lender enter into a

Lender Consent Agreement with Buyer containing customary provisions. If required by a Facility Lender, Buyer will enter into a Lender Consent Agreement with the Facility Lender and Seller containing customary provisions. Seller will reimburse Buyer for all costs reasonably incurred by Buyer in connection with any request by Seller for Buyer's consent pursuant to Section 15.3(a).

15.4 Entire Agreement

This EPA contains the entire agreement between the Parties with respect to the purchase and sale of Energy and supersedes all previous communications, understandings and agreements between the Parties with respect to the subject matter hereof. There are no representations, warranties, terms, conditions, undertakings or collateral agreements express, implied or statutory between the Parties other than as expressly set out in this EPA. **[Note to Developers – as described in the SOP Rules, to the extent that a Project interconnects into AEY's portion of the YIS, there may be additional agreements required between AEY and Seller, in which case this section may need to be modified]**

15.5 Amendment

This EPA may not be amended except by an agreement in writing signed by both Parties.

15.6 No Waiver

Other than in respect of the specific matter or circumstance for which a waiver is given, and except as otherwise specified in this EPA, no failure by a Party to enforce, or require a strict observance and performance of, any of the terms of this EPA will constitute a waiver of those terms or affect or impair those terms or the right of a Party at any time to enforce those terms or to take advantage of any remedy that Party may have in respect of any other matter or circumstance.

15.7 Notices

Any notice, consent, waiver, declaration, request for approval or other request, statement or bill that either Party may be required or may desire to give to the other Party under this EPA must be in writing addressed to the other Party at the address for that Party stated in Schedule "A" and:

(a) notices under Section 14.1, Article 8 and Article 9 must be delivered by hand or by a courier service during normal business hours on a Business Day and a notice so delivered will be deemed to have been delivered on that Business Day;

(b) all notices other than notices described in Section 15.7(a) may be delivered by email during normal business hours on a Business Day and a notice so delivered will be deemed to have been delivered on that Business Day; and

(c) either Party may change its address for notices under Section 3 of Schedule "A" to this EPA by notice to the other Party.

15.8 Interconnection Notices

Nothing in the System Interconnection Guidelines and no exercise of any right thereunder, restricts or otherwise affects any right, obligation or liability of either Party under this EPA,

except to the extent set out expressly herein, and no notice, consent, approval or other communication or decision under or in relation to the System Interconnection Guidelines will constitute or be relied upon as a notice, consent, approval or communication or decision under this EPA.

15.9 Commodity Contract/Forward Contract

The Parties agree and intend that this EPA constitutes an "eligible financial contract" under the *Bankruptcy and Insolvency Act* (Canada) and *Companies' Creditors Arrangement Act* (Canada).

15.10 Further Assurances

Each Party will, upon the reasonable request of the other Party, do, sign or cause to be done or signed all further acts, deeds, things, documents and assurances required for the performance of this EPA including, in the case of Seller, completing any registration process required in respect of Environmental Attributes as requested by Buyer.

15.11 Severability

Any provision of this EPA which is illegal or unenforceable will be ineffective to the extent of the illegality or unenforceability without invalidating the remaining provisions of this EPA.

15.12 Counterparts

This EPA may be executed in counterparts, each of which is deemed to be an original document and all of which are deemed one and the same document.

[Signature Page Follows]

IN WITNESS WHEREOF each Party by its duly authorized representative(s) has signed this EPA effective as of the date set out on page one of this EPA.

[SELLER]	**[UTILITY - BUYER]**
Per: _____	Per: _____
[Name]	[Name]
[Title]	[Title]
Per: _____	Per: _____
[Name]	[Name]
[Title]	[Title]

SCHEDULE "A"

DEFINITIONS AND INTERPRETATION

1. DEFINITIONS

References in a Schedule to a section or Section mean a section or Section of this EPA, and not a Schedule, unless otherwise stated. The following words and expressions wherever used in this EPA have the following meaning:

1.1 "**Affiliate**" means, with respect to any Party or any third Person, any Person directly or indirectly Controlled by, Controlling, or under common Control with, such Party or the third Person.

1.2 "**Annual Operating Plan**" means a 12-month operating plan for the Seller's Plant that includes for term of each operating plan, (a) a schedule of the expected total deliveries of Energy at the POI in each month and (b) a schedule of any Planned Outages of the Seller's Plant expected by Seller. The Annual Operating Plan will be consistent with Good Industry Practice and shall be substantially in the form attached hereto as Schedule "C", subject to such modifications thereto as may be reasonably required by Buyer.

1.3 "**Application**" means the application and all supporting documents and information with respect to the Seller's Plant filed by Seller with Buyer in the Standing Offer Program.

1.4 "**Assign**" or "**Assignment**" means to assign or dispose of this EPA or any direct or indirect interest in this EPA, in whole or in part, for all or part of the Term and, without limiting the foregoing, each of the following is deemed to be an Assignment of this EPA by Seller:

(a) any sale or other disposition of all or a substantial part of Seller's ownership interest in the Seller's Plant, or of all or any interest of Seller in this EPA or revenue derived from this EPA;

(b) any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's Plant or Seller's ownership interest therein; and

(c) any change of Control, merger, amalgamation or reorganization of Seller.

1.5 "**Audit Parties**" means the applicable Party conducting an audit under this EPA and its Affiliates, representatives, consultants, advisors and any other third Person retained in respect of the applicable audit.

1.6 "**Bankrupt or Insolvent**" means, with respect to a Person:

(a) the Person has started proceedings to be adjudicated a voluntary bankrupt or consented to the filing of a bankruptcy proceeding against it;

(b) the Person has filed a petition or similar proceeding seeking reorganization, arrangement or similar relief under any bankruptcy or insolvency law;

(c) a receiver, liquidator, trustee or assignee in bankruptcy has been appointed for the Person or the Person has consented to the appointment of a receiver, liquidator, trustee or assignee in bankruptcy;

(d) the Person has voluntarily suspended the transaction of its usual business; or

(e) a court of competent jurisdiction has issued an order declaring the Person bankrupt or insolvent.

1.7 "**Business Day**" means any calendar day which is not a Saturday, Sunday or Yukon statutory holiday.

1.8 "**Buyer**" means _____ and its successors and permitted assigns.

1.9 "**Buyer Confidential Information**" means technical or commercial information disclosed by Buyer to Seller that Buyer directs, and clearly marks, as confidential, including the System Interconnection Guidelines and this EPA but excluding information that (i) is or becomes in the public domain, other than as a result of a breach of this EPA by Seller, or (ii) is known to Seller before disclosure to it by Buyer, or becomes known to Seller, thereafter by way of disclosure to Seller by any other Person who is not under an obligation of confidentiality with respect thereto.

1.10 "**Buyer's COD**" shall occur when the System Upgrades have been completed and Buyer provides a notice of completion of the same to Seller.

1.11 "**Change in Law**" means (a) the enactment, adoption, promulgation, modification or repeal of any applicable Laws or any change in the interpretation or administration of any applicable Laws resulting from a decision of a Governmental Authority which occurs after the Effective Date; but in each case excluding a Change in Law relating to income tax, or (b) the requirement for a new Permit (including due to a change in the circumstances in which a Permit is required), a change in the terms of any Permit after the date such Permit is granted, or any change in the interpretation or administration of any Permits resulting from a decision of a Governmental Authority.

1.12 "**Condition Date**" means the date specified as such in Schedule "B".

1.13 "**Conditions Precedent**" means those conditions precedent set out in Schedule "B".

1.14 "**Control**" of any Person means:

(a) with respect to any corporation or other Person having voting shares or the equivalent, the ownership or power to vote, directly or indirectly, shares, or the equivalent, representing 50% or more of the power to vote in the election of directors, managers or Persons performing similar functions;

(b) ownership of 50% or more of the equity or beneficial interest in that Person; or

(c) the ability to direct the business and affairs of any Person by acting as a general partner, manager or otherwise.

1.15 "**CPI**" means the "Canada All Items (Not Seasonally Adjusted)" Consumer Price Index as published by Statistics Canada or any successor agency thereto.

1.16 "**Delivered Energy**" means in each month after Buyer's COD the amount of Energy delivered by Seller at the POI in that month as recorded by Buyer's Meter less the applicable Line Losses.

1.17 "**Development Progress Report**" means a report describing the progress of the financing, design, engineering, construction, Interconnection, and commissioning of the Seller's Plant, that is in form and content acceptable to Buyer, acting reasonably.

1.18 "**Discretion**" (whether or not capitalized) means sole, absolute and unfettered discretion unless this EPA expressly states otherwise.

1.19 "**Dispatch/Turn-Down**" means for Seller to turn down or shut off the Seller's Plant.

1.20 "**Dispatch/Turn-Down Deemed Energy**" has the meaning given to such term in Section 4.9(b)(i).

1.21 "**Distribution System**" means the distribution, protection, control and communication facilities in the Yukon that are or may be used in connection with, or that otherwise relate to, the transmission of electrical energy at 35 kilovolts or less, and includes all additions and modifications thereto and repairs or replacements thereof.

1.22 "**Distribution/Transmission Constraint**" means any disconnection of the Seller's Plant from the Distribution System or Transmission System, or any outage, suspension, constraint or curtailment in the operation of the Distribution System or Transmission System preventing or limiting deliveries of Energy at the POI or within the Distribution System or Transmission System or any direction from Buyer to reduce generation of the Seller's Plant as a result of any outage, suspension, constraint or curtailment in the operation of the Distribution System or Transmission System.

1.23 "**Effective Date**" shall mean the date on which all Conditions Precedent have been satisfied or waived in accordance with Section 2.1.

1.24 "**Electrical Grid**" means the electrical grid into which the Seller's Plant will be interconnected, as identified in Schedule "B"**.**

1.25 "**Eligible Clean Energy**" means wind, hydro, geothermal, biomass and solar energy sources permitted under the IPP Policy for the SOP generated by a Project located in Yukon which is directly connected into the YIS or the WLG through the New Interconnection Facilities.

1.26 "**Energy**" means all electrical energy expressed in KWh generated by the Seller's Plant, excluding electrical energy generated by the Seller's Plant which is required to service the Seller's Plant Load.

1.27 "**Energy Price**" has the meaning given to such term in Schedule "B".

1.28 "**Environmental Attributes**" means the following as attributable to Energy delivered to Buyer under this EPA:

(a) all attributes directly associated with, or that may be derived from, the Energy delivered to Buyer under this EPA having decreased environmental impacts relative to certain other generation facilities or technologies including any existing or future credit, allowance, "green" tag, ticket, certificate or other "green" marketing attribute or proprietary or contractual right, whether or not tradeable;

(b) any credit, reduction right, offset, allowance, allocated pollution right, certificate or other unit of any kind whatsoever, whether or not tradeable and any other proprietary or contractual right, whether or not tradeable, resulting from, or otherwise related to the actual or assumed reduction, displacement or offset of emissions at any location other than the Seller's Plant as a result of the generation, purchase or sale of the Energy delivered to Buyer under this EPA;

(c) any credit, reduction right, off-set, allowance, allocated pollution right, certificate or other unit of any kind whatsoever whether or not tradeable resulting from or otherwise related to the reduction, removal, or sequestration of emissions at or from the Seller's Plant; and

(d) all revenues, entitlements, benefits and other proceeds arising from or related to the foregoing, but for certainty not including:

i. benefits or proceeds from environmental incentive programs offered by Governmental Authorities that do not require a transfer of the attributes in (a) to (c) above; and

ii. benefits or proceeds from social programs, including programs relating to northern or rural development, employment or skills training, or First Nations, that do not require a transfer of the attributes in Sections (a) to (c) above.

1.29 "**Environmental Certification**" means any certification Buyer requires Seller to obtain under Section 6.1.

1.30 "**Facility Lender**" means any lender(s) providing any debt financing or debt hedging facilities for the design, engineering, construction and/or operation of the Seller's Plant and any successors or assigns thereto and any Person taking any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's Plant.

1.31 "**Final Amount**" means an amount owing by either Party to the other Party under this EPA, including as a result of a breach of this EPA, where such amount is: (a) undisputed by the Party owing such amount; or (b) has been finally determined by an arbitration award under Section 12.1 of this EPA or by a court order and all rights of appeal in respect of such award or order have been exhausted or have expired.

1.32 "**First Nation Claim**" means a legal claim or proceeding or written threat to commence a legal claim or proceeding from or on behalf of First Nations where such claim or threat alleges a breach or potential breach of, or an impact to: any First Nations' Treaty rights, rights under a Settlement Agreement (as that term is defined in the Yukon Umbrella Final Agreement), or rights under section 35 of the *Constitution Act*, 1982, by (a) this EPA, (b) the Seller's Plant, (c) the Interconnection or any works related to the Interconnection, or (d) any authorization granted by the Yukon or federal government relating to the Seller's Plant and its operations.

1.33 "**First Nations**" means any one of the 14 First Nations in the Yukon.

1.34 "**Force Majeure**" means any event or circumstance not within the control of the Party, or any of its Affiliates, claiming Force Majeure, but does not include:

(a) any economic hardship or lack of money, credit or markets;

(b) an event or circumstance that is the result of a breach by the Party seeking to invoke Force Majeure of a Permit or of any applicable Laws;

(c) a mechanical breakdown or control system hardware or software failure, unless the Party seeking to invoke Force Majeure can demonstrate by clear and convincing evidence that the breakdown or failure was caused by a latent defect in the design or manufacture of the equipment, hardware or software, which could not reasonably have been identified by normal inspection or testing of the equipment, hardware or software;

(d) an event or circumstance caused by a breach of, or default under, this EPA or a willful or negligent act or omission by the Party seeking to invoke Force Majeure;

(e) any Distribution/Transmission Constraint unless such event is caused by an event or circumstance not within the control of Buyer; or

(f) any acts or omissions of: (i) any Affiliate, employee, director, officer, agent or other representative of the Party invoking Force Majeure; (ii) any vendor, supplier, contractor, subcontractor, consultant or customer of or to the Party invoking Force Majeure; or (iii) any other Person for whom the Party invoking Force Majeure is responsible at law, unless the act or omission is caused by an event or circumstance that would constitute Force Majeure if the Person described above was a party to this EPA in place of a Party invoking Force Majeure.

1.35 "**Forced Outage**" means the immediate removal of one or more generating units of the Seller's Plant or transmission or distribution infrastructure of the Seller's Plant from service in response to equipment alarms or any damage identified during a Planned Outage or Maintenance Outage requiring extension of those Planned Outage or Maintenance Outage.

1.36 "**General Rate Application**" means any application, review, process, or procedure in which the YUB sets and approves rates to be charged by Buyer for the supply of the service for which it is franchised in accordance with the *Public Utilities Act*.

1.37 "**Good Industry Practice**" means:

(a) in respect of Buyer, any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition; provided such practices, methods and acts are not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the Yukon; and provided that Buyer shall be in compliance with Good Industry Practice in respect of any equipment comprising the Distribution System or Transmission System, if it operates such equipment in accordance with all applicable original equipment manufacturer guidelines and requirements provided to Buyer by supplier of such equipment; and

(b) in respect of Seller, any of the practices, methods and acts engaged in or approved by a significant portion of the electric generation industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in

light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition; provided such practices, methods and acts are not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in Western Canada.

1.38 "**Governmental Authority**" means any federal, provincial, local or foreign government or any of their boards or agencies, or any regulatory authority other than Buyer and Seller and entities controlled by Buyer or Seller.

1.39 "**GST**" means the goods and services tax imposed under the *Excise Tax Act* (Canada) as that Act may be amended or replaced from time to time.

1.40 "**Interconnection**" means the POI.

1.41 "**IPP Policy**" has the meaning given to such term in the recitals to this EPA.

1.42 "**Joint Operating Procedure**" means the joint operating procedure attached as Schedule "H" as may be modified by Buyer from time to time. **[Note to Developer - where the Project is located on AEY's portion of the YIS, the EPA will be entered into between Seller and YEC, however the System Interconnection Guidelines and the Joint Operating Procedure will be established under a 3 party agreement among Seller, YEC and AEY]**

1.43 "**KW**" means kilowatt.

1.44 "**KWh**" means kilowatt-hour.

1.45 "**Laws**" means any and all statutes, laws (including common law), ordinances, rules, regulations, codes, orders, bylaws, policies, directions, standards, guidelines, protocols and other lawful requirements of any Governmental Authority in effect from time to time.

1.46 "**Lender Consent Agreement**" means a lender consent agreement in the form and substance acceptable to Buyer, acting reasonably.

1.47 "**Line Losses**" means losses of electricity associated with the transmission and transformation of Energy and other electricity, if applicable, from the Seller's Plant to the POI that are recorded by the Meter or reasonably estimated by Buyer.

1.48 "**Line Loss Methodology**" means the Line Loss Methodology set forth in the System Interconnection Study Report for the purposes of this Project.

1.49 "**Maintenance Outage**" means any outage of Buyer's Distribution System or Transmission System or the Seller's Plant that is not a Planned Outage or a Forced Outage that typically has a flexible start and end time and of shorter duration than a Planned Outage.

1.50 "**Meter**" means a meter owned by Buyer that is: (a) capable of accurately measuring the quantity of Energy generated by the Seller's Plant and delivered to the POI independent of all other generation equipment or facilities, (b) capable of being remotely interrogated; and (b) calibrated to measure on an hourly basis the quantity of Energy delivered by Seller to the POI.

1.51 "**Monthly Energy Shortfall Payment**" has the meaning given to such term in Schedule "E".

1.52 "**New Interconnection Facilities**" means those additions, modifications and upgrades required to interconnect the Project to the Electrical Grid which are identified in the System Interconnection Study Report (and as further refined in subsequent interconnection studies, if required by Buyer) and approved by Buyer, but excluding any System Upgrades.

1.53 "**New Interconnection Facilities Costs**" means all costs incurred by Buyer for the design, engineering, procurement, construction, installation and commissioning of the New Interconnection Facilities, including applicable studies required by Buyer, an estimate of which is set out in the System Interconnection Study Report.

1.54 "**Non-Permitted Distribution/Transmission Constraint**" has the meaning given to such term in Section 4.8(a).

1.55 "**Outage**" means a Forced Outage, Maintenance Outage, or Planned Outage of Buyer's Distribution System or Transmission System or Seller's Plant.

1.56 "**Outage Notice**" means a notification of any Outage or revised notification of any Outage required to be delivered by Seller to Buyer or Buyer to Seller under this EPA that describes the timing, frequency, nature and duration of the Outage and that is in a format that may be prescribed by Buyer from time to time.

1.57 "**Party**" means Buyer or Seller, and "**Parties**" means both Buyer and Seller.

1.58 "**Permits**" means permits, certificates, licences, approvals and other authorizations issued by any Governmental Authorities as may be required for the design, construction, ownership, operation, maintenance and decommissioning of (i) the Seller's Plant and the delivery of Energy to the POI, and (ii) the System Upgrades and the New Interconnection Facilities.

1.59 "**Person**" means an individual, body corporate, firm, partnership, joint venture, trust, legal representative or other legal entity.

1.60 "**Planned Outage**" means an outage that is scheduled well in advance for purposes of inspections, maintenance, or repair of Buyer's Distribution System or Transmission System or Seller's Plant, that typically has a predetermined duration and scope of work, occurs only once or twice per year, and may last for several days.

1.61 "**POI**" or "**Point of Interconnection**" means the point at which the Seller's Plant interconnects with the Distribution System or Transmission System, as identified on the Single Line Diagram.

1.62 "**Potential Impacts**" means any adverse or potentially adverse impact on the established or potential aboriginal rights (including title) of First Nations as a result of:

(a) this EPA;

(b) the Project;

(c) the interconnection of the Seller's Plant to the Distribution System or Transmission System; or

(d) any activities directly related to the Seller's Plant that enable Seller to comply with its obligations under this EPA that are carried out by Seller, any Affiliate, consultant or contractor of Seller, or any other Person for whom Seller is responsible at law.

1.63 "**PPT**" means Pacific Prevailing Time, which means Pacific Daylight Time or Pacific Standard Time as applicable.

1.64 "**Present Value Rate**" means the annual yield on a Government of Canada bond having a term and maturity date that most closely matches the remaining Term (as at the date of the applicable calculation) and expiry date of this EPA, plus 3%.

1.65 "**Prime Rate**" means the floating prime interest rate announced from time to time by the main branch of Bank of Montreal in Whitehorse, Yukon, or any successor thereto, expressed as an annual rate, as the reference rate it will use to determine rates of interest payable on Canadian dollar commercial loans made in Canada.

1.66 "**Project**" means the financing, design, engineering, procurement, construction, commissioning, operation and maintenance of the Seller's Plant.

1.67 "**Project Cluster**" means two or more existing or proposed Projects under the SOP Rules that Buyer determines in its Discretion are so closely related to each other that they should be considered a project cluster for the purposes of the Standing Offer Program.

1.68 "**Project Energy Volume**" (in KWh) means the maximum annual Energy which Buyer may sell to Seller from the Project in any calendar year as set out in Schedule "B"; provided that where the Term does not commence on January 1, such amount shall be prorated for the first and last contract year which do not reflect a full calendar year. **[Note to Developers – this amount will be set when the EPA is executed. It will be determined based on the annual energy volume which is expected to be generated by the Project in a calendar year determined based on the maximum number of KWh which the applicable Project would generate assuming that it generated in accordance with the Nameplate Capacity after taking into account a reasonable capacity factor for the applicable Eligible Clean Energy type]**

1.69 "**Project Standards**" means:

(a) all applicable Laws;

(b) the terms and conditions of all Permits, including land tenure agreements, issued in connection with the Seller's Plant;

(c) Good Industry Practice;

(d) the description of the Seller's Plant in Schedule "B";

(e) the requirement that Energy must qualify as Eligible Clean Energy; and

(f) the terms and conditions of this EPA (including the System Interconnection Guidelines).

1.70 "**Public Utilities Act**" means the *Public Utilities Act* (Yukon) and any successor or replacement legislation.

1.71 "**Records**" means all records and logs required to properly administer this EPA, including:

(a) Energy generation records and operating logs;

(b) Meter readings;

(c) maintenance reports;

(d) invoice support records;

(e) documents concerning compliance with Project Standards, but excluding any such documents that are protected by solicitor-client privilege;

(f) records related to System Upgrade Costs and New Interconnection Facilities Costs;

(g) all information reasonably required to establish the amount of Energy Seller could have sold during a Distribution/Transmission Constraint including logs of all Outages of the Seller's Plant and other reductions in Energy output (specifying the date, time, duration and reasons for each such outage and each reduction in Energy output); and

(h) information relating to the Environmental Certification, information relating to the existence, nature and quality of Environmental Attributes, information required for the purposes of any Environmental Attributes or energy certification or tracking system, and any other information Buyer requires to enable it or any of its Affiliates to obtain and realize the benefit of the Environmental Attributes,

all consistent with Good Industry Practice.

1.72 "**Regulatory Agency Authorizations**" means the issuance of those Permits which are specified as required for the Project in the YESAB assessment report recommendation to proceed issued in respect of the Project.

1.73 "**Seller**" means the Party so identified on page one of this EPA, and its successors and permitted assigns.

1.74 "**Seller Confidential Information**" means any of Seller's confidential technical or financial information provided by Seller to Buyer in confidence with express written notice to Buyer of the confidential nature of the information, but excluding:

(a) this EPA; and

(b) information that (i) is or becomes in the public domain, other than as a result of a breach of this EPA by Buyer, or (ii) is known to Buyer before disclosure to it by Seller, or becomes known to Buyer thereafter by way of disclosure to Buyer by any other Person who is not under an obligation of confidentiality with respect thereto.

1.75 "**Seller's COD**" means the commercial operation date of Seller's Plant which is the date on which all of the following conditions have been satisfied in respect of the Seller's Plant:

(a) Seller has obtained all Permits required for the construction, commissioning, and operation of the Seller's Plant and all such Permits are in full force and effect;

(b) the Seller's Plant has been fully constructed in accordance with the Project Standards;

(c) Seller is not: (A) Bankrupt or Insolvent; (B) in default of any payment obligation or requirement to post security under this EPA; (C) in material default of any of its other covenants, representations, warranties or obligations under this EPA; or (D) in material default under any Permit or Law applicable to the construction, commissioning or operation of the Seller's Plant or under any land tenure agreement for the site on which the Seller's Plant is located;

(d) a Meter has been installed at the POI in accordance with Section 3.6 of this EPA;

(e) Seller has delivered to Buyer a written notice together with certificate of Seller's professional registered engineer confirming that Seller's COD has been achieved; and

(f) Buyer has delivered a Commission Notice to Operate, or such other document(s) of similar effect as may be substituted therefor, which evidences no material deficiencies, in respect of the Seller's Plant Capacity and Seller's Plant operations;

and for purposes of this EPA, Seller's COD will be deemed to have occurred at 24:00 PPT on the later of the dates set out above.

1.76 "**Seller's Plant**" means Seller's plant described in Schedule "B" and all assets required to interconnect that plant to the Distribution System or Transmission System; all rights, property, facilities, assets, equipment, materials, Permits and contracts required to design, engineer, procure, construct, commission, operate and maintain the plant described in Schedule "B" and to interconnect that plant to the Distribution System or Transmission System, whether real or personal and whether tangible or intangible including all land tenure and all books, Records and accounts with respect to the Seller's Plant described in Schedule "B"; and shall include replacement parts or equipment which are of the same or similar nature as the parts or equipment being replaced and which do not materially increase the amount of Energy available from Seller's Plant.

1.77 "**Seller's Plant Capacity**" means the electrical generating capacity of the Seller's Plant set out in Schedule "B".

1.78 "**Seller's Plant Load**" means any electrical energy consumed by Seller's Plant.

1.79 "**Single Line Diagram**" means the simplified electrical representations of the Seller's Plant, the Interconnection, the Distribution System and Transmission System attached hereto in Schedule "B".

1.80 "**SOP OIC**" means that Order in Council issued by the Government of Yukon on January 24, 2019 regarding, among other things, the Standing Offer Program.

1.81 "**SOP Rules**" means the Standing Offer Program Rules developed by the Government of Yukon which governed this EPA as at the date of this EPA.

1.82 "**Standing Offer Program**" or "**SOP**" means the Standing Offer Program as described in the IPP Policy.

1.83 "**System Interconnection Guidelines**" means those system interconnection guidelines in the form attached as Schedule "G" hereto, as amended or replaced by Buyer from time to time. **[Note to Developer - where the Project is located on AEY's portion of the YIS, the EPA will be entered into between Seller and YEC, however the System Interconnection Guidelines and the Joint Operating Procedure will be established under a 3 party agreement among Seller, YEC and AEY]**

1.84 "**System Interconnection Study Report**" means the detailed interconnection study issued to Seller by Buyer which, among other things, (i) evaluates the impact of the Project on the reliability of Buyer's system, (ii) provides a planning-level estimate of the required System Upgrades and New Interconnection Facilities and associated costs, and (iii) establishes the Line Loss Methodology for this Project, a copy of which is attached as Schedule "D".

1.85 "**System Upgrades**" means additions, modifications and upgrades to the Distribution System, Transmission System or any portion of Buyer's generation system that are determined by Buyer to be required in order to facilitate the interconnection and to allow such Distribution System, Transmission System or any portion of Buyer's generation system to support the integration of the Energy produced by the Seller's Plant in accordance with this EPA and the System Interconnection Guidelines, which are identified in the System Interconnection Study Report (and as further refined in subsequent interconnection studies, if required by Buyer) and approved by Buyer, but excluding any New Interconnection Facilities.

1.86 "**System Upgrade Costs**" means all costs incurred by Buyer for the design, engineering, procurement, construction, installation and commissioning of the System Upgrades, including applicable studies required by Buyer, an estimate of which is set out in the System Interconnection Study Report.

1.87 "**Target Buyer's COD**" means the target date for achieving Buyer's COD, being the date specified for such term in Schedule "B", as may be extended pursuant to Section 3.9, if applicable.

1.88 "**Target Seller's COD**" means the target date for achieving Seller's COD, being the date specified for such term in Schedule "B", as may be extended pursuant to Section 3.9, if applicable.

1.89 "**Term**" has the meaning given to such term in Section 2.1.

1.90 "**Termination Payment**" has the meaning given to such term in Schedule "F".

1.91 "**Transmission System**" means the transmission, substation, protection, control and communication facilities owned and operated by Buyer, and includes all additions and modifications to those facilities and repairs or replacements of those facilities.

1.92 "**Upgrade Costs Advance**" has the meaning given to such term in Section 3.5(a).

1.93 "**Upgrade Costs Security**" has the meaning given to such term in Section 3.5(a).

1.94 "**Utilities**" means both Yukon Energy Corporation or Yukon Electrical Company, doing business as ATCO Electric Yukon, as applicable.

1.95 "**YESAA**" means the *Yukon Environmental and Socio-economic Assessment Act*, SC 2003, c 7.

1.96 "**YESAB**" means the Yukon Environmental and Socio-economic Assessment Board.

1.97 "**YUB**" means the Yukon Utilities Board and any successor thereto appointed from time to time under the *Public Utilities Act*.

2. INTERPRETATION

2.1 **Headings** - The division of this EPA into Articles, sections, Sections, paragraphs and Schedules and the insertion of headings are for convenience of reference only and do not affect the interpretation of this EPA.

2.2 **Plurality and Gender** - Words in the singular include the plural and vice versa. Words importing gender include the masculine, feminine and neuter genders.

2.3 **Governing Law** - This EPA is made under, and will be interpreted in accordance with, the Laws of the Yukon. Subject to Section 12.1, any suit, action or proceeding (a "**Proceeding**") arising out of or relating to this EPA may be brought in the courts of the Yukon at Whitehorse, and those courts have non-exclusive jurisdiction in respect of any Proceeding and the Parties hereby irrevocably attorn to the jurisdiction of such courts in respect of any Proceeding.

2.4 **Industry Terms** - Technical or industry specific phrases or words not otherwise defined in this EPA have the well-known meaning given to those terms as of the date of this EPA in the industry or trade in which they are applied or used.

2.5 **Statutory References** - Reference to a statute means, unless otherwise stated, the statute and regulations, if any, under that statute, in force from time to time, and any statute or regulation passed and in force which has the effect of supplementing or superseding that statute or those regulations.

2.6 **Currency** - References to dollars or $ means Canadian dollars, unless otherwise stated.

2.7 **Reference Indices** - If any index, tariff or price quotation referred to in this EPA ceases to be published, or if the basis therefor is changed materially, there will be substituted an available replacement index, tariff or price quotation that most nearly, of those then publicly available, approximates the intent and purpose of the index, tariff or quotation that has so ceased or changed. This EPA will be amended as necessary to accommodate such replacement index, tariff or price quotation, all as determined by written agreement between the Parties, or failing agreement, by arbitration under Section 12.1 of this EPA.

2.8 **Conversions** - If a value used in a calculation in this EPA must be converted to another unit of measurement for purposes of consistency or to achieve a meaningful answer, the value will be converted to that different unit for purposes of the calculation.

2.9 **Additional Interpretive Rules** - For the purposes of this EPA, except as otherwise expressly stated:

(a) "this EPA" means this EPA as it may from time to time be supplemented or amended and in effect, and includes the Schedules attached to this EPA;

(b) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this EPA as a whole and not to any particular section, Section or other subdivision;

(c) the word "including" or "includes" is not limiting whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto;

(d) the words "year" and "month" refer to a calendar year and a calendar month;

(e) any consent, approval or waiver contemplated by this EPA must be in writing and signed by the Party against whom its enforcement is sought, and may be given, withheld or conditioned in the unfettered discretion of the Party of whom it is requested, unless otherwise expressly stated;

(f) all rights and remedies of either Party under this EPA are cumulative and not exclusive of any other remedies to which either Party may be lawfully entitled, and either Party may pursue any and all of its remedies concurrently, consecutively and alternatively; and

(g) any notice required to be given, or other thing required to be done, under this EPA on or before a day that is not a Business Day, will be deemed to be given or done when required hereunder if given or done on or before the next following Business Day.

3. ADDRESSES FOR NOTICES

3.1 Notices to Buyer - Except as noted below, all notices addressed to Buyer will be delivered to the following address:

To: [BUYER]
_____
Whitehorse, YT
_____
Attention: Attention: Manager
Email: _____

3.2 Notices to Seller - All notices addressed to Seller will be delivered to the following address:

To: [SELLER]
_____
Whitehorse, YT
_____
Attention: Attention: Manager
Email: _____

SCHEDULE "B"

PROJECT DESCRIPTION

CONTRACT PARTICULARS:

1. **Condition Date:**

[Insert the date on which the Conditions Precedent must be satisfied by Seller]

2. **Conditions Precedent:**

The Conditions Precedent are as follows:

(a) *[Seller shall have received all of the Permits described below in form and substance acceptable to Seller and Buyer, acting reasonably:*

(i) *[Regulatory Agency Authorizations]*

(ii) *[Other]*

(b) *[provision of security under Section 3.5 for System Upgrade Costs and New Interconnection Facilities Costs]; and*

(c) *[others Conditions Precedent]*.

3. **Term:**

The "**Term**" of this EPA commences on the Effective Date and continues for a period of __ years following Buyer's COD.

[Note to Developers: Developers may elect a single term under an EPA of <u>up to</u> the following number of years for the applicable Eligible Clean Energy:

<u>Eligible Clean Energy</u>	**<u>Term Limit</u>**
Wind	**25 years**
Hydro	**40 years**
Geothermal	**40 years**
Biomass	**20 years**
Solar	**25 years]**

4. **Energy Price and Seasonal Adjustment:**

(a) In each billing period, Seller shall pay to Buyer, for each KWh of Delivered Energy the "**Energy Price**" calculated as follows:

[Note to Developers: For Projects connected to the YIS, the Energy Price will be calculated as follows. The first and third blanks above will be completed with the applicable Base Fuel Price as described in Section 4.2 of the SOP Rules. The blank in the subscript will be completed with the year in which the EPA is signed.

Energy Price$_n$ = (.5 * $__/KWh * CPI$_{\text{January 1, n}}$ / CPI$_{\text{January 1, __}}$) + (.5 * $__/KWh)]

[Note to Developers: For Projects connected to the WLG, the Energy Price will be calculated as follows. The first blank above will be completed with the applicable Base Fuel Price as described in Section 4.2 of the SOP Rules. The blank in the subscript will be completed with the year in which the EPA is signed.

Energy Price$_n$ = ($__/KWh * CPI$_{\text{January 1, n}}$ / CPI$_{\text{January 1, __}}$)]

Where:

n = the year for which the relevant calculation is being conducted

CPI $_{\text{January 1, n}}$ = the CPI for December in the year immediately prior to the year for which the relevant calculation is being conducted;

(b) For each hour, the Energy Price determined above for Delivered Energy during that hour will be adjusted to an amount (expressed in $/KWh) equal to the percentage of that Energy Price applicable for that hour as set out in the table in Schedule "I".

SELLER'S PLANT

1. **Location of Control Building:**

[Insert nearest latitude and longitude]

2. **Eligible Clean Energy Type:**

[Describe Eligible Clean Energy utilized]

3. **Seller's Plant Capacity:**

[Insert Project Nameplate Capacity]

4. **Project Energy Volume:**

[Insert Project Energy Volume in KWh in any year, being the annual energy volume which is expected to be generated by the Project determined based on the maximum number of KWh which the applicable Project would generate assuming that it generated in accordance with the Seller's Plant Capacity after taking into account a reasonable capacity factor for the applicable Eligible Clean Energy type]

5. **Seller's Plant Description:**

[Insert Project description]

Please refer to Seller's single line diagram in Exhibit B-1.

Total AC Power:
Primary AC line voltage:
Total AC line current:

Total DC power:
Open-circuit DC voltage:
Operating DC voltage:
Total DC operating current:

6. **Target Seller's COD:**

[Insert]

7. **Electrical Grid:**

[Insert Yukon Integrated System (YIS) or Watson Lake Grid (WLG)].

BUYER'S SYSTEM UPGRADES

[Note to Developers – These System Upgrades will be more fully scoped in the System Interconnection Study Report]

1. **System Upgrades:**

[Description to come]

Please refer to Buyer's single line diagram in Exhibit B-2.

2. **New Interconnection Facilities:**

[Description to come]

Please refer to Buyer's single line diagram in Exhibit B-2.

3. **Target Buyer's COD:**

[To come]

BREAKERS/SWITCHES AND SYNCHRONIZATION

[Note to Developers – To be developed for each Project]

EXHIBIT B-1

Seller's Single Line Diagram

[Note to Developers – To be developed for each Project]

EXHIBIT B-2

Buyer's Single Line Diagram

[Note to Developers – To be developed for each Project]

SCHEDULE "C"

FORM OF ANNUAL OPERATING PLAN

DATE: _____, 20__.

TO: _____ ("Buyer")

RE: Electricity Purchase Agreement between _____ ("Seller") and Buyer dated the ___ day of _____, 20__ (the "EPA")

The following sets out the Annual Operating Plan of Seller for the 12 months commencing on January 1, 20__ (the "**Applicable Period**").

(a) The following (from Table E-1 of Schedule "E" of the EPA) is the schedule of the expected total deliveries of Energy at the POI in each month of the Applicable Period:

	Projected Hourly Energy (KWh/h) **(A)**	**Projected Monthly Energy (KWh)** **(B)**
January		
February		
March		
April		
May		
June		
July		
August		
September		
October		
November		
December		

(b) The following is the schedule of any Planned Outages of the Seller's Plant expected by Seller for the Applicable Period:

[to come]

(c) The following is the schedule of operations and maintenance activities planned for the Seller's Plant expected by Seller for the Applicable Period:

[to come]

Dated effective as of the date set forth above.

[SELLER]

Per: _____
[Name]
[Title]

Per: _____
[Name]
[Title]

SCHEDULE "D"

SYSTEM INTERCONNECTION STUDY REPORT

SCHEDULE "E"

MONTHLY ENERGY SHORTFALL PAYMENT

Monthly Energy Shortfall Payments

In any calendar month in which there has occurred a Non-Permitted Distribution/Transmission Constraint then Buyer shall pay Seller Monthly Energy Shortfall Payment,

where:

"**Monthly Energy Shortfall Payment**" means the Monthly Constraint Shortfall multiplied by the price which is payable for Delivered Energy under Section 5.1 of the EPA; and

"**Monthly Constraint Shortfall**" (expressed in KWh) means, for each calendar month, means the aggregate of the duration of each Non-Permitted Distribution/Transmission Constraint (measured as a fraction determined as the aggregate number of minutes in such Non-Permitted Distribution/Transmission Constraint divided by 60) multiplied by the "Non-Permitted Distribution/Transmission Constraint Hourly Deemed Energy" set out in Table E-1 below for the applicable calendar month.

Table E-1

	Projected Hourly Energy (KWh/h) (A)	**Projected Monthly Energy (KWh) (B)**	**Non-Permitted Distribution/Transmission Constraint Factor (F1)**	**Non-Permitted Distribution/Transmission Constraint Hourly Deemed Energy (KWh/h) (A x F1)**
January			_%	
February			_%	
March			_%	
April			_%	
May			__%	
June			__%	
July			__%	
August			__%	
September			__%	
October			__%	
November			__%	
December			__%	

Revisions to Projected Hourly Energy and Projected Monthly Energy

Within 90 days following the end of the 2nd year after Buyer's COD, the Parties shall review and revise the values in Table E-1 above for Projected Hourly Energy and Projected Monthly Energy to reflect the average actual amount of Delivered Energy sold to Buyer in the 2 years following Buyer's COD for the applicable months.

SCHEDULE "F"

TERMINATION PAYMENT

The "**Termination Payment**" at any time shall be equal to (a) the Gross Termination Payment set out below for the Contract Year in which the termination occurred, less (b) the actual amounts paid or owing by Buyer to Seller for Delivered Energy for the Contract Year in which the termination occurred.

Table F-1

Termination Year	**Gross Termination Payment**
Year 1	
Year 2	
Year 3	
Year 4	
Year 5	
Year 6	
Year 7	
Year 8	
Year 9	
Year 10	
Year 11	
Year 12	
Year 13	
Year 14	
Year 15	
Year 16	
Year 17	
Year 18	
Year 19	
Year 20	
Year 21	
Year 22	
Year 23	
Year 24	
Year 25	

SCHEDULE "G"

SYSTEM INTERCONNECTION GUIDELINES

SCHEDULE "H"

JOINT OPERATING PROCEDURE

SCHEDULE "I"

DELIVERY TIME ADJUSTMENT TABLE

Seasonal Adjustment is subject to change.

Month	**Seasonal Adjustment**
January	100%
February	100%
March	100%
April	100%
May	100%
June	100%
July	100%
August	100%
September	100%
October	100%
November	100%
December	100%

Yukon Energy Corporation

Independent Power Producers Interconnection Technical Guide

Revision: 04b
Release Date: 2019 01 24

Disclaimer

This report was prepared under the supervision of Teshmont Consultants LP ("Teshmont"), whose responsibility is limited to the scope of work as shown herein. Teshmont disclaims responsibility for the work of others incorporated or referenced herein.

Revision History

Revision Number	Date Released	Prepared by	Reviewed by	Comments
00	May 14, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng Robert Baker, PEng	First Draft
01	May 30, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Second Draft
02	June 5, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Third Draft. Incorporated YEC Comments.
03	June 18, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Fourth Draft. Incorporated YEC Comments.
04	September 17, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Fifth Draft. Incorporated YEC Comments.

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Executive Summary

The purpose of the Interconnection Technical Guide is to provide guidelines for Independent Power Producers (IPP) who wish to interconnect a generation facility of greater than 50 kW and up to 10 MW to the Yukon Integrated System (YIS) via the Yukon Energy Corporation (YEC) or ATCO Electrical Yukon (AEY) distribution systems. The maximum allowable generation at the Point of Interconnection (POI) between the distribution system and IPP will depend on the results of a system impact study conducted by YEC. This guide details the technical and operational requirements of the facility and is not intended to be used as a design guide.

The purpose of this document is to:

- Provide technical specifications for the interconnection of IPP generation to the YIS (via YEC or AEY distribution systems).
- Clarify, where necessary, the technical requirements in CSA Standard C22.3 No. 9-08 (R2015) "Interconnection of Distributed Resources and Electricity Supply Systems" [1] and to provide an outline for how each section applies to interconnections with the YIS.

1. Introduction and Scope

1.1. Purpose

This guide establishes criteria and technical requirements for Independent Power Producers (IPP) who wish to interconnect generation, with a net capacity greater than 50 kW and up to 10 MW, to the Yukon Integrated System (YIS), at the distribution level (35 kV and below), or at the transmission level (above 35 kV). This guide has been developed considering CSA Standard C22.3 No. 9-08 (R2015) [1] and IEEE Standard 1547-2018 [2] and is subject to regular review and revision due to evolving standards.

The technical guide is intended to assist IPPs who apply to connect to the YIS through the Standing Offer Program, Call for Power, or through other unsolicited requests to connect.

1.2. Limitations

The criteria and technical requirements described within this section apply to the following generation interconnections:

- Interconnections to the Yukon Energy Corporation (YEC) and ATCO Electric Yukon (AEY) distribution systems at voltages of 34.5 kV and below, and
- Interconnections to the YEC transmission system at voltages over 34.5 kV by means of an existing or new substation. Transmission interconnections will require specific detailed review and approval by YEC and all interconnection costs will be borne by the IPP.

This Guide establishes the minimum requirements for the Point of Interconnection (POI). The IPP generation may be subject to additional requirements to ensure the project meets all applicable standards.

This Guide is not to be used:

- As an Operating Agreement and does not address the following:
    - Joint operating agreements
    - Costs
    - Tariffs
    - Other contractual issues
- As an Interconnection Process and Procedures Guide, and does not include the following:
    - Protection of the IPP's generation facilities
    - Transmission system impact and upgrades
    - System planning and design
    - Operation of the distribution system
    - Other system related issues
- As a design handbook for a generation facility.
- For any IPP generation not connected indirectly or directly to the YIS, i.e. an island grid.

2. Terms, Definitions, and Abbreviations

2.1. Definitions

Accredited Certification Organization – An organization that has been accredited by the Standards Council of Canada to operate a certification program for electrical equipment, such as the Canadian Standards Association (CSA).

Anti-islanding – A means of detecting and preventing a DR from energizing a part of the distribution system that becomes disconnected from the grid.

ATCO Electric Yukon – A private investor-owned utility, and member of the ATCO Group of Companies.

Automatic Circuit Recloser (ACR) – An overcurrent protection device used by utilities to detect faults on distribution system feeders, which has the ability to open and then reclose after a specified time delay allowing adequate time for temporary faults to clear.

Bi-directional Meter – A meter that measures real and reactive power and energy in both directions.

Cease to Energize – The cessation of energy outflow capability.

Clearing Time – The time from the start of the abnormal condition to when the distributed resource ceases to energize the distribution system.

Dispensated Metering Equipment – Any metering equipment that has received Measurement Canada approval under Section 9(2) or 9(3) of the Electricity & Gas Inspection Act.

Disconnecting Means – A device or group of devices that allows the conductors of a circuit to be disconnected from their source of supply.

Distributed Generation (DG) – Small, decentralized electric power generation facilities, typically interconnected to the distribution system.

Distribution System – The portion of the electrical system that operates at a nominal voltage of 34.5 kV line to line and below, and which distributes electric power between distribution substations and customers.

Effectively Grounded Distribution System – Distribution facilities where the neutral conductor is solidly grounded and the ratio of the zero sequence reactance to the positive sequence reactance is less than or equal to 3 and the ratio of the zero sequence resistance to the positive sequence reactance is less than 1.

Electromagnetic Interference (EMI) – Any electromagnetic disturbance that interrupts, obstructs, or otherwise degrades or limits the effective performance of a device, equipment or system.

Exporting – supplying power into the distribution system through the POI.

Facilities – A physical plant including, without limitation, generating plants, transmission and distribution lines, transformers, meters, equipment and machinery.

Flicker – The subjective impression of fluctuating luminance caused by voltage fluctuations.

Frequency – The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz (Hz).

Generation – The process of converting solar, thermal, wind, hydro, or chemical energy into electric energy.

Independent Power Producer (IPP) – An agency or individual other than a public utility (as defined by the Public Utilities Act) who generates electricity to sell (to the utilities). An independent power producer does not own transmission facilities and is dependent on the utilities to purchase and distribute the power it produces.

Interconnection – The physical connection of DG to YEC's distribution system so that parallel operation can occur.

Island Grid – A community power system which is energized solely by one or more local power producers and is separated electrically from the YIS.

Islanding – A condition where a portion of the utility's distribution system is energized exclusively by one or more power producers through their DR interconnection.

Operating Interface Point – See Point of Interconnection.

Parallel Operation – the simultaneous energization at a POI by the generating facility and the utility distribution system.

Point of Interconnection (POI) – The location of the electrical connection between an IPP facility and the utility's distribution system. This will be the point where the ownership changes from the utility to the IPP.

Power Factor – The ratio of active power to apparent power. It is the cosine of the phase angle difference between the current and voltage of a given phase.

Protection Scheme – The protection functions, including associated sensors, relays, and power supplies, intended to protect a distribution system or interconnection equipment.

Public Utility – As defined by the Public Utilities Act and Regulations (i.e., YEC and/or AEY).

Ride-through – The ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.

Secondary Injection Testing – A method in which low level signals obtained from current and voltage signal generators are injected into a power system protective device to test device response.

Stabilized – The state of the distribution system after voltage and frequency has returned to normal range for a period of at least five minutes (or another period of time, as agreed with YEC) following a disturbance.

Stand Alone – The state where a distributed generation can operate by controlling the frequency and voltage of their facility while in islanded or isolated mode.

Telemetering – Transmission of measurable quantities using telecommunications systems.

Total Demand Distortion (TDD) – The ratio of the root mean square of the harmonic content, considering harmonic components up to the 50th order and specifically excluding interharmonics, expressed as a percent of the maximum demand current. Harmonic components of order greater than 50 may be included when necessary.

Total Harmonic Distortion (THD) –The ratio of the root mean square of the harmonic content, considering harmonic components up to the 50th order and specifically excluding interharmonics, expressed as a percent of the fundamental. Harmonic components of order greater than 50 may be included when necessary.

Transfer Trip – A remote signal directed from an upstream device to command a DG to cease to energize the distribution system upon detection of an islanding condition and to prevent re-energization.

Transmission System –The portion of the system that operates above a nominal voltage of 34.5 kV line to line and transmits electric power between YEC substations.

Trip Time – The time between the start of the abnormal condition and the interconnection device ceasing to energize the distribution system.

Type Test – A test performed on a sample of a particular model of a device to verify specific aspects of its design, construction and performance.

Utility – See Public Utility (i.e., YEC and/or AEY).

Visible-Break Disconnect – A switch or circuit breaker by means of which the generator and all protective devices and control apparatus can be simultaneously disconnected under full load entirely from the circuits supplied by the generator. All blades or moving contacts must be connected to the generator side, and the design of the disconnect switch must allow adequate visible inspection of all contacts in the open position.

Voltage Flicker – A condition of fluctuating voltage on a power system that can lead to noticeable fluctuations in the output of lighting systems.

Yukon Energy Corporation (YEC) – A publicly-owned electrical utility that is the main generator and transmitter of electrical energy in Yukon.

Yukon Integrated System – The integrated Whitehorse-Aishihik-Faro and Mayo-Dawson electrical grids which are owned by YEC.

2.2. Abbreviations

ACR	Automatic Circuit Recloser
AEY	ATCO Electric Yukon
AEUC	Alberta Electrical Utility Code
CEA	Canadian Electricity Association
CEC	The Canadian Standards Association's C22.1-98 Safety Standard for Electrical Installations Part 1, also known as the Canadian Electrical Code
CSA	Canadian Standards Association
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers, Inc.
IPP	Independent Power Producer
LTC	Load Tap Changer
NEMA	National Electrical Manufacturers Association
POI	Point Of Interconnection
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SCC	System Control Center
SIS	System Impact Study
YEC	Yukon Energy Corporation
YIS	Yukon Integrated System
YUB	Yukon Utilities Board

3. Party Responsibilities

Refer to the IPP Policy as released in January 2019 for the individual responsibilities of the Government of Yukon, utilities (YEC and AEY), Yukon Utilities Board and the IPP during the generation interconnection process.

3.1. IPP Responsibilities

The IPP is responsible to:

- Provide technical information to the utility as specified in Appendix A and Appendix B;
- Assume ownership of the facility including the design, installation, operation, and maintenance of all equipment, station and distribution line facilities from the POI to the IPP facility, unless otherwise agreed to in writing;
- Pay the costs of system interconnection in accordance with the commercial terms established by the utilities;
- Obtain all regulatory approvals, including environmental assessment approvals, if necessary, for the construction and operation of its facilities. The IPP facilities shall be designed, constructed, operated and maintained in compliance with the applicable statutes, regulations, by-laws, codes and technical requirements specified by the utility (e.g. remote monitoring etc.);
- Submit all specifications of its facilities and detailed plans to the utility for review prior to receiving permission to connect to their distribution system;
- Ensure the technical requirements given in the standards and codes in Appendix D are met;
- Ensure metering requirements are met (see section 12); and
- Negotiate the timing and any testing requirements for the commissioning process with YEC

3.2. YEC Responsibilities

YEC is responsible for the operation of the Yukon Integrated System (YIS) and for certain local distribution systems interconnected with the YIS. This guide applies to all transmission and YEC distribution system interconnections.

YEC is responsible for all system studies performed on the YIS. The IPP and AEY, in the case of an AEY interconnection, shall provide all necessary information to YEC for the interconnection of the IPP facility. The system studies conducted by YEC will be paid for by the IPP.

After receiving the application for interconnection, YEC shall provide the IPP, at the IPP's cost, the information specified in Appendix C.

3.3. AEY Responsibilities

AEY is responsible for the operation of certain local distribution systems interconnected with the YIS. This guide applies to these AEY distribution system interconnections.

After receiving the application for interconnection, AEY shall, in consultation with YEC, provide the IPP, at the IPP's cost, the information specified in Appendix C.

4. General Requirements

4.1. Standards

When planning, designing, and operating an IPP Generation Facility, the IPP shall meet all applicable national, territorial and local construction and safety codes and standards.

The interconnection facility must comply, as a minimum, with the following:

- All CSA Standards, including the Canadian Electrical Code (CEC),
- Applicable YEC and AEY standards and the requirements set forth in this Guide,
- National, Territorial and local Governing law, acts, by-laws and codes, and
- Alberta Electrical Utility Code (AEUC) [4].

Applicable standards are located in Appendix D, however not all may be applicable for the IPP facility and additional standards may apply.

The interconnection of new generation can adversely affect the electric service to existing or future customers. The IPP must work with the utility to mitigate any adverse effects.

The facility must be constructed and maintained to provide a safe environment for employees as well as the public. If the generation facility adversely affects other customers, the utility may disconnect it until such time as the concern has been mitigated. The IPP is responsible for any costs incurred as a result.

The IPP is required to install, operate and maintain the facility and to ensure it is in sufficiently good order and repair at all times. Maintenance shall conform to good electrical practice, adequate for safe parallel operation when connected to the YIS. The utility and the IPP shall share commissioning reports, operating procedures and annual shutdown, maintenance, and inspection reports.

4.2. Operating Requirements

A joint operating agreement template will be developed in conjunction with the utility. The agreement requirements are not included within the scope of this Guide. A sample operating agreement is located in Appendix E.

5. Site Specific Conditions and Capacity Limitations

During the preliminary stage of project development any limitations regarding the proposed interconnection, and any additional system upgrades required, will be determined in consultations between the IPP, YEC and AEY, if interconnected via an AEY distribution system.

A system impact study will be necessary to identify any site-specific conditions and capacity limitations of the distribution and/or transmission system. To facilitate the study, the utility and the IPP will exchange information concerning load, feeder characteristics, protection philosophies, station layouts, capacities, ratings and other relevant information of the distribution and/or transmission system. The utility controls reliability design and reliability standards.

Under certain circumstances, YEC and AEY may limit the size or reconfigure the proposed connection arrangement of the IPP facility in order to maintain the integrity of their system.

6. YIS Transmission and Distribution System Characteristics

6.1. YEC Transmission System

6.1.1. General System Configuration

The YIS is an 'Islanded grid' which has no interconnection with the main North American electric grid. The Yukon must produce all of its own power, and cannot generate more electricity than is there is load, since there are no neighboring markets into which to sell surplus energy.

The YIS includes the 138 kV Whitehorse – Aishihik – Faro (WAF) grid, the 69 kV Mayo-Dawson-Keno (MD) grid, and the 138 kV Carmacks-Stewart Transmission Line (CSTL) which interconnects the WAF and MD grids. YEC provides power to major industrial customers connected to the 69 kV and 138 kV grids.

A map of the YIS is shown in Figure 6–1.

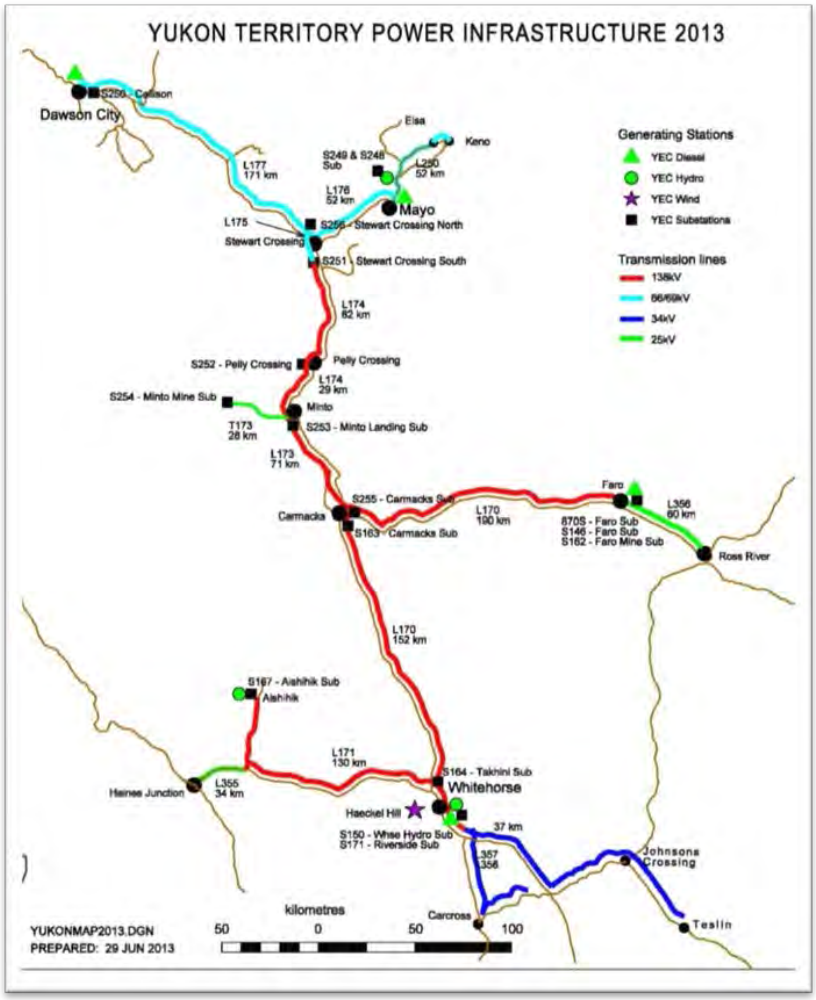


Figure 6–1: YIS Map

6.1.2. System Unbalance

Voltage unbalance on the transmission system is minimal during normal operation. The voltage unbalance under normal operating conditions will be less than three (3) percent. The IPP facilities may be subjected to voltage unbalance and negative sequence current during system disturbances. The generation connected to the transmission system must be able to withstand significantly unbalanced voltages with high negative phase sequence currents for short periods of time.

6.1.3. Frequency

The YEC transmission system operates at 60 Hertz (Hz) Alternating Current (AC) with equipment standard for this frequency. Frequency variations are typically in the range between 59.0 Hz to 61.0 Hz for small contingencies that cause modest disturbances, however variations between 58 Hz to 66 Hz or greater can occur for larger contingencies.

The frequency of the electric system is controlled by synchronous generator governor systems. Such governor systems respond automatically to changes in system frequency to prevent further deviation. These variations are system dependent and subject to change.

6.1.4. Steady State Voltage Levels

During normal steady state conditions, the 69 kV and 138 kV systems can vary between 90% and 105% of nominal voltage. However, under extreme conditions, the 69 kV and 138 kV systems can vary between 85% and 110% of nominal voltage with some 138 kV facilities designed to operate continuously up to 110% of nominal voltage.

6.1.5. System Fault Levels and System Impedances

The IPP generation facilities connecting directly to the transmission system shall be designed for operation at short circuit (fault) levels that take into account reasonable future development of the YIS transmission system. The short circuit levels to be used in the design depend on the point(s) of interconnection and future planned development and are available on request from YEC.

6.1.6. Fault Clearing and Automatic Reclosing

The YIS does not implement auto-reclosing at the transmission level.

6.1.7. System Grounding

The transmission system is effectively grounded.

6.2. YIS Distribution System Characteristics

6.2.1. General

Both YEC and AEY operate distribution systems in the Yukon which are interconnected with the YIS. The systems are predominantly three phase, wye connected, with nominal voltages of 4.16/2.4 kV, 6.9/4 kV, 12.5/7.2 kV, 13.8/8 kV, 25.00/14.4 kV and 34.5/20 kV.

AEY also operates a number of distribution systems which are not interconnected to the YIS, and are not covered by this Guide:

- Watson Lake
- Old Crow
- Beaver Creek
- Destruction Bay / Burwash Landing
- Swift River

For information on connecting to the AEY distribution systems which are isolated from the YIS, refer to AEY's document entitled, "ATCO Electric Yukon's Isolated Community Generation System Interconnection Guidelines".

6.2.2. Voltage Levels

The YEC and AEY distribution systems operate to meet CSA Standard CAN3 C235.83 – "Preferred Voltage Levels for AC Systems 0 to 50,000V" which defines the preferred operating voltage levels for normal and extreme operating conditions. The distribution system steady state voltage is typically maintained between + 5% to 7% and - 5% to 7%.

6.2.3. Power Quality (Harmonics and Voltage Flicker)

The YEC and AEY distribution systems operate to limit the maximum individual frequency voltage harmonics to 3% of the fundamental frequency and the voltage total harmonic distortion (THD) to 5% on the utility side of the POI.

6.2.4. Voltage Regulation

The operating voltages on the low voltage buses of YEC distribution substations are generally regulated by transformer automatic load tap changers (LTC), bus voltage regulators or feeder voltage regulators. YEC will provide set-points for the equipment upon request.

6.2.5. Voltage Unbalance

Distribution facilities are typically three-phase systems, incorporating single-phase distribution taps. The voltage unbalance on a distribution system under normal operating conditions may exceed 3%, due to the unbalanced loading and single-phase regulation. Voltage unbalance will be calculated using the following formula, as derived from CSA Standard C22.3 No. 9-08 (R2015) [1]:

Voltage Unbalance (%) = 100 x (negative sequence voltage of the fundamental frequency component) / (positive sequence voltage of the fundamental frequency component)

6.2.6. Fault Levels

Fault levels and maximum allowable fault currents vary significantly through the distribution system and must be considered in the design of the IPP interconnection.

6.2.7. System Grounding

The utility distribution facilities are typically three phase, four wire, multi-grounded systems that incorporate single phase distribution taps. The lines are normally operated as effectively (solidly) grounded with grounded-wye connected sources at the distribution substation secondary bus.

6.2.8. Phasing

The phase sequence on the utility system may vary, and must be confirmed between the IPP and the utility during the design phase of the installation.

6.2.9. Fault and Line Clearing and Automatic Reclosing

The YEC distribution systems do not currently include auto reclosing. The AEY distribution systems may have auto reclosing and this will be confirmed during the design phase of the application.

7. Power Quality Requirements for the System Interconnection

7.1. Harmonics

The following industry standards may provide guidance for appropriate performance.

- IEEE 1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces, IEEE, 2018 [2]
- IEEE 519-2014 – IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems [5]
- IEC 61000-4-15 – Testing and Measurement Techniques – Flickermeter - Functional and Design Specifications [6]

The generation facility shall not inject harmonic currents such that will cause objectionable voltage distortion as per standard IEEE 519 Harmonic current injections cause intolerable voltage distortions on the distribution system and may damage equipment.

The Utility, at the IPP's expense, shall conduct a Power Quality Assessment of the distribution system in the immediate vicinity of the interconnection using a measurement technique compliant with IEC 61000-4-7.

When performing a Power Quality Benchmark, the measurements at the customer's POI shall be taken over a one week (168 hour) period during typical production load levels.

7.2. Flicker

The generation facility shall meet the requirements of Section 6.2.3 and shall not cause unacceptable levels of flicker on the distribution system. The utility, at the IPP's expense, shall measure the flicker level using a power quality measuring device that meets the requirements of the IEC Flickermeter Standard 61000-4-15.

When performing a Flicker assessment, the measurements at the customer POI shall be taken over a representative load cycle of one day or greater.

7.3. Speed Regulation and Frequency Control

The frequency of the YIS is controlled by the generators operated by YEC.

The YIS operates at 60 Hertz (Hz) Alternating Current (AC). The nominal frequency variations are typically 59.0 Hz to 61.0 Hz for small contingencies that cause modest disturbances, and the frequency may drop to 58 Hz or rise to 66 Hz or higher for larger contingencies.

The frequency of the YIS is automatically controlled by the governor systems of the generators operated by YEC, within the specified limits.

IPP generators rated at 1 MVA and greater are required to have a governor system, capable of operating in droop mode, to respond to system frequency changes. The droop setting of the governor will typically be in the range of 5%.

IPP generators rated less than 1 MVA may operate in base load mode rather than in frequency control mode.

The utility will define frequency requirements on a project by project basis and may require the control of these parameters directly via the YEC SCC.

Equipment connected to the YIS shall be capable of withstanding the dynamic frequency performance criteria listed in Table 1.

Table 1: Transmission Minimum Frequency Performance

Under Frequency Limit	Over Frequency Limit	Minimum Time
60.0-59.0 Hz	60.0-61.0 Hz	N/A (continuous operating range)
58.9-58.5 Hz	61.1-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
less than 56.4 Hz	greater than 61.7 Hz	Instantaneous trip

Under-frequency and over-frequency relaying that automatically disconnects generators from YIS must not operate for frequencies in the range of 59.0 to 61.0 Hz if no other abnormal system event is underway.

7.4. Voltage Regulation and Power Factor

The IPP is responsible for ensuring that the voltage levels at the POI are maintained within this guidelines prescribed by the utility. The IPP interconnection must maintain the voltage levels, under all feeder load conditions, at the same values as they were prior to the interconnection.

Synchronous generators connected to the distribution system must be equipped with adequate excitation controllers. The IPP shall operate generators with Automatic Voltage Regulators (AVR) adjustable from 95% to 105% of nominal bus voltage. The Generation should be run in Voltage control unless required to run in power factor (pf) mode by the Utility. Operation in MW or MVAR control is not acceptable. The AVR response should with no intentional delay when in Voltage Control mode.

Induction generators do not have voltage or reactive power control capability and consume reactive power (VAR). In this case, the generator must provide reactive compensation to correct the power factor to 0.9 lagging or better at the POI, unless other terms are specified by the utility.

Inverter type generating equipment can control the power factor over a wide range, typically ± 0.75. An inverter type generator connected to the distribution facility must be capable of adjusting the power factor in the range of ± 0.9. The IPP may operate outside that range only by prior agreement with the utility.

The utility will define voltage and reactive power requirements on a project by project basis and may require the control of these parameters directly via the YEC SCC. The IPP and utility will identify and

agree on the exact transformer ratio to allow optimal voltage regulation on the system and the IPP will determine whether an on-load tap changer is needed.

In order to coordinate with its existing voltage control devices, the utility may require that the generator operate in a power factor control mode. This means operating within a constant power factor set point range. The voltage/power factor regulator must be capable of controlling the power factor of the generator. The utility shall determine the actual set point between these limits.

In power factor control mode, the voltage regulator must have a voltage override that causes it to reduce excitation if the voltage at the POI exceeds an upper limit to be specified by the utility. The normal upper limit is 105% of nominal; however, the voltage regulator shall have the provision to adjust this upper limit between 100% and 110% of nominal. The voltage regulator must also have provision for a time delay between sensing an excursion of the upper voltage and initiating control action. The power factor control equipment must have the capability to allow for the adjustment of this time delay from between 0 and 180 seconds. The utility will specify the required time delay for each project.

7.5. Voltage Unbalance

Unbalanced phase voltages and currents can affect protective relay coordination and cause high neutral currents and thermal overloading of transformers. Of particular concern is negative sequence voltage and the resulting effect, particularly on rotating generators and motors connected to the system.

To protect the utility and the IPP equipment, the 3-phase generation contribution at the POI should not cause a voltage unbalance greater than 1% or a current unbalance greater than 5%.

If the existing unbalance at the POI is shown to be already close to the maximum unbalance condition, the IPP contribution may cause the unbalance to exceed the specified amount. This will be considered on a case-by-case basis.

7.6. Voltage and Frequency Transients

The IPP is responsible for the cost of any necessary transient or dynamic stability studies, which must be performed in a manner approved by YEC.

7.7. Resonance and Self-Excitation of Induction Generators

The potential effects of resonance should be considered as part of the design of the generating facility. The effects include:

- Ferro-resonance in the transformer,
- Sub-synchronous resonance due to the presence of capacitor banks, and
- Harmonic resonance with other customers when capacitors are being added as part of the installation.

When induction generators are used, the potential for self-excitation should be assessed and addressed as part of the system impact study and mitigated accordingly.

The IPP shall be responsible for the engineering analysis as part of the design process to evaluate the existence of, and to eliminate the harmful effects of resonance and the assessment of the self-excitation effects of induction generators. The engineering analysis of resonance and the assessment of the self-excitation effects of induction generators must be submitted to YEC for approval or further evaluation.

7.8. DC Current Injection

The IPP facility system shall not inject a dc current at the POI.

7.9. Fault Levels

The utility will provide the IPP with the anticipated fault levels or the data necessary for the IPP to calculate the distribution system fault contributions at the POI.

The IPP facility must not increase the fault levels on the utility distribution or transmission system above their design levels for maximum faults.

8. Physical Interconnection

8.1. Safety

The safety of the public, operating personnel and the environment is of primary concern in the design, construction, operation and maintenance of the interconnection facilities.

8.2. Point of Interconnection (POI)

The POI is the point at which the utility (YEC or AEY) distribution facilities or conductors are connected to the IPP's facilities or conductors, and where any transfer of electric power between the IPP and the utility takes place. The POI must be identified in the design and on the Single Line Diagram (SLD).

Depending on ownership, YEC or AEY will coordinate the design, construction, maintenance and operation of the facility on the distribution system side of the POI. The IPP is responsible to coordinate the design, construction, maintenance and operation of the facility on the generation side of the POI.

All voltage and frequency parameters specified in this section must be met at the POI unless otherwise stated.

The IPP is responsible for any incremental costs to the electric systems caused by the interconnection. The responsible utility will carry out the engineering, design and construction required for these installations and charges those costs back to the IPP. Ongoing O&M costs incurred on the distribution feeder side will also be recovered by the utility.

There may be cases where either the utility or the IPP may own equipment located on the other's side of the POI. For example, the utility may own and operate communications, supervisory, or metering equipment, which is located on the IPP side of the POI. The IPP must provide a site with the necessary space for utility to install current transformers, potential transformers, switching equipment, meters, and any other AC and DC auxiliaries, protection and controls, SCADA or communications equipment required to interconnect with the generating facility. The site is to be approved by the utility and a 120-volt AC power service is to be available for the use of portable tools.

8.3. Point of Disconnection

For transmission interconnections, the visible-break disconnect switch shall be located on the high voltage side of the interconnection transformer.

For distribution interconnections, the visible-break disconnect switch may be located on the high or low voltage side of the interconnection transformer.

The disconnect switch must be gang operated to simultaneously isolate all three phases.

If the IPP site interconnects multiple generators, one disconnect switch must be capable of isolating all of the generators simultaneously. There may be other means of meeting this requirement; however the approval of the utility must be obtained before using other means.

The IPP must follow the utility switching, clearance and tagging procedures. The utility is responsible to instruct the IPP in this regard.

8.3.1. High Side and Low Side Disconnect Switches

For transmission interconnections the disconnect switch on the high voltage side of the interconnection transformer shall be installed, owned and maintained by the IPP.

For distribution interconnections the disconnect switch, if on the high voltage side of the interconnection transformer shall be installed, owned and maintained by the utility, and if on the low voltage side of the interconnection transformer shall be installed, owned and maintained by the IPP.

8.3.2. Disconnect Switch Specification

The disconnect switch must be a manual, visible-break disconnect that provides safe isolation for the utility's personnel from the generators and all other possible customer sources of energy.

The disconnect switch must:

- Be adequately rated to break the connected generation/load;
- Be located within five meters (horizontal) of the POI, unless otherwise approved by the utility;
- Provide a direct, visible means to verify contact operation;
- Allow simultaneous disconnection of all ungrounded conductors of the circuit;
- Plainly indicate whether the switch is in the "open" or "closed" position;
- Be lockable in the "open" position;
- Be capable of being energized from both sides;
- Be readily accessible to the utility's operating personnel;
- Be externally operable without exposing the operator to contact with live parts;
- Be capable of being closed without risk to the operator while there is a fault on the system;
- Be labeled with utility's switch number;
- Meet all applicable CSA Part II standards and all applicable codes; and
- Undergo annual inspections and maintenance, with reports submitted to the utility for approval.

8.4. Interconnection Transformer

A generator step-up transformer boosts the voltage of the DG to match the voltage of the utility distribution feeder. The transformer winding configuration impacts how system faults are detected and what type of protection is required (see Section 9.10). The IPP must submit their transformer connection proposal to the utility for review and approval prior to placing an order for purchase.

8.5. Interconnection Grounding

The IPP facility must be grounded in accordance with the latest revisions of the CEC and AEUC. A ground grid of sufficient size to handle the maximum available ground fault current must be designed and installed in order to limit ground potential rise (GPR) step and touch potentials to safe levels as set forth in ANSI/IEEE Std. 80 IEEE Guide for Safety in AC Substation Grounding.

The ground grid will be designed for foreseeable future fault levels obtainable from the System Impact Study.

Grounding of the interconnection shall be designed to provide:

- Solid grounding of the distribution feeder neutral connection,
- Fault detection that isolates all sources of ground fault contribution,
- A circuit to block the transmission of harmonic currents and voltages, and
- Protection of the low voltage side from damage due to high side faults.

The preferred configuration, for an IPP owned interconnection transformer, is delta connection on the generator side of the transformer and a grounded-wye configuration on the utility's side of the transformer. If this configuration is not technically feasible, the configuration chosen must still address the above concerns. Grounding must conform to the AEUC [4].

Sample single line diagrams are shown in Appendix F.

8.6. Phasing and Phasing Sequence

Since phasing is not standardized across distribution facilities, the phase sequence must be coordinated between the IPP and utility's distribution system.

8.7. Interrupting Device Ratings

The design of the generation facility must consider the fault contributions from both the distribution system and the IPP generation facility, to ensure that all circuit fault interrupters are adequately sized. The utility will inform the IPP of the present and anticipated future fault contribution from the interconnected electric system.

9. Interconnection Protection

9.1. General

The purpose of the IPP facility protection is to reduce the risk of damage to IPP and utility equipment and maintain the reliability of supply.

The protection scheme shall be designed to detect the following conditions at the POI:

- Balanced and unbalanced system faults (i.e. line-ground, line-line and three phase faults)
- Frequency variations
- Voltage variations
- Reverse power flow
- Islanding conditions
- Out of synchronism

Depending upon location, the protection scheme may be required to detect additional conditions such as open phase, ferro-resonance, negative sequence voltage, or zero sequence currents.

The protection scheme must fully coordinate with any existing distribution system protective devices. The IPP must submit a complete protection design package, including all relay settings, tripping schemes and schematics, to the utility for review and approval prior to installation. Both existing and ultimate bus fault levels should be considered. A sample Protective Setting Commissioning Sheet with guideline limits is included in Appendix G.

The point of measurement for voltage and frequency shall be at the POI or as agreed upon with the utility.

The IPP must revise and re-submit the protection information for any proposed modification.

9.2. Device Ratings

Equipment shall be rated to carry and interrupt the fault levels that are, or will be, present at the IPP facility - this includes the ultimate fault currents specified by the utility. The IPP's equipment covers all station and distribution facilities, including but not limited to all protection equipment forming the entrance and distribution line protection: circuit breakers, current transformers, potential transformers, secondary cabling, dc system/battery charger, switchboard wiring and protective relays.

9.3. Minimum Protection Requirements

The following minimum protection requirements shall be provided for an interconnected IPP facility:

- Overcurrent
- Over-frequency
- Under-frequency
- Over-voltage
- Under-voltage

Additional protection requirements are dependent upon the transformer configuration and the distribution system characteristics.

9.4. Phase and Ground Fault Protection

The IPP must install utility grade protective devices to detect and promptly isolate the generation facility for faults occurring either in the DG facility itself or on the distribution system. Virtual devices (i.e., computer or programmable-logic controller systems) are acceptable provided they meet standard utility practice for system protection and they have been type tested and approved by an independent testing laboratory.

The protective devices in the IPP generation facility must fully coordinate with the protective relays on the distribution system unless otherwise agreed. The IPP must calculate the protective device settings and submit the relay characteristics and settings to YEC for review and approval.

The generation facility must be able to detect the following situations and isolate itself from the distribution system:

- A short circuit between any phase(s) and ground (if distribution system is a grounded system)
- A short circuit between phase(s)

9.5. Over-Frequency and Under-Frequency Protection

Each synchronous generator must be capable of continuous operation between 59.0 Hz and 61.0 Hz and of limited time operation for larger deviations from normal frequency, as shown in Table 1.

Over/under frequency relays are normally installed to protect the generators from extended off-nominal operation. It is expected that larger (> 1 MW) synchronous generators shall remain connected to the system during frequency excursions. To ensure that the generator is not tripped prematurely, YEC will specify the minimum required time delays and levels for setting the IPP over/under frequency protection relays.

9.6. Over-Voltage and Under-Voltage Protection

The IPP must operate its generation facility such that the voltage levels on the utility's system are not significantly altered by the connection of the generation facility. IPP facility paralleling shall not cause voltage fluctuations of more than ± 5% at the POI.

The IPP must install necessary relays to trip the circuit breaker when the phase-to-ground voltage, measured on any one of the three phases, deviates outside predetermined limits. Under-voltage relays should be adjustable and should have a settable time delay to prevent unnecessary tripping of the generator on external faults. Over-voltage relays should be adjustable and may be instantaneous.

The interconnection facility must cause the generator to cease to energize the utility's system within the trip times indicated in Table 2. "Trip time" refers to the period of time between the start of the abnormal condition and the moment the interconnection device ceases to energize YEC's system.

To ensure that the generator is not tripped prematurely, the utility will specify the minimum required time delays and levels for setting the IPP over/under frequency protection relays.

Table 2: Response to Abnormal Voltages

RMS Voltage (based on 120V nominal)	Trip Time
RMS Voltage: V=<50%	Trip time: Instantaneous

RMS Voltage (based on 120V nominal)	Trip Time
RMS Voltage: 50% < V < 90%	Trip time: 120 cycles
RMS Voltage: 90% < V < 105%	Normal Operation
RMS Voltage: 105% < V < 120%	Trip time: 30 cycles
RMS Voltage: V >= 120%	Trip time: Instantaneous

The IPP may reconnect when the system is stabilized (i.e. voltage and frequency have returned to normal range for a time as identified by the utility).

9.7. Additional Protection

The utility may require additional protection on a case by case basis. Possible protection may include:

- **Unbalance or negative sequence protection**: The IPP generator is tripped on excessive current unbalance. This is important if fuse protection is used on the primary of the generator step-up transformer or for any other open phase condition
- **Broken delta protection (59G)**: Using a grounded wye-broken delta potential transformer, this protection can facilitate detection of ground faults on ungrounded systems.
- **Rate of change of frequency**: Protection to detect a power island condition.
- **Reverse power protection**: Protection to detect a generator motoring condition.

9.8. Anti-Islanding Protection

Islanding is the condition where the generation facilities and a portion of the distribution system have become isolated from the rest of the system, and continue to operate in isolated mode. Unless agreed upon by the utility, generating facilities shall not be permitted to remain connected to an islanded system, i.e. islanding is not generally allowed. Generation facilities may continue to supply station service loads while disconnected from the interconnection system.

Anti-islanding protection is required to:

- Prevent power quality issues to customers connected to the island,
- Avoid out-of-phase reclosing between the utility and the DR facility, and
- Prevent safety hazards created as a result of back feeding isolated portions of the utility distribution system.

For rotating generators, the IPP must install a transfer tripping scheme using tele-protection signals from the system to separate the DG facility from the distribution system in the event of an islanding condition.

Transfer tripping requirements are also applicable to induction generators, unless the IPP can demonstrate that that there is no potential for self-excitation. For inverter-based generation a detection scheme designed in accordance with the requirements of IEEE 1547 [2] may be acceptable.

The IPP is responsible for damage to the YIS caused as a result of failure to safely separate from the system during an islanding event or subsequently during reconnection to the system following the event.

9.9. Transformer Winding Configuration

The winding configuration of any three phase transformer will have an influence on the location of the protection measurement points and the level of protection required for the IPP interconnection. See Appendix F for examples for typical synchronous generator protection single line diagrams for different transformer configurations.

9.10. Conditions for Connecting to an Energized Distribution System

The IPP system must not energize the utility distribution system when the distribution system is de-energized or following the operation of any interconnection protection functions. The utility will inform the IPP facility when it is safe to reconnect to the distribution system.

Where transfer trip protection is installed, the transfer trip protection must ensure that the generator disconnects before a substation feeder breaker or intermediate automatic circuit reclose (ACR) operation. General requirements are:

- Generator lockout within 0.6 seconds of breaker or ACR opening; and
- Fail-safe lockout within 6 seconds of communication loss.

These conditions will be finalized via the operating agreement between the utility and the IPP.

9.11. Synchronization

Any DG facility able to generate voltage while disconnected from the YIS requires synchronization facilities before connection is permitted.

The IPP facility shall maintain in synchronism with the system while operating in parallel. The generating facility has the responsibility of maintaining synchronization with the system. The utility cannot synchronize to the generating facility. Any proposed synchronizing scheme must be submitted to the utility, prior to the installation.

For synchronous generators, an approved automatic synchronizing device must be provided in all cases where the plant is to be operated unattended. Automatic synchronizing shall be supervised by a synchronizing check relay. Synchronizing controls should satisfy the conditions in Table 3 for synchronous generators.

Table 3: Synchronization Criteria for Synchronous Generators

Aggregate Rating of Generators (kVA)	Frequency Difference (Hz)	Voltage Difference (%)	Phase Angle Difference (degrees)
0-500	0.3	10	20
>500 – 1500	0.2	5	15
>1500	0.1	3	10

Induction generators do not require synchronization since there is no generated voltage prior to connecting to the distribution system. The generator speed shall be brought to within 0.5% of its rated value. These units may be started as induction motors using power from the distribution system provided that these units do not cause unacceptable voltage flicker as specified in Section 7.2 on start - up or on connect/disconnect. The interconnection process of the induction generator shall not create a voltage drop pf greater than 5 percent.

Inverter-type or line-commutating voltage-following equipment does not require synchronization facilities. Operation of the interconnection (or disconnecting of the DR facility) shall not cause voltage drop greater that 5 percent and shall meet the flicker requirements

9.12. Protection from Electromagnetic Interference (EMI)

The influence of EMI must not result in a change in state or mis-operation of the interconnection facility.

9.13. Surge Withstand Performance

The interconnection facility must have the capability to withstand voltage and current surges in accordance with the environments described in IEEE/ANSI C62.41 or C37.90.1

9.14. Batteries and Auxiliaries

Batteries and auxiliaries shall have sufficient capacity to ensure the operation of all DC loads during loss of AC supply. Typically the batteries must be capable of supplying the substation DC load for 8 hours.

9.15. Mitigation of Protection Scheme Failure

Relays with self-diagnostic features, which provide information on the integrity of the protection scheme, should be used whenever possible.

The protection scheme must be designed by a qualified professional engineer, or a competent technical person working with the utility's engineers, to ensure that the self-diagnostic feature is integrated into the overall protection scheme for the safe and reliable operation of the system.

Depending on the scheme and its design, where relays with the self-diagnostic feature do not trip the appropriate breaker(s), sufficient redundant or backup protection must be provided for the system. The malfunctioning relay must also send a signal to notify operating personnel to investigate the malfunction.

9.16. Instrument Transformers used for Protection

Instrument transformers used for protection must comply with CAN/CSA-C60044-6 or IEEE C57.13 [8].

10. Remote Monitoring and Information Exchange

The IPP facility shall provide information in real-time to YEC SCC regarding:

a. Connection or circuit breaker status,
b. Real and reactive power output in kW and kVAR,
c. Load Tap Changer (LTC) position of the interconnecting transformer,
d. Communication and RTU failure alarm,
e. Intelligent Electronic Device (IED)/Relay failed status, and
f. Voltage at the POI.

The communication protocol and the equipment required will be specified by YEC.

The IPP facility shall log the operation of any protective device, including which protection elements operated, and the status of the DG facility including power output, voltage, and current waveforms.

YEC may have additional requirements on a case by case basis.

If it is determined that the IPP facility will have an impact on YEC's Transmission Network, the IPP will be required to provide a Remote Terminal Unit (RTU) or Data Link to a YEC RTU capable of exchanging Supervisory Control and Data Acquisition (SCADA) information with the YEC Control Centre. The protocol for data exchange via the RTU shall be compatible with that used for communications used by YEC. The communication protocol and the equipment required will be specified by YEC.

The IPP will be required to provide the following typical data needed by the (SCADA) system:

a. Individual generator(s) MW and MVAR
b. Individual generator(s) MWh and MVARh
c. Generator(s) breaker status
d. Individual generator on/off status, if no generator breaker exists
e. Total station MW and MVAR
f. Station service MW, MVAR, hourly MWh and MVARh
g. Generator transformer(s) high voltage side breaker(s) and isolator(s) status
h. Bus voltage at high voltage bus
i. PSS status, if applicable
j. AVR status, if applicable
k. AVR voltage setpoint, if requested
l. Total plant MW setpoint, if requested
m. Generator step-up transformer tap setting, if requested

11. Construction

The construction and installation of the IPP's generating facility must meet all applicable statutes, regulations, by-laws and codes. The IPP is responsible for obtaining all permits and complying with all safety and environmental regulations, codes and assessment approvals, if necessary, for the construction and operation of its facilities. Copies of all permits, compliance reports and inspection documents must be provided to the utility prior to energizing the POI.

All single line diagrams provided to the utility must be drawn in accordance with IEEE standards and conventions, and must be stamped by a professional engineer assuming responsibility for the design.

12. Metering

12.1. General

Two meters, primary meter and backup meter, will be required at the IPP facility:

- The utility shall install, own, operate and maintain one meter (primary) necessary for measuring the energy and demand supplied to the YIS, unless otherwise specifically provided in a contract with the IPP. This meter shall remain the sole property of YEC. The meter will comply with Measurement Canada requirements and will be owned and maintained by YEC.
- The IPP shall install, own, operate and maintain the other meter (backup) which does not necessarily have to comply with Measurement Canada requirements.

Generators exporting power onto the distribution system shall be equipped with bi-directional meters with four-quadrant measurement capability. An appropriate number of channels are required for four-quadrant meters to separately record active and reactive power in both the export and the import directions.

The high voltage side of the interconnection transformer is designated as the Measured Billing Point for all energy imported and exported from the IPP facility.

The metering equipment will be:

- Suitable for use in the environmental conditions reasonably expected to occur at the installation site; and
- Appropriate for measuring the power system characteristics reasonably expected to exist at the installation under all power system conditions and events.

The IPP shall provide Measurement Canada Approved instrument transformers. Each meter shall be connected to its own individual core/winding. For the utility meter the IPP shall wire from the instrument transformers to the meter receptacle using CSA-approved tamper resistant conduit and accessories suitable for the utility meter or metering equipment.

For transmission interconnections the IPP will provide burden calculations for proposed instrument transformer secondary wiring, for approval by YEC. If necessary the wiring burden may have to be reduced, by increasing the CT secondary conductor size, to meet Revenue Meter requirements.

The IPP shall supply and install the meter base to meet the utility requirements. The utility will provide the specifications for the meter base during the design phase.

12.2. Meter Requirements

The primary meter supplied by the utility will:

- Be Measurement Canada Approved for revenue metering;
- Be dispensated, with accuracy class ratings for active and reactive energy management as per Table 4;
- Be verified and sealed in accordance with the Electricity and Gas Inspection Act;
- Be capable of maintaining the interval boundaries within 60 seconds of the hour and every quarter hour thereafter;

- Measure all quantities required to determine active energy and reactive energy transferred in the required directions at the Measured metering point;
- Provide a separate register to maintain the continuously cumulative readings of the active energy and reactive energy transferred in the required directions at the Measured metering Point;
- Retain readings and, if applicable, all clock functions for at least 14 days in the absence of line power;
- Be equipped with meter failure alarm and communication failure alarm;
- Communicate all metering and equipment status to the YEC system control centre via the IPP's communication equipment;
- Apply loss compensation (such as line losses) factors where applicable to the revenue meters; and
- The meter shall have an accuracy class of 0.2% or better.

The backup meter supplied by IPP will:

- The backup metering will be of the same accuracy class and capability as the primary metering and shall include all equipment to provide the necessary billing data.
- Be non- dispensated, with accuracy class ratings for active and reactive energy management as per Table 5;
- .

Table 4: Schedule of Accuracies for Dispensated Metering Equipment Approved Under Section 9(2) or Section 9(3) of the Electricity and Gas Inspection Act

Metering Point Capacity (MVA)	Points of Delivery	Points of Supply	Measurement Transformers Accuracy Class
10 and above	1.0%	1.0%	0.3%
10	1.0%	1.0%	0.3%

Table 5: Schedule of Accuracies for Non-Dispensated Metering Equipment Approved Under Section 9(2) or Section 9(3) of the Electricity and Gas Inspection Act

Metering Point Capacity (MVA)	Watthour Meter Accuracy Class	Varhour Meter Accuracy Class
10 and above	0.2%	0.5%
10	0.5%	1.0%

12.3. Measurement Transformers

The applicable winding(s) of the current and potential instrument transformers supplied and installed by the IPP must:

- Be approved by Measurement Canada for revenue metering.
- Be burdened to a degree that does not compromise the accuracy required by this guideline.
- Have a minimum of two cores per instrument transformer. One core connection for the utility meter and the other core connection for the IPP meter.
- Be used solely for metering and not to be used for any other purposes.
- Have an accuracy class rating that equals or exceeds the values specified in Table 4.

12.4. Remote Communications Equipment

The remote communications equipment may or may not be an integral part of the meter or the recorder. However, it must incorporate protocol schemes that will prevent the corruption of data during interval data transmission. The protocol must be suitable for the communications equipment type and nature of the communications media and path.

12.5. Password Protection

Two or more levels of password protection will be required for each meter data collection agency. One level is for full access to set time functions and a second level is for read only access to interval data and event logs.

12.6. Safety Requirements

The facility installation must conform to:

- Measurement Canada Standard Drawings;

- AEUC [4];
- CSA Standard C22.2 General requirements - Canadian electrical code, part II [7] ; and
- ANSI/IEEE C57.13-2016 IEEE Guide for Grounding of Instrument Transformers [8].

13. Interconnection Tests

13.1. General Testing Requirements

The IPP must notify YEC (and AEY if the interconnection is via the AEY distribution system) in writing at least three weeks prior to the initial energization and start-up testing of the IPP generation facility. YEC may witness any testing of the equipment and protection schemes associated with the interconnection. Tests must align with the requirements specified in IEEE 1547 and CSA 22.3 No 9-08.

13.2. Type Testing

Type testing is considered an acceptable method of verification where suitable and applicable equipment standards exist, and must be performed once for each specific protection scheme. All interconnection equipment must include a type testing procedure as part of the documentation in order to determine the protection settings meet the requirements set forth within this technical guide. A type test may be performed on one device of a combination of devices. In a case of a combination of devices which comprise a system, the testing will demonstrate that the devices are able to operate as a system.

The type tests shall be performed on a representative unit or system, either in a factory, testing laboratory, or in the field. Results from a resource within a similar product family or design, including hardware or software, shall be acceptable as a representative within the same product family where ratings are within 50% to 200% of the tested resource.

The following type tests must be performed in accordance with IEEE 1547.1 [9]:

- Temperature stability
- Response to abnormal frequency
- Response to abnormal voltage
- Synchronization
- Interconnection integrity
- Unintentional islanding
- Open phase
- Reconnect following abnormal condition disconnect
- DC injection (for inverters without interconnection transformers)
- Harmonics

13.2.1. Temperature Stability

The temperature stability test verifies the interconnection equipment maintains measurement accuracy of parameters over its specified voltage range.

13.2.2. Response to Abnormal Frequency

This test verifies the interconnected generation facility ceases to energize the connected system as specified to IEEE 1547.1 with regards to abnormal frequency.

13.2.3. Response to Abnormal Voltage

This test verifies the interconnected generation facility ceases to energize the connected system as specified to IEEE 1547.1 with regards to abnormal voltage.

13.2.4. Synchronization

This test verifies the interconnected IPP facility will accurately and reliably synchronize with the utility as per IEEE 1547.1.

13.2.5. Interconnection Integrity

The interconnection integrity test verifies the IPP facility meets the surge withstand requirements as specified in Section 9.14 when tested in accordance with IEEE 1547.1.

13.2.6. Unintentional Islanding

Where YEC requires an anti-islanding protection function (other than transfer trip) or minimum import power levels, this test verifies that an IPP facility will cease to energize in accordance with IEEE 1547.1.

13.2.7. Open Phase

The open phase test verifies that the IPP facility will cease to energize the utility interconnection upon the loss of an individual phase on the distribution network when tested in accordance with IEEE 1547.1.

13.2.8. Reconnect following Abnormal Condition Disconnect

This test verifies the functionality of the IPP facility interconnection component or system reconnect timer, which shall delay the reconnection to the utility following a trip event prior to the distribution system stabilization, as specified in Section 9.11.

13.2.9. DC Injection (for Inverters without interconnection transformers)

This test verifies that an inverter-based IPP facility will comply with the DC current inject limit specified in Section 7.9 when tested in accordance with IEEE 1547.1.

13.2.10. Harmonics

The individual current harmonics and the total demand distortion (TDD) of the IPP facility shall be measured and recorded under normal operating conditions to ensure the values are within the limits specified in Section 7.1

13.3. Production Tests

Production tests shall be conducted on each IPP generating unit and interconnection equipment prior to delivery to verify they meet the applicable standards and verify the operability of every generating unit manufactured for customer use.

The tests assume the equipment has met the applicable interconnection and interoperability requirements of the applicable standards and may be conducted as a factory test or performed as part of an evaluation or commissioning test. Facilities with adjustable set points shall be tested at a single

series of test points specified by the manufacturer. The summary report must provide a list of normal and abnormal performance category capability, final function settings, and final operating mode settings.

The following production tests are specified within IEEE 1547.1:

1. Response to abnormal frequency
2. Response to abnormal voltage
3. Synchronization

14. Commissioning Tests and Verifications

14.1. General

Commissioning tests are tests and verification on the IPP facility equipment to confirm the system as delivered, designed, and installed meets the interconnection and interoperability requirements of this guide and the applicable standards. These tests include visual inspections, and may include operability and functional performance tests as required.

Prior to the energization of the IPP facility, or changes to the facility, verification testing must be performed and coordinated with the utility. After the equipment is installed and ready for operation, the testing must be performed by a qualified individual in accordance the manufacturer's published test procedures, or IPP developed procedures that have been approved by the utility. Qualified individuals include: licensed, professional engineers; factory-trained and certified technicians and licensed electricians experienced in testing protective equipment. The utility reserves the right to witness the verification test or to require written certification that the test was performed.

Verification testing must also be performed annually or when major system upgrades or modifications are carried out.

14.2. Interconnection Verifications and Inspections

The following commissioning tests and inspections shall take place:

a. Final IPP facility protection settings shall be verified, recorded, and provided to the utility. A sample protective settings commissioning report is located in Appendix G.

b. Visual inspection shall ensure the grounding coordination requirements in Section 8.5 have been met.

c. Visual inspection shall ensure the presence of a disconnecting means in accordance with Section 8.3 has been met.

d. The polarities, burdens, and ratios of field wired instrument transformers shall be verified as correct and in accordance with the design documentation.

e. Field installed power and control wiring shall be verified to be in compliance with drawings and manufacturer requirements.

f. For three-phase systems, the phase rotation of the distribution system and the IPP facility as installed shall be verified as compatible.

g. All monitoring and information exchange provisions shall be verified as functional in accordance with Section 10.

h. Calibration checks of each protective relay or the equivalent protection device shall be performed using injection of appropriate ac quantities, secondary injection, or set-point adjustment verification.

i. Functionality of the protective relays or the equivalent protection device, circuit breakers, and telecommunications equipment shall be tested to verify the system operates as intended.

j. Load tests of protective relays or the equivalent shall be conducted immediately after energization, where applicable.

k. The ohmic value and connection of the transformer neutral impedance grounding device shall be verified as correct.

l. Upon loss of DC power supply to the protective relays or the equivalent protection device, it shall be verified the protection scheme activates the interconnection circuit breaker.

m. Upon loss of a communication signal, it shall be verified the fail-safe transfer trip occurs when required by the utility in accordance with Section 9.8.

n. Inverter operation must be verified annually by operating the load break disconnect switch and verifying the generation facility shuts down and does not restart for five minutes after the disconnect switch has closed.

o. Any system depending on a battery for trip power must be checked for proper voltage and logged monthly. Once every four years, the battery must be replaced or a discharge test performed.

p. The IPP shall submit to the utility the station LAN design architecture for review during the conceptual design phase of the project.

q. The IPP is responsible for all hardware design, RTU drawings, installation, testing and commissioning.

r. The IPP shall prepare a preliminary but tested version of the RTU Configuration and a preliminary version of the Point Assignment, and send them to the YEC SCC, together with all RTU drawings, P&C drawings and DNP point lists of all LAN devices, at least ten weeks before the in service date.

s. The IPP and YEC SCC shall jointly test all control, status and analog points and confirm visibility at the SCC.

14.3. Disconnection Means Operability

Prior to the operation of the IPP facility, the disconnecting means provided in accordance with Section 8.3 operates as intended.

14.4. Energization Cessation

Tests shall be conducted in accordance with IEEE 1547.1 to verify the functionality of the protection that ensures the IPP facility does not energize the utility under the following conditions described within this standard:

1. Abnormal frequency
2. Abnormal voltage
3. Protection scheme failure

Additional protection functions shall also be verified in accordance with IEEE 1547.1 as needed. The following protective functions must be verified if used at the IPP facility:

1. If available, the anti-islanding function must be checked by operating a load break disconnect switch and verifying that the IPP facility ceases to energize the output terminals and does not restart once the load break disconnect switch has reclosed.
2. If reverse power or minimum power function is used to meet the interconnection requirements, the functionality must be tested using secondary injection techniques. Alternatively, this

function can be tested by the means of a local trip test or by adjusting the IPP output and local loads to verify that the applicable non-export criterion are met.

14.5. Re-Verification

Re-verification of the interconnection and interoperability requirements may be required when any of the following occurs:

- Functional software of firmware changes have been made to the IPP facility equipment;
- Any hardware component of the facility has been modified in the field, been replaced or repaired with parts that are not substitutive components compliant with the applicable standards;
- Protection settings have been changed after factory testing; or
- Protection functions have been adjusted after the initial commissioning / verification process.

15. Maintenance

The IPP has full responsibility for the maintenance of its equipment, up to the Point-of-Interconnection, consistent with the Interconnection Agreement and this Guide. The IPP shall maintain the facilities in accordance with Rule 2-300 of the Canadian Electrical Code to ensure safe parallel operation with the YEC or AEY system. Failure to do so may result in disconnection of the IPP generation facility.

The IPP must present to the utility the planned maintenance procedures and a maintenance schedule for the interconnection protection equipment, and keep records of such maintenance.

The utility reserves the right to periodically inspect the interconnection protection system to verify that it meets the requirements outlined in this document.

Maintenance procedures up to the POI will be performed in accordance with good utility practice and the utility's policies and procedures.

16. Marking and Tagging

The disconnect switch must be clearly marked as the "IPP Disconnect Switch" and tagged with an identification number approved by the utility. The IPP must follow the utility's switching, clearance and tagging procedures. The utility is responsible to instruct the IPP in this regard.

The IPP switchgear equipment must include the manufacturer name and the manufacturer's serial number.

17. Modification of Installation

The IPP shall obtain written approval from the utility before commencing any modification to the generation facility. If the change requires the installation or modification of equipment, the IPP shall provide documentation that the new equipment meets the requirements of Type and Production tests.

If the changes require modifications to the protection and controls information the IPP must obtain approval from the utility for the proposed modifications. Whenever changes are made to interconnection hardware or software that can affect the functions listed below, the potentially affected functions must be retested:

- Over-voltage and under-voltage
- Over-frequency and under-frequency
- Non-islanding function (if applicable)
- Reverse or minimum power function (if applicable)
- Inability to energize dead line
- Time delay restart after utility outage
- Fault detection, if used
- Synchronizing controls (if applicable)

To ensure that commissioning tests are performed correctly, the utility may require the ability to witness the tests and receive written certification of the results.

18. Technical Data Requirements

The following outlines the minimum data required at various stages for planning, design and commissioning the IPP's project. This data is required by YEC (and AEY if connected to AEY distribution system) to ensure suitable steps are taken to interconnect the IPP facility to the YEC system. Expanded data requirements for the proposal and design stages are located in Appendix A and Appendix B. The IPP Policy (in development as of June 2018) shall apply.

18.1. Proposal Stage

During the proposal stage the IPP Facility conceptual design must be submitted before any further detailed studies is approved by the utility. The list of information to be provided for this approval may be the result of preliminary discussions with the utility. Based on the information provided by the IPP, the utility will provide their proposition, their commitment and their own requirements concerning the connection of the IPP facility.

The following list of drawings and data required for the proposal stage of the project includes, but is not limited to:

- A Single Line Diagram (SLD)showing the following :
    - The proposed protection relays, circuit and fuses with fuse type and rating,
    - The connections of all substation equipment with voltage levels and equipment ratings
    - The location of the revenue metering equipment.
- Description of protection scheme
- Generating station site plan showing the layout and location (coordinates) of the generating plant and the location of lockable, "visible" disconnect device
- Based on the size of the project the utility may require more additional generator, exciter and speed governor data for a preliminary interconnection study.

18.2. Approval (Design) Stage

Once the project has been approved by the utility the IPP will proceed to submit the facility detailed design.

The following list of drawings and data required for approval stage of the project includes, but is not limited to:

- Single Line Diagram
- Description of protection scheme
- Control schematic
- Protection and control philosophy
- Major equipment nameplate schedules and statements
- Fuse and protective relay coordination study and settings
- Current transformer characteristic curve
- Measurement Canada approval numbers for instrument transformers

- Generating station site plan showing the layout and land location coordinates and legal description. The drawing should also show the proposed terminal pole or service manhole with the routing of aerial line or underground cables from utility to the generating station.
- SCADA Diagram
- Obtaining all permits and complying with all safety and environmental regulations, codes and assessment approvals, if necessary, for the construction and operation of its facilities.
- Proposed In-Service Date

18.3. Verified Stage

When the project is nearing completion, the IPP must submit the proposed testing, commissioning and start-up procedures to be performed before the facility is connected to the YIS.

The following list of drawings and data required for commissioning and verification stages of the project includes, but is not limited to:

- Commissioning report
- Copies of all permits, compliance reports and inspection documents
- Final Single Line Diagram
- Final protection scheme
- Final control schematic
- Protection and control philosophy
- Major equipment nameplate schedules, statements, test reports and data sheets
- Final fuse and protective relay coordination settings
- Current transformer characteristic curve
- Final generating station site plan showing the layout and land location coordinates and legal description

19. References

The technical guide was created using the following primary reference standards. Additional applicable standards are located within Appendix D.

[1] CSA Standard C22.3 No. 9-08 (R2015) – Interconnection of Distributed Resources and Electricity Supply Systems, CSA Group, 2015.

[2] IEEE 1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces, IEEE, 2018.

[3] Energy Strategy For Yukon Independent Power Production Policy, Yukon Energy, Mines and Resources, 2018

[4] Alberta Electrical Utility Code, latest Edition

[5] IEEE Std 519-2014 - IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems

[6] IEC 61000-4-15: Testing and Measurement Techniques – Flickermeter - Functional and Design Specifications

[7] CSA Standard CAN/CSA-C22.2 NO. 0-10 (R2015) - General requirements - Canadian electrical code, part II

[8] IEEE Std C57.13-2016 (Revision of IEEE Std C57.13-2008) - IEEE Standard Requirements for Instrument Transformers

[9] IEEE 1547.1-2005 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

Appendix A

Information Required from IPP (Proposal Stage)

Appendix A
Information Required from IPP (Proposal Stage)

Independent Power Producer Contact Information

Company Name	
Company Address	
Commercial Contact	
Commercial Contact Name	
Commercial Contact Phone	
Commercial Contact Email	
Commercial Contact Address	
Engineering Contact	
Engineering Contact Name	
Engineering Contact Phone	
Engineering Contact Email	
Engineering Contact Address	
Operating Contact	
Operating Contact Name	
Operating Contact Phone	
Operating Contact Email	
Operating Contact Address	

Project Overview

Land Location	
Legal Location Description	
Proposed In-Service Date	
General Description	

Generator Data

Generation Type (Synchronous, Induction, Inverter)	
Single Phase or Three Phase	
Prime Mover Type	
Number of Generators	
Generator Nominal kW Rating	
Generator Nominal kVA Rating	
Generator Nominal kV Rating	
Power Factor, at Rated Output	
Annual Energy Production (MW-hr)	
Production Capacity Range(MW)	

Transformer Data

Transformer Rating (ONAN/ONAF, kVA)	
Transformer Voltage Rating (kV)	
Load Tap Changer steps	
Winding Connection	
Positive Sequence Impedance (%, ONAN base)	
Zero Sequence Impedance (%, ONAN base)	

Prime Mover Data

Prime Mover Type	

Drawings

General Site Map, Including IPP Generation Facility	
Preliminary Substation Layout Drawings	
Preliminary Protection & Metering Single Line	

Company Authorization

Authorizing Personnel	
Authorization Signature	
Authorization Date	

Appendix B

Information Required from IPP (Design Stage)

Appendix B
Information Required from IPP (Design Stage)

Independent Power Producer Contact Information

Company Name	
Company Address	
Commercial Contact	
Commercial Contact Name	
Commercial Contact Phone	
Commercial Contact Email	
Commercial Contact Address	
Engineering Contact	
Engineering Contact Name	
Engineering Contact Phone	
Engineering Contact Email	
Engineering Contact Address	
Operating Contact	
Operating Contact Name	
Operating Contact Phone	
Operating Contact Email	
Operating Contact Address	

Project Overview

Land Location	
Legal Location Description	
Proposed In-Service Date	
General Description	

Generator Data

Generation Type (Synchronous, Induction, Inverter)	
Single Phase or Three Phase	
Number of Generators	
Manufacturer	
Model	
Nominal kW Rating	
Nominal KVA Rating	
Nominal kV Rating	
Power Factor at Rated Output	
Maximum Authorized Real Power (MARP)	
Leading and Lagging Reactive Power at MARP	
Generator Grounding (Resistive, Reactive, None)	
Individual Generator Parameters - impedances in per unit, on nominal machine base	
Speed (RPM)	
Inertia Constant, H (generator)	
Direct Axis Synchronous Reactance , X_D	
Direct Axis Transient Reactance , X'_D	
Direct Axis Subtransient Reactance , X''_D	
Quadrature Axis Synchronous Reactance , X_Q	
Quadrature Axis Transient Reactance , X'_Q	
Quadrature Axis Subtransient Reactance , X''_Q	
Open Circuit Direct Axis Transient Time Constant, T'_{DO}	

Short Circuit Direct Axis Transient Time Constant, T'_D	
Open Circuit Direct Axis Subtransient Time Constant, T''_{DO}	
Short Circuit Direct Axis Subtransient Time Constant, T''_D	
Quadrature Axis Transient Time Constant, T'_{QO}	
Quadrature Axis Subtransient Time Constant, T''_{QO}	
Saturation Factor (1.0 per unit flux)	
Saturation Factor (1.2 per unit flux)	
Armature Resistance, R_A	
Stator Leakage Reactance, X_L	
Negative Sequence Resistance, R_2	
Negative Sequence Reactance, X_2	
Zero Sequence Resistance, R_0	
Zero Sequence Reactance, X_0	
Armature Short Circuit Time Constant, T_A	
Governor Droop (%)	
Short-time unbalanced current factor (K)	
Continuous negative sequence current level (%).	
Induction Generator Data (if applicable) - impedances in per unit, on nominal machine base	
Rating (kVA)	
Rated Power Factor	
Speed (RPM)	
Inertia Constant, H (generator)	
Stator Resistance, R_S	
Stator Reactance, X_S	
Rotor Resistance, R_R	
Rotor Reactance, X_R	
Armature Magnetizing Reactance, X_M	
Other Attachments	
Reactive capability curve (D-curve) comes with	
a. Under excitation limiter	
b. Over excitation limiter	

Exciter nameplate	
VEE curves	
Single line diagram	

Power Factor Regulator

Reactive Power Limit - Lagging (out)	
Reactive Power Limit - Leading (in)	
Accuracy Tolerance (%)	

Voltage Regulator

Voltage Regulator Range (V)	
Accuracy Tolerance (%)	

Transformer Data

Transformer kVA Ratings	
Transformer kV Ratings	
Cooling Type (ONAN, ONAF)	
Winding Connection	
Transformer Grounding (Resistive, Reactive, None)	
Grounding Impedance in Ohms (if applicable)	
Positive Sequence Impedance (%, ONAN base)	
Zero Sequence Impedance (%, ONAN base)	
Tap Details (if applicable)	
On-Load Tap Range	
On-Load Tap Size	
Off-Load Tap Range	
Off-Load Tap Size	
Other Attachments	
Factory Test Reports (minimum requirements)	
No Load Loss & Exciting Current Measurements	
Measurement of Load Loss & Impedance Voltage and Zero Sequence Impedance Measurements	

Prime Mover Data

Prime Mover Type	
Prime Mover Rating	
Inertia Constant (prime mover)	
Manufacturer	
Model	
Other Attachments	
Elevation versus Output Curve	
Ambient Temperature versus Output Curve	

Drawings Required

General Site Map, Including IPP Generation Facility	
Complete and Accurate Protection Diagrams	

Single Line Diagrams	
AC / DC Schematics	
Wiring Diagrams	
Major Equipment Nameplates (Transformer, Generator, etc.)	

Protection Requirements

Proposed Protection Schemes Provided	
Verified Interconnection Functionality Provided	
Inertia Constant (prime mover) Provided	
Maintenance Plans for Protection Devices Provided	
Maintenance Plans for Interrupting Devices Provided	

Compliance with Electrical Inspector

Permit or Equivalent Compliance Provided (Yes / No)	

Metering Requirements

Element (2 Element, 3 Element)	
Metering Service Provider	
Metering Data Manager	
Asset ID Number	

Company Authorization

Authorizing Personnel	
Authorization Signature	
Authorization Date	

D.1 Modelling Information

In some cases, a generator (or the aggregate generation on a line) is large enough that adjacent customers or the dynamic stability of utility's distribution system could be affected. The IPP is responsible for the cost of any required transient or dynamic stability studies, and the studies must be done in a manner suitable to, and approved by, the utility.

IPPs are responsible for ensuring the data they submit provides an adequate mathematical representation of the facility's electric behavior. If the data is not available prior to purchasing equipment, it must be submitted as soon as it becomes available.

The studies must accurately determine:

1. The impact of the IPP's facility on adjacent customers of the utility.
2. The dynamic stability, in aggregate, of the utility system.

Data may be supplied by the manufacturer or acquired directly by testing. It must include generator characteristics (i.e., speed, reactance, resistance, excitation system etc.) and governor characteristics (i.e., lead time/lag time constants, valve or gate opening data etc.).

The information requirements vary for induction generators and inverter generators, and for hydro or thermal systems.

Appendix C

Information Provided by the Utility

Appendix C

Information Provided by the Utility

After receiving the application for interconnection, the utility will provide the following information to the IPP, if required:

a. Single Line Diagram or maps of the system up to the POI.
b. Minimum and maximum 60 Hz source impedances (positive-sequence, negative- sequence and zero-sequence) at the POI.
c. Maximum and minimum normal and emergency system operating voltage ranges at the POI.
d. Harmonic impedance envelope at the POI if available.
e. Planning, operating and reliability criteria, standards and policies.
f. The results of a planning study (e.g. the System Impact Study) documenting the availability of the requested amount of system capacity and any other specific technical issues to be addressed.
g. Cost estimates and time schedule to build the upstream facilities.
h. Characteristics and settings of protection on the distribution system.
i. Costs to implement any required changes to the distribution system that are identified by the System Impact Study.

Some or all of this information will be required by the IPP to properly design the interconnection protection. The utility will identify when the costs of producing this information are to be assigned to the IPP.

Appendix D

Applicable Codes and Standards

Appendix D
Applicable Codes and Standards

D.1 Primary Standards

CSA Standard C22.3 No. 9-08 (R2015) Interconnection of Distributed Resources and Electricity Supply Systems

IEEE Standard 1547-2018 Standard for Interconnecting Distributed Resources with Electric Power Systems with Associated Electric Power Systems Interfaces

Power Quality Standards

ANSI C84.1-2016 American National Standards for Electric Power Systems and Equipment Ratings (60 Hertz). Establishes nominal voltage ratings and operating tolerances for 60 Hz electric power systems from 100 V through 1200kV.

IEEE Std. 493-2007 IEEE Recommended Practice for Design of Reliable Industrial and Commercial Power Systems (IEEE Gold Book).

IEEE Std. 519-2014 IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.

IEEE Std. 1100-2005 IEEE Recommended Practice for Powering and Grounding Sensitive Electronic Equipment (IEEE Emerald Book).

IEEE Std. 1159-2009 IEEE Recommended Practice for Monitoring Electric Power Quality.

IEEE Std. 1250-2011 IEEE Guide for Identifying and Improving Voltage Quality in Power Systems.

In addition to the power quality standards, the following standards are applicable to the interconnection of generation facilities to YEC's system:

IEEE Std. 100 - 2000 IEEE Standard Dictionary of Electrical and Electronics Terms.

IEEE Std 315-1975 (Reaffirmed 1993) ANSI Y32.3-1975 (R1989) CSA Z99-1975 Graphic Symbols for Electrical and Electronics Diagrams (including Reference Designation Letters).

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic (PV) Systems.

C37.1-2007 ANSI/IEEE Standard Definitions, Specifications and Analysis of Systems Used for Supervisory Control, Data Acquisition and Automatic Control.

C37.2-2008 IEEE Standard Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.

C37.18-1979 ANSI/IEEE Standard Enclosed Field Discharge Circuit Breakers for Rotating Electric Machinery.

C37.20.1-2015 ANSI/IEEE Standard for Metal-Enclosed Low-Voltage (1000 Vac and below, 3200 Vdc and below) Power Circuit Breakers Switchgear.

C37.20.3-2001 ANSI/IEEE Standard for Metal-Enclosed Interrupter Switchgear.

C37.24-2017 ANSI/IEEE Standard for Evaluating the Effect of Solar Radiation on Outdoor Metal-Enclosed Switchgear.

C37.27-2015 ANSI/IEEE Standard Application Guide for Low-Voltage AC (635 V and below) Power Circuit Breakers with Separately Mounted Current-Limiting Fuses.

C37.29-1981 ANSI/IEEE Standard for Low-Voltage AC Power Circuit Protectors Used in Enclosures.

C37.50-1989 ANSI Standard Test Procedures for Low-Voltage AC Circuit Breakers Use In Enclosures.

C37.51-1989 ANSI Standard Conformance Test Procedure for Metal Enclosed Low- Voltage AC Power Circuit-Breaker Switchgear Assemblies.

C.52-1974 ANSI Standard Test Procedures for Low-Voltage AC Power Circuit Protectors Used in Enclosures.

C57.12-2015 IEEE Standard General Requirements for Liquid Immersed Distribution, Power and Regulating Transformers.

C57.12.13-1982 Conformance Requirements for Liquid Filled Transformers Used in Unit Installations including Unit Substations.

C57.13.1-2006 IEEE Guide for Field Testing of Relaying Current Transformers.

C57.13.2-2005 IEEE Standard Conformance Test Procedures for Instrument Transformers.

C37.58-2003 (R2010) ANSI Standard Conformance Test Procedures for Indoor AC Medium- Voltage Switches for Use in Metal-Enclosed Switchgear.

C37.90-2005 ANSI/IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.

C37.90.1-2002 ANSI/IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems.

C37.90.2-2004 ANSI/IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers.

C37.95-2014 IEEE Guide for Protective Relaying of Utility Consumer Interconnections.

C37.98-2013 ANSI/IEEE Standard for Seismic Testing of Relays.

IEC 1000-3-3 Limitation of Voltage Fluctuations and Flicker in Low-Voltage Supply Systems for Equipment with Rated Current Less than 16A.

IEC1000-3-5 Limitation of Voltage Fluctuations and Flicker in Low-Voltage Supply Systems for Equipment with Rated Current Greater than 16A.

UL1008 Transfer Switch Equipment.

UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources

IEEE P1547, DRAFT Standard for Distributed Resources Interconnected with Electric Power Systems. Canadian Electrical Code, CSA no. C22-1, latest version.C22.2 No. 31- M89 (R2000) Switchgear Assemblies.

Can/CSA - C22.2 No. 1071 95Commercial and Industrial Power Supplies.

Can/CSA - C22.2 No. 1010.1-92 Safety Requirements For Electrical Equipment for Measurement, Control and Laboratory Use.

Can/CSA - C22.2 No. 144-M91 (R2015) Ground Fault Circuit Interrupters.

C22.2 No. 193-M1983 (R2014) High-Voltage Full-Load Interrupter Switches.

C22.2 No. 201-M1984 (R2014) Metal Enclosed High-Voltage Busways.

C22.2 No. 229-M1988 (R2014) Switching and Metering Centres.

CSA Standard CAN3 C235 83 Preferred Voltage Levels for AC Systems 0 to 50,000V.

Alberta Electrical and Communication Utility Code (formerly the Alberta Electrical and Communication Utility System Regulation 44/1976 or future amendments).

Measurement System Standard / Transmission Administrator Metering Standard GC301 Practices for Management and Transfer of Metered Data.

C37.04-1999 IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI/DoD).

C37.06-2000 American National Standard for Switchgear--AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis--Preferred Ratings and Related Required Capabilities.

C37.09-1999 IEEE Standard Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI/DoD).

C37.010- IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.011-2011 IEEE Application Guide for Transient Recovery Voltage for AC High- Voltage Circuit Breakers.

C37.012-2014 IEEE Application Guide for Capacitance Current Switching for AC High-Voltage Circuit Breakers Above 1000 V.

C37.013-1997 IEEE Standard for AC High-Voltage Generator Circuit Breaker Rated on a Symmetrical Current Basis.

C37.015-2017 IEEE Application Guide for Shunt Reactor Switching.

C37.081-1981 (R1988) Guide for Synthetic Fault Testing of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.081a-1997 Supplement to IEEE Guide for Synthetic Fault Testing of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.11-2014 IEEE Standard Requirements for Electrical Control for Electrical Control for AC High-Voltage (>1000 V) Circuit Breakers.

C37.13-2008 IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures.

C37.14-2015 IEEE Standard for DC (3200 V and below) Power Circuit Breakers Used in Enclosures.

C37.16-2009 IEEE Standard for Preferred Ratings, Related Requirements, and Application Recommendations for Low-Voltage AC (635 V and below) and DC (3200 V and below) Power Circuit Breakers.

C37.20.2-2015 IEEE Standard for Metal-Clad and Station-Type Cubicle Switchgear.

C37.23-2015 IEEE Standard for Metal-Enclosed Bus.

C37.30-1997 IEEE Standard Requirements for High-Voltage Switches.

C37.32-2002 American National Standard for Switchgear--High-Voltage Air Switches, Bus Supports, and Switch Accessories--Schedules of Preferred Ratings, Manufacturing Specifications, and Application Guide.

C37.34-1994 IEEE Standard Test Code for High-Voltage Air Switches.

C37.35-1995 IEEE Guide for the Application, Installation, Operation, and Maintenance of High-Voltage Air Disconnecting and Load Interrupter Switches.

C37.36b-1990 IEEE Guide to Current Interruption with Horn-Gap Air Switches.

C37.37-1996 IEEE Standard for Loading Guide for AC High-Voltage Air Switches (in Excess of 1000 V).

C37.38-1989 IEEE Standard for Gas-Insulated, Metal-Enclosed Disconnecting, Interrupter, and Grounding Switches.

C37.42-2016 IEEE Standard Specifications for High-Voltage (>1000 V) fuses and Accessories.

C37.44-1981 (R1992) American National Standard Specifications for Distribution Oil Cutouts and Fuse Links.

C37.54-1996 American National Standard for Switchgear--Indoor Alternating-Current High-Voltage Circuit Breakers Applied as Removable Elements in Metal-Enclosed Switchgear Assemblies--Conformance Test Procedures.

C37.55-2002 American National Standard for Switchgear--Metal-Clad Switchgear Assemblies--Conformance Test Procedures.

C37.57-2003 (R2010) American National for Switchgear--Metal-Enclosed Interrupter Switchgear Assemblies-Conformance Testing.

C37.66-2005 American National Standard for Requirements for Oil- Filled Capacitor Switches for AC Systems (1 kV to 38 kV).

C37.81-2017 IEEE Guide for Seismic Qualification of Class 1E Metal- Enclosed Power Switchgear Assemblies.

C37.85-1989 (R1998) American National Standard for Switchgear--Alternating- Current High-Voltage Power Vacuum Interrupters-Safety Requirements for X- Radiation Limits.

ANSI/IEEE C37.90.1-2102 Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus.

120-1989 (Reaff-1997) IEEE Master Test Guide for Electrical Measurements in Power Circuits.

1291-1993 IEEE Guide for Partial Discharge Measurement in Power Switchgear.

IEEE Std C62.23-2017 Application Guide for Surge Protection of Electric Generating Plants.

ANSI /IEEE C62.41-1991 Recommended Practices on Surge Voltages in Low- Voltage AC Power Circuits.

C57.13-2016 IEEE Standard Requirements for Instrument Transformers.

C57.13.3-2014 IEEE Guide for the Grounding of Instrument Transformer Secondary Circuits and Cases.

C57.98-2011 IEEE Guide for Transformer Impulse Tests.

C57.19.100-2012 IEEE Guide for Application of Power Apparatus Bushings.

C57.110-2008 IEEE Recommended Practice for Establishing Liquid-Filled and Dry-Type Power and Distribution Transformer Capability When Supplying Non-sinusoidal Load Currents.

C62.92.4-2014 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part IV – Distribution.

IEEE Std. 242-2001 Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems.

ANSI C12.20-2010 Electricity Meters 0.2 And 0.5 Accuracy Classes.

ANSI C62.1-1981 Surge Arresters for AC Power Circuits.

ANSI C62.11-2012 Metal-Oxide Surge Arresters for AC Power Circuits (>1 kV).

NEMA CC 1-2009 Electric Power Connectors for Substations.

NEMA LA 1-2009 Surge Arresters.

NEMA MG 1-2016 Motors and Generators

Appendix E

Sample Operating Agreement

Appendix E
Sample Operating Agreement

1. Purpose

This agreement outlines the steps to take to ensure a reliable and safe interconnection between the IPP and YEC and/or AEY through a variety of circumstances.

2. Definitions

Operating Authority: The organizational unit assigned responsibility for operating a portion of the electrical system. For each utility the YEC System Control Center (SCC) operator is the operating authority. For the IPP, the *<IPP Contact>* is the operating authority.

Operational Boundary/Interface Point or Point of Interconnection: The location on the electrical system at which responsibilities between Operating Authorities meet. The breaker *<Breaker ID>* is the interface point between the IPP and the utility.

3. Operational Information

Circuit Breaker Identification

List circuit breakers providing interconnection between IPP and the utility.

3.1 Interlocks

List identified circuit breaker interlocks with sequence information

3.2 Contact Information

SCC – Phone (867) *XXX-XXXX* or (867) *XXX-XXXX* (recorded lines)

Contact Name	Title	Phone Number
<Utility Contact>	Leadhand SCC	(867) *XXX-XXXX*
<Utility Contact>	Operation Coordinator	(867) *XXX-XXXX*
<Utility Contact>	Manager Operations	(867) *XXX-XXXX*
<Utility Contact>	Director of Operations	(867) *XXX-XXXX*
<IPP Contact>	<Contact Position>	(867) *XXX-XXXX*

3.3 Normal Operation

Under normal operating conditions the IPP facility will be connected to the utility grid. The breakers status under normal operating conditions is as follows.

Breaker	**Status**
<Breaker ID>	*Open/Closed*
<Breaker ID>	*Open/Closed*
<Breaker ID>	*Open/Closed*
<Breaker ID>	*Open/Closed*

4. Operating Procedures

4.1. Line L### (<Utility Line> to <IPP Facility>) Isolation

L### isolation requires the minimum notification defined in section 4.3, with the exception of emergency repairs. The utility will provide a Condition Guarantee on breaker <Breaker ID>. The Condition Guarantee is used in communications between external parties. It is a formal method of communication that switching has been completed. It ensures the status of the breaker/device will not change until the work is complete, the lock out tag out is surrendered and all workers are clear.

4.2. Voltage Support

Based on the power quality conditions defined in Schedule *<X>* of the Power Purchase Agreement (PPA) and system security requirements, SCC may request voltage support. Voltage support can be accomplished by placing IPP generation on line, or other means such as capacitor banks or transformer tap changing. If such support is part of the operating agreement then:

- When the IPP has generation online, the generators regulate the generator bus voltage between 100 and 105% of nominal and the utility shall have control of this set-point. Generators reactive output will be adjusted by the utility in real time, to regulate the system voltage, by pulsing the AVR voltage set-points. The IPP sets the acceptable range within which the utility can adjust voltage.
- The utility must have full SCADA visibility of the IPP substation and control of critical elements.

4.3. SCC Remote Monitoring and Control

- SCC will have visual indication of the IPP breakers, generator status, capacitor status and electrical measurement information for the IPP facility.
- The utility control will be limited to:
    - Approving requests from the IPP to connect and disconnect from the utility system
    - Approving requests from the IPP for changes in generation output
    - Requesting the IPP to disconnect from the utility system for operational and safety reasons
- All IPP requests must be communicated and approved by the utility
- The utility shall have control (open and close) of incoming line breaker *<Breaker ID>* at the IPP facility.

5. Operational Notification

5.1. Daily Operating Communications

Under normal operating conditions IPP will be supplying *<XXX>* kW to the YIS. Generation changes of more than *<XXX>* kW must be communicated and approved by the utility.

5.2. The transition from winter to summer and conversely summer to winter generation levels must be established with SCC with a minimum of 30 days' notice.

5.3. IPP Facility Planned Maintenance and Scheduling

The IPP shall operate under the utility approved maintenance procedures established.

To meet changing operating conditions and coordinate maintenance efforts, maintenance shutdowns by the IPP need to be communicated to SCC at least one week in advance for shutdowns of up to 12 hours and 30 days for shutdowns longer than 12 hours. Changes in the availability and capacity of the onsite generation need to be communicated to SCC. The utility and the IPP shall share annual shutdown/maintenance plans in February of each year.

5.4. Transmission and Distribution Maintenance and Scheduling

The utility performs annual line maintenance on its transmission and distribution lines, during which grid power to the IPP facility may be curtailed or suspended. The duration of this annual maintenance can be up to 14 days per calendar year.

The utility will provide a minimum of 30 days' notice of the start date and expected duration of work that will curtain or otherwise interrupt the supply of grid power to the IPP facility.

6. Loss of Supply Procedures

6.1. Loss of Supply - Short Term

In the event of a disturbance that results in the loss of grid power to the IPP facility, SCC will make one attempt to re-energize the line to the IPP facility. If successful the following steps apply to resume the IPP facility operation with grid power.

a) SCC will confirm the status of the breakers located at the IPP's POI.

b) SCC will request closed breaker <Breaker ID>.

c) Once complete and with confirmation from SCC the IPP facility may proceed with the restarting of their operation. The IPP will communicate to SCC on generation greater than <XXX> kW. The request to increase generation may be communicated verbally or via SCADA.

6.2. Loss of Supply - Long Term

In the event of a disturbance that results in the loss of grid power to the IPP facility and SCC is unsuccessful in re-energizing the line the following steps will apply.

a) SCC will confirm the status of the breakers.

b) At the direction of SCC the IPP personnel will start and stage their generation on line supplying power to the IPP facility.

c) Once the line to the IPP facility has been re-energized, SCC will request the IPP synchronize and close its POI breaker.

d) The IPP facility is now connected to YEC system. Once complete and with confirmation from SCC the IPP facility may proceed with resuming generation. The IPP will communicate to SCC on generation increases greater than *<XXX>* kW. The request to load up may be communicated verbally or via SCADA.

7. Revision and Approval

7.1. This Agreement comes into effect once it is signed by the IPP and the utility.

7.2. This Agreement will remain in effect unless cancelled upon the mutual agreement of both Parties.

7.3. The Parties shall provide 90 days' notice in writing of the intention to modify the Agreement.

7.4. The Agreement may be revised upon mutual agreement of both Parties. The agreement will be formally reviewed every two (2) years.

Approved by: _____
Yukon Energy Corporation

Approval Date: _____

Approved by: _____
ATCO Electrical Yukon

Approval Date: _____

Approved by: _____
IPP

Approval Date: _____

Appendix F

Typical Interconnection Single Line Diagrams

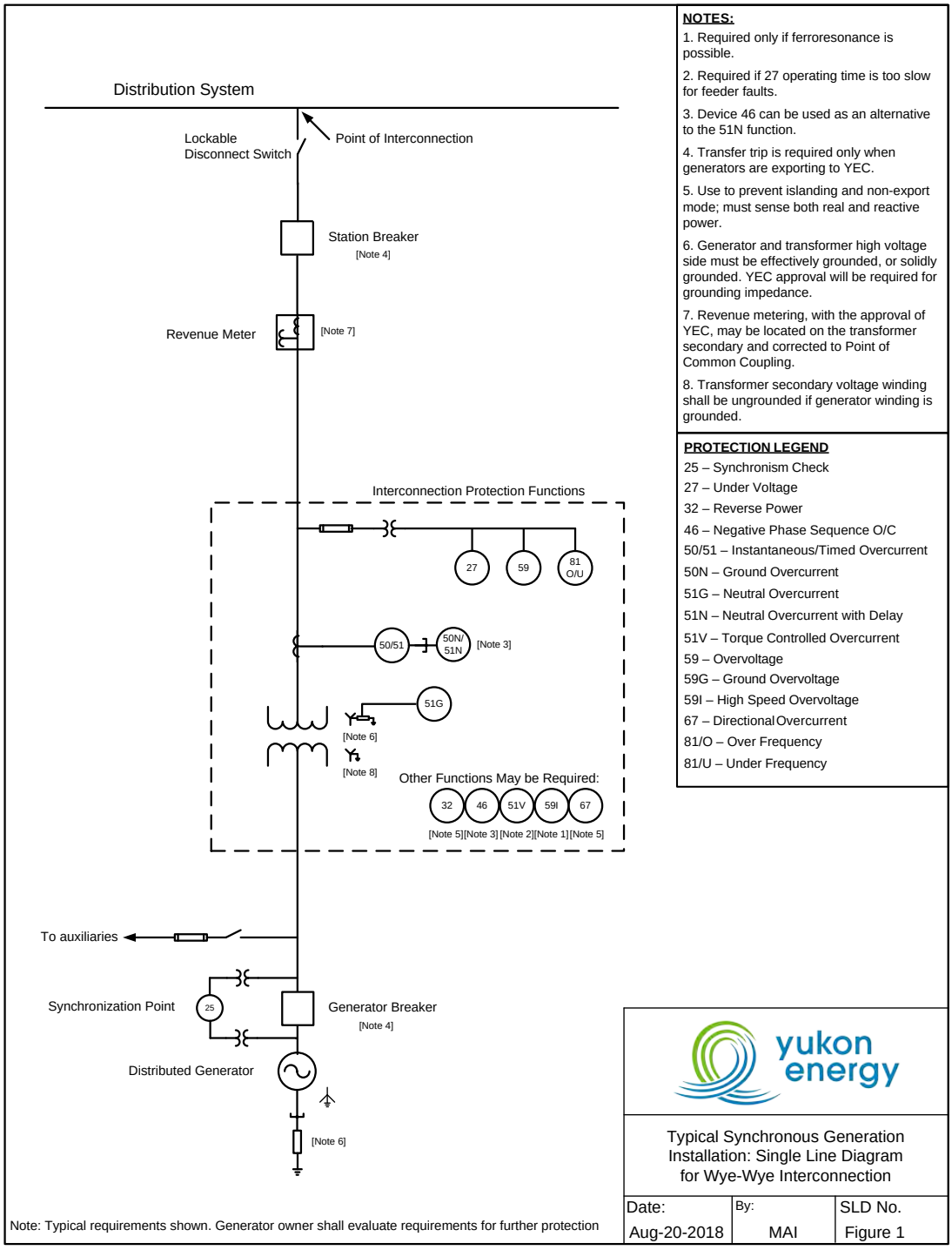


Figure F- 1: Single Line Diagram for Wye-Wye Interconnection

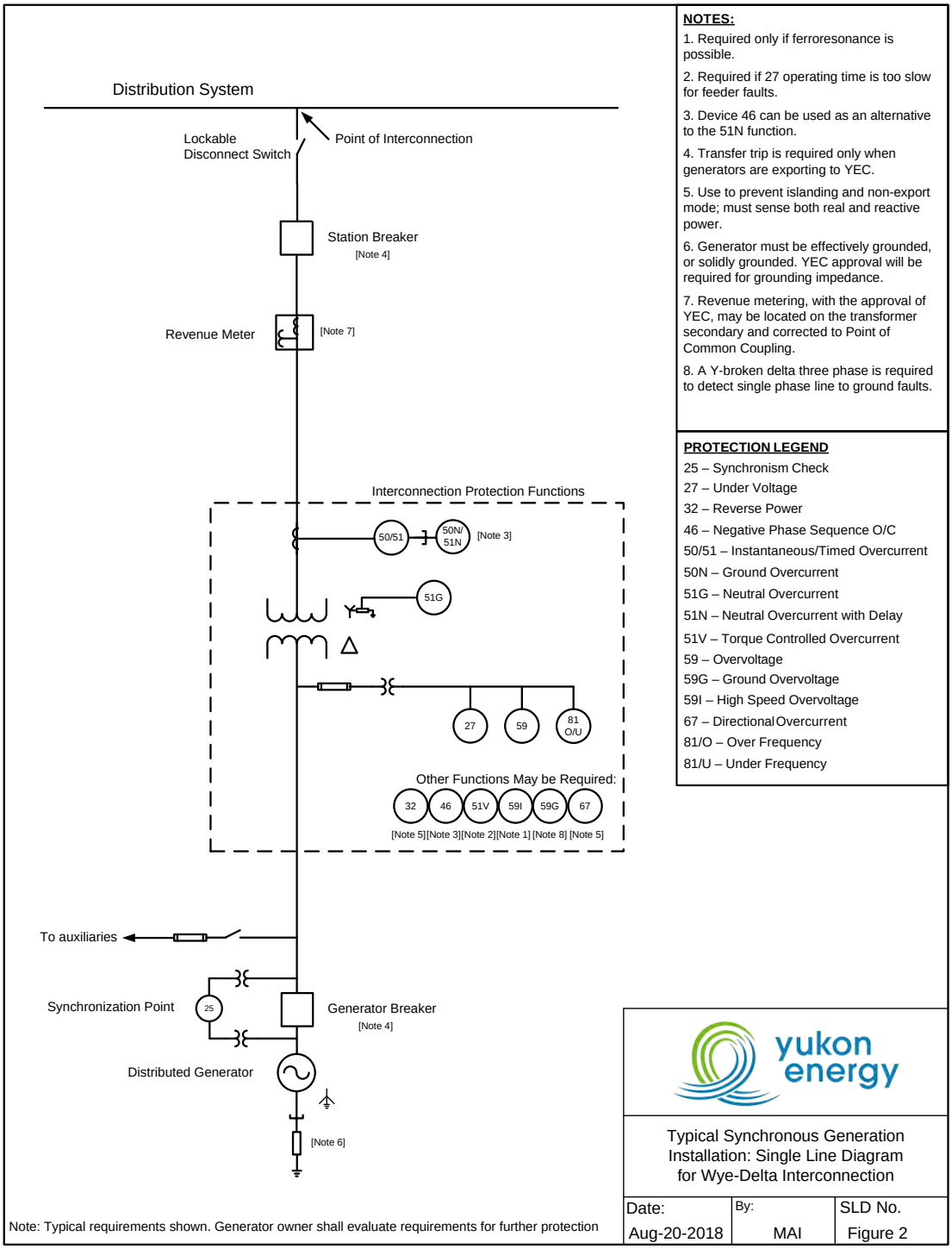


Figure F- 2: Single Line Diagram for Wye-Delta Interconnection

Appendix G

Protective Settings Commissioning Document

Appendix G
Protective Settings Commissioning Document

Over Voltage Protection Parameters

	PHASE VOLTAGE TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	106% - 120% 1% Increments						30 Cycles					
Fast Trip	144% - 120% 1% Increments						100 ms					

Under Voltage Protection Parameters

	PHASE VOLTAGE TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	50% - 90% 1% Increments						120 Cycles					
Fast Trip	Less than 50% 1% Increments						100 ms					

Non-Islanding Function Test

Loss of Utility Voltage	100 ms	
Generator Restart Delay	5 min Minimum	
Dead Bus Test	Fail to Start Successful (Yes/ No)	

Over Frequency Protection Parameters

	FREQUENCY TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	60.5 Hz - 61.5 Hz 1% Increments						3 minutes					
Fast Trip	61.5 Hz - 61.7 Hz 1% Increments						30 seconds					

Under Frequency Protection Parameters

	FREQUENCY TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	59.5 Hz - 58.5 Hz 1% Increments						3 minutes					
Second Trip	58.5 Hz - 57.9 Hz 1% Increments						30 seconds					
Third Trip	57.9 Hz - 57.4 Hz 1% Increments						7.5 seconds					
Fourth Trip	57.4 Hz - 56.9 Hz 1% Increments						45 cycles					
Fifth Trip	56.9 Hz - 56.5 Hz 1% Increments						7.2 cycles					
Fast Trip	Less than 56.4 Hz 1% Increments						100 ms					

Reverse AC Current Protection Function

	CURRENT TO TRIP						DURATION TO TRIP					
	DESIGN VALUE	ADJUSTABLE RANGE	AS SET	TESTED			DESIGN VALUE	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip												

Syncronization Limits for Synchronous Generators

	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET
Frequency Difference	+ 0.2 Hz		
Voltage Difference	5%		
Phase Difference	10° (degrees)		

Phase and Ground Fault Protection

	MAXIMUM CURRENT OR VOLTS TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Phase Current							200 ms					
Neutral Current							200 ms					

Transfer Trip Protection

	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET
Generator Lockout	0.6 seconds		
Fail Safe Lockout	6 seconds		

Test Certification and Historical Data

Type Of Test	**Original Commissioning Test**		**Protection System Re-Test**	

Date of Test

Utility Representative Title

IPP Owner Representative

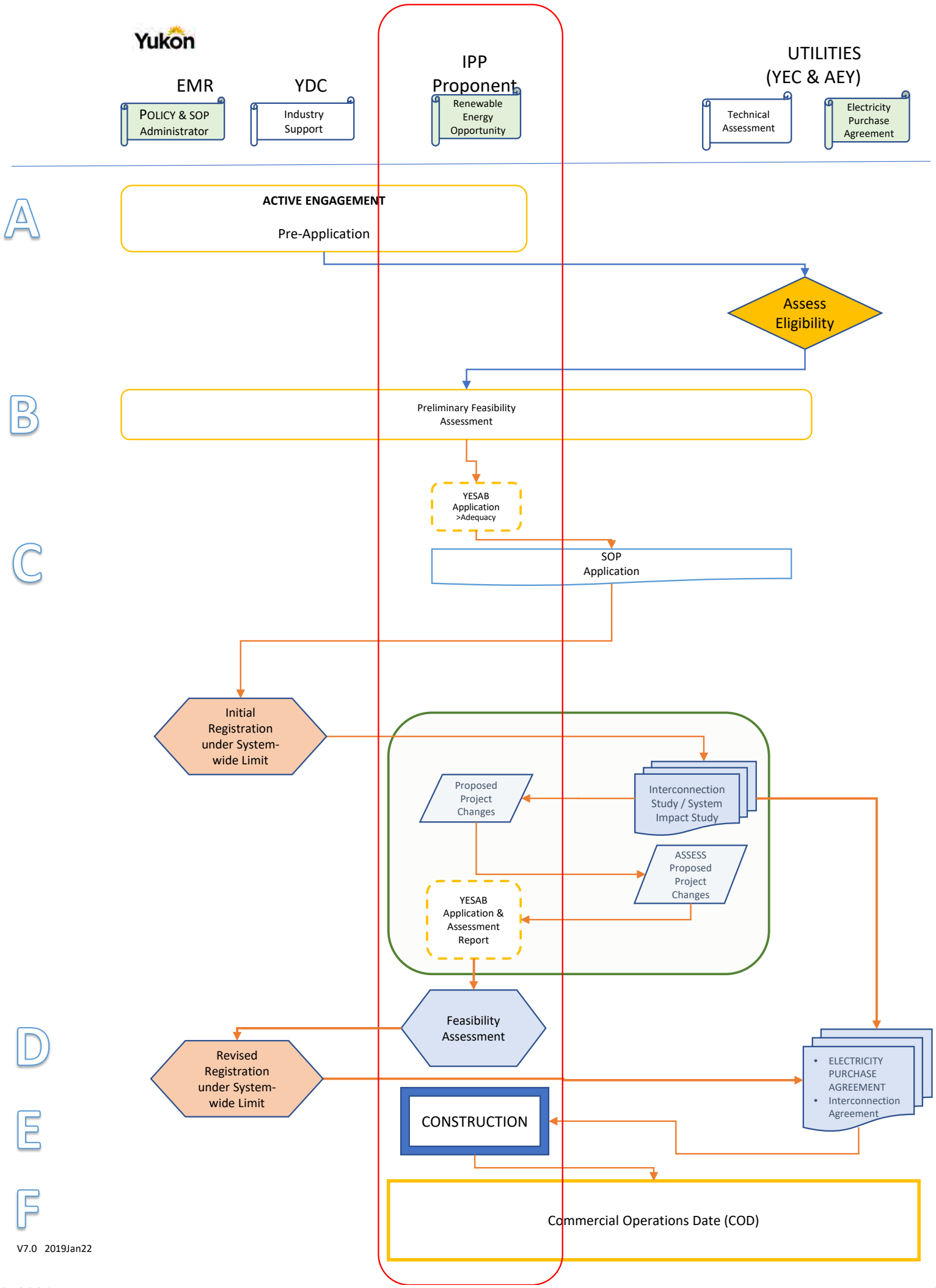
Signature

IPP Owner Representative Title

Date

Signature

IPP Standing Offer Program – **APPLICATION PROCESS**



V7.0 2019Jan22

STANDING OFFER PROGRAM

Program Rules

Version 3.2
April 2016

BC Hydro
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Standing Offer Program
Rules

April 2016

For more information, please contact:

Standing Offer Program
Business and Economic Development
BC Hydro
17th Floor – 333 Dunsmuir Street
Vancouver, BC V6B 5R3
standing.offer@bchydro.com

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Standing Offer Program Rules

1. Introduction

BC Hydro's Standing Offer Program ("SOP") encourages the development of new small and clean or renewable energy Projects by multiple developers throughout British Columbia. The SOP was developed to streamline the process for selling electricity to BC Hydro for Projects that will be connected to BC Hydro's Distribution System, and to simplify the contract, called the Standard Form Electricity Purchase Agreement ("Standard Form EPA"), between BC Hydro and the Developer. The SOP is also intended to decrease transaction costs for Developers while remaining cost-effective for ratepayers, and embodies the principles and policies set out in the BC Energy Plan and the *Clean Energy Act*. BC Hydro intends for the SOP to provide Project development opportunities to a broad range of experienced and new Developers alike.

The SOP Rules ("the Rules") explain the SOP eligibility requirements, the payment price offered by BC Hydro for energy delivered under the SOP, and the Application process. Additional information about the SOP, including Frequently Asked Questions ("FAQs") on a number of topics and how the SOP was developed, can be found at www.bchydro.com/standingoffer.

2. Eligibility Requirements

To be eligible for the SOP, the Developer and the Project must meet both the key eligibility requirements and the standard eligibility requirements outlined below. If an Application is submitted without meeting the key eligibility requirements, it will be rejected immediately. The Developer must also meet the standard eligibility requirements before the Application Review process is completed in order to be offered an EPA for the Project.

KEY ELIGIBILITY REQUIREMENTS

2.1 Generation Technology

- The generation technologies meets the requirements to be considered either Commercial Operation Generation Technology or Completed Prototype Generation Technology; and

- The generators are new. Projects with existing generation are not eligible to apply under the SOP. At sites where there is existing generation, only incremental generation from one or more additional new generating units is eligible to apply under the SOP, provided the new generation is measured, or is capable of being measured, separately from existing generation.

2.2 Eligible Energy

Energy delivered to BC Hydro under the EPA must be Clean Energy generated from a Clean or Renewable Resource.

Energy that does not qualify as Clean Energy due to the use of some Auxiliary Fuel for Start-up or for other limited operational requirements may be eligible for the SOP at BC

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Hydro's discretion. When BC Hydro exercises its discretion to allow a Project that uses Auxiliary Fuel to participate in the SOP, the use of Auxiliary Fuel in each calendar year must not exceed the Auxiliary Fuel Annual Baseline.

2.3 Location

- Projects must be located in British Columbia, which includes Canadian and British Columbia territorial waters; and
- Projects must not be located in a Protected Area.

2.4 Project Size

The generators must have a combined total Nameplate Capacity over 100 kW up to and including15 MW. Where a Project is part of a Project Cluster or Common Generation Facility, the aggregate nameplate capacity of all generators in the Project Cluster or Common Generation Facility must not exceed 15 MW. This rule supports the objective of creating opportunities for many developers in the SOP.

If the Project is expected to be connected to the Distribution System in an area where BC Hydro has system constraints, BC Hydro Generator Interconnections may require that the Project has a Maximum Power Injection that is less than 15 MW. In that case, BC Hydro will not accept an Application with a Nameplate Capacity that is greater than the maximum permitted by BC Hydro's Generator Interconnections for the Project.

BC Hydro may request any additional information it requires to assess the reasonableness of Project's Nameplate Capacity or expected generation specified in the Application, including verification by a qualified B.C. registered professional engineer.

2.5 BC Hydro Incentives

A Project is not eligible for the SOP if the Project has received funding or has a reasonable expectation of receiving funding from BC Hydro through a Load Displacement or Demand Side Management program. Projects that have been subject to BC Hydro funding other than through a Load Displacement or Demand Side Management program may be eligible for the SOP at the discretion of BC Hydro.

2.6 Permits, Site Control and Zoning

The Application Form identifies the permits, site control and evidence of zoning that are key or standard eligibility requirements that must be satisfied by the Project.

2.6.1 Permits – The Developer must have obtained the permits specified in the Application Form to the extent required for the Project under applicable laws.

Where the Project consists of a Completed Prototype Generation Technology, BC Hydro reserves the discretion to identify the permits that are required prior to an offer of an EPA following a review of the Project.

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2.6.2 **Site Control** – The Developer must demonstrate that it has obtained the right to use the site for the Project (including, unless otherwise acceptable to BC Hydro in its discretion, all areas where the generating facility and related access roads, transmission lines and other Project facilities will be built) for a period generally consistent with the Term of the EPA or a shorter period if acceptable to BC Hydro in its discretion.

2.6.3 **Zoning –** If local government land use requirements apply to all or any part of the Project site (including all areas where the generating facility and related access roads, transmission lines and other Project facilities will be built), that part of the Project site must be appropriately zoned for the applicable Project use. Please refer to section 121 of the *Utilities Commission Act* and the Public Utility Regulation.

Where the Project forms part of a Common Generation Facility, BC Hydro may require the Developer to provide evidence that the permits, site control and zoning requirements are satisfied for the entire Common Generation Facility.

2.7 Public Utility Status

If a Developer is a "public utility" for purposes of the *Utilities Commission Act* it must have an exemption from regulation as a public utility under Part 3 of the *Utilities Commission Act* with respect to the sale of energy to BC Hydro under the EPA (e.g., Minister's Order No. M-22-0205). A Developer that is otherwise a public utility, such as one actively serving customers, is not eligible to apply under the SOP.

2.8 Customers of Public Utilities Other than BC Hydro

Customers taking electrical service from a public utility other than BC Hydro are not eligible to apply under the SOP, with the exception of customers that take only back-up or start-up electricity service from that public utility.

2.9 Target Commercial Operation Date

The Target Commercial Operation Date ("Target COD") submitted by the Developer in the Application must be:

a) a reasonable estimate of the date on which the Project is expected to achieve COD with considerations for the SOP application review process, interconnection study and any implications there may be on the Project maintaining its generator interconnection queue position as per the Open Access Transmission Tariff or established Distribution Generator Interconnection practices.

b) in a year where there is sufficient room available for the Project's annual energy volume in BC Hydro's Energy Volume Target at the time of application; and

c) within three years, but not earlier than six months, after signing the EPA [please note that BC Hydro's interconnection agreements require COD to occur within three years of execution].

Developers are expected to review the SOP Website for available annual energy volumes and use this information to select their Projects' Target COD year. BC Hydro does not represent or warrant that the available volume posted on the SOP Website will be or remain available at the time developers submit an Application. Developers are encouraged to contact BC Hydro prior to submitting an Application to verify the energy volume expected to be available in their Target COD year.

The Target COD selected by a Developer for a Project will be eligible for registration in the corresponding COD year after BC Hydro has determined, in its discretion, that the Developer and Project have met the key eligibility criteria as described in section 2 of these Rules. Target CODs will be registered on a first-come, first-served basis.

BC Hydro may request any additional information it requires to assess the reasonableness of the Project's Target COD or the Project's estimated energy specified in the Application. If BC Hydro determines, in its discretion, that the Target COD is not achievable, BC Hydro may reject the Application.

If the Developer's selected Target COD year has insufficient room in the Energy Volume Target to allow for the Project's annual energy, BC Hydro will give the Developer the opportunity to postpone their Target COD to the next COD year with sufficient available energy volume. If the Developer declines to postpone their Target COD, BC Hydro may reject the Application.

BC Hydro may, at its discretion, allow a Project to exceed the available energy volume in its Target COD year. In determining whether to allow a Project to exceed the available energy volume in the Target COD year, BC Hydro may consider:

- the extent to which all or part of the Project's energy exceeds the available energy volume in the Target COD year;
- if a majority of the Project's energy is available in its Target COD year;
- if BC Hydro's available energy volume is already expected to be exceeded by other projects registered in the Target COD year;
- if the available energy volume was exceeded in the year before the Target COD year; and
- if there is available energy volume in the year following the Project's Target COD year to apply any excess energy to.

STANDARD ELIGIBILITY REQUIREMENTS

2.10 Projects Behind a BC Hydro Customer Load

Projects located Behind a BC Hydro Customer Load are eligible to apply under the SOP; however, BC Hydro will only purchase energy on a Net-of-Load basis.

2.11 Previous, Current and Future EPAs with BC Hydro

If BC Hydro signed an EPA with respect to a Project, that Project is eligible for SOP, provided that (i) the Project did not achieve commercial operation while the original EPA was in effect, and (ii) the original EPA has been terminated in accordance with its terms and all other post-termination conditions and restrictions in that EPA have been satisfied.

BC Hydro may determine in its discretion whether or not a Project submitted to the SOP constitutes the same project as a project for which an EPA was previously signed with BC Hydro. Factors BC Hydro may consider include, but are not limited to, the location, permits, licenses and site tenure, and the Developer (including ownership structure) of the Project submitted to the SOP, relative to the prior project.

If a Project is part of a Common Generation Facility or a Project Cluster, and BC Hydro has entered into an EPA(s) for generation from that Common Generation Facility or from any project in that Project Cluster, the Project is eligible for the SOP provided the aggregate nameplate capacity of all generators in the Project Cluster or Common Generation Facility does not exceed 15 MW and the Project otherwise meets the eligibility requirements. If BC Hydro accepts an Application from a Project that is part of a Common Generation Facility or Project Cluster, any EPA will contain provisions to address delivery limitations and priorities.

If the existing generation in a Common Generation Facility or Project Cluster is the subject of a BC Hydro SOP EPA, BC Hydro will determine, in its discretion, if the new, incremental generation will be offered a separate EPA or whether the pre-existing EPA will be amended to include the new generation.

2.12 Environmental Attributes

All Environmental Attributes for the energy delivered to BC Hydro under the EPA must be transferred to BC Hydro. The value of the Environmental Attributes is included in the price paid for energy delivered under the SOP and is not paid separately to the Developer. For Projects where Greenhouse Gas ("GHG") emissions can be reduced in the process of methane capture and combustion, such as biogas, landfill gas control systems, and other similar projects, the term "Environmental Attributes" excludes any rights associated with GHG reductions arising from the methane capture and combustion process for those projects. Those credits will be retained by the Developer. For biomass Projects, the term "Environmental Attributes" excludes rights derived from the harvest, collection or delivery of fuel to the Project. Those rights will be retained by the Developer.

2.13 EPAs with Third Parties

A Project is not eligible for the SOP if there are any agreements with a third party or parties for the purchase and sale of electricity from any generator in the Project or, from any generator in the Common Generating Facility or Project Cluster if the Project is part of a Common Generating Facility or Project Cluster. Any such third party agreements must be terminated prior to submitting an Application for the SOP.

2.14 Conflicts of Interest

The Developer must not be in or have the potential to be in an actual, apparent or deemed conflict of interest as a result of entering into an EPA with BC Hydro. The Developer must inform BC Hydro, by completing and submitting a Conflict of Interest Statement form, of any disclosures required under BC Hydro's Contractor Standards for Ethical Conduct and any potential conflicts of interest it may have with BC Hydro or BC Hydro's directors, officers or employees. The Conflict of Interest Statement form and BC Hydro's Contractor Standards for Ethical Conduct can be found on the Documents page of the SOP Website at www.bchydro.com/standingoffer.

If the Developer has any directors, officers, owners (with 20 per cent or more direct or indirect ownership in the Developer or its affiliates), or Project team members who have been employed by BC Hydro or its subsidiaries at any time in the two years preceding the submission of the Application, BC Hydro will deem there to be a conflict of interest.

BC Hydro will review the Conflict of Interest Statement form and determine, in its discretion, whether there is any actual, apparent or deemed conflict of interest.

2.15 Interconnection

All Projects must be interconnected to the Transmission System or the Distribution System through a direct interconnection or an Indirect Interconnection.

Projects located outside the Integrated System Area in another utility's service territory may be eligible for the SOP, but the delivery of energy must be at a specified point of delivery on the Integrated System, and the Developer must bear all costs of transmission and energy losses to that point of delivery.

Projects that would require BC Hydro to transmit energy to the Lower Mainland through another jurisdiction or another utility's service territory, including Projects in the Fort Nelson service area, are not eligible for the SOP.

For Projects with an Indirect Interconnection:

- the Developer will be required to deliver energy to BC Hydro at a specified Point of Interconnection ("POI") on the Transmission System or Distribution System and the Developer will be responsible for all risks, costs and energy losses associated with transmission of energy to that POI;

- BC Hydro must be satisfied that adequate arrangements are in place to enable BC Hydro to accurately determine the quantity of energy delivered to that POI;

- the Developer must demonstrate to BC Hydro that it has obtained the right to transmit energy to the POI for the Term of the EPA from any owner(s) of the transmission or distribution facilities the Project will use (e.g., by providing a copy of private line agreement between the line owner and the Developer);

- before BC Hydro offers an EPA for the Project, BC Hydro will amend the Standard Form EPA to address the Developer's responsibilities associated with the Indirect Interconnection. If the owner(s) of the transmission or distribution facilities the Project will use to transmit its energy to the POI are seeking to enter into an EPA with BC

Hydro for their project(s) at the same time, their EPAs may similarly be amended and the parties may be required to enter into a joint Interconnection Agreement;

- if the owner(s) of the transmission or distribution facilities that the Project will use to transmit its energy to the POI have already entered into an EPA(s) with BC Hydro, BC Hydro may require the Developer to secure the owner's agreement to amend its EPA(s) and Interconnection Agreement to address the risks, costs and energy losses associated with the Indirect Interconnection;

- BC Hydro is likely to require additional time to review the Application, make necessary amendments to the Standard Form EPA, make amendments to EPA(s) of the owner(s) of the transmission or distribution facilities that the Project will be using, and conduct the System Impact Study. Developers are expected to take these anticipated delays into consideration when selecting a Target COD; and

- Developers should be aware that if the Indirect Interconnection is overly complicated or would be burdensome for BC Hydro to administer, the Application may be rejected.

2.16 First Nations

BC Hydro will assess the adequacy of First Nations consultation before it makes a decision to offer an EPA for the Project. In its assessment, BC Hydro will consider a number of factors, which may include:

- information on how the Developer determined which First Nations to consult;

- the extent to which the Project has gone through the B.C. permitting and land tenure processes and any permit(s) or licence(s) of occupation issued for the Project. BC Hydro will consider the issuance of land tenure, permits and licenses to indicate that a Crown agency has completed First Nations consultation. Permits and tenures issued by the Ministry of Forests, Lands and Natural Resource Operations will also indicate that the Crown agency has considered impacts of the sale of power to BC Hydro in its consultation process;

- information on the potential impact from the Project on asserted Aboriginal rights and title, and information on how the Developer reached this impact assessment; and

- information on the level of consultation as evidenced by consultation reports, logs, letters of support, correspondence and any other material submitted demonstrating consultation with First Nations for the Project.

For a Project being developed by one or more First Nations, BC Hydro will also consider:

- The consultative boundaries of other First Nations overlapping with the Project area. Depending on the circumstances of the Project, BC Hydro may require the First Nation(s) to consult with other First Nations whose consultative boundaries include the Project area.

- Where a Project is being developed by a First Nation(s) owned company, the First Nation(s) must provide information about how its Chief and Council is kept informed of the Project development including the Project ownership information provided in response to section 1.3 of the Application.

BC Hydro strongly encourages all Developers to contact their local FrontCounter BC office to confirm they have all of the necessary permits or permit amendments in place and to obtain information on any First Nations consultation that may be required in relation to the Project. FrontCounter BC is the Provincial government's "single window service" within the Ministry of Forests, Lands and Natural Resource Operations for natural resource authorizations and permits. Developers should include any information obtained from FrontCounter BC in the Application.

3. Energy Price

To determine the price BC Hydro will pay for energy delivered under an EPA, the SOP uses a base price in 2016$ determined by the region of the POI for the Project. The base price is set out in the table below.

Figure 1 – Base Price

Region of POI	Base Price (2016$/MWh)
Vancouver Island	110.01
Lower Mainland	111.56
Kelly/Nicola	104.39
Central Interior	106.80
Peace Region	102.06
North Coast	103.47
South Interior	106.50
East Kootenay	109.94

One hundred percent of the base price will be escalated at CPI annually up to the year in which an EPA is signed; escalation will be effective as of January 1st in each year. If CPI data is not available when the EPA is signed, the EPA will provide for a base price adjustment when the CPI data is released. After the EPA is signed, 50 per cent of the escalated base price is further escalated annually at CPI effective as of January 1st in each year.

The escalated base price is further adjusted based upon the time of day and month when the energy is delivered to establish the payment price for each MWh of energy delivered to the POI. The time of delivery adjustments are contained in the Standard Form EPA.

The price described above applies to the quantity of energy delivered at the POI.

The price per MWh described above is the only amount payable by BC Hydro. There is no additional payment for Environmental Attributes, for environmental certification (as defined in the Standard Form EPA) or any other expenses. The price will apply for one non-renewable EPA term of the duration selected in the Application.

Developers should note that BC Hydro is currently reviewing SOP pricing, including escalation and adjustments. BC Hydro expects that new pricing will take effect for Projects with Target CODs beginning in 2020.

4. Application Process and Review

4.1 Pre-Application Meeting and Preliminary Assessment

Potential applicants to the SOP are strongly encouraged to request a meeting or conference call with BC Hydro at any time prior to submitting an Application. The purpose of the pre-application meeting is to review the SOP Rules, the Application process, the Standard Form EPA, the interconnection requirements and study costs, First Nations consultation requirements and other matters required to facilitate the Application process, such as available annual energy volume, basic interconnection information and other topics that may be the subject of a preliminary assessment.

To arrange a pre-application meeting or conference call, Developers should submit:

- a completed Pre-Application Meeting Form, available on the Documents page of the SOP Website at www.bchydro.com/standingoffer; and
- a scanned copy of the completed Confidentiality and Compliance Agreement signed by the Developer, also available on the Documents page of the SOP Website at www.bchydro.com/standingoffer.

by email to the SOP Administrator at standing.offer@bchydro.com.

Potential applicants to the SOP may also request a preliminary assessment of whether the Developer and/or the Project meet certain eligibility requirements of the SOP. To request a preliminary assessment of specific eligibility requirements for the SOP, Developers should submit:

- a written request for a preliminary assessment of one, or more, specific eligibility requirement(s) for the SOP including a description of the Developer and the Project. For a Project Cluster preliminary assessment, include a completed Appendix 1 – Project Cluster and/or Common Generation Facilities available on the Documents page of the SOP Website; and
- a scanned copy of the completed Confidentiality and Compliance Agreement signed by the Developer, available on the Documents page of the SOP Website at www.bchydro.com/standingoffer.

by email to the SOP Administrator at standing.offer@bchydro.com.

A preliminary assessment is based on the information provided to BC Hydro in the request for the preliminary assessment and the SOP Rules in effect at the date of the preliminary assessment. A preliminary assessment is not binding on BC Hydro. Any variance between the information contained in a request for a preliminary assessment and the information contained in an Application or actual Project conditions may result in

a final decision that is different from the preliminary assessment. As set out in Section 7.5 of the Rules, BC Hydro may amend the SOP Rules at any time. A change in the SOP Rules may also result in a final decision that is different from the preliminary assessment.

4.2 Submitting an Application

To apply for the SOP, the Developer must submit the following:

- a scanned copy of a completed SOP Application signed by the Developer, with applicable exhibits, in electronic form; and
- a scanned copy of the completed Confidentiality and Compliance Agreement signed by the Developer (if not previously submitted with a pre-application meeting or preliminary assessment request).

by email to the SOP Administrator at standing.offer@bchydro.com or delivered on one (1) disk or USB flash drive to:

BC Hydro
Standing Offer Program
17th Floor, 333 Dunsmuir Street
Vancouver, BC V6B 5R3
Attention: SOP Administrator

The Application Form and Confidentiality and Compliance Agreement are available on the Documents page of the Standing Offer Program Website at www.bchydro.com/standingoffer.

4.3 Review and EPA Process

4.3.1 Application Review

a) Completeness Review – Upon receipt of the Application, BC Hydro will provide the Developer with a written acknowledgement and will perform a completeness review to ensure that it has all the information required to proceed with the Application Review. At a minimum, the Developer will have submitted:

- a signed application;
- all exhibits marked for inclusion by the Developer; and
- a signed Confidentiality and Compliance Agreement.

In order to commence the Application Review, the Confidentiality and Compliance Agreement must be valid – that is, it must be with the appropriate entity which needs to be in good standing.

In the event the Application is incomplete, BC Hydro may request additional information or clarification from the Developer. Depending upon how much information is missing from the Application, BC Hydro will either (1) keep the Application and request submission of the missing information subject to Section 4.6 of the Rules or (2) reject the Application.

BC Hydro will notify the Developer in writing upon completion of the completeness review.

b) Initial Eligibility Review and Application Review – BC Hydro will perform an initial eligibility review and the Application Review.

An initial eligibility review assesses whether the Developer and the Project meet the key eligibility requirements as described in Section 2 of the Rules. BC Hydro will reject an application that has not met the key eligibility requirements upon submission of the Application.

Once BC Hydro determines that the Developer and Project meet the key eligibility requirements, the Application Review continues with the assessment of whether the Developer and the Project meets all eligibility requirements.

In the event BC Hydro is unable to confirm the Project's eligibility under the SOP, BC Hydro may request additional information or clarification from the Developer. Depending upon how much information is missing from the Application, BC Hydro will either (1) keep the Application and request submission of the missing information subject to Section 4.6 of the Rules or (2) reject the Application.

BC Hydro will notify the Developer in writing of the result of the Application Review, and if the Application is retained or rejected following completion of this step. If retained, BC Hydro will also advise the Developer on the status of registering the Project's energy volume under its Target COD year.

c) Registration Under the Energy Volume Target – For each Application that is retained following completion of the steps described in Section 4.3.1 b) of the Rules, BC Hydro will register the Project's energy volume under its Target COD year as described in Section 2.9 of the Rules. BC Hydro will notify the Developer in writing upon completion of the registration.

4.3.2 Review of System Impact Study

a) For each Application that is retained following completion of the steps described in Section 4.3.1 of the Rules, BC Hydro will request that the Developer begin the System Impact Study (or other study if applicable). The Developer must file a complete application with BC Hydro Generator Interconnections for the System Impact Study and pay the applicable study fees within 28 Days after the request, or the Application may be rejected.

b) If the Developer submits a System Impact Study application with a Plant Capacity and Nameplate Capacity or other material information that is not the same as the Plant Capacity and Nameplate Capacity or other information described in the Application, the Application will be rejected.

c) Upon completion of the System Impact Study, BC Hydro will review the System Impact Study to determine whether BC Hydro is ready to support the Project's interconnection to the Distribution System or Transmission System. BC Hydro may reject an Application if the System Impact Study indicates that the proposed interconnection and Interconnection Network Upgrades are not capable of being completed at least 90 Days prior to the Target COD specified by the Developer in the Application, or it indicates Interconnection Network Upgrade Costs that are not acceptable to BC Hydro.

Developers should note that a System Impact Study may become out-of-date and invalid if further studies or steps are not commenced within the time required by BC Hydro Generator Interconnections.

4.3.3 EPA Preparation

a) Following completion of the steps described in Section 4.3.2 of the Rules:

i) BC Hydro will review any Project-specific EPA changes requested by the Developer in the Application. BC Hydro may request additional information or clarification regarding proposed changes; and

ii) BC Hydro may advise the Developer of required changes to the Standard Form EPA based on a review of the Application.

BC Hydro then expects to provide the Developer with a draft EPA for the Developer's review and comment. If required, BC Hydro may also exchange subsequent drafts with the Developer. Once BC Hydro sends a draft EPA to the Developer, the Developer is expected to provide its response and comments to BC Hydro within a commercially reasonable period of time. Failure to do so may result in rejection of the Application.

Developers should note that Projects with an Indirect Interconnection or that are otherwise unusually complicated, will require an extended time for BC Hydro to review and make changes to the Standard Form EPA.

b) For each Application that is retained following completion of the steps described in Section 4.3.3 a) of the Rules:

i) BC Hydro will request that the Developer completes and submits a Statement of Project Changes that identifies any changes to any information in the Application; and

ii) BC Hydro will prepare a final draft EPA and present it to the Developer for review and comment.

The Developer is required to submit a Statement of Project Changes and provide comments on the final draft EPA within a commercially reasonable period of time or the Application may be rejected.

4.3.4 EPA Offer and Acceptance

a) After completion of the process described in Section 4.3.3 of the Rules, including the filing of all required documents, BC Hydro will send the Developer either an offer of an EPA or a notice of rejection of the Application.

b) If the Developer wishes to accept the offer of an EPA, the Developer must sign the EPA and deliver it to BC Hydro at the address specified in Section 4.2 of the Rules. If the Developer has not delivered the signed EPA within a commercially reasonable period of time, BC Hydro's offer of an EPA will be withdrawn.

c) Subject to Section 4.3.4 d) of the Rules, BC Hydro will send a fully signed EPA to the Developer after receipt by BC Hydro of the signed EPA from the Developer.

d) BC Hydro may withdraw an offer of EPA, without liability, at any time prior to delivery of the fully-signed EPA to the Developer.

4.4 **Amending Applications** – Developers may amend an Application at any time prior to delivery of an offer of an EPA by BC Hydro to the Developer. Any such amendment may extend BC Hydro's Application review and EPA offer timelines.

Developers should note that any amendments that may result in a change to an interconnection queue position or System Impact Study may invalidate the interconnection queue position or the System Impact Study. If the generator interconnection queue position or System Impact Study become invalid (as determined by BC Hydro Generator Interconnections) prior to execution of an EPA by both BC Hydro and the Developer, the Application may be rejected.

4.5 **Withdrawing Applications** – Developers may withdraw a submitted Application, without liability, at any time prior to signing an EPA on written notice to BC Hydro.

4.6 **Request for Further Information/Meetings** – BC Hydro may, but is not required to, request further information, clarification or verification concerning an Application or other communication received from a Developer. Failure to respond to such a request within 28 Days after the date of the request may result in rejection of an Application. BC Hydro may telephone or meet with any Developer or group of Developers at any time prior to or following submission of any Application or Applications.

4.7 **Due Diligence and Consultation** – BC Hydro may, but is not required to, undertake any investigation or inquiries and/or undertake any consultation with any governmental or regulatory authority or any other person or group as BC Hydro considers necessary in its discretion with respect to a Developer, a Project, and/or an Application and may, in reviewing an Application, consider any information received as a result of such investigation, inquiry and/or consultation.

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4.8 Rejecting Applications – BC Hydro may accept or reject any Application and may decide to offer or not to offer an EPA to a Developer at its discretion. BC Hydro may reject an Application at any stage in the Application Review process notwithstanding any prior decision by BC Hydro in the Application review process or prior completion of any step in the Application review process. Reasons for rejection of an Application and/or a decision not to offer an EPA to a Developer may include, but are not limited to:

i) an incomplete Application;

ii) an Application that does not meet the eligibility requirements set out in Section 2 of the Rules;

iii) failure to respond to a request by BC Hydro for additional information, failure to respond to or accept Project-specific EPA changes requested by BC Hydro and/or failure to file a System Impact Study or Statement of Project Changes within the required time limits;

iv) a generator interconnection queue position or System Impact Study that become invalid at any time prior to execution of an EPA by both BC Hydro and the Developer;

v) a System Impact Study and generator interconnection queue position (if applicable) that indicate that the proposed interconnection and Interconnection Network Upgrades are not capable of being completed at least 90 Days prior to the Target COD specified by the Developer in the Application;

vi) an Application that proposes Standard Form EPA amendments that are not acceptable to BC Hydro;

vii) an Application for a Project that BC Hydro determines requires material Standard Form EPA amendments or that is too complex to be an appropriate Project for the SOP;

viii) an Application for a Project that will result in Interconnection Network Upgrade Costs that are not acceptable to BC Hydro;

ix) an Application in respect of which any of the information included in the Application is not satisfactory to BC Hydro in any respect;

x) an Application in respect of which BC Hydro determines that the Developer has, or by entering into an EPA, would have, an actual, apparent, or deemed conflict of interest; or

xi) an Application in respect of which BC Hydro determines that the Project and/or the Developer are unsuitable for the SOP or that it would not be in the public interest to offer an EPA for the Project or to the Developer.

If the Application is rejected, the Developer can request an information meeting with BC Hydro to discuss the reasons for the rejection.

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A rejected Application can be resubmitted at a later date provided the deficiencies or issues noted as reasons for rejection have been addressed. A rejected Application will have its Target COD deregistered.

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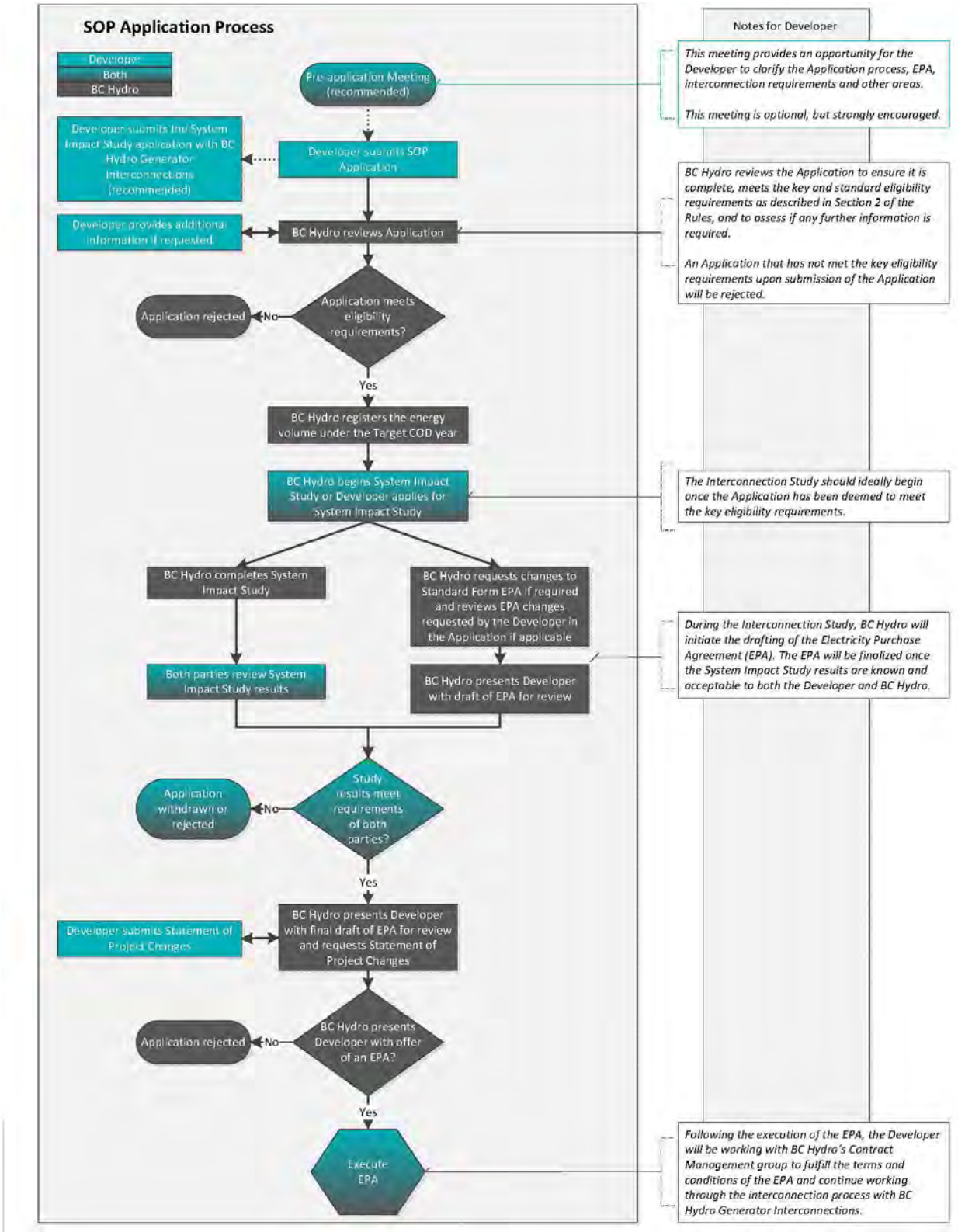
Figure 2 – Application Process



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5. Interconnection

INTERCONNECTION REQUEST PROCESS

The interconnection process will be conducted by BC Hydro Generator Interconnections. All inquiries should be directed to distribution.generators@bchydro.com.

5.1 **Interconnection Requirements –** All generators connected to BC Hydro's Transmission System or Distribution System are required to meet BC Hydro's technical interconnection requirements. In order to determine these requirements and assess the impacts to BC Hydro's system from the proposed interconnection for the purpose of identifying the required network upgrades, technical studies must be performed. These studies provide cost estimates of the required upgrades.

5.2 **Direct Interconnections** – A valid System Impact Study is required for all Projects that are expected to be directly interconnected to the Transmission System or Distribution System. For Projects under 1 MW that are expected to be directly interconnected to the Distribution System, BC Hydro Generator Interconnections may, in its discretion, accept an interconnection study for the Project other than a System Impact Study (e.g., a screening study). The Plant Capacity in the System Impact Study or, other interconnection study if applicable, must be equal to the Plant Capacity in the SOP Application and EPA.

For Projects that are interconnected directly to the Distribution System, the Developer may obtain an optional screening study prior to submitting an Application to the SOP which provides a conceptual level estimate of the interconnection requirements for the Project. For Projects that are interconnected directly to the Transmission System, the Developer may obtain an optional feasibility study prior to submitting an Application to the SOP that provides a high level assessment of technical requirements and potential interconnection costs. These studies are available prior to investing in a System Impact Study but do not replace the requirement for a valid System Impact Study prior to entering into an EPA.

Following the completion of the System Impact Study, Developers will typically be required to apply for a Facilities Study. A Facilities Study is generally required before the Developer enters into an Interconnection Agreement for the Project. While a Facilities Study is not required before an EPA is offered, BC Hydro encourages developers to begin the Facilities Study application as soon as reasonably practical after the completion of the System Impact Study..

All interconnection studies are a part of the interconnection process. For further information regarding any of the studies referred to above, please contact BC Hydro Generator Interconnections (see Section 5.5 of the Rules).

5.3 **Indirect Interconnections** – A valid System Impact Study is required for all Projects with an Indirect Interconnection to the Distribution System or the Transmission System through a BC Hydro Customer facility or a private transmission line. The Developer must arrange for the BC Hydro Customer or the owner of the private line to contact BC Hydro

Generator Interconnections to obtain the required System Impact Study and any required Facilities Study.

A System Impact Study is not required for Projects with an Indirect Interconnection to the Distribution System or the Transmission System through a public utility such as the FortisBC system. The Developer will need to contact that public utility regarding the interconnection of the Project to the public utility's system. The INU Threshold, as described in Section 5.9 of the Rules, does not apply to Projects interconnected through a public utility such as FortisBC.

5.4 **Early Contact and System Impact Study Timing** –Developers are strongly encouraged to contact BC Hydro Generator Interconnections early in the planning process to discuss the interconnection concept and feasibility for their Project.

As previously noted, a System Impact Study may become invalid if further studies or further steps are not commenced within the time required by BC Hydro Generator Interconnections. Accordingly, BC Hydro recommends Developers file their System Impact Study application with BC Hydro Generator Interconnections at the time they submit their Application to the SOP.

5.5 **Interconnection Issues** – For questions related to interconnection, please contact BC Hydro Generator Interconnections at:

BC Hydro Generator Interconnections
6911 Southpoint Drive, Edmonds B03
Burnaby, B.C. V3N 4X8
Email: distribution.generators@bchydro.com or
transmission.generators@bchydro.com

Complete details on the interconnection process can be found at www.bchydro.com/distributiongenerators or www.bchydro.com/transmissiongenerators.

RESPONSIBILITY FOR COSTS

5.6 **Interconnection Study Costs** – The Developer will be responsible for the costs of all studies required for the interconnection of the Project to the Distribution System or Transmission System.

5.7 **Transmission Costs** –The Developer will be responsible for the cost to transmit power sold under the EPA to the POI. BC Hydro will be responsible for the cost to transmit power acquired under the EPA from the POI to BC Hydro's Integrated System.

5.8 **Interconnection Costs** – Interconnection costs refer to the cost of any modifications or additions to the Distribution System or Transmission System arising from the direct or indirect interconnection of the Project to the Distribution System or Transmission System as the case may be. An estimate of these costs will be provided in the System Impact Study. The System Impact Study will (1) identify those costs that are the responsibility of the Developer and (2) provide an estimate of Interconnection Network Upgrade Costs ("INU Costs").

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5.9 **INU Costs and INU Threshold** – Unless the EPA is terminated prior to 90 Days after COD, BC Hydro is responsible for all INU Costs incurred after the effective date of an EPA up to the INU Threshold. The INU Threshold will be escalated at CPI annually up to the year in which an EPA is signed, effective as of January 1st, starting in 2017. BC Hydro will also be responsible for INU Costs in excess of the INU Threshold resulting from a change in the Base Case after the effective date of the EPA, but excluding any changes to the Base Case caused by the Developer or the Project. The Developer is responsible for all costs in excess of the INU Threshold, except as described above.

5.10 **Transmission Network Upgrade (TNU) Costs** – BC Hydro is responsible for TNU Costs, except for TNU Costs that arise as a result of any Project changes made by the Developer relative to the information provided as part of the Application, including the System Impact Study.

5.11 **Network Upgrade (NU) Security** – After receipt by the Developer of the interconnection Facilities Study, and prior to entering into any agreement for construction of Interconnection Network Upgrades with BC Hydro Generator Interconnections, the Developer must deliver the NU Security to BC Hydro for 100 per cent of the INU Costs as estimated in the System Impact Study.

The required amount of NU Security may change from time to time to reflect the full amount of INU Costs estimated plus any TNU Costs that are the responsibility of the Developer due to Project changes made by the Developer relative to the information provided as part of the Application, including the System Impact Study.

The required form of NU Security can be found on the Documents page on the SOP Website.

The NU Security will be returned to the Developer within 15 Days after the date that is 90 Days after COD after deducting any amounts payable by the Developer for INU Costs and Base Case liabilities, as prescribed by BC Hydro Generator Interconnections.

5.12 **Revenue Meters –** Developers are required to have a revenue class Revenue Meter for the Project which is sealed and approved for revenue purposes by Measurement Canada.

The Revenue Meter must be leased from BC Hydro and its installation must be in accordance with BC Hydro's revenue metering requirements. Developers should contact BC Hydro Generator Interconnections as early as possible in the Project development process, and in advance of the Target COD, to make arrangements for the location, installation and testing of the Revenue Meter, with a copy to BC Hydro's Contract Management group at ipp.contract@bchydro.com.

6. Electricity Purchase Agreement

6.1 **Standard Form EPA** – The Standard Form EPA for the SOP is available at www.bchydro.com/standingoffer.

The Standard Form EPA is based on a "standard" type of Project and Developer. For example, the Standard Form EPA assumes that the Project consists of a new generator

that is not part of a Common Generation Facility, has a direct and independent interconnection to the Distribution System or the Transmission System and will have a Revenue Meter that measures output only from the Project and no other electricity generators. The Standard Form EPA also assumes that the Developer is a corporation.

6.2 **EPA Changes** – BC Hydro may require changes to the Standard Form EPA with respect to any Application where BC Hydro considers in its discretion that changes to the Standard Form EPA are required based on the information in the Application.

Developers are encouraged to carefully review the Standard Form EPA prior to submitting an Application. Developers may propose changes to the Standard Form EPA in their Application. BC Hydro may in its discretion accept or reject any proposed changes to the Standard Form EPA. BC Hydro may reject an Application that contains proposed changes to the Standard Form EPA that are not acceptable to BC Hydro. Developers should make every effort to limit the number of proposed changes to the Standard Form EPA.

6.3 **EPA Term** –The EPA will have a single term of 20 to 40 years, as selected by the Developer, or 10 to 40 years for Projects Behind a BC Hydro Customer Load, commencing on the Commercial Operation Date (as defined in the Standard Form EPA).

After the term of the EPA expires, BC Hydro will determine whether it is prepared to enter into negotiations with the owner of the Project regarding a new EPA for the Project. BC Hydro's determination will be based on its need for the electricity, prevailing market conditions, energy price, and power procurement practices at the time. If BC Hydro wishes to enter into a new EPA for the Project, BC Hydro expects that the price it offers for energy will assume that all initial capital costs for the Project have been recovered during the term of original EPA.

7. Additional Rules

7.1 **Costs –** Developers are responsible for all costs incurred by them in connection with the SOP, including the costs of preparing an Application and any other submission required under the SOP, all interconnection study costs and the execution and delivery of any EPA.

7.2 **Nature of Process** – The SOP is *not* a Call for Tenders. No legal offer, legal contract or legal duties or obligations of any kind whatsoever, whether express or implied, are intended to be created by or under the Rules, or by the filing of an Application, or the acceptance of an Application for review, or the review of an Application, or in any other manner whatsoever under or in connection with the SOP except for those arising under an EPA that has been signed and delivered by both the Developer and BC Hydro.

7.3 **Waiver** – BC Hydro may waive any provision of these Rules, including any of the eligibility requirements, where BC Hydro determines in its discretion that such waiver would be consistent with the objectives of the SOP or is otherwise in the public interest or the ratepayers' interest.

7.4 **Program Suspension/Cancellation** – BC Hydro may cancel or suspend the SOP at any time without any liability to any Developer or to any other person.

7.5 **Program Amendments** – BC Hydro may amend the SOP Rules, the Application Form, the Standard Form EPA and any Reference Documents in any respect in whole or in part at any time, provided that any such amendments shall not affect any EPA that has been offered to a Developer prior to the amendment. Any amendment will apply to all EPAs offered after the amendment.

7.6 **No Liability** – BC Hydro (including its affiliates, and their respective directors, officers, employees, contactors, subcontractors, consultants, agents and representatives), incurs no liability of any nature or kind whatsoever to any person in connection with the SOP or the administration of the SOP, or information provided with respect to, or in the course of, the SOP, or the acceptance, rejection, or review of any Application, or any other decision, assessment, determination, statement, act or omission whatsoever, whether negligent or not, relating to the SOP or its administration.

7.7 **Unsolicited Information Not Considered** – BC Hydro is not required to consider any information with respect to an Application that is not contained in the Application, or any written response to a request from BC Hydro for further information, clarification or verification.

7.8 **Ownership of Documents** – All Applications and all documents filed with an Application and all other submissions by a Developer under or in relation to the SOP will be retained by, and become the property of, BC Hydro, provided however that BC Hydro does not thereby acquire any ownership interest in intellectual property embedded therein.

7.9 **Other BC Hydro Power Procurement Processes** – BC Hydro may at any time reject an Application for a Project that is the subject of a submission in any other BC Hydro power procurement process.

7.10 **Filing Requirements** – If the last day for completing any act required or contemplated under the Rules falls on a day that is a Saturday, Sunday or other day recognized as a statutory holiday in British Columbia, the time for completing that act will be extended to the next day that is not a Saturday, Sunday or other day recognized as a statutory holiday in British Columbia.

8. Further Information

Developers should direct any questions regarding the SOP in writing to the SOP Administrator as follows:

by email to: standing.offer@bchydro.com

or by mail to: BC Hydro
Standing Offer Program
17th Floor, 333 Dunsmuir Street
Vancouver, BC V6B 5R3
Attention: SOP Administrator

Any questions submitted and subsequent answers may be posted at www.bchydro.com/standingoffer.

To avoid any potential misunderstandings and for administrative ease, Developers must not contact any BC Hydro director, officer or employee on any matter pertaining to the SOP except as set out above or, in the case of inquiries with respect to the interconnection process, as set out in Section 5 of the Rules.

Communication from Developers should originate from the contact person(s) specified in the Application. Contact persons can be changed by notice to the SOP Administrator. Developers should communicate in writing (which may include email).

9. Reference Documents

A. Pre-Application Meeting Form

B. Application Form

C. Statement of Project Changes Form

D. Standard Form EPA

E. Conflict of Interest Statement Form

F. BC Hydro's Contractor Standards for Ethical Conduct

G. Confidentiality and Compliance Agreement

H. Project Cluster and/or Common Generation Facilities

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Glossary – Standing Offer Program Rules

All references to section numbers are to sections of the SOP Rules, not the Application Form or Standard Form EPA, unless otherwise expressly stated.

1. **Application** means the Application Form for a Project as submitted by the Developer to BC Hydro together with all amendments thereto filed by the Developer and all supporting documents and information filed by the Developer with BC Hydro with respect to the Project, including the interconnection study or studies and Statement of Project Changes. [back]

2. **Application Form** means the form titled "Standing Offer Program Application Form" available at www.bchydro.com/standingoffer. [back]

3. **Application Review** means the review process conducted by BC Hydro once a completed Application has been received, as outlined in Section 4.3.1 of the Rules. [back]

4. **Auxiliary Fuel** means any combustible fuel that would render the energy generated as a result of such combustion ineligible for acceptance as energy generated by a Clean or Renewable Resource. [back]

5. **Auxiliary Fuel Annual Baseline** means 3 per cent of the total fuel, excluding Start-up Fuel, and determined in GJ, used to generate the energy sold to BC Hydro under an EPA in each calendar year. [back].

6. **Base Case** means the base case power flow, short circuit, and stability data models used as the basis for the Interconnection Study. [back]

7. **BC Energy Plan** means the document titled "The BC Energy Plan: A Vision for Clean Energy Leadership" published by the B.C. Ministry of Energy in 2007. [back]

8. **BC Hydro** means British Columbia Hydro and Power Authority. [back]

9. **BC Hydro Customer** means a customer of BC Hydro as defined in the BC Hydro Electric Tariff. However, the following are not customers for the purpose of the SOP: (i) a public utility, as defined in the *Utilities Commission Act*; including any affiliates; an entity that has as its primary business or purpose generation and sale of electricity, including independent power producers (IPPs); an entity that takes only back-up or start-up electricity service from BC Hydro. [back]

10. **Behind a BC Hydro Customer Load** means a Project with an Indirect Interconnection through a facility that purchases power from BC Hydro. [back]

11. **Clean Energy** means energy that is generated from a Clean or Renewable Resource. [back]

12. **Clean Energy Act** means the *Clean Energy Act,* SBC 2010, c. 22, as amended from time to time. [back]

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13. **Clean or Renewable Resource** has the meaning given in the *Clean Energy Act* and regulations from time to time which at the date of publication of the Rules is biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any biogenic waste, waste heat and any additional prescribed resources. [back]

14. **Commercial Operation Date ("COD")** has the meaning given in the Standard Form EPA. [back]

15. **Commercial Operation Generation Technology** means that the generation technology is readily available in commercial markets and in commercial use (not demonstration use only), as evidenced by at least one generation plant (which need not be owned or operated by the Developer) generating energy for a period of not less than one year, to a standard of reliability generally required by Good Utility Practice (as defined in the Standard Form EPA). [back]

16. **Common Generation Facility** – see definition of "Project Cluster and Common Generation Facilities". [back]

17. **Completed Prototype Generation Technology** means that the generation technology has completed a program of testing, with satisfactory results, using a sub-scale or full-scale prototype of the technology to simulate real-world conditions, which sufficiently demonstrates technical viability and safe performance of the technology at full-scale and under real-world conditions, as evidenced by the certification of a professional engineer (or equivalent engineering designation) registered or licensed in a jurisdiction that regulates the practice of engineering. [back]

18. **CPI** means the British Columbia Consumer Price Index, All Items (Not Seasonally Adjusted) as published by Statistics Canada or any successor agency thereto. [back]

19. **Day** means any calendar day including Saturday, Sunday or British Columbia statutory holiday. [back]

20. **Demand Side Management** means actions that modify customer demand for electricity, helping to defer the need for new energy and capacity supply additions. [back]

21. **Developer** means the developer or owner of a Project that submits an Application under the SOP. [back]

22. **Discretion** (whether or not capitalized) means sole, absolute and unfettered discretion unless the Rules expressly state otherwise. [back]

23. **Distribution System** means the distribution, protection, control and communication facilities in British Columbia that are or may be used in connection with, or that otherwise relate to, transmission of electrical energy at 35 kV or less and that are owned by BC Hydro, and includes all additions and modifications thereto and repairs and replacements thereof. [back]

24. **Energy Volume Target** means the target in GWh that BC Hydro will set from time to time for the annual amount of energy to acquire from the SOP and Micro-Standing Offer Program. [back]

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25. **Environmental Attributes** has the meaning given to that term in the Standard Form EPA. [back]

26. **EPA** means an electricity purchase agreement offered to a Developer under the Standing Offer Program. [back]

27. **Facilities Study** means a detailed interconnection study that consists of a project plan which includes the detailed design for the network upgrades required for interconnection, and specifies and estimates the cost of the equipment, engineering, procurement and construction work required to implement the conclusions of the System Impact Study. [back]

28. **GJ** means gigajoule. [back]

29. **Greenhouse Gas or GHG** means: (i) one or more of the following gases: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride; and (ii) any other gas that is identified as having significant global warming potential and is added, at any time before the expiry of the Term, to Schedule 1 to the *Canadian Environmental Protection Act, 1999*, or to the *Greenhouse Gas Reduction Targets Act* (British Columbia), or to any other regulation(s) governing the emission of the gases noted in (i) from the Project. [back]

30. **Indirect Interconnection** means the indirect interconnection of a Project to the Distribution System or Transmission System through (i) a configuration involving generating equipment interconnected through a BC Hydro customer facility, or (ii) a private transmission line or distribution line owned by a party other than the proposed Seller under the EPA, such as an existing independent power producer, or (iii) a public utility transmission/distribution system owned and operated by any party other than BC Hydro, such as the FortisBC system; or (iv) a transmission/distribution system that is owned by the proposed Seller under the EPA or one of its affiliates that transmits energy in addition to the energy generated by the Project. [back]

31. **Integrated System** means the Transmission System and the Distribution System, both within British Columbia, excluding the Fort Nelson service area and certain remote areas where electricity supply is provided by local generation which is isolated from the provincial transmission system. [back]

32. **Integrated System Area** means that part of British Columbia within which Projects may be connected directly to the Integrated System as determined by BC Hydro Generator Interconnections. [back]

33. **Interconnection Agreement** means an agreement with BC Hydro for the interconnection of the Project to the BC Hydro Distribution System or Transmission System**.** [back]

34. **Interconnection Network Upgrades or INU** means those additions, modifications and upgrades to the Transmission System or Distribution System identified in the interconnection study (and as further refined in subsequent interconnection studies) determined by BC Hydro to be “interconnection network upgrades” under the applicable policies of BC Hydro or under the OATT in effect from time to time. [back]

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35. **Interconnection Network Upgrade Costs or INU Costs** means all costs for the design, engineering, procurement, construction, installation and commissioning of Interconnection Network Upgrades. See Section 5.9 of the Rules. [back]

36. **Interconnection Network Upgrade Threshold or INU Threshold** means $157.59 (2016$) per kilowatt of Plant Capacity as defined in Appendix 2 of the EPA or the Maximum Power Injection, whichever is lower. [back]

37. **kV** means kilovolt**.** [back]

38. **kW** means kilowatt. [back]

39. **Load Displacement** means a reduction in electricity sales by the electricity provider to the customer due to electricity conservation or customer self-generation, although the customer's pattern of peak and off-peak periods (load shape) may not have changed. [back]

40. **Maximum Power Injection** means the maximum amount of power the Project can inject on the Distribution System, expressed in MW, as specified by BC Hydro Generator Interconnections. [back]

41. **MVA** means megavolt ampere. [back]

42. **MW** means megawatt. [back]

43. **MWh** means megawatt-hour. [back]

44. **Nameplate Capacity** means the aggregate of the nameplate capacities of all the generators included in the Project. For each generator, nameplate capacity is expressed in MW and consistent with the equipment manufacturer's maximum rated generating capacity. Where the nameplate capacity is expressed in MVA, the nameplate capacity will be multiplied by the power factor stated on a generator's nameplate to determine the nameplate capacity in MW. [back]

45. **Net-of-Load** means that, in a given hour, only the generation (MWh) produced by a Developer (including a BC Hydro Customer) that is in excess of the energy consumed (MWh) by a BC Hydro Customer during the same hour will be eligible for sale to BC Hydro under the EPA at the prevailing SOP price ($/MWh). [back]

46. **Network Integration Transmission Service Study** has the meaning given in the OATT. [back]

47. **Network Upgrade Security or NU Security** means a letter of credit in the amount described in Section 5.11 of the Rules, in the form found on the Documents page of the SOP Website, with such modifications as approved by BC Hydro in writing and issued and advised as required under Section 5.11 of the Rules. [back]

48. **Open Access Transmission Tariff or OATT** means the tariff that governs both wholesale transmission services and generator interconnection services offered by BC Hydro to its customers. [back]

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49. **Plant Capacity** means the Nameplate Capacity of the generators for a new project or a portion of the Nameplate Capacity of the generators that is allocated to the SOP where a new generator is added to existing project, expressed in MW. [back]

50. **Point of Interconnection or POI** means:

a. for a Project with a direct interconnection to the Distribution System or the Transmission System, the point at which the Project interconnects with the Distribution System or Transmission System;

b. for a Project with an Indirect Interconnection through a BC Hydro Customer facility, the point at which the customer's load interconnects with the Distribution System or Transmission System; or

c. for a Project with an Indirect Interconnection through: (i) a private transmission or distribution line owned by a party other than the proposed Seller under the EPA; or (ii) a public utility transmission/distribution system owned and operated by any person other than BC Hydro, or (iii) a transmission or distribution system owned by the Seller or any of its affiliates that transmits energy in addition to the energy generated by the Project, the point at which the private line or the public utility line interconnects with the Distribution System or Transmission System, as specified in the EPA. [back]

51. **Project** means an electrical generation facility and includes all land and interests in land, buildings, equipment and material related to the generation facility as required for the generation and delivery of electrical energy to the point of delivery under the EPA. In the case of a Project that consists of incremental new generation, the "Project" for the purposes of the SOP consists of the new generator(s) and related facilities that are added to an existing generating facility. [back]

52. **Project Cluster and Common Generation Facilities:**

a. A Project Cluster means two or more existing or proposed Projects that BC Hydro determines in its discretion are so closely related to each other that they should be considered a project cluster for the purposes of the SOP.

   BC Hydro will generally determine that a Project Cluster exists where the existing or proposed Projects have the following characteristics (although BC Hydro may conclude otherwise in its discretion): (i) have common direct or indirect ownership or control; (ii) have common development timelines; (iii) are being developed by the same or an affiliated developer; (iv) are located in close proximity (e.g., in same watershed); and/or (v) share any tenures, permits, facilities or other infrastructure such as roads, power lines, interconnection facilities or POI. Projects with common development timelines that are in close proximity may be considered as a Project Cluster despite having separate majority owners.

b. A Common Generation Facility means the Project together with any other existing or proposed generator that BC Hydro determines in its discretion is so closely connected

with, or related to, the Project that the Project and the other existing or proposed generator should be considered a single generation facility for the purposes of the SOP.

BC Hydro will generally determine that a Common Generation Facility exists where a Project together with another existing or proposed generator have the following characteristics (although BC Hydro may conclude otherwise in its discretion): (i) are located on the same site or in close proximity to each other and use the same fuel source; (ii) share common facilities and infrastructure; and/or (iii) the energy generated is metered by a single Revenue Meter.

BC Hydro may determine that a Project Cluster or a Common Generation Facility exists even if there are no shared tenures, permits, ownership, facilities or other infrastructure. This situation would arise if BC Hydro considers in its discretion that such separation was put in place for the purpose of meeting the SOP eligibility requirements.

There may be certain exceptional cases where, notwithstanding the existence of limited shared infrastructure, BC Hydro may determine, in its discretion that a Project Cluster or a Common Generation Facility does not exist.

Furthermore, there may be some instances where BC Hydro may require two or more Projects or generators to share interconnection facilities and/or a POI in order to provide BC Hydro with technical or other benefits. In such cases, BC Hydro will use its discretion to determine whether the Projects or generators are eligible to apply under the SOP notwithstanding the shared infrastructure.

The foregoing does not limit the circumstances in which BC Hydro may in its discretion determine that a project cluster exists. [back]

53. **Protected Area** has the meaning given in British Columbia's *Clean Energy Act* which at the date of publication of the Rules is: (a) a park, recreation area, or conservancy, as defined in section (1) of the *Park Act*; (b) an area established under the *Environment and Land Use Act* as a park or protected area, or (c) an area established or continued as an ecological reserve under the *Ecological Reserve Act* or by the *Protected Areas of British Columbia Act*. [back]

54. **Reference Documents** means the documents listed in Section 9 of the Rules. [back]

55. **Revenue Meter** means a meter that measures energy output and/or consumption for purposes of calculating payments under an EPA and that meets the requirements specified in the EPA. [back]

56. **Rules** has the meaning given in Section 1 of the Rules.

57. **Seller** means a Developer that enters into an EPA with BC Hydro. [back]

58. **SOP** means the Standing Offer Program as described in these Rules. [back]

59. **SOP Administrator** means the person appointed by BC Hydro to act as the SOP Administrator as described in Section 4 of these Rules.

60. **Standard Form EPA** means the Standard Form Electricity Purchase Agreement for the Standing Offer Program available at www.bchydro.com/standingoffer. [back]

61. **Standing Offer Program ("SOP")** means the Standing Offer Program as described in these Rules.[back]

62. **Standing Offer Program Website** means the website with respect to the Standing Offer Program located at www.bchydro.com/standingoffer. [back]

63. **Start-up** means a "black start" or "cold start" of generation facilities, from the time when fuel is first combusted until the time when generation is stabilized. [back]

64. **Start-up Fuel** means that quantity of Auxiliary Fuel, expressed in GJ, used in a Start-up. [back]

65. **Statement of Project Changes** has the meaning given in Section 4.3.3 of the Rules. [back]

66. **System Impact Study** means a detailed interconnection study which evaluates the impact of a proposed Project on the reliability of BC Hydro's system and provides a planning-level estimate of the interconnection costs and Interconnection Network Upgrades. [back]

67. **Target Commercial Operation Date or Target COD** means the date when the Developer expects the Project to achieve COD as specified by the Developer in the Application. [back]

68. **Term** means the term of the EPA as specified by the Developer in the Application. [back]

69. **Transmission Network Upgrades or TNU** means those additions, modifications and upgrades to the Transmission System identified in the Network Integration Transmission Service Study as determined by BC Hydro.

70. **Transmission Network Upgrade Costs or TNU Costs** means all costs incurred by BC Hydro after an EPA is entered into for the design, engineering, procurement, construction, installation and commissioning of Transmission Network Upgrades. [back]

71. **Transmission System** means the transmission, substation, protection, control and communication facilities (transmitting energy at voltages greater than 35 kV) owned and operated by BC Hydro in British Columbia, and includes all additions and modifications thereto and repairs or replacements thereof. [back]

Contractor standards for ethical conduct

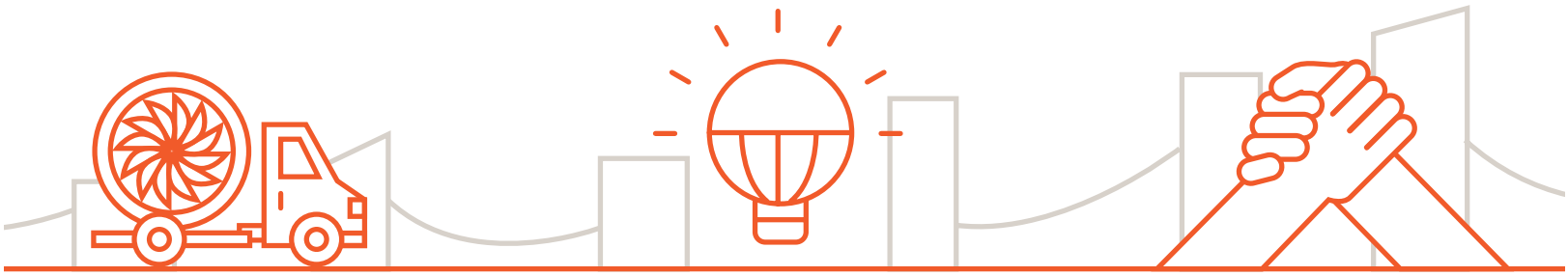
In these Standards:

"**BC Hydro**" means BC Hydro and Power Authority or any of its subsidiaries that has entered into the Contract.

"**Contract**" means a contract with BC Hydro in which these Standards are included directly or by reference as a term or condition.

"**Contractor**" means the contractor, consultant, supplier or business associate who has a Contract.

"**Owner**" means any person who, individually or together with relatives, directly or indirectly owns 20% or more of the voting rights of the Contractor.



February 2016

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1. At all times in the course of its performance of the Contract, the Contractor will conduct itself with fairness, integrity and honesty.

2. At all times during the term of the Contract, the Contractor will avoid any actual, or apparent conflict of interests, in which its interests outside of the Contract (including any engagements the Contractor may have with third parties), and its obligations to BC Hydro under the Contract and these Standards conflict.

3. The Contractor will promptly disclose to BC Hydro in writing, to the best of its knowledge, any actual or apparent conflicts between its interests and those of BC Hydro during the term of the Contract, including:

   (a) the name of any current director or employee of BC Hydro who is an Owner, or representative of the Contractor;

   (b) any business relationship that the Contractor or any of its Owners or officers has with a director or officer of BC Hydro or with an employee of BC Hydro who may have actual or apparent involvement in any BC Hydro procurement process, or the Contract; and

   (c) the name of any director or employee of BC Hydro who is connected by frequent or close association to the Contractor, any of its Owners or officers, or any representatives of the Contractor who may have actual or apparent involvement in any BC Hydro procurement process, or the performance or administration of the Contract.

   For the purposes of this section, BC Hydro's interests include non-economic considerations such as reputation.

4. In addition to disclosure required above, the Contractor will take any steps reasonably required by BC Hydro to address or mitigate any actual or apparent conflict of interest.

5. Subject to the terms of the Contract, the Contractor will keep confidential all non-public, confidential information provided to it by BC Hydro or developed during performance of the Contract. The Contractor will not use that information for any purpose unrelated to performance of its obligations under the Contract.

6. If BC Hydro gives the Contractor access to any BC Hydro property during the term of the Contract, the Contractor will use that property solely for purposes of the Contract.

7. The Contractor will not attempt to secure preferential treatment with BC Hydro by offering gifts, entertainment, or benefits to BC Hydro directors or employees. Reasonable gifts, entertainment, or benefits common to business relationships, as described in the BC Hydro Code of Conduct, are acceptable.

8. Unless the Contractor has the express permission of BC Hydro, the Contractor will not solicit or recruit any BC Hydro employee during the term of the Contract. This obligation doesn't prevent the Contractor from hiring a BC Hydro employee who responds to a public and broadly issued job advertisement without prompting or encouragement from the Contractor.

9. The Contractor must treat its employees and subcontractors performing work under the Contract respectfully and in a manner free of discrimination and harassment. The Contractor will provide those employees, and subcontractors with a safe and healthy workplace.

10. The Contractor and its employees and subcontractors must treat individuals they encounter in the course of performing work under the Contract respectfully and in a manner free of discrimination and harassment.

11. When the Contractor is participating in any public discussions or taking a position of leadership in other organizations, it must not represent itself as a spokesperson of BC Hydro unless BC Hydro has specifically retained or instructed the Contractor to act in that capacity.

Contractors who would like further information or advice on the application of these Standards are encouraged to speak to BC Hydro's contract representative.

A Contractor's failure to adhere to the provisions of these Standards may be a breach of Contract and could result in termination of the Contract.

Standing offer program pricing regions in B.C.

B16-194
Version 2.0

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BC Hydro Distributed Generation Interconnection Practices (distribution-connected projects only**)

	Program Type	Interconnections					
		Size	Required Studies	Study Costs	Agreements	Customer Upgrades	Interconnection and System Upgrades
BC Hydro Offered Programs – Clean or Renewable Generation	**Net Metering (RS 1289)** • open to BC Hydro customers • load displacement plus NM energy price paid for annual excess • tariffed process (Rate Schedule 1289)	0 kW to 50 kW	Simple Net Metering: None Required[1] Complex Net Metering: Technical screen	$0[2]	No Interconnection Agreement (terms and conditions are in RS 1289)	Customers are required to upgrade their service at their cost.	System upgrades are paid by BC Hydro
		Over 50 kW to 100 kW	Technical screen[3]	Incremental costs[4]			System upgrades are paid by the Customer[5]
	Micro-SOP • for First Nations and community projects • single energy price for all energy • simplified Electricity Purchase Agreement	Over 100 kW to 1 MW	Basic Distribution Information Request.	First two requests per year – free. Additional requests - $200	Simplified Interconnection Agreement	Customers are required to upgrade their service/build their interconnection facilities at their cost.	• Customers will provide a deposit of $7,500 with their Distribution Micro-Generator Project Design Application, which will be refunded when we receive the security (Letter of Credit) for the estimated network upgrade costs. • Customers provide security (Letter of Credit) in the amount of the estimated network upgrades costs. • BCH covers $150,000 per MW of installed capacity. • Reduction of security is governed by the applicable Interconnection Agreement. See also Interconnection Security Methodology posted at https://www.bchydro.com/accounts-billing/new-electrical-connections/generator-interconnections.html • Network upgrades costs and construction schedules are project-specific. Estimates of costs and schedules will be provided in the design stage during the interconnection process.
			Screening Study If the project passes the screens in the Screening Study, then the project proceeds to the next step: the Distribution micro-generator project design stage application form. If the project fails the screens in the Screening Study, then the project proceeds through the standard generator interconnection process.[6]	$5,000 flat fee $7,500 deposit Deposit is refunded when Letter of Credit (LOC) is received for the network upgrades			
	SOP • open to clean energy producers and BC Hydro customers (net of load) • energy price varies at time of delivery • Electricity Purchase Agreement	Over 1 MW to 15 MW	Basic Distribution Information Request	First two requests per year – free. Additional requests - $200	Standard Interconnection Agreement		
			Screening Study (optional)	$5,000 flat fee			
			System Impact Study	$20,000 - $80,000[7]			
			Facilities Study	$40,000 - $175,000[7]			
Other	**Other Customer Generation Projects** • for projects that do not fit into programs above • open to research, pilot/educational projects, projects generating intermittent energy as a result of existing industrial process • no payment for energy	Up to 100 kW	Technical Screen	Same as Net Metering Incremental costs[4]	Simplified Interconnection Agreement	Customers are required to upgrade their service at their cost.	• Customers provide advanced payment in the amount of the estimated network upgrades costs. Final costs are based on actuals. • Network upgrades costs and construction schedules are project-specific. Estimates of costs and schedules will be provided in study reports during the interconnection process.
		Over 100 kW to 1 MW	Same as Micro-SOP	Same as Micro-SOP	Simplified Interconnection Agreement	Customers are required to upgrade their service/build their interconnection facilities at their cost.	
		Over 1 MW to 15 MW	Same as SOP	Same as SOP	Standard Interconnection Agreement		

* This table is intended as an overview of current practices only. Project-specific requirements may vary.

** Interconnection requests for transmission-connected projects follow the Standard Generator Interconnection Procedures found in Appendix M-2 of BC Hydro's Open Access Transmission Tariff (OATT). For more information, see https://www.bchydro.com/accounts-billing/new-electrical-connections/transmission-generator-interconnections.html

1 Basic technical screen – no detailed studies. For areas of high penetration, BC Hydro may reject project.

2 For synchronous generators and customers connected at a primary potential and customers with generating facilities with a nameplate rating greater than 50 kW, customers are responsible for incremental costs.

3 Technical Screen scope for DG >50 kW includes a review of power flows and BC Hydro equipment ratings, a comparison of generator size to minimum feeder section load, a check of total generation on the feeder, and a short circuit study and protection review.

4 Typical range of interconnection review costs for Net Metering applications up to 50 kW, other than at primary potential or with synchronous generators:

Project Type	Technical Review
Simple Projects	Minimal
Complex Projects	$500-$1,000

5 Costs are dependent on location, generator size, feeder available capacity, condition/limitations of the substation. Note: There are no pioneer rights.

6 Projects that fail any of the screens will be required to complete the System Impact Study and/or Facilities Study.

7 Costs may be less or greater depending on project specifics.

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Pre-Application Meeting Request Form

Thank you for your interest in the Micro- SOP or Standing Offer Program. To ensure that the meeting is productive and to help us respond to your questions, please complete the following.

Project Information

Developer Name: _____

Project Name: _____

Nearest Community: _____

The approximate latitude and longitude of the project site is (in degrees minutes seconds)

Latitude: 99°99'99" North Longitude: 999°99'99" West

Potential point of interconnection (if known):

_____

Interconnecting to (if known): _____

Approximate size of the Project: _____ ◯ kW ◯ MW _____ GWh/yr

Generation technology the Project will use: _____

Describe if "Other": _____

Target application date: YYYY-MMM-DD Target commercial operation date: YYYY-MMM-DD

Meeting Information

Please check the box(es) corresponding to the topic(s) that you would like to discuss at the pre-application meeting and, if applicable, include questions in the space provided.

☐ Application Process

Questions: _____

☐ Eligibility Requirements

Questions: _____

☐ Interconnections

Questions: _____

☐ Permitting

Questions: _____

☐ First Nations consultation requirements

Questions: _____

Other questions you would like addressed:

_____

Names and positions of meeting participants:

_____

Please indicate how you would prefer to meet:

◯ a meeting at BC Hydro's corporate headquarters in downtown Vancouver

◯ a conference call

Please provide a selection of preferred dates and times for the meeting:

_____

Micro-SOP & Standing Offer Program Pre-Application Meeting Request
Version 1.1 March 2016
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Standing Offer Program Application Form

Revised: August 2016

General Instructions

- Words and phrases used in this Application Form and defined in the Rules have the meanings given in the Glossary to the Rules, unless otherwise defined herein.
- To complete the Application Form, fill out each field that is represented by a blue box. Use drop down menus to make selections, where provided.
- A Developer should be fully responsive to each instruction, as applicable to the Developer and its Project. If a Developer is in any doubt as to the requirements contained in these instructions, it should seek clarification from the SOP Administrator at the address specified in Section 8 of the Rules.
- When completed, name the Application Form "Application" and save in Adobe ("PDF") format for inclusion in the electronic copy of your Application submission.

  Name the Exhibits according to the labelling of Exhibits in the Application Form and save the Exhibits in PDF, MS Excel or MS Word format for inclusion in the electronic copy of your Application submission. Insert "N/A" for Exhibits not applicable to your Project.
- BC Hydro reserves the right to request additional information in relation to any information requested in this Application Form.

Application Submission Instructions

To apply for the Standing Offer Program, the Developer must submit the following:

- a scanned copy of the completed Standing Offer Program Application signed by the Developer with applicable Exhibits, in electronic form; and
- a scanned copy of the completed Confidentiality and Compliance Agreement signed by the Developer (if not previously submitted with a pre-application meeting or preliminary assessment request);

  by email to the SOP Administrator at standing.offer@bchydro.com or delivered on one (1) disk or USB flash drive to:

  BC Hydro
  Standing Offer Program
  17th Floor, 333 Dunsmuir Street
  Vancouver, BC V6B 5R3
  Attention: SOP Administrator

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1. Developer

1.1 Developer Information

Project name:				
Developer's full legal name:				
Address:	City:	Province/State:	Country:	Postal/Zip Code:
Developer / Project website address:				

Main Contact Person
(All Correspondence and Agreements will be sent to the Main Contact Person)

First name:	Last name:	
Title:	Email:	
Phone:	Alternate phone:	Fax:

Alternate Contact Person (optional)

First name:	Last name:	
Title:	Email:	
Phone:	Alternate phone:	Fax:

1.2 Developer Identity

Form of organization (e.g., corporation, general partnership, limited partnership, joint venture, local government, public institution, etc.):		Is the Developer a Public Utility, as defined in Section 2.7 of the Rules?
Jurisdiction in which the Developer is incorporated or formed:	Date of incorporation or formation: YYYY-MMM-DD	Incorporation (or similar) number:
Date of registration in British Columbia: YYYY-MMM-DD	Registration number:	

For a limited partnership, general partnership, joint venture or other entity with more than one member, provide the same information with respect to each member of the above entity. Use the "Add a Member" button opposite this text to add additional "member" sections.

Member Details

Member's full name:
Form of organization (e.g., corporation, general partnership, limited partnership, joint venture, local government, public institution, etc.):

Jurisdiction in which the Member is incorporated or formed:	Date of incorporation or formation: YYYY-MMM-DD	Incorporation (or similar) number:
Date of registration in British Columbia: YYYY-MMM-DD		Registration number:

1.3 Project Ownership Structure

Provide an organization chart that shows all direct and indirect owners to the ultimate controlling owner(s) of the Project.

☐ Included and named Exhibit 1.

1.4 Project Team

Provide a list of Project development team members including key outside contractors and consultants. Add additional rows if necessary.

Team Member	Role

1.5 Conflict of Interest

As required under BC Hydro's Contractor Standards for Ethical Conduct, the Developer must provide on its own behalf and on behalf of each member of the Developer's team a declaration in relation to the potential to be in an actual, apparent or deemed conflict of interest as a result of entering into an EPA with BC Hydro, as described in Section 2.14 of the Rules.

Complete the Conflict of Interest Statement form found on the Documents page of the SOP Website.

☐ Included and named Exhibit 2.

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2.Project Information

2.1 Project Description

a) Provide a short, general description of the Project:

b) Provide the Nameplate Capacity of each new generator.

Add additional rows if necessary.

Generator(s)	
1	MW

Total: 0 MW

Comments:

c) Location

Project region: Nearest community:

The approximate latitude and longitude of the project site is (in degrees minutes seconds):

Latitude: 99°99'99" North Longitude: 999°99'99" West

Provide the parcel identifier number for all legal parcels on which the Project will be located:

Parcel Identifier Number	Ownership Status	Describe if "Other"

Provide a geographical map of the Project location.
☐ Included and named Exhibit 3.

Provide the expected layout of the key facilities comprising the Project.
☐ Included and named Exhibit 4.

Is the Project described in the Application located on the same site or in the vicinity of a Project Cluster or Common Generation Facility?

Does the Project share any facilities with a Project Cluster or Common Generation Facility?

If "Yes" to either of the above two questions:

i) Does any project that is part of a Project Cluster or Common Generation Facility have an EPA with BC Hydro or another party?

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ii) Complete Project Clusters and/or Common Generation Facilities - Supplementary Information available on the Documents page of the SOP Website.

☐ Included and named Exhibit 5.

Is any part of your Project located in a Protected Area, as defined in the Glossary to the Rules? ☐

Does any part of the Project require access to a BC Hydro right of way? ☐

d) The Target COD for the project is: YYYY-MMM-DD
Please refer to www.bchydro.com/standingoffer for information on available energy volume under the target for your target COD year, and on the target management process.

e) The Term of the EPA for the Project is ☐ years.

f) Provide the Project schedule.
☐ Included and named Exhibit 6.

g) Total estimated Project energy.

Month	Average monthly energy output (MWh)
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	
Total:	

Provide calculations supporting the average monthly energy output.
☐ Included and named Exhibit 7.

h) Project Type
The energy delivered to BC Hydro under the EPA must be Clean Energy. Select the Project type:

☐ Biogas ☐ Ocean - tidal

- ☐ Biogenic waste
- ☐ Biomass
- ☐ Geothermal heat
- ☐ Hydro
- ☐ Ocean - wave
- ☐ Solar
- ☐ Waste heat
- ☐ Waste hydrogen
- ☐ Wind

☐ Other prescribed resource. Describe:

i) Fuel

Complete the table for all fuel types used in the Project:

Fuel	Describe if "Other"	% of annual fuel [1]
	Total:	0

[1]The percentages should total to 100%, including Start-up Fuel.

If there is any fuel listed above that qualifies as Auxiliary Fuel as defined in the Glossary to the Rules, provide the % amount of annual fuel that is used for Start-up: ☐ %

j) Are all Environmental Attributes owned by the Developer? ☐

BC Hydro may request further information to verify ownership of Environmental Attributes.

k) For biogas, landfill gas control systems, and other similar projects, are there any GHG reduction rights associated with the project? ☐

If "Yes", describe: (BC Hydro may request further information to verify GHG reduction claims.)

2.2 Generation Technology

a) Describe the complete generation process that converts raw fuel into electricity. If necessary, include diagrams in Exhibit 8.

☐ Included and named Exhibit 8.

b) Is your technology considered a Commercial Operation Generation Technology or a Completed Prototype Generation Technology as defined in the Glossary to the Rules?

If Commercial Operation Generation Technology, go to c), if Completed Prototype Generation Technology, go to d).

c) Commercial Operation

Describe how the generation technology meets the requirements of Commercial Operation Generation Technology as defined in the Glossary to the Rules:

Provide the location and date of initial operation for at least one generation plant that is using the same generation technology proposed for the Project:

Date of initial operation: YYYY-MMM-DD

d) Completed Prototype

Describe how the generation technology meets the requirements of Completed Prototype Generation Technology, as defined in the Glossary to the Rules:

Complete Completed Prototype Generation Technology Certification form available on the Documents page of the SOP Website.

☐ Included and named Exhibit 9.

2.3 Generation Type

Is the Project described in the Application located Behind a BC Hydro Customer Load?

If "Yes", provide the following information:

Facility Name:

Customer Name:

Customer Account Number:

Describe the involvement of the BC Hydro customer in the Project:

Provide Electricity or Energy Service Agreement.

☐ Included and named Exhibit 10.

2.4 Existing and Previous Electricity Purchase Agreements

a) Is the Project currently subject to an EPA with BC Hydro?

b) Has the Project ever previously been subject to an EPA with BC Hydro?

If "Yes", describe and provide the effective date of termination of the EPA: YYYY-MMM-DD

Did the Project reach commercial operation while the EPA was in effect?

c) Is the Project currently subject to an EPA with a party other than BC Hydro?

If "Yes", describe and provide the EPA (pricing information may be kept confidential).

☐ Included and named Exhibit 11.

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2.5 BC Hydro Incentives

Has any of the energy offered for sale under the SOP received, or will it receive, funding through a Load Displacement or Demand Side Management ("DSM") program with BC Hydro or otherwise become available due to funding by BC Hydro? ☐

If "Yes", provide information relating to the funding, including any relevant agreements.

☐ Included and named Exhibit 12.

2.6 Preliminary Assessment

Has BC Hydro completed a preliminary assessment of the Project and/or the Developer as described in Section 4.1 of the Rules? ☐

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3.Permits, Site Control and Zoning

The Developer must comply with all laws, statutes and regulations relating to the Project whether federal, provincial and/or municipal and must obtain all permits, licenses and approvals required for the development, construction and operation of the Project. The following list is not a complete list of all permits, licenses and approvals required for any Project. Developers are solely responsible for determining the permitting and other legal requirements for their Projects.

The information provided by the Developer in response to this part of the Application should address all parts of the Project site (including all areas where the generating facility and related access roads, transmission lines and other Project facilities will be built).

BC Hydro may request the Developer to provide confirmation from the relevant regulatory authority that a permit or approval is not required for a Project.

KEY REQUIREMENT is indicated beside each relevant item in the list below. Key eligibility requirements must be in place and evidenced at the time of SOP Application submission or the Application will be rejected. All other permits applicable to the Project must be in place and evidenced before an Electricity Purchase Agreement is executed for the Project.

Indicate if the item listed below is applicable or not-applicable. Provide a copy of all of the applicable documents.

3.1 Federal Permits

a) Approval or exemption under section 5 of the *Navigation Protection Act*.
☐ Applicable and included and named Exhibit 13a.

b) Approvals under the *Fisheries Act* (including authorizations under section 35(2)(b) of the *Fisheries Act*) or a review demonstrating that such an approval is not required.
☐ Applicable and included and named Exhibit 13b.

c) Approvals under the *Aeronautics Act* and Canadian Aviation Regulations (e.g. lighting schemes, aeronautical safety for structures over 90 meters).
☐ Applicable and included and named Exhibit 13c.

d) Permit(s) or exemption(s) under the *Migratory Birds Convention Act* and Migratory Birds Regulations.
☐ Applicable and included and named Exhibit 13d.

e) Permit(s) or exemption(s) under the *Species at Risk Act*.
☐ Applicable and included and named Exhibit 13e.

f) **KEY REQUIREMENT** (for Projects that are reviewable under this Act) – Evidence of completion of assessment under the *Canadian Environmental Assessment Act 2012*, if applicable.
☐ Applicable and included and named Exhibit 13f.

3.2 Provincial Permits

a) Change approval under section 11 of the *Water Sustainability Act*.
☐ Applicable and included and named Exhibit 14a.

b) **KEY REQUIREMENT** (for hydro projects) – Licence under section 9 of the *Water Sustainability Act*.
☐ Applicable and included and named Exhibit 14b.

c) Permit(s) under section 14 or Operational Certificate(s) under section 28 of the *Environmental Management Act* (air, effluent and refuse, as required for the Project).
☐ Applicable and included and named Exhibit 14c.

d) Permit under section 12 of the *Heritage Conservation Act*.

☐ Applicable and included and named Exhibit 14d.

e) **KEY REQUIREMENT** (for geothermal projects) – Lease under section 8 of the *Geothermal Resources Act*.

☐ Applicable and included and named Exhibit 14e.

f) **KEY REQUIREMENT** (for Projects located on the Agricultural Land Reserve) – Permission under section 25 of the *Agricultural Land Commission Act*.

☐ Applicable and included and named Exhibit 14f.

g) Certificate issued under section 25 of the *Oil and Gas Activities Act*.

☐ Applicable and included and named Exhibit 14g.

h) Wildlife Management Area Permit (*Wildlife Act*, section 4) and/or permit under section 3 of the Permit Regulation (*Wildlife Act*) and/or Park Use Permit and/or Resource Use Permit (*Park Act*, section 20).

☐ Applicable and included and named Exhibit 14h.

i) **KEY REQUIREMENT** (for Projects that are reviewable under this Act) – Evidence of completion of assessment under the *British Columbia Environmental Assessment Act*, if applicable.

☐ Applicable and included and named Exhibit 14i.

3.3 Site Control

a) **KEY REQUIREMENT** (for Projects on Crown Land) – Lease, licence, right of way, easement and/or permit under the *Land Act* (B.C.), *Forest Act* (B.C.), *Transportation Act* (B.C.), Federal Real Property and *Federal Immovables Act*, *Canada Marine Act*, *Indian Act* or other provincial or federal legislation requiring land tenure for any aspect of the Project.

☐ Applicable and included and named Exhibit 15a.

b) **KEY REQUIREMENT** (for Projects on private land) – Copy of fee simple title, option to purchase, lease, licence, joint venture agreement or other contract granting occupancy rights for private land.

☐ Applicable and included and named Exhibit 15b.

c) Powerline sharing agreement if sharing powerline access with another entity.

☐ Applicable and included and named Exhibit 15c.

d) Where works are located on the foreshore, a letter of consent from the upland land owner permitting the infringement of their riparian rights; or, a copy of a Statutory right of way ceding those riparian rights to the applicant; or, copy of the fee simple title to the adjacent upland identifying it is owned by the applicant.

☐ Applicable and included and named Exhibit 15d.

e) **KEY REQUIREMENT** (for geothermal projects) – Permit under section 5 of the *Geothermal Resources Act* (B.C.).

☐ Applicable and included and named Exhibit 15e.

f) Lease under section 8 of the *Geothermal Resources Act* (B.C.)

☐ Applicable and included and named Exhibit 15f.

g) Where a Project's works are located within the right-of-way, access authorizations(s) under section 62 of the *Transportation Act* (B.C.).

☐ Applicable and included and named Exhibit 15g.

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h) Where a Project's works are located within the right-of-way, Road Permit(s) or Road Use Permit(s) under Part 8 of the *Forest Act* (B.C.).

☐ Applicable and included and named Exhibit 15h.

i) Where a Project's works are located within the right-of-way, agreements where a third party's infrastructure is required or crossed (e.g., road, railway, pipeline, transmission line crossings).

☐ Applicable and included and named Exhibit 15i.

3.4 Zoning / Local Government - KEY REQUIREMENT

Except for those public utilities that meet the conditions in section 2 of the Public Utility Regulation (BC Reg. 174/2006) other than the condition in subsection 2(a) of that Regulation, provide the following:

a) Letter from applicable local government confirming that those lands on which Project facilities are located and that are subject to local government land use requirements are appropriately zoned for those facilities.

☐ Applicable and included and named Exhibit 16a.

b) Development Permit issued by municipality or local government.

☐ Applicable and included and named Exhibit 16b.

3.5 Supplementary Information

a) Are any of the permits, licenses and approvals for the Project under appeal or judicial review? ☐

If "Yes", describe: ☐

b) Is there any outstanding order, judgment, litigation or other proceeding with respect to the Project? ☐

If "Yes", describe: ☐

c) Is there any significant opposition to the Project? ☐

If "Yes", describe: ☐

4.Interconnection

a) Has a System Impact Study application been submitted to BC Hydro Generator Interconnections? ☐

b) Have any other interconnection studies been completed for this Project? ☐

If "Yes", provide the study identifier, for example DGI-DSC-13.03.02.

☐

c) Point of Interconnection (e.g. nearest substation), if known.

☐

d) Interconnection voltage level: ☐ kV

e) Interconnection to: ☐

f) Interconnection type: ☐

If "Indirect", describe: ☐

g) If the Project has an Indirect Interconnection:

i) Describe the proposed point of delivery of energy to BC Hydro on the Distribution System or the Transmission System.

ii) Provide a copy of the agreement that authorizes the Developer to transmit energy from the Project to the proposed point of delivery on the Distribution System or the Transmission System.

☐ Included and named Exhibit 17.

iii) Describe the proposed method of calculating the quantity of energy delivered to BC Hydro at the point of delivery described in the response to ii) above.

iv) Complete and sign Interconnection Disclosure Consent Form available on the Documents page of the SOP Website.

☐ Included and named Exhibit 18.

5.First Nations

Provide information on how it was determined which First Nations may require consultation. Provide any information or direction Crown permitting agencies have provided in respect of consultation with First Nations.

Describe all First Nation consultations and engagement conducted relative to the Project. Provide a copy of all executed agreements with First Nations with respect to the Project. Include any letters of support from First Nations for the Project, if available.

Provide information on the potential impact from the Project on Aboriginal rights and title, and information on how this assessment was reached.

Refer to Section 2.16 of the Rules for more information on the adequacy of First Nations consultation.

☐ All the foregoing included and named Exhibit 19.

6.Proposed Project-Specific Changes to Standard Form EPA

Proposed changes to the Standard Form EPA are as follows:

EPA Section	Proposed Wording Change	Rationale

7.Representations, Warranties and Covenants

The Developer represents, warrants, and covenants with BC Hydro as follows and understands that BC Hydro is relying on these representations, warranties and covenants in deciding whether to offer an EPA to the Developer:

7.1 The Developer has reviewed carefully and fully understands the Rules, the Standard Form EPA and all related documents posted to the Standing Offer Program Website and has taken legal, accounting, engineering and other professional advice as the Developer considers necessary for it to understand its rights and obligations under the EPA if an EPA is offered to the Developer.

7.2 In preparing and submitting this Application, the Developer has not relied on any information given to it by BC Hydro, whether orally, in writing, electronically or in any other form whatsoever, except information disclosed in the Rules, the Standing Offer Program Website or advised in writing by the SOP Administrator.

7.3 In consideration for BC Hydro reviewing the Developer's Application, the Developer agrees to the terms, conditions and exclusions and limitations of liability set out in the Rules in effect at the time the Application was submitted, including without limitation those contained in Section 7 of the Rules, regardless of whether the Application is accepted, rejected or otherwise returned to the Developer.

7.4 The information contained in the Application is true and correct in all material respects and there is no material information omitted from the Application that makes the information in the Application misleading or inaccurate in any material respect.

7.5 The Developer is duly incorporated, organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation, is registered or otherwise lawfully authorized to carry on business in British Columbia, and has full power, capacity and authority to own its assets and to carry on its business as now conducted and to enter into and to perform its obligations under the EPA if an EPA is offered to the Developer. If the Developer is a joint venture or partnership, this representation is true and correct for each of the participants in the joint venture or partnership.

7.6 No actions have been taken or authorized by the Developer or any other person to initiate proceedings for, or in respect of, the bankruptcy, insolvency, liquidation, dissolution or winding-up of the Developer or to appoint a receiver, liquidator, trustee or assignee in bankruptcy in respect of the Developer.

7.7 No appropriation, expropriation or seizure of all or any portion of the Project, or the assets required to construct, operate or maintain the Project, is pending or threatened.

7.8 Neither the signing of the EPA, nor the carrying out of the Developer's obligations under the EPA will: (i) constitute or cause a breach of, default under, or violation of, the constating documents or bylaws of the Developer, any permit, franchise, lease, license, approval or agreement to which the Developer is a party, or any other covenant or obligation binding on the Developer or affecting any of its properties, (ii) cause a lien or encumbrance to attach to any of the assets included in the Project (as defined in the Standard Form EPA), other than a security interest granted in respect of financing the design, construction or operation of the Project, or (iii) result in the acceleration, or the right to accelerate, any obligation under, or the termination of, or the right to terminate, any permit, franchise, lease, license, approval or agreement related to the Project.

7.9 In consideration for BC Hydro reviewing the Developer's Application, the Developer agrees that: (A) BC Hydro has no liability to the Seller or any affiliates of the Seller for any failure by BC Hydro prior to the effective date of an EPA to adequately consult with, and/or accommodate, any First Nations in relation to: (i) any decision to offer or not to offer an EPA to the Developer, (ii) the Project, (iii) the Seller's Plant, or (iv) the interconnection of the Seller's Plant to the Transmission System or the Distribution System (excluding matters arising on BC Hydro's side of the point of interconnection to the Transmission System or Distribution System); and (B) BC Hydro's liability, if any, for any failure by BC Hydro after the effective date of an EPA to adequately consult with, and/or accommodate any First Nations in relation to the foregoing matters will be determined in accordance with the EPA as if it was still in effect notwithstanding any expiry, termination, declaration by any order of a court or regulatory authority that the EPA is invalid, void or unenforceable, or any other means by which the EPA ceases to be in effect.

7.10 The Developer has read carefully, and it is in compliance with, the BC Hydro Contractor Standards for Ethical Conduct which is current at the time of the Application. The BC Hydro Contractor Standards for Ethical Conduct is available on the Standing Offer Program Website.

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8.Signatures

[If Developer is a corporation, use the following signature block]

[Full legal name of Developer] _____

_____

Signature

Name: _____

Title: _____

Date: YYYY-MMM-DD

[If Developer is a limited partnership, use the following signature block]

[Full legal name of Developer] _____ , a limited partnership,

by its general partner, [Full legal name of general partner] _____.

_____

Signature

Name: _____

Title: _____

Date: YYYY-MMM-DD

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[If Developer is a general partnership, use the following signature block]

[Full legal name of Developer] _____ , a general partnership,
by its partners:

Partner 1 :

[Full legal name of Partner] _____

_____

Signature

Name: _____

Title: _____

Date: YYYY-MMM-DD _____

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[If Developer is a joint venture, use the following signature block]

[Full legal name of Developer] _____ , a joint venture,
by its members:

JV Member 1 :

[Full legal name of JV Member] _____

_____

Signature

Name: _____

Title: _____

Date: YYYY-MMM-DD _____

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List of Exhibits marked for inclusion

Exhibits — page reference

☐ 1. Project Ownership Structure 4
☐ 2. Conflict of Interest Statement Form 4
☐ 3. Geographical Map of the Project Location 5
☐ 4. Layout of the Key Project Facilities 5
☐ 5. Project Clusters and/or Common Generation Facilities - Supplementary Information 6
☐ 6. Project Schedule 6
☐ 7. Estimated Project Energy Calculations 6
☐ 8. Generation Process Diagrams 7
☐ 9. Completed Prototype Generation Technology Certification Form 8
☐ 10. Electricity or Energy Service Agreement 8
☐ 11. Non-BC Hydro Electricity Purchase Agreement 8
☐ 12. BC Hydro Incentives 9
☐ 13. Federal Permits 10
☐ 14. Provincial Permits 10
☐ 15. Site Control 11
☐ 16. Zoning / Local Government 12
☐ 17. Transmission Agreement for Indirect Interconnection 13
☐ 18. Interconnection Disclosure Consent Form 13
☐ 19. First Nations Information 13

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Exhibit 2

Conflict Of Interest Statement Form

[Form of disclosures required under BC Hydro's Contractor Standards for Ethical Conduct and any potential conflict of interests with BC Hydro, or BC Hydro's directors, officers or employees. Include and name Exhibit 2.]

Project Name: _____

Developer Name: _____

The Developer declares on its own behalf and on behalf of each member of the Developer's team that:

a) this declaration is made to the best of the knowledge of the Developer and, with respect to relationships of each member of the Developer's team, to the best of the knowledge of that member;

b) the Developer and the members of the Developer's team have reviewed the Contractor Standards for Ethical Conduct; and

c) the following is:

1) a full disclosure of all members of the Developer's team who were employees of BC Hydro at any time during the previous two year period from the date of this disclosure;

2) a full disclosure of all known relationships the Developer and each member of the Developer's team has, or has had, with:

i) BC Hydro;

ii) any current employees, shareholders, directors or officers, as applicable, of BC Hydro;

iii) any former shareholders, directors or officers, as applicable, of BC Hydro, who ceased to hold such position within two years from the date of this disclosure; and

iv) any other person who, on behalf of BC Hydro, has participated in or been involved in the design of the Standing Offer Program or any past BC Hydro competitive energy acquisition process; and

3) a full description of the actions that the Developer has undertaken or offers to undertake to address any actual, perceived or potential conflict of interest or unfair advantage arising from the relationships disclosed pursuant to subsections c)1) and c)2) above; and

d) if no such relationships are disclosed by the Developer, the Developer is not aware of any former employees as described in subsection c)1) above nor any relationships between the Developer or any member of the Developer's team, and any of the persons described in subsection c)2) above, and the Standing Offer Program Application has not been/is not being prepared with any involvement from any of those persons.

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Disclosures pursuant to section c) above are as follows:

Name of Member of Developer's Team e.g.: John Smith	Name of Party with Relationship (e.g., BC Hydro; employee name) BC Hydro	Details of the Nature of the Relationship with BC Hydro John Smith was a BC Hydro employee from [date] to [date]

For the purposes of this Conflict of Interest Statement Form:

"**Developer's Team**" means:

a) all persons who have been involved in the preparation of the Developer's Proposal; and

b) all persons who the Developer proposes to perform work or services under any resulting Electricity Purchase Agreement.

The Developer has undertaken or offers to undertake the following actions to address any actual, perceived or potential conflict of interest or unfair advantage arising from the relationships disclosed pursuant to subsections c) 1) and c)2) above:

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Exhibit 5

Project Clusters and/or Common Generation Facilities – Supplementary Information

[Projects that are located on the same site or in the vicinity of a Project Cluster or a Common Generation Facility. Include and name Exhibit 5.]

Provide responses to the following.

Project Name: _____

Developer Name: _____

a) Provide a geographical map which identifies the Project and the other existing or proposed generators ("the projects").

☐ Included and named Exhibit 5a.

b) Provide a brief description of the other existing or proposed generators, including the size of each generator.

c) Do the projects share common facilities, such as penstock, powerhouse, etc.?

d) Do the projects share interconnection facilities and/or a point of interconnection with the BC Hydro Integrated System?

e) Are the projects operating under common permits or tenures?

f) Do the projects share the same fuel source?

g) Are the projects under a common ownership (direct or indirect)?

h) Provide any other information that may support these projects being considered separate from the Project described in the Application.

i) Does any part of the projects (other than the Project being submitted to the SOP) have an EPA with BC Hydro or any third party?

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Exhibit 9

Completed Prototype Generation Technology Certification

This form must be completed by a professional engineer (or equivalent engineering designation) registered or licensed in a jurisdiction that regulates the practice of engineering. Include and name Exhibit 9.

Project Name: _____

Developer Name: _____

a) Generally describe the innovative components or sub-systems that are included in the overall generation technology system.

b) Describe the prototype testing environment, the tests completed to date, and the relevance of the test conditions to real-world conditions.

c) Certification. By signing below, the professional engineer certifies that the generation technology has completed a program of testing, with satisfactory results, using a sub-scale or full-scale prototype of the technology to simulate real-world conditions, which sufficiently demonstrates technical viability and safe performance of the technology at full-scale and under real-world conditions, subject to any qualifications listed below.

Describe any qualifications to the above certification.

_____
Signature

Name: _____

Title: _____

Date: YYYY-MMM-DD

Licensed professional engineer (or equivalent engineering designation) in the following jurisdiction(s):

Association License Number:

Name of licensing authority:

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Exhibit 18

Interconnection Disclosure Consent Form

[Form of consent to disclosure of project information between BC Hydro and third party owner of transmission or distribution system. Include and name Exhibit 18.]

Where the Project has an Indirect Interconnection through any transmission or distribution system other than the BC Hydro system, such as the FortisBC system or a third party privately owned line, this Form must be completed and signed to provide the Developer's consent to disclosure of information by the third party to BC Hydro and vice versa.

Project Name: _____

Developer Name: _____

The undersigned consents to:

(i) the disclosure by [INSERT NAME OF THIRD-PARTY] to BC Hydro of all information submitted by the undersigned to [INSERT NAME OF THIRD-PARTY] relating, directly or indirectly, to the interconnection of the Project to [INSERT NAME OF THIRD-PARTY] 's electricity transmission / distribution system (including any services related to the interconnection), the interconnection between [INSERT NAME OF THIRD-PARTY] 's electricity / distribution system and BC Hydro's Transmission System, and the transmission of electricity from the Project through the transmission / distribution system to BC Hydro's Transmission System and/or the impact of the Project on the transmission / distribution system, BC Hydro's Transmission System, or the interconnection between the Project and the transmission / distribution system or between BC Hydro's Transmission System and the transmission / distribution system, including any and all study reports, calculations and other information of any kind whatsoever with respect thereto whether submitted by the undersigned to [INSERT NAME OF THIRD-PARTY] or prepared by [INSERT NAME OF THIRD-PARTY] ; and

(ii) the disclosure by BC Hydro to [INSERT NAME OF THIRD-PARTY] , at BC Hydro's sole discretion, of information submitted by the undersigned to BC Hydro relating, directly or indirectly, to the interconnection of the Project and the transmission of electricity from the Project and any and all study reports, calculations and other information of any kind whatsoever with respect thereto whether submitted by the undersigned to BC Hydro or prepared by BC Hydro.

By: _____

Signature

Name: _____

Title: _____

Date: YYYY-MMM-DD

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CONFIDENTIALITY AND COMPLIANCE AGREEMENT

Revised: March 2016

This Confidentiality and Compliance Agreement (the "***Agreement***") is made as of _____, 20____ ***[Note: Date to be completed by BC Hydro at time of signing by BC Hydro.]***

BY AND BETWEEN

[INSERT FULL LEGAL NAME OF COUNTERPARTY]
of [INSERT FULL ADDRESS WITH POSTAL CODE]
("***Counterparty***")

AND

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, a British Columbia Crown Corporation, having an office at 333 Dunsmuir Street, Vancouver, British Columbia, V6B 5R3
("***BC Hydro***")

(the foregoing may be referred to individually as a "***Party***" or collectively as the "***Parties***")

WHEREAS BC Hydro and the Counterparty wish to enter into discussions, which may include negotiations concerning an electricity purchase agreement (an "**EPA**"), pursuant to BC Hydro's Micro-SOP or Standing Offer Program (the "***Program***").

NOW THEREFORE, in consideration of the Parties entering into this Agreement and the mutual promises and agreements contained in this Agreement, the Parties agree as follows:

1. DEFINITIONS

1.1 **Confidential Information**. "***Confidential Information***" means any of the Counterparty's confidential technical or financial information provided by the Counterparty to BC Hydro in confidence in connection with the Program and/or any related EPA with express written notice to BC Hydro of the confidential nature of the information, whether such confidential information is provided orally, in writing, electronically or by any other media, but excluding any executed and delivered EPA or related securities delivered thereunder or any agreement collateral thereto, and also excluding information that:

(a) is or becomes in the public domain, other than as a result of a breach of this Agreement by BC Hydro;

(b) is known to BC Hydro before disclosure to it by the Counterparty, or becomes known to BC Hydro thereafter by way of disclosure to BC Hydro by any other person who, to BC Hydro's knowledge, is not under an obligation of confidentiality with respect thereto; or

(c) is, or has been, disclosed by the Counterparty to any government authority in connection with any permit, approval or tenure for any project proposed by the Counterparty in the Program and any information that is directly related to or that is based on or derived from that information, other than any financial information relating to the Counterparty or any such project.

1.2 **Affiliate**. "***Affiliate***" has the meaning given in the Standard Form Electricity Purchase Agreement for the Program.

1.3 **Discussions**. "***Discussions***" means discussions, including negotiations, whether orally, in

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writing, electronically or by any other media, between the Parties pertaining to the Program and/or any related EPA from the effective date of this Agreement to the termination of such discussions or an EPA, if any, between the Parties is fully executed and delivered, whichever shall first occur and "discussions" includes, but is not limited to, the Counterparty's questions and BC Hydro's responses thereto in the Q & A process under the Program and any preliminary assessment of eligibility for the Program provided by BC Hydro to the Counterparty.

1.4 **Rules**. "***Program Rules***" means the BC Hydro document so entitled and available on the websites at www.bchydro.com/microsop and www.bchydro.com/standingoffer, as amended or replaced from time to time.

2. CONFIDENTIALITY OBLIGATION

2.1 **Confidentiality Obligation**. BC Hydro shall treat as confidential, and shall not disclose to any third person, Confidential Information, and both Parties shall treat as confidential and shall not disclose to any third person, all or any part of the Discussions, provided however that the foregoing obligations, and nothing in this Agreement, prevents or restricts:

(a) disclosure of the fact that Discussions, if any, are occurring, or have occurred, and/or the fact that this Agreement exists and the general nature hereof;

(b) in the case of BC Hydro, disclosure of the Discussions and/or Confidential Information:

(i) to any ministers, deputy ministers, servants or employees of the Province of British Columbia; and

(ii) to BC Hydro's directors, officers, employees, subsidiaries, consultants and advisors;

provided that each of the foregoing to whom Discussions and/or Confidential Information is disclosed is advised of the confidential nature thereof;

(c) in the case of BC Hydro, disclosure of Discussions and/or Confidential Information in any regulatory proceeding, whether in respect of an EPA entered into with the Counterparty pursuant to the Program or in respect of other matters, to the extent that BC Hydro considers disclosure necessary or desirable to support its position in any such proceeding, provided that, to the extent reasonably practicable, BC Hydro gives reasonable notice to the Counterparty before making the disclosure, and, to the extent requested by the Counterparty, requests the relevant tribunal to treat all or any part of the disclosure as confidential or to limit its further disclosure;

(d) in the case of BC Hydro, disclosure:

(i) of the Counterparty's questions and BC Hydro's response thereto in the Q&A process under the Program without attribution to the Counterparty;

(ii) to a third person of Confidential Information that was known by that third person before disclosure thereof by BC Hydro, including information that originated from that third person or that the Counterparty or any other person has given to the third person, in each case as indicated on the face of any document or as acknowledged by the Counterparty; and

(iii) such information as BC Hydro considers necessary to provide any publicly available report on the conduct and outcome of the Program, including the Counterparty's participation in the Program and the conclusion of an EPA with the Counterparty (if applicable), the location and capacity of any project proposed by the Counterparty, and the energy associated with any project proposed by the Counterparty;

(e) in the case of the Counterparty, disclosure of Discussions to its directors, officers, employees and affiliates, consultants and advisors, provided that each of the foregoing to whom Discussions are disclosed is advised of the confidential nature thereof and

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undertakes in writing to respect such confidentiality on the terms of this Agreement, provided that the Counterparty shall give to BC Hydro, at its request, a copy of each such undertaking;

(f) without limiting BC Hydro's disclosure rights under section 2.1(c) above, disclosures required to be made by BC Hydro or the Counterparty by an order of a court or tribunal or under any law, regulatory requirement or requirement of any stock exchange that is binding upon it, provided that, (i) to the extent reasonably practicable, the Party making such disclosure gives reasonable notice to the other Party before making the disclosure, and (ii) limits the disclosure to that required by the applicable order, law, or regulatory or stock exchange requirement;

(g) disclosures in any legal proceedings for the enforcement of this Agreement and/or any EPA or in the defence of any legal proceedings brought by any third person(s) against either or both the Parties in any way relating to the Program; or

(h) disclosures of the Discussions and/or Confidential Information by agreement or consent of both Parties.

2.2 **Disclosure of EPA**. Disclosure of any executed EPA, or any summary thereof or information contained therein, will be governed by the EPA.

2.3 **Freedom of Information and Protection of Privacy Act**. The Counterparty acknowledges that BC Hydro is subject to the British Columbia *Freedom of Information and Protection of Privacy Act* and associated regulations, and agrees that BC Hydro's non_disclosure obligations under this Agreement are subject to the provisions of that legislation, as the same may be amended or replaced from time to time.

2.4 **Term:** BC Hydro's obligation of confidentiality with respect to Confidential Information expires three years after the date hereof.

3. PROGRAM RULES BINDING

The Counterparty acknowledges and agrees that it is bound by, and will comply with, the terms and conditions of the Program Rules, including without limitation Section 7 and all exclusions and limitations of liability therein, in relation to its participation in the Program.

4. MISCELLANEOUS

4.1 **Liability Exclusion**. In no event will either Party be liable to the other Party in connection with any breach of this Agreement for any indirect, incidental or consequential damages, including loss of profits.

4.2 **Governing Law**. This Agreement shall be interpreted, governed and construed under the laws of the Province of British Columbia and the laws of Canada applicable therein as if it were executed, and to be performed wholly, within the Province of British Columbia.

4.3 **Equitable Relief**. Each Party agrees that in the event of a breach of this Agreement, or to prevent a breach or contemplated breach, by that Party, the other Party shall be entitled to equitable relief, including injunction and specific performance, in addition to all other remedies available at law or equity.

4.4 **Entire Agreement**. This Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof and supersedes and cancels all prior agreements and communications relative to such subject matter.

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4.5 **No Implied Terms**. No terms or conditions whatsoever may be implied in this Agreement.

4.6 **Amendments**. This Agreement shall not be modified, except by a written agreement dated after the date of this Agreement and signed by both Parties.

4.7 **Assignment**. This Agreement may not be assigned by either Party without the prior written consent of the other Party, without releasing the liabilities and obligations of the Counterparty hereunder.

4.8 **Enurement**. This Agreement is binding upon and enures to the benefit of the Parties and their respective successors and permitted assigns.

4.9 **Execution In Counterparts**. This Agreement may be executed in counterparts, and each counterpart shall for all purposes be an original, and all such counterparts shall together constitute one and the same Agreement.

4.10 **Facsimile Signature.** This Agreement may be executed and delivered by signatures transmitted by facsimile or other electronic means.

4.11 **Relationship**. Entering into this Agreement shall in no way be construed to:

(a) preclude in any way either Party from pursuing any business opportunities;

(b) establish any relationship between BC Hydro and the Counterparty with respect to such business opportunities; or

(c) establish any other relationship between BC Hydro and the Counterparty with respect to any project proposed by the Counterparty under the Program.

IN WITNESS WHEREOF, the Parties have entered into this Agreement effective as of the date first above written.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

By: _____

Name: _____

Title: _____

_____
Signature

Name: _____

Title: _____

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REFERENCE: **Application, Appendix 5.4, page 5.4-3**

ISSUE: **Mt. Sumanik Wind Feasibility Studies**

QUOTE: "From 2016 to 2017, the project work consisted mostly of data collection and management, as well as evaluating upgrades to the power system for the monitoring equipment which experienced difficulties. In 2018 work was conducted to repair the laser of the Lidar unit as the equipment was malfunctioning… The need for YEC to directly conduct resource wind monitoring and site assessments has since been eliminated due to the high likelihood that future wind resources will be developed by Independent Power Producers. As such, the project was decommissioned in 2020 with total expenditures of $775,581 to be amortized over five years."

PREAMBLE: **YEC incurred $694,427 in 2018, $31,155 in 2019 and $50,000 in 2020.**

QUESTION:

a) Please confirm that the cost to repair the laser of the Lidar unit was included in the 2018 costs, provide the exact cost of this repair and provide a breakdown of any other costs incurred in that year.

b) Please provide a breakdown of the costs for the wind feasibility projects incurred for 2019 and 2020.

c) Please explain how YEC determined that it was not required to conduct wind monitoring and site assessments. For example, did it engage in meetings with Independent Power Producers who expressed interest in wind development?

ANSWER:

(a) and **(b)**

Confirmed that cost to repair the laser of the Lidar unit was included in the 2018 costs. Please see Attachment 1 to this response for breakdown of 2018 costs, as well as of 2019 and 2020 actual costs. The following are noted with regard to this information:

- The Application's costs shown for 2018, as stated at pages 5.4-2 and 5.4-3, include all costs incurred prior to 2018; and

- The 2020 costs in Attachment at $25,005 are actual costs (and differ from the $50,000 forecast cost in the Application due to the cost for removing the unit being much lower than had been forecast).

(c)

Wind was not identified as a required resource in the 10-Year Renewable Electricity Plan, given its provision of intermittent renewable energy and no dependable capacity (which is currently at a shortfall). As YEC is not pursuing any wind projects, wind monitoring and site assessments are unnecessary at this time. It is expected wind energy will be provided from the Independent Power Producer Standing Offer Program. Proponents of this program are responsible for all development costs for their projects, including wind monitoring and site assessments.

2018 Mt Sumanik Costs

Task/Cost type

AFUDC	$14,537.47
Communication	$1,219.39
Consultants	
Subscription: Land permit	$150.00
YEC internal labour: includes project management and site visits and maintenance	$10,318.73
Propane	$1,750.52
Materials and supplies: Includes Lidar repair ($28,793.6)	$31,658.90
Shipping: Lidar and equipment for repair	$4,257.36
Travel to site	$12,349.64
TOTAL 2018 COST	**$76,242.01**

2019 Mt Sumanik Costs

Task/Cost type

AFUDC	$16,804.38
Communication	$480.00
Consultants - Hatch wind data assessment	$11,790.00
Subscription: Land Permit	$150.00
YEC internal labour: includes project management and site visits and maintenance	$1,640.00
Propane	$270.00
Materials and supplies	
Shipping	
Travel to site	$20.23
TOTAL 2019 COST	**$31,154.61**

2020 Mt Sumanik Costs

Task/Cost type

AFUDC	$18,221.41
Communication	$480.00
Consultants	
Subscription: Land Permit	
YEC internal labour: includes project management and site visits and maintenance	$1,402.94
Propane	
Materials and supplies	$234.96
Shipping	
Travel to site	$4,666.00
TOTAL 2020 COST	**$25,005.31**

REFERENCE: **Application, Appendix 5.4, pages 5.4-3 to 5.4-4 and footnote 1, page 5.4-3**

ISSUE: **WH2 Uprate Engineering**

QUOTE: From pages 5.4-3 to 5.4-4 of the Application:

"See Section 5.2.1.10 for a full description and business case for completing the WH2 Uprate Project before the end of 2021."

From page 5.4-3, footnote 1 of the Application:

"1 By end of 2021 WH2 Uprate Engineering costs will be transferred to Property, Plant and Equipment and added to WH2 Uprate total cost [amortized over 72 years starting in 2022]."

QUESTION:

a) Please explain why costs for the WH2 Uprating Engineering study are not included in the costs for the WH2 Uprate Project, which is classified as a Capital Works project.

b) Is a 72-year amortization period typical for projects of this nature? If not, please explain why such an amortization period was chosen for this project.

ANSWER:

(a)

WH2 Uprate Engineering costs included under Table 5.6 of Tab 5 are part of WH2 Uprate project as indicated in the footnote #1 to Appendix 5.4 and note #2 to Table 5.6 in Tab 5. This project has a separate project number and the spending maintained separately from other capital expenditures for the WH2 Uprate project. Therefore, it was presented under Table 5.6, deferred costs.

There is no impact to the revenue requirement or requested rate increases as the project is amortized starting in 2022.

(b)

The amortization rate was mis-quoted. A 72 year life applies to hydro structures, asset class 1615-200. The proper asset class is 1615-506 – Waterwheels, Turbines and Generators with an expected life of 60 years. There is no impact to the revenue requirement request in this application as this project will not enter service until 2022 (i.e., outside the test year).

REFERENCE: **Application, Appendix 5.4, page 5.4-4**

ISSUE: **Building Condition Reports 2020-2024**

QUOTE: "YEC is moving from a crisis management model (e.g. waiting for a furnace to fail in the middle of winter), towards a preventive maintenance schedule (identifying life cost cycling of a furnace) for all YEC-owned buildings. This change in approach can provide material cost savings. Building condition reports are required to formally document the structure and fabric of a property, describe the construction of the building and its current condition, and outline work required, timing and costs for completion."

QUESTION:

a) Please explain YEC's rationale for implementing a crisis management model originally.

ANSWER:

(a)

Prior to having a full wide Building Condition Reports (BCRs) in 2013 by Golder Engineering maintenance was very reactive in nature. There was no proper structured capture of property management, hence the terminology of Crisis Management, which implies repairs were being done as required. The cost implications saved by having detailed BCRs in place allows for life cycle management of equipment and replacement of required building components in a timely fashion to avoid expensive "right now" repair call-outs for individual items.

REFERENCE: **Application, Appendix 5.4, page 5.4-6**

ISSUE: **Whitehorse Diesel Rental Substation Improvements**

QUOTE: "The project is to be closed in 2021 with total expenditures of $100,000 to be amortized over 45 years."

QUESTION:

a) Is a 45-year amortization period typical for projects of this nature? If not, please explain why such an amortization period was chosen for this project.

ANSWER:

(a)

Yes. A 45 year amortization period is typical for projects of this nature.

REFERENCE: **Application, Appendix 5.5, page 5.5-1**

ISSUE: **Deferred Studies Between $100,000 and $1 Million Not Impacting Rate Base**

PREAMBLE: YEC included the expenditures for the EV Infrastructure Project and P125 Trashrack Study, forecasted at $200,000 for each study in 2021.

QUESTION:

a) Please confirm that the $200,000 for each project will not be added to rate base in this GRA. Please explain if there are plans to include costs for these projects in future GRAs.

ANSWER:

(a)

Confirmed. These projects are not forecast to be included in rate base in the test year.

See YUB-YEC-1-101 for further information regarding status of the EV Infrastructure Project; the response notes YEC has chosen to defer this project to a future year, as it is expected to take several years for the rollout of electric vehicles to take place at a larger scale in Yukon. YUB-YEC-1-102 provides further information regarding status the trash rack study.

Costs for the above studies would be included in a subsequent GRA for prudence review by the Board after the studies have been completed.

REFERENCE: **Application, Appendix 5.5, page 5.5-1**

ISSUE: **Deferred Studies, EV Infrastructure Project, Electric Vehicle Charging Stations**

QUOTE: "The Yukon government 'Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy' includes a number of actions to encourage the adoption of electric vehicles in Yukon, and the construction of public electric vehicle charging stations. The Yukon Government is forecasting 5,000 electric vehicles in the Yukon by 2030. YEC must be proactive in undertaking infrastructure upgrades and improvements to accommodate the anticipated increased demand on the electrical grid due to this planned growth. Strategy development will assess the potential impact of electric vehicles on the Yukon electrical system and identify a path forward for YEC to meet these challenges. Not addressing this could result in unforeseen costs and reactionary programs."

QUESTION:

a) Please provide a breakdown of the forecasted $200,000 for this project. More specifically, provide the activities YEC is planning to engage in and provide the cost allocated to each activity. Does YEC foresee any customer contributions related to costs for this project?

b) Please provide your preliminary view on whether the Capital Works projects discussed in this application will defer or eliminate infrastructure upgrades related to electric vehicle charging station growth.

c) How many electric vehicle charging stations have been installed by the Yukon Government and YEC?

d) What rate schedule(s) apply to these charging stations and how are these revenues accounted for in YEC's Application?

e) Please include details of the quantities of energy supplied through and any revenues for YEC resulting from the charging stations.

f) In YEC's view, why is it reasonable for system demand to be increased and the charges recovered through rates when the benefits of the charging stations would only accrue to those who own electric vehicles?

ANSWER:

(a) to **(f)**

Subsequent to the submission of the Application, YEC has chosen to defer this project to a future year, as it is expected to take several years for the rollout of electric vehicles to take place at a larger scale in Yukon. The Compliance Filing will be adjusted to reflect this decision. This change has no impact on the forecast revenue requirement for the 2021 test year, i.e., Appendix 5.5 includes only projects forecast to remain in WIP.

REFERENCE: **Application, Appendix 5.5, page 5.5-1**

ISSUE: **P125 Trashrack Study**

QUOTE: "The P125 intake is becoming blocked with debris and frazil ice. These blockages are currently being removed manually by divers and plant operators. This results in multiple outages each year to address blockages. Not addressing this issue will mean continued outages and requirement for divers to address the issue manually. A track [sic] rack must be installed that can permanently address the variety of debris encountered at the intake. The study will confirm the deck structural capacity and other details such as power supply and trash rack geometry."

QUESTION:

a) Please provide the number and duration of outages caused by the debris and frazil ice blockage in the last 10 years, on a per annum basis, and the costs incurred for these outages.

b) Please provide a breakdown of the forecast $200,000 for this project. More specifically, provide the activities YEC is planning to engage in and provide the cost allocated to each activity.

ANSWER:

(a)

Yukon Energy is in the process to complete the Trashrack Study. The initial observations for the 2018 and 2019 year was Yukon Energy had an average of 6 days of plant outages for cleaning out the trashrack. Based on this estimate, crane cost in addition to potential energy gains from the having the trashrack partly blocked in between cleanings, initial estimates show that the trashrack cleaner is potently economic and should be studied. Also, having a trashrack cleaner would help to lower the risk of frazil ice blockages on WH1,2,3,4, in the early winter, which leads to system instability. During the full study, all potential benefits will be reviewed and the last 10 years of history will be included.

(b)

Costs for the project include $100,000 for detailed design, $30,000 for project management, and $70,000 for procurement and selection of vendor(s).

REFERENCE: **Application, Appendix 5.6, page 5.6-1**

ISSUE: **ERP System Upgrades**

QUOTE: "Given YEC's role as the primary generator of electricity for an isolated grid, it is critical to maintain a modern and robust Enterprise Resource Planning (ERP) system. ERP system refers to a type of software that organizations use to manage day-to-day business activities such as accounting, procurement, project management, maintenance management and supply chain operations. Best practice is to update systems regularly to ensure that the systems are up to date. The project involves upgrades to the ERP system components to the recommended latest stable versions. System experts are contracted to help with individual components as these are critical systems and YEC has no inhouse expertise."

QUESTION:

a) Please explain the implications of not upgrading the ERP system components to the recommended latest stable versions.

b) Please explain how often YEC has updated the ERP system in the last 10 years and provide the cost of these upgrades.

c) Please provide YEC's analysis comparing the expected benefits of this project to the forecast costs. Please include an explanation of cost savings or cost avoidances that have been or are expect to be realized.

ANSWER:

(a)

There are many implications of not upgrading the ERP system components to the recommended latest stable versions, including the following:

- **Lack of support -** You can no longer get support when calling up vendors as they will only support clients with up-to-date stable systems.

- **Security concerns because security patches cannot be installed -** Security holes have been identified and these need the latest versions to be fixed.

- **System instability -** Older protocols are no longer supported; YEC can no longer get client applications (i.e., Internet explorer 8).

(b)

Prior to the upgrade in 2020, YEC has updated the ERP system once in 2016 at a cost of $66,000.

(c)

Due to the nature of the implications indicated in part (a), a financial cost/benefit analysis is not considered necessary.

REFERENCE: **Application, Tab 7 schedules, Schedule 4, page 7-8**

ISSUE: **Cost of Capital Calculation**

QUESTION:

a) Please confirm that cell G58 of Schedule 4 should equal cell N25 of Schedule 7. If not confirmed, please explain and provide the calculation of the value in cell G58.

b) Please confirm that cell M56 of Schedule 4 should equal cell M60 multiplied by cell K56. If not confirmed, please explain and provide the calculation of the value in cell M56.

c) Please confirm that cell M58 of Schedule 4 should equal cell M60 multiplied by cell K58. If not confirmed, please explain and provide the calculation of the value in cell M58.

d) Please confirm that cell M60 of Schedule 4 should yield the same value as the sum of cells M56 and M58. If not confirmed, please explain. If confirmed, please explain why it does not yield the same value and correct if necessary.

e) If any of parts (a), (b), (c) and (d) are confirmed, please provide the corrected schedules along with an explanation of any changes to YEC's revenue requirement or rates resulting from the corrections.

ANSWER:

(a) through **(e)**

Minor edits to Tab 7 schedules are noted below and then responses are provided to the specific questions.

YEC identified that the number in line 20 of Schedule 4 [cell G58 in the excel file] was not correctly linked. YEC also revised the calculations for cells M56 and M58 to use the capitalization ratios in Schedule 4, column K in the excel file to avoid impact of rounding of decimal points [the overall impact to the revenue requirement is less than $300].

Please see YUB-YEC-1-104(e) Attachment 1 for revised version of Tab 7 schedules. Please note that there is no impact to the requested rate increase from the above adjustments.

With regard to the specific questions, the following responses are provided:

(a)

Not confirmed. Cell G58 of Schedule 4 is mid-year 2021, and cell N25 of Schedule 7 is only year end 2021.

(b), **(c)** and **(d)**

Confirmed.

(e)

See Attachment 1 to this response.

Yukon Energy Corporation
Computation of Rate Base
($000s)

Schedule 1
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	**Property, Plant and Equipment**							
2	Year end balance	S.3 L.4	612,436	615,387	642,738	677,309	738,663	738,663
	Deduct:							
3	Accumulated depreciation (note 1)	S.3 L.8	163,053	160,541	172,426	185,389	198,334	198,970
4	Construction-in-progress	S.3 L.12	7,620	4,491	8,088	10,796	37,389	37,389
5	Disallowed assets	S.3 L.11	2,193	2,193	1,989	1,785	1,582	1,582
6	Miscellaneous reserves	S.3 L.16	7,808	7,249	6,231	4,849	4,655	5,012
7	Total deductions		180,674	174,474	188,735	202,820	241,960	242,953
	Add:							
8	Deferred study costs and Intangible assets (note 2)	S.3 L.59	41,695	30,118	32,133	37,884	44,400	44,400
9	Less: Studies and Intangible Assets in Progress	S.3 L.60	29,498	18,930	20,881	26,065	29,972	29,972
10	Total additions		12,198	11,188	11,252	11,819	14,428	14,428
	Net plant in Service							
11	Current year-end balance	S.3 L.62	443,960	452,101	465,255	486,307	511,131	510,138
12	Previous year-end balance		446,777	446,782	452,101	465,255	486,307	486,307
13	Mid-year balance		445,368	449,441	458,678	475,781	498,719	498,223
14	Mid-year regulatory deferral		3,879	3,805	3,009	2,484	2,732	2,732
15	Working capital	S.2 L.8	5,344	5,617	5,935	6,592	6,985	7,141
16	**Gross Rate Base**		454,592	458,864	467,622	484,858	508,436	508,096
	Deduct:							
	Contributions for extensions (PP&E)							
17	Current year-end balance		201,232	199,527	211,719	228,231	257,031	257,031
18	Contributions in WIP		-	603	385	776	20,776	20,776
19	Current year-end balance in-service		201,232	198,924	211,333	227,455	236,255	236,255
20	Accumulated amortization of contributions		35,976	34,536	39,276	44,306	48,767	48,767
21	Net current year-end balance in-service		165,256	164,387	172,057	183,149	187,488	187,488
22	Previous year-end balance		168,967	168,967	164,387	172,057	183,149	183,149
23	Mid-year balance		167,112	166,677	168,222	177,603	185,319	185,319
24	**Net Rate Base**	S.5 L.1	287,480	292,186	299,399	307,255	323,117	322,777

Note 1: Including Reserve for Future Removal and Site Restoration
Note 2: Planning and Study costs, Relicencing, Dam Safety costs, Vegetation Management and Intangible Assets. Net of contributions.

Yukon Energy Corporation
Computation of Allowance for Working Capital
($000s)

Schedule 2
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	Operating and maintenance	S.5 L.5	23,715	27,794	29,784	37,653	41,119	43,863
2	Taxes other than income	S.5 L.6	708	671	673	739	750	750
3	Non-allowable expenses		(100)	(99)	(166)	(95)	(120)	(120)
4	Cash operating expenses		24,323	28,366	30,290	38,298	41,748	44,492
5	27/365		1,799	2,098	2,241	2,833	3,088	3,291
6	Inventory (three year average)		3,703	3,697	3,837	3,913	4,014	4,014
7	GST Impact on working capital	S.2A L.11	(158)	(178)	(143)	(154)	(117)	(164)
8	Working capital	S.1 L.19	5,344	5,617	5,935	6,592	6,985	7,141

Yukon Energy Corporation
Effect of GST on Working Capital
($000s)

Schedule 2A
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	Expenses subject to GST		42,084	37,733	53,916	69,534	99,535	102,279
2	GST Rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
3	GST Recoverable		2,104	1,887	2,696	3,477	4,977	5,114
4	Day Factor		14	14	14	14	14	14
5	Recoverable portion of GST impact		81	72	103	133	191	196
6	Revenue subject to GST		49,794	52,059	51,302	59,947	64,164	75,135
7	GST blended rate (2009 GRA)		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
8	GST payable		2,490	2,603	2,565	2,997	3,208	3,757
9	Day factor		35	35	35	35	35	35
10	Payable portion of GST impact		239	250	246	287	308	360
11	Net impact of GST on working capital	S.2 L.7	(158)	(178)	(143)	(154)	(117)	(164)

Yukon Energy Corporation
Continuity Schedule of Property, Plant and Equipment, Deferred Costs and Intangible Assets
($000s)

Schedule 3
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
	Property, Plant and Equipment							
1	Balance at beginning of year		598,756	598,756	615,387	642,738	677,309	677,309
2	Net Increases to PPE (Table 5.1)		13,680	20,189	29,259	34,571	61,354	61,354
3	Retirements, disposals and adjustments		-	(3,559)	(1,908)	-	-	-
4	Balance at end of year	S.1 L.2	612,436	615,387	642,738	677,309	738,663	738,663
	Accumulated depreciation							
5	Balance at beginning of year		150,857	150,857	160,541	172,426	185,389	185,389
6	Depreciation expense	S.6 L.7	12,196	12,185	12,677	12,963	12,945	13,581
7	Retirements, disposals and adjustments		-	(2,501)	(791)	-	-	-
8	Balance at end of year	S.1 L.3	163,053	160,541	172,426	185,389	198,334	198,970
	Deductions from PP&E:							
9	Disallowed assets		2,746	2,746	2,746	2,746	2,746	2,746
10	Accum. Disallowed depreciation		(553)	(553)	(757)	(961)	(1,164)	(1,164)
11	Net Disallowed	S.1 L.5	2,193	2,193	1,989	1,785	1,582	1,582
12	Construction-in-progress	S.1 L.4	7,620	4,491	8,088	10,796	37,389	37,389
	Miscellaneous Reserves							
13	Fire Insurance Reserve		4,704	4,704	4,442	4,180	3,918	3,918
14	Reserve for Injuries and Damages		(1,035)	(1,419)	(1,002)	(2,121)	(2,053)	(1,697)
15	Reserve for Future Removal and Site Restoration		4,139	3,963	2,790	2,790	2,790	2,790
16	Total Miscellaneous Reserves	S.1 L.6	7,808	7,249	6,231	4,849	4,655	5,012
17	Total Deductions		17,621	13,933	16,308	17,431	43,626	43,983
18	Net Property, Plant and Equipment for Rate Base		431,762	440,913	454,003	474,489	496,703	495,710
	Add:							
19	Deferred study costs and Intangible assets (net of contributions)							
20	Feasibility Studies							
21	Opening balance		18,499	18,499	17,798	16,841	16,791	16,791
22	Additions		14,127	1,091	866	1,819	7,370	7,370
23	Amortization		(1,838)	(1,791)	(1,824)	(1,869)	(2,272)	(2,272)
24	Year-end balance		30,788	17,798	16,841	16,791	21,889	21,889
25	Relicensing							
26	Opening balance		6,604	6,604	8,447	10,123	11,970	11,970
27	Additions		1,544	2,359	2,102	2,148	1,745	1,745
28	Amortization		(515)	(515)	(427)	(301)	(368)	(368)
29	Year-end balance		7,633	8,447	10,123	11,970	13,347	13,347
30	Dam Safety							
31	Opening balance		118	118	89	59	345	345
32	Additions		-	-	-	315	-	-
33	Amortization		(30)	(30)	(30)	(30)	(93)	(93)
34	Year-end balance		89	89	59	345	252	252
35	Vegetation Management							
36	Opening balance		1,994	1,994	1,772	1,551	1,329	1,329
37	Additions		-	-	-	-	-	-
38	Amortization		(222)	(222)	(222)	(222)	(222)	(222)
39	Year-end balance		1,772	1,772	1,551	1,329	1,108	1,108
40	Intangibles							
41	Opening balance		1,859	1,859	1,684	2,339	6,000	6,000
42	Additions		79	308	1,215	4,239	495	495
43	Amortization		(478)	(482)	(560)	(578)	(749)	(749)
44	Year-end balance		1,460	1,684	2,339	6,000	5,746	5,746
45	DSM							
46	Opening balance		990	995	1,253	1,319	1,510	1,510
47	Additions		-	350	210	375	894	894
48	Amortization		(110)	(92)	(144)	(184)	(228)	(228)
49	Year-end balance		880	1,253	1,319	1,510	2,176	2,176
50	Hearing Reserve							
51	Opening balance		(1,026)	(1,026)	(926)	(99)	(61)	(61)
52	Additions		155	155	883	93	-	-
53	Amortization		(55)	(55)	(55)	(55)	(55)	(55)
54	Year-end balance		(926)	(926)	(99)	(61)	(116)	(116)
55	Total Deferred Costs and Intangible Assets							
56	Opening balance		29,038	29,043	30,118	32,133	37,884	37,884
57	Additions		15,906	4,262	5,276	8,989	10,504	10,504
58	Amortization		(3,248)	(3,187)	(3,261)	(3,239)	(3,987)	(3,987)
59	Year-end balance	S.1 L.8	41,695	30,118	32,133	37,884	44,400	44,400
60	Less: Working in Progress	S.1 L.9	29,498	18,930	20,881	26,065	29,972	29,972
61	Total Net Deferred Costs and Intangible Assets for Rate Base		12,198	11,188	11,252	11,819	14,428	14,428
62	Total Net PP&E, Deferred Costs and Intangible Assets for Rate Base	S.1 L.11	443,960	452,101	465,255	486,307	511,131	510,138
63	Other Regulatory							
64	Opening balance		3,868	3,863	3,746	2,272	2,696	2,696
65	Additions		318	141	(1,209)	670	500	500
66	Amortization		(295)	(258)	(266)	(246)	(428)	(428)
67	Year-end balance		3,891	3,746	2,272	2,696	2,768	2,768
68	Total Net PP&E, Deferred Costs and Intangible Assets		447,850	455,847	467,527	489,004	513,899	512,906

Yukon Energy Corporation
Calculation of Depreciation Expense for 2021
($000s)

Schedule 3A
November 2020

Description	Cost at 2020 Year End	2021 Additions	Cost at 2021 Year End	Existing Depreciation Rate (Years)	2021 Existing Forecast Depreciation	Proposed Depreciation Rate (Years)	2021 Proposed Forecast Depreciation
Land							
Hydraulic Production	444.9	0.0	444.9	0	0.0	0	0.0
Diesel Production	27.7	0.0	27.7	0	0.0	0	0.0
Main Transmission Facilities	576.9	0.0	576.9	0	0.0	0	0.0
Distribution System	17.8	0.0	17.8	0	0.0	0	0.0
General Plant	548.0	0.0	548.0	0	0.0	0	0.0
Rights	128.8	0.0	128.8	50	1.6	50	1.6
Depreciation Study Differences					0.0		0.0
Total Land	**1,744.0**	**0.0**	**1,744.0**		**1.6**		**1.6**
Hydro Plant							
Structures and Improvements	37,647.8	17,068.5	54,716.3	72	522.9	72	522.9
Buildings and Improvements	10,278.7	0.0	10,278.7	40	257.0	40	257.0
Reservoirs, Dams, and Waterways	173,561.2	300.0	173,861.2	103	1,685.4	103	1,685.4
Overhaul	6,712.1	0.0	6,712.1	10	671.2	10	671.2
Waterwheels,Turbines & Generation	26,904.6	0.0	26,904.6	85	309.9	60	439.0
Accessory Electric Equipment	27,364.1	750.0	28,114.1	45	608.0	40	684.0
Accessory Digital Equipment	837.9	0.0	837.9	20	41.9	20	41.9
Misc Power Plant Equipment	11,791.4	25.0	11,816.4	30	393.0	30	393.0
Fencing	107.1	0.0	107.1	30	2.7	30	2.7
Depreciation Study Differences					-307.6		-140.5
Total Hydro Plant	**295,205.0**	**18,143.5**	**313,348.5**		**4,184.4**		**4,556.6**
Diesel Production							
Structures and Improvements	1,562.4	0.0	1,562.4	72	21.7	72	21.7
Buildings and Improvements	466.1	0.0	466.1	55	8.5	55	8.5
Fuel Holders, Products, and ACC	1,688.5	0.0	1,688.5	25	41.6	40	26.0
Generating Equipment and Prime	14,596.8	0.0	14,596.8	40	635.2	40	635.2
Overhaul	2,962.8	580.0	3,542.8	5	592.6	5	592.6
Minto Generating Equipment	243.5	0.0	243.5	12	26.1	12	26.1
Accessory Electric Equipment	9,018.9	0.0	9,018.9	45	199.7	45	199.7
Misc Power Plant Equipment	1,837.7	0.0	1,837.7	30	59.2	30	59.2
Depreciation Study Differences					-80.6		-70.2
Total Diesel Production	**32,376.6**	**580.0**	**32,956.6**		**1,503.9**		**1,498.7**
Wind Turbine							
Wind Turbine	0.0	0.0	0.0	0	0.0	0	0.0
Total Wind Turbine	**0.0**	**0.0**	**0.0**		**0.0**		**0.0**
Main Transmission Facilities							
Poles and Fixtures	86,010.6	12,855.0	98,865.6	65	1,323.2	50	1,720.2
Brushing	14,082.3	0.0	14,082.3	50	281.6	60	234.7
Survey Costs	4,380.7	0.0	4,380.7	50	238.7	60	198.9
Overhead Conductors / Poles	20,561.3	0.0	20,561.3	50	411.2	60	342.7
Overhead Conductors / Towers	278.0	0.0	278.0	50	5.6	60	4.6
Substation Equipment	81,331.5	300.0	81,631.5	54	1,512.8	45	1,815.3
Substation Buildings	1,536.2	0.0	1,536.2	55	27.9	55	27.9
Substation Fences	274.5	0.0	274.5	20	13.4	30	8.9
Depreciation Study Differences					-53.4		-79.6
Total Main Transmission Facilities	**208,455.0**	**13,155.0**	**221,610.0**		**3,761.1**		**4,273.7**
Sub Transmission Lines							
Poles and Fixtures	4,579.6	0.0	4,579.6	45	100.0	50	90.0
25Kv Minto Spur- Structure	2,646.1	0.0	2,646.1	12	0.0	12	0.0
Brushing	41.6	0.0	41.6	50	0.8	60	0.7
Brushing Minto	432.5	0.0	432.5	12	0.0	12	0.0
Survey costs	0.0	0.0	0.0	50	0.0	60	0.0
Survey costs Minto	95.1	0.0	95.1	12	0.0	12	0.0
Overhead Conductors	1,840.4	0.0	1,840.4	45	40.7	60	30.5
Underground Conductors / Conduit	83.9	0.0	83.9	45	1.9	45	1.9
Overhead Conductors Minto	920.7	0.0	920.7	12	0.0	12	0.0
Substation Equipment	8,013.6	0.0	8,013.6	40	200.3	45	178.1
Substation Equipment Minto	7,111.2	0.0	7,111.2	12	74.6	12	74.6
Depreciation Study Differences					-27.4		-45.8
Total Sub Transmission Lines	**25,764.8**	**0.0**	**25,764.8**		**391.0**		**330.0**

Yukon Energy Corporation
Calculation of Depreciation Expense for 2021
($000s)

Schedule 3A
November 2020

Description	Cost at 2020 Year End	2021 Additions	Cost at 2021 Year End	Existing Depreciation Rate (Years)	2021 Existing Forecast Depreciation	Proposed Depreciation Rate (Years)	2021 Proposed Forecast Depreciation
Distribution System							
Poles and Fixtures	9,798.1	649.1	10,447.1	35	280.1	40	245.1
Brushing	44.8	0.0	44.8	50	0.9	50	0.9
Survey costs	619.4	0.0	619.4	50	17.7	50	17.7
Overhead conductors - Poles	268.2	0.0	268.2	35	7.7	50	5.4
Overhead Costs	2,117.4	0.0	2,117.4	40	52.9	40	52.9
Underground Services	385.2	0.0	385.2	40	9.6	40	9.6
Underground Conduit	40.5	0.0	40.5	40	1.0	40	1.0
Wind Monitoring Equipment	0.0	0.0	0.0	0	0.0	0	0.0
Meters	312.6	0.0	312.6	30	8.6	16	16.1
Meter Equipment	288.4	0.0	288.4	30	9.2	16	17.2
Substation Equipment	1,287.2	0.0	1,287.2	40	30.3	40	30.3
Substation Buildings	64.8	0.0	64.8	55	1.2	55	1.2
Substation Fences	100.3	0.0	100.3	20	5.0	30	3.3
Street Lights	591.6	0.0	591.6	40	13.8	40	13.8
Line Transformers	4,051.1	0.0	4,051.1	40	98.9	35	113.0
Sentinel Lights	36.4	0.0	36.4	30	1.2	30	1.2
Depreciation Study Differences					-27.6		1.3
Total Distribution System	**20,005.9**	**649.1**	**20,654.9**		**510.5**		**530.1**
Building and Other Equipment							
Survey Costs Land	4.3	0.0	4.3	50	0.1	50	0.1
Structures and Improvements (Hydro)	2,791.6	0.0	2,791.6	40	69.4	50	55.5
Building and Improvements	10,632.1	125.0	10,757.1	55	193.3	50	212.6
Office Furniture and Equipment	1,877.4	25.0	1,902.4	20	47.2	20	47.2
Communication Site Towers	19.3	0.0	19.3	30	0.6	40	0.5
Communication Site Fences	64.1	25.0	89.1	20	3.2	30	2.1
Computer Hardware	2,063.4	230.0	2,293.4	5	188.7	7	134.8
Computer Software	0.0	0.0	0.0	5	0.0	5	0.0
Tool and Instruments	2,157.5	490.0	2,647.5	20	84.4	20	84.4
Wind Monitoring Equipment	14.3	0.0	14.3	20	0.7	15	1.0
Communication Equipment	5,615.6	100.0	5,715.6	20	234.1	20	234.1
Company Owned Houses / Land	59.0	0.0	59.0	30	1.7	40	1.3
Company Owned Houses	2,132.4	230.0	2,362.4	30	22.8	40	17.1
Depreciation Study Differences					-29.0		-19.0
Total Building and Other Equipment	**27,431.1**	**1,225.0**	**28,656.1**		**817.1**		**771.6**
Transportation							
Utility Vehicles	371.6	30.0	401.6	7	29.3	8	25.6
Sedans and Stationwagons	137.8	0.0	137.8	7	9.4	11	6.0
Trucks & Pole Trailer	11.0	0.0	11.0	31	0.4	25	0.4
Pole Trailers > 10,000 Lbs	53.7	0.0	53.7	25	1.7	25	1.7
Trucks 3/4 to 2 Ton	3,378.4	580.0	3,958.4	10	242.4	9	269.3
Trucks > 3 Ton	1,459.8	185.0	1,644.8	20	58.4	20	58.4
Foremost	1,003.9	0.0	1,003.9	25	40.2	20	50.2
Depreciation Study Differences					-0.7		19.3
Total Transportation	**6,416.1**	**795.0**	**7,211.1**		**381.0**		**431.0**
Critical Spares							
Critical Spares	1,193.6	0.0	1,193.6	0	0.0	0	0.0
Total Critical Spares	**1,193.6**	**0.0**	**1,193.6**		**0.0**		**0.0**
LNG Production							
Structures and Improvements	6,184.7	0.0	6,184.7	72	85.9	72	85.9
Fuel Holders	13,200.7	0.0	13,200.7	32	412.5	60	220.0
Generator	20,891.0	0.0	20,891.0	40	522.3	40	522.3
Overhaul	343.3	180.0	523.3	2	171.4	2	171.4
Accessory Electric Equipment	3,655.9	0.0	3,655.9	45	81.2	45	81.2
Misc Power Plant Equipment	2,850.6	35.0	2,885.6	30	95.0	30	95.0
Fence	779.7	0.0	779.7	30	26.0	30	26.0
Depreciation Study Differences					0.0		-14.0
Total LNG Prodution	**47,905.9**	**215.0**	**48,120.9**		**1,394.4**		**1,187.9**
Total	**666,498.0**	**34,762.5**	**701,260.5**		**12,944.9**		**13,581.1**

Yukon Energy Corporation
Cost of Capital Calculation
($000s)

Schedule 4
November 2020

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio		Mid Year Rate Base	Mid Year Cost Rate	Return
	2018 GRA Compliance							
1	Long-Term debt	S.11 L.18	172,472	60.0%		172,473	2.23%	3,844
2	Common Stock	S.7 L. 8	115,005	40.0%		115,007	8.70%	10,006
3	Total	S.5 L.3	287,477	100.0%		287,480	4.82%	13,850
	2018 Actual							
7	Long-Term debt	S.11 L.18	159,362	57.4%		167,813	2.58%	4,336
8	Common Stock	S.7 L. 8	118,109	42.6%		124,373	6.25%	7,773
9	Total	S.5 L.3	277,471	100.0%		292,186	4.14%	12,110
	2019 Actual							
10	Long-Term debt	S.11 L.18	170,377	58.6%		175,532	2.71%	4,757
11	Common Stock	S.7 L. 8	120,229	41.4%		123,867	3.81%	4,723
12	Total	S.5 L.3	290,606	100.0%		299,399	3.17%	9,480
	Existing 2020							
10	Long-Term debt	S.11 L.18	179,873	59.6%		183,023	2.92%	5,339
11	Common Stock	S.7 L. 8	122,093	40.4%		124,232	3.88%	4,824
12	Total	S.5 L.3	301,966	100.0%		307,255	3.31%	10,163
	Existing 2021							
16	Long-Term debt	S.11 L.18	193,756	60.0%		193,870	2.81%	5,446
17	Common Stock	S.7 L. 8	129,171	40.0%		129,247	3.10%	4,002
18	Total	S.5 L.3	322,927	100.0%		323,117	2.92%	9,448
	Proposed 2021				**Deemed Ratio**			
19	Long-Term debt	S.11 L.18	193,505	59.8%	60.0%	193,666	2.81%	5,447
20	Common Stock	S.7 L. 8	130,088	40.2%	40.0%	129,111	8.70%	11,235
21	Total	S.5 L.3	323,593	100.0%	100.0%	322,777	5.17%	16,682

Yukon Energy Corporation
Utility Revenue Requirement
($000s)

Schedule 5
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	Net rate base	S.1 L.24	287,480	292,186	299,399	307,255	323,117	322,777
2	Average Rate of return on rate base		4.82%	4.14%	3.17%	3.31%	2.92%	5.17%
3	Utility income	S.8 L.1	13,850	12,110	9,480	10,163	9,448	16,682
4	Utility expenses							
5	Operating and maintenance (note 1)	S.6 L.3	23,715	27,794	29,784	37,653	41,119	43,863
6	Taxes other than income	S.6 L.4	708	671	673	739	750	750
7	Amortization of deferred costs	S.6 L.5	3,543	3,500	3,582	3,540	4,471	4,471
8	Reserve for Injuries and Damages	S.6 L.6	479	479	479	479	479	835
9	Depreciation	S.6 L.7	12,196	12,185	12,677	12,963	12,945	13,581
10	Amortization of contributions and fire insurance recoveries	S.6 L.8	(4,394)	(4,377)	(5,002)	(5,291)	(4,723)	(4,723)
11	Disallowed depreciation		(204)	(204)	(204)	(204)	(204)	(204)
12	Donations		(100)	(99)	(166)	(95)	(120)	(120)
13	Total utility expenses		35,943	39,949	41,822	49,784	54,716	58,453
14	Revenue Requirement	S.6 L.1	49,794	52,059	51,302	59,947	64,164	75,135

Note 1: Includes fuel expenses and purchased power.

Yukon Energy Corporation
Statement of Earnings
($000s)

Schedule 6
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	Revenues (note 1)	S.5 L.14	49,794	52,059	51,302	59,947	64,164	75,135
2	**Operating expenses**							
3	Operating and maintenance	S.10 L.15	23,715	27,794	29,784	37,653	41,119	43,863
4	Taxes other than income	S.5 L.6	708	671	673	739	750	750
5	Amortize deferred costs		3,543	3,500	3,582	3,540	4,471	4,471
6	Reserve for Injuries and Damages	S.5 L.8	479	479	479	479	479	835
7	Depreciation	S.3 L.8	12,196	12,185	12,677	12,963	12,945	13,581
8	Amortization of contributions and fire insurance recoveries	S.5 L.10	(4,394)	(4,377)	(5,002)	(5,291)	(4,723)	(4,723)
9	Total		36,247	40,252	42,192	50,083	55,040	58,777
10	**Operating income**		13,546	11,807	9,110	9,864	9,124	16,359
11	**Other income**							
12	Allowed for Funds Used	S.8 L.2	542	539	648	831	1,269	1,269
13	Miscellaneous (note 2)	S.8 L.3	(515)	(824)	(951)	(508)	(307)	(327)
14	Total		28	(284)	(304)	323	961	941
15	**Other expenses**							
16	Interest expense	S.8 L.4	4,431	5,583	6,124	9,663	5,631	5,631
17	Total		4,431	5,583	6,124	9,663	5,631	5,631
18	**Net earnings**	S.8 L.8	9,142	5,939	2,683	524	4,454	11,669

Note 1: Includes revenues from sales and other revenues.
Note 2: Miscellaneous primarily consistent of Regulatory gain/losses and other interest income/expenses.

Yukon Energy Corporation
Statement of Retained Earnings
($000s)

Schedule 7
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	Balance at beginning of year		60,775	61,366	67,653	65,606	66,983	69,153
	Add:							
2	Net earnings	S.6 L.18	9,142	5,939	2,683	524	4,454	11,669
3	IFRS Comprehensive Income Adjustment		1,660	348	(1,859)	853	-	-
4	Balance at end of year before dividend		71,577	67,653	68,477	66,983	71,437	80,821
	Less:							
5	Common Dividends (note 1)		10,414	-	2,871	-	-	3,623
6	Balance at end of year		61,163	67,653	65,606	66,983	71,437	77,198
	Shareholder's Equity							
7	Common shares		54,036	53,600	53,600	57,998	61,924	57,998
8	Retained earnings		61,163	67,653	65,606	66,983	71,437	77,198
9	Total		115,200	121,253	119,206	124,981	133,361	135,196

Note:
1. YDC equity injection/dividend estimates required in order to maintain 60/40 debt to equity ratio.

Yukon Energy Corporation

Reconciliation of Utility Income to Net Earnings
($000s)

Schedule 8
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	Utility Income (Return on Rate Base)	S.5 L.3	13,850	12,110	9,480	10,163	9,448	16,682
	Add:							
2	Allowance for funds used	S.6 L.12	542	539	648	831	1,269	1,269
3	Other income (expenses)	S.6 L.13	(515)	(824)	(951)	(508)	(307)	(327)
			13,878	11,825	9,176	10,486	10,409	17,624
	Less:							
4	Interest - long-term	S.6 L.17	4,431	5,583	6,124	9,663	5,631	5,631
5	Donations	S.5 L.12	100	99	166	95	120	120
6	Disallowed costs	S.5 L.13	-	-	-	-	-	-
7	Disallowed depreciation	S.5 L.11	204	204	204	204	204	204
			4,735	5,886	6,494	9,962	5,955	5,955
8	Net earnings	S.6 L.18	9,142	5,939	2,683	524	4,454	11,669

Yukon Energy Corporation
Summary of Customers, Energy Sales and Revenues
($000s)

Schedule 9
November 2020

Line No.	Description	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Proposed 2021
1	**Residential**					
2	Customers	1,635	1,689	1,730	1,756	1,780
3	Sales in MWh	13,719	15,626	15,384	16,730	16,210
4	MWh sales per customer	8.4	9.3	8.9	9.5	9.1
5	Revenue ($000s)	2,016	2,262	2,262	2,413	2,384
6	Cents per KWh	14.7	14.5	14.7	14.4	14.7
7	**General Service**					
8	Customers	489	506	517	516	514
9	Sales in MWh	25,436	27,171	29,148	32,250	32,323
10	MWh sales per customer	52.0	53.7	56.4	62.5	62.9
11	Revenue ($000s)	4,054	4,490	4,833	5,351	5,388
12	Cents per KWh	15.9	16.5	16.6	16.6	16.7
13	**Industrial**					
14	Sales in MWh	32,193	36,910	27,286	64,856	102,904
15	Revenue ($000s)	3,952	4,378	3,673	7,260	11,535
16	Cents per KWh	12.3	11.9	13.5	11.2	11.2
17	**Street lights**					
18	Sales in MWh	214	224	168	168	168
19	Revenue ($000s)	56	87	82	82	82
20	Cents per KWh	26.0	39.1	48.8	48.8	48.8
21	**Space lights**					
22	Sales in MWh	12	11	10	10	10
23	Revenue ($000s)	3	3	3	3	3
24	Cents per KWh	22.5	29.2	26.7	28.1	26.6
25	**Total Company - Firm Retail and Industrial**					
26	Customers	2,125	2,195	2,247	2,272	2,293
27	Sales in MWh	71,573	79,941	71,997	114,013	151,614
28	Revenue ($000s)	10,081	11,221	10,853	15,108	19,392
29	Cents per KWh	14.1	14.0	15.1	13.3	12.8
30	**Wholesale sales**					
31	Sales in MWh	314,700	332,270	331,495	351,775	343,537
32	Revenue ($000s)	26,114	27,572	27,507	29,190	28,507
33	Cents per KWh	8.3	8.3	8.3	8.3	8.30
34	**Total Company - Firm**					
35	Sales in MWh	386,273	412,212	403,491	465,788	495,151
36	Revenue ($000s)	36,194	38,792	38,360	44,298	47,899
37	Cents per KWh	9.4	9.4	9.5	9.5	9.7
38	**Secondary**					
39	Sales in MWh	2,059	258	0	0	0
40	Revenue ($000s)	115	20	0	0	0
41	Cents per KWh	5.6	7.6	7.6	0.0	0.0
42	**Total Company**					
43	Sales in MWh	388,332	412,470	403,492	465,788	495,151
44	Revenue ($000s)	36,310	38,812	38,360	44,298	47,899
45	Cents per KWh	9.4	9.4	9.5	9.5	9.7
46	Rider J	13,231	13,329	13,842	15,289	15,897
47	Post-GRA Reconcil Req'd					
48	GRA Increase Req'd				0	10,971
49	Total Sales of Power	49,541	52,141	52,203	59,588	74,767
50	Other Revenues	253	-82	-901	359	369
51	Total Revenues	49,794	52,059	51,302	59,947	75,135

Yukon Energy Corporation
Summary of Operating and Maintenance Expenses
($000s)

Schedule 10
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	**Utility operations**							
2	Production		5,930	7,755	8,402	9,871	10,909	10,909
3	Transmission and distribution		3,445	2,835	2,767	3,215	3,187	3,187
4	General		1,615	1,746	1,921	1,695	1,770	1,770
5	Administration and general		8,917	8,966	9,201	9,603	10,557	10,557
6	Insurance		1,031	1,046	1,117	1,299	1,423	1,423
7	Sub-total		20,938	22,347	23,407	25,684	27,845	27,845
8	Donations		100	99	166	95	120	120
9	Sub-total		100	99	166	95	120	120
10	O&M not including fuel and							
11	purchased power		21,038	22,447	23,574	25,779	27,965	27,965
12	Fuel		2,638	5,295	6,153	11,814	12,787	15,530
13	Purchased power		39	53	57	60	367	367
14	Sub-total		2,677	5,348	6,211	11,874	13,153	15,897
15	Total operating and maintenance	S.6 L.3	23,715	27,794	29,784	37,653	41,119	43,863
	Operating and Maintenance Expense Reported in Tab 3 excludes fuel and purchase power, but also includes the following:							
16	*Reserve for Injuries and Damages*		*479*	*479*	*479*	*479*	*479*	*835*
17	*Property Taxes*		*708*	*671*	*673*	*739*	*750*	*750*
18	*less: Donations*		*(100)*	*(99)*	*(166)*	*(95)*	*(120)*	*(120)*
19	*O&M per Table 3.3 (Tab 3)*		*22,125*	*23,497*	*24,559*	*26,903*	*29,074*	*29,430*

Yukon Energy Corporation
Summary of Labour Costs
($000s)

Schedule 10A
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	**Total FTEs**	Tab 3, Table 3.4	93.7	94.9	98.4	97.9	103.6	103.6
2	**Total Labour Costs**		14,394	14,173	14,131	15,420	16,148	16,148
3	O&M Labour Costs	Sum Lines 5-9	11,932	12,083	11,863	12,727	13,310	13,310
4	Labour Costs to Capital		2,461	2,090	2,268	2,694	2,838	2,838
	Labour Costs							
5	Production		4,131	4,455	4,467	4,995	4,931	4,931
6	Transmission		635	526	545	659	674	674
7	Distribution		856	801	625	617	629	629
8	General		395	351	391	343	378	378
9	Administration		5,916	5,949	5,835	6,113	6,699	6,699
10	Total Labour		11,932	12,083	11,863	12,727	13,310	13,310

Yukon Energy Corporation
Summary of Cost of Long - Term Debt
($000s)

Schedule 11
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
	General Purpose Long-Term Debt Balance							
1	YDC Mayo B Flexible Term Debt		19,542	19,542	19,205	18,868	18,531	18,531
2	TD Bank Swap (2.69%)		8,991	8,991	8,623	8,245	7,858	7,858
3	Minto Decommissioning Reserve		2,684	2,710	2,769	2,800	2,816	2,816
4	YDC $5.5M Debt (2.40%)		5,505	5,505	5,505	5,505	5,505	5,505
5	YDC $92.5M Debt (2.40%/2.83%)		77,723	77,723	74,039	70,356	66,672	66,672
6	YDC $21.0M Debt (2.21%)		18,466	18,466	17,627	16,788	15,948	15,948
7	YDC $12.1M Debt (2.10%)		12,136	12,136	12,136	12,136	12,136	12,136
8	TD Bank Swap (3.665%)		21,940	23,406	22,811	22,194	21,554	21,554
9	New 2018 Debt-2018 True Up (2.15%)		5,776	0	0	0	0	0
10	TD Bank Swap (2.899%)		0	0	6,688	6,498	6,303	6,303
11	YDC $2.9M Debt (2.899%)		0	0	2,871	2,871	2,871	2,871
12	New 2020 Debt-2019 True Up (2.19%)		0	0	0	8,760	8,760	8,760
13	New 2020 Debt-2020 True Up (2.19%)		0	0	0	12,450	12,450	12,450
14	New 2021 Debt-2021 True Up (2.19%)		0	0	0	0	18,638	18,135
15	Current year-end balance		172,763	168,479	172,274	187,471	200,041	199,539
16	Previous year-end balance		172,181	150,244	168,479	172,274	187,471	187,471
17	Mid Year		172,472	159,362	170,377	179,873	193,756	193,505
	Interest Costs							
18	YDC Mayo B Flexible Term Debt		334	771	690	1,049	1,030	1,030
19	TD Bank Swap (2.69%)		247	247	237	227	217	217
20	Minto Decommissioning Reserve		24	45	59	31	16	16
21	YDC $5.5M Debt (2.40%)		132	132	132	132	132	132
22	YDC $92.5M Debt (2.40%/2.83%)		1,954	1,954	1,865	1,984	1,886	1,886
23	YDC $21.0M Debt (2.21%)		427	427	408	390	371	371
24	YDC $12.1M Debt (2.10%)		255	255	255	255	255	255
25	TD Bank Swap (3.665%)		472	287	848	826	803	803
26	New 2018 Debt-2018 True Up (2.15%)		0	0	0	0	0	0
27	TD Bank Swap (2.899%)		0	0	81	191	186	186
28	YDC $2.9M Debt (2.899%)		0	0	42	83	83	83
29	New 2020 Debt-2019 True Up (2.19%)		0	0	0	79	192	192
30	New 2020 Debt-2020 True Up (2.19%)		0	0	0	0	273	273
31	New 2021 Debt-2021 True Up (2.19%)		0	0	0	0	0	0
32	**Total Cost of Interest**		3,844	4,118	4,618	5,247	5,443	5,443
33	Mid-Year Cost of Debt		2.23%	2.58%	2.71%	2.92%	2.81%	2.81%

REFERENCE: **Application, Tab 7 schedules, Schedule 9, page 7-13**

ISSUE: **Revenues**

QUESTION:

a) Please explain how the revenue figures in rows 5, 11, 15, 19, 23 and 32 are calculated.

b) Please provide references to where the calculation(s) for part (a) are explained in the Application.

ANSWER:

(a) and **(b)**

The revenues at existing rates are calculated as follows:

- The revenues at existing rates for YEC retail customers [lines 5, 11, 19 and 23, Schedule 9] are calculated based on forecast energy sales for the test year multiplied by average revenue per kW.h sales. The average revenues per KW.h sales are determined based on actual base rate revenues for last five years, 2015 through 2019 as shown below [please note the numbers are subject to rounding]:

    - Average base rate revenues per kW.h for residential customers at 14.71 cents/kW.h [by way of example AEY's 2016-17 GRA Compliance Filing average revenue per kW.h at 14.10 cents/kW.h].

    - Average base rate revenues per kW.h for general service customers at 16.67 cents/kW.h [by way of example AEY's 2016-17 GRA Compliance Filing average revenue per kW.h at 16.33 cents/kW.h].

    - Average base rate revenues per kW.h for streetlight and space light at 38.44 cents/kW.h and 27.18 cents/kW.h respectively.

- For wholesales [line 15, Schedule 32] – the revenues at existing rates are calculated based on forecast sales for the test year [343,537 MW.h] multiplied by the existing wholesales rate [8.298 cents/kW.h].

- For industrial customers [line 15, Schedule 9] the revenues at existing rates are calculated based on:
    - Forecast energy sales for the test year multiplied by existing energy rates, including fixed Rider F;
    - Forecast peak demand multiplied by existing demand rate; plus
    - Fixed Charge revenues based on assumed new Fixed Charges.[1]

Forecast sales and revenues are described in Section 2.2 of the Application and Table 2.1. Additional details on the calculations have been provided above.

[1] At the time of preparation of the Application YEC forecasted the new Transmission Facilities Development coming into service connecting the McQuesten Substation with a substation at Mayo in late November 2020/early December 2020 triggering new Fixed Charges effective January 1, 2021 as outlined in section 4.4.2 of the Application and Appendix 4.3. Based on this assumption the existing rate revenues for industrial customers in the Application used Fixed Charge at $35,734/month effective January 1, 2021 [subject to a separate application] compared to $8,402/month existing Fixed Charge. However, the in service date for the new Transmission Facilities Development is delayed. YEC will adjust the existing rate revenues for industrial customers in Compliance Filing.

REFERENCE: **Application, Tab 7 schedules, Schedule 11, page 7-16**

ISSUE: **Interest Costs**

QUESTION:

a) Please explain why there is no interest cost in cell N46 of Schedule 11 for new 2021 debt-2021 true up.

ANSWER:

(a)

The GRA assumes the new long-term debt for 2021 is issued in late 2021 to finance the capital projects and maintain 60/40 debt to equity ratio. Therefore, no interest expense is calculated for the 2021 new debt [the interest expense assumed to start in January 2022].

REFERENCE: **Application, Section 3.4, Rate base, page 3-22; and Tab 7, Schedule 2A, page 7-4**

ISSUE: **Working Capital**

QUOTE: "The balance of the change in net rate base from mid-year 2018 approved to mid-year 2020 reflects increased working capital ($1.8 million increase in 2021 forecast over 2018 approved of $5.3 million)."

Schedule 2A from page 7-4:

Yukon Energy Corporation
Effect of GST on Working Capital
($000s)

Schedule 2A
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	Expenses subject to GST		42,084	37,733	53,916	69,534	99,535	102,279
2	GST Rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
3	GST Recoverable		2,104	1,887	2,696	3,477	4,977	5,114
4	Day Factor		14	14	14	14	14	14
5	Recoverable portion of GST impact		81	72	103	133	191	196

QUESTION:

a) Please provide a complete reference to any Tab 3, Tab 5, Tab 7 or other schedule that can be used for the same purpose of clearly arriving at the YEC's Line No. 1 "Expenses subject to GST" for all years indicated.

ANSWER:

(a)

Please see Table 1 for the requested information.

Table 1: Expenses Subject to GST for Working Capital Calculation Purposes

Line No		Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021	References
1	Feasibility Studies	17,798	16,841	16,791	21,889	21,889	Schedule 3, Line 24
2	Relicensing	8,447	10,123	11,970	13,347	13,347	Schedule 3, Line 29
3	Dam Safety	89	59	345	252	252	Schedule 3, Line 34
4	Intangibles	1,684	2,339	6,000	5,746	5,746	Schedule 3, Line 44
5	DSM	1,253	1,319	1,510	2,176	2,176	Schedule 3, Line 49
6	Hearing Reserve	-926	-99	-61	-116	-116	Schedule 3, Line 54
7	Other Regulatory Deferred Costs	3,746	2,272	2,696	2,768	2,768	Schedule 3, Line 67
8=Sum(1:7)	**Total Deferred Costs**	**32,092**	**32,855**	**39,251**	**46,061**	**46,061**	
9	Annual Change in Deferred Costs	1,180	763	6,396	6,810	6,810	
10	Annual amortization added back	4,316	4,298	4,192	4,951	4,951	Note 1
11=9+10	**Total Additions to Deferred Costs for Working Capital Purposes**	**5,496**	**5,060**	**10,589**	**11,761**	**11,761**	
12	Property, Plant and Equipment Cost Year End Balance	615,387	642,738	677,309	738,663	738,663	Schedule 3, Line 4
13	Annual Change	16,631	27,351	34,571	61,354	61,354	
14	Remove AFUDC	539	648	831	1,269	1,269	Note 2
15=13-14	**Total Additions to PP&E for Working Capital Purposes**	**16,091**	**26,704**	**33,739**	**60,086**	**60,086**	
	Operating and Maintenance Costs						
16	Fuel	5,348	6,211	11,874	13,153	15,897	Schedule 10, Line 14
17	LWRF Transfer [estimate]	-534	-4,398	-375	0	0	Note 3
18=16-17	Total Fuel	5,882	10,609	12,248	13,153	15,897	
19	Non-fuel O&M net of Labour Cost	10,264	11,544	12,958	14,535	14,535	Schedule 10, Line 7 less Labour Cost per Tab 3, Table 3.3
20=18+19	**Total for Working Capital Purposes**	**37,733**	**53,916**	**69,534**	**99,535**	**102,279**	Schedule 2A, Line 1

Notes:

1. Amortization expense for deferred costs are added back to calculate annual change in deferred cost balances before amortization. The amortization expense is before impact of contributions. During the review of calculations YEC noticed that amortization expense of Intangibles was not added back. However, the impact is insignificant [the revenue requirement is underestimated by less than $100].
2. AFUDC is removed for GST impact calculations.
3. LWRF transfers are estimated at the time of filing of the Application.

REFERENCE: **Application, Summary item 1(c), page 5; Table 3.14, page 3-22**

ISSUE: **Depreciation Expense**

QUOTE: "Depreciation and Amortization Expenses: Approval of depreciation and amortization expenses forecast of $13.125 million for 2021, including approval of the following:

i. Updated Depreciation Rates: Approval of updated depreciation rates as set out in Tab 7, with an overall increase to 2021 depreciation expense of approximately $0.636 million; and …

c. **Depreciation and Amortization Expenses:** Approval of depreciation and amortization expenses forecast of $13.125 million for 2021, including approval of the following:

i. **Updated Depreciation Rates:** Approval of updated depreciation rates as set out in Tab 7, with an overall increase to 2021 depreciation expense of approximately $0.636 million; and

Table 3.14:
Depreciation and Amortization
($000)

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Fixed Asset Depreciation	$ 12,196	$ 12,185	$ 12,677	$ 12,963	$ 12,945	$ 13,581
Less: Customer contribution	-5,652	-5,635	-6,237	-6,482	-5,911	-5,911
Less: Amortization of fire insurance recoveries	-262	-262	-262	-262	-262	-262
Less: Disallowed Depreciation	-204	-204	-204	-204	-204	-204
Plus: Amortization of deferred charges	5,063	5,020	5,079	4,992	5,921	5,921
Total Depreciation & Amortization	$ 11,141	$ 11,104	$ 11,053	$ 11,007	$ 12,489	$ 13,125

Notes:
1. Disallowed depreciation reflects fixed asset depreciation amounts for disallowed assets per YUB Orders: $0.004 million (YUB 1992-1), $0.012 million (YUB 2013-01) and $0.188 million (YUB 2018-10).

QUESTION:

a) Please clarify that the difference between Forecast 2020 ($12,963 thousand) and Forecast Existing 2021 ($12,945 thousand) fixed asset depreciation amounts represent a decrease in depreciation expense of $18 thousand that is due to decreases in fixed asset amounts subject to depreciation expense. If not confirmed, please fully explain all reasons for the $18 thousand decrease in fixed asset depreciation expense. Please include in the response the total amount of depreciable assets used in each of the Forecast 2020 fixed asset depreciation ($12,963 thousand) and Forecast Existing/Proposed 2021 fixed asset depreciation

calculations ($12,945/$13,581 thousand) and a complete reference to where those amounts can be confirmed in YEC's supporting Tabs.

b) Please clarify that the difference between Forecast Proposed 2021 ($13,581 thousand) and Forecast Existing 2021 ($12,945 thousand) fixed asset depreciation amounts represents an increase in depreciation expense of $636 thousand that is due to changes in proposed depreciation parameters of average service life and Iowa curve dispersion and mode. If not confirmed, please explain the reason for the $636 thousand increase in fixed asset depreciation expense.

c) Please provide a breakdown of the $636 thousand increase in fixed asset depreciation expense, referenced in part (b) above, between changes in average service life and changes in Iowa Curve dispersion and mode.

d) Please provide detailed calculations by asset class ID and description that support YEC's amortization of customer contributions in the amounts of Forecast 2020 ($6,482 thousand) and Forecast Existing 2021 / Forecast Proposed 2021 ($5,911 thousand). Please ensure that both asset class ID, description and working formulae are included in the requested worksheet. Alternatively, if the calculations are available elsewhere in YEC's Application, please provide a complete reference to any Tab 3, Tab 5, Tab 7 or other schedule that can be used for the same purpose of clearly arriving at the referenced amounts.

e) Please explain how YEC determines its amortization rates for contributions and its process for retiring contributions.

f) For Forecast 2020 ($4,992 thousand) and Forecast Existing 2021 / Forecast Proposed 2021 ($5,921 thousand) amortization of deferred charges amounts, please provide a list identifying each deferred charge that comprises the amounts noted and the basis of the amortization period for each deferred charge. If each constituent calculation is available elsewhere in YEC's Application, please provide a complete cross reference to any Tab 3, Tab 5, Tab 7 or other schedule that can be used for the same purpose of clearly arriving at the referenced amounts.

g) The Board has summarized YEC's reporting in Tab 3 and Tab 7 of the amortization of contributions, fire insurance recoveries and deferred charges in the following table. Please reconcile the "Variance between reporting schedule" column by

identifying the nature of the cost that constitutes the variance and by providing an explanation for why the costs are not being reported consistently by YEC between Tab 3 and Tab 7 schedules:

	Tab 3, Schedule 3.14	Tab 7, Schedule 5	Variance between reporting schedule
	($ thousands)		
Amortization of customer contributions	(6,482)	(5,291)*	(1,453)
Amortization of fire insurance recoveries	(262)		
Amortization of deferred charges/costs	4.992	$3,540	1,452
Total Forecast 2020	(1,752)	(1,751)	
Amortization of customer contributions	(5,911)	(4,723)*	(1,450)
Amortization of fire insurance recoveries	(262)		
Amortization of deferred charges/costs	5,921	4,471	1,450
Total Forecast (Exiting and Proposed) 2021	(252)	(252)	

Source: Tab 3, Schedule 3.14 and Tab 7, Schedule 5 (where * is described as "amortization of contributions and fire insurance recoveries").

h) Please explain how the lack of complete references between schedules (as noted in part (f) above) and the variance between reporting schedules for what has effectively been described as the same cost (as noted in part (g) above) has been responsive or helpful to the Board with respect to Directive #23 which addressed the Board's concerns about YEC's standard of disclosure with respect to its deferral and reserve accounts.

ANSWER:

(a)

The difference between Forecast 2020 ($12,963 thousand) and Forecast Existing 2021 ($12,945 thousand) fixed asset depreciation amounts represent a decrease in depreciation expense of $18 thousand that is due to decreases in fixed asset amounts subject to depreciation expense.

The total amount of depreciable assets used in each of the Forecast 2020 fixed asset depreciation ($12,963 thousand) and Forecast Existing/Proposed 2021 fixed asset depreciation calculations ($12,945/$13,581 thousand) are in the top section of Tab 7, Schedule 3. Specifically, these depreciation amounts can be found on Line 6 of this schedule.

(b)

Confirmed.

(c)

A breakdown of the $636 thousand increase in fixed asset depreciation expense is found in Tab 7, Schedule 3A. In this schedule, the columns labelled '2021 Existing Forecast Depreciation' and '2021 Forecast Proposed Forecast Depreciation' breakdown the differences by each asset category.

(d)

A summary of YEC's amortization of customer contributions in the amounts of Forecast 2020 ($6,482 thousand) and Forecast Existing 2021 / Forecast Proposed 2021 ($5,911 thousand) by asset class ID is below. These amounts were system generated so no additional excel calculations were done (or available to report). Amortization is based on historical cost at the appropriate amortization rate (see response to part (e)).

	($000's)
Property, Plant & Equipment Contributions	
Residential Customer Contributions	136.33
General Service Customer Contributions	68.32
Industrial Customer Contributions	20.96
Street & Sentinel Light Customer Contributions	0.96
Other Contributions	2.70
Minto Contribution 138Kv Line	189.91
Minto Spur Contribution 25 Kv Line	825.08
Victoria Gold McQuestent Contribution	961.38
Yukon Development Corporation Contributions	1,604.26
Yukon Government Contributions	228.73
Government of Canada Contributions	990.71
	5,029.35
Feasibility Contributions	1,333.82
Regulatory Contributions	118.65
	6,481.82

(e)

YEC determines its amortization rates for contributions by applying International Financial Reporting Standards (IFRS) and as reviewed by YEC's external auditor, the Auditor General of Canada. Typically, the amortization period of the contribution matches the asset to which the contribution relates to. An exception to this is the Victoria Gold McQuesten contribution as much of the assets are being amortized over their life (45 years) but IFRS and the Auditor General of Canada required the contribution to be amortized over the expected life of the Victoria Gold mine (12 years).

YEC's process for retiring contributions is to remove the contribution from its records when it is fully amortized, or whenever the asset to which it relates to is disposed of, whichever is earlier.

(f) to **(h)**

Please see YUB-YEC-1-108 Attachment 1 that provides reconciliation of the referenced amortization numbers in the questions with detailed cross-references to the Application tabs, tables and schedules.

As illustrated in YUB-YEC-1-108 Attachment 1, the forecast amortization of deferred costs for 2020 at $4.992 million and forecast for 2021 test year at $5.921 million are before contributions.

As indicated in response to part d), the total amortization of contributions of $6.482 million for 2020 forecast [Table 3.14] includes amount of deferred cost related contributions of $1.452 million. The amortization of contributions for deferred costs for 2021 test year is $1.450 million out of total amortization of contributions at $5.911 million [Table 3.14].

The following Table 1 shows revised version of Table 3.14 where amortization of contributions for fixed assets and amortization of contributions for deferred costs are shown separately. A row was also added to the end of the table to show how the referenced numbers of $5.291 million for 2020 and $4.723 million for 2021 are derived.

Table 1: Depreciation and Amortization for 2020 Forecast and 2021 Test Year

		Forecast 2020	Proposed 2021
1	Fixed Asset Depreciation	$ 12,963	$ 13,581
2	Less: Customer contribution [fixed assets]	-5,029	-4,461
3	Less: Amortization of fire insurance recoveries	-262	-262
4	Less: Disallowed Depreciation	-204	-204
5	Plus: Amortization of deferred charges	4,992	5,921
6	Less: Customer contribution [deferred charges]	-1,452	-1,450
7=Sum(1:6)	Total Depreciation & Amortization	$ 11,007	$ 13,125
8=2+3	Amortization of customer contributions and fire insurance recoveries	-5,291	-4,723

Amortization of Deferred Study Costs and Intangible Assets
($000s)

Line No.	Description	2020 Forecast	2021 Test Year	Cross Ref.
	Deferred study costs and Intangible assets (net of contributions)			
	Feasibility Studies			
1	Amortization of Costs	3,202	3,568	Tab 5, Table 5.5 [2020] and Table 5.6 [2021]
2	Amortization of Contributions	(1,334)	(1,295)	Tab 5, Table 5.5 [2020] and Table 5.6 [2021]
3=1+2	Net Amortization	1,869	2,272	Tab 7, Schedule 3, Line 23
	Relicensing			
4	Amortization of Costs	301	368	Tab 5, Table 5.5 [2020] and Table 5.6 [2021]
5	Amortization of Contributions	-	-	
6=4+5	Net Amortization	301	368	Tab 7, Schedule 3, Line 28
	Dam Safety			
7	Amortization of Costs	30	93	Tab 5, Table 5.5 [2020] and Table 5.6 [2021]
8	Amortization of Contributions	-	-	
9=7+8	Net Amortization	30	93	Tab 7, Schedule 3, Line 33
	Regulatory [DSM, Other regulatory]			
10	Amortization of Costs	604	867	Tab 5, Table 5.5 [2020] and Table 5.6 [2021]
11	Amortization of Contributions	(119)	(155)	Tab 5, Table 5.5 [2020] and Table 5.6 [2021]
12=10+11	Net Amortization	485	712	Tab 7, Schedule 3, Sum of Lines 48, 66
	Intangibles			
13	Amortization of Costs	578	749	Tab 5, Table 5.7
14	Amortization of Contributions	-	-	
15=13+14	Net Amortization	578	749	Tab 7, Schedule 3, Line 43
	Vegetation Management			
16	Amortization of Costs	222	222	Tab 3, Table 3.14.2
17	Amortization of Contributions	-	-	
18=16+17	Net Amortization	222	222	Tab 7, Schedule 3, Line 38
	Hearing Reserve Amortization			
19	Amortization	55	55	Tab 7, Schedule 3, Line 53
20	Amortization of Contributions	-	-	
21=19+20	Net Amortization	55	55	
22=1+4+7+10+13+16+19	Total before contributions	4,992	5,921	Tab 3, Table 3.14
23=2+5+8+11+14+17+20	Amortization of contributions	(1,452)	(1,450)	
24=22+23	Total after contributions	3,540	4,471	Tab 7, Schedule 6, Line 5; Tab 7, Schedule 5, Line 7

REFERENCE: **Application, Section 6.12, Directives (from Board Order 2018-10) related to revenue requirement: YEC response to Directive #21 – Depreciation and amortization expense details, page 6-5; YEC response to Directive #23 – Improved disclosures on deferral & reserve accounts, page 6-5; Tab 9 Depreciation Study, pages 9-6, 9-98 and 9-99; Tab 7, Schedule 3A, page 7-6**

ISSUE: **Responses to Board Directives #21 and #23**

QUOTE: "Basis of Depreciation Estimates
The straight-line, broad (average) life group, remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset less allocated depreciation reserve less estimated net salvage by its respective average life group remaining life. The resulting annual accrual amounts of all depreciable property within a function were accumulated, and the total was divided by the original cost of all functional depreciable property to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The computations of the annual functional depreciation rates are shown in Appendix A."

PREAMBLE: In response to Directive #21 of Board Order 2018-10, YEC prepared "Tab 7, Schedules 3A and 3B" which it stated provided the Board-directed detailed depreciation and amortization calculations.

With respect to YEC's response to Direction #21, the Board observes that Tab 7 contains Schedule 3A only and not Schedules 3A and 3B as referenced by YEC.

Further, the Board observes that Tab 7, Schedule 3A does not consistently include working formulae that would otherwise provide confirmation of the depreciation expense calculations therein.

In response to Directive #23 of Board Order 2018-10, YEC prepared "Tab 7, Schedules 1 and 3" which it stated implemented changes to the structure of those schedules in order to improve disclosure and reporting of deferral and reserve accounts as directed by the Board.

QUESTION:

a) Please revise Tab 7, Schedule 3A to include the "Asset Class ID" for each account and corresponding working formulae supporting the depreciation expense calculations under each of the "2021 Existing Forecast Depreciation" and "2021 Proposed Forecast Depreciation" columns. Please provide references that would build to the $666,498 thousand "cost at 2020 year end" using individual line items from Tab 7, Schedule 3 or any other Tab 7 schedule.

b) Please explain why Tab 7, Schedule 3A does not appear to use a mid-year approach for the purposes of calculating depreciation expense. Please explain this observation fully and clarify whether this is a change from previously approved YEC depreciation expense calculation methodology.

c) Please explain why Tab 7, Schedule 3A appears to generally rely on the use of a depreciation rate based on "years" alone and does not appear to use a depreciation rate that includes consideration of the proposed Iowa Curve (including the associated mode and dispersion). Please explain this observation fully and clarify whether this is a change from previously approved YEC depreciation expense methodology.

d) Referring to the responses to parts (a) to (c) above, please explain any difference between the depreciation expense methodology described in those responses and the basis of the annual depreciation estimates as described in the Tab 9 Depreciation Study on page 9-6 and quoted above.

e) Please provide the calculations (including working formulae) supporting the amount of "depreciation study differences" by asset class grouping shown on Tab 7, Schedule 3A, given that the amounts to not appear to reflect the same amounts provided in the Tab 9 Depreciation Study, Appendix A at pages 9-98 and 9-99. Please also explain fully why the "depreciation study differences" on Tab 7,

Schedule 3A should not reflect the same "depreciation true-up annual provision for true-up" amounts in Appendix A on pages 9-98 and 9-99.

f) Notwithstanding the differences in dollar amounts noted in part (e) above, please explain fully whether YEC's implied method to collect or refund any required "depreciation study differences" as a set dollar amount (as indicated on Tab 7, Schedule 3A) is a change from previously approved YEC depreciation expense methodology.

g) Please clarify whether any of the information from Tab 9, Depreciation Study, Appendix A is used to inform the Tab 7, Schedule 3A depreciation expense calculations. If confirmed, please clearly cross reference the specific information originating from Tab 9, Depreciation Study, Appendix A and where it is relied on, or input, in Tab 7, Schedule 3A.

h) Referring to Tab 9, Depreciation Study, Appendix A on pages 9-98 and 9-99, please revise Appendix A to include working formulae supporting the depreciation expense calculations therein.

i) Referring to Tab 9, Depreciation Study, Appendix A on pages 9-98 and 9-99, please clarify why the columns identified as "Accumulated Depreciation," "AD difference" and "Accumulated depreciation of A/D Difference" must be added together to collectively determine the December 31, 2018 accumulated depreciation balance. Please also explain why, in the alternative, YEC did not simply provide the December 31, 2018 actual book accumulated depreciation balances.

j) Referring to the quote in the preamble, if Schedule 3B was omitted by YEC in error, please provide the schedule and ensure that it includes an "Asset Class ID" and description for each account and working formulae for any calculations contained therein.

ANSWER:

(a)

In Schedule 3A the "Asset Class ID" for each account is listed under the column labelled 'Description'. The '2021 Existing Forecast Depreciation' is system generated. The YEC fixed asset database consists of thousands of assets and excel is not used in this part of the forecast; therefore, a revised file with working formulae support is not available with excel. The system takes the cost of each of the individual assets and amortizes them individually over their respective amortization period. The depreciation system is audited by YEC's external auditor, the Auditor General of Canada.

Regarding the '2021 Proposed Forecast Depreciation' column, the formula was included in the excel file submitted with the Application. The formula can be interpreted in the following words:

Step 1:	Calculate average rate on existing Class ID	Cost at 2021 Year End / 2021 Existing Forecast Depreciation
Step 2:	Calculate existing rate to proposed rate ratio	Existing Depreciation Rate / Proposed Depreciation Rate
Step 3:	Calculate average proposed rate	Average rate on existing Class ID (Step 1) / Existing rate to proposed rate ratio (Step 2)
Step 4:	Calculate 2021 Proposed Forecast Depreciation	Cost at 2021 Year End / Average proposed rate (Step 3)

The $666,498 thousand "cost at 2020 year end" is built up from all categories and Class ID's listed on Schedule 3A. It can be reconciled to Tab 7, Schedule 3 as follows:

Forecast 2020		($M)
Schedule 3, Line 4	Property, Plant and Equipment, balance at end of year	$ 677.3
Schedule 3, Line 12	Construction-in-progress	10.8
		$ 666.5

(b)

There is no basis to calculate depreciation on a mid-year basis. YEC calculates depreciation in accordance with International Financial Reporting Standards. Each asset is depreciated monthly based on its cost. For forecast depreciation, the methodology is the same as it provides the most accurate forecast. As stated in part (a), this forecast is system generated. Our understanding is this is not a change from previously approved YEC depreciation expense calculation methodology.

(c)

YEC depreciates assets on a straight-line basis using 'Years' in accordance with International Financial Reporting Standards. As YEC uses straight-line depreciation, use of 'Years' or 'Rates' does not result in any differences in calculations. Years are the inverse of Rates. This is not a change from previously approved YEC depreciation expense methodology.

(d)

The depreciation expense methodology described in parts (a), (b) and (c) are consistent with the basis of the annual depreciation estimates as described in the Tab 9 Depreciation Study on page 9-6.

(e)

A comparison to Depreciation Study Differences as per the Depreciation Study compared to Schedule 3A is provided below:

	Per Depreciation Study	Per Schedule 3A	Variance
Land	-13	-13	0
Hydro Plant	-140,298	-140,465	167
Diesel Production	-88,166	-70,208	-17,958
Main Transmission Facilities	-79,597	-79,597	0
Sub Transmission Lines	-46,022	-45,813	-209
Distribution System	49,971	1,329	48,642
Building and Other Equipment	-67,334	-18,982	-48,352
Transportation	19,268	19,267	1
LNG Production	-13,981	-13,981	0
	(366,172)	(348,463)	(17,709)

The differences above result due to a timing difference between when the Depreciation Study was performed and the current asset base. There is a variance in the Diesel Production class as Schedule 3A was updated for the retirement of the Mirlees diesel engines which were previously included in the Diesel Production Depreciation Differences calculation. As a result, International Financial Reporting Standards and the Auditor General of Canada required the 2019 Diesel Depreciation differences from a previous amount of $101,236 per year to $80,615 per year (a reduction of 20.4%). Therefore, the adjusted amount of $80,615 is the 2021 Existing Forecast Depreciation amount found in Tab 7, Schedule 3A. YEC needed to adjust the 2021 Proposed Forecast Depreciation for this change in its actual existing depreciation study difference amount. The calculation to obtain this is as follows:

	Per Depreciation Study	Adjustment for Mirlees Retirement (%)	Adjustment for Mirlees Retirement ($)	Per Schedule 3A
Diesel Production	$ (88,166)	20.4%	$ 17,959	$ (70,208)

The other variance in depreciation differences between the Depreciation Study and Schedule 3A is a reclassification of assets, and therefore, depreciation differences between the classes of Distribution System ($48,642) and Building and Other Equipment ($-48,352) leaving an insignificant variance of $290. The amounts in Schedule 3A should be used for regulatory purposes as those amounts will be used for accounting purposes according to International Accounting Reporting Standards.

(f)

There is not a change from previously approved YEC depreciation expense methodology.

(g)

As discussed in part (e), the depreciation study Appendix A is being used as the basis for the calculation of depreciation study differences, subject to the adjustments also noted in part (e).

(h)

Appendix A is being provided in native format. Since the computations have links to other tabs in the workpaper the complete workpaper is being provided as Attachment 1 to this response.

(i)

Certain true-ups in the depreciation reserve are used to comply with prior Board actions. The format of presentation is the same as in the Company's last depreciation study.

(j)

The Application referenced Schedule 3B in error. There is no Schedule 3B.

YUKON ENERGY
COMPUTATION OF PROPOSED DEPRECIATION ACCRUAL RATE
AT DECEMBER 31, 2018

Asset Class ID	Asset Class ID Description	Plant	Accumulated Depreciation	AD Difference	Accumulated Depreciation of A/D Difference	Net Book Value	Calculated Accumulated Depreciation	Accumulated Depreciation Variance	Proposed Depreciation Rate	Proposed Depreciation Amount	Remaining Life	Depreciation True-Up Annual Provision for True Up
	Land											
1610-003	Land Hydro Production	444,912	0			444,912						
1610-004	Land Diesel Production	27,680	0			27,680						
1610-006	Land Main Trx Facilities	576,862	0	699	(199)	577,363						
1610-008	Land Distribution System	17,775	0			17,775						
1610-009	Land General Plant	547,992	0			547,992						
1610-106	Land Rights	128,780	(25,910)			102,870	(25,391)	(519)	2.00%	2,576	40.14	(13)
		1,744,002	(25,910)	699	(199)	1,718,592	(25,391)	(519)		2,576		(13)
	Hydro Plant											
1615-200	Hydro-Strctrs & Imprvmts	34,163,123	(6,803,403)	(977,149)	63,766	26,446,337	(7,308,246)	(408,540)	1.39%	474,488	56.60	(7,218)
1615-201	Hydro-Building & Imprvmnt	10,278,688	(427,340)			9,851,348	(362,324)	(65,016)	2.50%	256,967	38.59	(1,685)
1615-205 & 1615-206	Hydro-Rsrvoirs Dams & Wtrways	172,919,206	(52,689,116)	(18,131,142)	1,386,390	103,485,339	(49,449,636)	(19,984,232)	0.97%	1,678,827	73.55	(271,727)
1615-506	Hydro-Wtrwhls, Trbines & Gen's	26,339,447	(3,747,076)	(269,433)	44,824	22,367,762	(6,351,635)	2,379,950	1.67%	438,991	45.53	52,271
1615-600	Hydro-Accessory Electric Equip	26,598,355	(5,186,340)	65,942	(23,197)	21,454,761	(7,445,689)	2,302,095	2.50%	664,959	28.80	79,926
1615-601	Hydro Accessory Digital Equip	837,945	(63,362)			774,582	(62,846)	(517)	5.00%	41,897	18.50	(28)
1615-700	Hydro-Misc Power Plant Equip	11,490,781	(3,087,765)	83,244	(46,809)	8,439,452	(3,223,878)	172,549	3.33%	383,026	21.58	7,995
1615-730	Hydro- Fences	107,086	(25,967)			81,119	(29,641)	3,674	3.33%	3,570	21.70	169
	Hydro Plant Total	282,734,632	(72,030,369)	(19,228,538)	1,424,975	192,900,700	(74,233,895)	(15,600,037)		3,942,725		(140,298)
	Diesel Plant											
1620-200	Diesel-Strctrs and Imprvmts	1,562,352	(781,875)	(432,852)	106,295	453,920	(634,175)	(474,257)	1.39%	21,699	42.77	(11,087)
1620-201	Diesel-Building & Imprvmnt	466,054	(99,651)	(20,501)	3,345	349,246	(62,300)	(54,507)	1.82%	8,474	47.65	(1,144)
1620-403	Diesel-Fuel Hldrs,Prdcts&Accss	1,688,501	(954,217)	(122,114)	114,775	726,946	(589,294)	(372,262)	2.50%	42,213	26.04	(14,296)
1620-500	Diesel-Gnrtng Equip & Prime	13,841,607	(8,510,645)	(732,079)	1,052,443	5,651,327	(7,105,089)	(1,085,191)	2.50%	346,040	19.47	(55,744)
1620-501	Diesel-Gnrtng Equip & Prime Retire	1,970,549	(974,499)			996,050	(1,522,697)	548,198	NA	332,017	0.00	0
1620-508	Diesel-Minto Gnrtng Equip	243,548	(176,888)			66,660	(192,809)	15,921	8.33%	20,296	2.50	6,368
1620-600	Diesel-Acc Electric Equip	5,416,976	(1,583,903)	(478,962)	171,809	3,525,920	(1,850,307)	(40,749)	2.22%	120,377	29.63	(1,375)
1620-700	Diesel-Misc Power Plant Equip	1,867,523	(825,077)	(371,646)	240,340	911,140	(763,247)	(193,136)	3.33%	62,251	17.74	(10,888)
	Diesel Plant Total	27,057,109	(13,906,754)	(2,158,154)	1,689,007	12,681,208	(12,719,918)	(1,655,983)		953,366		(88,166)
	Distribution System											
1625-300	Dist System - Poles & Fxtrs	7,969,883	(1,905,688)	(14,629)	6,125	6,055,691	(1,614,735)	(299,457)	2.50%	199,247	31.90	(9,389)
1625-304	Dist System - Brushing	44,763	(17,835)	(3,235)	996	24,689	(26,238)	6,164	2.00%	895	20.69	298
1625-305	Dist System - Survey Costs	600,378	(168,274)	297		432,401	(112,698)	(55,279)	2.00%	12,008	40.61	(1,361)
1625-401	Dist System - O/H Cndctrs	74,570	(31,009)			43,561	(19,120)	(11,889)	2.00%	1,491	37.18	(320)
1625-410	Dist System - O/H Services	2,117,381	(847,311)	(78,539)	30,910	1,222,442	(931,877)	36,937	2.50%	52,935	22.40	1,649
1625-501	Underground Conduit	385,155	(26,519)			358,636	(22,631)	(3,888)	2.50%	9,629	37.65	(103)
1625-510	Dist System - Undrgrnd Cnduit	40,460	(7,467)	(454)	171	32,710	(6,862)	(888)	2.50%	1,012	33.22	(27)
1625-610	Dist System - Meters	312,633	(185,181)	(33,787)	18,820	112,484	(266,434)	66,286	6.25%	19,540	2.36	28,035
1625-620	Dist System - Meter Equip	288,392	(148,993)	3,308	(968)	141,739	(237,596)	90,943	6.25%	18,025	2.82	32,270
1625-710	Dist System - Sbstn EEquip	1,287,180	(512,564)	(50,938)	22,068	745,746	(473,237)	(68,197)	2.50%	32,180	25.29	(2,696)
1625-720	Dist System - Sbstn Buildings	64,798	(35,020)	(19,520)	7,988	18,246	(31,214)	(15,339)	1.82%	1,178	28.51	(538)
1625-730	Dist System- Substation Fences	100,328	(15,200)			85,128	(11,684)	(3,517)	3.33%	3,344	26.51	(133)
1625-815	Dist System - Street Lights	588,493	(206,165)	(99,674)	39,803	322,456	(181,113)	(84,924)	2.50%	14,712	27.69	(3,067)
1625-905	Dist System - Line Trxformers	4,000,082	(1,959,650)	(564,652)	249,975	1,725,756	(2,362,021)	87,694	2.86%	114,288	14.33	6,118
1625-961	Dist System - Sentinel Lights	36,443	(25,911)	(12,948)	9,589	7,173	(16,992)	(12,278)	3.33%	1,215	16.01	(767)
	Distributution System Total	17,910,940	(6,092,787)	(874,771)	385,478	11,328,860	(6,314,451)	(267,629)		481,697		49,971
	Main Transmission Facilities											
1635-300	Main Trx - Poles & Fxtrs	60,444,290	(11,208,130)	(1,367,921)	441,757	48,309,996	(12,407,344)	273,051	2.00%	1,208,886	39.74	6,872
1635-304	Main Trx - Brushing	14,082,336	(3,234,991)	48,456	(13,702)	10,882,098	(2,588,715)	(611,522)	1.67%	234,706	48.97	(12,488)
1635-305	Main Trx - Survey Costs	3,541,446	(866,916)	(61,687)	17,348	2,630,191	(759,406)	(151,849)	1.67%	59,024	47.13	(3,222)
1635-402	Main Trx - O/H Cndctrs/Poles	20,561,275	(5,081,116)	(45,903)	11,990	15,446,247	(4,166,859)	(948,169)	1.67%	342,688	47.84	(19,819)
1635-404	Main Trx - O/H Cndctrs/Towers	277,975	(110,991)	(7,067)	2,070	161,987	(136,749)	20,761	1.67%	4,633	30.48	681
1635-710	Main Trx - Sbstn Equip	66,600,655	(14,772,921)	(633,579)	246,252	51,440,407	(13,394,976)	(1,765,271)	2.22%	1,480,015	35.95	(49,104)
1635-720	Main Trx - Sbstn Buildings	1,536,213	(216,619)	(2,223)	480	1,317,851	(156,704)	(61,659)	1.82%	27,931	49.39	(1,248)
1635-730	Main Trx - Sbstn Fences	274,477	(92,674)	769	(605)	181,968	(63,234)	(29,275)	3.33%	9,149	23.09	(1,268)
	Main Transmission Facilities Total	167,318,667	(35,584,356)	(2,069,155)	705,591	130,370,747	(33,673,988)	(3,273,933)		3,367,031	322.59	(79,597)

YUKON ENERGY
COMPUTATION OF PROPOSED DEPRECIATION ACCRUAL RATE
AT DECEMBER 31, 2018

Asset Class ID	Asset Class ID Description	Plant	Accumulated Depreciation	AD Difference	Accumulated Depreciation of A/D Difference	Net Book Value	Calculated Accumulated Depreciation	Accumulated Depreciation Variance	Proposed Depreciation Rate	Proposed Depreciation Amount	Remaining Life	Depreciation True-Up Annual Provision for True Up
	Sub Transmission Lines											
1640-300	Sub Trx - Poles & Fxtrs	4,092,701	(2,281,354)	(780,721)	281,918	1,312,545	(2,059,673)	(720,483)	2.00%	81,854	24.84	(29,008)
1640-301	Sub Trx - Poles & Fxtrs Mnt Mn	2,646,132	(2,223,467)			422,665	(2,205,110)	(18,357)	8.33%	220,511	2.00	(9,179)
1640-304	Sub Trx - Brushing	41,597	(834)			40,763	(1,023)	189	1.67%	693	58.52	3
1640-306	Sub Trx - Brushing Mnt Mn	432,533	(363,453)			69,080	(360,444)	(3,009)	8.33%	36,044	2.00	(1,504)
1640-307	Sub Trx - Survey Costs Mnt Mn	95,136	(79,940)			15,196	(79,280)	(660)	8.33%	7,928	2.00	(330)
1640-401	Sub Trx - O/H Cndctrs	1,840,369	(564,991)	(112,184)	41,214	1,204,408	(490,758)	(145,203)	1.67%	30,673	44.00	(3,300)
1640-405	Sub Trx - Undrgrnd Cndctrs/Cnd	83,873	(47,669)	(194)	121	36,130	(57,555)	9,813	2.22%	1,864	14.12	695
1640-407	Sub Trx - O/H Cndctrs Mnt Mn	920,693	(773,631)			147,062	(767,244)	(6,387)	8.33%	76,724	2.00	(3,194)
1640-710	Sub Trx - Sbstn EEquip	8,013,609	(756,527)			7,257,082	(557,208)	(199,319)	2.22%	178,080	41.87	(4,760)
1640-711	Sub Trx - Sbstn Equips Mnt Mn	6,948,253	(5,781,101)			1,167,153	(5,790,211)	9,111	8.33%	579,021	2.00	4,555
	Sub Transmission Lines Total	25,114,895	(12,872,966)	(893,099)	323,253	11,672,083	(12,368,507)	(1,074,306)		1,213,393		(46,022)
	Buildings & Other Equipment											
1645-110	Bldg&Otr - Survey Costs Land	4,321	(1,950)	(601)	193	1,963	(2,837)	479	2.00%	86	17.18	28
1645-200	Bldg&Otr-Strctrs/Imprvmnt Hyd	2,243,942	(333,448)	(3,049)	1,122	1,908,567	(251,936)	(83,440)	2.00%	44,879	44.39	(1,880)
1645-201	Bldg&Otr - Building & Imprvmnt	10,102,549	(3,653,478)	(946,961)	232,163	5,734,274	(3,535,922)	(832,354)	2.00%	202,051	32.50	(25,611)
1645-202	Bldg&Otr-Office Frntr & Equip	1,736,569	(1,267,513)	(130,011)	120,096	459,141	(1,272,514)	(4,914)	5.00%	86,828	5.34	(919)
1645-210	Bldg&Otr - Comm Site Towers	19,297	(11,471)	(1,115)	557	7,268	(7,109)	(4,920)	2.50%	482	25.26	(195)
1645-220	Bldg&Otr - Comm Site Fences	64,126	(30,756)	326	(241)	33,456	(19,994)	(10,676)	3.33%	2,138	20.65	(517)
1645-320	Bldg&Otr - Computer Hardware	1,715,886	(1,022,714)	70,421	(70,023)	693,569	(982,253)	(40,064)	14.29%	245,127	2.99	(13,386)
1645-330	Bldg&Otr - Computer Software	304,004	(132,784)	(7,872)	7,872	171,220	(148,885)	16,101	20.00%	60,801	2.55	6,311
1645-505	Bldg&Otr - Tools & Instruments	1,654,638	(904,640)	(168,321)	140,874	722,551	(889,892)	(42,195)	5.00%	82,732	9.24	(4,565)
1645-507	Bldg&Otr - Wind Mntrng Equip	14,283	(11,022)		1,332	4,592	(12,854)	3,164	6.67%	952	1.50	2,109
1645-605	Bldg&Otr - Comm Equip	4,583,047	(2,453,712)	(53,911)	52,353	2,127,778	(2,365,191)	(90,078)	5.00%	229,152	9.68	(9,307)
1645-810	Bldg&Otr - Houses/Land	59,031	(22,410)	7,862	(4,433)	40,050	(14,986)	(3,996)	2.50%	1,476	29.85	(134)
1645-820	Bldg&Otr - Houses/Buildings	2,051,769	(1,430,615)	365,433	(190,775)	795,812	(777,167)	(478,790)	2.50%	51,294	24.85	(19,268)
	Total Building	24,553,463	(11,276,513)	(867,799)	291,091	12,700,242	(10,281,540)	(1,571,682)		1,007,998		(67,334)
	Transportation											
1650-411	Trxptn - Utility Vehicles	344,073	(193,559)	12,716	(12,716)	150,514	(173,164)	(20,395)	12.50%	43,009	3.97	(5,132)
1650-412	Trxptn - Sedans & Stn Wagons	137,764	(90,423)	6,160	(6,160)	47,340	(78,421)	(12,003)	9.09%	12,524	4.74	(2,533)
1650-420	Trxptn - Trucks & Pole Trailer	11,000	(2,686)			8,314	(2,724)	37	4.00%	440	18.81	2
1650-430	Trxptn -Pole Trailer>10,000lbs	53,711	(18,374)	(748)	445	35,033	(17,243)	(1,434)	4.00%	2,148	16.97	(84)
1650-440	Trxptn - Trucks 3/4 to 2 Ton	2,644,537	(1,015,122)	(17,178)	17,178	1,629,415	(1,106,240)	91,118	11.11%	293,837	5.24	17,405
1650-470	Trxptn - Trucks > 3Tons	1,459,849	(401,649)	(12,391)	9,860	1,055,670	(453,561)	49,382	5.00%	72,992	13.79	3,582
1650-490	Trxptn - Foremost	1,003,858	(352,963)			650,895	(422,764)	69,801	5.00%	50,193	11.58	6,029
	Total Transporation	5,654,791	(2,074,777)	(11,441)	8,608	3,577,181	(2,254,117)	176,507		475,144		19,268
	Critical Spares											
1655-750	Critical Spares	1,170,184	0			1,170,184						
	LNG Plant											
1665-200	Structures and Improverments	6,184,735	(301,000)			5,883,735	(270,787)	(30,213)	1.39%	85,899	68.85	(439)
1665-403	Fuel Holders	13,200,669	(1,445,518)			11,755,151	(692,600)	(752,919)	1.67%	220,011	56.85	(13,243)
1665-500	LNG Generator	20,880,293	(1,157,153)			19,723,140	(1,233,591)	76,437	2.50%	522,007	37.64	2,031
1665-600	Accessory Electric Equipment	3,655,939	(282,214)			3,373,725	(253,176)	(29,038)	2.22%	81,243	41.88	(693)
1665-700	Miscellanours Power Plant Equi	2,828,210	(321,574)			2,506,636	(287,467)	(34,106)	3.33%	94,274	26.95	(1,266)
1665-730	LNG Fence	779,651	(91,066)			688,585	(81,109)	(9,957)	3.33%	25,988	26.88	(370)
	Total LNG	47,529,497	(3,598,525)	0	0	43,930,972	(2,818,729)	(779,796)		1,029,423		(13,981)
	Total Yukon	600,788,180	(157,462,958)	(26,102,258)	4,827,804	422,050,768	(154,690,534)	(24,047,378)		12,473,354		(366,170)

Note: The following accounts were excluded from the depreciation study:
1615-504
1620-504
Asset 7060 removed from asset group 1615-506
Asset 8856 transferred from asset group 1645-200 to 1615-201

REFERENCE: **Application, Section 1.2, Table 1-2, footnote 1, page 1-6; Section 3.4, page 3-22**

ISSUE: **Depreciation Expense**

QUOTE: From footnote 1, Table 1-2:
"1. Excludes depreciation rate changes & impact of accelerated amortization of VGC Group contributions."

From Section 3.4:
New contributions since 2018 include $11.5 million from VGC Group to fund McQuesten Substation and system improvement capital costs, which contributions are being amortized over the expected 12 year life of the Eagle Gold mine."

"Accelerated amortization of VGC Group contributions related to McQuesten Substation and system improvement costs result in these assets reducing total depreciation and amortization costs by $0.665 million in the 2021 test year."

PREAMBLE: Referring to Table 1-2, YEC states that "depreciation (fixed asset increases)" increases by the amount of $1.154 million when comparing "2021 GRA over 2018 Approved" revenue. Further, YEC provides footnote 1 which states that the $1.154 million increase "excludes depreciation rate changes & impacts of accelerated amortization of VGC Group contributions."

QUESTION:

a) Please provide further information detailing the how the contribution amount was determined and any agreement between parties (if required) with respect to the $11.5 million contribution from VGC Group to fund McQuesten Substation and system improvement capital costs.

b) Please provide the calculation of the $1.154 million increase noted in the preamble and include a complete reference to where the information used in the requested calculation can be found in YEC's supporting Tabs.

c) Please provide the calculation of the $0.665 million decrease as quoted and include a complete reference to where all information used in the requested calculation can be found in YEC's supporting Tabs.

d) Please provide further detail with respect to the contributions being amortized on an "accelerated" basis as compared to the amortization periods and rates YEC uses for other contribution amounts. Please also explain whether the contribution assets at issue are collectively the "McQuesten Substation and system improvement costs" of [sic] some portion thereof.

e) Please clarify whether YEC had previous Board approval for the 12-year amortization period being used and, in the absence of previous Board approval of a 12-year amortization period, what the expected average service is for the contribution assets at issue.

ANSWER:

(a)

Under the VGC Power Purchase Agreement (PPA), VGC Group is responsible for funding the construction of the McQuesten Substation and certain identified system improvement capital costs. More specifically, the contribution was determined as follows:

McQuesten Substation contribution	$10.688
System Improvement contribution	$0.840
	$11.528

- McQuesten Substation responsibilities and costs are set out in Schedule B to the PPA. Except as otherwise specified in the PPA, VGC Group was responsible for developing and funding all of the costs of the McQuesten Substation (including actual final YEC Owner's Costs) prior to turning the facility over to YEC for ownership and commercial operation. The only McQuesten Substation costs funded by YEC related to the costs specifically required for the facility to be able to be operated at 138 kV voltage if so required at some future time. YEC provisions for payments to VGC Group are set out in Section 6.1 (c) and (d) of the PPA. The McQuesten Substation is required to connect the VCG Group's Mine Facilities to

YEC's Transmission Facilities. YEC's Transmission Facilities also supply electricity to other customers in the Keno region, including Alexco Resources.

- Initial system improvement costs of YEC to be funded by VGC Group are set out in Schedule C to the PPA, with an estimate of $1,677,883. Payment provisions are detailed in Section 6.1(b) of the PPA. These system improvements are required to enable YEC to provide electricity service to the VGC Group's Mine Facilities.

- The PPA provisions for VGC Group contributions were intended to result in VGC Group fully funding the costs as noted so as to ensure that other ratepayers would not be subject to any future cost risks related to these amounts.

(b)

The $1.154 million increase is the increase in depreciation costs for fixed assets prior to any changes in depreciation rates and prior to the impact of accelerated amortization of VGC Group contributions. This amount is calculated as follows (subject to rounding):

1. The increase (after customer contributions) of $0.490 million for 2021 Fixed Asset Depreciation under Existing ($7.034 million) versus 2018 Approved Fixed Asset Depreciation ($6.544 million) as provided in Table 3.14 of the Application; plus

2. The added customer contribution amount for 2021 of $0.665 million due to the accelerated amortization of VGC Group contributions (see response to "c" below).

(c)

The $0.665 million decrease in net depreciation in 2021 represents the impact of the addition of McQuesten Substation and system improvement capital costs net of contributions. The total is determined as follows:

Capital Costs - $11.5 million	
Depreciation (54 years)	$0.214
Return on rate base	$0.572
Contribution - $10.688 million	
Depreciation (12 years)	($0.961)
Return on rate base	($0.489)
Net Increase in Depreciation	**$0.665**

Return on rate base calculation is based on average 5.166% per Table 3.15 average cost of debt and equity. Additional explanation as follows:

1. Total contributions for McQuesten Substation ($10.688 million contribution – see Section 5.2.1.4 of Application) and system improvements ($0.840 million – the balance of the $11.528 million VGC contributions related to these YEC assets. These assets were in YEC rate base in 2020. The attributed value for McQuesten Substation costs as funded by VGC Group has been included in YEC's costs included in rate base and subject to depreciation.

2. Costs funded by VGC Group for these facility contributions are amortized over an approximate 54 year average asset life (see Appendix 4.3, Table 4.3-1 for confirmation of approximate 54 year amortization of YEC's net McQuesten Substation Costs), resulting in annual depreciation of $0.214 million for the $11.5 million referenced amount; 2021 return on this portion of the rate base cost approximates $0.572 million, resulting in a total annual 2021 cost in the proposed revenue requirement at $0.785 million.

3. However, the related contributions are amortized over an approximate 12 year life of the Eagle Gold mine, resulting in annual amortization of $0.961 million; 2021 return reduced on this portion of the rate base cost approximates $0.489 million, resulting in a total annual 2021 contribution impact on reducing revenue requirement at $1.450 million.

4. The difference between contribution amortization over approximately 12 years (step 3 above) versus over the approximate 54 year asset life (step 2 above) is $0.665 million for 2021, with a variance in annual amortization of $0.747 million being partly offset by a decrease in rate base return of $0.083 million.

(d) and **(e)**

The referenced VGC Group contributions are all being amortized over the approximate expected 12 year life of the mine as required by YEC's auditors (the Auditor General of Canada) in accordance with International Financial Reporting Standards (IFRS) for customer contributions. YEC has not had any prior Board approval for the 12-year amortization of these contributions, nor any direction from the Board not to follow IFRS with regard to these contributions, although this treatment aligns with the approach directed by auditors with respect to the contributions to transmission system received from the Minto Mine customer. The expected life of the related assets is as shown for the amortization of the costs, i.e., approximately 54 years.

REFERENCE: **Application, Tab 9, Depreciation Study, pages 9-6 and 9-16**

ISSUE: **Depreciation Expense**

QUOTE: **"Basis of Depreciation Estimates**

The straight-line, broad (average) life group, remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset less allocated depreciation reserve less estimated net salvage by its respective average life group remaining life. The resulting annual accrual amounts of all depreciable property within a function were accumulated, and the total was divided by the original cost of all functional depreciable property to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The computations of the annual functional depreciation rates are shown in Appendix A."

"Depreciation True Up Calculation

Annual depreciation expense amounts for the depreciable accounts of Yukon Energy were calculated by the straight-line method, average life group procedure, and remaining-life technique. With this approach, remaining lives were calculated according to standard ALG expectancy techniques, using the Iowa Survivor Curves noted in the calculation. For each plant account, the difference between the book depreciation reserve and theoretical depreciation reserve, was divided by the average remaining life to yield the annual depreciation true up. These calculations are shown in Appendix A.

Depreciation Rate Calculation Process

Annual depreciation expense amounts for accounts all accounts were calculated by the straight-line, average life group procedure, whole-life technique.

These calculations are shown in Appendix A. The calculations of the theoretical depreciation reserve values and the corresponding

remaining life calculations are shown in workpapers. Book depreciation reserves were based on Company individual accounts and the theoretical reserve computation was used to compute a composite remaining life for each account."

PREAMBLE: The above quotes refer to the use of a remaining-life depreciation system; remaining-life technique and whole-life technique.

QUESTION:

a) Please fully explain the difference between each of the remaining-life depreciation system, remaining-life technique and whole-life technique references. Please also include an explanation of how each are incorporated and used within YEC's depreciation expense calculations.

b) Please provide a copy of the interview notes (as between YEC and Alliance Consulting Group) prepared during the course of YEC's depreciation study.

c) Please clarify that all data relied on during the preparation of YEC's depreciation study was actuarial-based and did not contain any simulated data.

d) YEC indicates in many instances "there was insufficient transactional data for an actuarial life analysis" notwithstanding that this statement was accompanied by other operational observations which implied the existence of actuarial data. Please provide a retirement rate analysis (observed life table) for each depreciation study account including the plotted actual data points and proposed survivor curve.

e) Please provide a calculated annual accrual and accrued depreciation for each depreciation study account.

f) Please clarify if YEC uses amortization accounting for all depreciation study accounts that have been assigned the use of a square curve (SQ). If not confirmed, please explain fully how YEC accounts for asset retirements for depreciation study accounts using an SQ.

g) Please explain the basis for YEC's asset classes and groupings. If YEC has relied on information respecting asset classes and groupings from other jurisdictions, please provide a copy of that information including a description of the assets that should be recorded into each separate asset class and grouping.

ANSWER:

(a)

The calculation of depreciation rates for YEC used the whole-life technique. The difference between the actual and calculated accumulated provision for depreciation for each group was allocated to future periods using the average remaining life for each group. Effectively, this translates into the remaining life technique. Please see the attached excerpt from Depreciation Systems for an explanation of the differences between the whole-life and remaining life techniques.

(b)

Please see Attachment 1 to this response (interview notes).

(c)

All data relied upon was actuarial.

(d)

Please see Attachment 2 to this response.

(e)

Please see response to YUB-YEC-1-109 for the requested information.

(f)

Alliance Consulting Group is interpreting the question in being vintage group amortization as set for the USA FERC accounting release 15.

https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/vintage-year-accounting-general-plant-accounts

YEC does not use amortization accounting. Asset retirements are made by YEC based on when assets are taken out of service. The SQ curve assigned in a few accounts in the depreciation study are assigned due to the lack of sufficient historical transactional data in which to determine a specific retirement dispersion. Therefore, those accounts were assigned a SQ dispersion.

(g)

YEC has developed a fixed asset catalog which details its system of accounts and the components within each account. Please see attachment 1 to this response.

Yukon Energy Interviews 5-6-19

IT – creating an integrated IT/communication asset management plan.
Communications towers – the current life is 30 years. They are there for satellite and microwave. They design for a 30-year life. The towers would likely have a longer life than 30 years.

Communication equipment (confirm that network equipment is in this account) – split network equipment (maybe 10-year life) from other communication equipment life satellite (possibly 30 years) and microwave (possibly 30 years) and phones (maybe 10 year life). Split network and set 10 year life, Other comm equip 25 year life.

Comm fencing should last longer than 20 years – maybe 30 years.

Computer hardware – servers, pcs, printers, etc. 70 percent of workstations are 4 years old or older. They don't have a solid refresh cycle or plan yet. Servers would have a longer life. The 7 year life seen is reasonable for now. They expect the life to decrease as they implement a management plan.

Computer software – they will give list of software with in-service dates and expected lives. Then we will look at buckets to separate software.

One wind monitoring site – will likely be out of this process within a year. It might be 10 years old now. At least move down to 15 years.

Operations
Transmission poles - Transmission Line Refurbishment (TLR) – Test and treat inspection and detailed line inspections. Results came back with prioritization to replace. The assets being replaced are around 50 years old. They would expect the same 50-year life for the remaining assets (with the caveat that there are no retirements). They are now using steel cross arms. Transmission poles in majority are capitalized when replaced but the original pole is not retired. New lines are capitalized.

Distribution – 25kv and less. Permafrost will put more stress on poles. ROW is narrower, closer to vehicles, shorter and lower-class poles. They would expect a shorter life than transmission – maybe 40 years. Replacements are charged to O&M. Only new lines are capitalized. They mostly use penta treatment.

Sub-transmission – 34.5kV – They have no 34.5kv lines. What is in this account? Life should follow what type. Teslin line? Built but another party operates.

Transmission – above 34.5kV. They are doing Distribution test and treat (no formal program though).

Over the last 3 years, they started using the "restoration fund" for removal cost.

What is Mnt Mn???

Brushing – capital clearing of ROW for new lines. There is a 10-year cycle for clearing brush on ROW – which is O&M. Setting the life to the life of the poles (or possibly ROW) is reasonable.

Transmission conductor – They would expect a longer life for conductor. They will replace poles without replacing conductor. Not a corrosive environment. Fire retardant will coat insulators and can cause replacements. Glass insulators are the norm. On some structures where it is anticipated that the line will be replaced within the next 20 years, they will use polymer insulators. They would expect maybe a 60-year life for transmission conductor.

Distribution conductor – Load growth would be a primary driver for replacement of conductor. There are a few extra reasons for replacing distribution conductor as compared to transmission conductor. They would expect a slightly shorter life for distribution conductor. A 50-year life is reasonable.

Distribution Services – most services are overhead. The capacity requirement for customers keep increasing (affecting both services and transformers). Many of the communities have older infrastructure. Commercial services would have a shorter life than residential services. Leaving the life at 40 years is reasonable.

Distribution UG – only substantially in 2 locations (Dawson and Farrow primarily) – They will often run a spare conduit with laying UG. Cable staying at a 40-year life is reasonable. Moving out to 50 years for conduit is reasonable.

Substation Equipment Transmission – 54 (versus 40 for distr) – transmission stations and distribution stations are in the same footprint. Differences between transmission sub equipment and distribution is primarily the voltage level – basically the same equipment in both. Distribution equipment would have a shorter life due in part to the faults that would reach distribution but not transmission, the number of operations on distribution would be higher, higher relative currents (and therefore more heat) in distribution, and the degree of attention that is focused on transmission brushing. Transformers – 40-50 year life, breakers 35 years from OCB and 50 from SF6. 7 HV breakers will be replaced in 2019 and 5 LV replaced in 2018. The 54-year life is too long considering the higher level of electronics and the move to SF6. Suggest making transmission 40 years and distribution 35 years.

Substation fencing – the 30-year life is reasonable.

Meters – 100% digital (or close). Current life is 30 years. Move to 16 years. Industry Canada Have to pull at 8 years, and if tested good, get another 5 years, and if sample is good, another 3 years. Then done. 16 years is the maximum life.

Line transformers- 40 years is a little long. Line transformers are subject to higher loading due to growth. Voltage fluctuations will also tend to shorten the life. This will shorten the life of the transformers. Suggest moving to 35 years.

Street lighting – 100% LED. There were a large number of failures at original installation. Replacement of heads would be O&M. Leaving at 40 years is reasonable.

Generation
Diesel plant – In White horse - 7 units in building (2 retired, one about to be – all three of same design - Mirrelees units) They lost vendor support for the Mirreless. 4 units remaining. 4 reciprocating diesels.

Most diesels are Catepillar engines across the system. They retire based on hrs of use. Diesels are back-up/peaking (100K until retirement) – they run very seldom. Gas is 60k hrs until engine replacement. 5-year capital plan is starting to look at retiring one unit every 5 years. Major overhauls ($350k) are capital. Gas overhauls (6k hr) are capitalized. Time between overhauls is based on use. The 5-year overhaul period is short – suggest moving to 10 years. Minto is the controls for a plant that wasn't purchased and is being amortized – continue the amortization at current. The structures and building lives are reasonable. Fuel holder life of 25 years is low. They will provide in service dates for tanks. 40 years is more reasonable. For the generators/prime movers, the block will last 40 years or more but some components will have a shorter life. Staying at the 40-year life is reasonable.

Hydro

Every 10 years, tear down and inspected. Uprating one unit in 2020. 2 run of the river and 1 multi-year storage plants. Mayo – discussions are in play to retire one of the Mayo units (not the dam – just the units) but not firm enough to use in the study.

Life of dams, overhauls, digital electrical, misc and fences as approved are reasonable. Accessory electrical should move to 40 is reasonable. Runners/generators should move to 60 years – they have already replaced runners at under 60 years and rewound generators at under 60 years. Other units are being looked at for efficiency improvements as well.

LNG Plant – 3 units, 4 day full run capacity. In-service 2 in 2015 and 1 in 2018. These are first run units. Over 7500 hours since 2015 (2018 unit has over 3k hours). They think around 4k hrs per year for each unit. Structures, accessory electrical, misc and fencing lives are reasonable. Fuel holder life of 32 years is short. They are nickel, double walled tanks with no moisture ingress. With reasonable maintenance, a 60 year life is reasonable. Their projection is that the generators will need to be replaced at 15 years (which would be 60k hours at the current projected rate). The vaporization process (NEED TO FIND OUT WHERE THIS IS BOOKED) will have a shorter life (maybe 30 years).

Transportation

IF a vehicle is 8 years or older and has 160k KM and incurred greater 15% maintenance cost in one year. They are behind on their schedule.

Utility vehicles – currently at a 7 year life. Line crews use for 7 years (that is held to well). Occasionally, a quad or snow mobile will move to a plant and have a longer life (probably around 80% do not). Moving the average out to 8 years to reflect the 20% that stay longer.

Sedans/Station wagons – currently a 7 year life. They are lasting longer – between 10-12 years years (landing on 11 with a steep dispersion is reasonable).

Pole trailers – the 25 year approved is reasonable.

Trucks – ¾ to 2 ton – 10 years is approved. Electrician($90k)/operations ($70) vehicles would only drive at a level that 10 years is reasonable. Linemen ($115k) would hit the maximum mileage in 3-4 years but other factors would let you keep them longer. They will be replaced by 8 years. There are equal numbers of each. Moving to a 9 year life for the average is reasonable.

Trucks greater than 3 ton – the approved 20 years is reasonable. They just spent $40k to overhaul a 10 year old vehicle.

Trucks – Foremost – tracked vehicle ($534k) and 2011 auger equipped Kenworth truck. The live should match the life of the greater than 3 ton trucks of 20 years.

Facilities Sean Munro Manager, Property & Projects

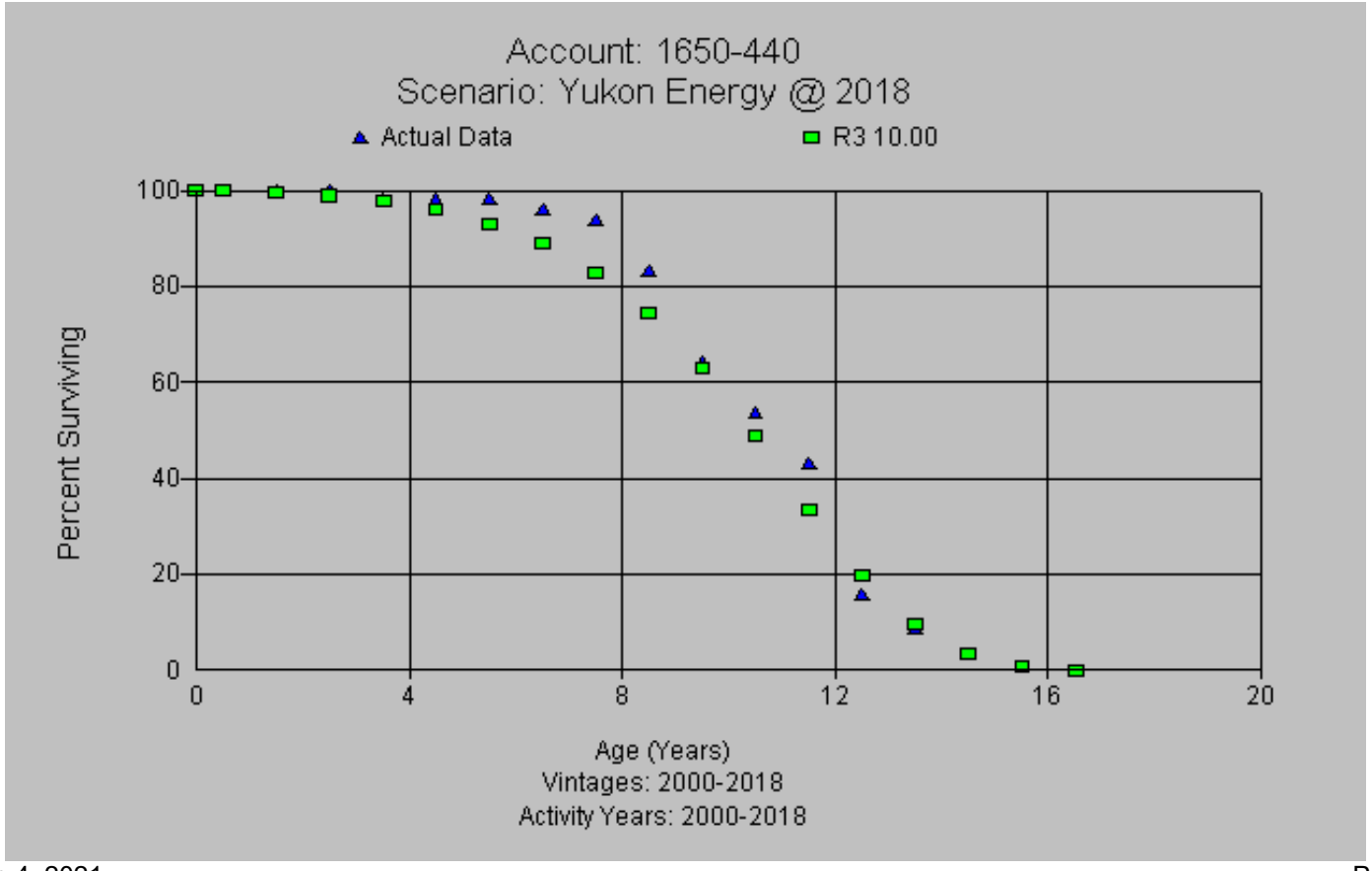
Furniture/Equipment – approved life is 20 years. When furniture is removed from a location, it is either transferred or disposed of. It is generally no reused. Michael can address the life.

Structures Hydro – hydro structures are on the water so they would have a little shorter life for various components. However, 40 years is shorter than expected. The newer buildings are more technology driven and have a little less longevity than the older built structures. Moving both hydro and non-hydro structures to 50 years is reasonable.

Some components of structures have a shorter life than the building itself. For example, Electrical panels (25 years), furnaces (15-20 years), fire alarm panels (20 years), flooring replacement (25 years), exterior (25-30 years),

Housing – currently 30 years is approved. The newest house is from 2005 and oldest is from pre-1980. 30 years is to low. Moving the life out to 40-year life is reasonable.

Fire protection systems – there is a large focus on fire protection and there is short life for the equipment (try to achieve 20 years maximum).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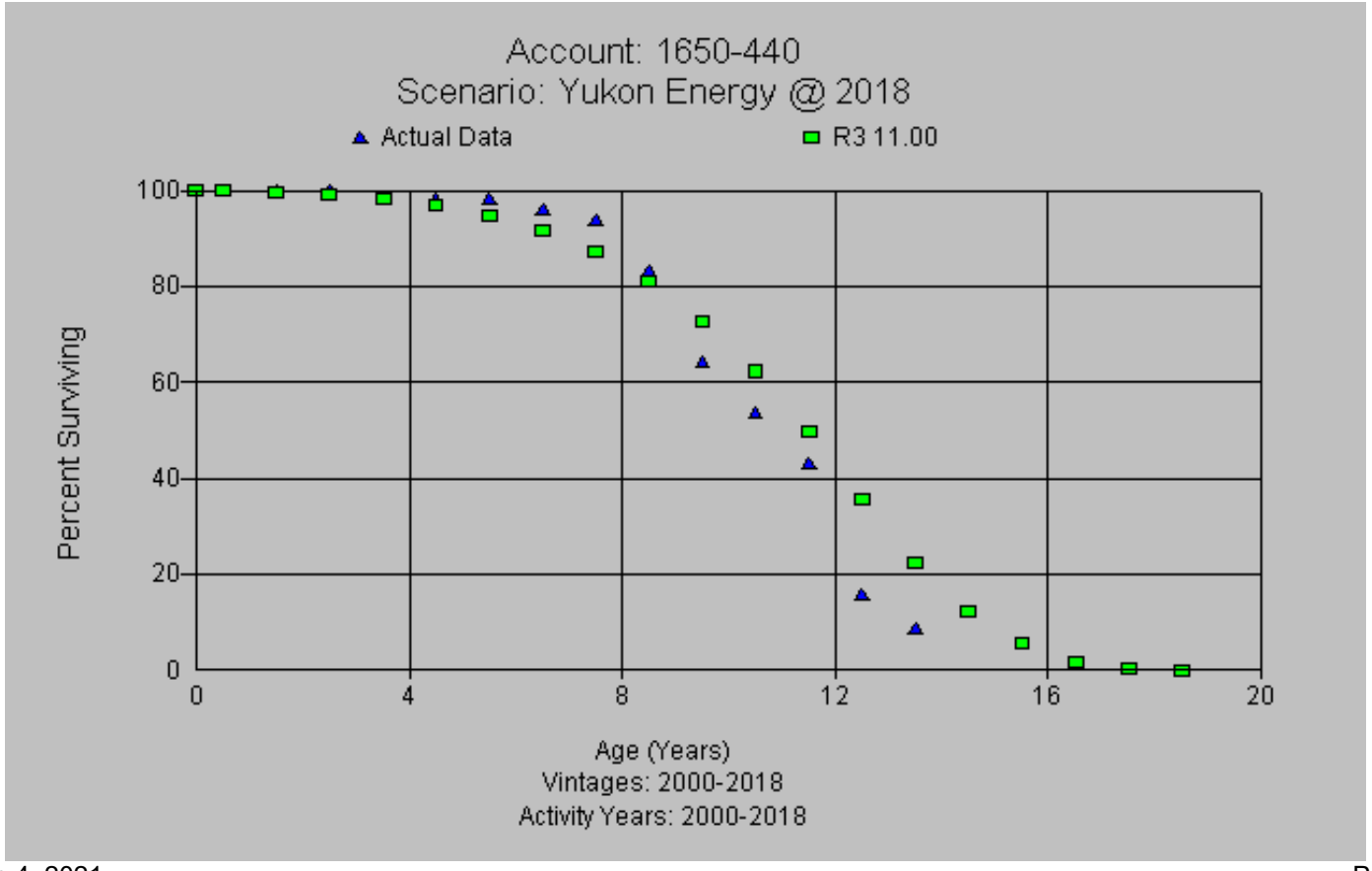
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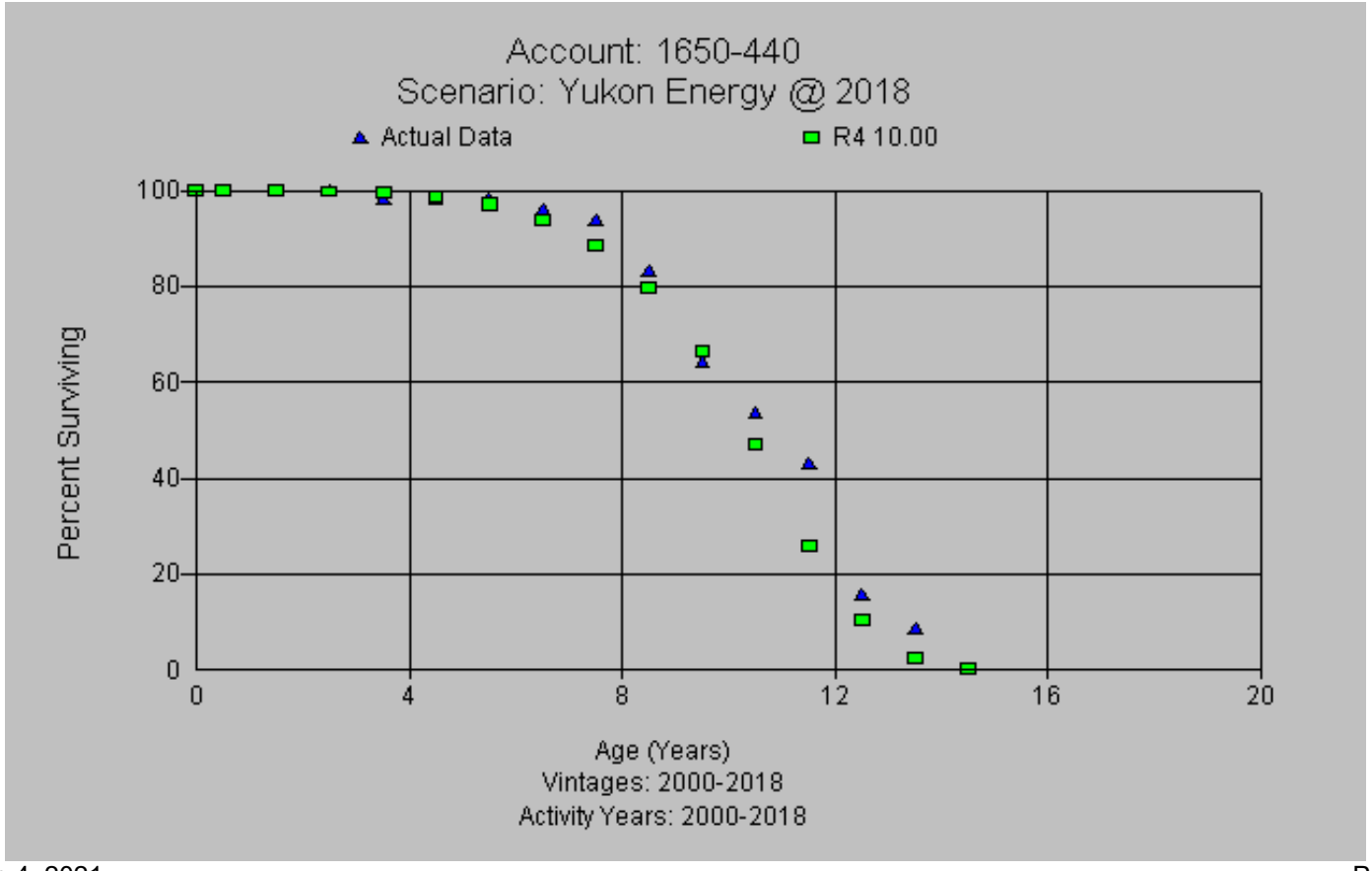
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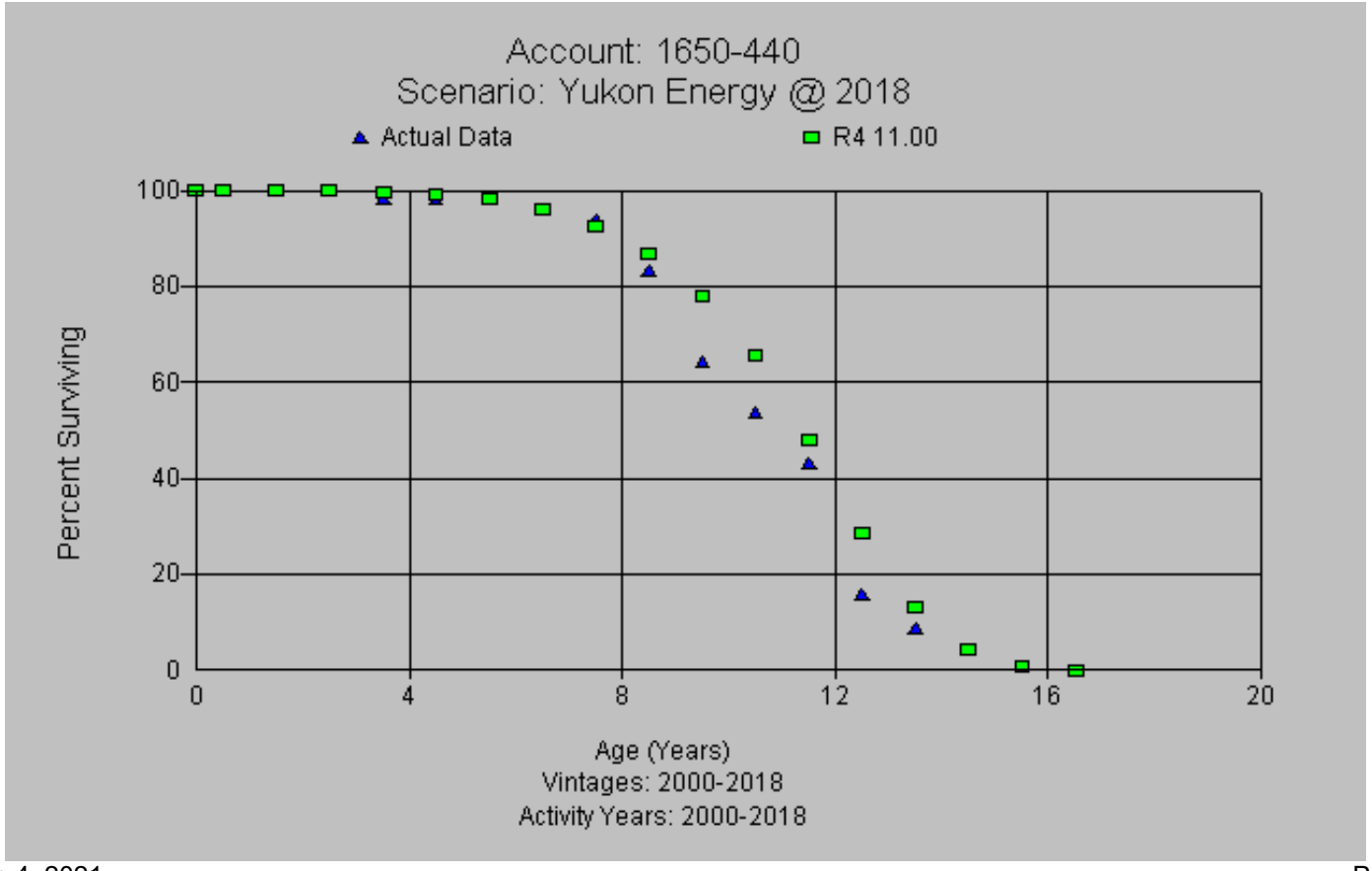
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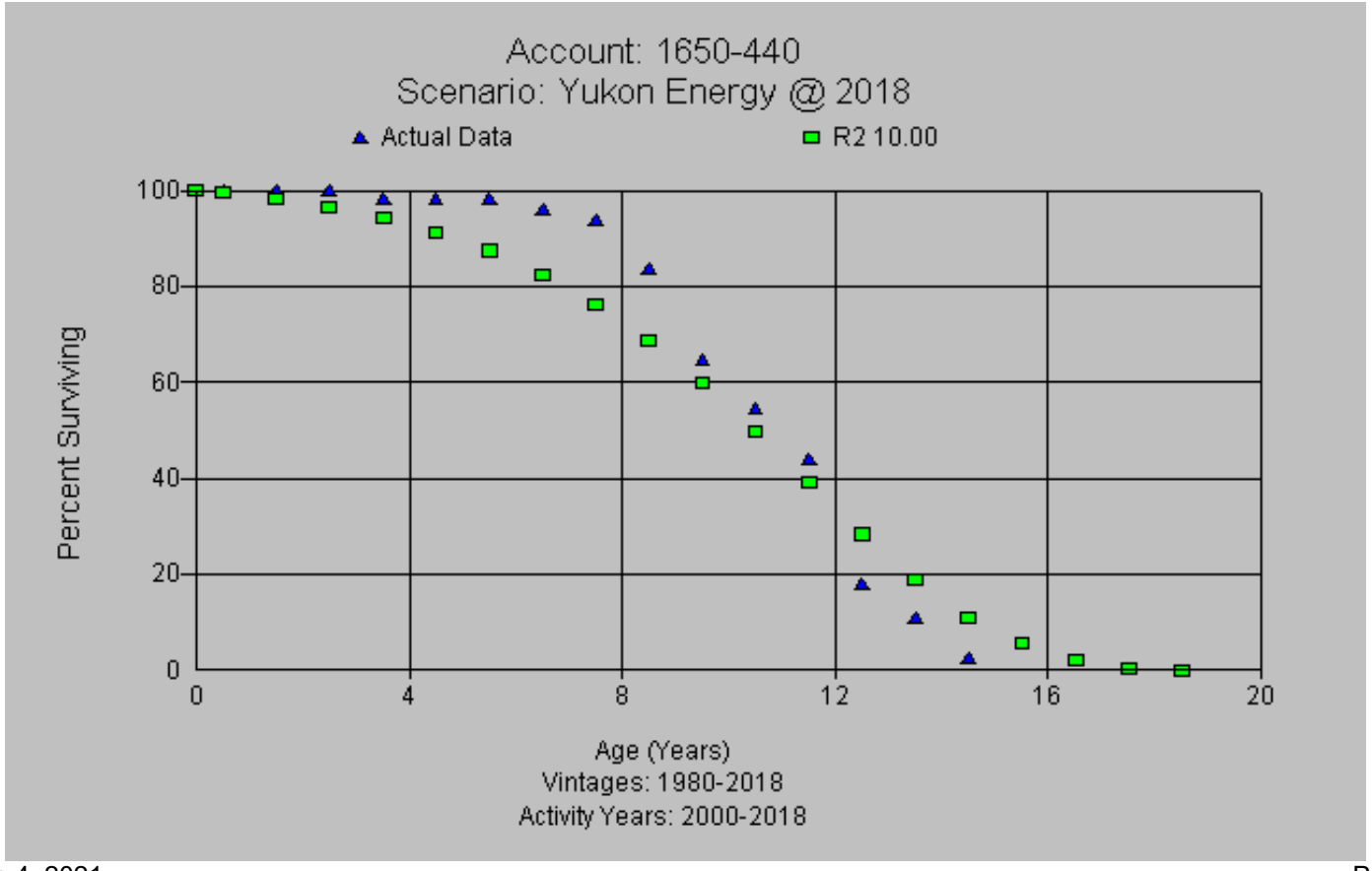
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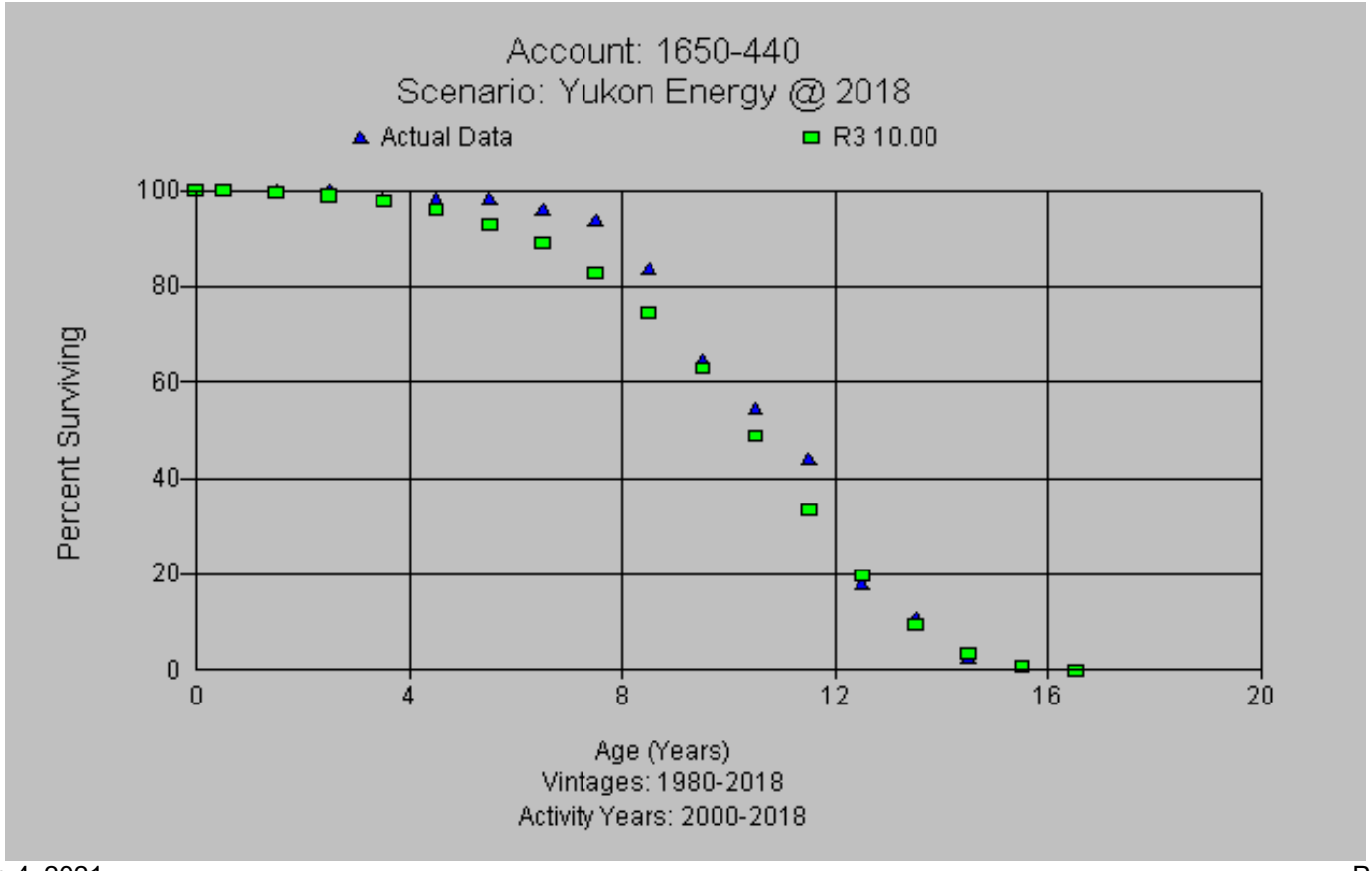
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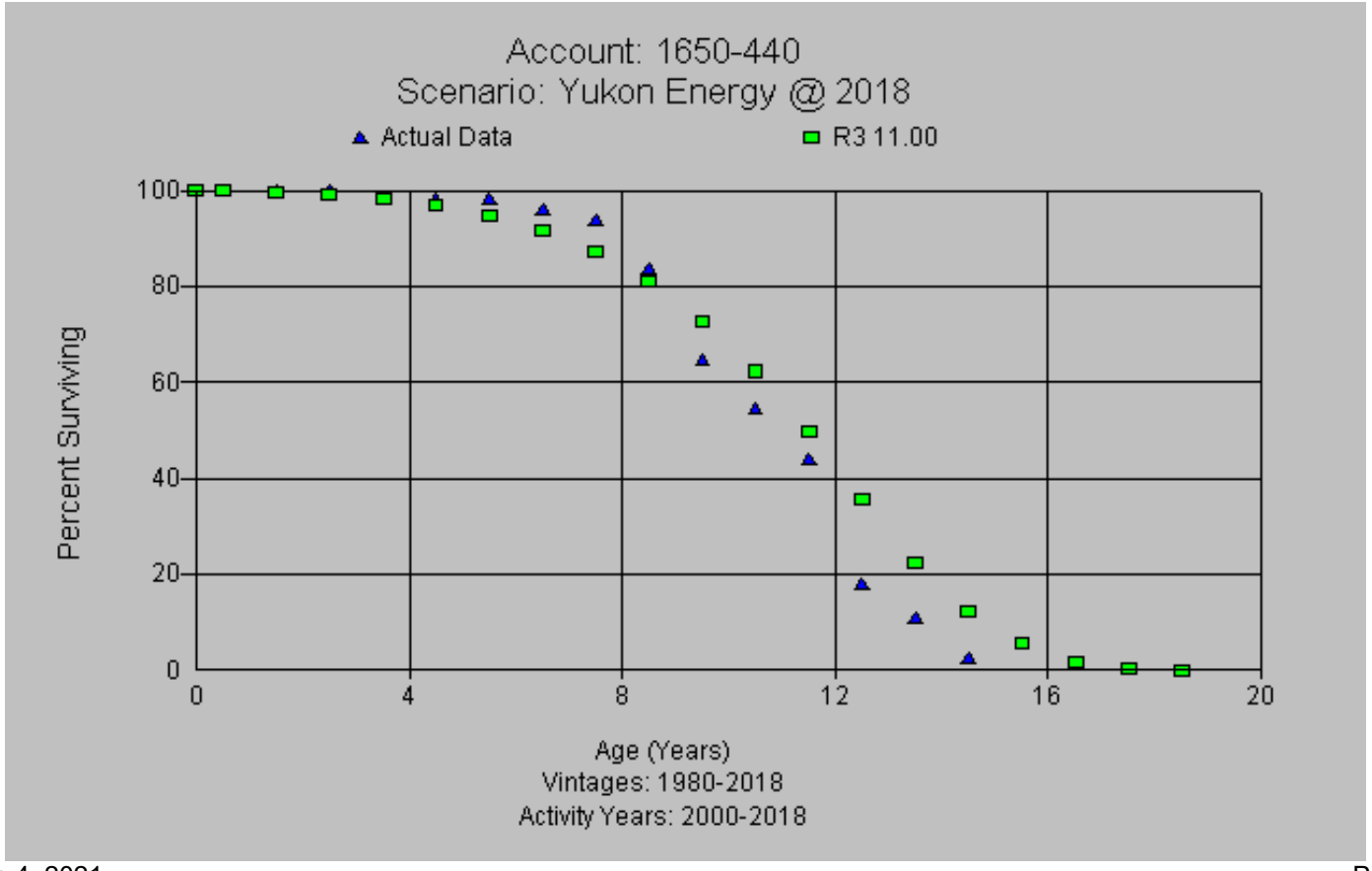
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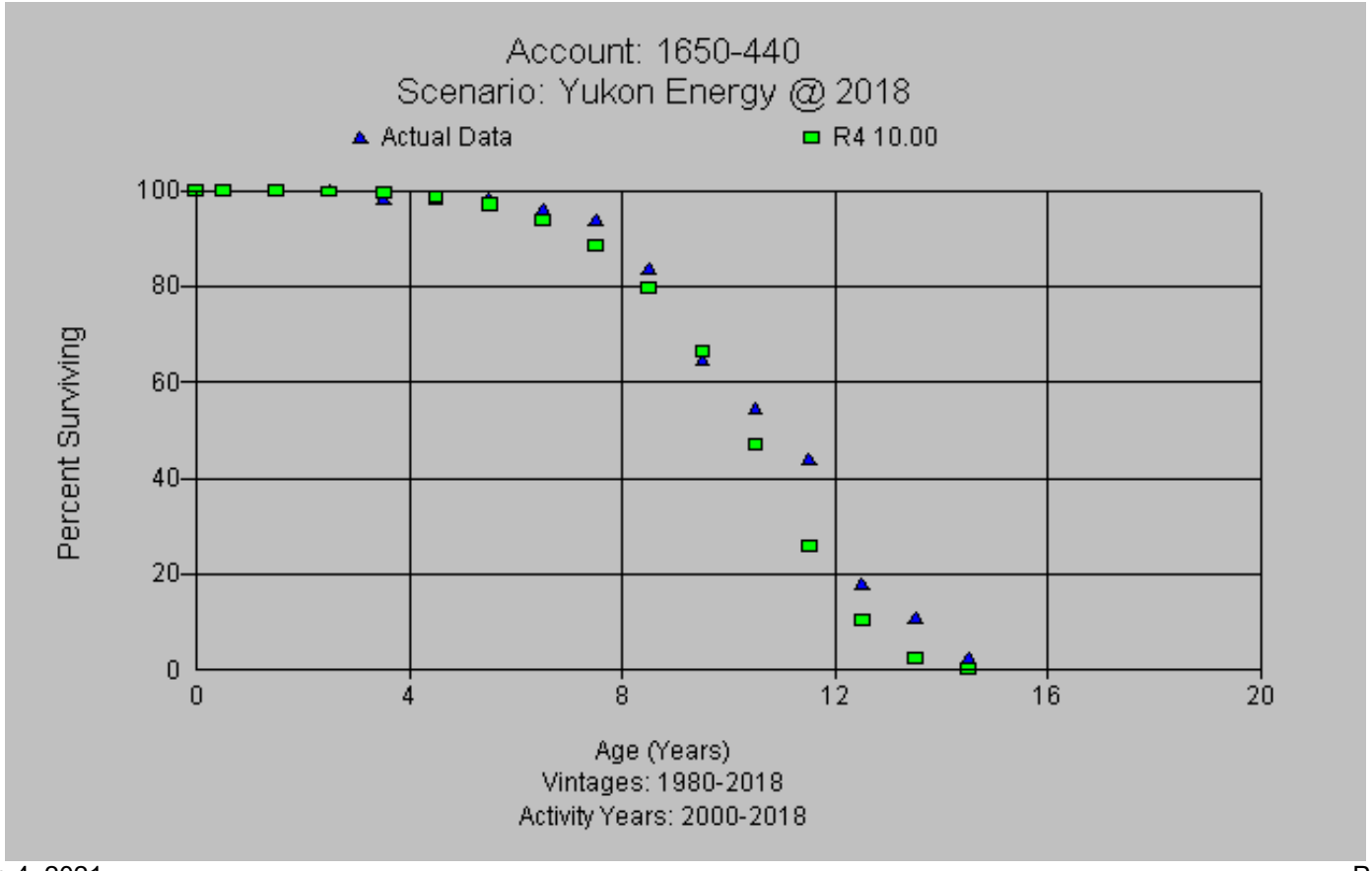
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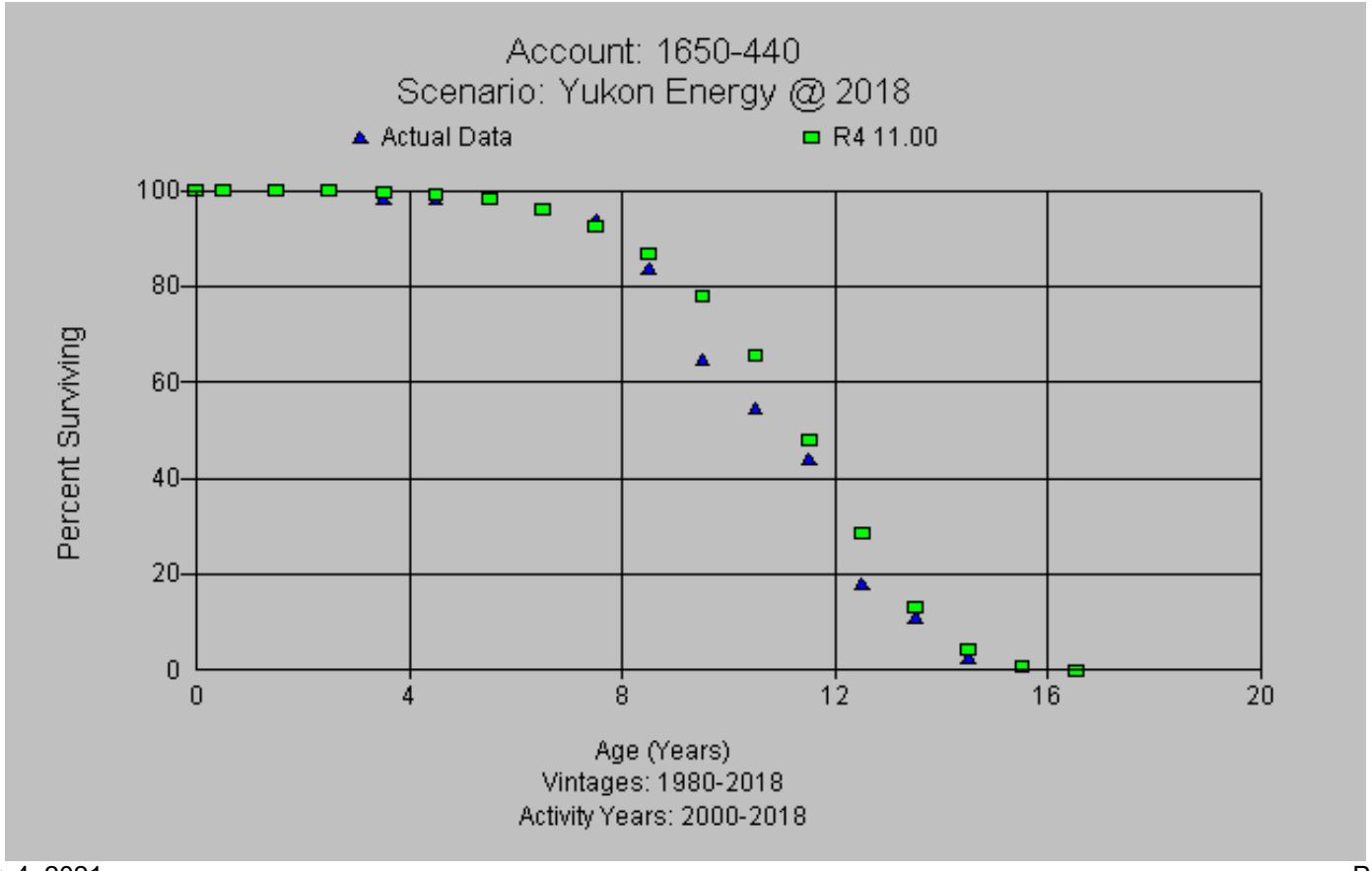
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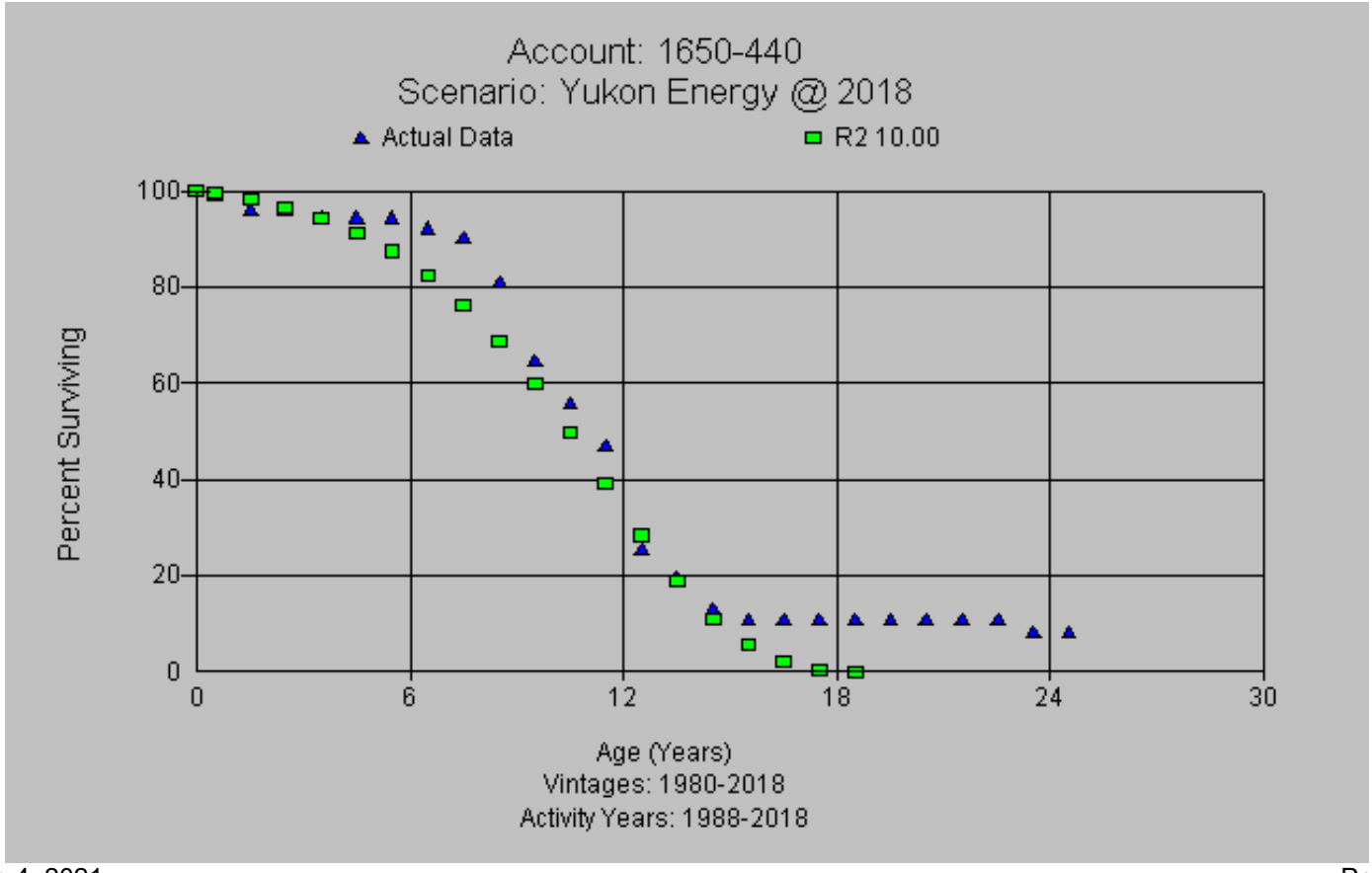
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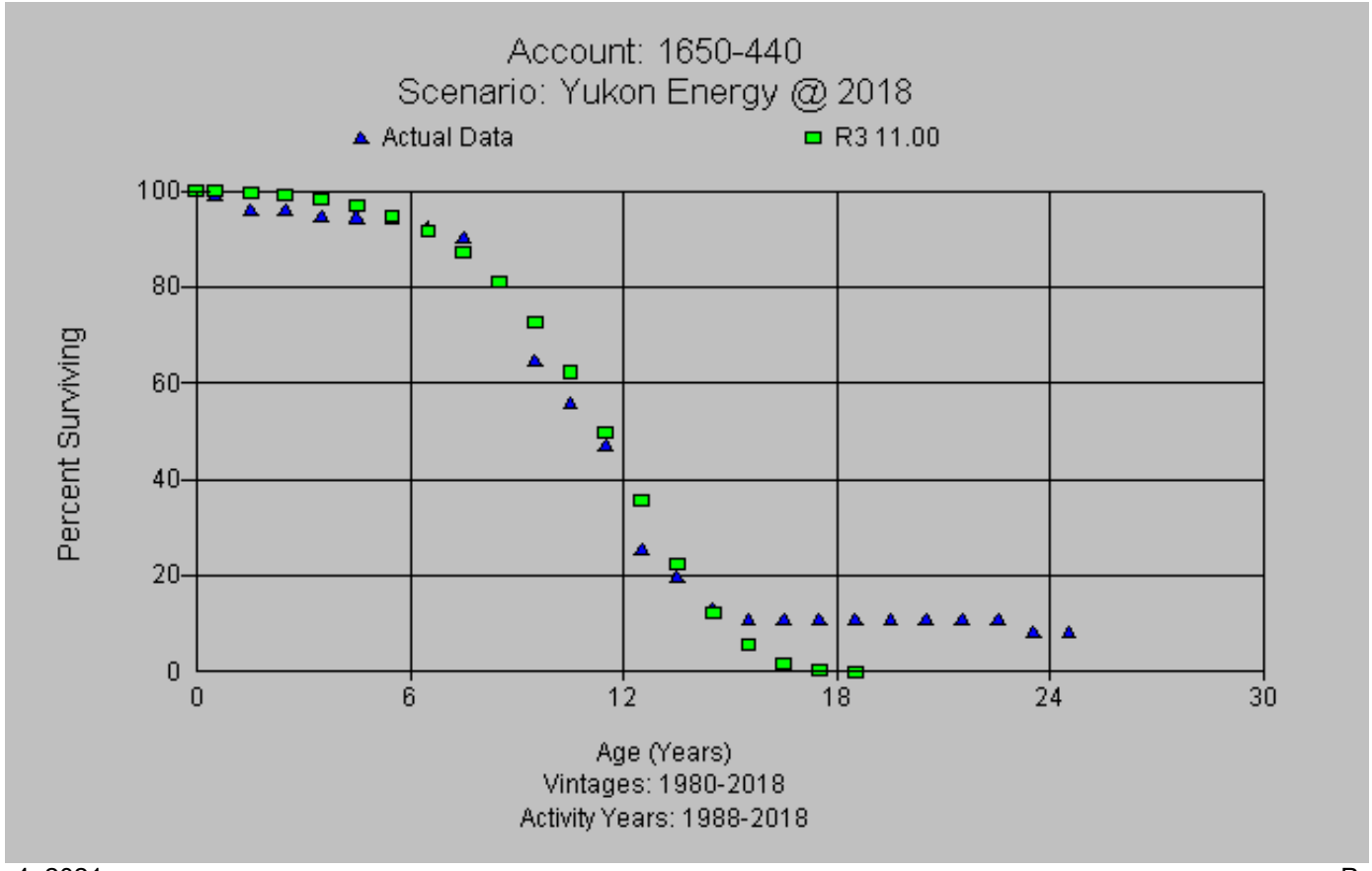
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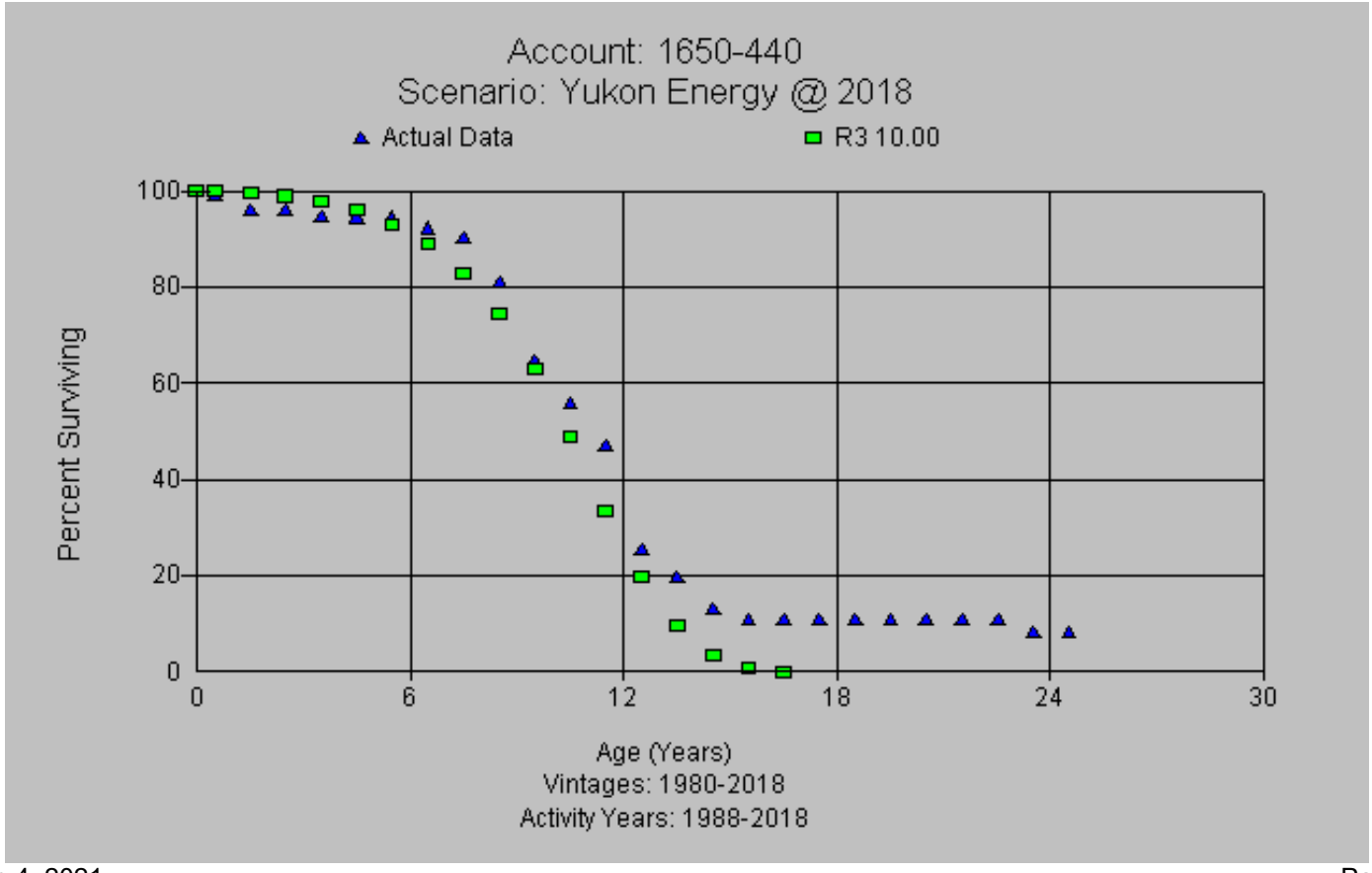
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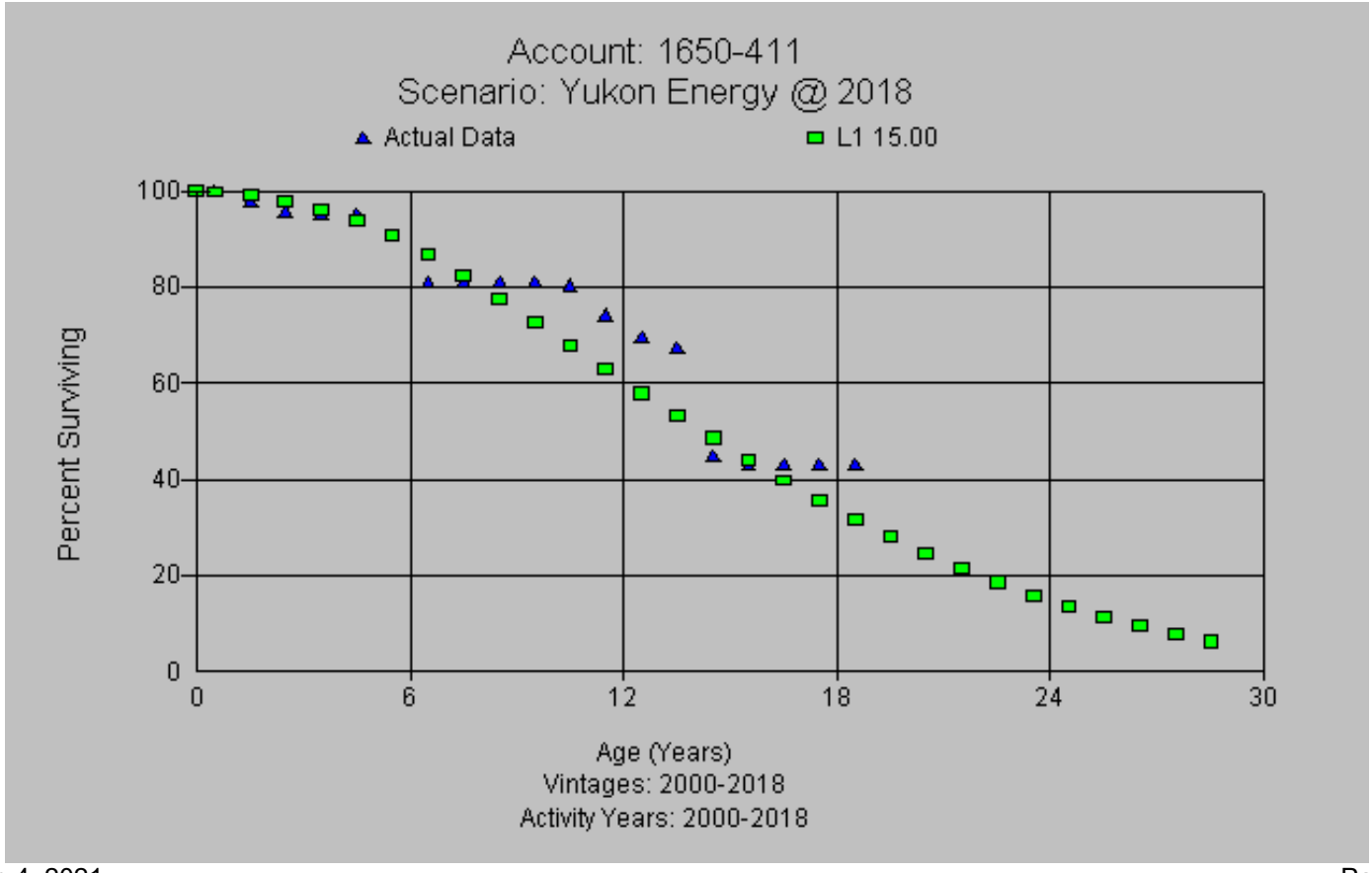
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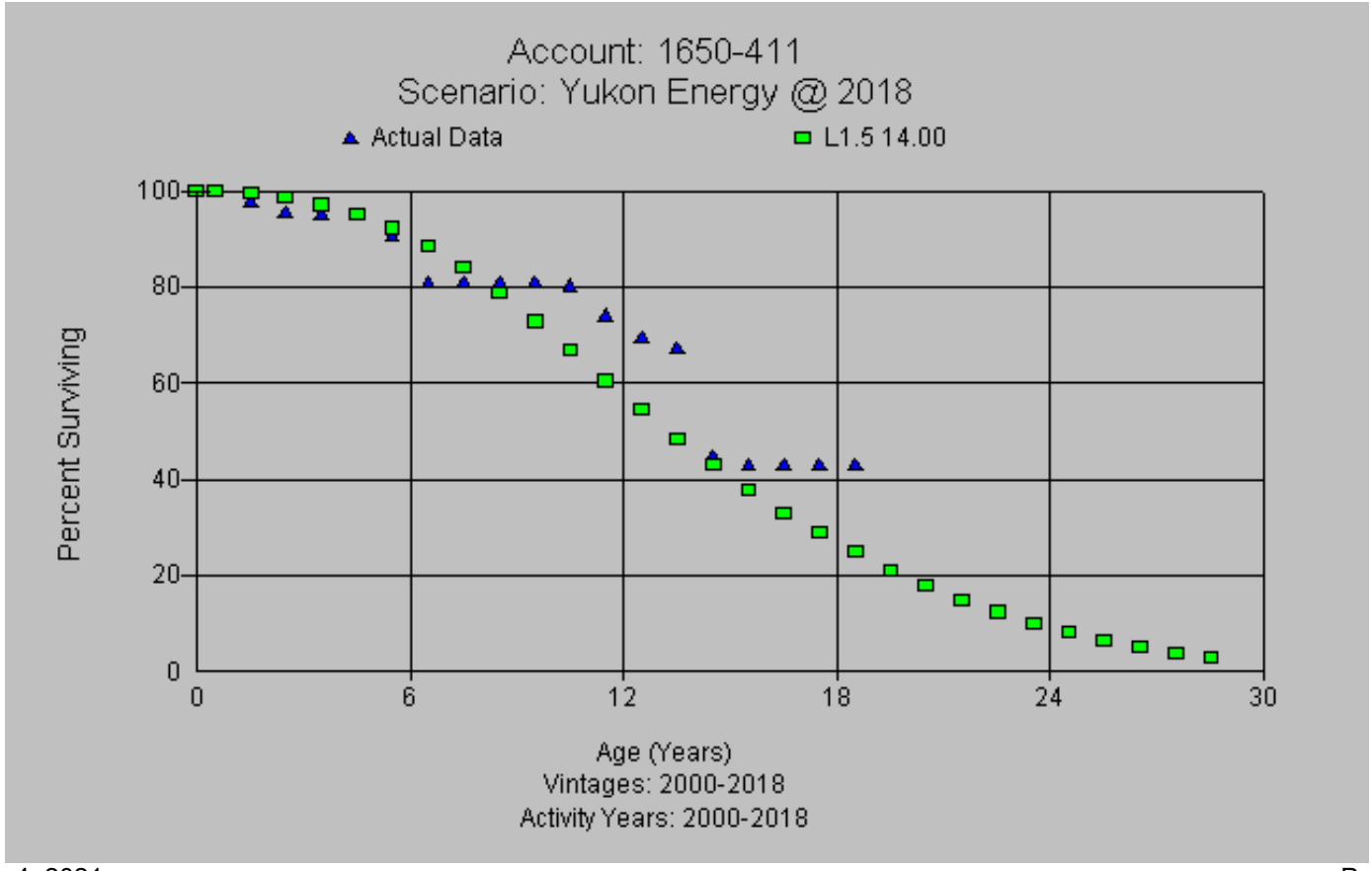
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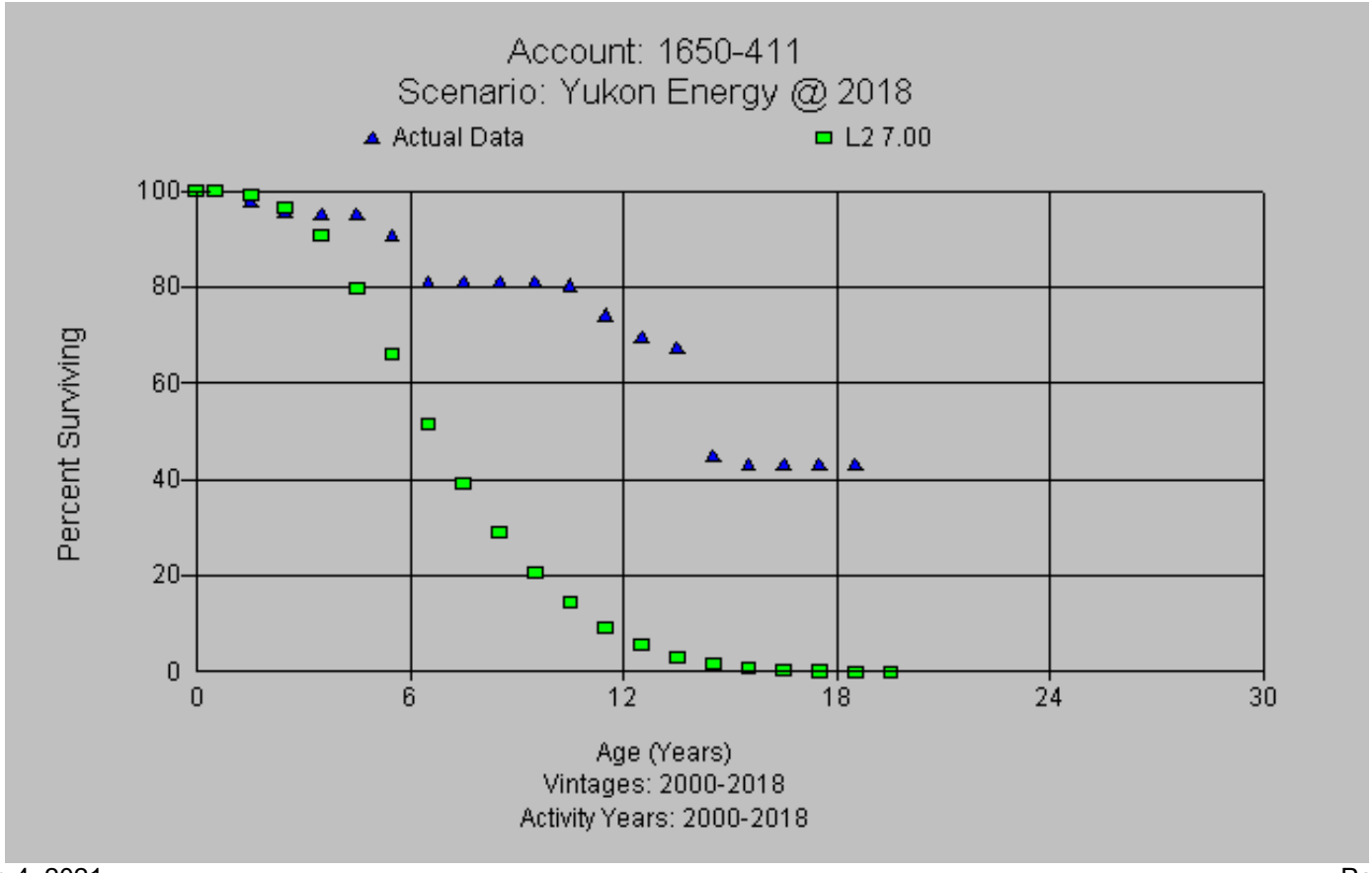
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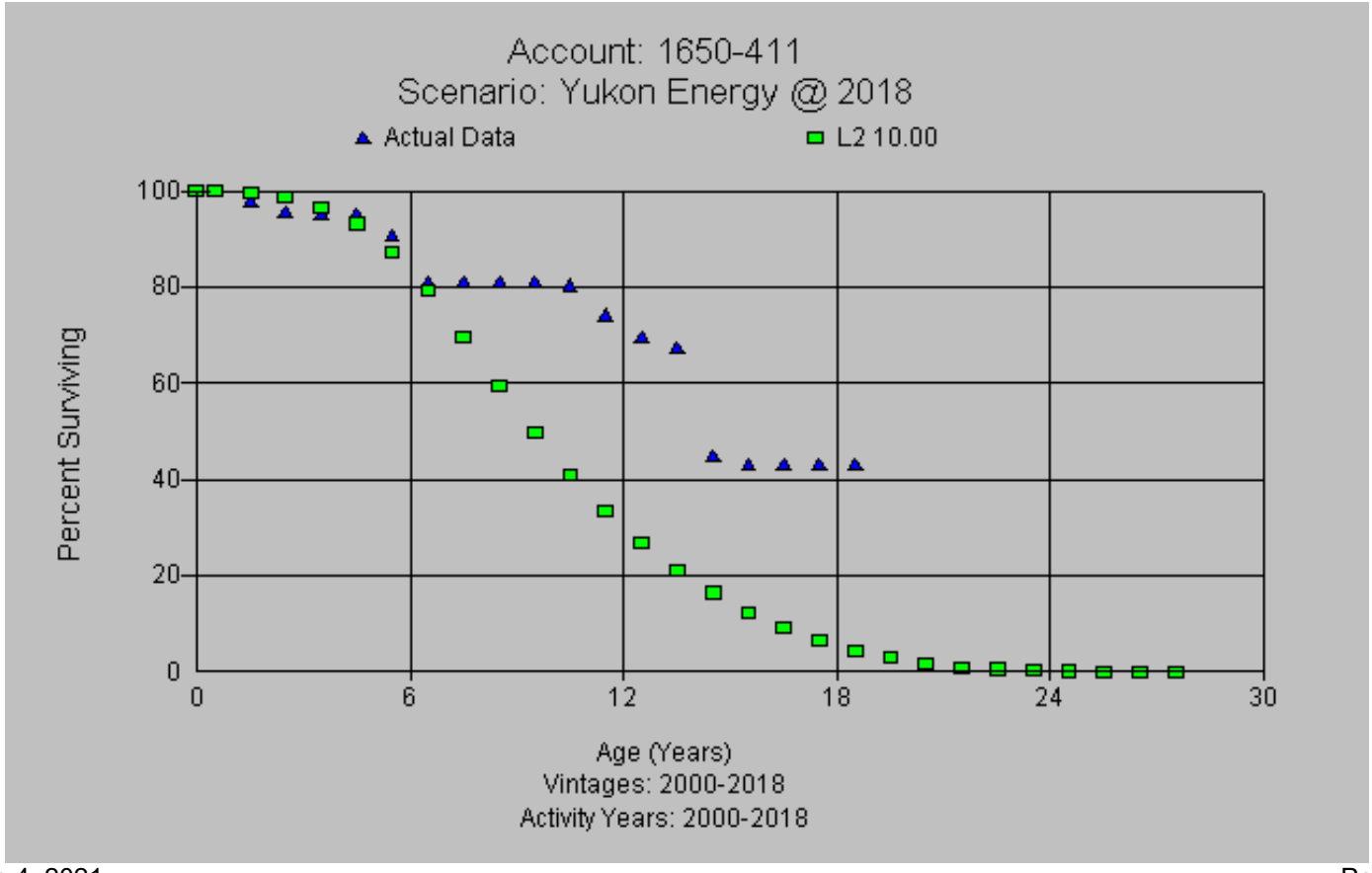
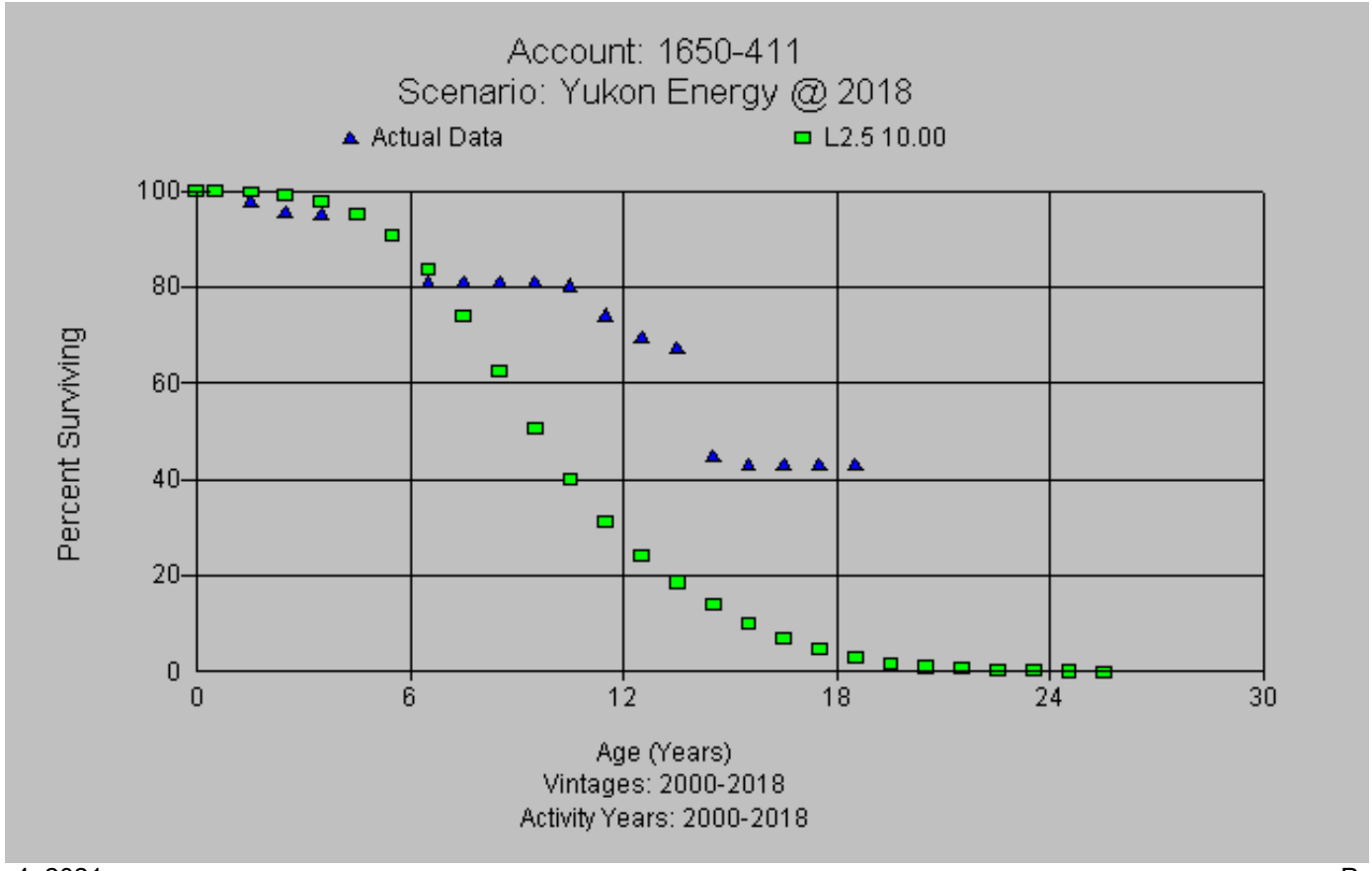
30
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

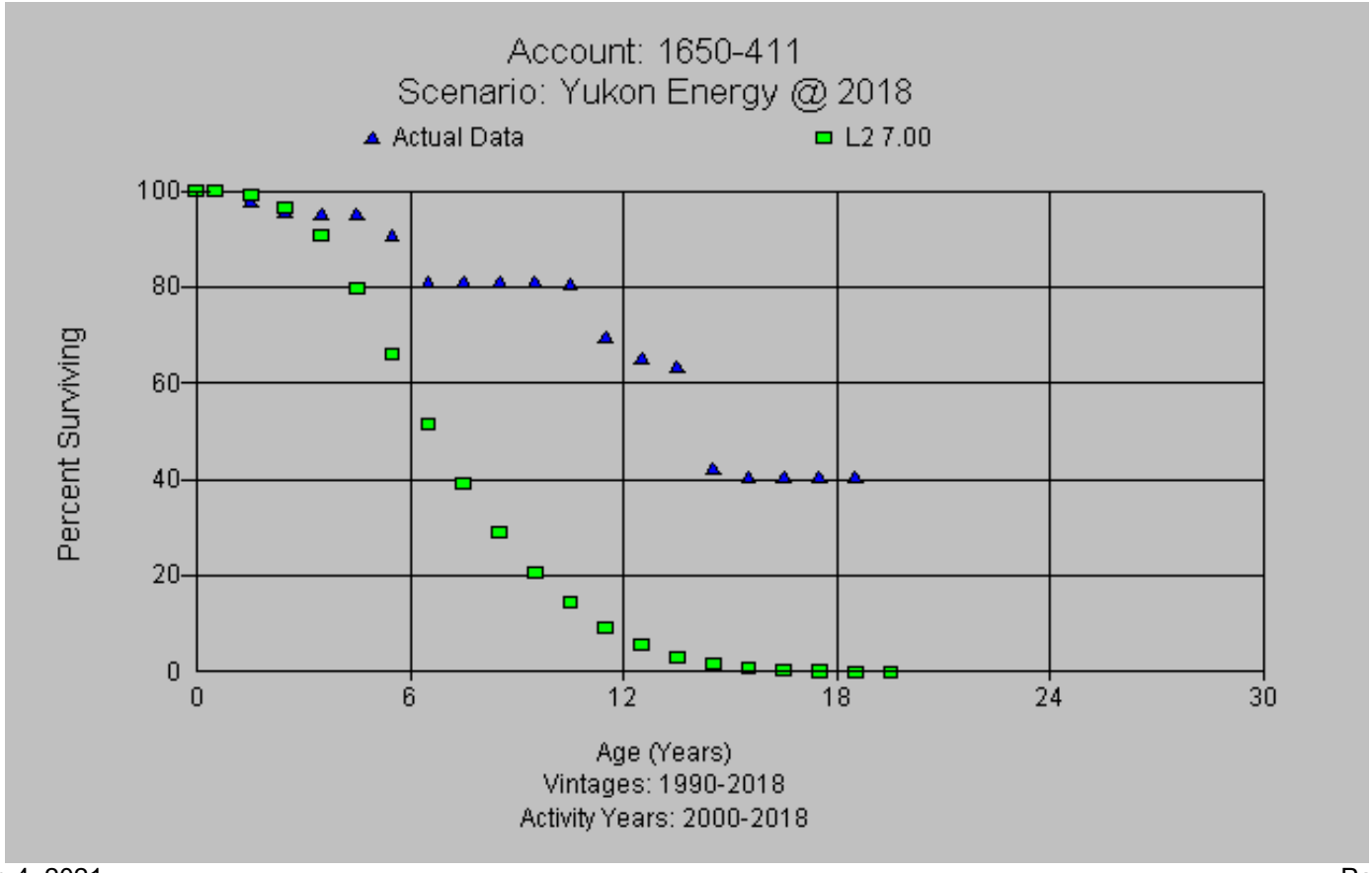

Account: 1650-411
Scenario: Yukon Energy @ 2018
Actual Data
L2 10.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

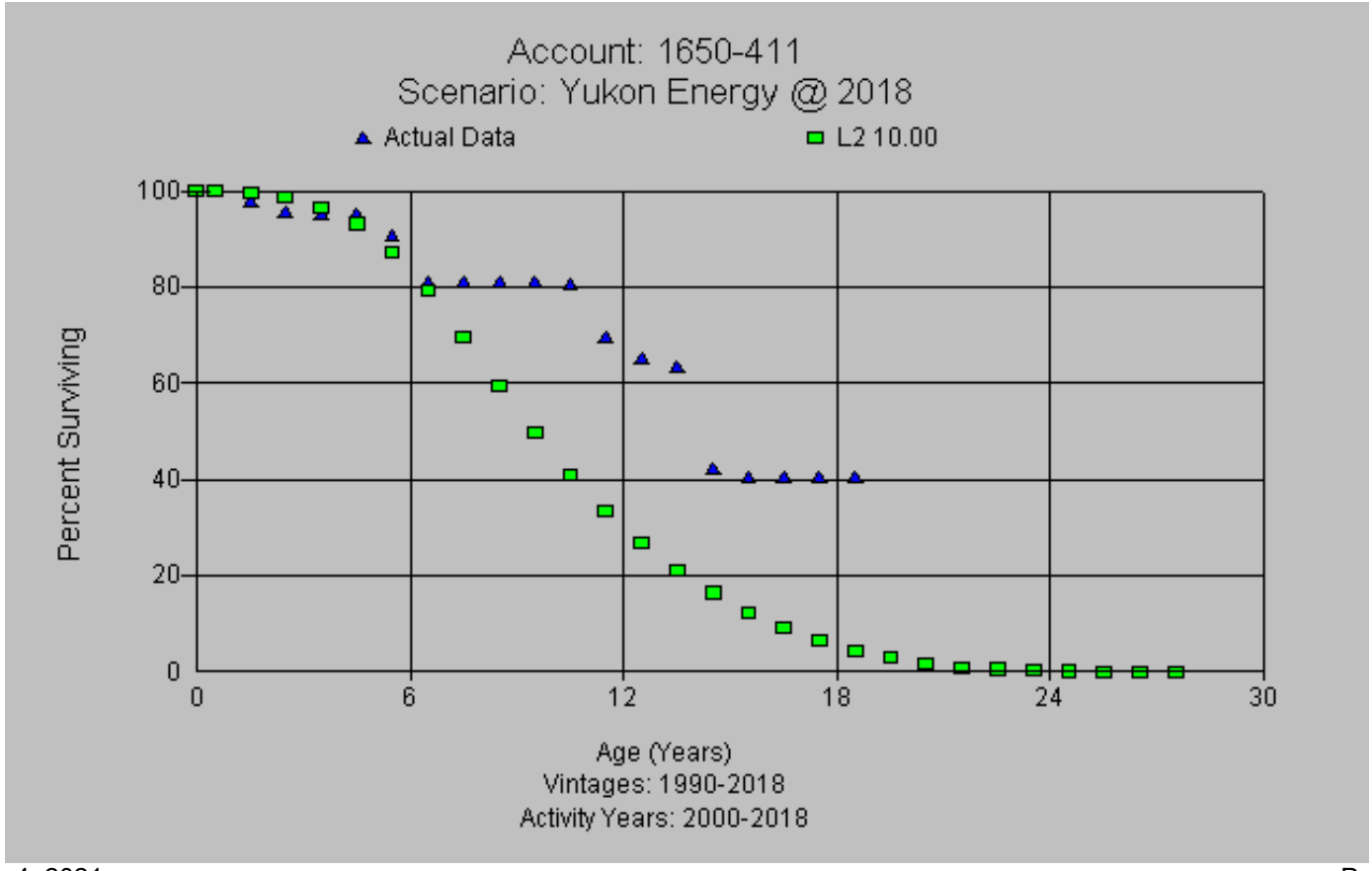

Account: 1650-411
Scenario: Yukon Energy @ 2018
Actual Data
L2.5 10.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1650-411
Placement Band: 2000 - 2018 **Observation Band:** 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	448,042.18	0.00	0.00000	1.00000	100.00
0.5	405,592.18	8,463.00	0.02087	0.97913	100.00
1.5	397,129.18	8,400.00	0.02115	0.97885	97.91
2.5	358,967.13	2,465.00	0.00687	0.99313	95.84
3.5	327,841.44	0.00	0.00000	1.00000	95.18
4.5	230,470.67	11,068.60	0.04803	0.95197	95.18
5.5	181,452.27	18,938.70	0.10437	0.89563	90.61
6.5	162,513.57	0.00	0.00000	1.00000	81.16
7.5	162,513.57	0.00	0.00000	1.00000	81.16
8.5	162,513.57	0.00	0.00000	1.00000	81.16
9.5	162,513.57	1,460.77	0.00899	0.99101	81.16
10.5	129,871.48	9,951.37	0.07662	0.92338	80.43
11.5	108,550.11	6,849.00	0.06310	0.93690	74.26
12.5	96,125.17	2,800.00	0.02913	0.97087	69.58
13.5	93,325.17	31,328.73	0.33569	0.66431	67.55
14.5	61,996.44	2,244.25	0.03620	0.96380	44.87
15.5	59,752.19	0.00	0.00000	1.00000	43.25
16.5	31,356.70	0.00	0.00000	1.00000	43.25
17.5	26,192.29	0.00	0.00000	1.00000	43.25
18.5	0.00	0.00	0.00000	0.00000	43.25

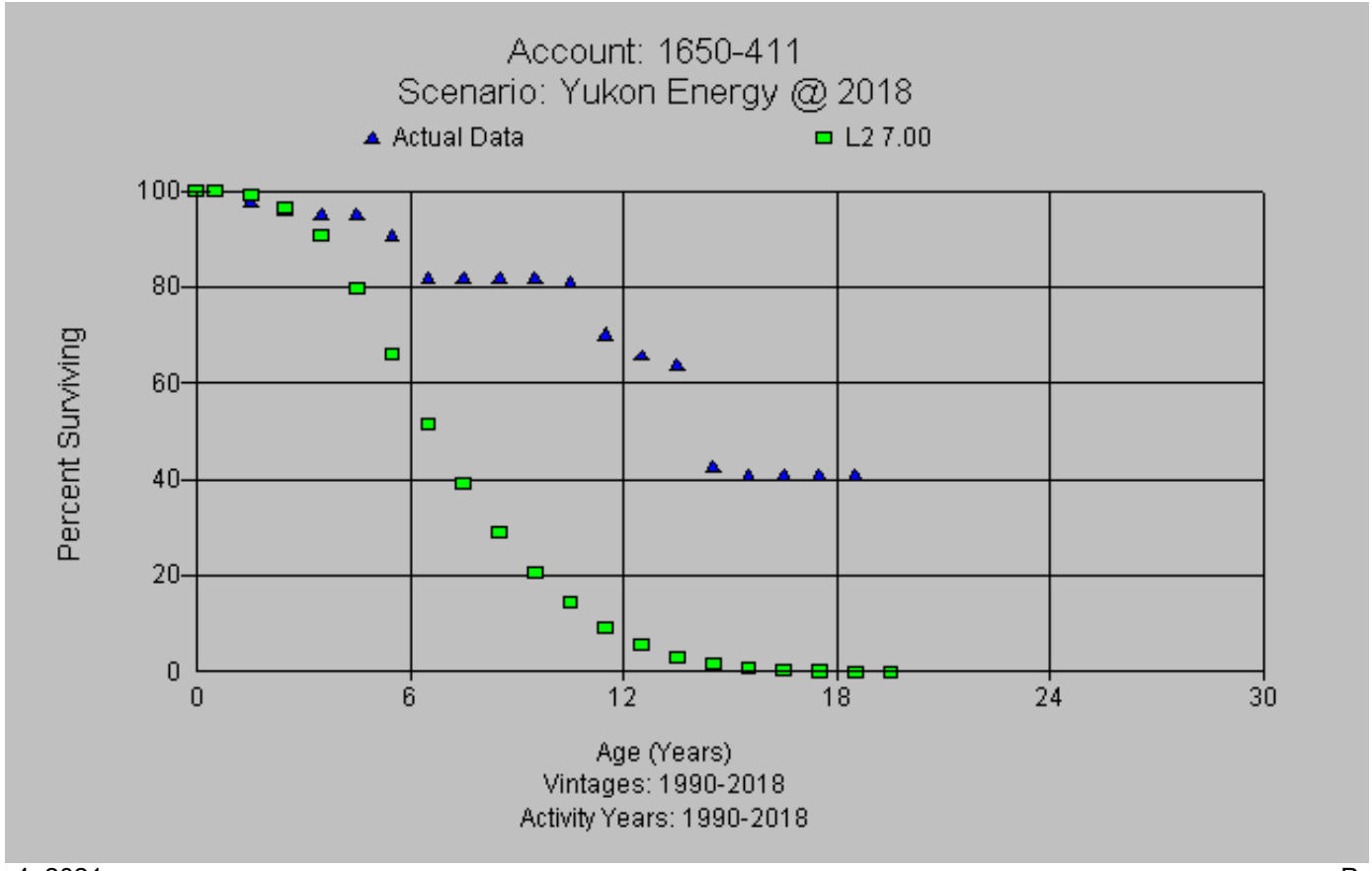

Account: 1650-411
Scenario: Yukon Energy @ 2018
Actual Data
L2 7.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1990-2018
Activity Years: 2000-2018

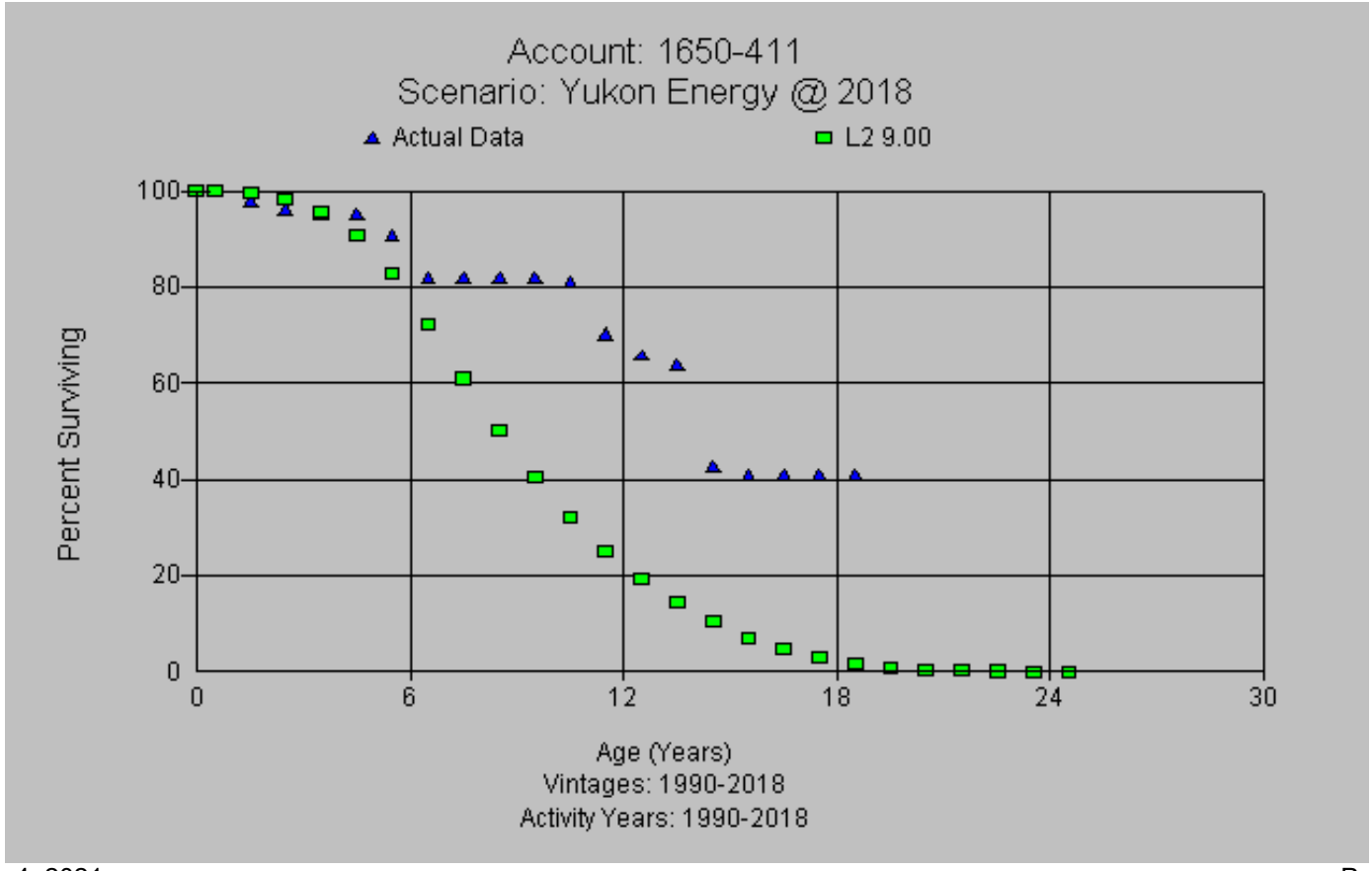

Account: 1650-411
Scenario: Yukon Energy @ 2018
Actual Data
L2 10.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1990-2018
Activity Years: 2000-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1650-411
Placement Band: 1990 - 2018 **Observation Band:** 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	448,042.18	0.00	0.00000	1.00000	100.00
0.5	405,592.18	8,463.00	0.02087	0.97913	100.00
1.5	397,129.18	8,400.00	0.02115	0.97885	97.91
2.5	358,967.13	2,465.00	0.00687	0.99313	95.84
3.5	327,841.44	0.00	0.00000	1.00000	95.18
4.5	230,470.67	11,068.60	0.04803	0.95197	95.18
5.5	181,452.27	18,938.70	0.10437	0.89563	90.61
6.5	162,513.57	0.00	0.00000	1.00000	81.16
7.5	162,513.57	0.00	0.00000	1.00000	81.16
8.5	162,513.57	0.00	0.00000	1.00000	81.16
9.5	171,063.57	1,460.77	0.00854	0.99146	81.16
10.5	138,421.48	18,501.37	0.13366	0.86634	80.46
11.5	108,550.11	6,849.00	0.06310	0.93690	69.71
12.5	96,125.17	2,800.00	0.02913	0.97087	65.31
13.5	93,325.17	31,328.73	0.33569	0.66431	63.41
14.5	61,996.44	2,244.25	0.03620	0.96380	42.12
15.5	59,752.19	0.00	0.00000	1.00000	40.60
16.5	31,356.70	0.00	0.00000	1.00000	40.60
17.5	26,192.29	0.00	0.00000	1.00000	40.60
18.5	0.00	0.00	0.00000	1.00000	40.60


Account: 1650-411
Scenario: Yukon Energy @ 2018
Actual Data
L2 7.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1990-2018
Activity Years: 1990-2018


Account: 1650-411
Scenario: Yukon Energy @ 2018
Actual Data
L2 9.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1990-2018
Activity Years: 1990-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1650-411
Placement Band: 1990 - 2018 **Observation Band:** 1990 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	456,592.18	0.00	0.00000	1.00000	100.00
0.5	414,142.18	8,463.00	0.02044	0.97956	100.00
1.5	405,679.18	8,400.00	0.02071	0.97929	97.96
2.5	367,517.13	2,465.00	0.00671	0.99329	95.93
3.5	336,391.44	0.00	0.00000	1.00000	95.28
4.5	239,020.67	11,068.60	0.04631	0.95369	95.28
5.5	190,002.27	18,938.70	0.09968	0.90032	90.87
6.5	171,063.57	0.00	0.00000	1.00000	81.81
7.5	171,063.57	0.00	0.00000	1.00000	81.81
8.5	171,063.57	0.00	0.00000	1.00000	81.81
9.5	171,063.57	1,460.77	0.00854	0.99146	81.81
10.5	138,421.48	18,501.37	0.13366	0.86634	81.11
11.5	108,550.11	6,849.00	0.06310	0.93690	70.27
12.5	96,125.17	2,800.00	0.02913	0.97087	65.84
13.5	93,325.17	31,328.73	0.33569	0.66431	63.92
14.5	61,996.44	2,244.25	0.03620	0.96380	42.46
15.5	59,752.19	0.00	0.00000	1.00000	40.92
16.5	31,356.70	0.00	0.00000	1.00000	40.92
17.5	26,192.29	0.00	0.00000	1.00000	40.92
18.5	0.00	0.00	0.00000	1.00000	40.92

Actuarial Life Analysis

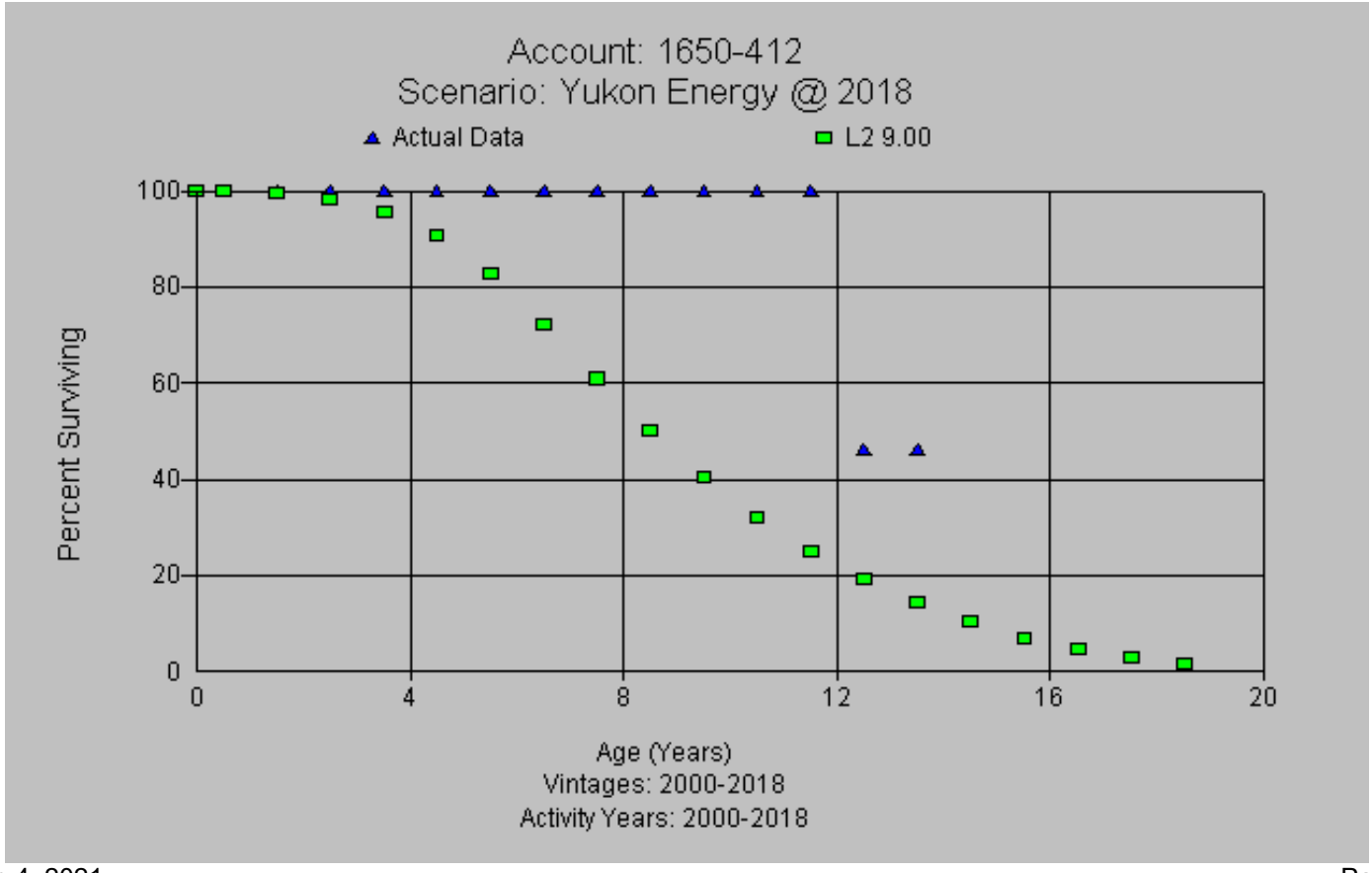
Account: 1650-411
Scenario: Yukon Energy @ 2018
Placement Band: 1990 - 1994
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

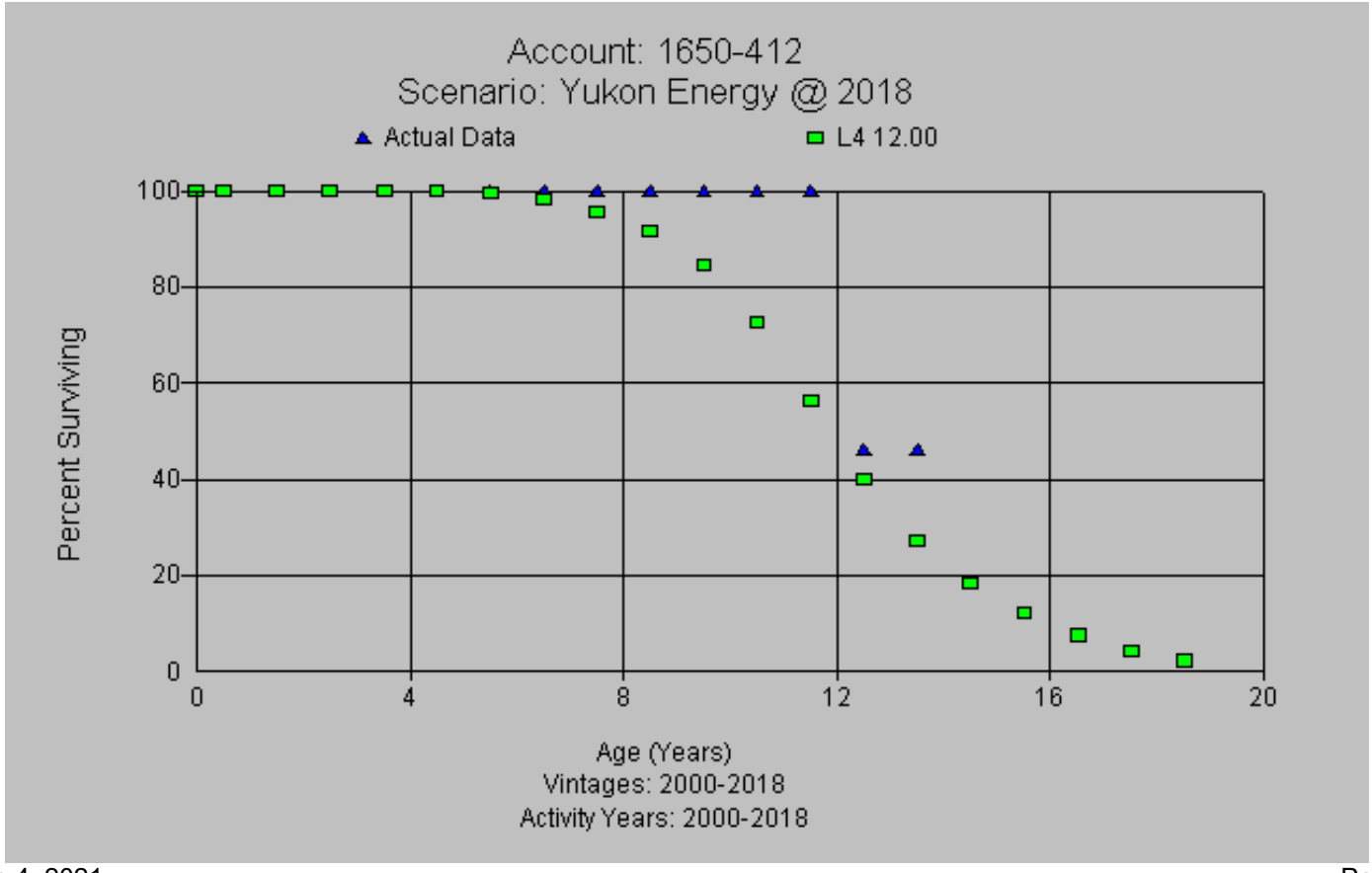
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1990 -1994		1.00			
1991 -1995		1.00			
1992 -1996		1.00			
1993 -1997		1.00			
1994 -1998		1.00			
1995 -1999		1.00			
1996 -2000		1.00			
1997 -2001	8.5	0.00	0.27976196	R4	7.15
1998 -2002	9.5	0.00	0.26840527	R4	7.25
1999 -2003	10.5	0.00	0.02795968	SQ	7.61
2000 -2004	11.5	0.00	0.02444965	SQ	7.64
2001 -2005	12.5	0.00	0.25298458	R4	7.20
2002 -2006	13.5	92.01	0.01360181	R0.5	40.28
2003 -2007	14.5	80.47	0.05407438	R0.5	20.27
2004 -2008	15.5	78.43	0.08433457	R0.5	19.44
2005 -2009	16.5	72.06	0.21165142	R0.5	15.96
2006 -2010	17.5	85.14	0.03720481	R0.5	33.76
2007 -2011	18.5	83.04	0.05522118	R0.5	31.01
2008 -2012		1.00			
2009 -2013	20.5	41.67	0.35368213	L0	13.95
2010 -2014	21.5	32.32	0.11686053	L1	14.90
2011 -2015	22.5	31.95	0.12452472	L0.5	15.45
2012 -2016	23.5	32.93	0.14060641	L0.5	15.61
2013 -2017	24.5	28.02	0.18447275	L0	14.70
2014 -2018	25.5	55.13	0.19831800	L1	25.45

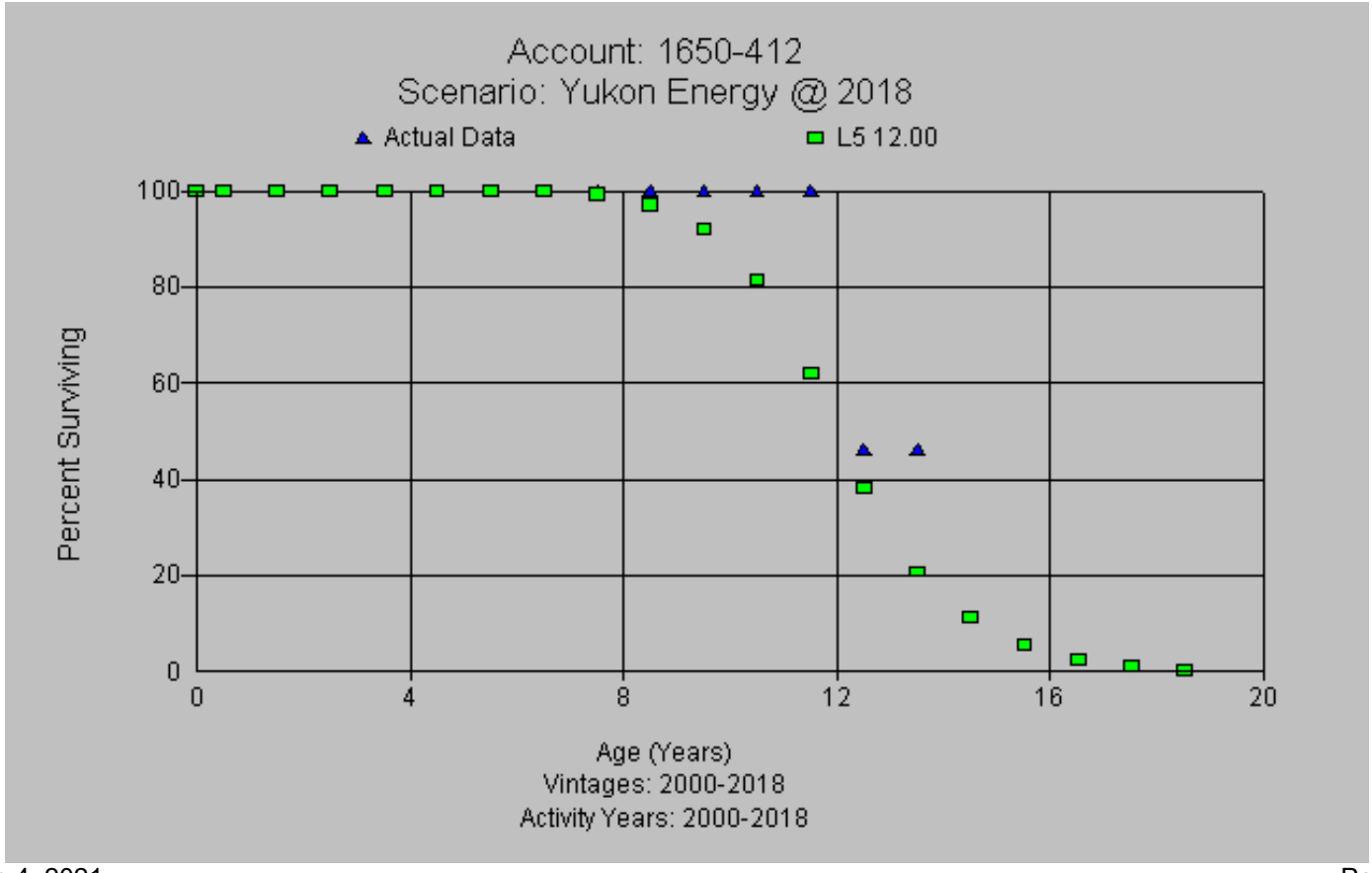
Actuarial Life Analysis

Account: 1650-411
Scenario: Yukon Energy @ 2018
Placement Band: 1990 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1990 -2018	28.5	40.93	0.19953081	L0	20.08
1995 -2018	28.5	40.88	0.19939398	L0	20.06
2000 -2018	28.5	40.60	0.20002144	L0	19.88
2005 -2018	28.5	43.66	0.18949751	L0	21.26
2010 -2018	28.5	38.56	0.25206453	L0	18.81
2015 -2018	28.5	76.36	0.10315800	L0	50.69


Account: 1650-412
Scenario: Yukon Energy @ 2018
Actual Data
L2 9.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

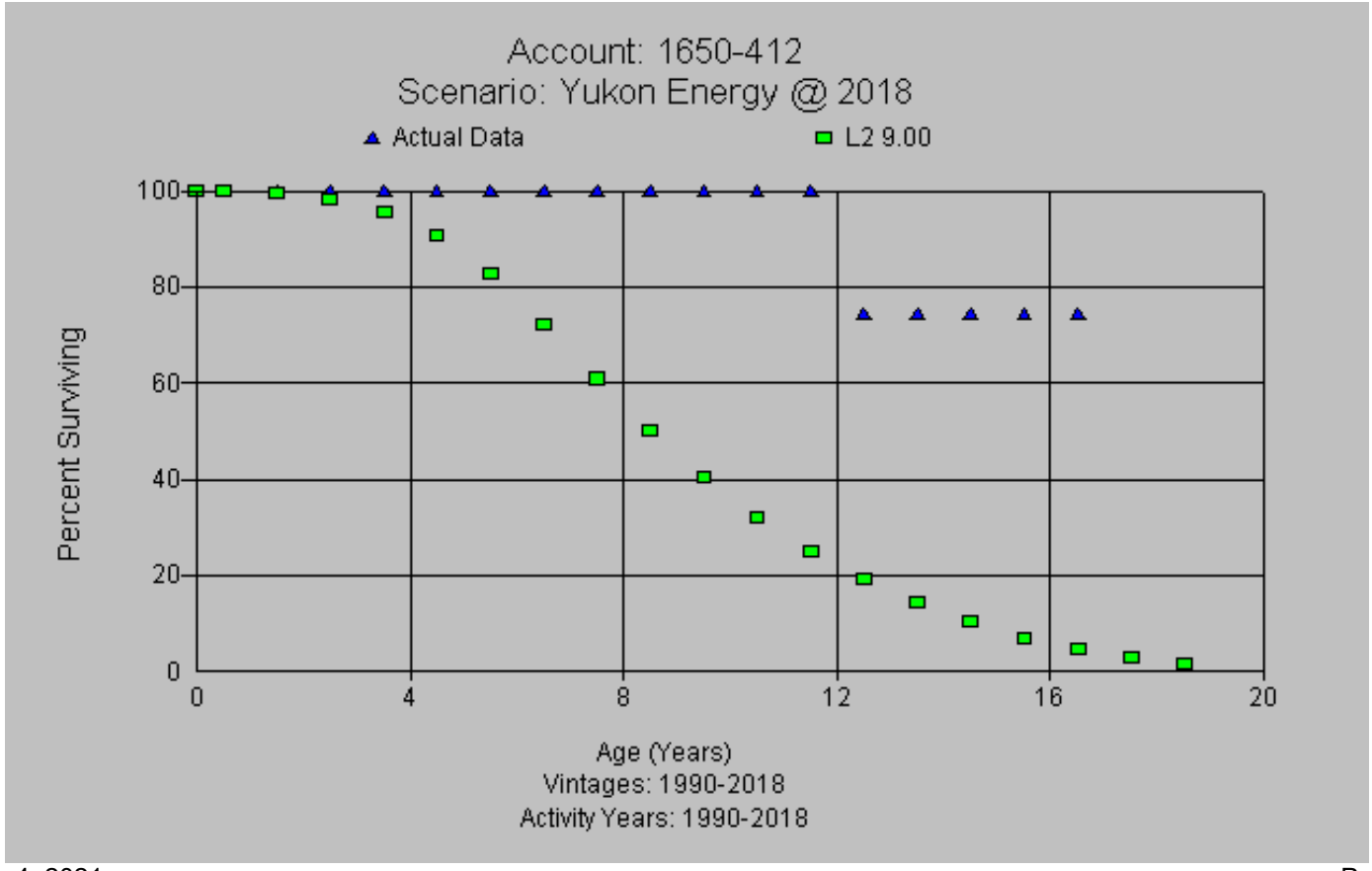

Account: 1650-412
Scenario: Yukon Energy @ 2018
Actual Data
L4 12.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

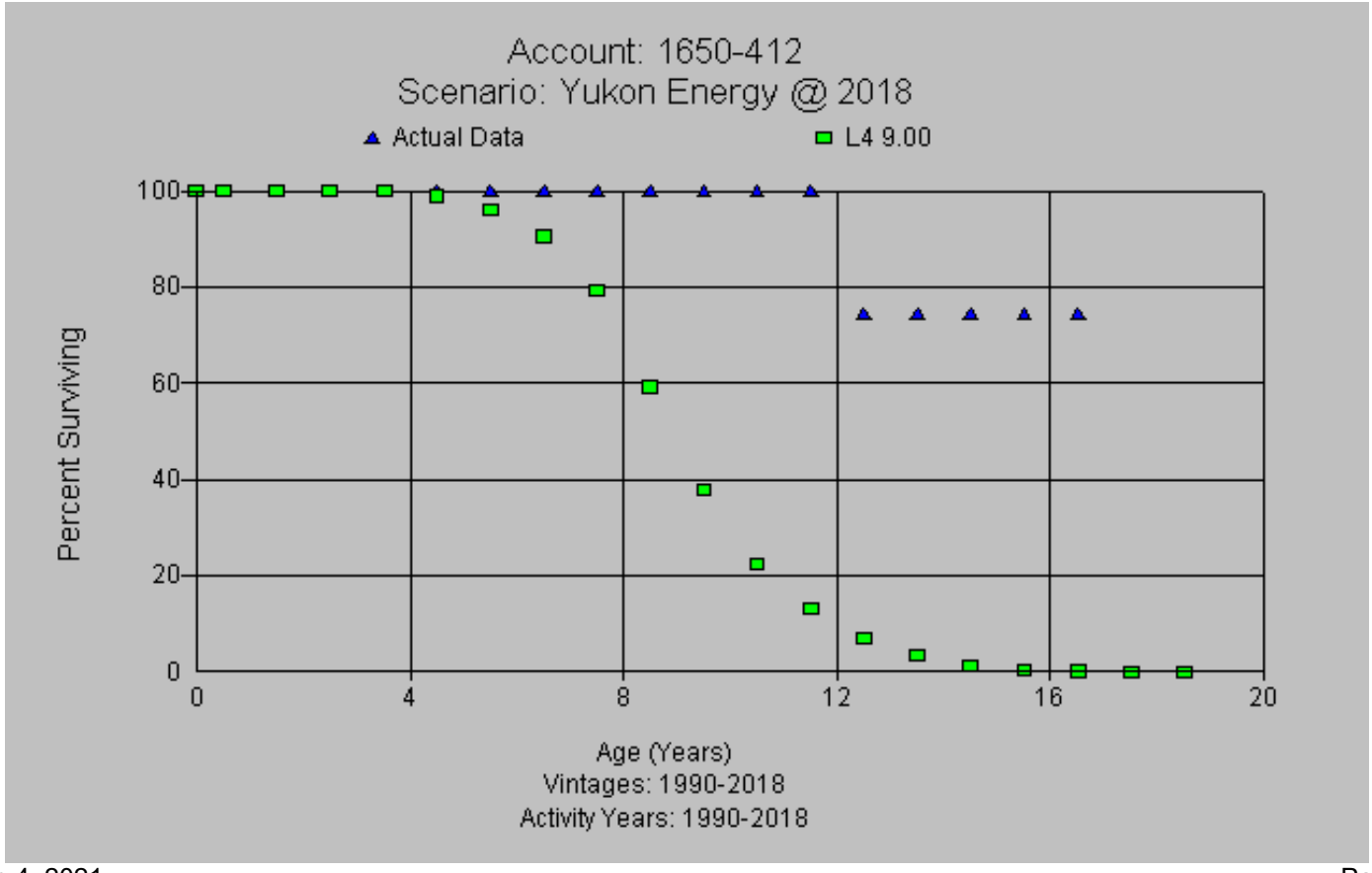

Account: 1650-412
Scenario: Yukon Energy @ 2018
Actual Data
L5 12.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

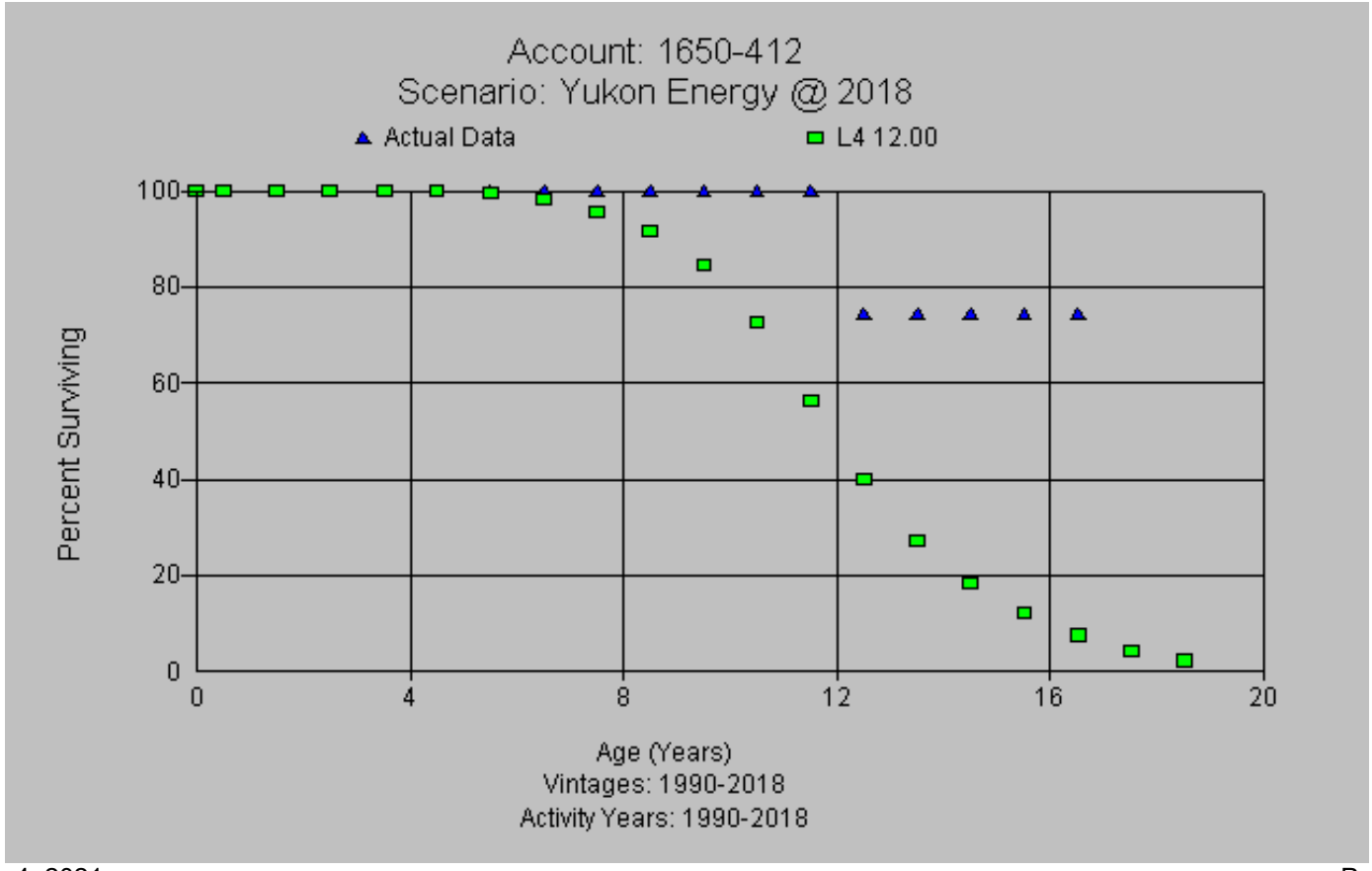
Observed Life Table

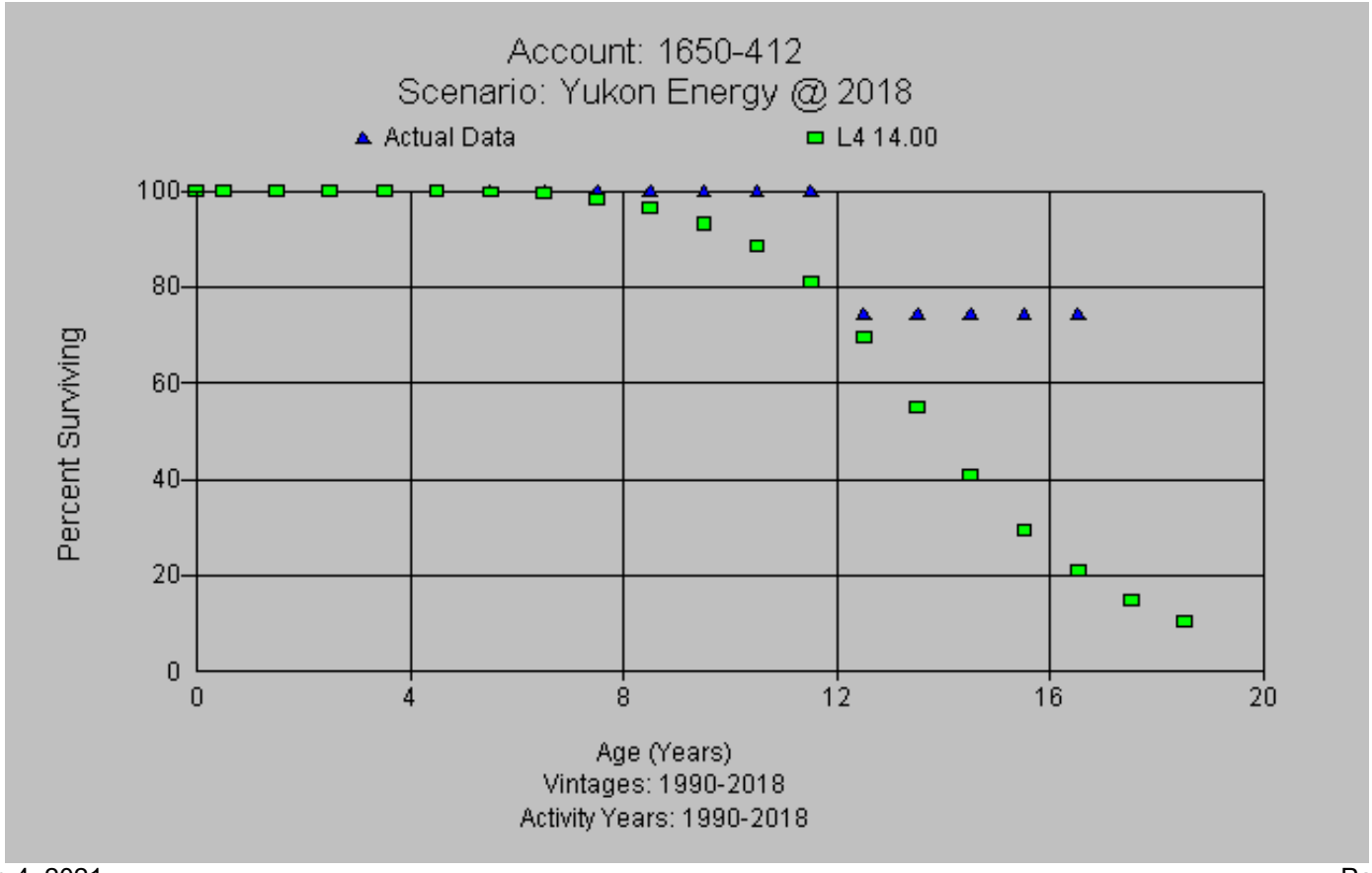
Scenario: Yukon Energy @ 2018
Account: 1650-412
Placement Band: 2000 - 2018 **Observation Band:** 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	168,107.25	0.00	0.00000	1.00000	100.00
0.5	168,107.25	0.00	0.00000	1.00000	100.00
1.5	168,107.25	0.00	0.00000	1.00000	100.00
2.5	168,107.25	0.00	0.00000	1.00000	100.00
3.5	168,107.25	0.00	0.00000	1.00000	100.00
4.5	83,295.55	0.00	0.00000	1.00000	100.00
5.5	83,295.55	0.00	0.00000	1.00000	100.00
6.5	83,295.55	0.00	0.00000	1.00000	100.00
7.5	83,295.55	0.00	0.00000	1.00000	100.00
8.5	56,355.66	0.00	0.00000	1.00000	100.00
9.5	56,355.66	0.00	0.00000	1.00000	100.00
10.5	56,355.66	0.00	0.00000	1.00000	100.00
11.5	56,355.66	30,343.66	0.53843	0.46157	100.00
12.5	26,012.00	0.00	0.00000	1.00000	46.16
13.5	0.00	0.00	0.00000	1.00000	46.16


Account: 1650-412
Scenario: Yukon Energy @ 2018
Actual Data
L2 9.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1990-2018
Activity Years: 1990-2018


Account: 1650-412
Scenario: Yukon Energy @ 2018
Actual Data
L4 9.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1990-2018
Activity Years: 1990-2018


Account: 1650-412
Scenario: Yukon Energy @ 2018
Actual Data
L4 12.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1990-2018
Activity Years: 1990-2018


Account: 1650-412
Scenario: Yukon Energy @ 2018
Actual Data
L4 14.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1990-2018
Activity Years: 1990-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1650-412
Placement Band: 1990 - 2018 **Observation Band:** 1990 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	230,388.76	0.00	0.00000	1.00000	100.00
0.5	230,388.76	0.00	0.00000	1.00000	100.00
1.5	230,388.76	0.00	0.00000	1.00000	100.00
2.5	230,388.76	0.00	0.00000	1.00000	100.00
3.5	230,388.76	0.00	0.00000	1.00000	100.00
4.5	145,577.06	0.00	0.00000	1.00000	100.00
5.5	145,577.06	0.00	0.00000	1.00000	100.00
6.5	145,577.06	0.00	0.00000	1.00000	100.00
7.5	145,577.06	0.00	0.00000	1.00000	100.00
8.5	118,637.17	0.00	0.00000	1.00000	100.00
9.5	118,637.17	0.00	0.00000	1.00000	100.00
10.5	118,637.17	0.00	0.00000	1.00000	100.00
11.5	118,637.17	30,343.66	0.25577	0.74423	100.00
12.5	88,293.51	0.00	0.00000	1.00000	74.42
13.5	62,281.51	0.00	0.00000	1.00000	74.42
14.5	62,281.51	0.00	0.00000	1.00000	74.42
15.5	62,281.51	0.00	0.00000	1.00000	74.42
16.5	62,281.51	62,281.51	1.00000	0.00000	74.42
17.5	0.00	0.00	0.00000	1.00000	0.00

Placement Band	Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -1984	1980 -1984		1.00			
1980 -1985	1981 -1985		1.00			
1980 -1986	1982 -1986		1.00			
1980 -1987	1983 -1987		1.00			
1980 -1988	1984 -1988		1.00			
1980 -1989	1985 -1989		1.00			
1980 -1990	1986 -1990		1.00			
1980 -1991	1987 -1991		1.00			
1980 -1992	1988 -1992		1.00			
1980 -1993	1989 -1993		1.00			
1980 -1994	1990 -1994		1.00			
1980 -1995	1991 -1995		1.00			
1980 -1996	1992 -1996		1.00			
1980 -1997	1993 -1997		1.00			
1980 -1998	1994 -1998		1.00			
1980 -1999	1995 -1999		1.00			
1980 -2000	1996 -2000		1.00			
1980 -2001	1997 -2001		1.00			
1980 -2002	1998 -2002		1.00			
1980 -2003	1999 -2003		1.00			
1980 -2004	2000 -2004	10.5	61.76	0.00205090	SQ	10.46
1980 -2005	2001 -2005	11.5	55.06	0.02917074	S5	11.43
1980 -2006	2002 -2006	12.5	55.06	0.05681257	S4	12.18
1980 -2007	2003 -2007	13.5	55.06	0.08222736	S3	13.12
1980 -2008	2004 -2008	14.5	55.06	0.10643770	L3	14.45
1980 -2009	2005 -2009	15.5	0.00	0.04708900	SQ	14.61
1980 -2010	2006 -2010	16.5	0.00	0.00000000	SQ	15.20
1980 -2011	2007 -2011	17.5	0.00	0.00000000	SQ	15.20
1980 -2012	2008 -2012	18.5	0.00	0.00000000	SQ	15.20
1980 -2013	2009 -2013	19.5	0.00	0.00000000	SQ	15.20
1980 -2014	2010 -2014		1.00			

Placement Band	Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -2015	2011 -2015	21.5	0.00	0.00000000	SQ	16.20
1980 -2016	2012 -2016	22.5	0.00	0.00000000	SQ	12.20
1980 -2017	2013 -2017	23.5	0.00	0.18016947	S4	13.90
1980 -2018	2014 -2018	24.5	0.00	0.18016947	S4	13.90

Actuarial Life Analysis

Account: 1650-412
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -2018	38.5	0.00	0.18800405	L3	20.06
1985 -2018	38.5	0.00	0.18800405	L3	20.06
1990 -2018	38.5	0.00	0.18800405	L3	20.06
1995 -2018	38.5	0.00	0.17621727	L3	19.26
2000 -2018	38.5	0.00	0.24650638	R5	15.77
2005 -2018	38.5	0.00	0.24650638	R5	15.77
2010 -2018	38.5	0.00	0.24650638	R5	15.77
2015 -2018		0.00			

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1650-440
Placement Band: 2000 - 2018 **Observation Band:** 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,271,334.92	0.00	0.00000	1.00000	100.00
0.5	4,062,392.91	0.00	0.00000	1.00000	100.00
1.5	3,870,565.79	0.00	0.00000	1.00000	100.00
2.5	3,467,190.96	58,633.84	0.01691	0.98309	100.00
3.5	3,078,687.98	1,679.77	0.00055	0.99945	98.31
4.5	2,910,388.95	0.00	0.00000	1.00000	98.26
5.5	2,618,780.95	61,456.44	0.02347	0.97653	98.26
6.5	2,420,767.51	49,192.00	0.02032	0.97968	95.95
7.5	2,106,627.22	238,926.04	0.11342	0.88658	94.00
8.5	1,492,087.54	340,973.61	0.22852	0.77148	83.34
9.5	1,151,113.93	188,671.58	0.16390	0.83610	64.29
10.5	759,094.23	152,182.98	0.20048	0.79952	53.76
11.5	535,081.39	337,715.98	0.63115	0.36885	42.98
12.5	197,365.41	89,067.71	0.45128	0.54872	15.85
13.5	108,297.70	108,297.70	1.00000	0.00000	8.70
14.5	0.00	0.00	0.00000	1.00000	0.00

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1650-440
Placement Band: 1980 - 2018 **Observation Band:** 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,271,334.92	0.00	0.00000	1.00000	100.00
0.5	4,062,392.91	0.00	0.00000	1.00000	100.00
1.5	3,904,185.71	0.00	0.00000	1.00000	100.00
2.5	3,500,810.88	58,633.84	0.01675	0.98325	100.00
3.5	3,112,307.90	1,679.77	0.00054	0.99946	98.33
4.5	2,944,008.87	0.00	0.00000	1.00000	98.27
5.5	2,652,400.87	61,456.44	0.02317	0.97683	98.27
6.5	2,454,387.43	49,192.00	0.02004	0.97996	96.00
7.5	2,140,247.14	238,926.04	0.11163	0.88837	94.07
8.5	1,526,410.46	340,973.61	0.22338	0.77662	83.57
9.5	1,189,235.85	189,374.58	0.15924	0.84076	64.90
10.5	796,513.15	152,182.98	0.19106	0.80894	54.57
11.5	572,500.31	341,514.98	0.59653	0.40347	44.14
12.5	230,985.33	89,067.71	0.38560	0.61440	17.81
13.5	141,917.62	108,297.70	0.76310	0.23690	10.94
14.5	33,619.92	33,619.92	1.00000	0.00000	2.59
15.5	0.00	0.00	0.00000	1.00000	0.00
16.5	0.00	0.00	0.00000	1.00000	
17.5	0.00	0.00	0.00000	1.00000	
18.5	0.00	0.00	0.00000	1.00000	
19.5	171,495.34	0.00	0.00000	1.00000	
20.5	171,495.34	0.00	0.00000	1.00000	
21.5	171,495.34	0.00	0.00000	1.00000	
22.5	171,495.34	39,180.95	0.22847	0.77153	
23.5	132,314.39	0.00	0.00000	1.00000	
24.5	132,314.39	132,314.39	1.00000	0.00000	
25.5	0.00	0.00	0.00000	1.00000	

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1650-440
Placement Band: 1980 - 2018 **Observation Band:** 1988 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,472,283.84	39,576.00	0.00885	0.99115	100.00
0.5	4,223,765.83	123,251.00	0.02918	0.97082	99.12
1.5	3,908,687.71	0.00	0.00000	1.00000	96.22
2.5	3,505,312.88	58,633.84	0.01673	0.98327	96.22
3.5	3,116,809.90	1,679.77	0.00054	0.99946	94.61
4.5	2,948,510.87	0.00	0.00000	1.00000	94.56
5.5	2,656,902.87	61,456.44	0.02313	0.97687	94.56
6.5	2,458,889.43	49,192.00	0.02001	0.97999	92.38
7.5	2,316,244.48	238,926.04	0.10315	0.89685	90.53
8.5	1,701,704.80	340,973.61	0.20037	0.79963	81.19
9.5	1,360,731.19	189,374.58	0.13917	0.86083	64.92
10.5	968,008.49	152,182.98	0.15721	0.84279	55.89
11.5	743,995.65	341,514.98	0.45903	0.54097	47.10
12.5	402,480.67	89,067.71	0.22130	0.77870	25.48
13.5	313,412.96	108,297.70	0.34554	0.65446	19.84
14.5	205,115.26	33,619.92	0.16391	0.83609	12.99
15.5	171,495.34	0.00	0.00000	1.00000	10.86
16.5	171,495.34	0.00	0.00000	1.00000	10.86
17.5	171,495.34	0.00	0.00000	1.00000	10.86
18.5	171,495.34	0.00	0.00000	1.00000	10.86
19.5	171,495.34	0.00	0.00000	1.00000	10.86
20.5	171,495.34	0.00	0.00000	1.00000	10.86
21.5	171,495.34	0.00	0.00000	1.00000	10.86
22.5	171,495.34	39,180.95	0.22847	0.77153	10.86
23.5	132,314.39	0.00	0.00000	1.00000	8.38
24.5	132,314.39	132,314.39	1.00000	0.00000	8.38
25.5	0.00	0.00	0.00000	1.00000	0.00

Actuarial Life Analysis

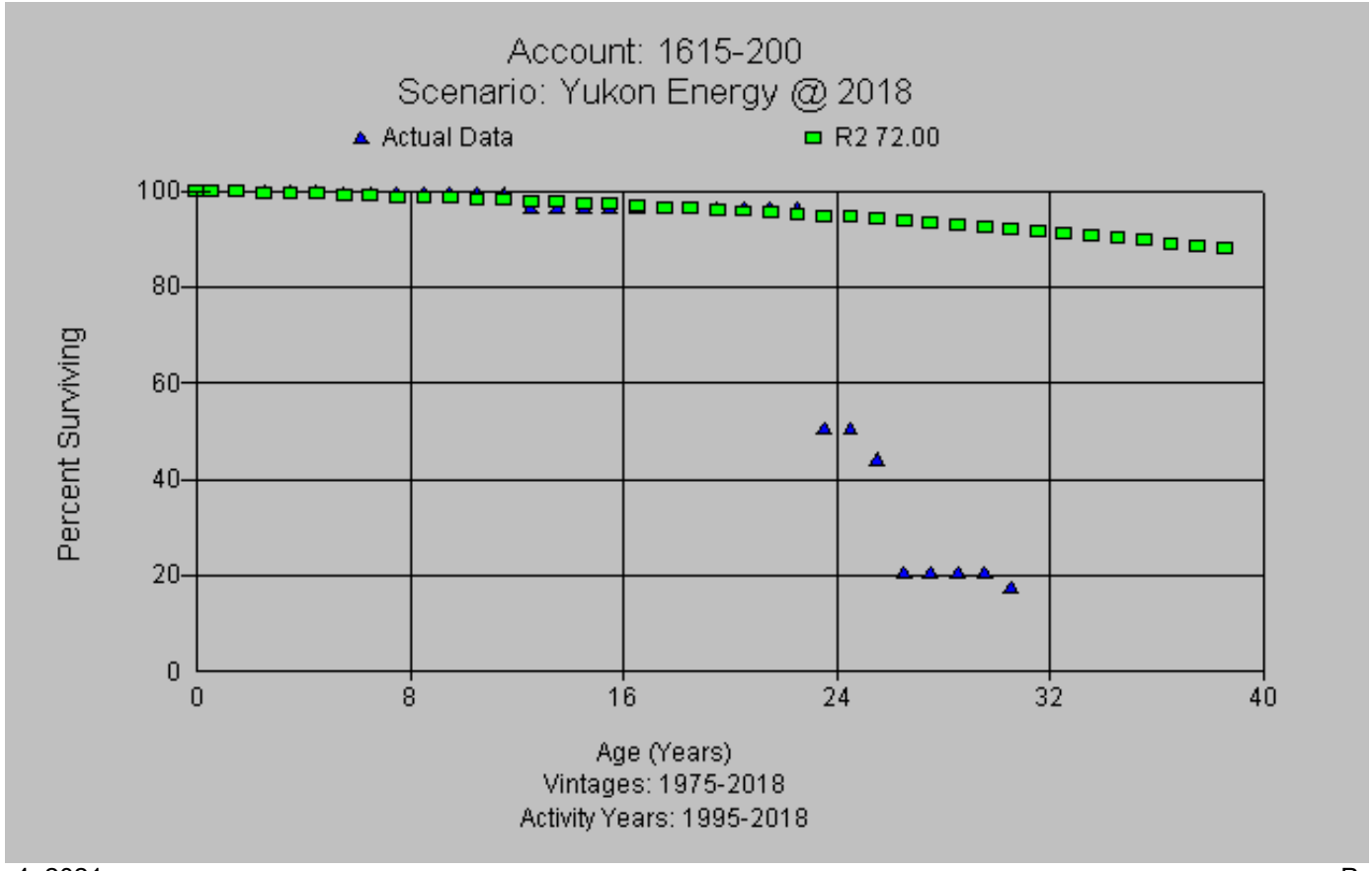
Account: 1650-440
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 1992
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

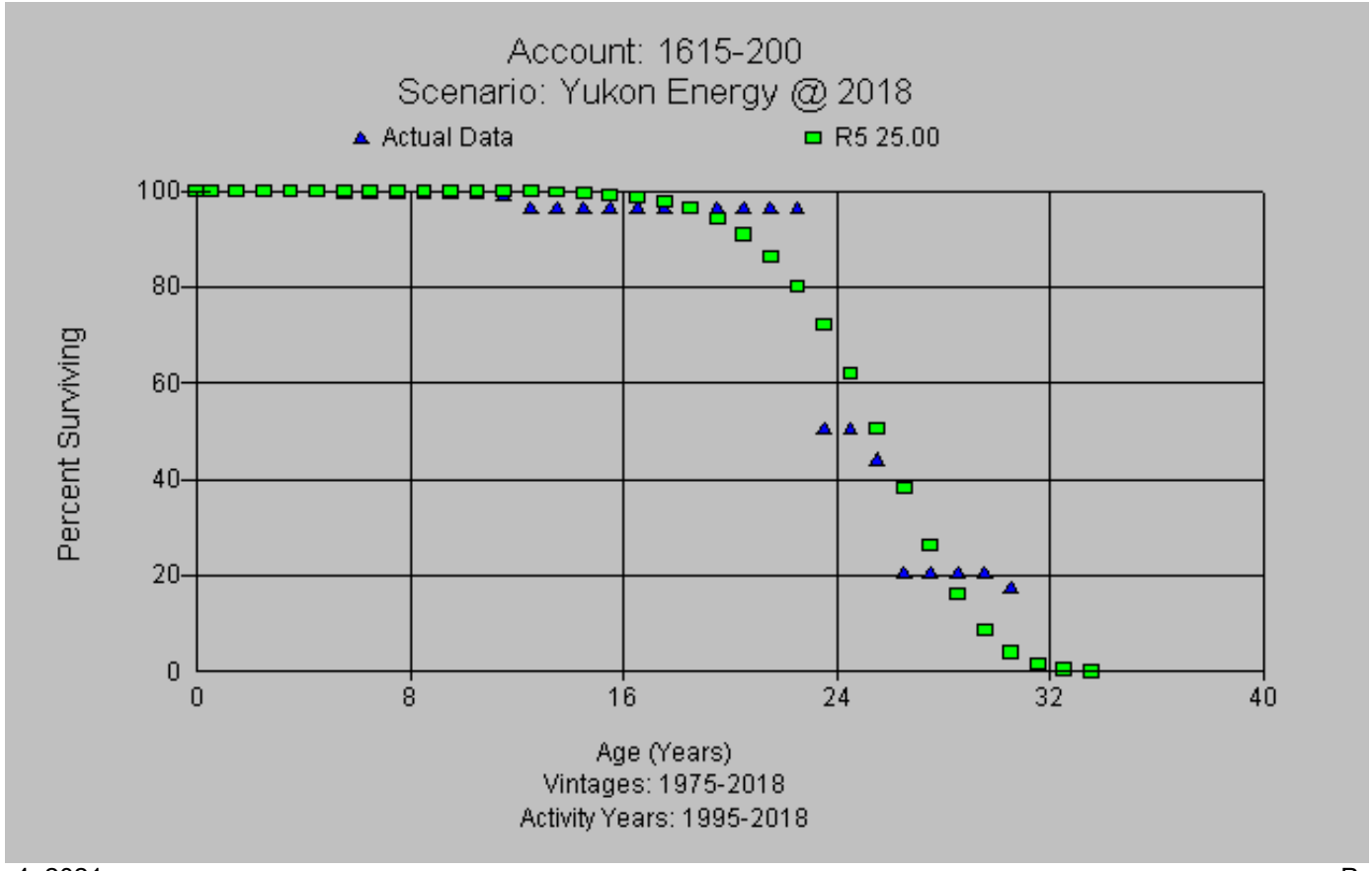
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1988 -1992	10.5	10.21	0.68975718	L0	1.35
1989 -1993		1.00			
1990 -1994		1.00			
1991 -1995		1.00			
1992 -1996		1.00			
1993 -1997		1.00			
1994 -1998		1.00			
1995 -1999	15.5	21.43	1.15483505	L0	4.25
1996 -2000	16.5	21.43	1.20337491	L0	4.37
1997 -2001	17.5	65.85	0.27806821	R0.5	14.72
1998 -2002	18.5	0.00	0.29725330	R3	8.41
1999 -2003	19.5	0.00	0.29725330	R3	8.41
2000 -2004	20.5	0.00	0.15361943	SQ	9.45
2001 -2005	21.5	0.00	0.03698002	SQ	7.62
2002 -2006	22.5	0.00	0.04150302	SQ	9.51
2003 -2007	23.5	0.00	0.38836051	R5	19.30
2004 -2008	24.5	0.00	0.78600263	R4	18.78
2005 -2009	25.5	0.00	0.00000000	SQ	21.20
2006 -2010		1.00			
2007 -2011		1.00			
2008 -2012	28.5	39.78	0.51553728	L0.5	20.07
2009 -2013	29.5	0.00	0.02862725	R4	11.52
2010 -2014	30.5	0.00	0.02702481	R4	10.95
2011 -2015	31.5	0.00	0.05330391	L4	9.64
2012 -2016	32.5	0.00	0.03623875	L4	9.72
2013 -2017	33.5	0.00	0.00486246	L5	9.42
2014 -2018	34.5	0.00	0.01958660	S4	9.97

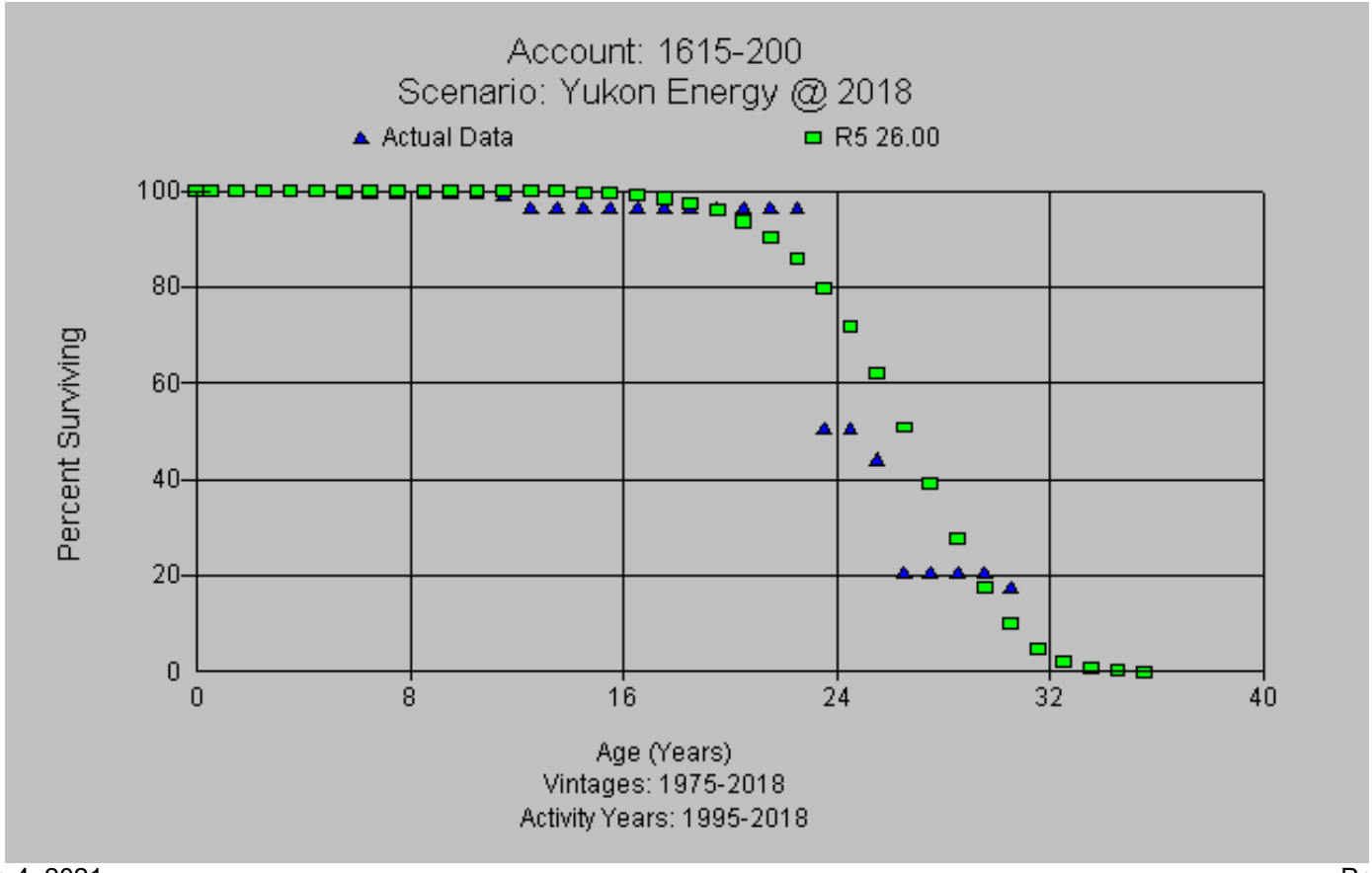
Actuarial Life Analysis

Account: 1650-440
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1988 -2018	38.5	0.00	0.08881781	L3	11.74
1993 -2018	38.5	0.00	0.07852830	L3	11.20
1998 -2018	38.5	0.00	0.02058427	R3	10.40
2003 -2018	38.5	0.00	0.01535568	R4	10.68
2008 -2018	38.5	0.00	0.01783253	R4	10.74
2013 -2018	38.5	0.00	0.01871452	S4	9.78
2018 -2018		1.00			


Account: 1615-200
Scenario: Yukon Energy @ 2018
Actual Data
R2 72.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1975-2018
Activity Years: 1995-2018

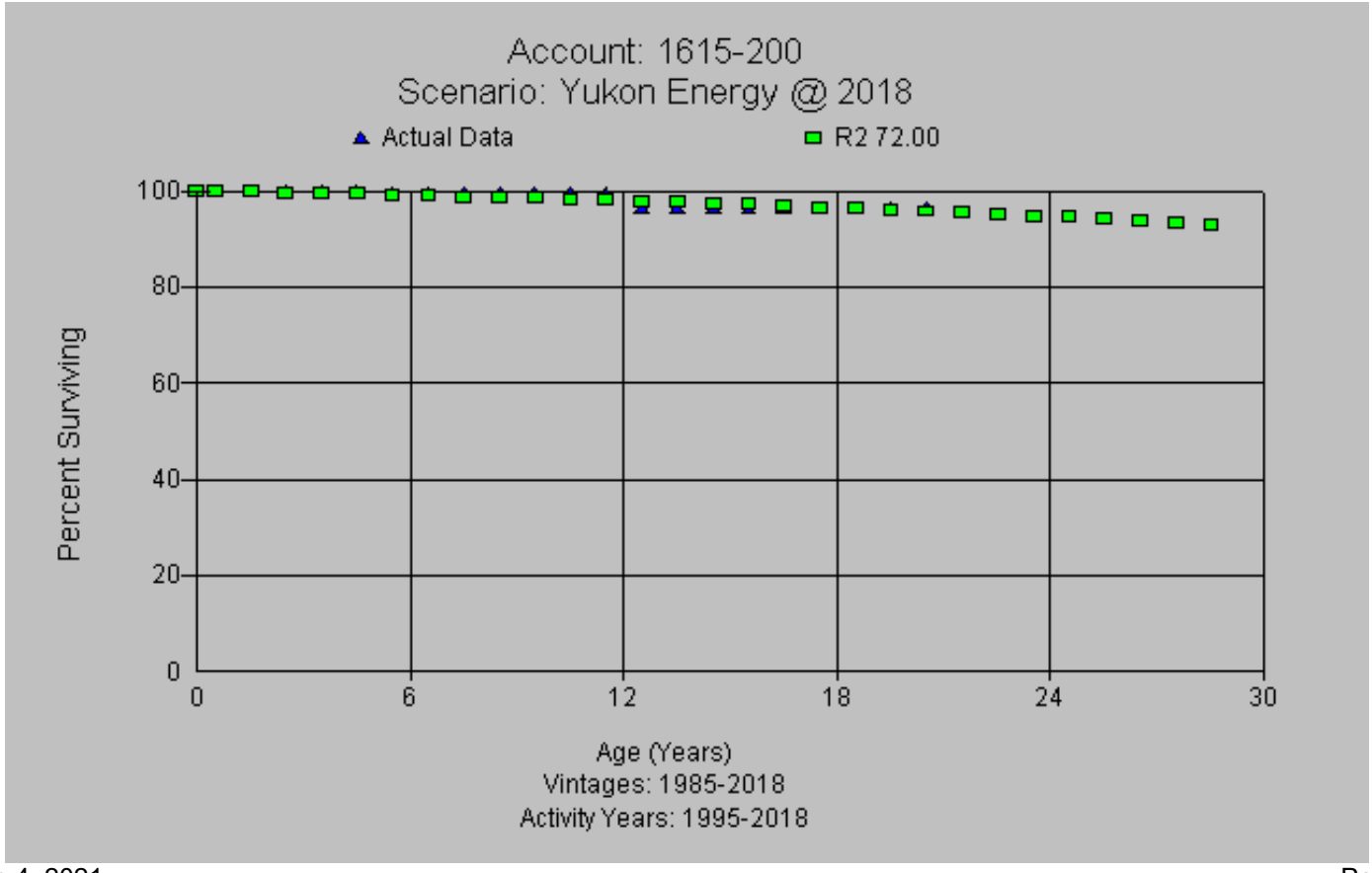

Account: 1615-200
Scenario: Yukon Energy @ 2018
Actual Data
R5 25.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1975-2018
Activity Years: 1995-2018

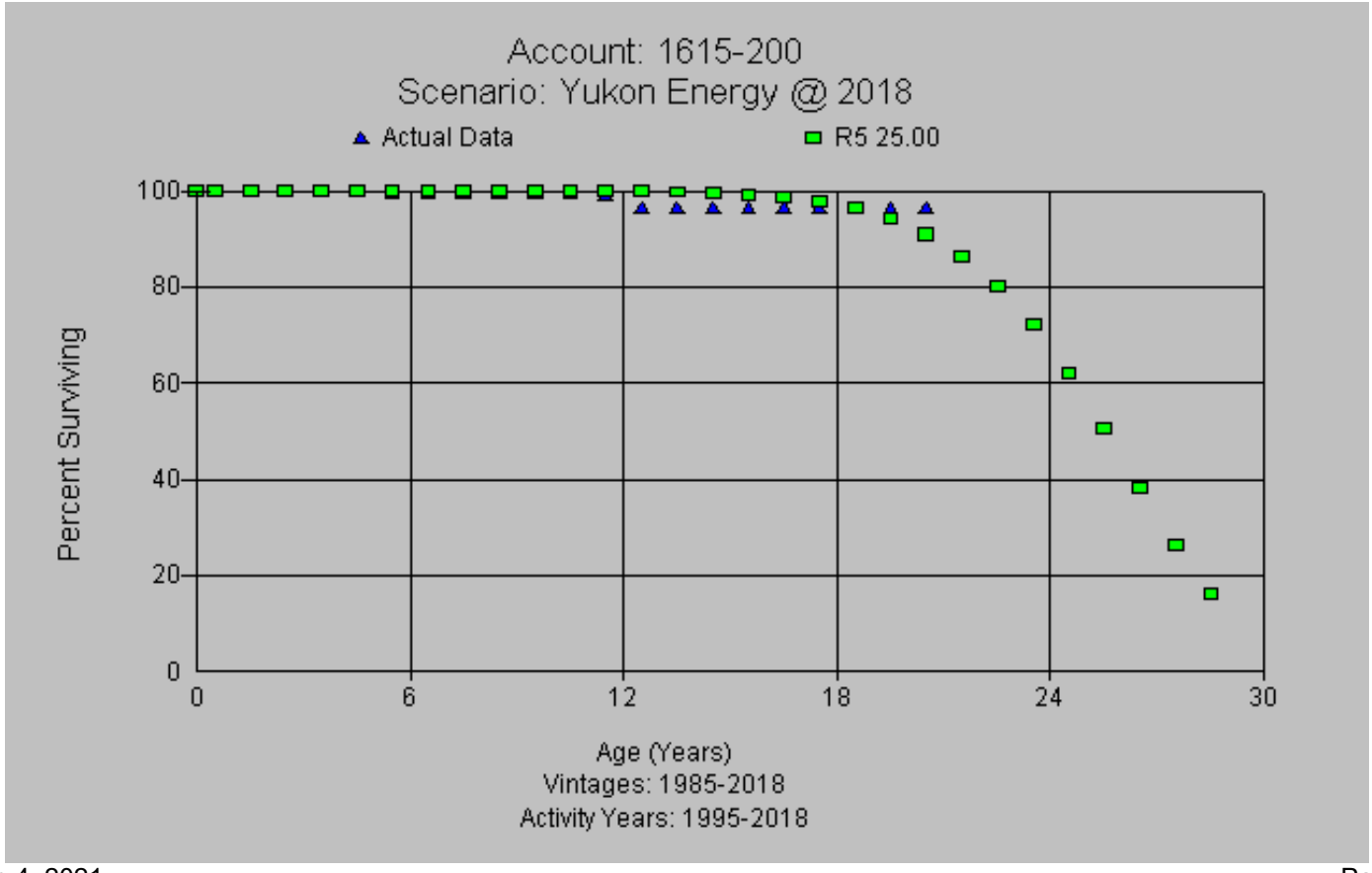

Account: 1615-200
Scenario: Yukon Energy @ 2018
Actual Data
R5 26.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1975-2018
Activity Years: 1995-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1615-200
Placement Band: 1975 - 2018 **Observation Band:** 1995 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	34,229,037.18	37,236.83	0.00109	0.99891	100.00
0.5	34,199,787.35	0.00	0.00000	1.00000	99.89
1.5	34,199,787.35	0.00	0.00000	1.00000	99.89
2.5	34,178,930.31	0.00	0.00000	1.00000	99.89
3.5	30,829,654.08	0.00	0.00000	1.00000	99.89
4.5	30,432,172.50	36,663.00	0.00120	0.99880	99.89
5.5	30,362,528.11	0.00	0.00000	1.00000	99.77
6.5	29,766,028.13	0.00	0.00000	1.00000	99.77
7.5	10,504,444.85	0.00	0.00000	1.00000	99.77
8.5	9,720,339.39	0.00	0.00000	1.00000	99.77
9.5	9,510,913.90	0.00	0.00000	1.00000	99.77
10.5	9,336,960.68	34,484.00	0.00369	0.99631	99.77
11.5	9,253,875.51	276,592.00	0.02989	0.97011	99.40
12.5	8,977,283.51	0.00	0.00000	1.00000	96.43
13.5	8,875,200.21	0.00	0.00000	1.00000	96.43
14.5	9,344,800.60	0.00	0.00000	1.00000	96.43
15.5	9,344,800.60	0.00	0.00000	1.00000	96.43
16.5	9,291,669.06	0.00	0.00000	1.00000	96.43
17.5	9,247,643.39	0.98	0.00000	1.00000	96.43
18.5	5,441,662.46	0.00	0.00000	1.00000	96.43
19.5	5,043,878.86	2,021.00	0.00040	0.99960	96.43
20.5	478,585.39	0.00	0.00000	1.00000	96.39
21.5	478,585.39	0.00	0.00000	1.00000	96.39
22.5	478,585.39	228,263.73	0.47696	0.52304	96.39
23.5	250,321.66	0.00	0.00000	1.00000	50.42
24.5	250,321.66	30,833.45	0.12318	0.87682	50.42
25.5	219,488.21	117,537.82	0.53551	0.46449	44.21
26.5	101,950.39	0.00	0.00000	1.00000	20.53
27.5	101,950.39	0.00	0.00000	1.00000	20.53
28.5	101,950.39	0.00	0.00000	1.00000	20.53
29.5	101,950.39	14,588.03	0.14309	0.85691	20.53
30.5	87,362.36	87,362.36	1.00000	0.00000	17.60
31.5	0.00	0.00	0.00000	1.00000	0.00


Account: 1615-200
Scenario: Yukon Energy @ 2018
Actual Data
R2 72.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1985-2018
Activity Years: 1995-2018


Account: 1615-200
Scenario: Yukon Energy @ 2018
Actual Data
R5 25.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1985-2018
Activity Years: 1995-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1615-200
Placement Band: 1985 - 2018 **Observation Band:** 1995 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	34,229,037.18	37,236.83	0.00109	0.99891	100.00
0.5	34,199,787.35	0.00	0.00000	1.00000	99.89
1.5	34,199,787.35	0.00	0.00000	1.00000	99.89
2.5	34,178,930.31	0.00	0.00000	1.00000	99.89
3.5	30,829,654.08	0.00	0.00000	1.00000	99.89
4.5	30,432,172.50	36,663.00	0.00120	0.99880	99.89
5.5	30,362,528.11	0.00	0.00000	1.00000	99.77
6.5	29,766,028.13	0.00	0.00000	1.00000	99.77
7.5	10,504,444.85	0.00	0.00000	1.00000	99.77
8.5	9,720,339.39	0.00	0.00000	1.00000	99.77
9.5	9,510,913.90	0.00	0.00000	1.00000	99.77
10.5	9,336,960.68	34,484.00	0.00369	0.99631	99.77
11.5	9,253,875.51	276,592.00	0.02989	0.97011	99.40
12.5	8,977,283.51	0.00	0.00000	1.00000	96.43
13.5	8,875,200.21	0.00	0.00000	1.00000	96.43
14.5	8,875,200.21	0.00	0.00000	1.00000	96.43
15.5	8,875,200.21	0.00	0.00000	1.00000	96.43
16.5	8,822,068.67	0.00	0.00000	1.00000	96.43
17.5	8,778,043.00	0.98	0.00000	1.00000	96.43
18.5	4,972,062.07	0.00	0.00000	1.00000	96.43
19.5	4,563,272.47	0.00	0.00000	1.00000	96.43
20.5	0.00	0.00	0.00000	1.00000	96.43

Actuarial Life Analysis

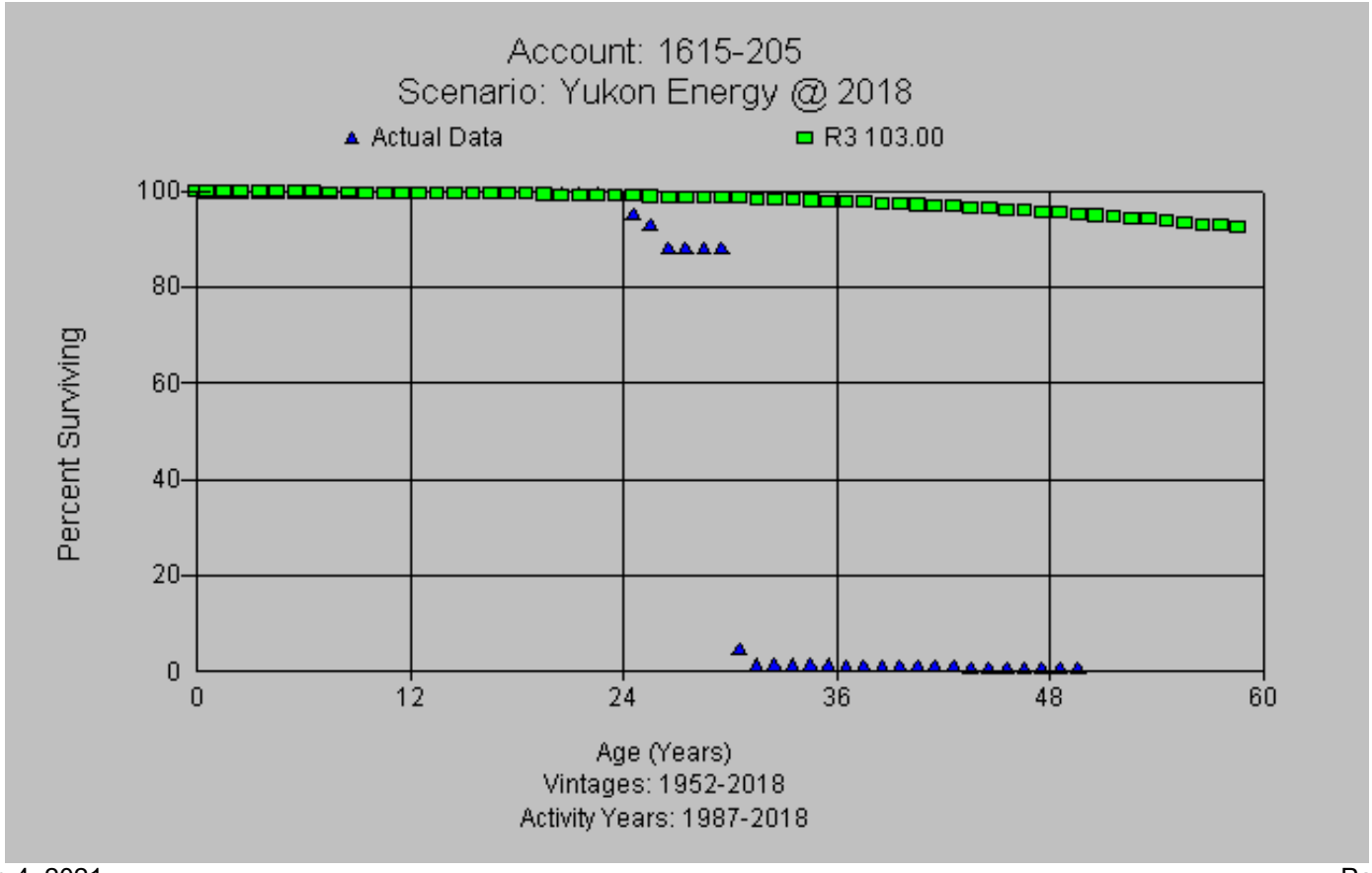
Account: 1615-200
Scenario: Yukon Energy @ 2018
Placement Band: 1975 - 1999
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

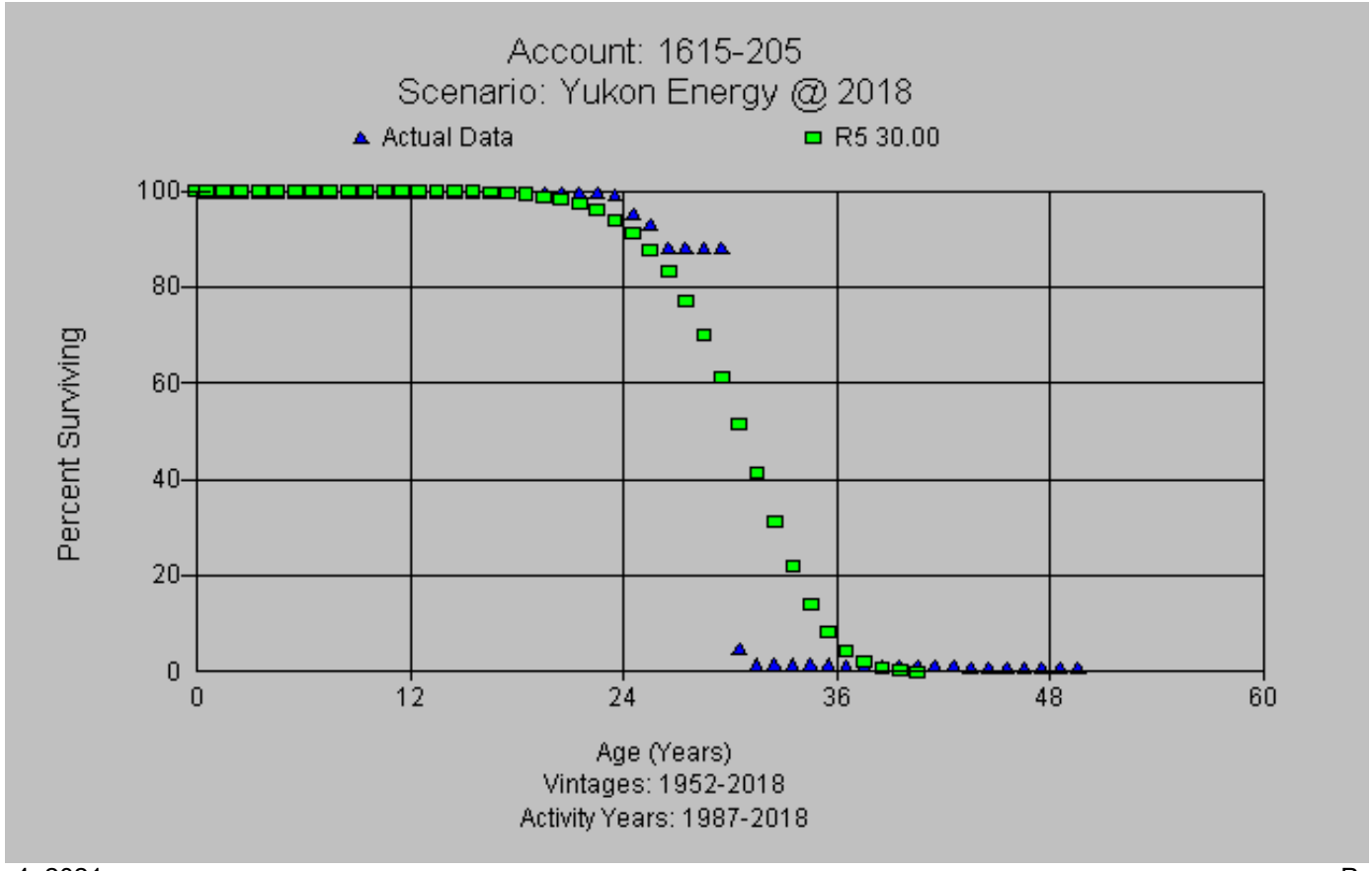
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1995 -1999	22.5	0.00	0.01227665	SQ	11.94
1996 -2000	23.5	0.00	0.01227665	SQ	11.94
1997 -2001	24.5	0.00	0.01227665	SQ	11.94
1998 -2002	25.5	0.00	0.00000000	SQ	5.39
1999 -2003	26.5	0.00	0.03564572	S6	11.38
2000 -2004	27.5	0.00	0.00037303	SQ	12.00
2001 -2005	28.5	0.00	0.10238057	S6	22.45
2002 -2006	29.5	21.62	0.18835803	L5	23.84
2003 -2007	30.5	21.71	0.23062425	L5	24.03
2004 -2008	31.5	42.24	0.30794155	L4	28.55
2005 -2009	32.5	39.49	0.31992874	L3	27.69
2006 -2010	33.5	40.27	0.28449291	L3	30.07
2007 -2011	34.5	0.00	0.02099987	SQ	28.85
2008 -2012	35.5	0.00	0.02099007	SQ	28.86
2009 -2013	36.5	0.00	0.02099007	SQ	28.86
2010 -2014	37.5	0.00	0.02047762	SQ	28.91
2011 -2015	38.5	0.00	0.00000000	SQ	29.20
2012 -2016		1.00			
2013 -2017		1.00			
2014 -2018		1.00			

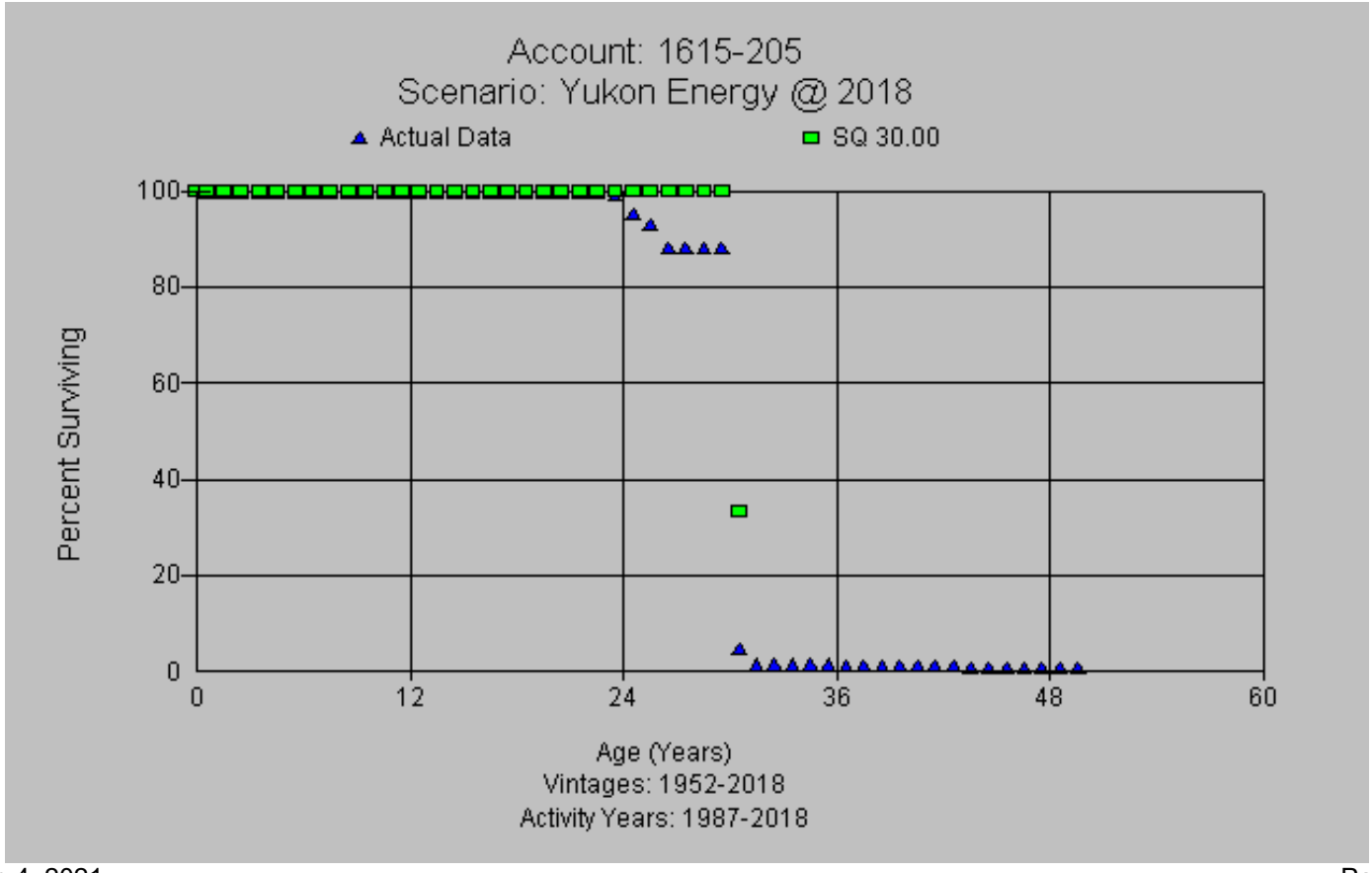
Actuarial Life Analysis

Account: 1615-200
Scenario: Yukon Energy @ 2018
Placement Band: 1975 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1995 -2018	43.5	0.00	0.13631357	L5	25.08
2000 -2018	43.5	0.00	0.16402773	S5	25.46
2005 -2018	43.5	0.00	0.18096111	S5	27.93
2010 -2018	43.5	0.00	0.02047762	SQ	30.91
2015 -2018		1.00			


Account: 1615-205
Scenario: Yukon Energy @ 2018
Actual Data
R3 103.00
Percent Surviving
100
80
60
40
20
0
0
12
24
36
48
60
Age (Years)
Vintages: 1952-2018
Activity Years: 1987-2018


Account: 1615-205
Scenario: Yukon Energy @ 2018
Actual Data
R5 30.00
Percent Surviving
100
80
60
40
20
0
0
12
24
36
48
60
Age (Years)
Vintages: 1952-2018
Activity Years: 1987-2018


Account: 1615-205
Scenario: Yukon Energy @ 2018
Actual Data
SQ 30.00
Percent Surviving
100
80
60
40
20
0
0
12
24
36
48
60
Age (Years)
Vintages: 1952-2018
Activity Years: 1987-2018

Observed Life Table

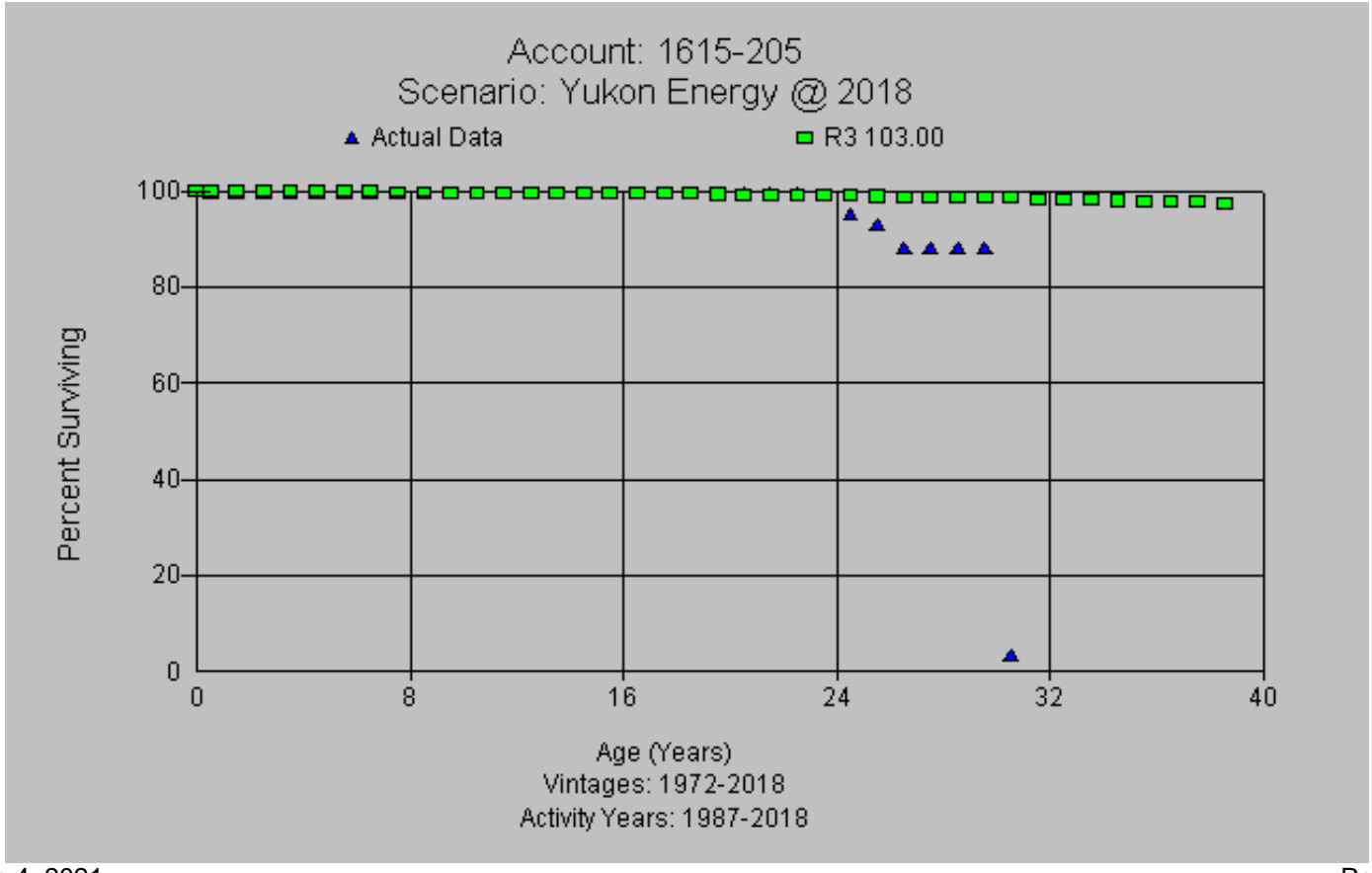
Scenario: Yukon Energy @ 2018
Account: 1615-205
Placement Band: 1952 - 2018 **Observation Band:** 1987 - 2018

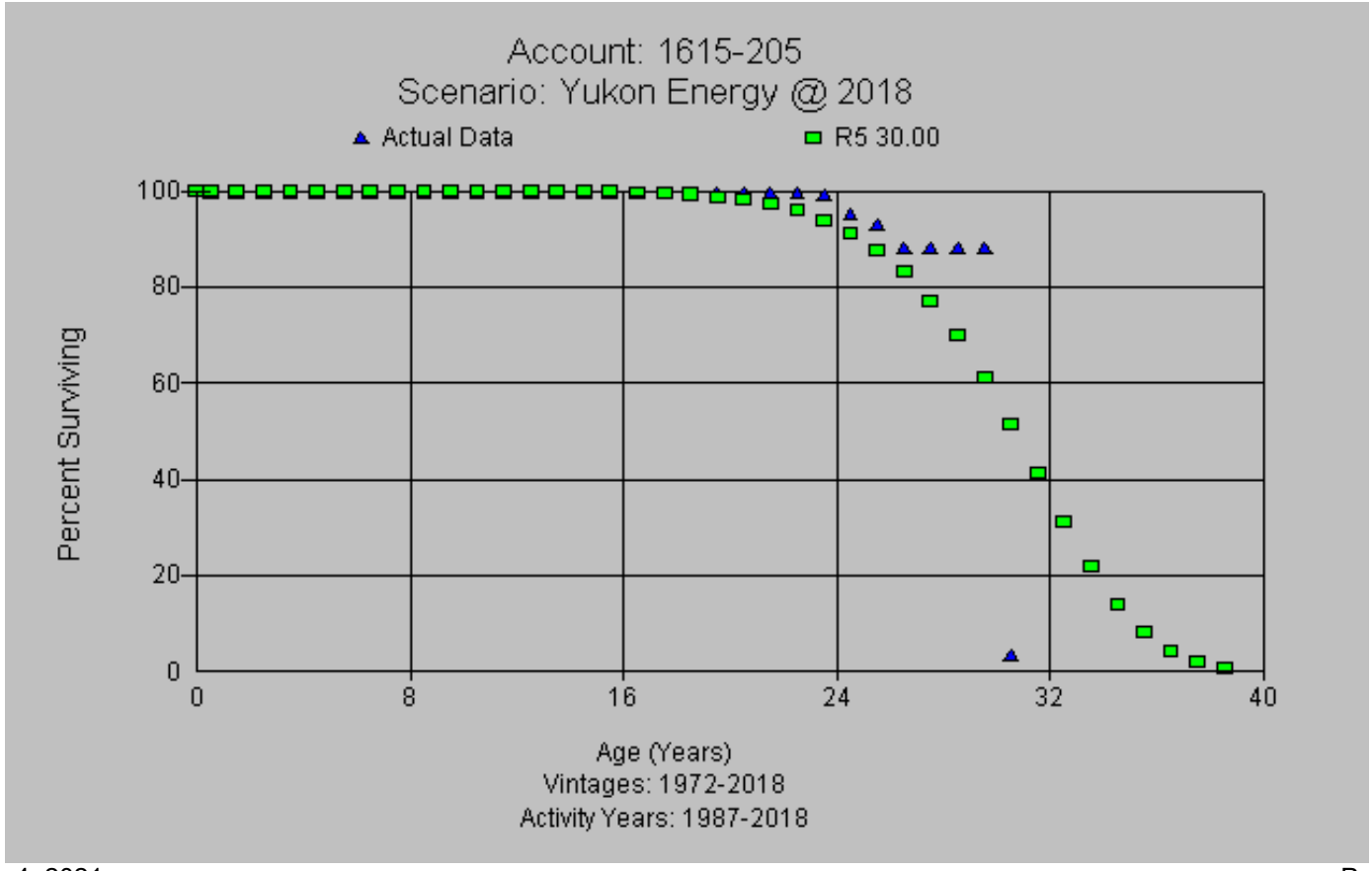
Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	167,051,651.70	755,970.13	0.00453	0.99547	100.00
0.5	166,189,765.40	0.00	0.00000	1.00000	99.55
1.5	166,189,765.40	0.00	0.00000	1.00000	99.55
2.5	165,508,456.23	0.00	0.00000	1.00000	99.55
3.5	165,344,086.97	0.00	0.00000	1.00000	99.55
4.5	163,396,997.85	0.00	0.00000	1.00000	99.55
5.5	162,158,231.63	57,497.64	0.00035	0.99965	99.55
6.5	157,606,800.79	0.00	0.00000	1.00000	99.51
7.5	83,605,930.67	0.00	0.00000	1.00000	99.51
8.5	83,053,637.90	0.00	0.00000	1.00000	99.51
9.5	82,776,971.96	0.00	0.00000	1.00000	99.51
10.5	82,695,891.07	0.00	0.00000	1.00000	99.51
11.5	82,497,485.71	0.00	0.00000	1.00000	99.51
12.5	82,493,246.01	0.00	0.00000	1.00000	99.51
13.5	82,458,633.01	0.00	0.00000	1.00000	99.51
14.5	81,191,587.73	0.00	0.00000	1.00000	99.51
15.5	81,170,982.40	0.00	0.00000	1.00000	99.51
16.5	79,890,383.67	0.00	0.00000	1.00000	99.51
17.5	79,846,354.58	0.00	0.00000	1.00000	99.51
18.5	69,625,966.72	0.00	0.00000	1.00000	99.51
19.5	62,514,295.59	0.00	0.00000	1.00000	99.51
20.5	386,381.71	0.00	0.00000	1.00000	99.51
21.5	386,381.71	0.00	0.00000	1.00000	99.51
22.5	386,381.71	925.68	0.00240	0.99760	99.51
23.5	385,456.03	16,031.35	0.04159	0.95841	99.27
24.5	369,424.68	7,757.25	0.02100	0.97900	95.14
25.5	367,002.43	18,906.88	0.05152	0.94848	93.15
26.5	348,095.55	0.00	0.00000	1.00000	88.35
27.5	348,095.55	0.00	0.00000	1.00000	88.35
28.5	348,095.55	0.00	0.00000	1.00000	88.35
29.5	348,095.55	330,236.72	0.94870	0.05130	88.35
30.5	17,858.83	12,523.83	0.70127	0.29873	4.53
31.5	5,335.00	0.00	0.00000	1.00000	1.35
32.5	10,335.00	0.00	0.00000	1.00000	1.35
33.5	10,335.00	0.00	0.00000	1.00000	1.35
34.5	22,942.00	0.00	0.00000	1.00000	1.35
35.5	22,942.00	5,335.00	0.23254	0.76746	1.35
36.5	17,607.00	0.00	0.00000	1.00000	1.04
37.5	17,607.00	0.00	0.00000	1.00000	1.04

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1615-205
Placement Band: 1952 - 2018 **Observation Band:** 1987 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
38.5	17,607.00	0.00	0.00000	1.00000	1.04
39.5	17,607.00	0.00	0.00000	1.00000	1.04
40.5	17,607.00	0.00	0.00000	1.00000	1.04
41.5	17,607.00	0.00	0.00000	1.00000	1.04
42.5	17,607.00	5,000.00	0.28398	0.71602	1.04
43.5	12,607.00	0.00	0.00000	1.00000	0.74
44.5	12,607.00	0.00	0.00000	1.00000	0.74
45.5	12,607.00	0.00	0.00000	1.00000	0.74
46.5	12,607.00	0.00	0.00000	1.00000	0.74
47.5	12,607.00	0.00	0.00000	1.00000	0.74
48.5	12,607.00	0.00	0.00000	1.00000	0.74
49.5	12,607.00	12,607.00	1.00000	0.00000	0.74
50.5	0.00	0.00	0.00000	1.00000	0.00


Account: 1615-205
Scenario: Yukon Energy @ 2018
Actual Data
R3 103.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1972-2018
Activity Years: 1987-2018


Account: 1615-205
Scenario: Yukon Energy @ 2018
Actual Data
R5 30.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1972-2018
Activity Years: 1987-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1615-205
Placement Band: 1972 - 2018 **Observation Band:** 1987 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	167,051,651.70	755,970.13	0.00453	0.99547	100.00
0.5	166,189,765.40	0.00	0.00000	1.00000	99.55
1.5	166,189,765.40	0.00	0.00000	1.00000	99.55
2.5	165,508,456.23	0.00	0.00000	1.00000	99.55
3.5	165,344,086.97	0.00	0.00000	1.00000	99.55
4.5	163,396,997.85	0.00	0.00000	1.00000	99.55
5.5	162,158,231.63	57,497.64	0.00035	0.99965	99.55
6.5	157,606,800.79	0.00	0.00000	1.00000	99.51
7.5	83,605,930.67	0.00	0.00000	1.00000	99.51
8.5	83,053,637.90	0.00	0.00000	1.00000	99.51
9.5	82,776,971.96	0.00	0.00000	1.00000	99.51
10.5	82,695,891.07	0.00	0.00000	1.00000	99.51
11.5	82,497,485.71	0.00	0.00000	1.00000	99.51
12.5	82,493,246.01	0.00	0.00000	1.00000	99.51
13.5	82,458,633.01	0.00	0.00000	1.00000	99.51
14.5	81,191,587.73	0.00	0.00000	1.00000	99.51
15.5	81,170,982.40	0.00	0.00000	1.00000	99.51
16.5	79,890,383.67	0.00	0.00000	1.00000	99.51
17.5	79,846,354.58	0.00	0.00000	1.00000	99.51
18.5	69,625,966.72	0.00	0.00000	1.00000	99.51
19.5	62,514,295.59	0.00	0.00000	1.00000	99.51
20.5	386,381.71	0.00	0.00000	1.00000	99.51
21.5	386,381.71	0.00	0.00000	1.00000	99.51
22.5	386,381.71	925.68	0.00240	0.99760	99.51
23.5	385,456.03	16,031.35	0.04159	0.95841	99.27
24.5	369,424.68	7,757.25	0.02100	0.97900	95.14
25.5	361,667.43	18,906.88	0.05228	0.94772	93.15
26.5	342,760.55	0.00	0.00000	1.00000	88.28
27.5	342,760.55	0.00	0.00000	1.00000	88.28
28.5	342,760.55	0.00	0.00000	1.00000	88.28
29.5	342,760.55	330,236.72	0.96346	0.03654	88.28
30.5	12,523.83	12,523.83	1.00000	0.00000	3.23
31.5	0.00	0.00	0.00000	1.00000	0.00

Actuarial Life Analysis

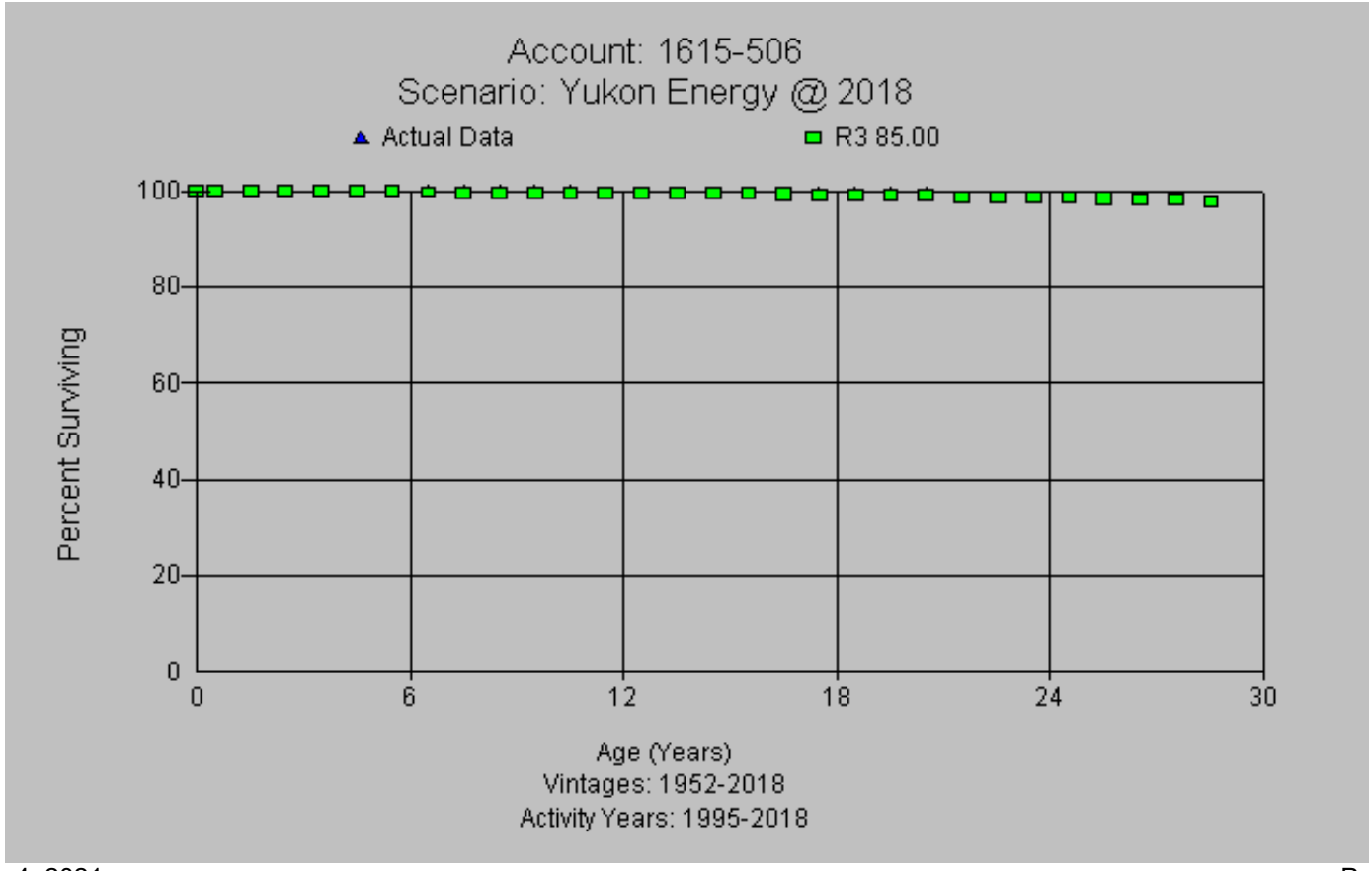
Account: 1615-205
Scenario: Yukon Energy @ 2018
Placement Band: 1952 - 1991
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1987 -1991	21.5	0.00	0.00000000	S5	0.30
1988 -1992		1.00			
1989 -1993		1.00			
1990 -1994		1.00			
1991 -1995	25.5	0.00	0.00000000	S5	0.30
1992 -1996	26.5	95.41	0.02001845	R0.5	114.31
1993 -1997	27.5	0.00	0.45784242	S6	19.14
1994 -1998	28.5	0.00	0.00000000	SQ	20.20
1995 -1999	29.5	0.00	0.00000000	SQ	20.20
1996 -2000	30.5	0.00	0.00000000	SQ	20.20
1997 -2001	31.5	0.00	0.00000000	SQ	20.20
1998 -2002	32.5	0.00	0.00000000	SQ	32.10
1999 -2003	33.5	0.00	0.00006336	SQ	32.02
2000 -2004	34.5	0.00	0.01927787	SQ	31.61
2001 -2005	35.5	0.00	0.06352852	SQ	31.43
2002 -2006	36.5	0.00	0.46408543	S6	31.04
2003 -2007	37.5	88.71	0.02189380	S1	65.89
2004 -2008	38.5	88.92	0.02333533	S1	67.11
2005 -2009	39.5	74.85	0.51304562	R0.5	40.52
2006 -2010	40.5	3.07	0.93211297	R4	25.10
2007 -2011	41.5	0.00	0.00143333	SQ	28.03
2008 -2012	42.5	0.00	0.00142297	SQ	28.04
2009 -2013	43.5	0.00	0.00142297	SQ	28.04
2010 -2014	44.5	0.00	0.00133225	SQ	28.18
2011 -2015	45.5	0.00	0.00000000	SQ	29.20
2012 -2016		1.00			
2013 -2017		1.00			
2014 -2018	48.5	99.93	0.00001866	R4	168.54

Actuarial Life Analysis

Account: 1615-205
Scenario: Yukon Energy @ 2018
Placement Band: 1952 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1987 -2018	66.5	0.00	0.06602996	SQ	29.59
1992 -2018	66.5	0.00	0.05980954	SQ	29.53
1997 -2018	66.5	0.00	0.05074651	SQ	29.49
2002 -2018	66.5	0.00	0.04715062	SQ	29.46
2007 -2018	66.5	0.00	0.00148783	SQ	30.02
2012 -2018	66.5	99.93	0.00002836	R4	228.13
2017 -2018	66.5	99.93	0.00002836	R4	228.13


Account: 1615-506
Scenario: Yukon Energy @ 2018
Actual Data
R3 85.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1952-2018
Activity Years: 1995-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1615-506
Placement Band: 1952 - 2018 **Observation Band:** 1995 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	26,904,609.39	0.00	0.00000	1.00000	100.00
0.5	26,904,609.39	0.00	0.00000	1.00000	100.00
1.5	26,151,748.89	0.00	0.00000	1.00000	100.00
2.5	26,151,748.89	0.00	0.00000	1.00000	100.00
3.5	25,989,238.46	0.00	0.00000	1.00000	100.00
4.5	25,469,057.91	0.00	0.00000	1.00000	100.00
5.5	25,174,304.79	0.00	0.00000	1.00000	100.00
6.5	21,951,366.84	0.00	0.00000	1.00000	100.00
7.5	10,982,369.66	0.00	0.00000	1.00000	100.00
8.5	10,982,369.66	0.00	0.00000	1.00000	100.00
9.5	10,596,875.30	0.00	0.00000	1.00000	100.00
10.5	10,608,779.30	11,904.00	0.00112	0.99888	100.00
11.5	9,972,120.10	0.00	0.00000	1.00000	99.89
12.5	8,715,827.32	0.00	0.00000	1.00000	99.89
13.5	8,187,103.25	0.00	0.00000	1.00000	99.89
14.5	7,682,624.12	0.00	0.00000	1.00000	99.89
15.5	6,314,045.68	0.00	0.00000	1.00000	99.89
16.5	3,928,008.98	0.00	0.00000	1.00000	99.89
17.5	3,786,769.85	0.00	0.00000	1.00000	99.89
18.5	3,308,918.95	0.00	0.00000	1.00000	99.89
19.5	3,105,275.76	0.00	0.00000	1.00000	99.89
20.5	0.00	0.00	0.00000	1.00000	99.89
21.5	0.00	0.00	0.00000	1.00000	
22.5	0.00	0.00	0.00000	1.00000	
23.5	0.00	0.00	0.00000	1.00000	
24.5	0.00	0.00	0.00000	1.00000	
25.5	63,672.00	0.00	0.00000	1.00000	
26.5	63,672.00	0.00	0.00000	1.00000	
27.5	63,672.00	0.00	0.00000	1.00000	
28.5	63,672.00	0.00	0.00000	1.00000	
29.5	63,672.00	0.00	0.00000	1.00000	
30.5	63,672.00	0.00	0.00000	1.00000	
31.5	63,672.00	0.00	0.00000	1.00000	
32.5	63,672.00	63,672.00	1.00000	0.00000	
33.5	0.00	0.00	0.00000	1.00000	
34.5	0.00	0.00	0.00000	1.00000	
35.5	0.00	0.00	0.00000	1.00000	
36.5	0.00	0.00	0.00000	1.00000	
37.5	36,169.00	0.00	0.00000	1.00000	

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1615-506
Placement Band: 1952 - 2018 **Observation Band:** 1995 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
38.5	36,169.00	0.00	0.00000	1.00000	
39.5	36,169.00	0.00	0.00000	1.00000	
40.5	36,169.00	0.00	0.00000	1.00000	
41.5	58,666.96	36,169.00	0.61651	0.38349	
42.5	35,984.96	0.00	0.00000	1.00000	
43.5	35,984.96	0.00	0.00000	1.00000	
44.5	35,984.96	0.00	0.00000	1.00000	
45.5	35,984.96	0.00	0.00000	1.00000	
46.5	35,984.96	0.00	0.00000	1.00000	
47.5	35,984.96	0.00	0.00000	1.00000	
48.5	35,984.96	0.00	0.00000	1.00000	
49.5	35,984.96	13,487.00	0.37480	0.62520	
50.5	22,497.96	0.00	0.00000	1.00000	
51.5	22,497.96	0.00	0.00000	1.00000	
52.5	22,497.96	0.00	0.00000	1.00000	
53.5	22,497.96	22,497.96	1.00000	0.00000	
54.5	0.00	0.00	0.00000	1.00000	

Actuarial Life Analysis

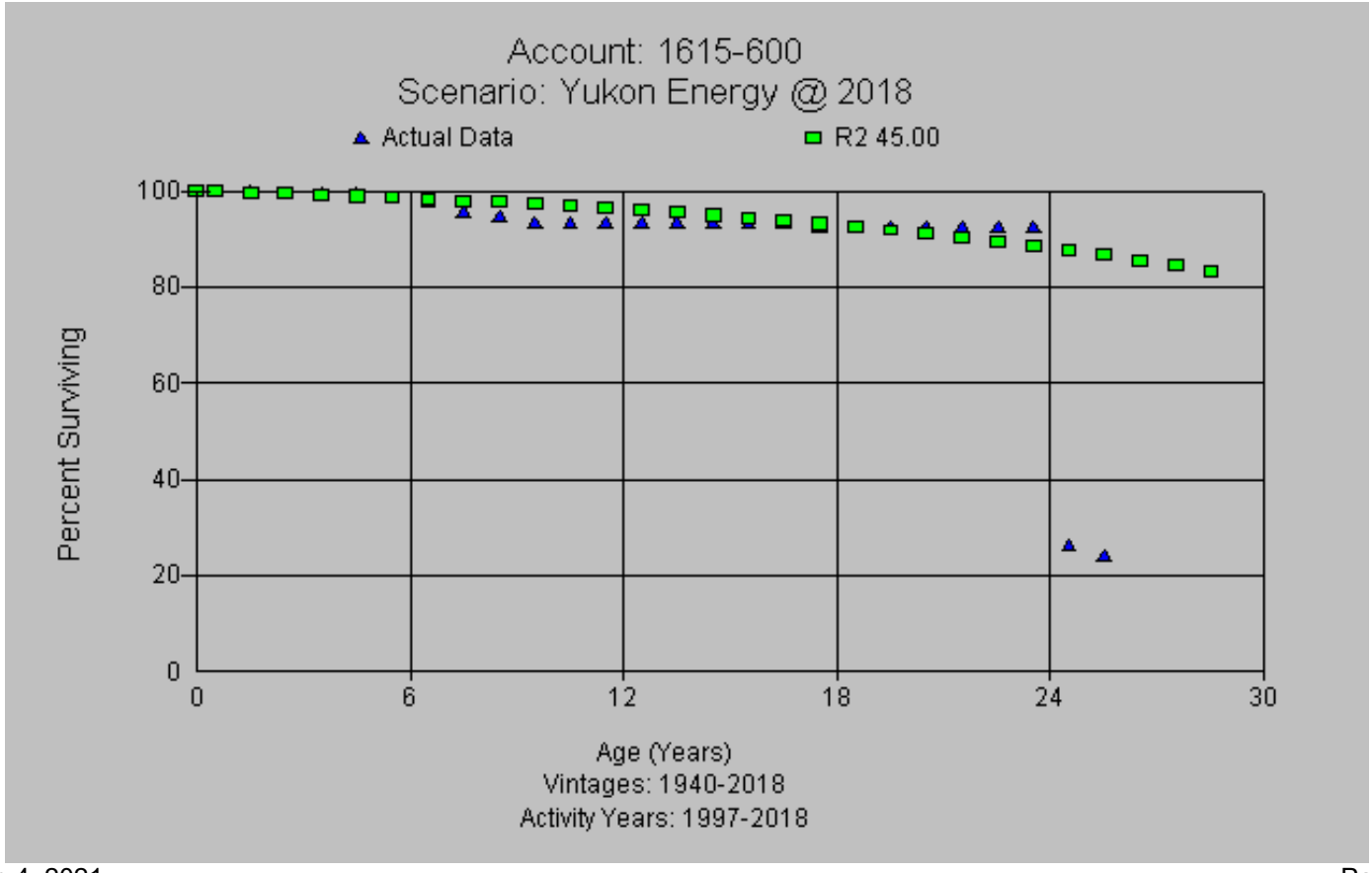
Account: 1615-506
Scenario: Yukon Energy @ 2018
Placement Band: 1952 - 1999
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

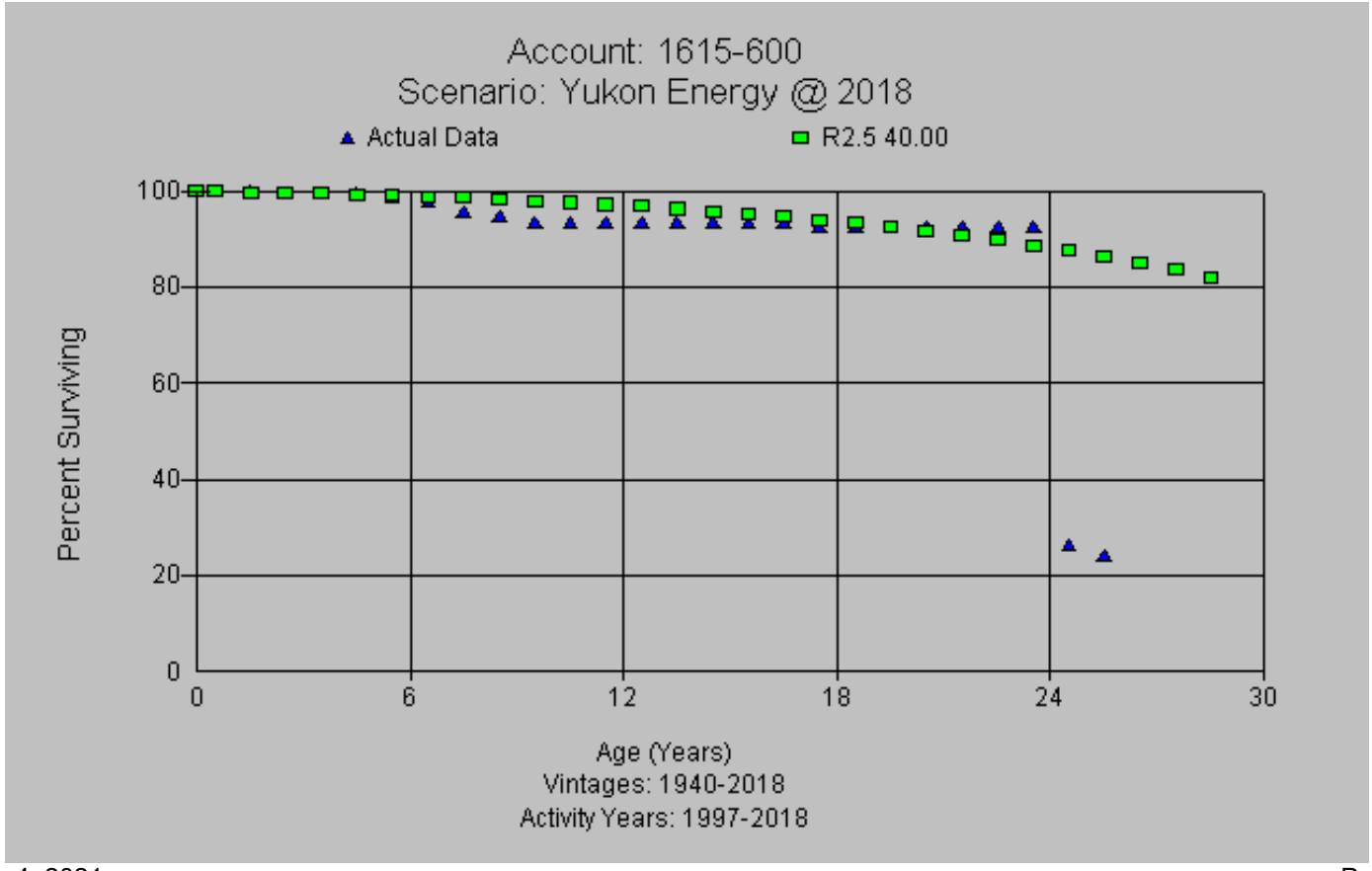
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1995 -1999	30.5	0.00	0.00000000	SQ	11.20
1996 -2000	31.5	0.00	0.00000000	SQ	25.20
1997 -2001	32.5	0.00	0.00000000	SQ	25.20
1998 -2002	33.5	0.00	0.00000000	SQ	23.20
1999 -2003	34.5	0.00	0.00000000	SQ	23.20
2000 -2004	35.5	0.00	0.00000000	SQ	23.20
2001 -2005	36.5	0.00	0.00000000	SQ	23.20
2002 -2006	37.5	0.00	0.00000000	SQ	23.20
2003 -2007	38.5	0.00	0.00000000	SQ	37.10
2004 -2008	39.5	0.00	0.00000000	SQ	37.10
2005 -2009	40.5	0.00	0.00000000	SQ	37.10
2006 -2010	41.5	0.00	0.00000000	SQ	37.10
2007 -2011	42.5	0.00	0.00000000	SQ	37.10
2008 -2012		1.00			
2009 -2013		1.00			
2010 -2014		1.00			
2011 -2015		1.00			
2012 -2016		1.00			
2013 -2017		1.00			
2014 -2018		1.00			

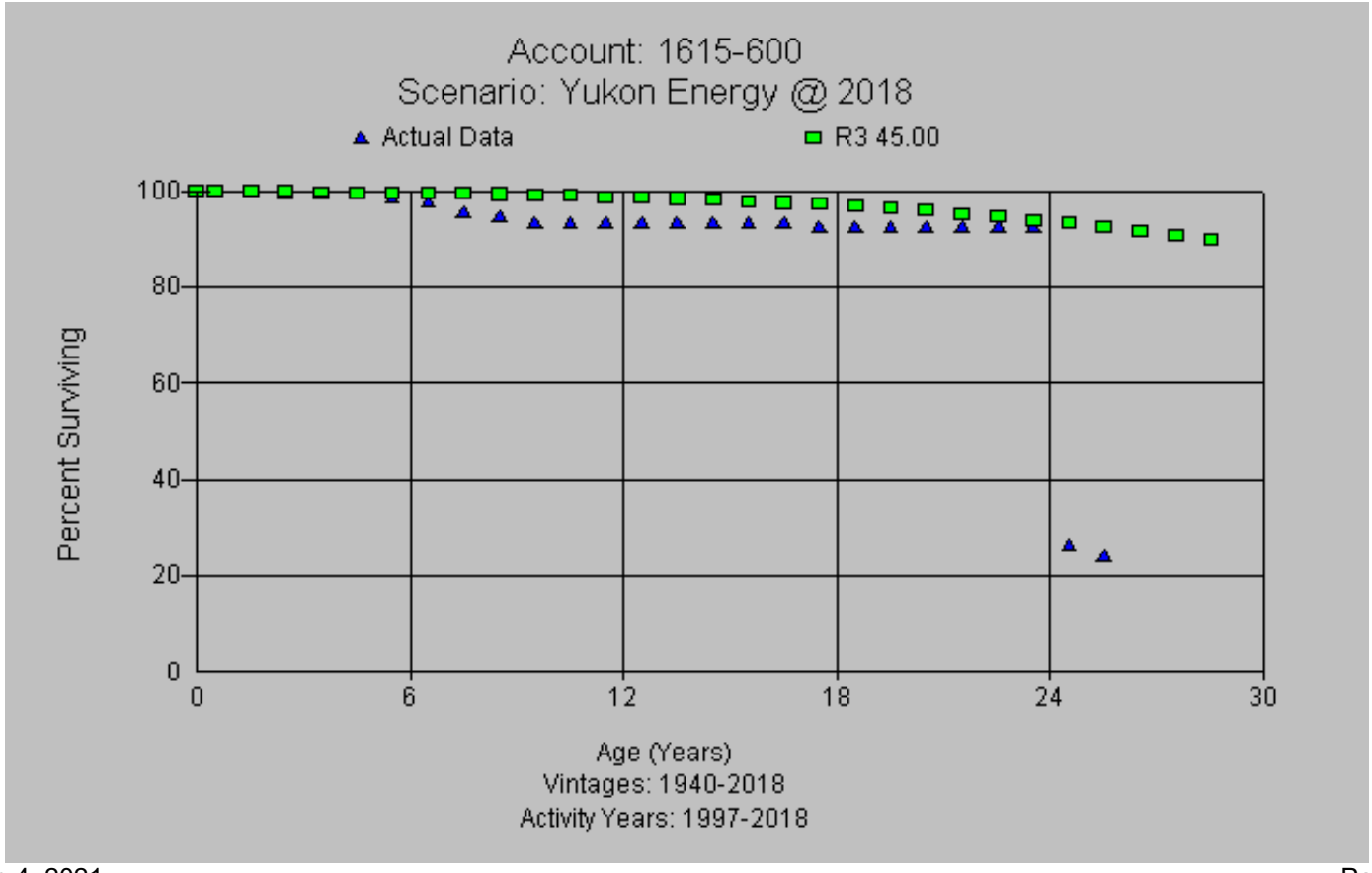
Actuarial Life Analysis

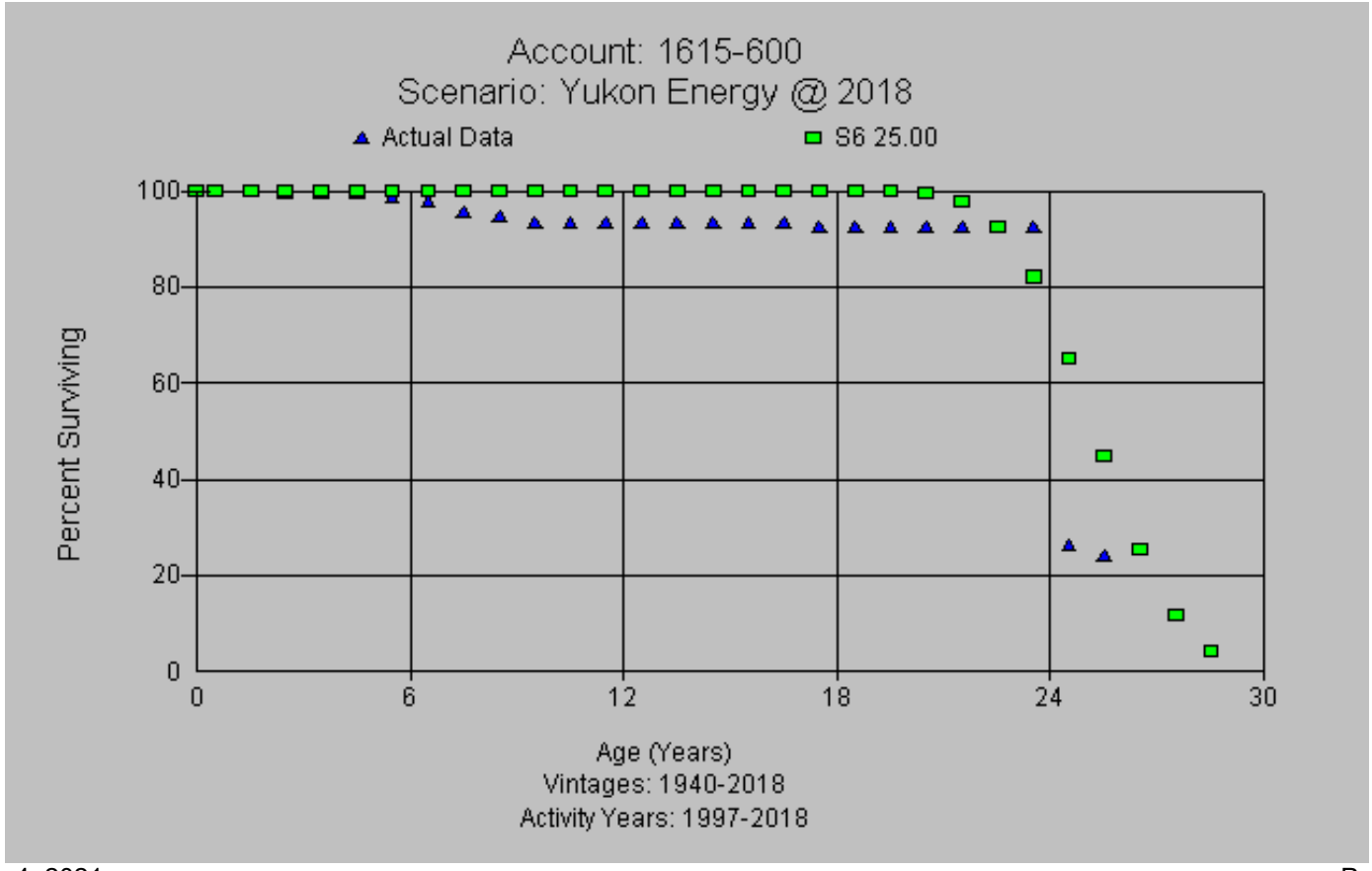
Account: 1615-506
Scenario: Yukon Energy @ 2018
Placement Band: 1952 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1995 -2018	66.5	0.00	0.00002662	SQ	33.02
2000 -2018	66.5	0.00	0.00000000	SQ	33.10
2005 -2018	66.5	0.00	0.02235499	SQ	53.05
2010 -2018		1.00			
2015 -2018		1.00			


Account: 1615-600
Scenario: Yukon Energy @ 2018
Actual Data
R2 45.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1940-2018
Activity Years: 1997-2018


Account: 1615-600
Scenario: Yukon Energy @ 2018
Actual Data
R2.5 40.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1940-2018
Activity Years: 1997-2018


Account: 1615-600
Scenario: Yukon Energy @ 2018
Actual Data
R3 45.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1940-2018
Activity Years: 1997-2018


Account: 1615-600
Scenario: Yukon Energy @ 2018
Actual Data
S6 25.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1940-2018
Activity Years: 1997-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1615-600
Placement Band: 1940 - 2018 **Observation Band:** 1997 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	26,641,460.13	6,035.49	0.00023	0.99977	100.00
0.5	26,542,172.76	0.00	0.00000	1.00000	99.98
1.5	24,393,671.89	37,070.00	0.00152	0.99848	99.98
2.5	24,558,838.89	0.00	0.00000	1.00000	99.83
3.5	24,031,734.37	70,394.00	0.00293	0.99707	99.83
4.5	24,274,965.64	202,237.00	0.00833	0.99167	99.53
5.5	23,690,560.44	226,566.00	0.00956	0.99044	98.70
6.5	23,506,897.26	507,868.00	0.02161	0.97839	97.76
7.5	6,644,878.73	48,776.00	0.00734	0.99266	95.65
8.5	6,560,287.68	106,341.00	0.01621	0.98379	94.95
9.5	6,412,698.03	0.00	0.00000	1.00000	93.41
10.5	6,160,493.39	0.00	0.00000	1.00000	93.41
11.5	5,869,364.37	0.00	0.00000	1.00000	93.41
12.5	5,761,966.91	0.00	0.00000	1.00000	93.41
13.5	5,593,629.11	0.00	0.00000	1.00000	93.41
14.5	5,334,234.29	0.00	0.00000	1.00000	93.41
15.5	4,424,156.16	0.00	0.00000	1.00000	93.41
16.5	4,371,293.01	43,490.00	0.00995	0.99005	93.41
17.5	4,327,803.01	0.00	0.00000	1.00000	92.48
18.5	3,364,090.40	0.00	0.00000	1.00000	92.48
19.5	3,246,948.82	0.00	0.00000	1.00000	92.48
20.5	279,574.16	0.00	0.00000	1.00000	92.48
21.5	279,574.16	0.00	0.00000	1.00000	92.48
22.5	279,574.16	0.00	0.00000	1.00000	92.48
23.5	279,574.16	199,606.49	0.71397	0.28603	92.48
24.5	79,967.67	7,240.29	0.09054	0.90946	26.45
25.5	72,727.38	72,727.38	1.00000	0.00000	24.06
26.5	0.00	0.00	0.00000	1.00000	0.00
27.5	0.00	0.00	0.00000	1.00000	
28.5	0.00	0.00	0.00000	1.00000	
29.5	0.00	0.00	0.00000	1.00000	
30.5	0.00	0.00	0.00000	1.00000	
31.5	0.00	0.00	0.00000	1.00000	
32.5	0.00	0.00	0.00000	1.00000	
33.5	0.00	0.00	0.00000	1.00000	
34.5	0.00	0.00	0.00000	1.00000	
35.5	0.00	0.00	0.00000	1.00000	
36.5	0.00	0.00	0.00000	1.00000	
37.5	0.00	0.00	0.00000	1.00000	

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1615-600
Placement Band: 1940 - 2018 **Observation Band:** 1997 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
53.5	15,933.84	0.00	0.00000	1.00000	
54.5	15,933.84	0.00	0.00000	1.00000	
55.5	15,933.84	0.00	0.00000	1.00000	
56.5	15,933.84	0.00	0.00000	1.00000	
57.5	15,933.84	0.00	0.00000	1.00000	
58.5	15,933.84	0.00	0.00000	1.00000	
59.5	15,933.84	0.00	0.00000	1.00000	
60.5	15,933.84	0.00	0.00000	1.00000	
61.5	15,933.84	0.00	0.00000	1.00000	
62.5	15,933.84	0.00	0.00000	1.00000	
63.5	15,933.84	15,933.84	1.00000	0.00000	
64.5	0.00	0.00	0.00000	1.00000	

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1615-600
Placement Band: 1903 - 2018 **Observation Band:** 1997 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	26,641,460.13	6,035.49	0.00023	0.99977	100.00
0.5	26,542,172.76	0.00	0.00000	1.00000	99.98
1.5	24,393,671.89	37,070.00	0.00152	0.99848	99.98
2.5	24,558,838.89	0.00	0.00000	1.00000	99.83
3.5	24,031,734.37	70,394.00	0.00293	0.99707	99.83
4.5	24,274,965.64	202,237.00	0.00833	0.99167	99.53
5.5	23,690,560.44	226,566.00	0.00956	0.99044	98.70
6.5	23,506,897.26	507,868.00	0.02161	0.97839	97.76
7.5	6,644,878.73	48,776.00	0.00734	0.99266	95.65
8.5	6,560,287.68	106,341.00	0.01621	0.98379	94.95
9.5	6,412,698.03	0.00	0.00000	1.00000	93.41
10.5	6,160,493.39	0.00	0.00000	1.00000	93.41
11.5	5,869,364.37	0.00	0.00000	1.00000	93.41
12.5	5,761,966.91	0.00	0.00000	1.00000	93.41
13.5	5,593,629.11	0.00	0.00000	1.00000	93.41
14.5	5,334,234.29	0.00	0.00000	1.00000	93.41
15.5	4,424,156.16	0.00	0.00000	1.00000	93.41
16.5	4,371,293.01	43,490.00	0.00995	0.99005	93.41
17.5	4,327,803.01	0.00	0.00000	1.00000	92.48
18.5	3,364,090.40	0.00	0.00000	1.00000	92.48
19.5	3,246,948.82	0.00	0.00000	1.00000	92.48
20.5	279,574.16	0.00	0.00000	1.00000	92.48
21.5	279,574.16	0.00	0.00000	1.00000	92.48
22.5	279,574.16	0.00	0.00000	1.00000	92.48
23.5	279,574.16	199,606.49	0.71397	0.28603	92.48
24.5	79,967.67	7,240.29	0.09054	0.90946	26.45
25.5	72,727.38	72,727.38	1.00000	0.00000	24.06
26.5	0.00	0.00	0.00000	1.00000	0.00
27.5	0.00	0.00	0.00000	1.00000	
28.5	0.00	0.00	0.00000	1.00000	
29.5	0.00	0.00	0.00000	1.00000	
30.5	0.00	0.00	0.00000	1.00000	
31.5	0.00	0.00	0.00000	1.00000	
32.5	0.00	0.00	0.00000	1.00000	
33.5	0.00	0.00	0.00000	1.00000	
34.5	0.00	0.00	0.00000	1.00000	
35.5	0.00	0.00	0.00000	1.00000	
36.5	0.00	0.00	0.00000	1.00000	
37.5	0.00	0.00	0.00000	1.00000	

Observed Life Table

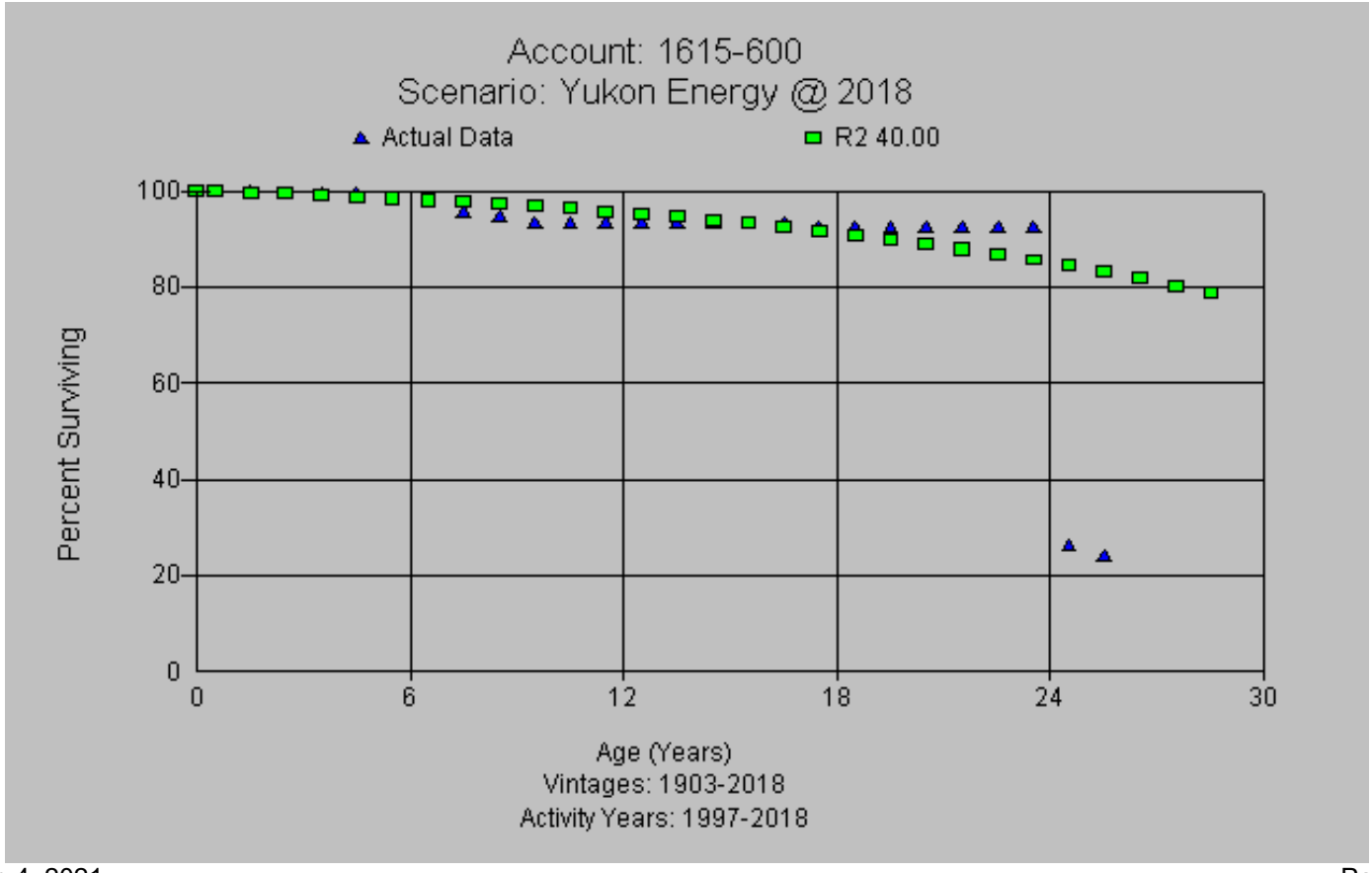
Scenario: Yukon Energy @ 2018
Account: 1615-600
Placement Band: 1903 - 2018 **Observation Band:** 1997 - 2018

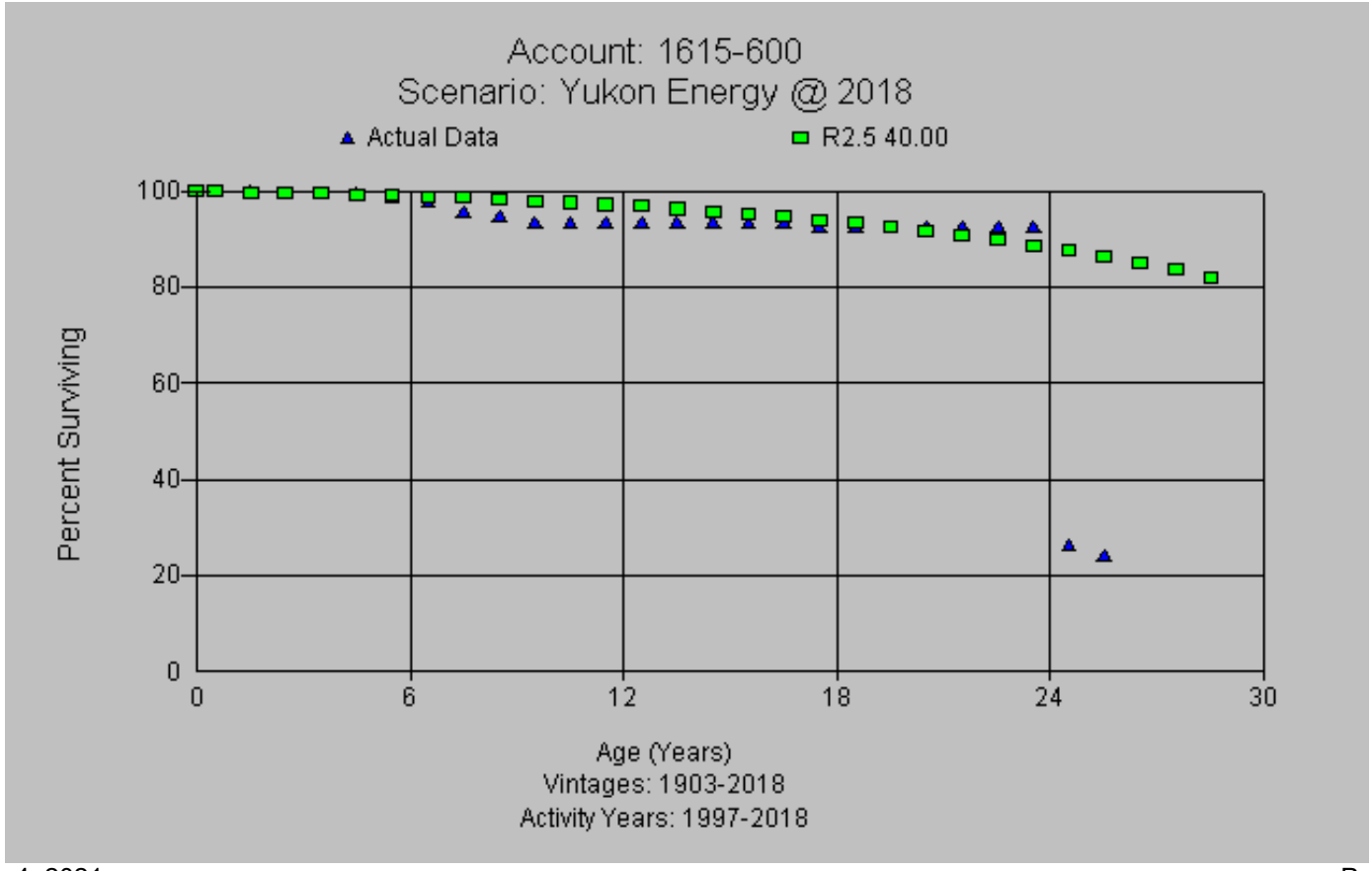
Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
53.5	15,933.84	0.00	0.00000	1.00000	
54.5	15,933.84	0.00	0.00000	1.00000	
55.5	15,933.84	0.00	0.00000	1.00000	
56.5	15,933.84	0.00	0.00000	1.00000	
57.5	15,933.84	0.00	0.00000	1.00000	
58.5	15,933.84	0.00	0.00000	1.00000	
59.5	15,933.84	0.00	0.00000	1.00000	
60.5	15,933.84	0.00	0.00000	1.00000	
61.5	15,933.84	0.00	0.00000	1.00000	
62.5	15,933.84	0.00	0.00000	1.00000	
63.5	15,933.84	15,933.84	1.00000	0.00000	
64.5	0.00	0.00	0.00000	1.00000	
65.5	0.00	0.00	0.00000	1.00000	
66.5	0.00	0.00	0.00000	1.00000	
67.5	0.00	0.00	0.00000	1.00000	
68.5	0.00	0.00	0.00000	1.00000	
69.5	0.00	0.00	0.00000	1.00000	
70.5	0.00	0.00	0.00000	1.00000	
71.5	0.00	0.00	0.00000	1.00000	
72.5	0.00	0.00	0.00000	1.00000	
73.5	0.00	0.00	0.00000	1.00000	
74.5	0.00	0.00	0.00000	1.00000	
83.5	6,772.41	0.00	0.00000	1.00000	
84.5	6,772.41	0.00	0.00000	1.00000	
85.5	6,772.41	0.00	0.00000	1.00000	
86.5	6,772.41	0.00	0.00000	1.00000	
87.5	6,772.41	0.00	0.00000	1.00000	
88.5	6,772.41	0.00	0.00000	1.00000	
89.5	6,772.41	0.00	0.00000	1.00000	
90.5	6,772.41	0.00	0.00000	1.00000	
91.5	6,772.41	0.00	0.00000	1.00000	
92.5	6,772.41	0.00	0.00000	1.00000	
93.5	12,323.85	6,772.41	0.54954	0.45046	
94.5	5,551.44	0.00	0.00000	1.00000	
95.5	5,551.44	0.00	0.00000	1.00000	
96.5	5,551.44	0.00	0.00000	1.00000	
97.5	5,551.44	0.00	0.00000	1.00000	
98.5	5,551.44	0.00	0.00000	1.00000	
99.5	5,551.44	0.00	0.00000	1.00000	

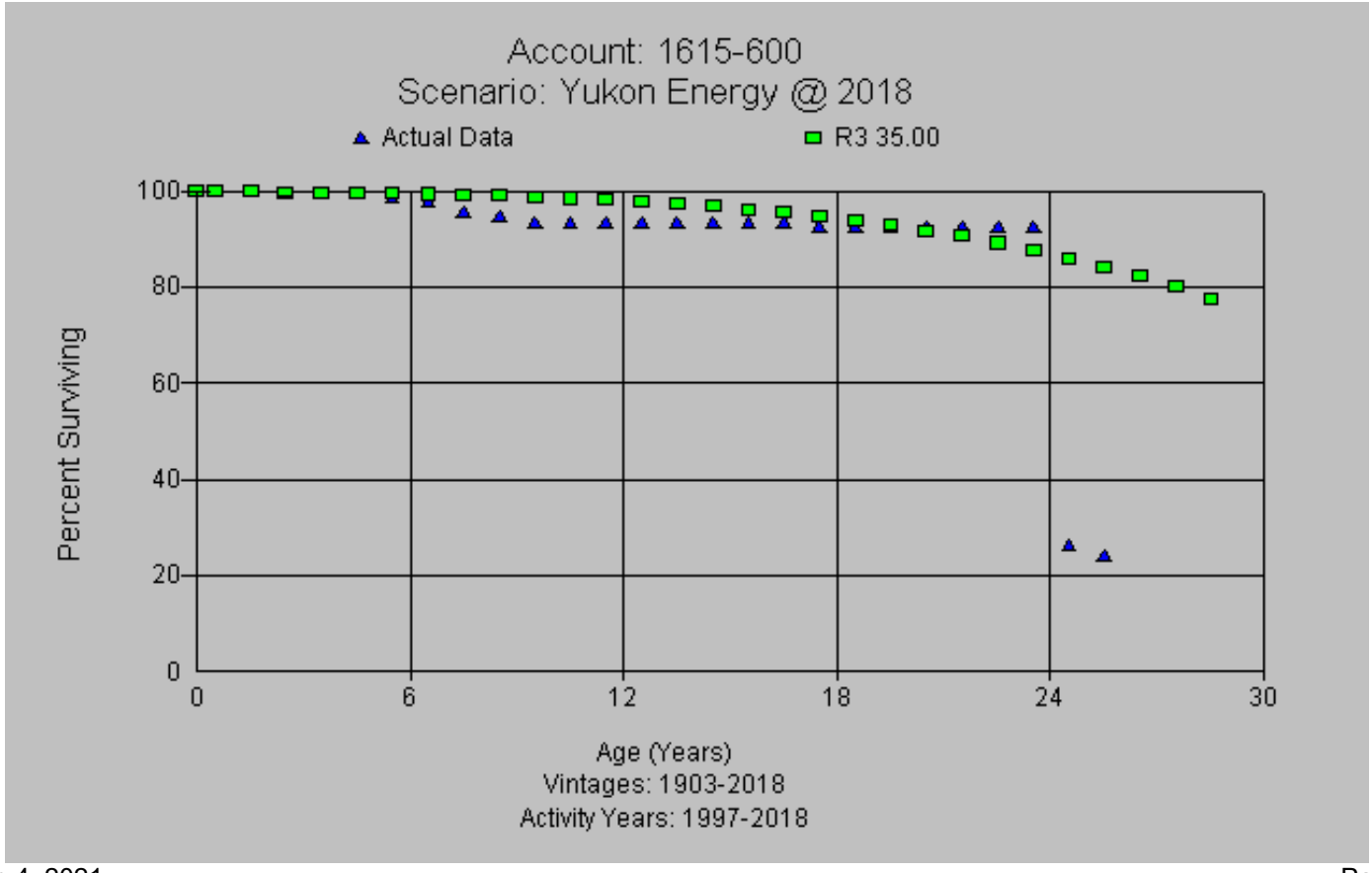
Observed Life Table

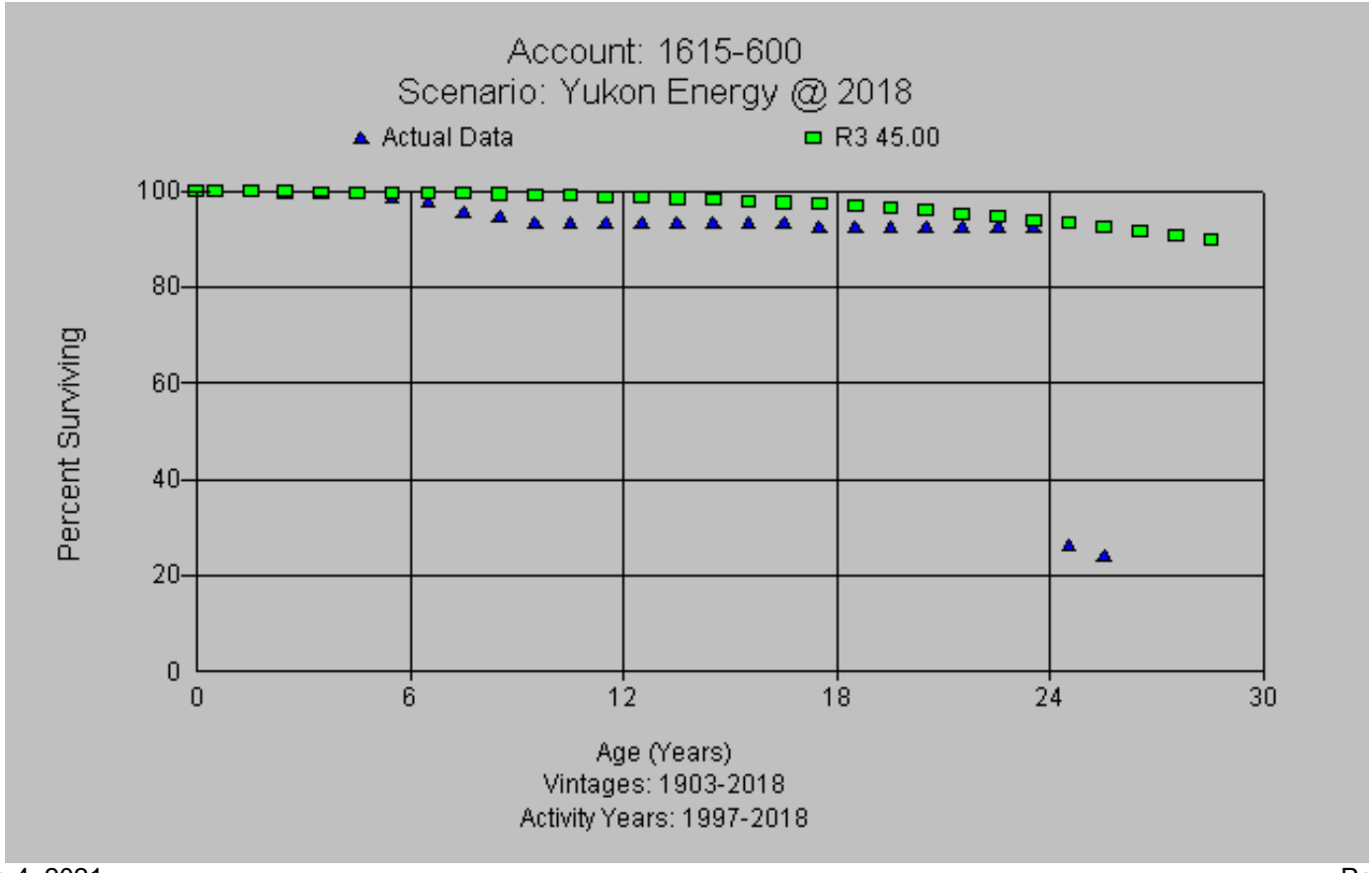
Scenario: Yukon Energy @ 2018
Account: 1615-600
Placement Band: 1903 - 2018 **Observation Band:** 1997 - 2018

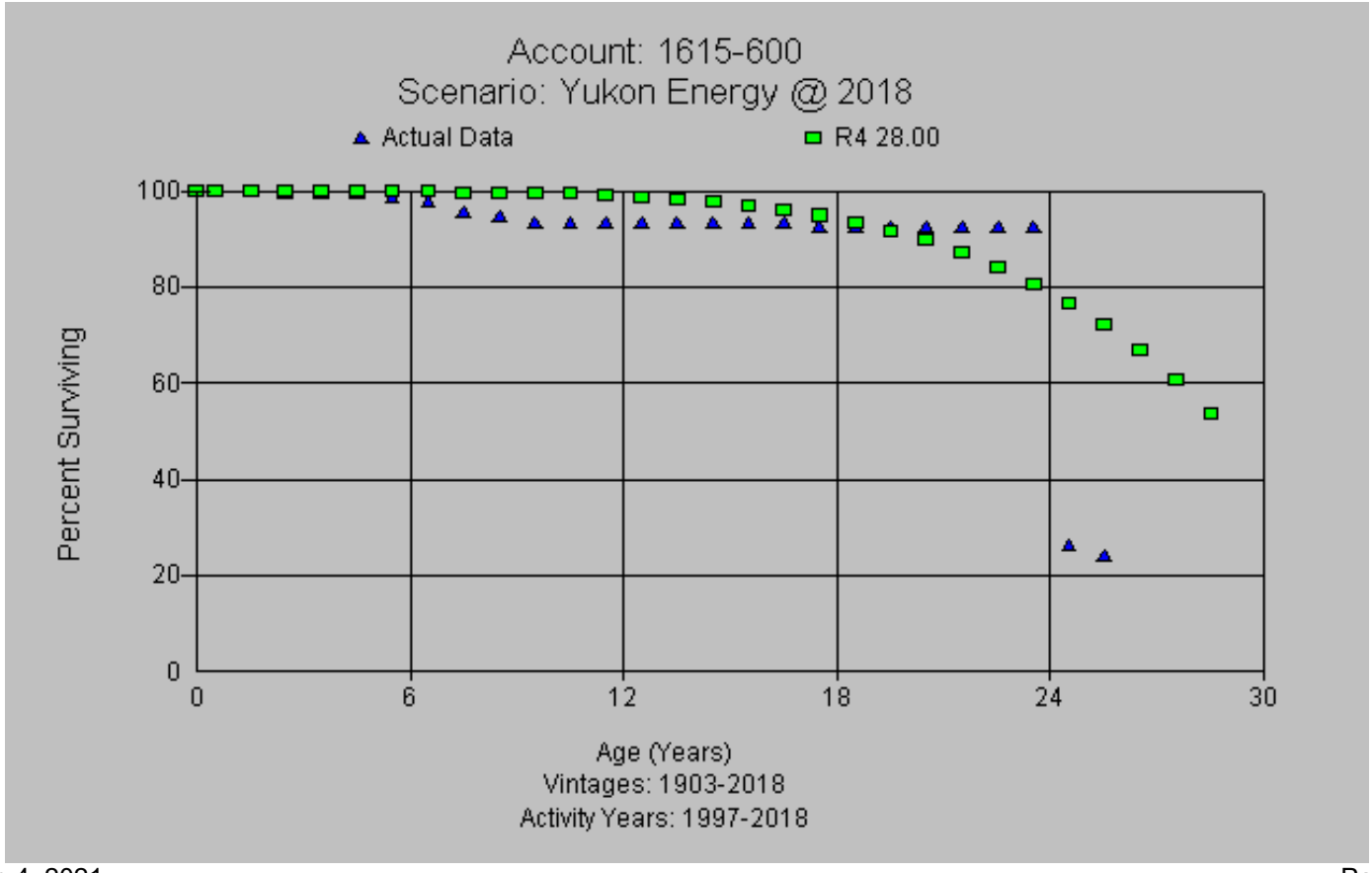
Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
100.5	5,551.44	0.00	0.00000	1.00000	
101.5	5,551.44	0.00	0.00000	1.00000	
102.5	5,551.44	0.00	0.00000	1.00000	
103.5	5,551.44	5,551.44	1.00000	0.00000	
104.5	0.00	0.00	0.00000	1.00000	


Account: 1615-600
Scenario: Yukon Energy @ 2018
Actual Data
R2 40.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1903-2018
Activity Years: 1997-2018


Account: 1615-600
Scenario: Yukon Energy @ 2018
Actual Data
R2.5 40.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1903-2018
Activity Years: 1997-2018


Account: 1615-600
Scenario: Yukon Energy @ 2018
Actual Data
R3 35.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1903-2018
Activity Years: 1997-2018


Account: 1615-600
Scenario: Yukon Energy @ 2018
Actual Data
R3 45.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1903-2018
Activity Years: 1997-2018


Account: 1615-600
Scenario: Yukon Energy @ 2018
Actual Data
R4 28.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1903-2018
Activity Years: 1997-2018

Actuarial Life Analysis

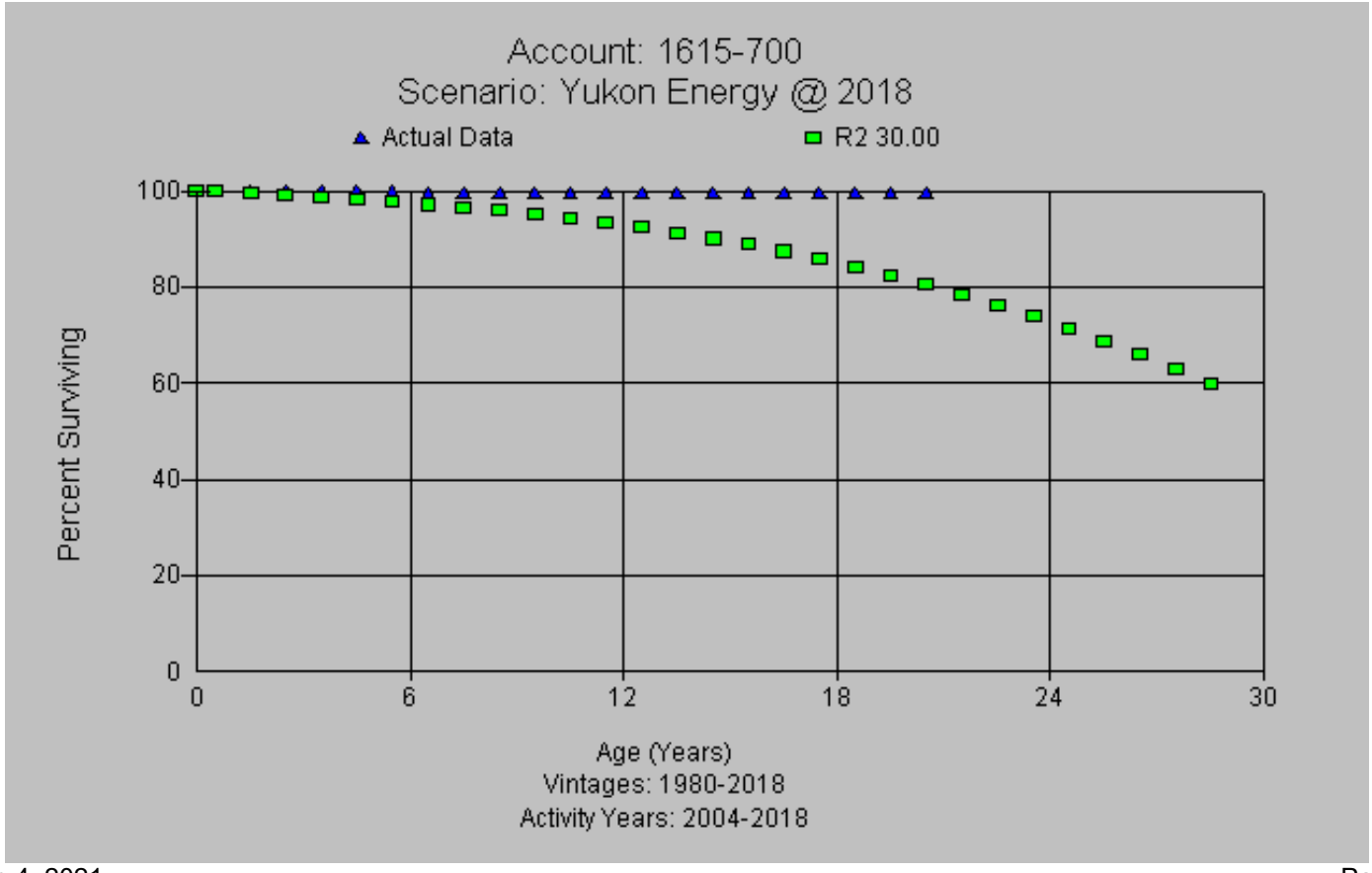
Account: 1615-600
Scenario: Yukon Energy @ 2018
Placement Band: 1903 - 2001
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

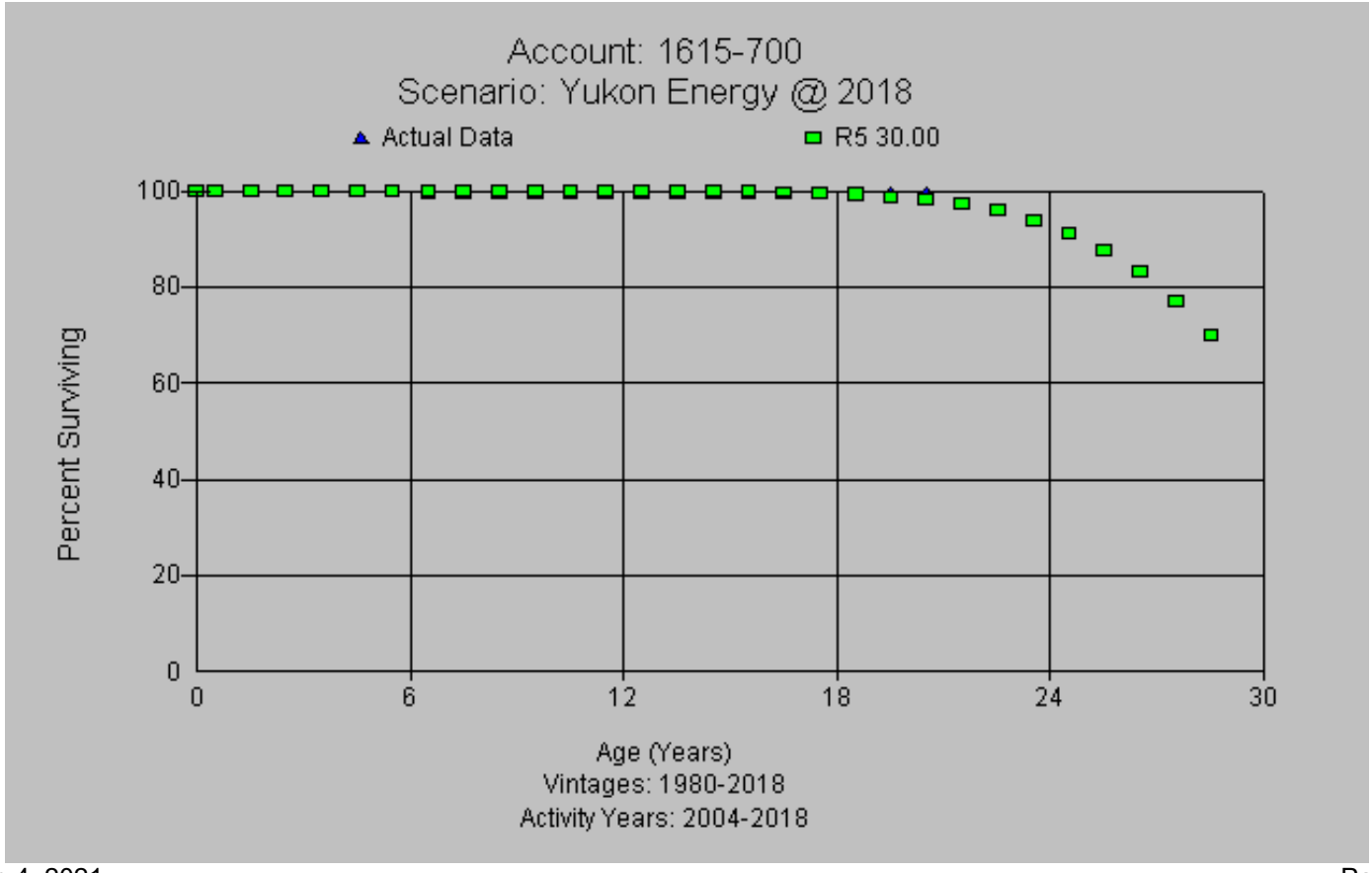
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1997 -2001	34.5	0.00	0.01203609	S3	6.20
1998 -2002	35.5	0.00	0.02862881	S4	5.92
1999 -2003	36.5	0.00	0.00978806	SQ	5.91
2000 -2004	37.5	28.60	0.74962477	L3	27.26
2001 -2005	38.5	26.01	0.79702039	L3	26.95
2002 -2006	39.5	0.00	0.15899192	S6	22.59
2003 -2007	40.5	0.00	0.15899192	S6	22.59
2004 -2008	41.5	0.00	0.15899192	S6	22.59
2005 -2009	42.5	0.00	0.00819025	SQ	23.96
2006 -2010	43.5	0.00	0.00000000	SQ	24.20
2007 -2011	44.5	0.00	0.00000000	SQ	30.20
2008 -2012		1.00			
2009 -2013		1.00			
2010 -2014	47.5	99.97	0.00000393	R4	217.85
2011 -2015	48.5	99.97	0.00000402	R4	222.36
2012 -2016	49.5	99.58	0.00057066	R3	190.85
2013 -2017	50.5	99.83	0.00018575	S1.5	243.43
2014 -2018	51.5	99.81	0.00023650	S1.5	238.76

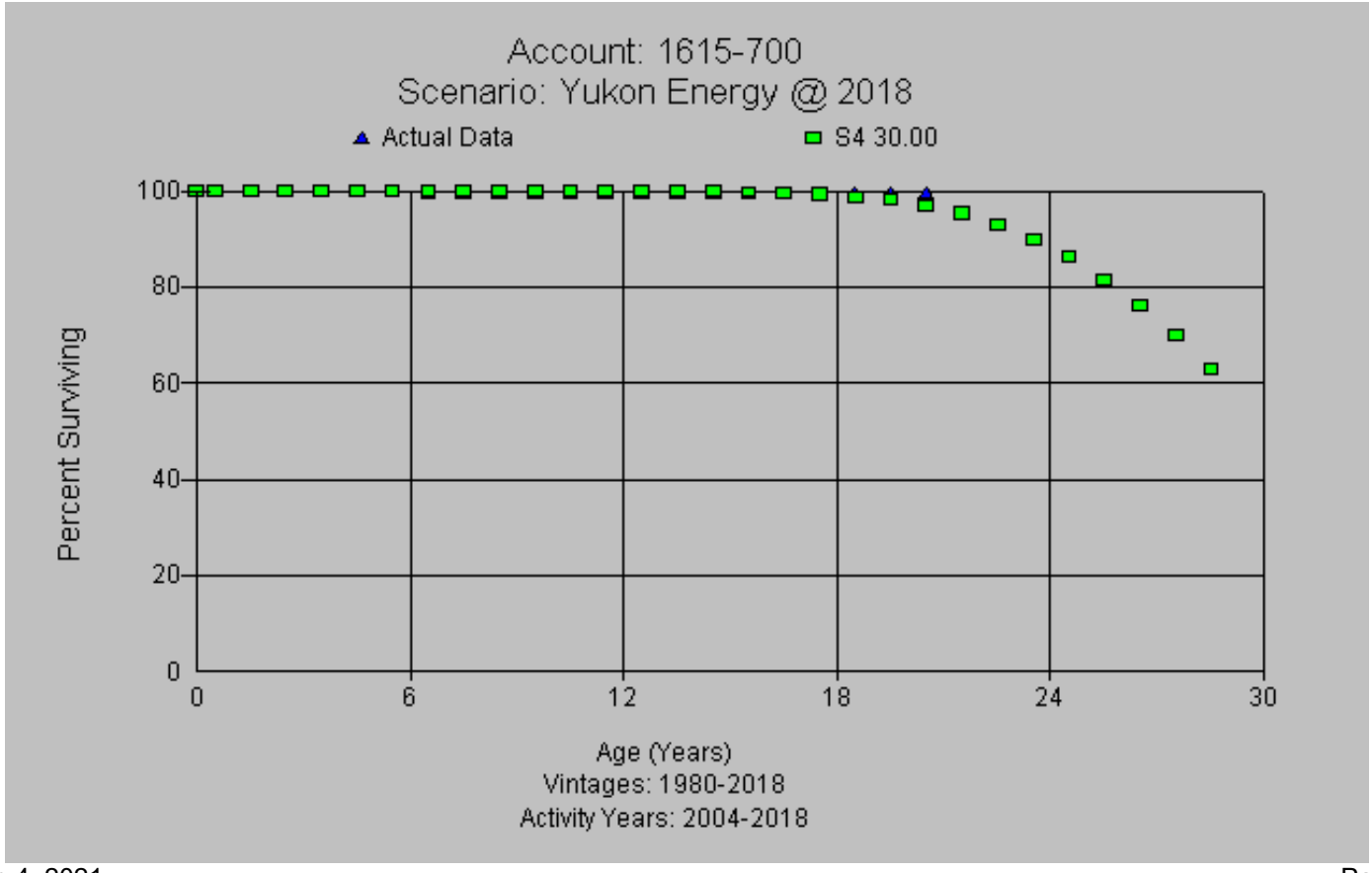
Actuarial Life Analysis

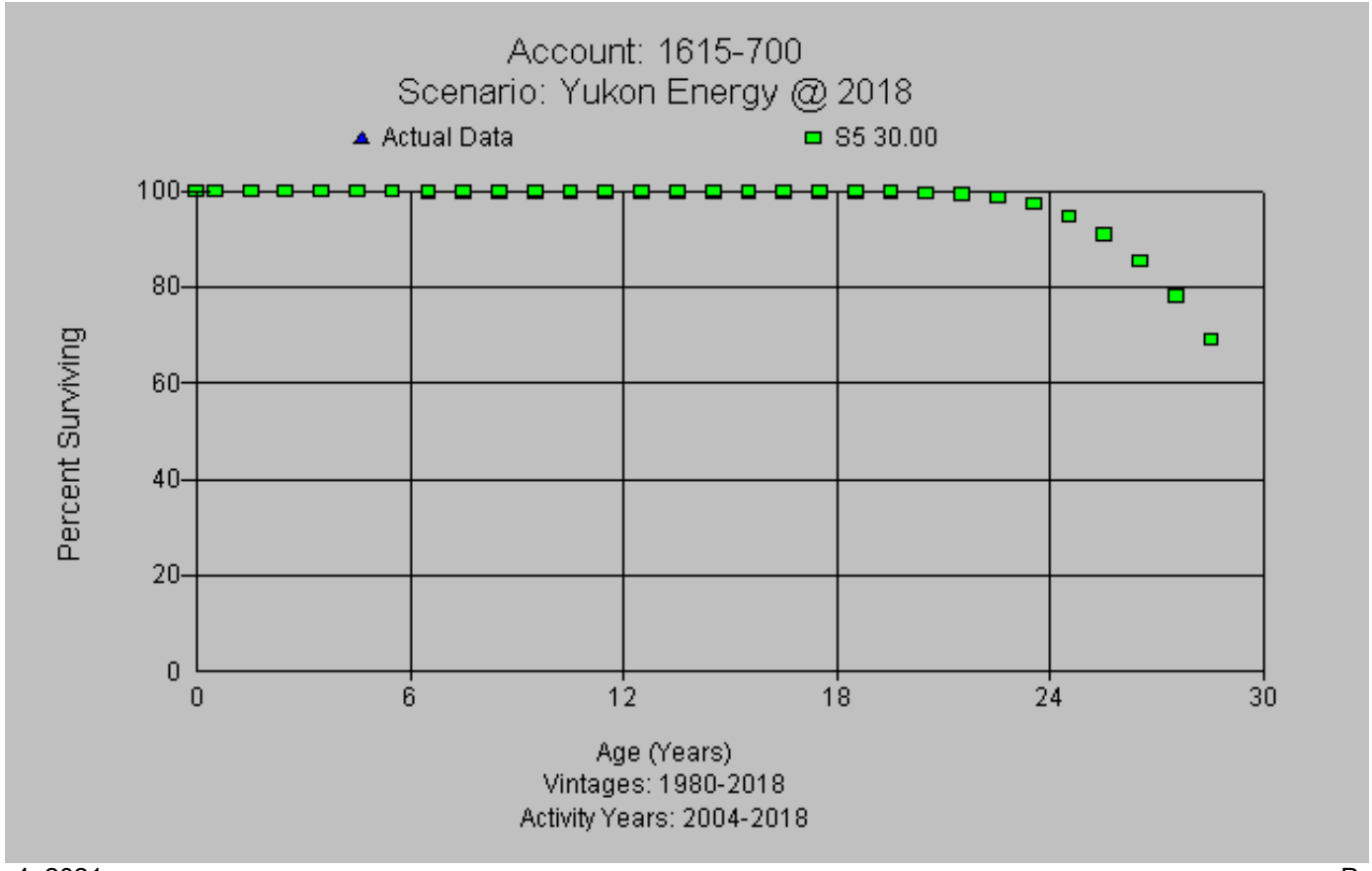
Account: 1615-600
Scenario: Yukon Energy @ 2018
Placement Band: 1903 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1997 -2018	92.5	0.00	0.34224055	S6	23.36
2002 -2018	92.5	0.00	0.18206357	S6	24.59
2007 -2018	92.5	0.00	0.00000351	SQ	39.04
2012 -2018	92.5	0.00	0.01022002	SQ	60.95
2017 -2018	92.5	0.00	0.06810302	SQ	61.05


Account: 1615-700
Scenario: Yukon Energy @ 2018
Actual Data
R2 30.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 2004-2018


Account: 1615-700
Scenario: Yukon Energy @ 2018
Actual Data
R5 30.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 2004-2018

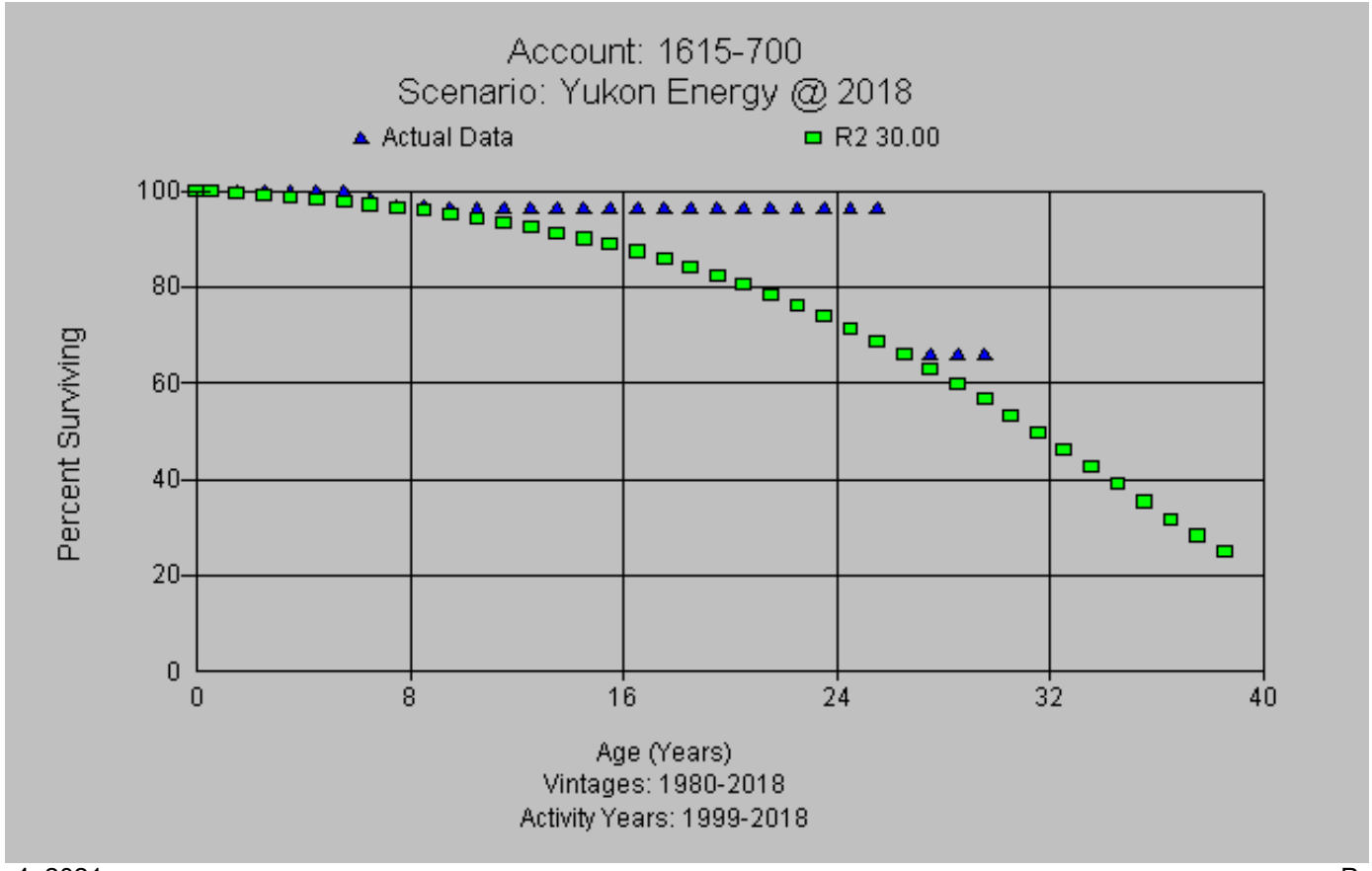

Account: 1615-700
Scenario: Yukon Energy @ 2018
Actual Data
S4 30.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 2004-2018

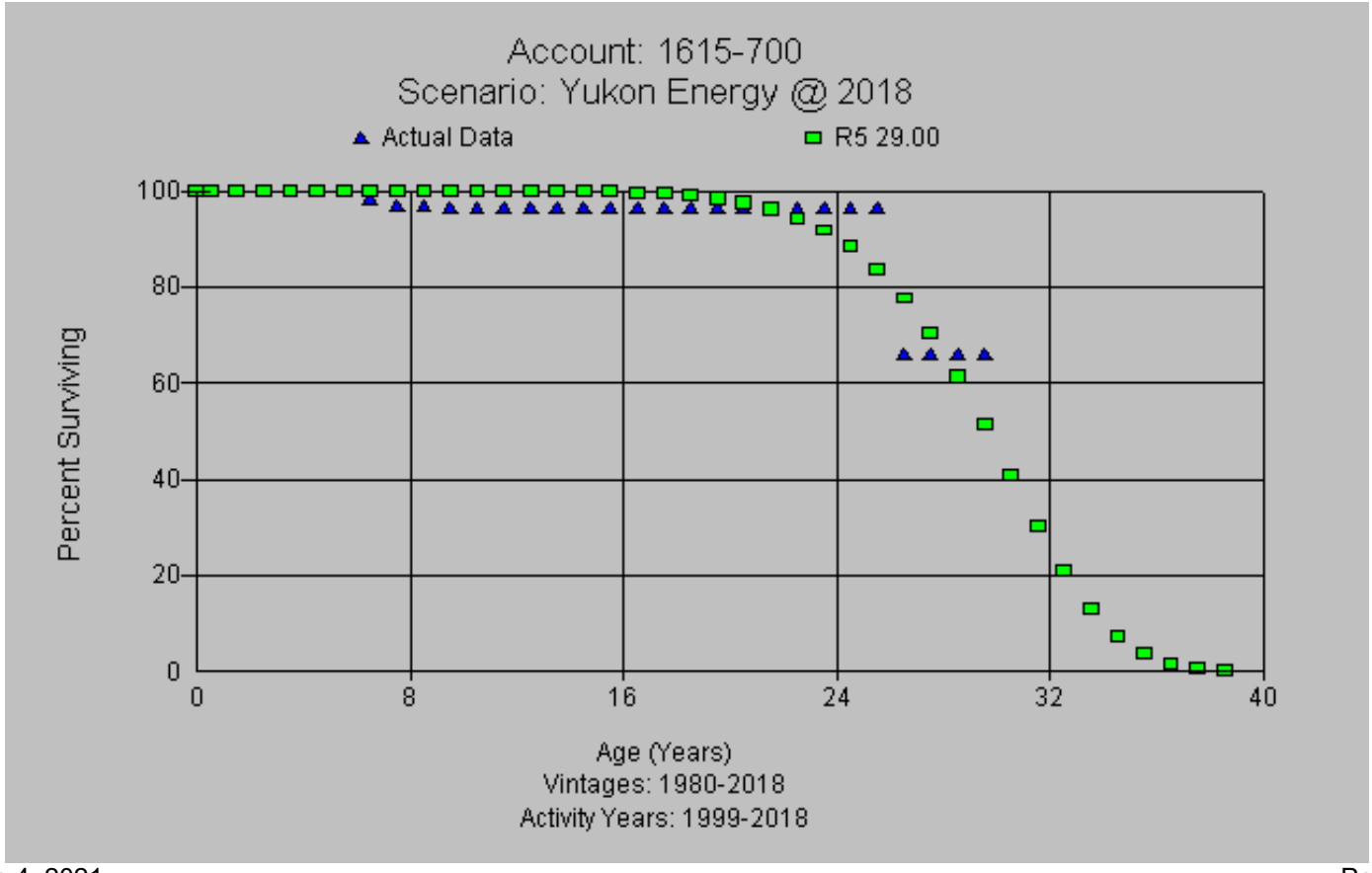

Account: 1615-700
Scenario: Yukon Energy @ 2018
Actual Data
S5 30.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 2004-2018

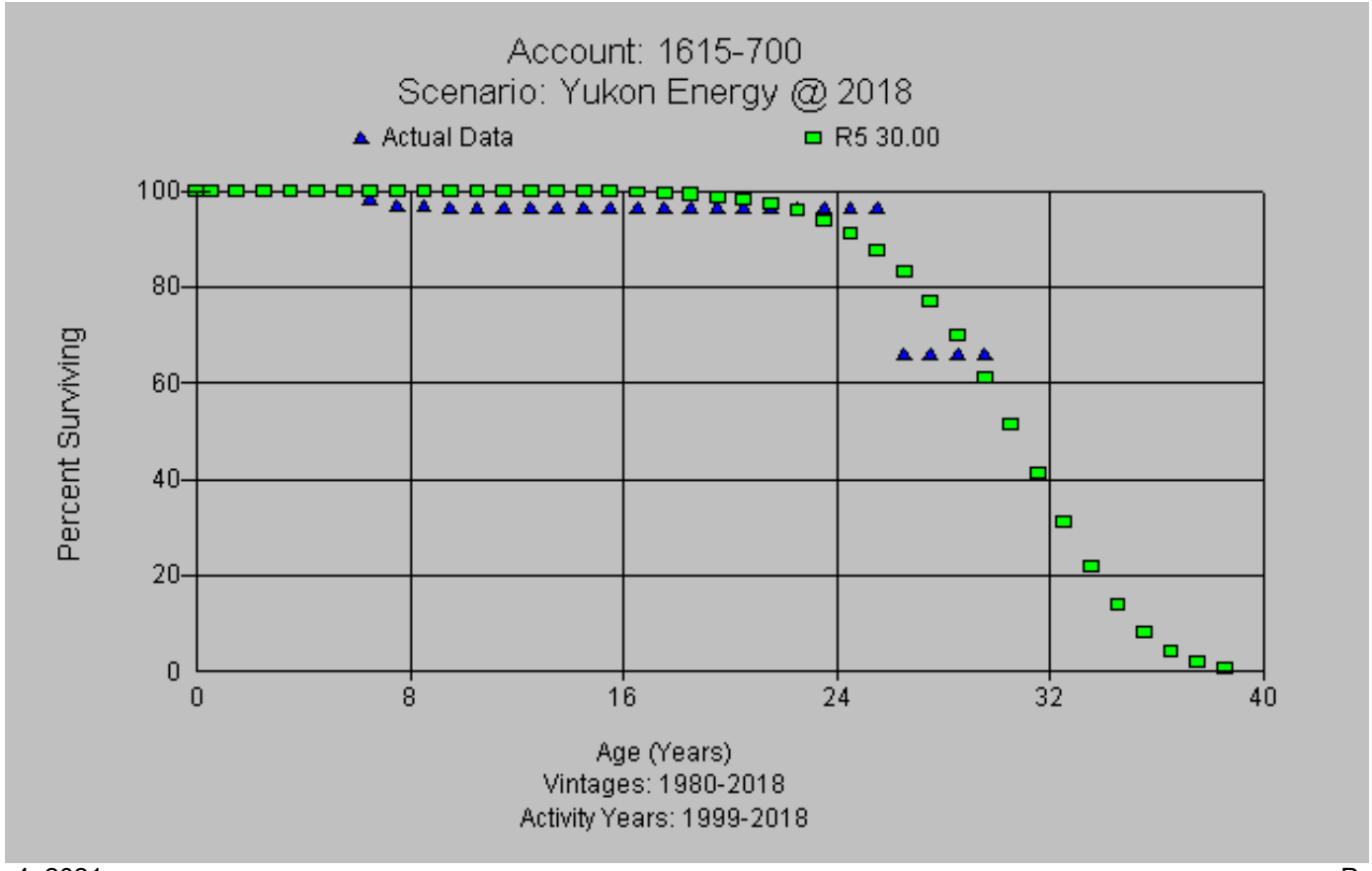
Observed Life Table

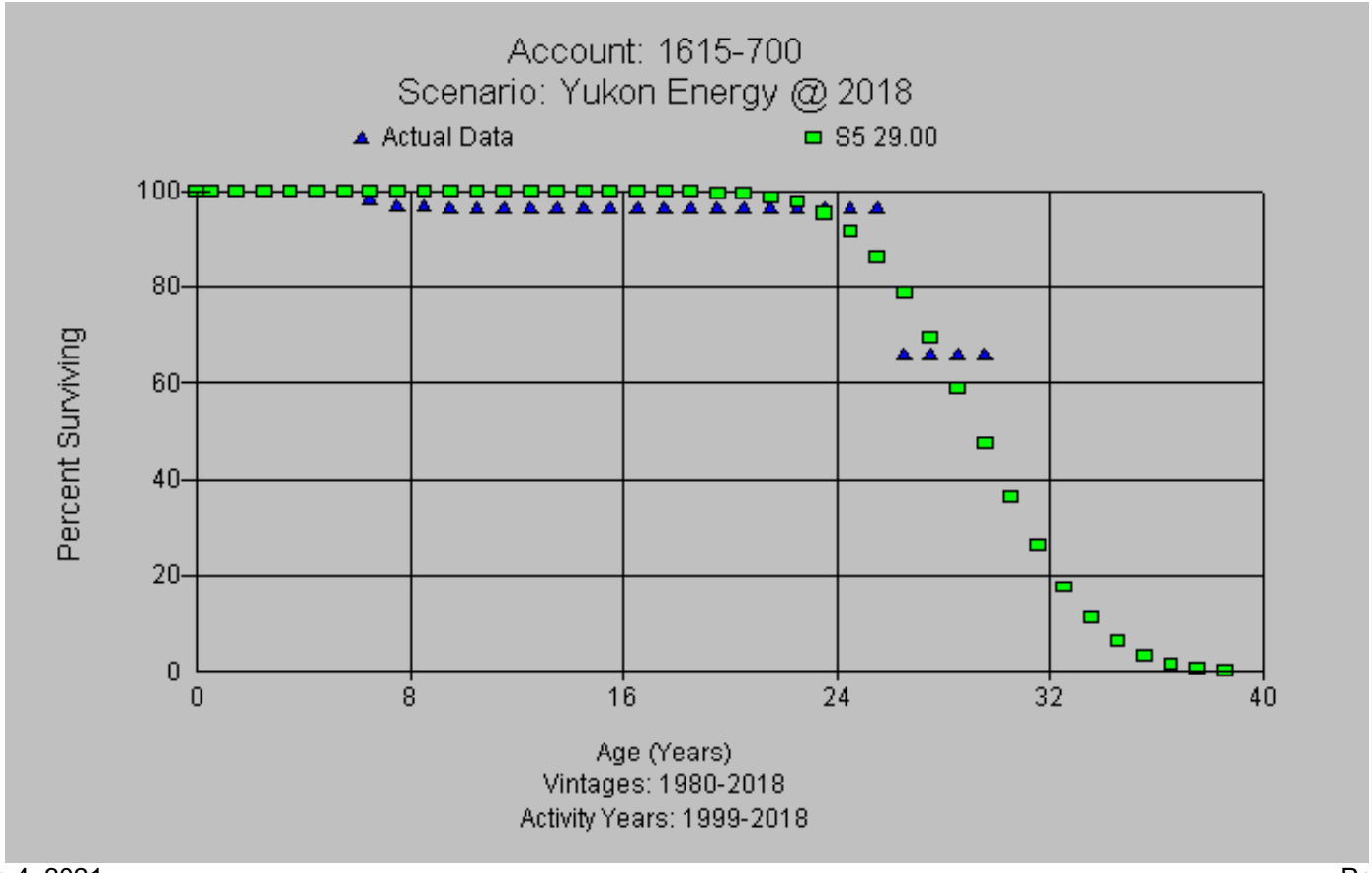
Scenario: Yukon Energy @ 2018
Account: 1615-700
Placement Band: 1980 - 2018 **Observation Band:** 2004 - 2018

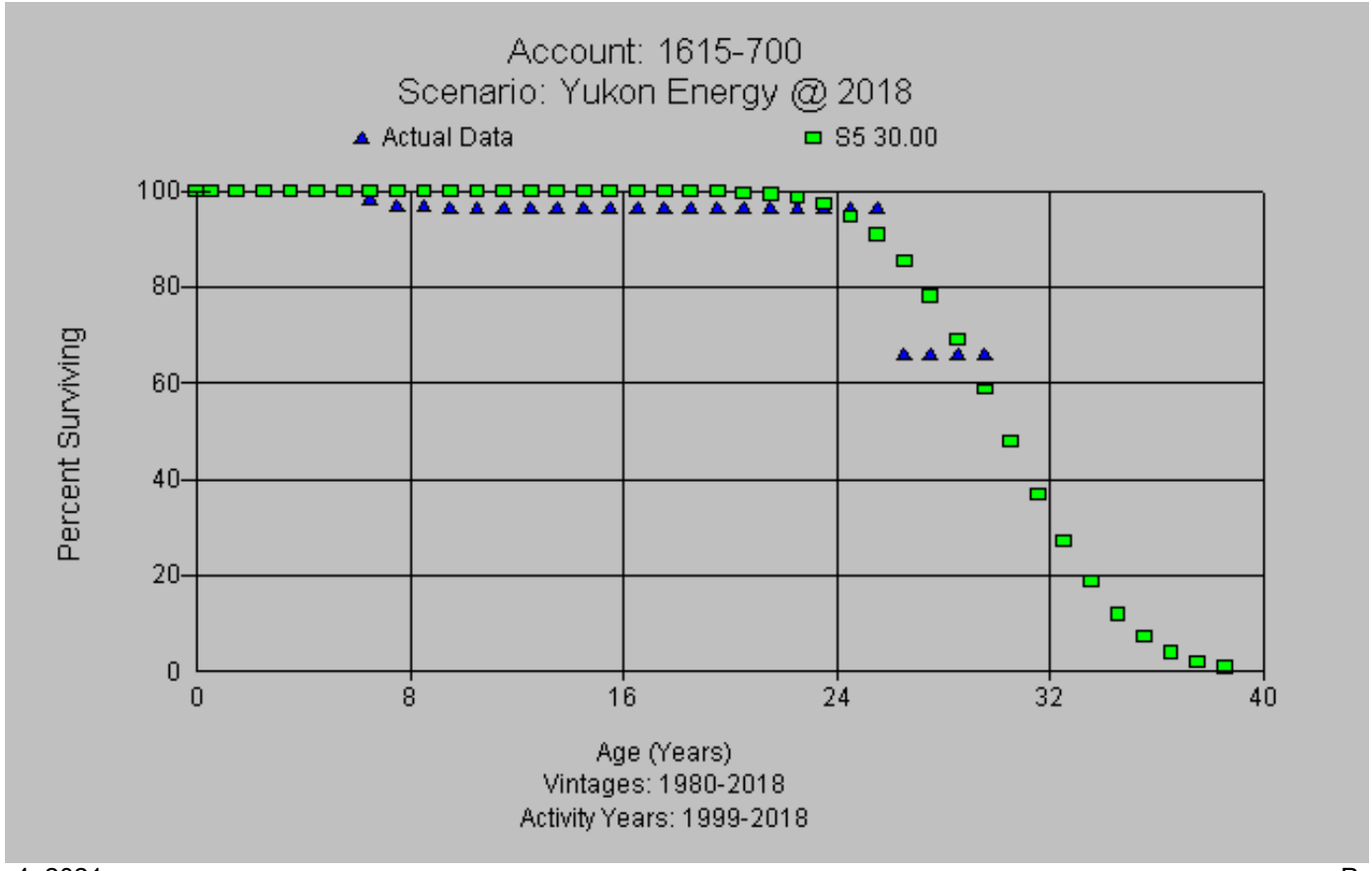
Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	10,158,484.37	0.00	0.00000	1.00000	100.00
0.5	10,112,467.28	0.00	0.00000	1.00000	100.00
1.5	10,091,835.50	0.00	0.00000	1.00000	100.00
2.5	9,425,719.05	0.00	0.00000	1.00000	100.00
3.5	9,346,677.84	0.00	0.00000	1.00000	100.00
4.5	9,323,280.27	0.00	0.00000	1.00000	100.00
5.5	9,933,800.70	26,931.00	0.00271	0.99729	100.00
6.5	8,770,441.84	0.00	0.00000	1.00000	99.73
7.5	2,515,787.59	0.00	0.00000	1.00000	99.73
8.5	1,791,101.04	0.00	0.00000	1.00000	99.73
9.5	1,705,719.93	0.00	0.00000	1.00000	99.73
10.5	1,629,209.35	0.00	0.00000	1.00000	99.73
11.5	1,428,044.89	0.00	0.00000	1.00000	99.73
12.5	1,422,991.62	0.00	0.00000	1.00000	99.73
13.5	1,359,227.58	0.00	0.00000	1.00000	99.73
14.5	1,359,227.58	0.00	0.00000	1.00000	99.73
15.5	1,323,622.95	0.00	0.00000	1.00000	99.73
16.5	1,110,981.21	0.00	0.00000	1.00000	99.73
17.5	1,070,730.43	0.00	0.00000	1.00000	99.73
18.5	930,993.96	0.00	0.00000	1.00000	99.73
19.5	930,993.96	0.00	0.00000	1.00000	99.73
20.5	0.00	0.00	0.00000	1.00000	99.73
21.5	0.00	0.00	0.00000	1.00000	
22.5	0.00	0.00	0.00000	1.00000	
23.5	73,929.28	0.00	0.00000	1.00000	
24.5	73,929.28	0.00	0.00000	1.00000	
25.5	73,929.28	23,481.52	0.31762	0.68238	
26.5	50,447.76	0.00	0.00000	1.00000	
27.5	50,447.76	0.00	0.00000	1.00000	
28.5	50,447.76	0.00	0.00000	1.00000	
29.5	50,447.76	50,447.76	1.00000	0.00000	
30.5	0.00	0.00	0.00000	1.00000	


Account: 1615-700
Scenario: Yukon Energy @ 2018
Actual Data
R2 30.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1980-2018
Activity Years: 1999-2018


Account: 1615-700
Scenario: Yukon Energy @ 2018
Actual Data
R5 29.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1980-2018
Activity Years: 1999-2018


Account: 1615-700
Scenario: Yukon Energy @ 2018
Actual Data
R5 30.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1980-2018
Activity Years: 1999-2018

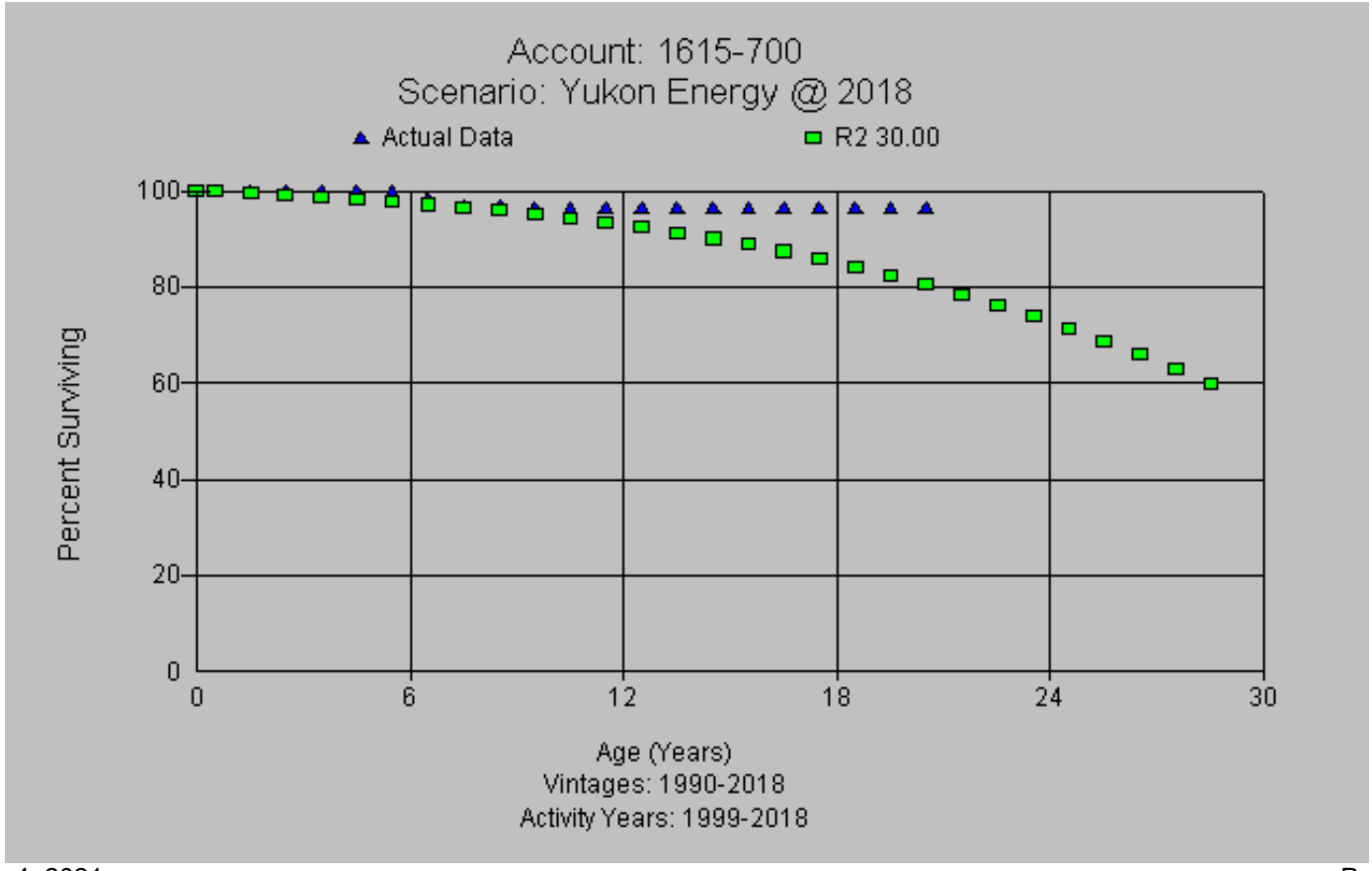

Account: 1615-700
Scenario: Yukon Energy @ 2018
Actual Data
S5 29.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1980-2018
Activity Years: 1999-2018

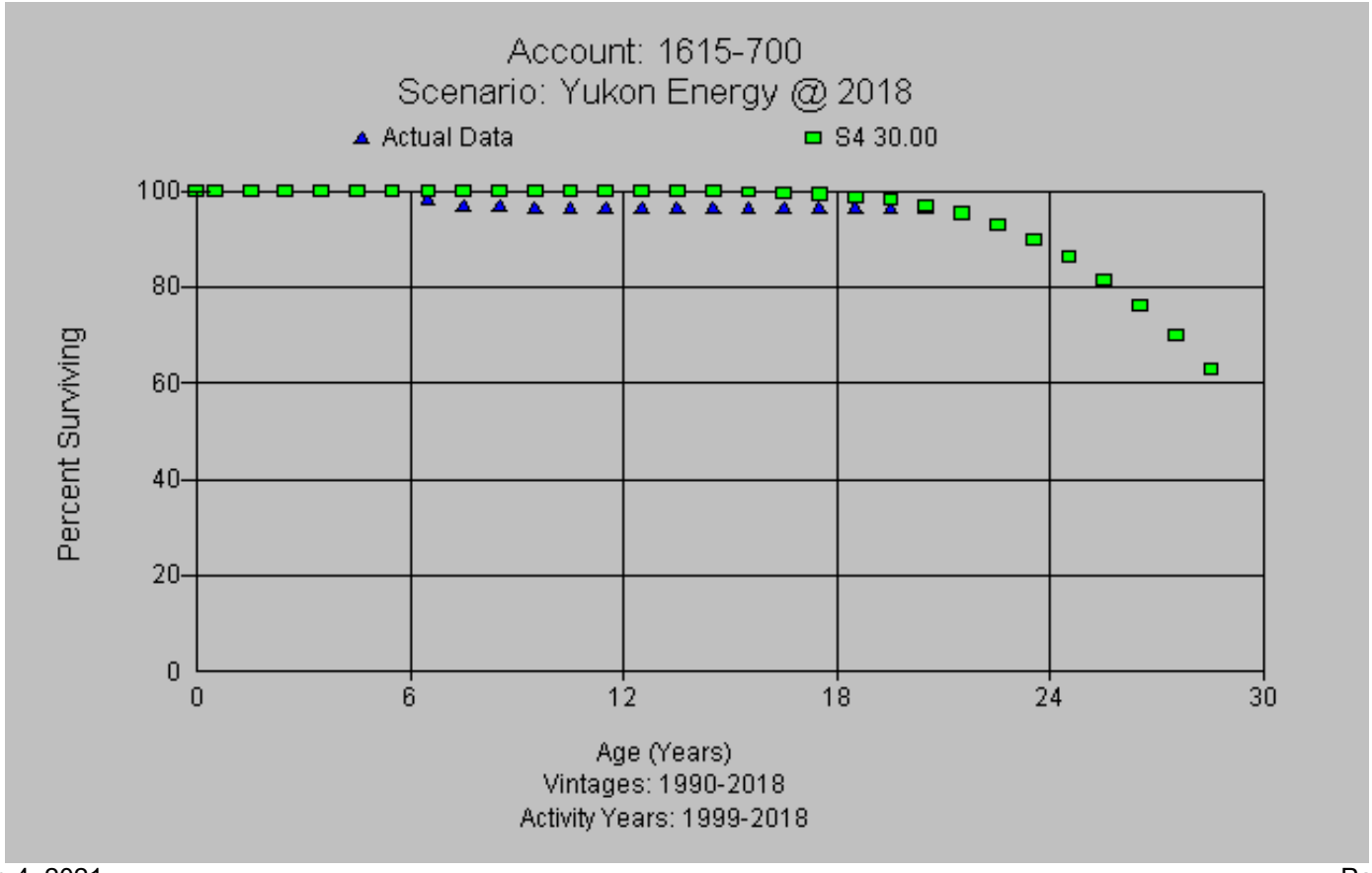

Account: 1615-700
Scenario: Yukon Energy @ 2018
Actual Data
S5 30.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1980-2018
Activity Years: 1999-2018

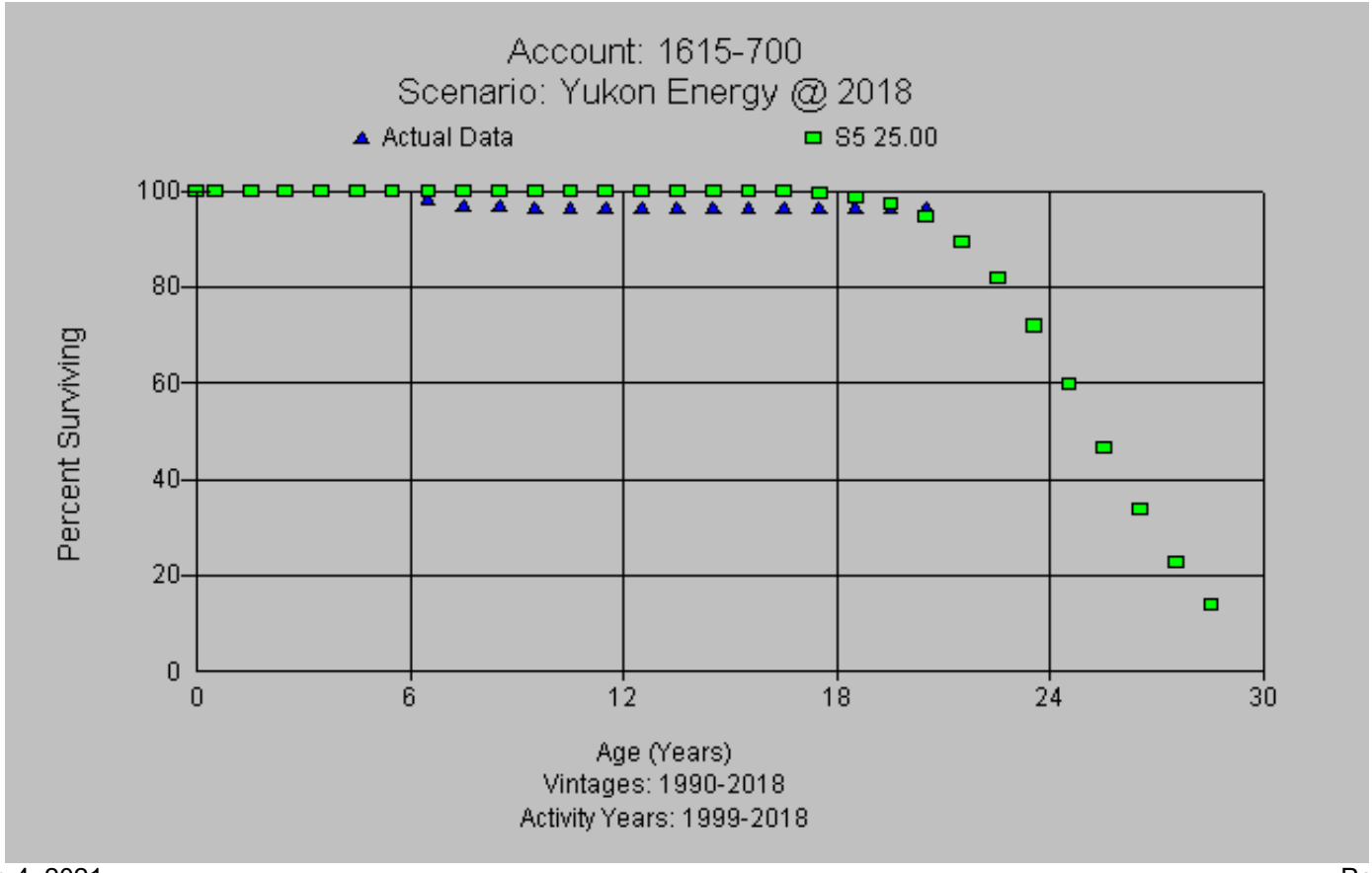
Observed Life Table

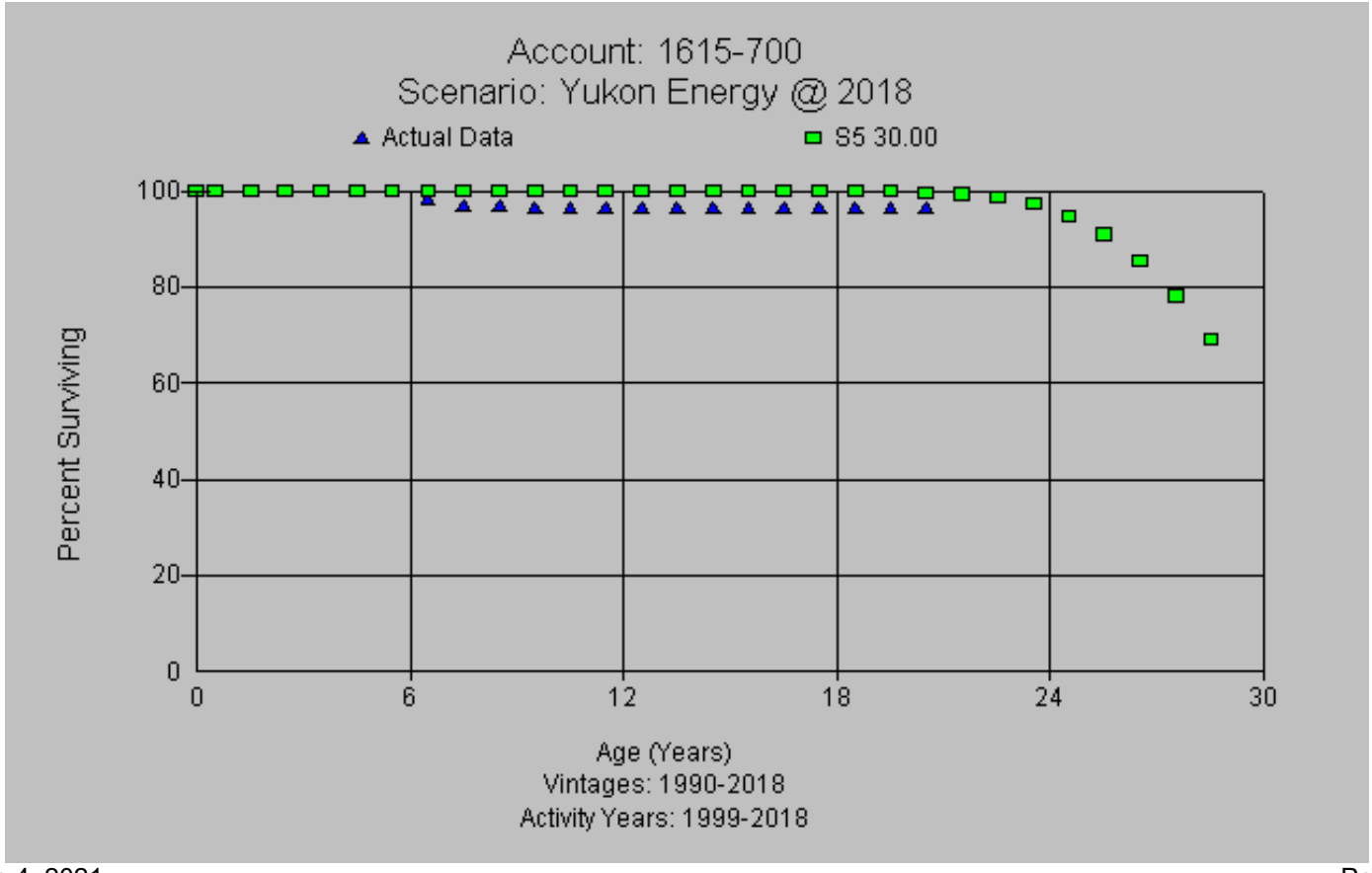
Scenario: Yukon Energy @ 2018
Account: 1615-700
Placement Band: 1980 - 2018 **Observation Band:** 1999 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	10,586,717.99	0.00	0.00000	1.00000	100.00
0.5	11,436,954.23	864.00	0.00008	0.99992	100.00
1.5	11,212,259.71	9,443.00	0.00084	0.99916	99.99
2.5	10,496,449.48	0.00	0.00000	1.00000	99.91
3.5	10,277,671.80	0.00	0.00000	1.00000	99.91
4.5	10,254,274.23	0.00	0.00000	1.00000	99.91
5.5	10,044,656.70	137,787.00	0.01372	0.98628	99.91
6.5	8,902,581.84	132,140.00	0.01484	0.98516	98.54
7.5	2,518,402.59	2,615.00	0.00104	0.99896	97.08
8.5	1,797,507.04	6,406.00	0.00356	0.99644	96.97
9.5	1,705,719.93	0.00	0.00000	1.00000	96.63
10.5	1,629,209.35	0.00	0.00000	1.00000	96.63
11.5	1,428,044.89	0.00	0.00000	1.00000	96.63
12.5	1,422,991.62	0.00	0.00000	1.00000	96.63
13.5	1,359,227.58	0.00	0.00000	1.00000	96.63
14.5	1,359,227.58	0.00	0.00000	1.00000	96.63
15.5	1,323,622.95	0.00	0.00000	1.00000	96.63
16.5	1,110,981.21	0.00	0.00000	1.00000	96.63
17.5	1,070,730.43	0.00	0.00000	1.00000	96.63
18.5	1,004,923.24	0.00	0.00000	1.00000	96.63
19.5	1,004,923.24	0.00	0.00000	1.00000	96.63
20.5	73,929.28	0.00	0.00000	1.00000	96.63
21.5	73,929.28	0.00	0.00000	1.00000	96.63
22.5	73,929.28	0.00	0.00000	1.00000	96.63
23.5	73,929.28	0.00	0.00000	1.00000	96.63
24.5	73,929.28	0.00	0.00000	1.00000	96.63
25.5	73,929.28	23,481.52	0.31762	0.68238	96.63
26.5	50,447.76	0.00	0.00000	1.00000	65.94
27.5	50,447.76	0.00	0.00000	1.00000	65.94
28.5	50,447.76	0.00	0.00000	1.00000	65.94
29.5	50,447.76	50,447.76	1.00000	0.00000	65.94
30.5	0.00	0.00	0.00000	1.00000	0.00


Account: 1615-700
Scenario: Yukon Energy @ 2018
Actual Data
R2 30.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1990-2018
Activity Years: 1999-2018


Account: 1615-700
Scenario: Yukon Energy @ 2018
Actual Data
S4 30.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1990-2018
Activity Years: 1999-2018


Account: 1615-700
Scenario: Yukon Energy @ 2018
Actual Data
S5 25.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1990-2018
Activity Years: 1999-2018


Account: 1615-700
Scenario: Yukon Energy @ 2018
Actual Data
S5 30.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1990-2018
Activity Years: 1999-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1615-700
Placement Band: 1990 - 2018 **Observation Band:** 1999 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	10,586,717.99	0.00	0.00000	1.00000	100.00
0.5	11,436,954.23	864.00	0.00008	0.99992	100.00
1.5	11,212,259.71	9,443.00	0.00084	0.99916	99.99
2.5	10,496,449.48	0.00	0.00000	1.00000	99.91
3.5	10,277,671.80	0.00	0.00000	1.00000	99.91
4.5	10,254,274.23	0.00	0.00000	1.00000	99.91
5.5	10,044,656.70	137,787.00	0.01372	0.98628	99.91
6.5	8,902,581.84	132,140.00	0.01484	0.98516	98.54
7.5	2,518,402.59	2,615.00	0.00104	0.99896	97.08
8.5	1,797,507.04	6,406.00	0.00356	0.99644	96.97
9.5	1,705,719.93	0.00	0.00000	1.00000	96.63
10.5	1,629,209.35	0.00	0.00000	1.00000	96.63
11.5	1,428,044.89	0.00	0.00000	1.00000	96.63
12.5	1,422,991.62	0.00	0.00000	1.00000	96.63
13.5	1,359,227.58	0.00	0.00000	1.00000	96.63
14.5	1,359,227.58	0.00	0.00000	1.00000	96.63
15.5	1,323,622.95	0.00	0.00000	1.00000	96.63
16.5	1,110,981.21	0.00	0.00000	1.00000	96.63
17.5	1,070,730.43	0.00	0.00000	1.00000	96.63
18.5	930,993.96	0.00	0.00000	1.00000	96.63
19.5	930,993.96	0.00	0.00000	1.00000	96.63
20.5	0.00	0.00	0.00000	1.00000	96.63

Actuarial Life Analysis

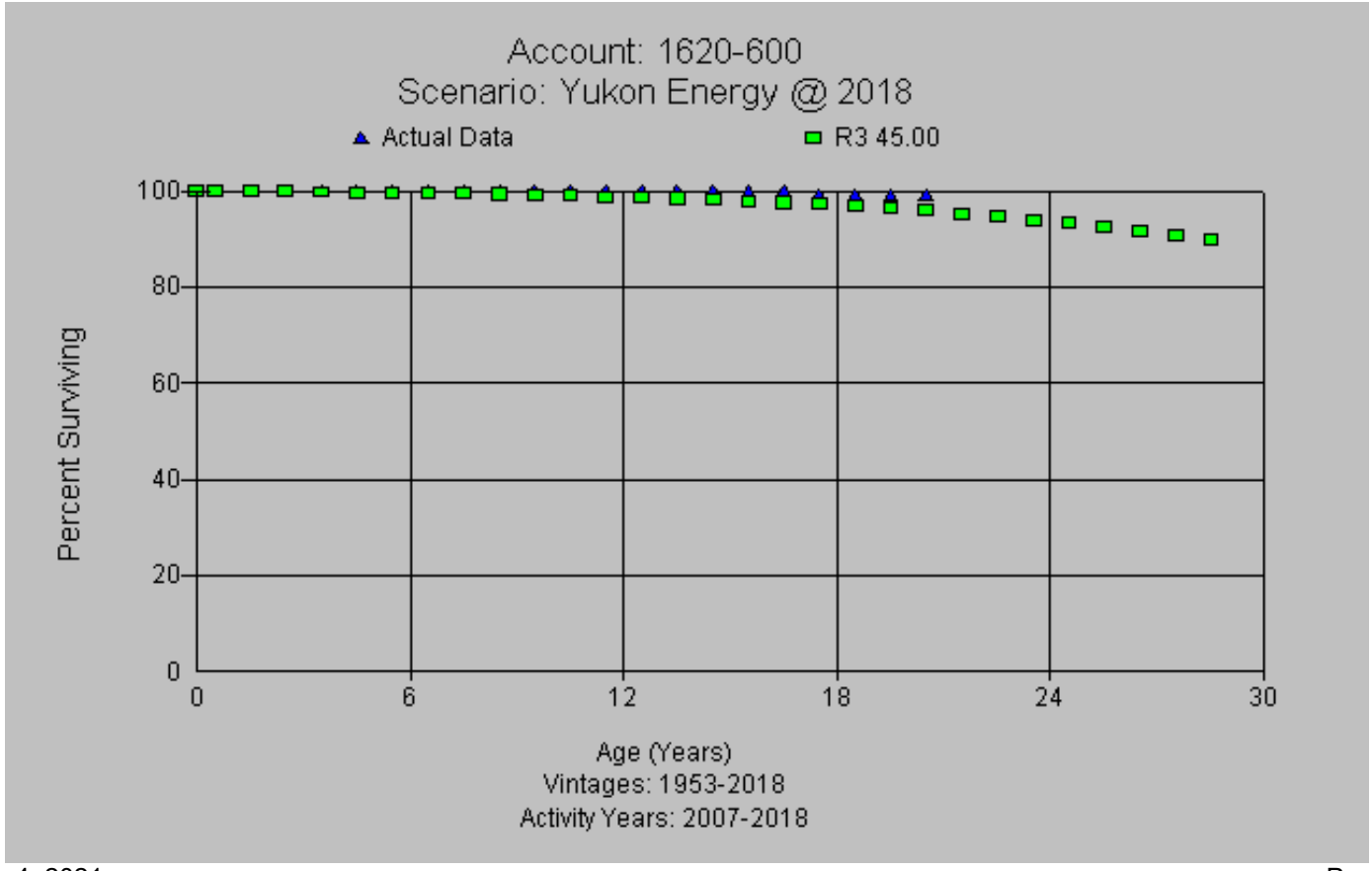
Account: 1615-700
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2003
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1999 -2003	21.5	0.00	0.00033160	SQ	6.01
2000 -2004		1.00			
2001 -2005		1.00			
2002 -2006	24.5	68.24	0.01776600	SQ	24.39
2003 -2007	25.5	68.24	0.02535341	S6	26.24
2004 -2008	26.5	68.24	0.04308835	S5	27.71
2005 -2009	27.5	68.24	0.06309002	S5	28.00
2006 -2010	28.5	0.00	0.19152124	S6	26.97
2007 -2011	29.5	0.00	0.00000000	SQ	28.20
2008 -2012	30.5	0.00	0.00000000	SQ	28.20
2009 -2013	31.5	0.00	0.00000000	SQ	28.20
2010 -2014	32.5	0.00	0.76148994	S6	26.46
2011 -2015	33.5	94.13	0.01661515	R0.5	136.62
2012 -2016	34.5	97.60	0.00317392	R1	233.77
2013 -2017	35.5	99.63	0.00014878	R3	163.56
2014 -2018	36.5	99.68	0.00011077	R3	183.23

Actuarial Life Analysis

Account: 1615-700
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1999 -2018	38.5	0.00	0.28882275	S6	28.04
2004 -2018	38.5	0.00	0.21049874	S6	28.72
2009 -2018	38.5	0.00	0.00023064	SQ	29.97
2014 -2018	38.5	99.68	0.00012148	R3	192.06


Account: 1620-600
Scenario: Yukon Energy @ 2018
Actual Data
R3 45.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1953-2018
Activity Years: 2007-2018

Actuarial Life Analysis

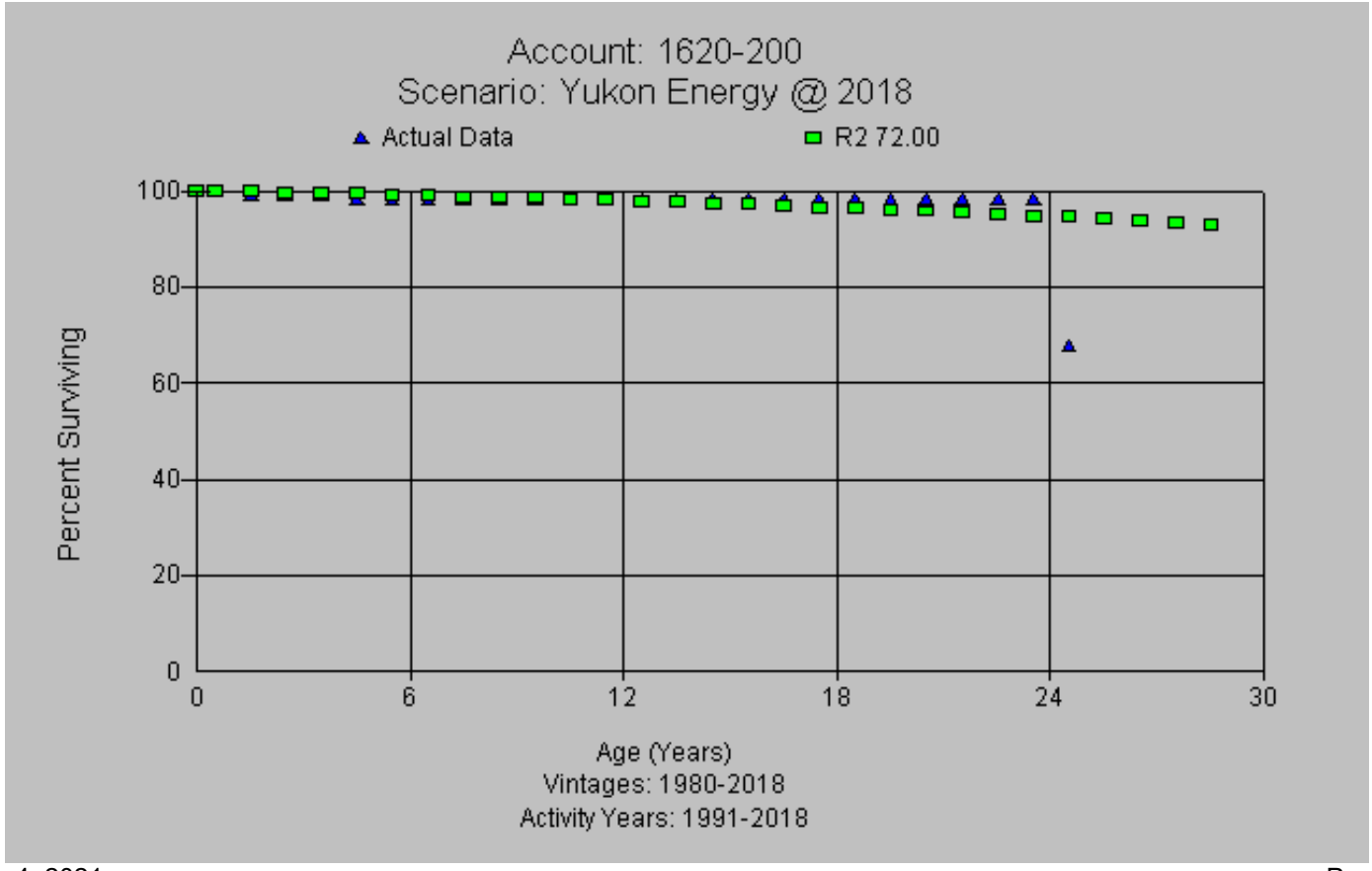
Account: 1620-600
Scenario: Yukon Energy @ 2018
Placement Band: 1953 - 2011
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

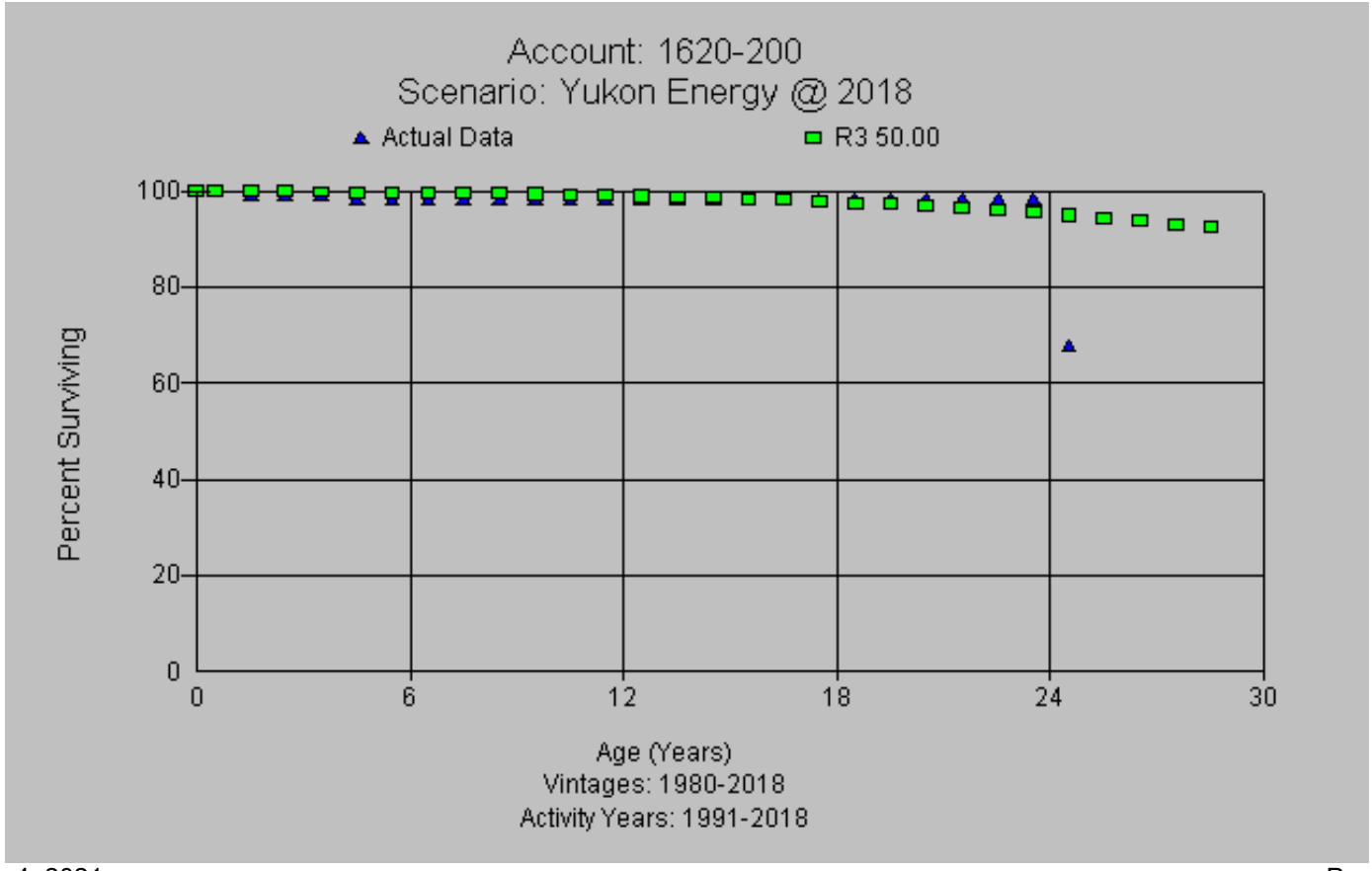
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
2007 -2011	40.5	0.00	0.00000000	SQ	36.10
2008 -2012		1.00			
2009 -2013		1.00			
2010 -2014		1.00			
2011 -2015	44.5	99.19	0.00037616	R3	155.36
2012 -2016	45.5	99.21	0.00037901	R3	159.87
2013 -2017	46.5	99.21	0.00040480	R3	162.23
2014 -2018	47.5	99.36	0.00026145	R3	184.85

Actuarial Life Analysis

Account: 1620-600
Scenario: Yukon Energy @ 2018
Placement Band: 1953 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
2007 -2018	60.5	0.00	0.00131072	SQ	48.84
2012 -2018	60.5	99.36	0.00050372	R3	221.11
2017 -2018		1.00			


Account: 1620-200
Scenario: Yukon Energy @ 2018
Actual Data
R2 72.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1991-2018


Account: 1620-200
Scenario: Yukon Energy @ 2018
Actual Data
R3 50.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1991-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1620-200
Placement Band: 1980 - 2018 **Observation Band:** 1991 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	1,577,615.90	0.00	0.00000	1.00000	100.00
0.5	1,575,615.90	13,264.20	0.00842	0.99158	100.00
1.5	1,562,351.70	0.00	0.00000	1.00000	99.16
2.5	1,562,351.70	0.00	0.00000	1.00000	99.16
3.5	1,574,490.70	12,139.00	0.00771	0.99229	99.16
4.5	1,525,367.38	0.00	0.00000	1.00000	98.39
5.5	1,525,367.38	0.00	0.00000	1.00000	98.39
6.5	1,525,367.38	0.00	0.00000	1.00000	98.39
7.5	1,525,367.38	0.00	0.00000	1.00000	98.39
8.5	1,525,367.38	0.00	0.00000	1.00000	98.39
9.5	1,525,367.38	0.00	0.00000	1.00000	98.39
10.5	1,515,842.93	0.00	0.00000	1.00000	98.39
11.5	1,515,842.93	0.00	0.00000	1.00000	98.39
12.5	1,515,842.93	0.00	0.00000	1.00000	98.39
13.5	1,515,842.93	0.00	0.00000	1.00000	98.39
14.5	1,515,842.93	0.00	0.00000	1.00000	98.39
15.5	1,230,673.42	0.00	0.00000	1.00000	98.39
16.5	1,230,673.42	0.00	0.00000	1.00000	98.39
17.5	1,189,948.58	0.00	0.00000	1.00000	98.39
18.5	1,189,948.58	0.00	0.00000	1.00000	98.39
19.5	789,891.92	0.00	0.00000	1.00000	98.39
20.5	11,435.91	0.00	0.00000	1.00000	98.39
21.5	11,435.91	0.00	0.00000	1.00000	98.39
22.5	11,435.91	0.00	0.00000	1.00000	98.39
23.5	11,435.91	3,533.63	0.30899	0.69101	98.39
24.5	7,902.28	7,902.28	1.00000	0.00000	67.99
25.5	0.00	0.00	0.00000	1.00000	0.00

Actuarial Life Analysis

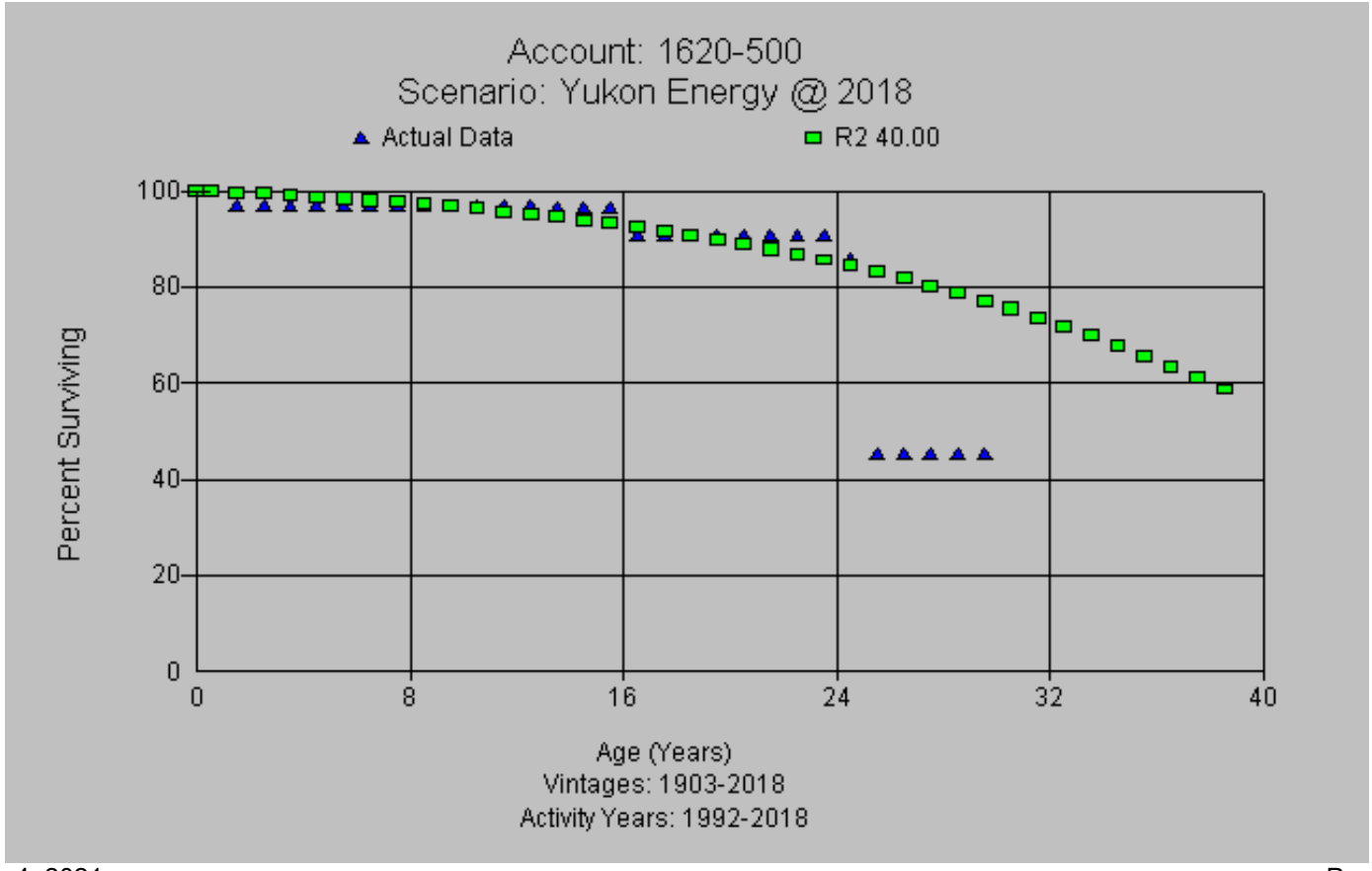
Account: 1620-200
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 1995
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

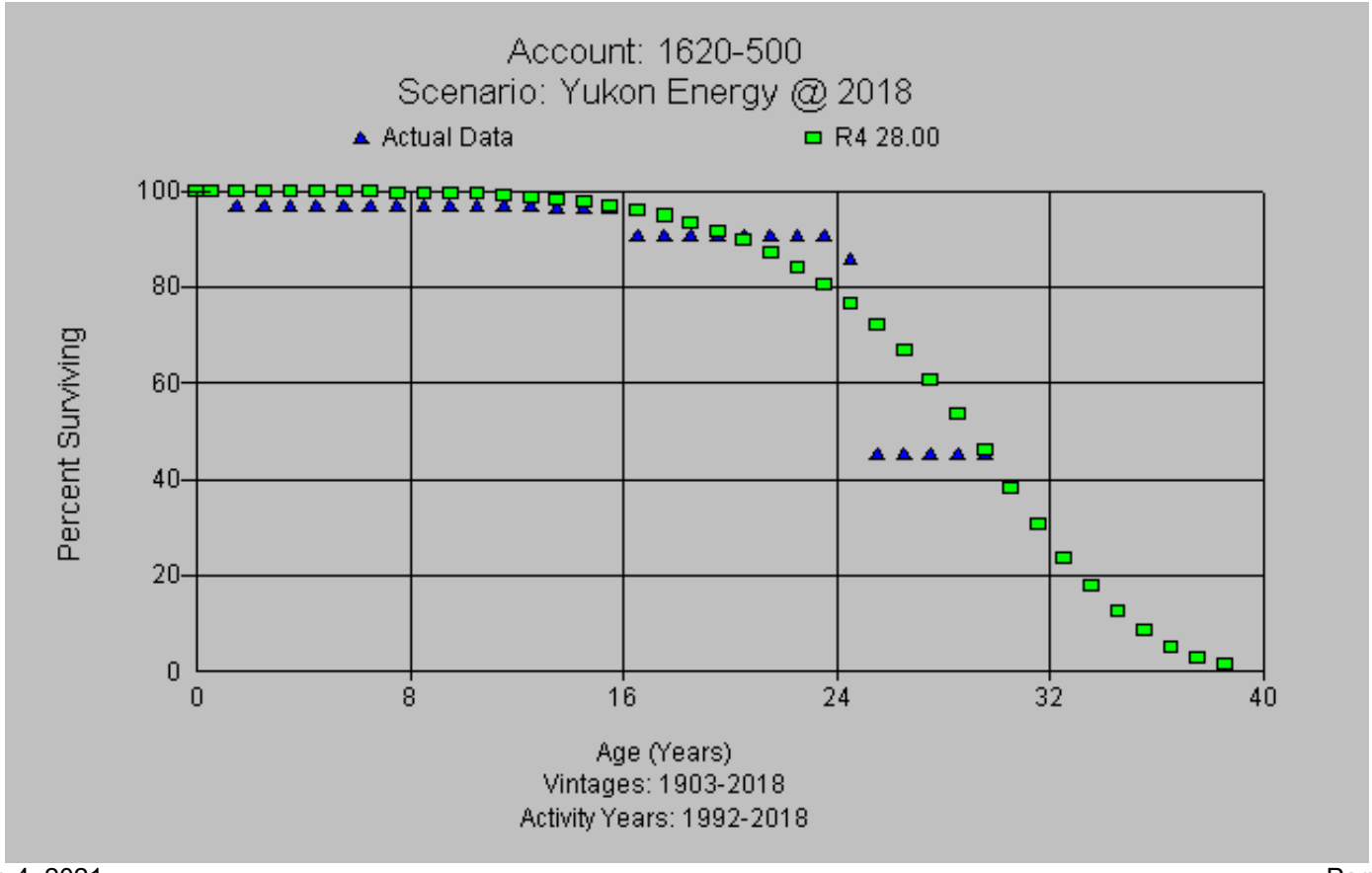
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1991 -1995	13.5	0.00	0.00000000	SQ	4.39
1992 -1996		1.00			
1993 -1997		1.00			
1994 -1998		1.00			
1995 -1999		1.00			
1996 -2000		1.00			
1997 -2001		1.00			
1998 -2002		1.00			
1999 -2003		1.00			
2000 -2004	22.5	69.10	0.02652489	SQ	22.39
2001 -2005	23.5	0.00	0.09548101	SQ	22.74
2002 -2006	24.5	0.00	0.09548101	SQ	22.74
2003 -2007	25.5	0.00	0.09548101	SQ	22.74
2004 -2008	26.5	0.00	0.09548101	SQ	22.74
2005 -2009	27.5	0.00	1.34187156	R0.5	14.52
2006 -2010	28.5	61.24	1.47069166	L0	20.14
2007 -2011	29.5	61.24	1.52449946	L0	20.85
2008 -2012	30.5	61.24	1.57829950	L0	21.56
2009 -2013		61.24			
2010 -2014		1.00			
2011 -2015		1.00			
2012 -2016		1.00			
2013 -2017		1.00			
2014 -2018		1.00			

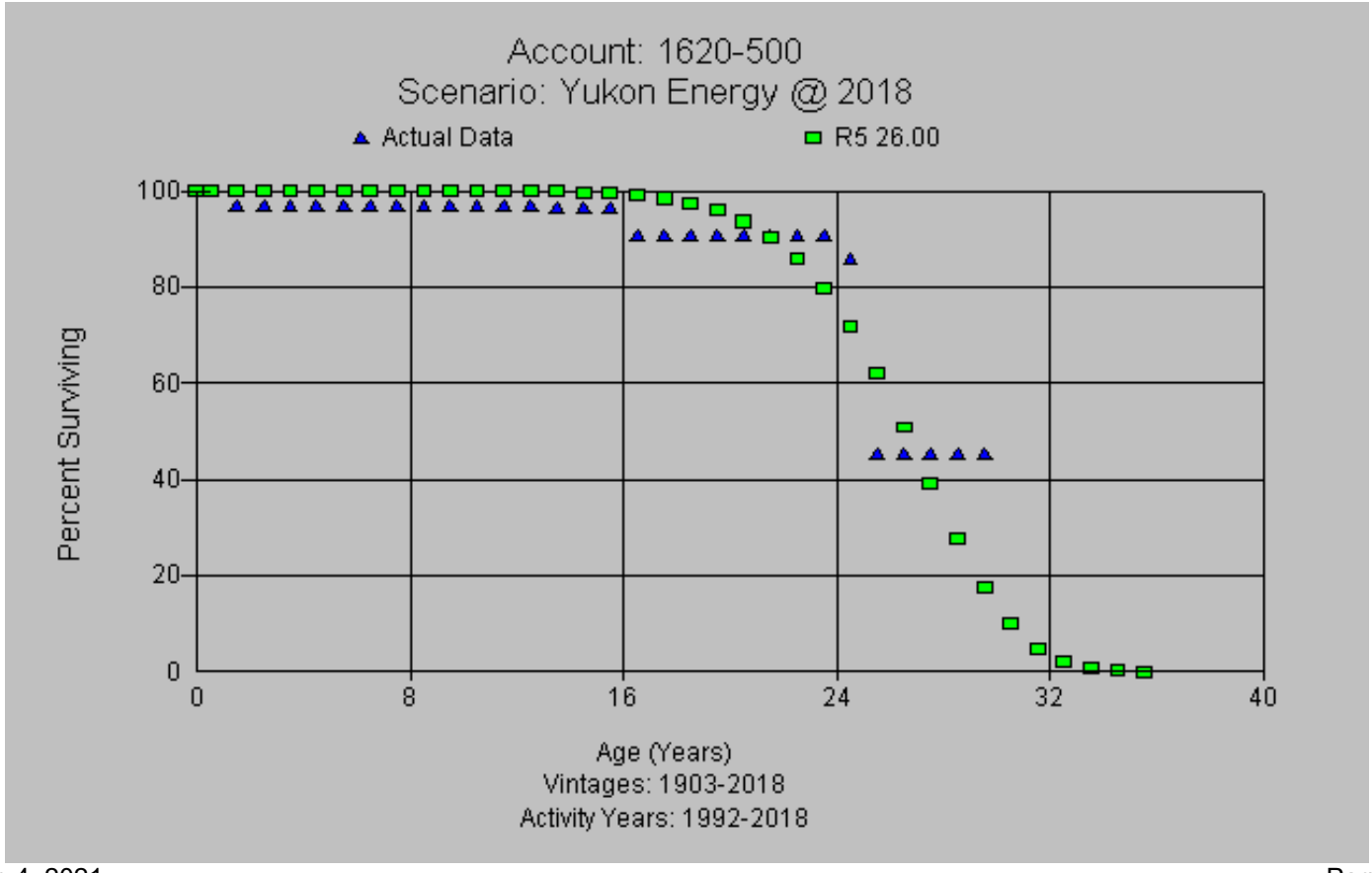
Actuarial Life Analysis

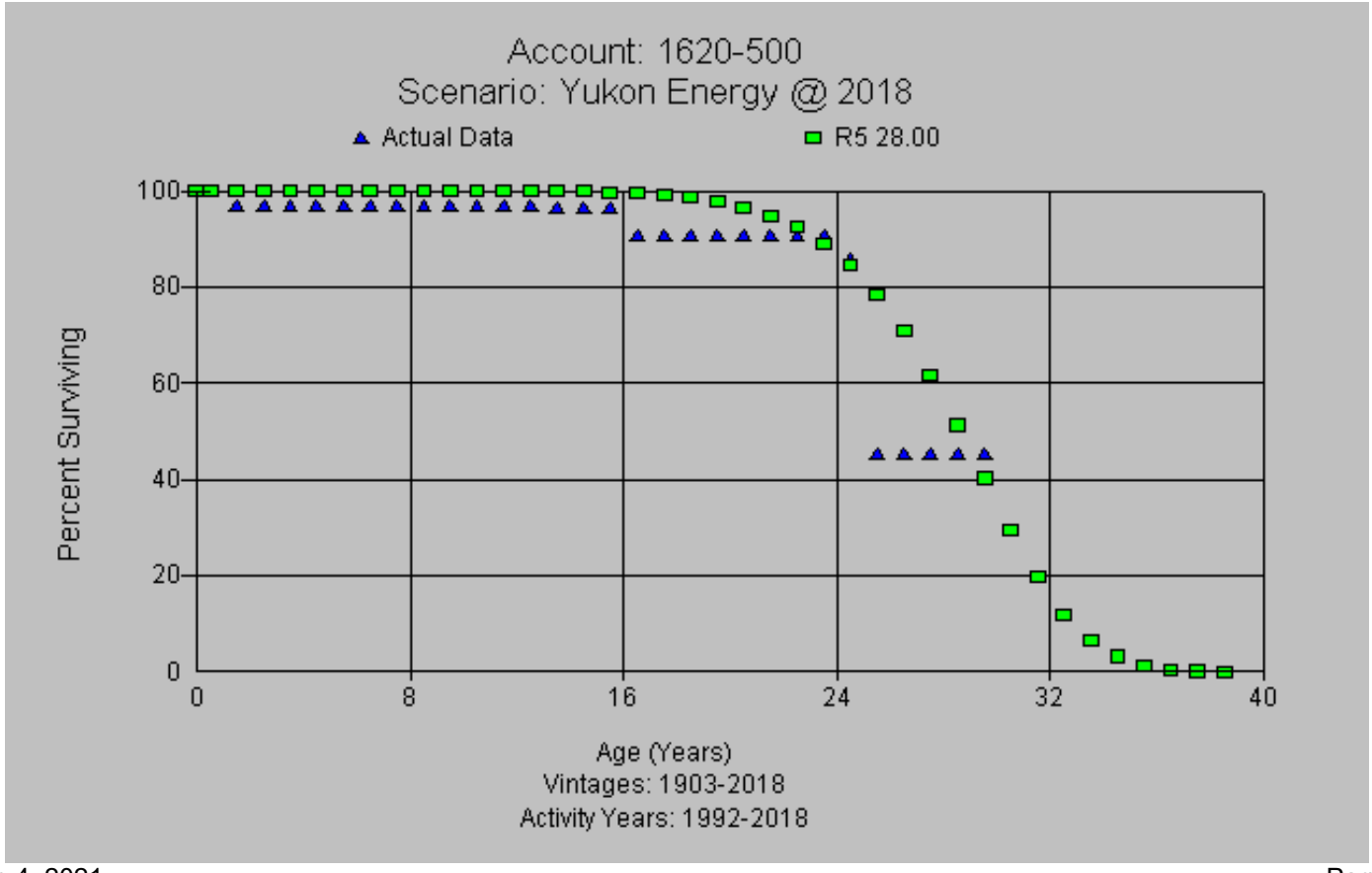
Account: 1620-200
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1991 -2018	38.5	0.00	0.03288727	SQ	24.38
1996 -2018	38.5	0.00	0.10072194	SQ	24.54
2001 -2018	38.5	0.00	0.32027529	S6	23.95
2006 -2018	38.5	81.37	0.47058170	R0.5	45.82
2011 -2018		1.00			
2016 -2018		1.00			


Account: 1620-500
Scenario: Yukon Energy @ 2018
Actual Data
R2 40.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1903-2018
Activity Years: 1992-2018


Account: 1620-500
Scenario: Yukon Energy @ 2018
Actual Data
R4 28.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1903-2018
Activity Years: 1992-2018


Account: 1620-500
Scenario: Yukon Energy @ 2018
Actual Data
R5 26.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1903-2018
Activity Years: 1992-2018


Account: 1620-500
Scenario: Yukon Energy @ 2018
Actual Data
R5 28.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1903-2018
Activity Years: 1992-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1620-500
Placement Band: 1903 - 2018 **Observation Band:** 1992 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	16,992,415.16	0.00	0.00000	1.00000	100.00
0.5	16,992,415.16	491,142.60	0.02890	0.97110	100.00
1.5	16,501,272.56	0.00	0.00000	1.00000	97.11
2.5	16,501,272.56	0.00	0.00000	1.00000	97.11
3.5	16,047,113.05	0.00	0.00000	1.00000	97.11
4.5	16,077,866.05	5,755.00	0.00036	0.99964	97.11
5.5	16,072,111.05	0.00	0.00000	1.00000	97.08
6.5	16,032,075.31	10,238.18	0.00064	0.99936	97.08
7.5	15,821,892.59	0.00	0.00000	1.00000	97.01
8.5	13,535,413.25	0.00	0.00000	1.00000	97.01
9.5	11,978,941.74	0.00	0.00000	1.00000	97.01
10.5	11,408,702.12	0.00	0.00000	1.00000	97.01
11.5	11,394,270.92	0.00	0.00000	1.00000	97.01
12.5	11,376,617.96	38,175.89	0.00336	0.99664	97.01
13.5	11,338,442.07	0.00	0.00000	1.00000	96.69
14.5	11,046,234.57	762.75	0.00007	0.99993	96.69
15.5	11,028,570.94	664,937.58	0.06029	0.93971	96.68
16.5	10,357,044.41	0.00	0.00000	1.00000	90.85
17.5	10,216,491.34	0.00	0.00000	1.00000	90.85
18.5	9,845,380.13	0.00	0.00000	1.00000	90.85
19.5	4,850,314.64	0.00	0.00000	1.00000	90.85
20.5	80,913.79	0.00	0.00000	1.00000	90.85
21.5	80,913.79	0.00	0.00000	1.00000	90.85
22.5	80,913.79	0.00	0.00000	1.00000	90.85
23.5	80,913.79	4,281.81	0.05292	0.94708	90.85
24.5	76,631.98	36,260.00	0.47317	0.52683	86.04
25.5	40,371.98	0.00	0.00000	1.00000	45.33
26.5	40,371.98	0.00	0.00000	1.00000	45.33
27.5	40,371.98	0.00	0.00000	1.00000	45.33
28.5	40,371.98	0.00	0.00000	1.00000	45.33
29.5	40,371.98	40,371.98	1.00000	0.00000	45.33
30.5	0.00	0.00	0.00000	1.00000	0.00
31.5	0.00	0.00	0.00000	1.00000	
32.5	0.00	0.00	0.00000	1.00000	
33.5	0.00	0.00	0.00000	1.00000	
34.5	0.00	0.00	0.00000	1.00000	
35.5	0.00	0.00	0.00000	1.00000	
36.5	0.00	0.00	0.00000	1.00000	
37.5	0.00	0.00	0.00000	1.00000	

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1620-500
Placement Band: 1903 - 2018 **Observation Band:** 1992 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
38.5	0.00	0.00	0.00000	1.00000	
39.5	0.00	0.00	0.00000	1.00000	
40.5	0.00	0.00	0.00000	1.00000	
41.5	0.00	0.00	0.00000	1.00000	
42.5	0.00	0.00	0.00000	1.00000	
43.5	0.00	0.00	0.00000	1.00000	
44.5	0.00	0.00	0.00000	1.00000	
45.5	0.00	0.00	0.00000	1.00000	
46.5	0.00	0.00	0.00000	1.00000	
88.5	5,591.97	0.00	0.00000	1.00000	
89.5	5,591.97	0.00	0.00000	1.00000	
90.5	5,591.97	0.00	0.00000	1.00000	
91.5	5,591.97	0.00	0.00000	1.00000	
92.5	5,591.97	0.00	0.00000	1.00000	
93.5	5,591.97	0.00	0.00000	1.00000	
94.5	5,591.97	0.00	0.00000	1.00000	
95.5	5,591.97	0.00	0.00000	1.00000	
96.5	5,591.97	0.00	0.00000	1.00000	
97.5	5,591.97	0.00	0.00000	1.00000	
98.5	5,591.97	0.00	0.00000	1.00000	
99.5	5,591.97	0.00	0.00000	1.00000	
100.5	5,591.97	0.00	0.00000	1.00000	
101.5	5,591.97	0.00	0.00000	1.00000	
102.5	5,591.97	0.00	0.00000	1.00000	
103.5	5,591.97	5,591.97	1.00000	0.00000	
104.5	0.00	0.00	0.00000	1.00000	

Actuarial Life Analysis

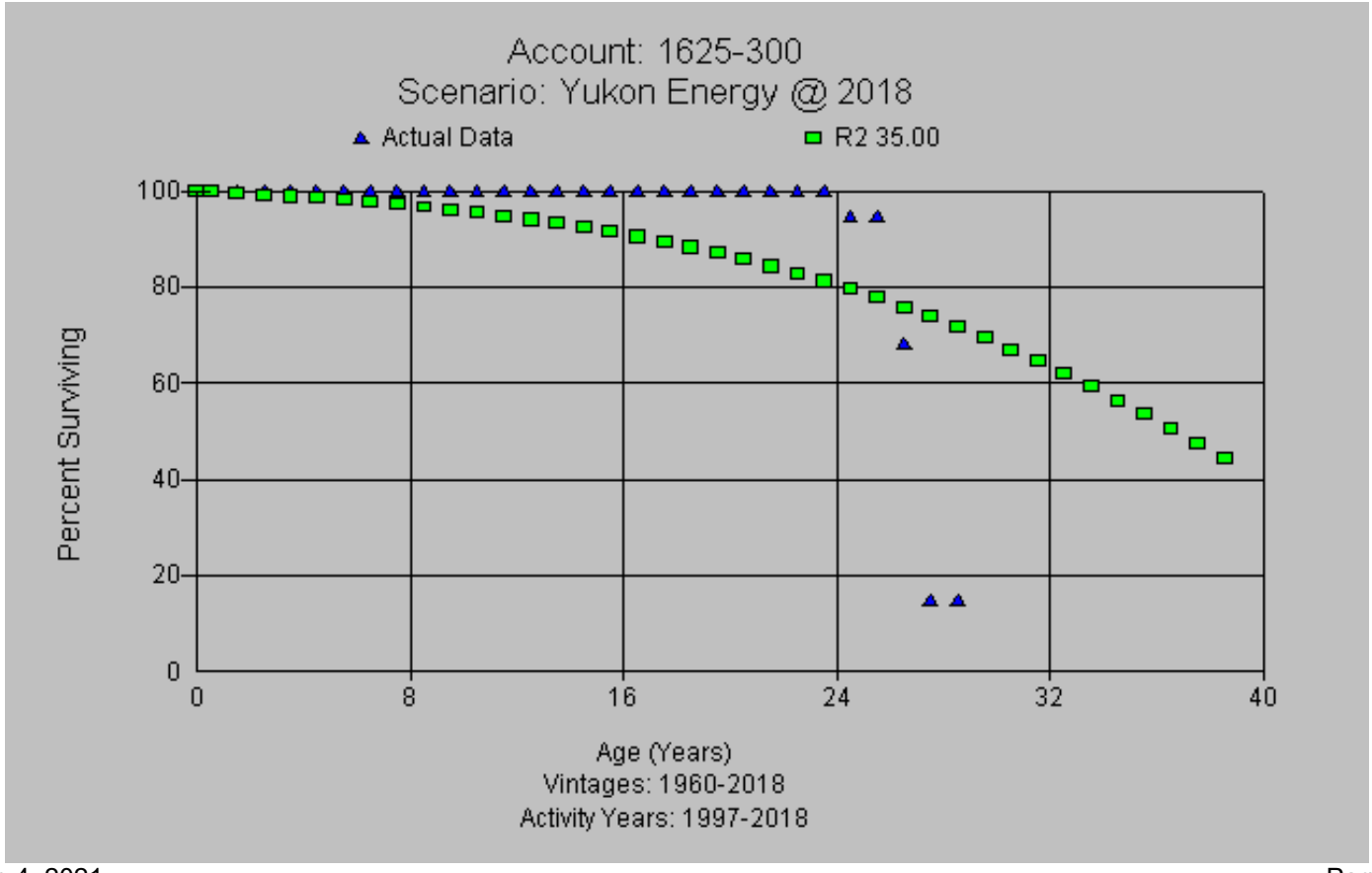
Account: 1620-500
Scenario: Yukon Energy @ 2018
Placement Band: 1903 - 1996
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

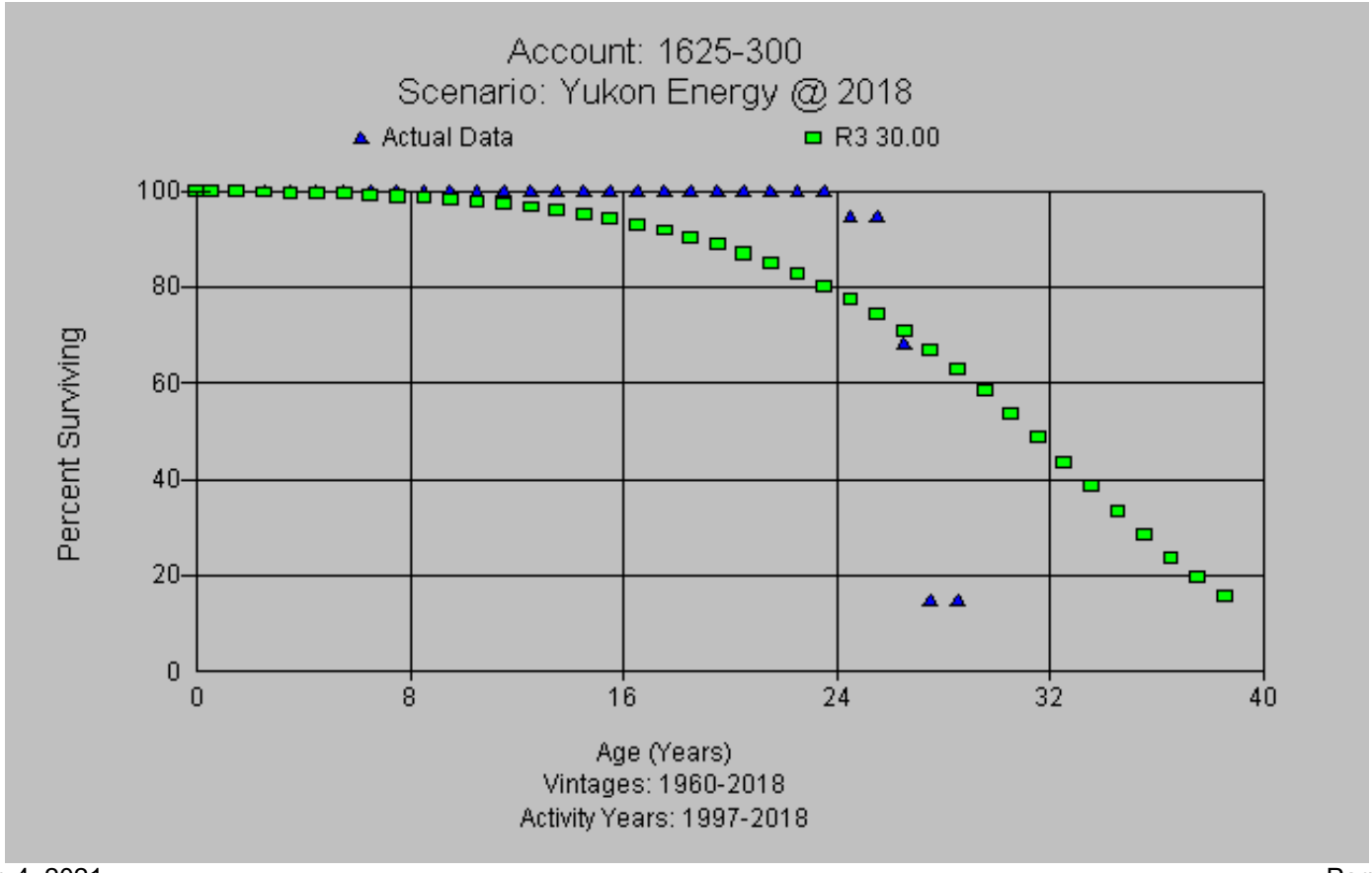
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1992 -1996	26.5	0.00	0.80498860	R3	18.06
1993 -1997	27.5	0.00	0.00000000	SQ	21.20
1994 -1998	28.5	0.00	0.00000000	SQ	21.20
1995 -1999	29.5	0.00	0.00000000	SQ	21.20
1996 -2000	30.5	0.00	0.00000000	SQ	13.20
1997 -2001	31.5	0.00	0.00000000	SQ	13.20
1998 -2002	32.5	0.00	0.00000000	SQ	13.20
1999 -2003	33.5	0.00	0.00000000	SQ	13.20
2000 -2004	34.5	0.00	0.00000000	SQ	13.20
2001 -2005	35.5	90.41	0.01705707	S1.5	62.28
2002 -2006	36.5	90.41	0.01810533	S1	71.78
2003 -2007	37.5	0.00	0.46166076	S6	36.39
2004 -2008	38.5	0.00	0.56130641	S6	36.00
2005 -2009	39.5	0.00	0.00000000	SQ	37.10
2006 -2010	40.5	0.00	0.00000000	SQ	30.20
2007 -2011	41.5	0.00	0.00000000	SQ	30.20
2008 -2012	42.5	0.00	1.12637979	R4	27.30
2009 -2013	43.5	0.00	1.12770668	R4	27.29
2010 -2014	44.5	0.00	1.01551197	R3	25.42
2011 -2015	45.5	77.46	0.49325094	R0.5	49.36
2012 -2016	46.5	54.58	2.70028670	L0	28.31
2013 -2017	47.5	92.25	0.01922855	R0.5	177.27
2014 -2018	48.5	91.10	0.02635143	R0.5	155.81

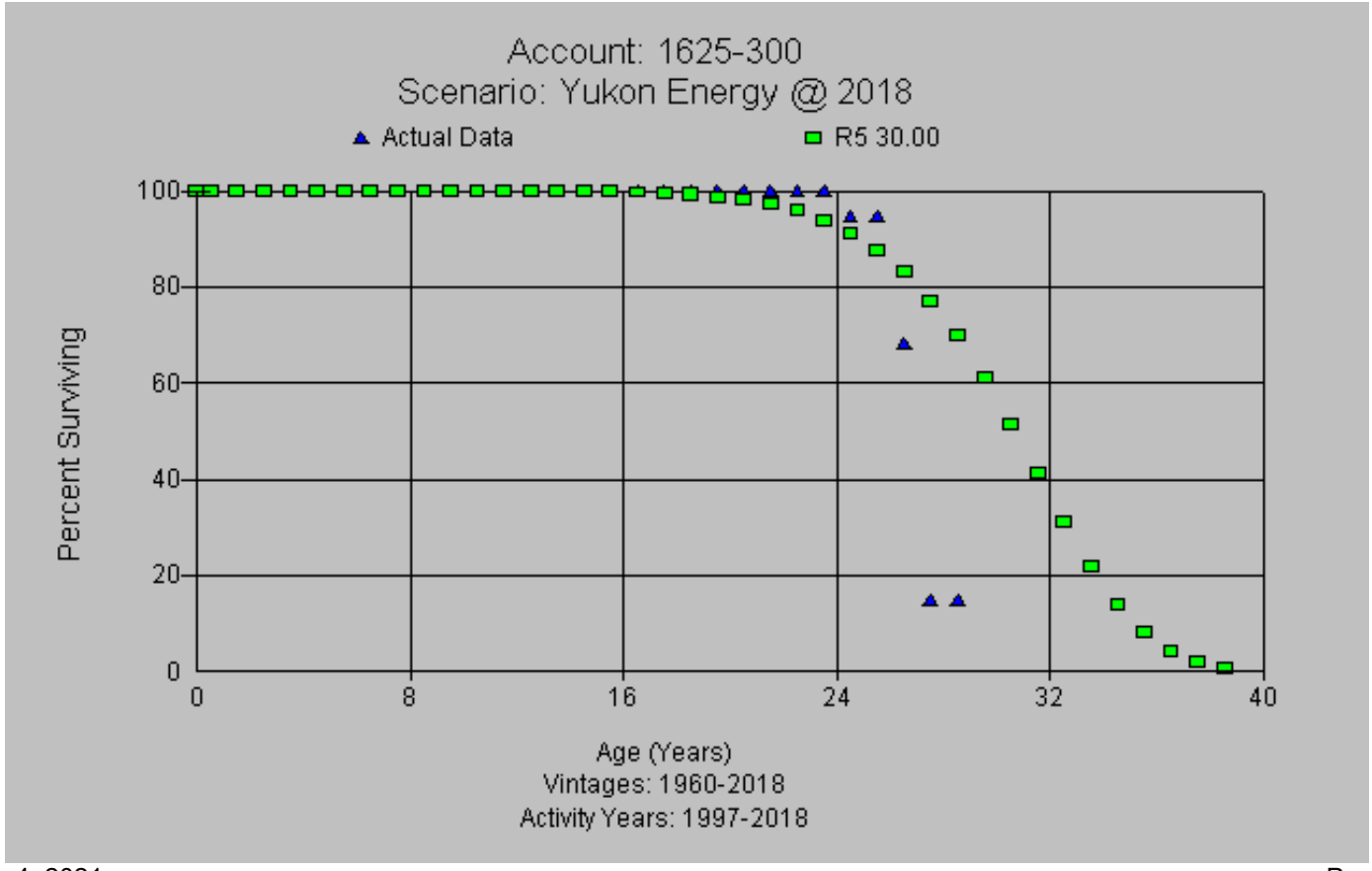
Actuarial Life Analysis

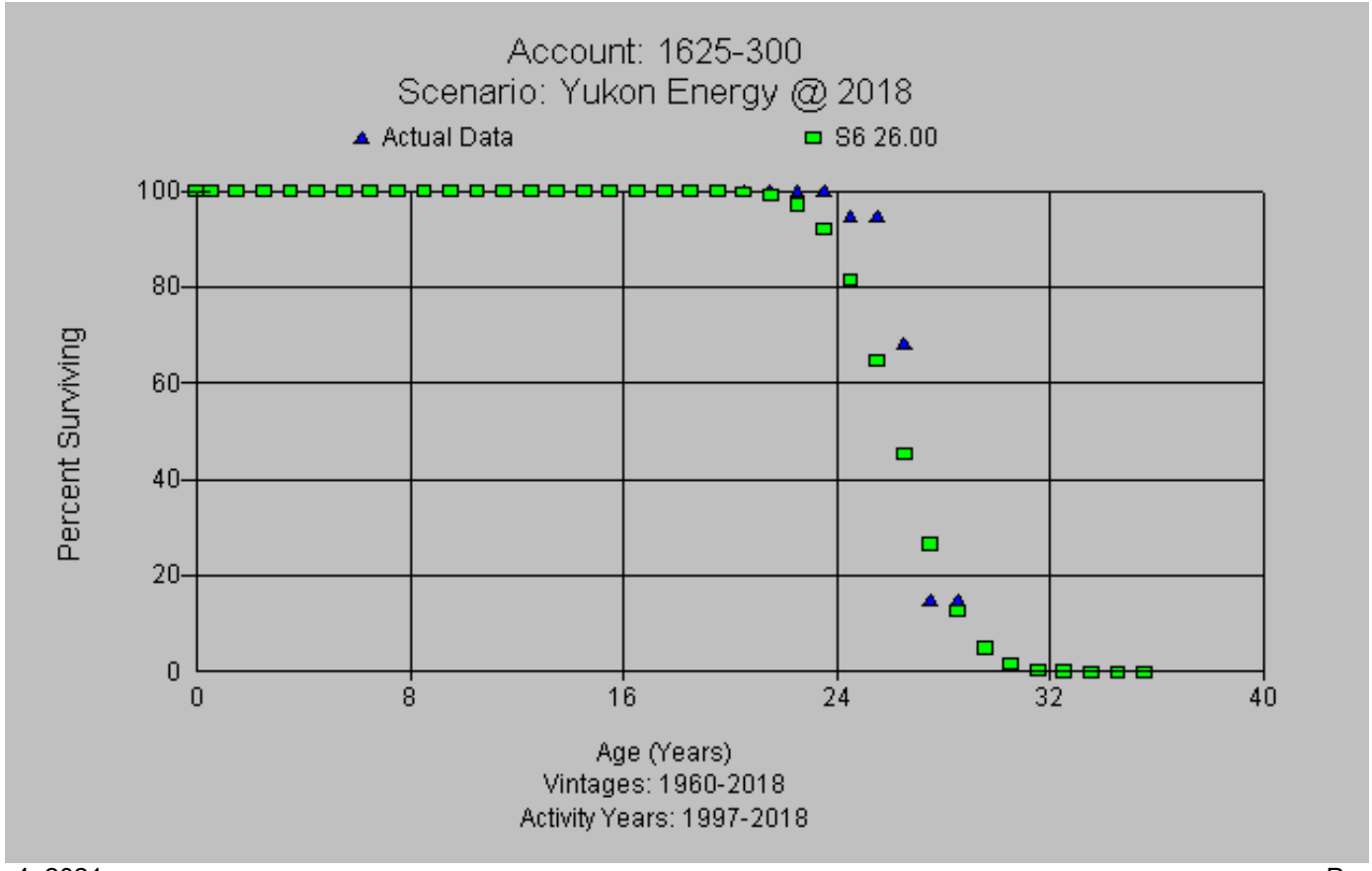
Account: 1620-500
Scenario: Yukon Energy @ 2018
Placement Band: 1903 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

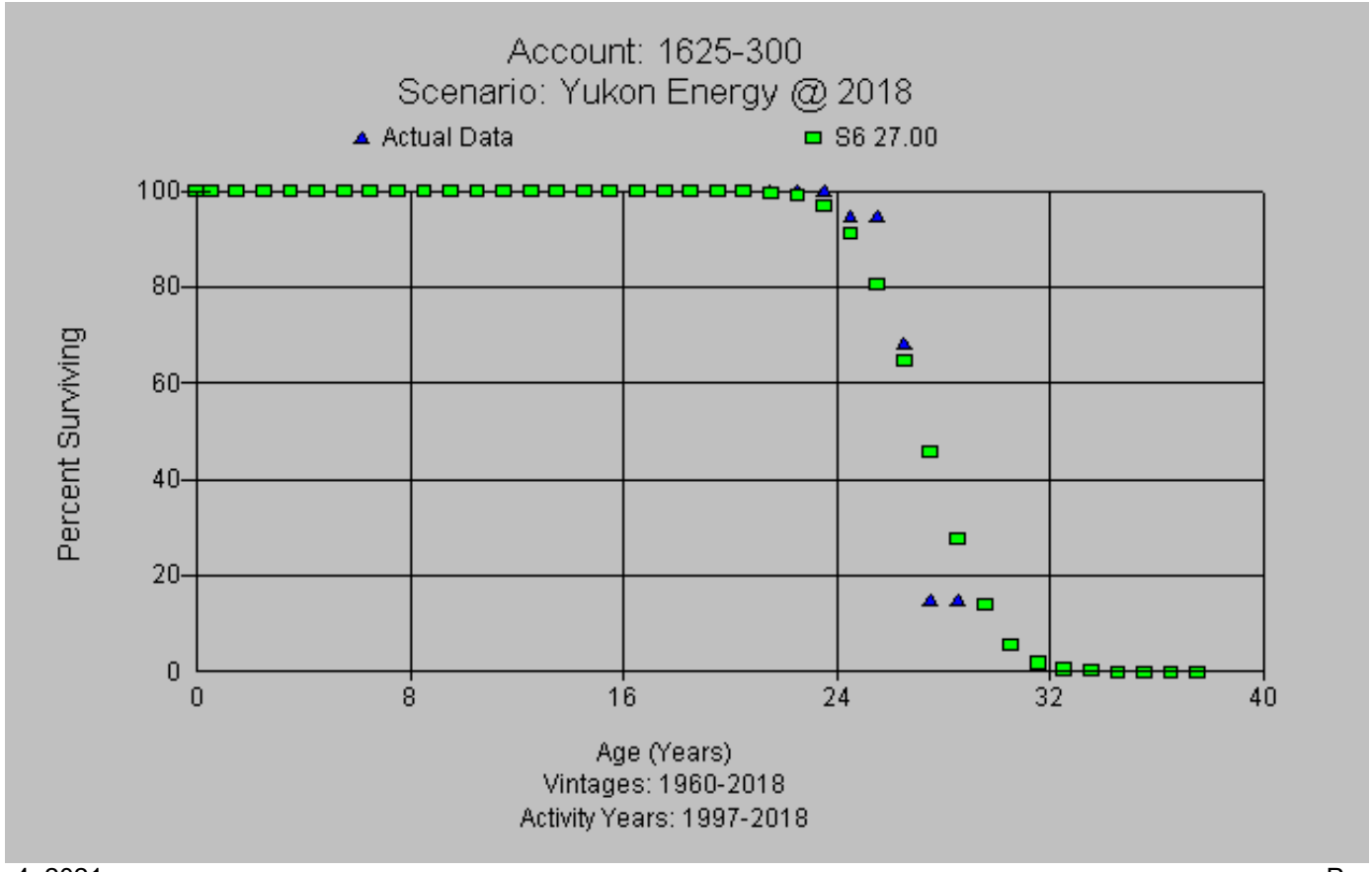
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1992 -2018	74.5	0.00	0.25301026	R5	25.99
1997 -2018	74.5	0.00	0.58543459	R5	27.80
2002 -2018	74.5	0.00	0.78546567	R4	26.43
2007 -2018	74.5	0.00	1.01866054	R4	26.71
2012 -2018	74.5	54.77	4.64191986	L0	44.69
2017 -2018		54.77			


Account: 1625-300
Scenario: Yukon Energy @ 2018
Actual Data
R2 35.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1960-2018
Activity Years: 1997-2018


Account: 1625-300
Scenario: Yukon Energy @ 2018
Actual Data
R3 30.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1960-2018
Activity Years: 1997-2018


Account: 1625-300
Scenario: Yukon Energy @ 2018
Actual Data
R5 30.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1960-2018
Activity Years: 1997-2018

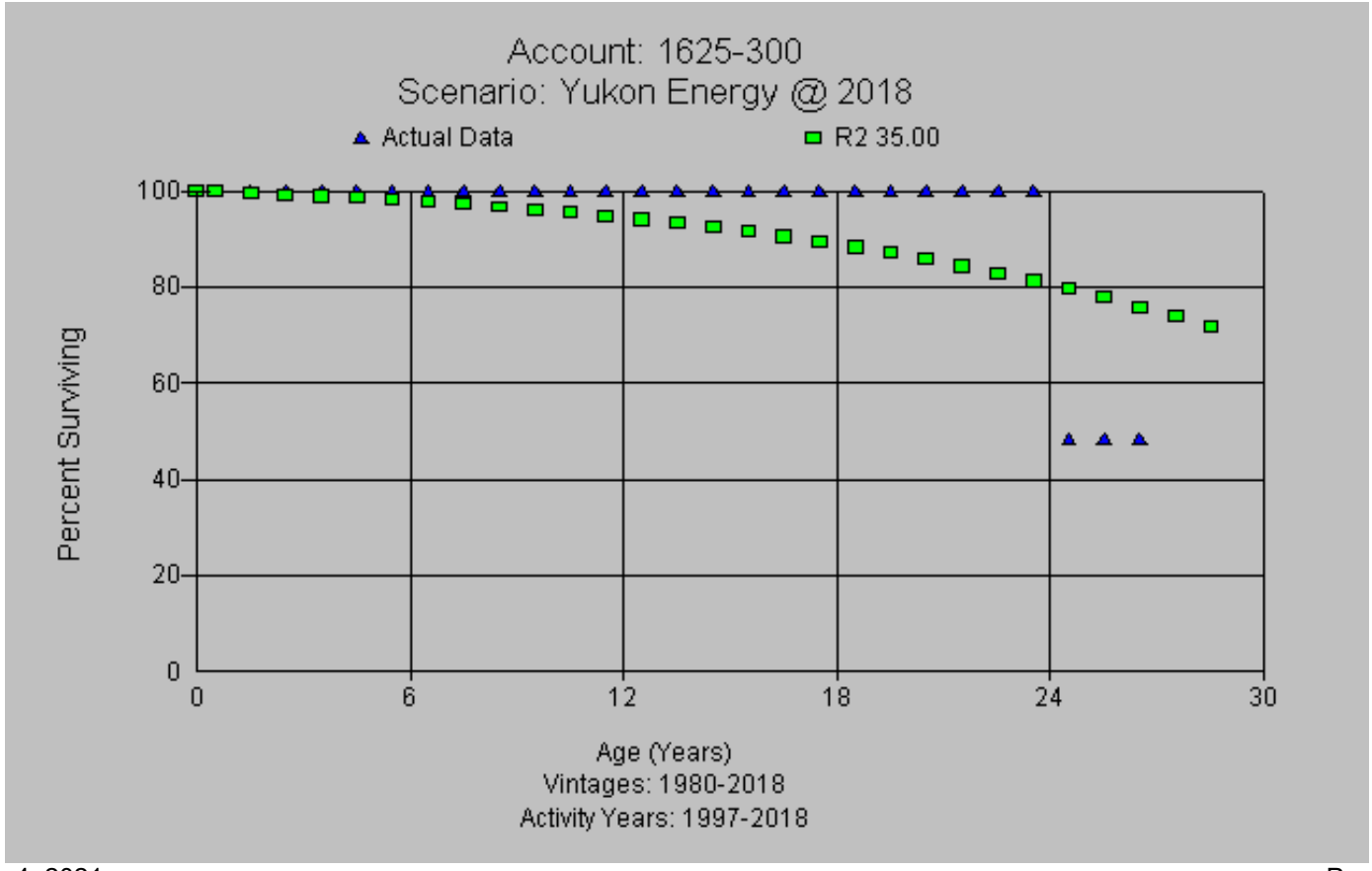

Account: 1625-300
Scenario: Yukon Energy @ 2018
Actual Data
S6 26.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1960-2018
Activity Years: 1997-2018

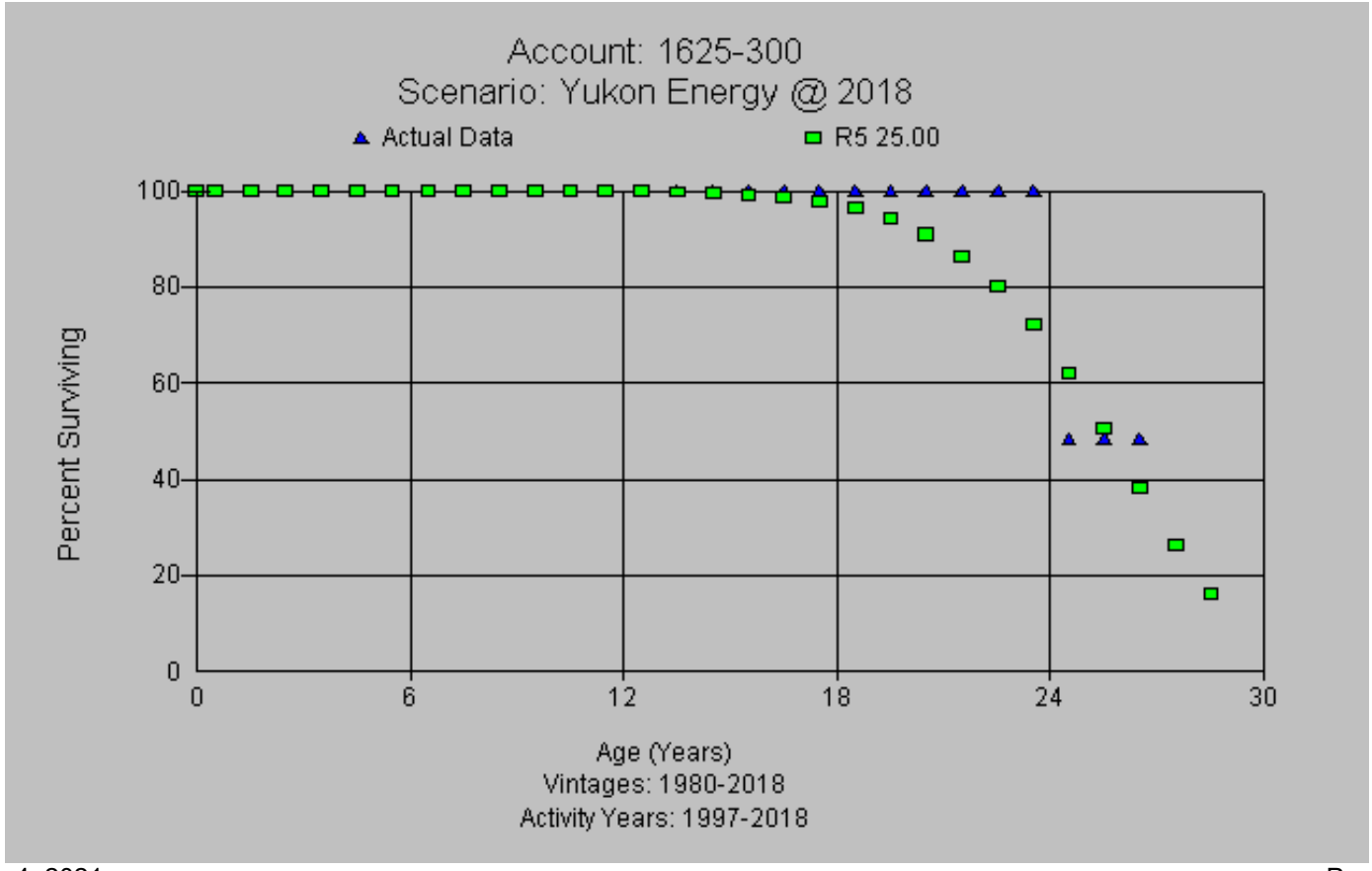

Account: 1625-300
Scenario: Yukon Energy @ 2018
Actual Data
S6 27.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1960-2018
Activity Years: 1997-2018

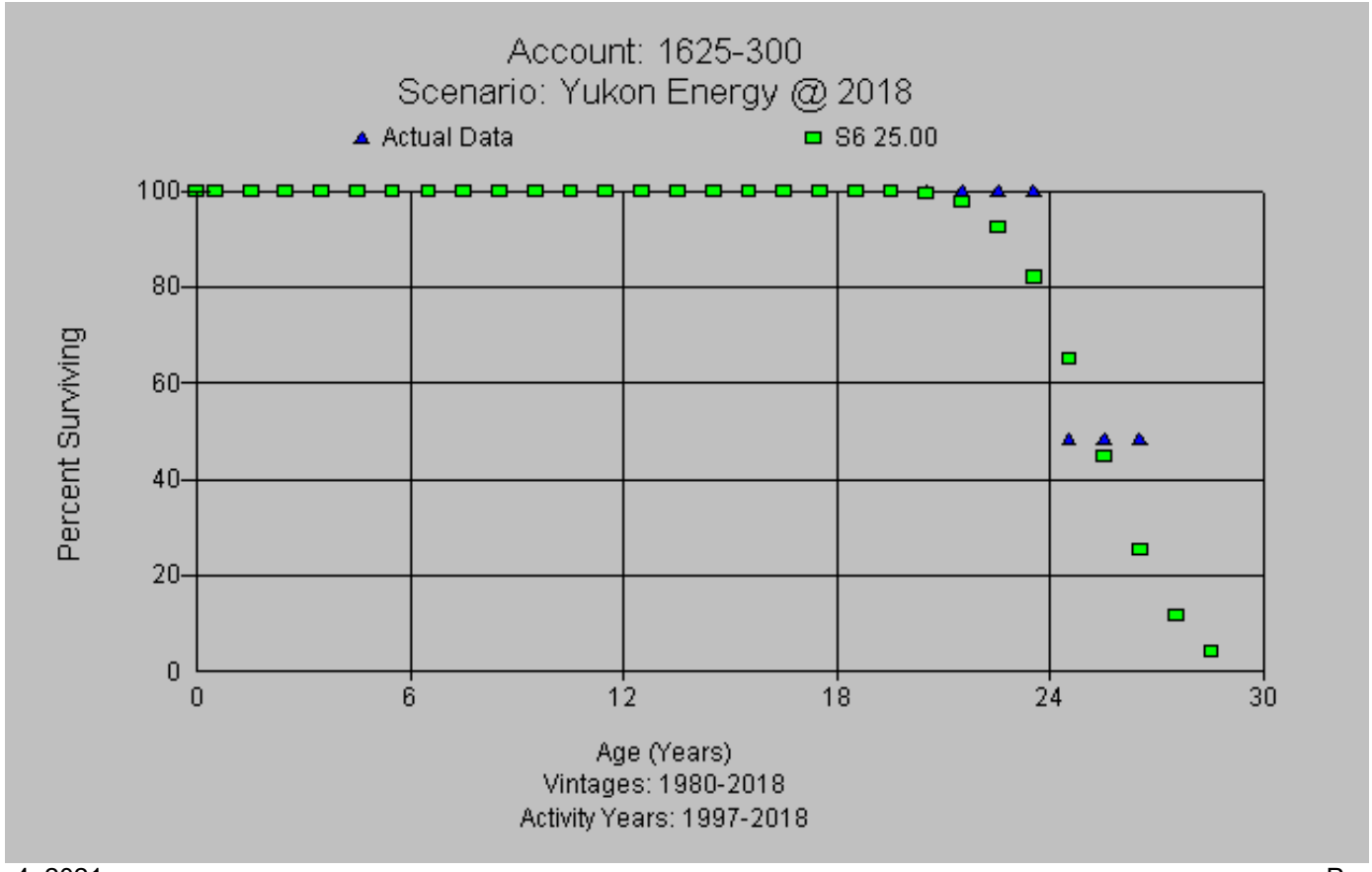
Observed Life Table

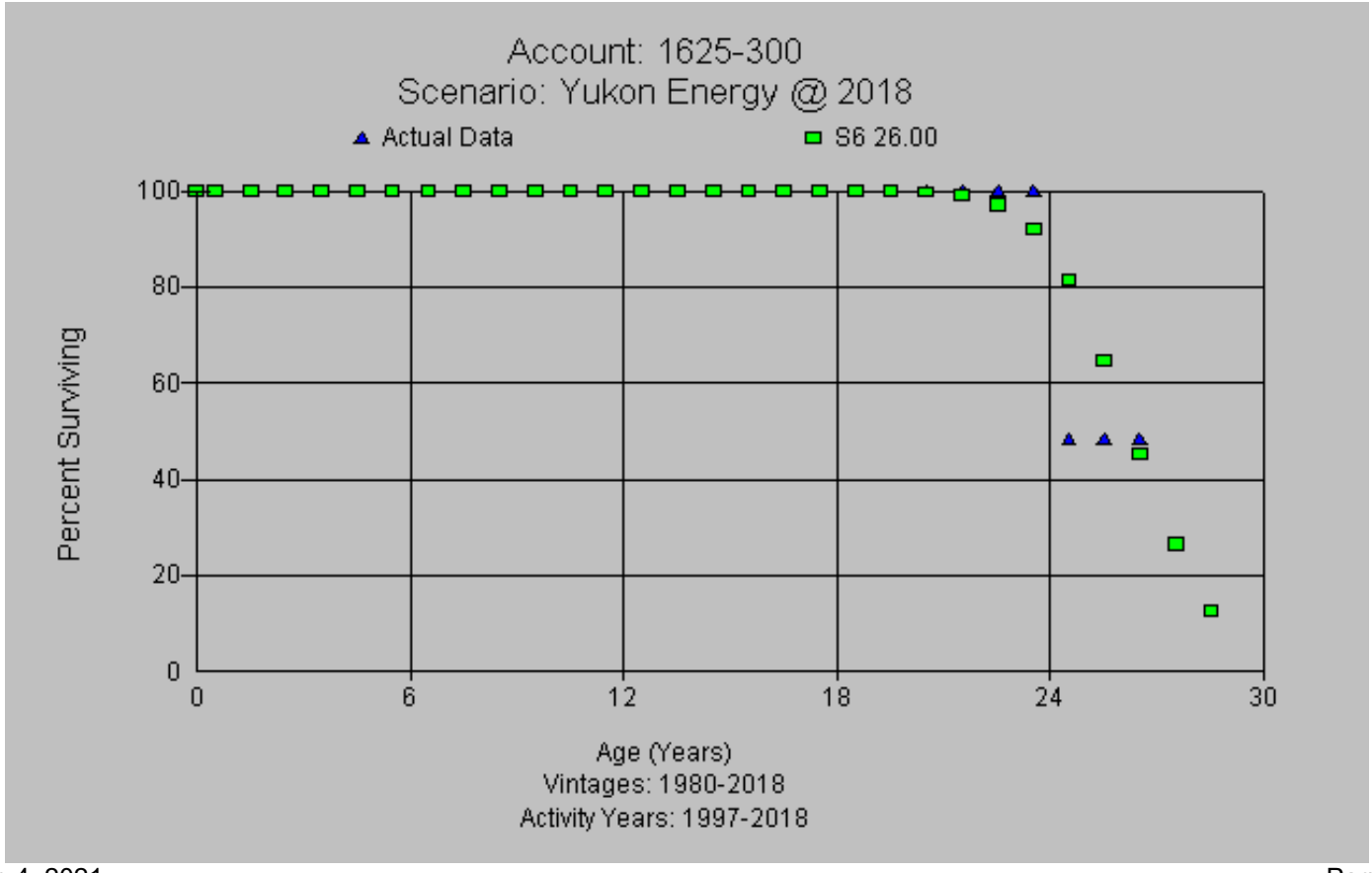
Scenario: Yukon Energy @ 2018
Account: 1625-300
Placement Band: 1960 - 2018 **Observation Band:** 1997 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	7,986,008.11	0.00	0.00000	1.00000	100.00
0.5	7,577,792.22	0.00	0.00000	1.00000	100.00
1.5	6,894,979.19	0.00	0.00000	1.00000	100.00
2.5	6,054,914.37	0.00	0.00000	1.00000	100.00
3.5	5,585,883.98	0.00	0.00000	1.00000	100.00
4.5	4,947,782.36	0.00	0.00000	1.00000	100.00
5.5	4,699,903.13	0.00	0.00000	1.00000	100.00
6.5	4,003,090.52	0.00	0.00000	1.00000	100.00
7.5	3,783,620.87	0.00	0.00000	1.00000	100.00
8.5	3,526,643.05	0.00	0.00000	1.00000	100.00
9.5	3,040,060.95	0.00	0.00000	1.00000	100.00
10.5	2,804,553.82	0.00	0.00000	1.00000	100.00
11.5	2,483,905.86	0.00	0.00000	1.00000	100.00
12.5	2,202,512.38	0.00	0.00000	1.00000	100.00
13.5	2,169,757.49	0.00	0.00000	1.00000	100.00
14.5	1,722,420.30	0.00	0.00000	1.00000	100.00
15.5	871,805.34	0.00	0.00000	1.00000	100.00
16.5	790,893.31	0.00	0.00000	1.00000	100.00
17.5	352,470.76	0.00	0.00000	1.00000	100.00
18.5	143,576.54	0.00	0.00000	1.00000	100.00
19.5	143,576.54	0.00	0.00000	1.00000	100.00
20.5	3,429.10	0.00	0.00000	1.00000	100.00
21.5	34,334.10	0.00	0.00000	1.00000	100.00
22.5	34,334.10	0.00	0.00000	1.00000	100.00
23.5	34,334.10	1,772.96	0.05164	0.94836	100.00
24.5	38,529.14	0.00	0.00000	1.00000	94.84
25.5	38,529.14	10,840.00	0.28135	0.71865	94.84
26.5	27,689.14	21,721.14	0.78446	0.21554	68.15
27.5	5,968.00	0.00	0.00000	1.00000	14.69
28.5	5,968.00	5,968.00	1.00000	0.00000	14.69
29.5	0.00	0.00	0.00000	1.00000	0.00
30.5	0.00	0.00	0.00000	1.00000	
31.5	0.00	0.00	0.00000	1.00000	
32.5	0.00	0.00	0.00000	1.00000	
33.5	0.00	0.00	0.00000	1.00000	
34.5	0.00	0.00	0.00000	1.00000	
35.5	0.00	0.00	0.00000	1.00000	
36.5	7,500.00	7,500.00	1.00000	0.00000	
37.5	0.00	0.00	0.00000	1.00000	


Account: 1625-300
Scenario: Yukon Energy @ 2018
Actual Data
R2 35.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1997-2018


Account: 1625-300
Scenario: Yukon Energy @ 2018
Actual Data
R5 25.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1997-2018


Account: 1625-300
Scenario: Yukon Energy @ 2018
Actual Data
S6 25.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1997-2018


Account: 1625-300
Scenario: Yukon Energy @ 2018
Actual Data
S6 26.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1997-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1625-300
Placement Band: 1980 - 2018 **Observation Band:** 1997 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	7,986,008.11	0.00	0.00000	1.00000	100.00
0.5	7,577,792.22	0.00	0.00000	1.00000	100.00
1.5	6,894,979.19	0.00	0.00000	1.00000	100.00
2.5	6,054,914.37	0.00	0.00000	1.00000	100.00
3.5	5,585,883.98	0.00	0.00000	1.00000	100.00
4.5	4,947,782.36	0.00	0.00000	1.00000	100.00
5.5	4,699,903.13	0.00	0.00000	1.00000	100.00
6.5	4,003,090.52	0.00	0.00000	1.00000	100.00
7.5	3,783,620.87	0.00	0.00000	1.00000	100.00
8.5	3,526,643.05	0.00	0.00000	1.00000	100.00
9.5	3,040,060.95	0.00	0.00000	1.00000	100.00
10.5	2,804,553.82	0.00	0.00000	1.00000	100.00
11.5	2,483,905.86	0.00	0.00000	1.00000	100.00
12.5	2,202,512.38	0.00	0.00000	1.00000	100.00
13.5	2,169,757.49	0.00	0.00000	1.00000	100.00
14.5	1,722,420.30	0.00	0.00000	1.00000	100.00
15.5	871,805.34	0.00	0.00000	1.00000	100.00
16.5	790,893.31	0.00	0.00000	1.00000	100.00
17.5	352,470.76	0.00	0.00000	1.00000	100.00
18.5	143,576.54	0.00	0.00000	1.00000	100.00
19.5	143,576.54	0.00	0.00000	1.00000	100.00
20.5	3,429.10	0.00	0.00000	1.00000	100.00
21.5	3,429.10	0.00	0.00000	1.00000	100.00
22.5	3,429.10	0.00	0.00000	1.00000	100.00
23.5	3,429.10	1,772.96	0.51703	0.48297	100.00
24.5	1,656.14	0.00	0.00000	1.00000	48.30
25.5	1,656.14	0.00	0.00000	1.00000	48.30
26.5	1,656.14	1,656.14	1.00000	0.00000	48.30
27.5	0.00	0.00	0.00000	1.00000	0.00

Actuarial Life Analysis

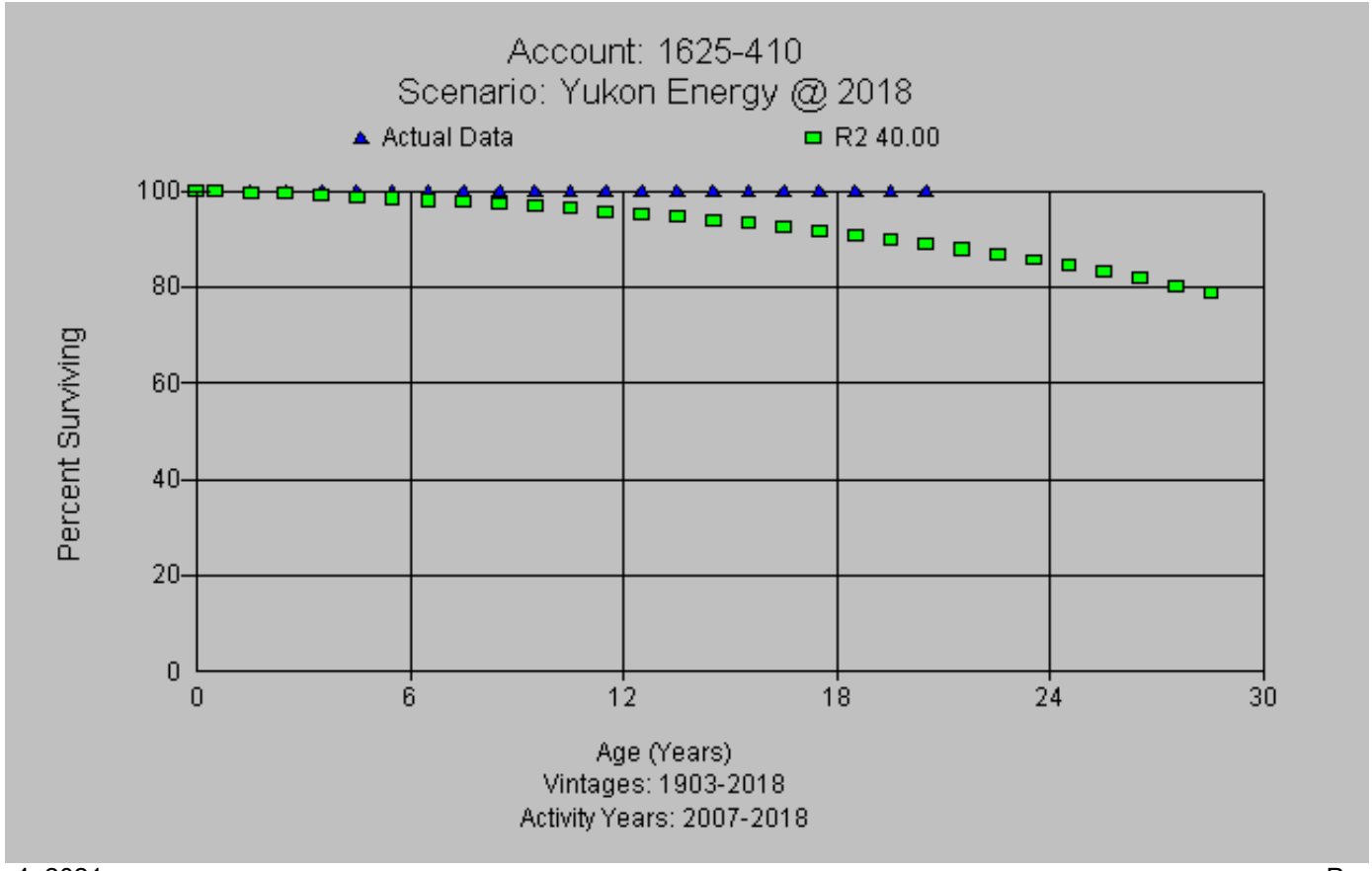
Account: 1625-300
Scenario: Yukon Energy @ 2018
Placement Band: 1960 - 2001
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1997 -2001	34.5	0.00	0.19160272	S6	28.17
1998 -2002	35.5	0.00	0.11273327	SQ	27.27
1999 -2003	36.5	0.00	0.15722826	S6	27.00
2000 -2004	37.5	0.00	0.12306062	SQ	26.70
2001 -2005	38.5	0.00	0.12306062	SQ	26.70
2002 -2006	39.5	0.00	0.00000000	SQ	27.20
2003 -2007	40.5	0.00	0.13170263	S6	25.50
2004 -2008	41.5	0.00	0.13170263	S6	25.50
2005 -2009	42.5	0.00	0.00000000	SQ	24.20
2006 -2010	43.5	0.00	0.00000000	SQ	24.20
2007 -2011	44.5	0.00	0.00000000	SQ	24.20
2008 -2012		1.00			
2009 -2013		1.00			
2010 -2014		1.00			
2011 -2015		1.00			
2012 -2016		1.00			
2013 -2017		1.00			
2014 -2018		1.00			

Actuarial Life Analysis

Account: 1625-300
Scenario: Yukon Energy @ 2018
Placement Band: 1960 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1997 -2018	58.5	0.00	0.12963243	S6	26.92
2002 -2018	58.5	0.00	0.13170263	S6	25.50
2007 -2018	58.5	0.00	0.00000000	SQ	24.20
2012 -2018		1.00			
2017 -2018		1.00			


Account: 1625-410
Scenario: Yukon Energy @ 2018
Actual Data
R2 40.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1903-2018
Activity Years: 2007-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1625-410
Placement Band: 1903 - 2018 **Observation Band:** 2007 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	346,579.96	0.00	0.00000	1.00000	100.00
0.5	469,512.80	0.00	0.00000	1.00000	100.00
1.5	630,996.01	0.00	0.00000	1.00000	100.00
2.5	635,446.02	0.00	0.00000	1.00000	100.00
3.5	643,005.53	0.00	0.00000	1.00000	100.00
4.5	653,853.33	0.00	0.00000	1.00000	100.00
5.5	815,473.49	0.00	0.00000	1.00000	100.00
6.5	1,508,468.54	0.00	0.00000	1.00000	100.00
7.5	1,553,017.41	0.00	0.00000	1.00000	100.00
8.5	1,978,056.83	0.00	0.00000	1.00000	100.00
9.5	1,916,990.45	0.00	0.00000	1.00000	100.00
10.5	1,780,694.78	0.00	0.00000	1.00000	100.00
11.5	1,770,801.00	0.00	0.00000	1.00000	100.00
12.5	1,647,868.16	0.00	0.00000	1.00000	100.00
13.5	1,486,384.95	0.00	0.00000	1.00000	100.00
14.5	1,481,934.94	0.00	0.00000	1.00000	100.00
15.5	1,474,375.43	0.00	0.00000	1.00000	100.00
16.5	1,463,527.63	0.00	0.00000	1.00000	100.00
17.5	1,301,907.47	0.00	0.00000	1.00000	100.00
18.5	490,394.54	0.00	0.00000	1.00000	100.00
19.5	431,376.49	0.00	0.00000	1.00000	100.00
20.5	0.00	0.00	0.00000	1.00000	100.00
21.5	0.00	0.00	0.00000	1.00000	
22.5	0.00	0.00	0.00000	1.00000	
23.5	0.00	0.00	0.00000	1.00000	
24.5	0.00	0.00	0.00000	1.00000	
25.5	0.00	0.00	0.00000	1.00000	
26.5	1,654.89	1,654.89	1.00000	0.00000	
27.5	0.00	0.00	0.00000	1.00000	
28.5	0.00	0.00	0.00000	1.00000	
29.5	0.00	0.00	0.00000	1.00000	
30.5	0.00	0.00	0.00000	1.00000	
31.5	0.00	0.00	0.00000	1.00000	
32.5	0.00	0.00	0.00000	1.00000	
33.5	0.00	0.00	0.00000	1.00000	
34.5	0.00	0.00	0.00000	1.00000	
35.5	0.00	0.00	0.00000	1.00000	
36.5	0.00	0.00	0.00000	1.00000	
37.5	0.00	0.00	0.00000	1.00000	

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1625-410
Placement Band: 1903 - 2018 **Observation Band:** 2007 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
43.5	20,049.37	20,049.37	1.00000	0.00000	
44.5	0.00	0.00	0.00000	1.00000	
45.5	0.00	0.00	0.00000	1.00000	
46.5	0.00	0.00	0.00000	1.00000	
47.5	0.00	0.00	0.00000	1.00000	
48.5	0.00	0.00	0.00000	1.00000	
49.5	0.00	0.00	0.00000	1.00000	
50.5	0.00	0.00	0.00000	1.00000	
51.5	0.00	0.00	0.00000	1.00000	
52.5	0.00	0.00	0.00000	1.00000	
53.5	0.00	0.00	0.00000	1.00000	
54.5	0.00	0.00	0.00000	1.00000	
66.5	0.00	0.00	0.00000	1.00000	
67.5	0.00	0.00	0.00000	1.00000	
68.5	0.00	0.00	0.00000	1.00000	
69.5	0.00	0.00	0.00000	1.00000	
70.5	0.00	0.00	0.00000	1.00000	
71.5	0.00	0.00	0.00000	1.00000	
72.5	0.00	0.00	0.00000	1.00000	
73.5	0.00	0.00	0.00000	1.00000	
74.5	0.00	0.00	0.00000	1.00000	
75.5	0.00	0.00	0.00000	1.00000	
76.5	0.00	0.00	0.00000	1.00000	
77.5	0.00	0.00	0.00000	1.00000	
103.5	20,646.50	20,646.50	1.00000	0.00000	
104.5	0.00	0.00	0.00000	1.00000	

Actuarial Life Analysis

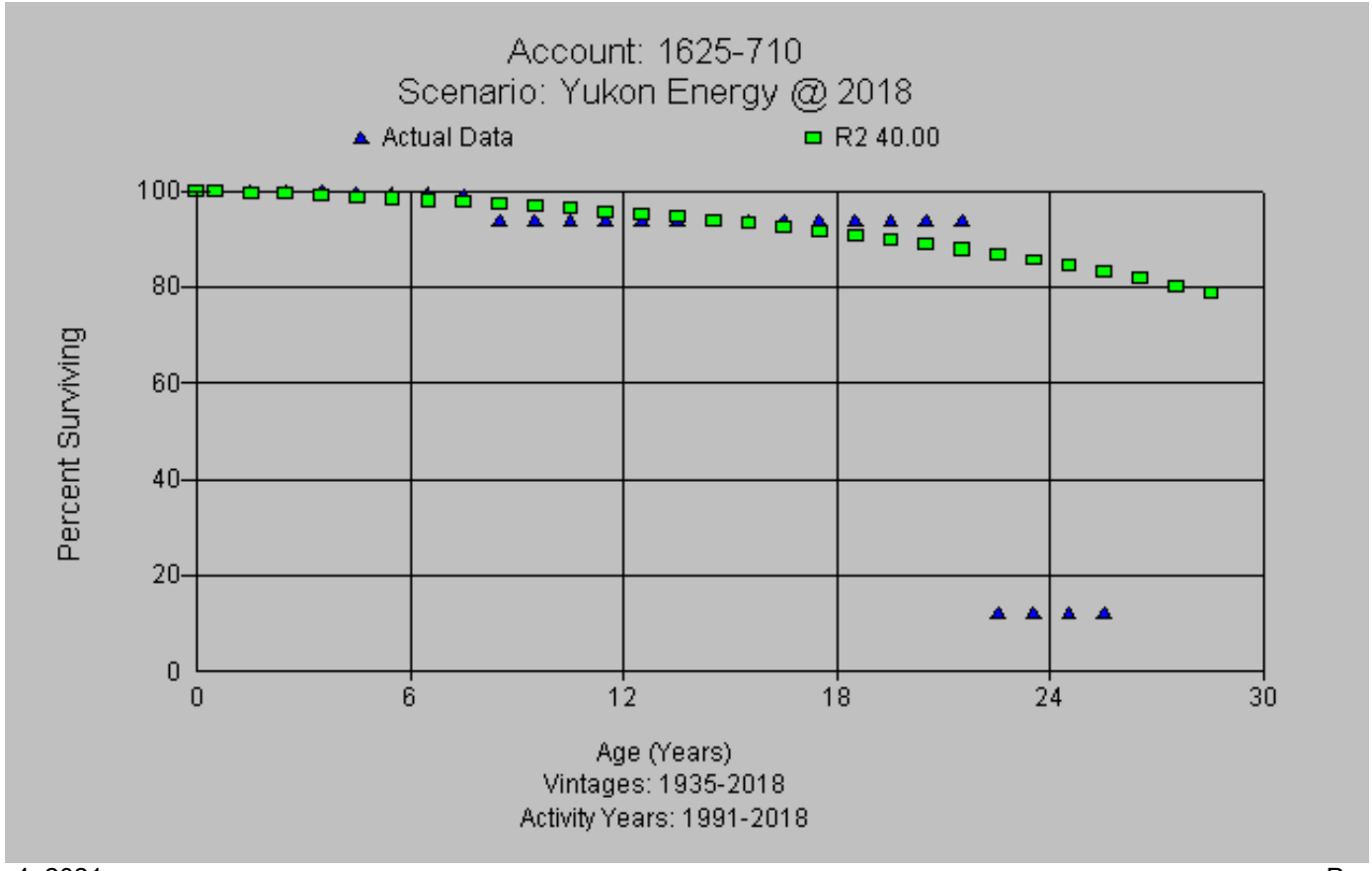
Account: 1625-410
Scenario: Yukon Energy @ 2018
Placement Band: 1903 - 2011
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

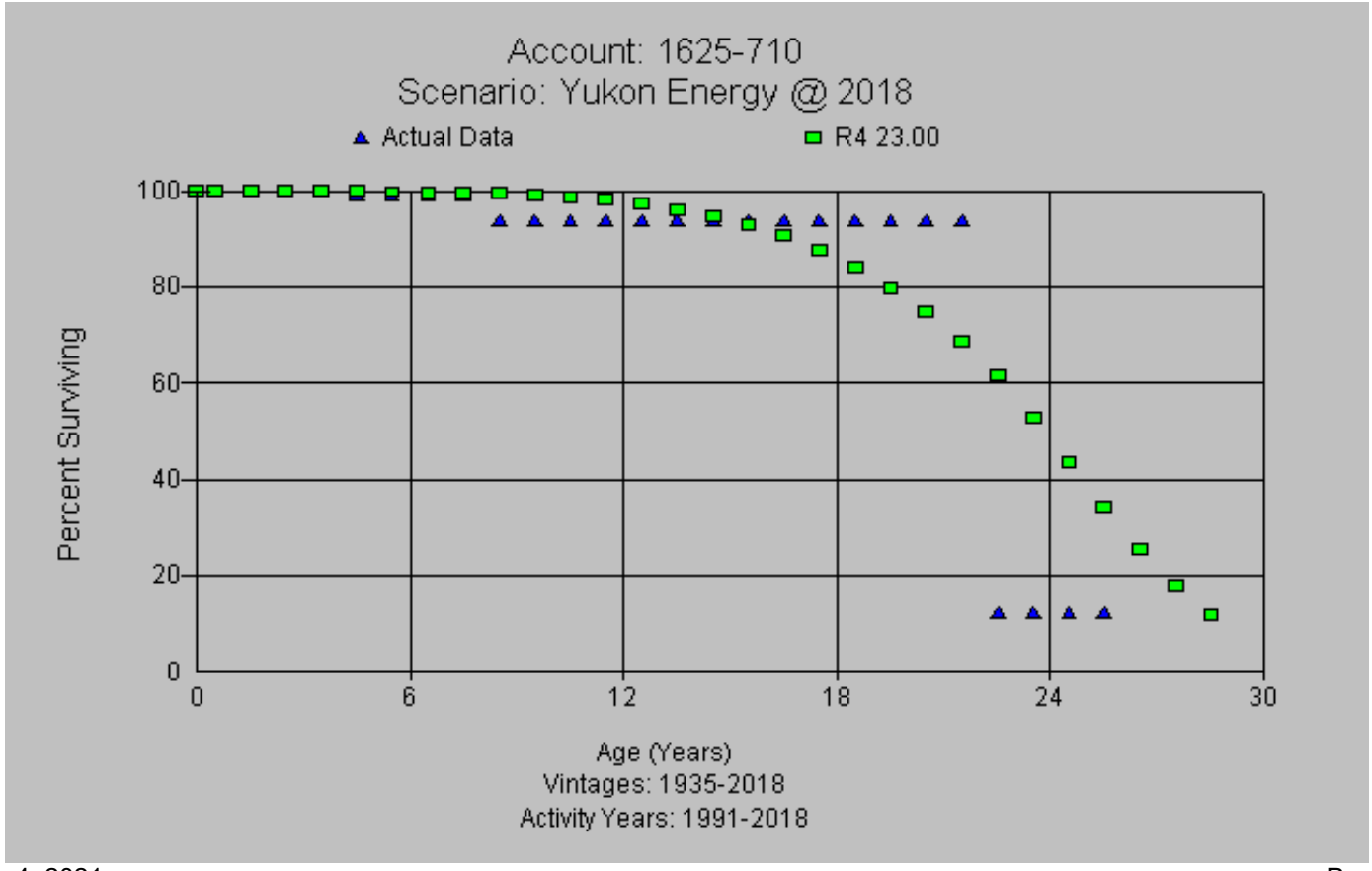
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
2007 -2011	44.5	0.00	0.00000000	SQ	25.20
2008 -2012		1.00			
2009 -2013		1.00			
2010 -2014		1.00			
2011 -2015		1.00			
2012 -2016		1.00			
2013 -2017		1.00			
2014 -2018		1.00			

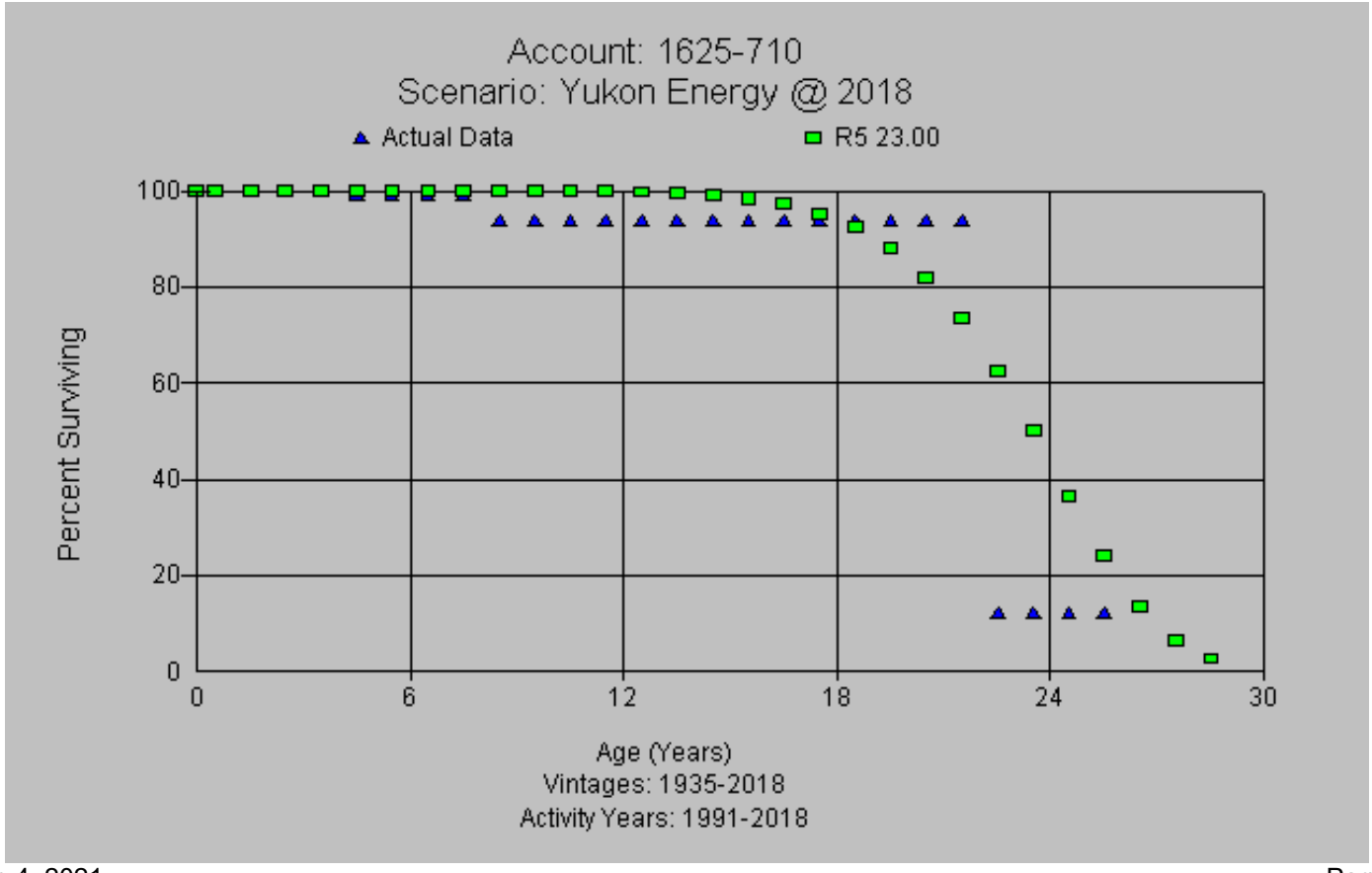
Actuarial Life Analysis

Account: 1625-410
Scenario: Yukon Energy @ 2018
Placement Band: 1903 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
2007 -2018	74.5	0.00	0.00000000	SQ	27.20
2012 -2018	74.5	0.00	0.08088835	SQ	63.05
2017 -2018		0.00			


Account: 1625-710
Scenario: Yukon Energy @ 2018
Actual Data
R2 40.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1935-2018
Activity Years: 1991-2018

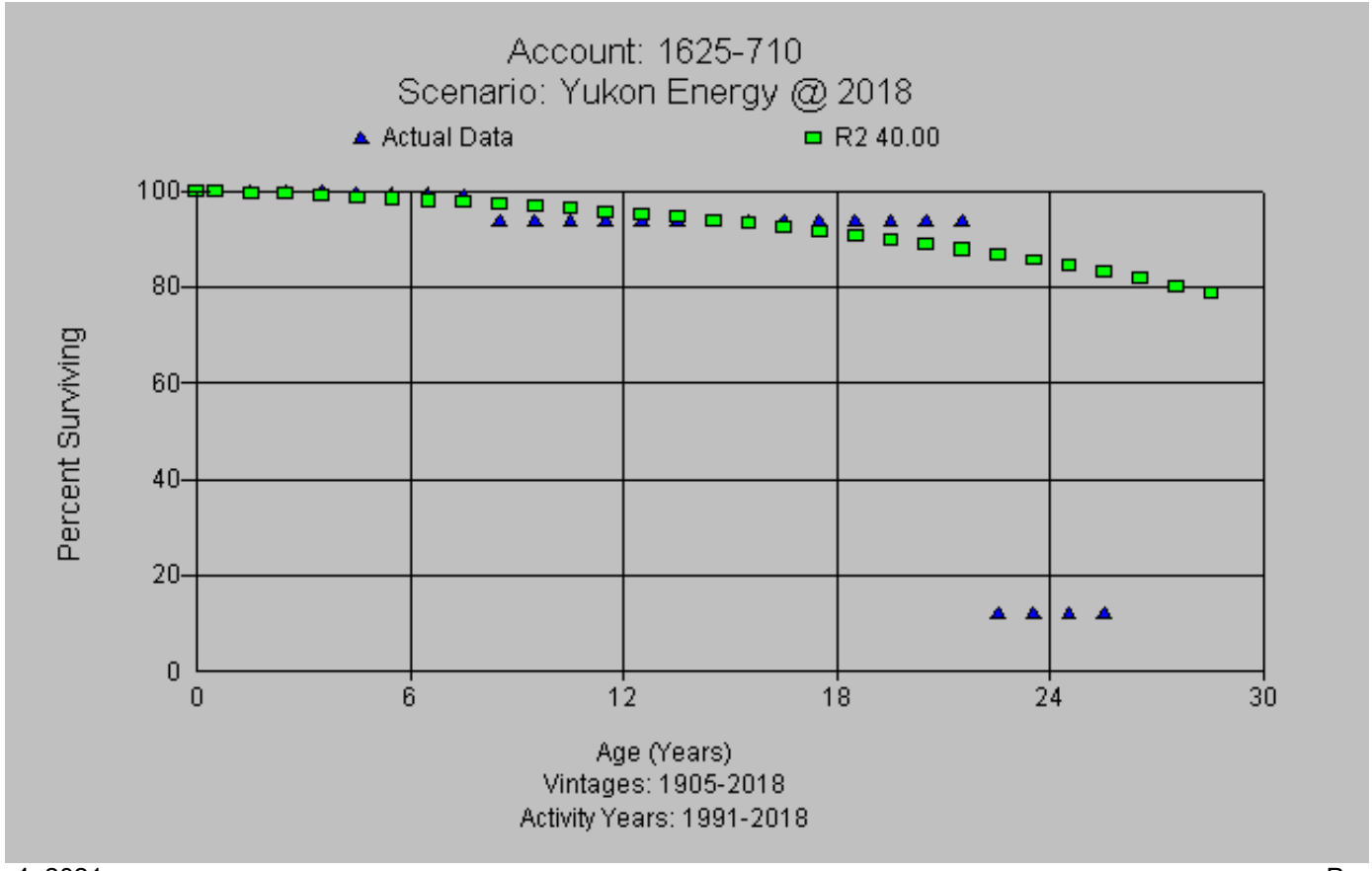

Account: 1625-710
Scenario: Yukon Energy @ 2018
Actual Data
R4 23.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1935-2018
Activity Years: 1991-2018

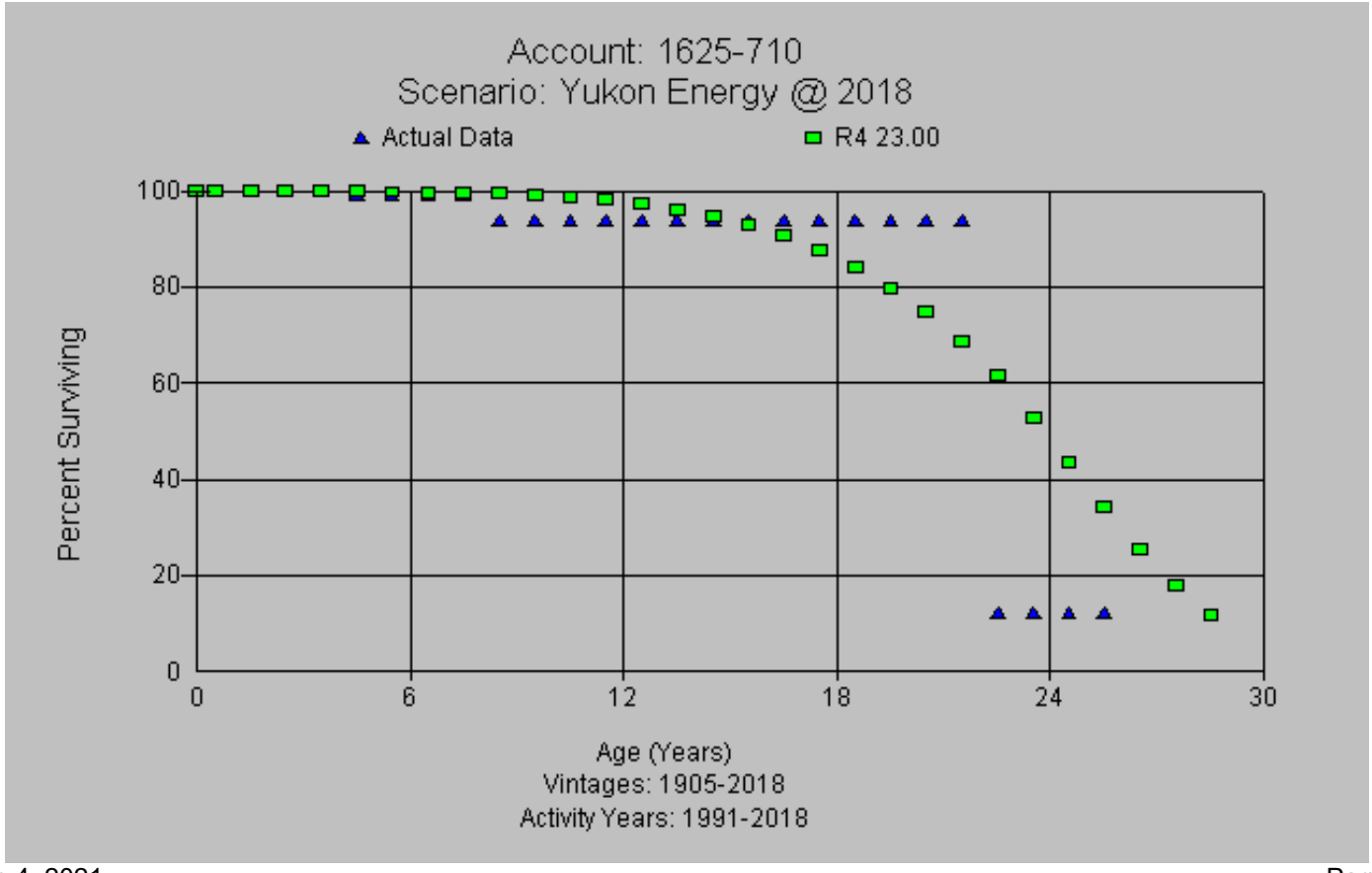

Account: 1625-710
Scenario: Yukon Energy @ 2018
Actual Data
R5 23.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1935-2018
Activity Years: 1991-2018

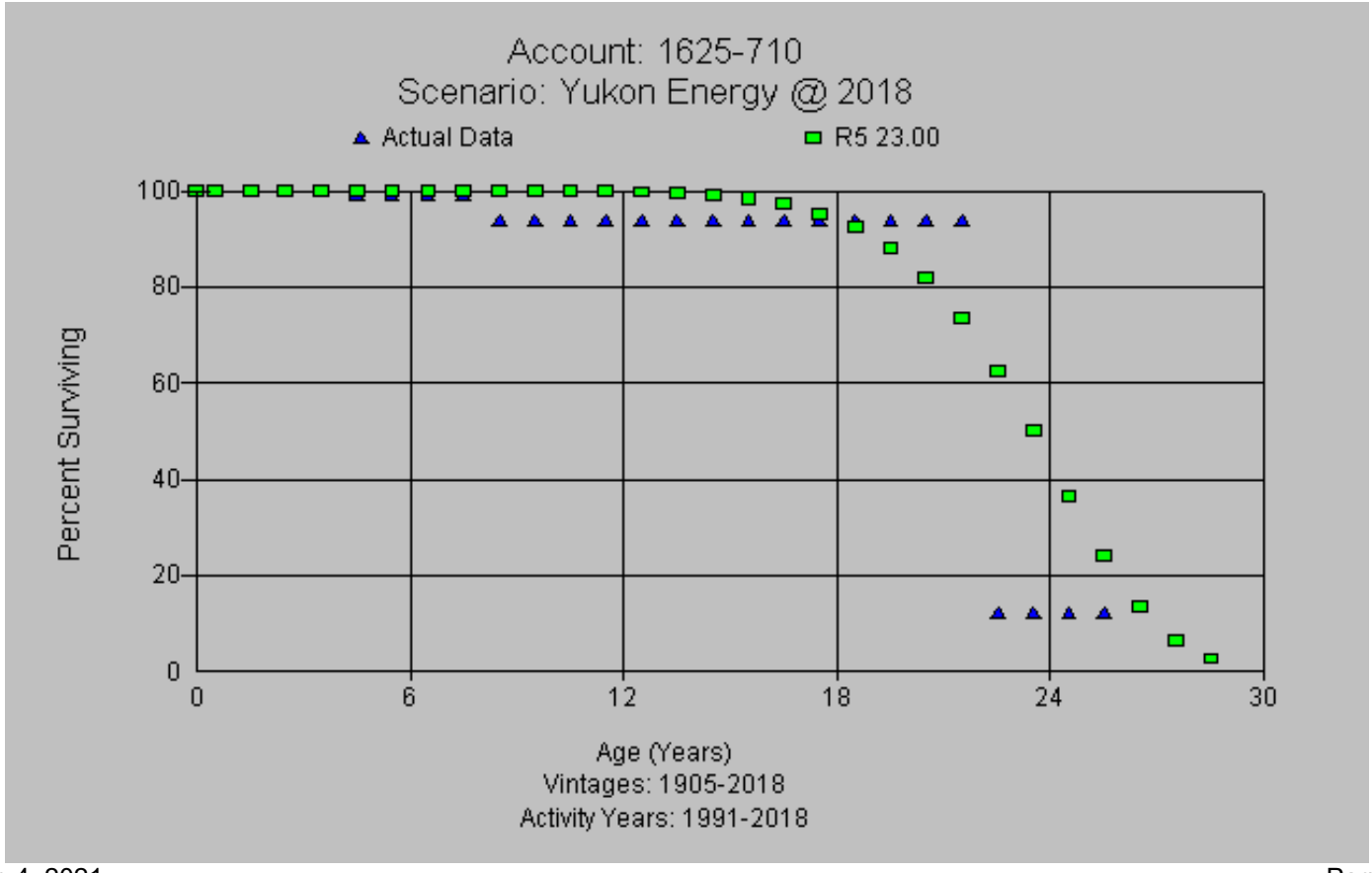
Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1625-710
Placement Band: 1935 - 2018 **Observation Band:** 1991 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	1,299,828.00	0.00	0.00000	1.00000	100.00
0.5	1,299,828.00	0.00	0.00000	1.00000	100.00
1.5	1,287,251.00	71.00	0.00006	0.99994	100.00
2.5	1,287,180.00	0.00	0.00000	1.00000	99.99
3.5	1,340,298.43	7,800.00	0.00582	0.99418	99.99
4.5	1,296,550.89	0.00	0.00000	1.00000	99.41
5.5	1,290,616.85	0.00	0.00000	1.00000	99.41
6.5	1,259,958.50	2,371.00	0.00188	0.99812	99.41
7.5	1,257,587.50	69,175.00	0.05501	0.94499	99.23
8.5	1,188,412.50	0.00	0.00000	1.00000	93.77
9.5	1,188,412.50	0.00	0.00000	1.00000	93.77
10.5	1,075,153.65	0.00	0.00000	1.00000	93.77
11.5	1,012,016.30	0.00	0.00000	1.00000	93.77
12.5	746,633.95	0.00	0.00000	1.00000	93.77
13.5	734,344.95	0.00	0.00000	1.00000	93.77
14.5	511,459.97	0.00	0.00000	1.00000	93.77
15.5	511,459.97	0.00	0.00000	1.00000	93.77
16.5	448,554.66	0.00	0.00000	1.00000	93.77
17.5	448,554.66	0.00	0.00000	1.00000	93.77
18.5	244,286.87	0.00	0.00000	1.00000	93.77
19.5	223,289.28	0.00	0.00000	1.00000	93.77
20.5	28,887.61	0.00	0.00000	1.00000	93.77
21.5	28,887.61	25,184.00	0.87179	0.12821	93.77
22.5	3,703.61	0.00	0.00000	1.00000	12.02
23.5	3,703.61	0.00	0.00000	1.00000	12.02
24.5	3,703.61	0.00	0.00000	1.00000	12.02
25.5	3,703.61	3,703.61	1.00000	0.00000	12.02
26.5	0.00	0.00	0.00000	1.00000	0.00
27.5	0.00	0.00	0.00000	1.00000	
28.5	0.00	0.00	0.00000	1.00000	
29.5	0.00	0.00	0.00000	1.00000	
30.5	457.00	0.00	0.00000	1.00000	
31.5	457.00	0.00	0.00000	1.00000	
32.5	457.00	0.00	0.00000	1.00000	
33.5	457.00	0.00	0.00000	1.00000	
34.5	457.00	457.00	1.00000	0.00000	
35.5	0.00	0.00	0.00000	1.00000	


Account: 1625-710
Scenario: Yukon Energy @ 2018
Actual Data
R2 40.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1905-2018
Activity Years: 1991-2018


Account: 1625-710
Scenario: Yukon Energy @ 2018
Actual Data
R4 23.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1905-2018
Activity Years: 1991-2018


Account: 1625-710
Scenario: Yukon Energy @ 2018
Actual Data
R5 23.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1905-2018
Activity Years: 1991-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1625-710
Placement Band: 1905 - 2018 **Observation Band:** 1991 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	1,299,828.00	0.00	0.00000	1.00000	100.00
0.5	1,299,828.00	0.00	0.00000	1.00000	100.00
1.5	1,287,251.00	71.00	0.00006	0.99994	100.00
2.5	1,287,180.00	0.00	0.00000	1.00000	99.99
3.5	1,340,298.43	7,800.00	0.00582	0.99418	99.99
4.5	1,296,550.89	0.00	0.00000	1.00000	99.41
5.5	1,290,616.85	0.00	0.00000	1.00000	99.41
6.5	1,259,958.50	2,371.00	0.00188	0.99812	99.41
7.5	1,257,587.50	69,175.00	0.05501	0.94499	99.23
8.5	1,188,412.50	0.00	0.00000	1.00000	93.77
9.5	1,188,412.50	0.00	0.00000	1.00000	93.77
10.5	1,075,153.65	0.00	0.00000	1.00000	93.77
11.5	1,012,016.30	0.00	0.00000	1.00000	93.77
12.5	746,633.95	0.00	0.00000	1.00000	93.77
13.5	734,344.95	0.00	0.00000	1.00000	93.77
14.5	511,459.97	0.00	0.00000	1.00000	93.77
15.5	511,459.97	0.00	0.00000	1.00000	93.77
16.5	448,554.66	0.00	0.00000	1.00000	93.77
17.5	448,554.66	0.00	0.00000	1.00000	93.77
18.5	244,286.87	0.00	0.00000	1.00000	93.77
19.5	223,289.28	0.00	0.00000	1.00000	93.77
20.5	28,887.61	0.00	0.00000	1.00000	93.77
21.5	28,887.61	25,184.00	0.87179	0.12821	93.77
22.5	3,703.61	0.00	0.00000	1.00000	12.02
23.5	3,703.61	0.00	0.00000	1.00000	12.02
24.5	3,703.61	0.00	0.00000	1.00000	12.02
25.5	3,703.61	3,703.61	1.00000	0.00000	12.02
26.5	0.00	0.00	0.00000	1.00000	0.00
27.5	0.00	0.00	0.00000	1.00000	
28.5	0.00	0.00	0.00000	1.00000	
29.5	0.00	0.00	0.00000	1.00000	
30.5	457.00	0.00	0.00000	1.00000	
31.5	457.00	0.00	0.00000	1.00000	
32.5	457.00	0.00	0.00000	1.00000	
33.5	457.00	0.00	0.00000	1.00000	
34.5	457.00	457.00	1.00000	0.00000	
35.5	0.00	0.00	0.00000	1.00000	
36.5	0.00	0.00	0.00000	1.00000	
37.5	0.00	0.00	0.00000	1.00000	

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1625-710
Placement Band: 1905 - 2018 **Observation Band:** 1991 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
38.5	0.00	0.00	0.00000	1.00000	
39.5	0.00	0.00	0.00000	1.00000	
40.5	0.00	0.00	0.00000	1.00000	
41.5	0.00	0.00	0.00000	1.00000	
42.5	0.00	0.00	0.00000	1.00000	
43.5	0.00	0.00	0.00000	1.00000	
44.5	0.00	0.00	0.00000	1.00000	
45.5	0.00	0.00	0.00000	1.00000	
46.5	0.00	0.00	0.00000	1.00000	
47.5	0.00	0.00	0.00000	1.00000	
48.5	0.00	0.00	0.00000	1.00000	
49.5	0.00	0.00	0.00000	1.00000	
50.5	0.00	0.00	0.00000	1.00000	
51.5	0.00	0.00	0.00000	1.00000	
52.5	0.00	0.00	0.00000	1.00000	
53.5	0.00	0.00	0.00000	1.00000	
54.5	0.00	0.00	0.00000	1.00000	
55.5	0.00	0.00	0.00000	1.00000	
56.5	0.00	0.00	0.00000	1.00000	
57.5	0.00	0.00	0.00000	1.00000	
85.5	8,770.08	0.00	0.00000	1.00000	
86.5	8,770.08	0.00	0.00000	1.00000	
87.5	8,770.08	0.00	0.00000	1.00000	
88.5	8,770.08	0.00	0.00000	1.00000	
89.5	8,770.08	0.00	0.00000	1.00000	
90.5	8,770.08	0.00	0.00000	1.00000	
91.5	8,770.08	0.00	0.00000	1.00000	
92.5	8,770.08	0.00	0.00000	1.00000	
93.5	8,770.08	0.00	0.00000	1.00000	
94.5	8,770.08	0.00	0.00000	1.00000	
95.5	8,770.08	0.00	0.00000	1.00000	
96.5	8,770.08	0.00	0.00000	1.00000	
97.5	8,770.08	0.00	0.00000	1.00000	
98.5	8,770.08	0.00	0.00000	1.00000	
99.5	8,770.08	0.00	0.00000	1.00000	
100.5	8,770.08	0.00	0.00000	1.00000	
101.5	8,770.08	8,770.08	1.00000	0.00000	
102.5	0.00	0.00	0.00000	1.00000	

Actuarial Life Analysis

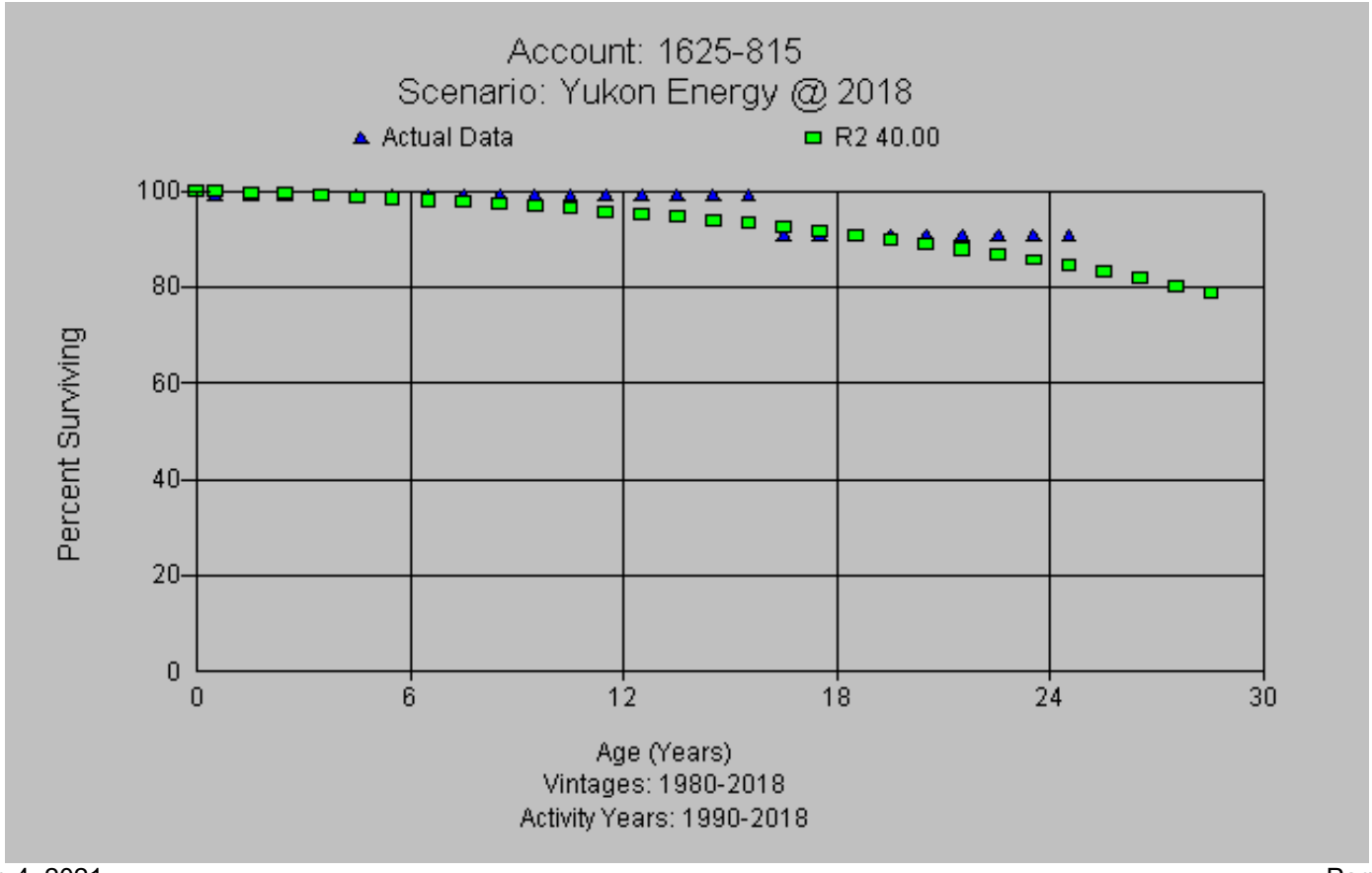
Account: 1625-710
Scenario: Yukon Energy @ 2018
Placement Band: 1905 - 1995
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1991 -1995	28.5	0.00	0.00000000	SQ	2.39
1992 -1996	29.5	0.00	0.00000000	SQ	2.39
1993 -1997	30.5	0.00	0.00000000	SQ	2.39
1994 -1998	31.5	0.00	0.00000000	SQ	2.39
1995 -1999	32.5	0.00	0.00000000	SQ	2.39
1996 -2000	33.5	0.00	0.00000000	SQ	19.20
1997 -2001		1.00			
1998 -2002		1.00			
1999 -2003		1.00			
2000 -2004		1.00			
2001 -2005		1.00			
2002 -2006	39.5	0.00	0.00000000	SQ	24.20
2003 -2007	40.5	0.00	0.00000000	SQ	24.20
2004 -2008	41.5	0.00	0.00000000	SQ	24.20
2005 -2009	42.5	0.00	0.00000000	SQ	24.20
2006 -2010	43.5	0.00	0.00000000	SQ	24.20
2007 -2011	44.5	0.00	0.00000000	SQ	40.10
2008 -2012		1.00			
2009 -2013		1.00			
2010 -2014		1.00			
2011 -2015		1.00			
2012 -2016		1.00			
2013 -2017		1.00			
2014 -2018		1.00			

Actuarial Life Analysis

Account: 1625-710
Scenario: Yukon Energy @ 2018
Placement Band: 1905 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1991 -2018	86.5	0.00	0.11229401	SQ	21.63
1996 -2018	86.5	0.00	0.26959783	S6	22.56
2001 -2018	86.5	0.00	0.00000000	SQ	26.20
2006 -2018	86.5	0.00	0.00000000	SQ	26.20
2011 -2018		1.00			
2016 -2018		1.00			


Account: 1625-815
Scenario: Yukon Energy @ 2018
Actual Data
R2 40.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1990-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1625-815
Placement Band: 1980 - 2018 **Observation Band:** 1990 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	609,892.87	5,150.00	0.00844	0.99156	100.00
0.5	589,892.75	0.00	0.00000	1.00000	99.16
1.5	587,355.96	0.00	0.00000	1.00000	99.16
2.5	587,355.96	0.00	0.00000	1.00000	99.16
3.5	579,287.98	0.00	0.00000	1.00000	99.16
4.5	578,075.46	0.00	0.00000	1.00000	99.16
5.5	578,075.46	0.00	0.00000	1.00000	99.16
6.5	578,075.46	0.00	0.00000	1.00000	99.16
7.5	573,504.77	0.00	0.00000	1.00000	99.16
8.5	573,504.77	0.00	0.00000	1.00000	99.16
9.5	583,078.73	0.00	0.00000	1.00000	99.16
10.5	575,042.76	0.00	0.00000	1.00000	99.16
11.5	574,742.76	0.00	0.00000	1.00000	99.16
12.5	210,733.11	0.00	0.00000	1.00000	99.16
13.5	210,733.11	0.00	0.00000	1.00000	99.16
14.5	199,431.79	0.00	0.00000	1.00000	99.16
15.5	196,405.17	16,249.78	0.08274	0.91726	99.16
16.5	174,126.87	0.00	0.00000	1.00000	90.95
17.5	167,180.56	0.00	0.00000	1.00000	90.95
18.5	128,174.14	0.00	0.00000	1.00000	90.95
19.5	79,509.16	0.00	0.00000	1.00000	90.95
20.5	14,988.89	0.00	0.00000	1.00000	90.95
21.5	14,988.89	0.00	0.00000	1.00000	90.95
22.5	14,988.89	0.00	0.00000	1.00000	90.95
23.5	14,988.89	0.00	0.00000	1.00000	90.95
24.5	14,988.89	14,988.89	1.00000	0.00000	90.95
25.5	0.00	0.00	0.00000	1.00000	0.00

Actuarial Life Analysis

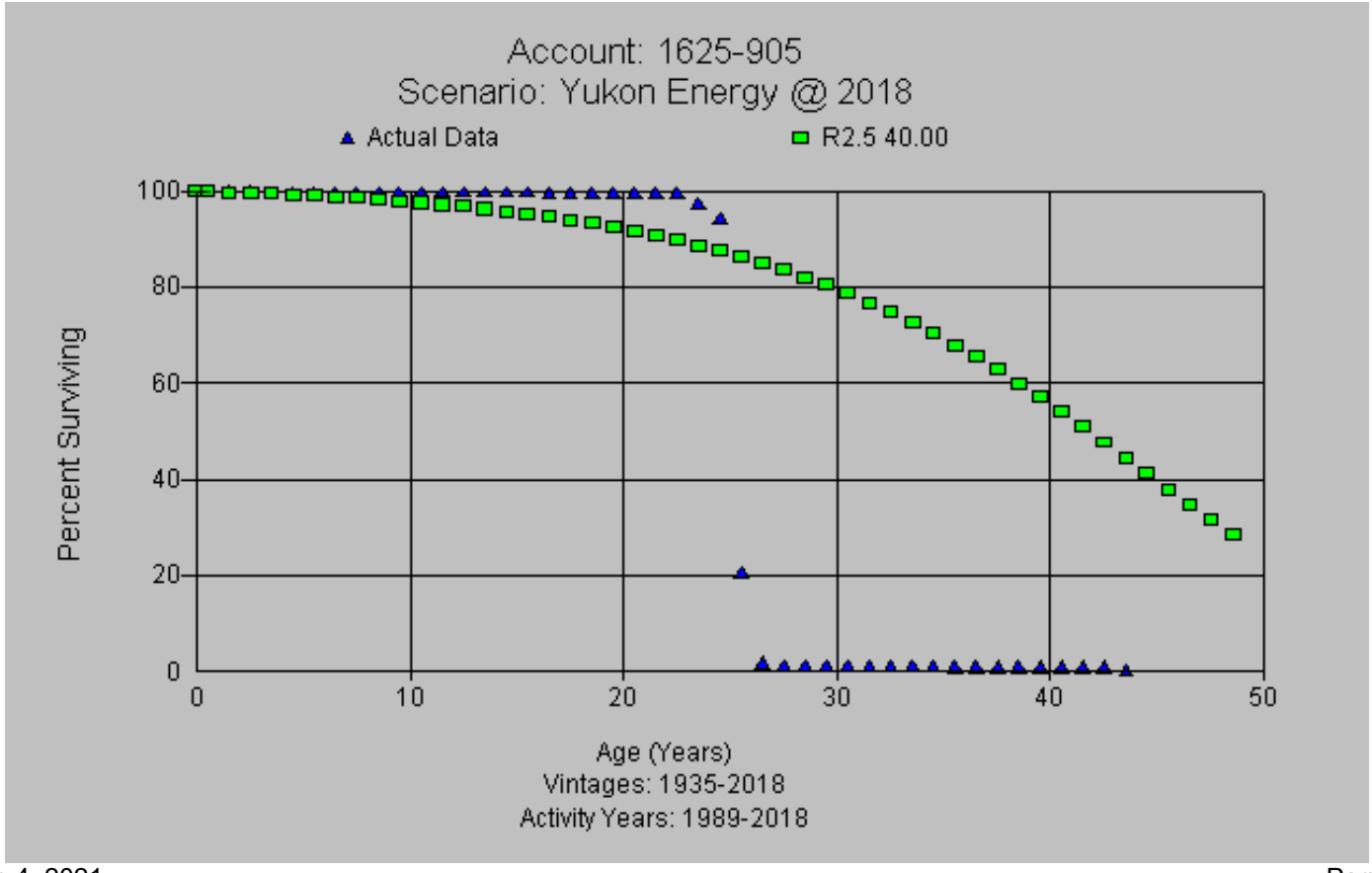
Account: 1625-815
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 1994
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

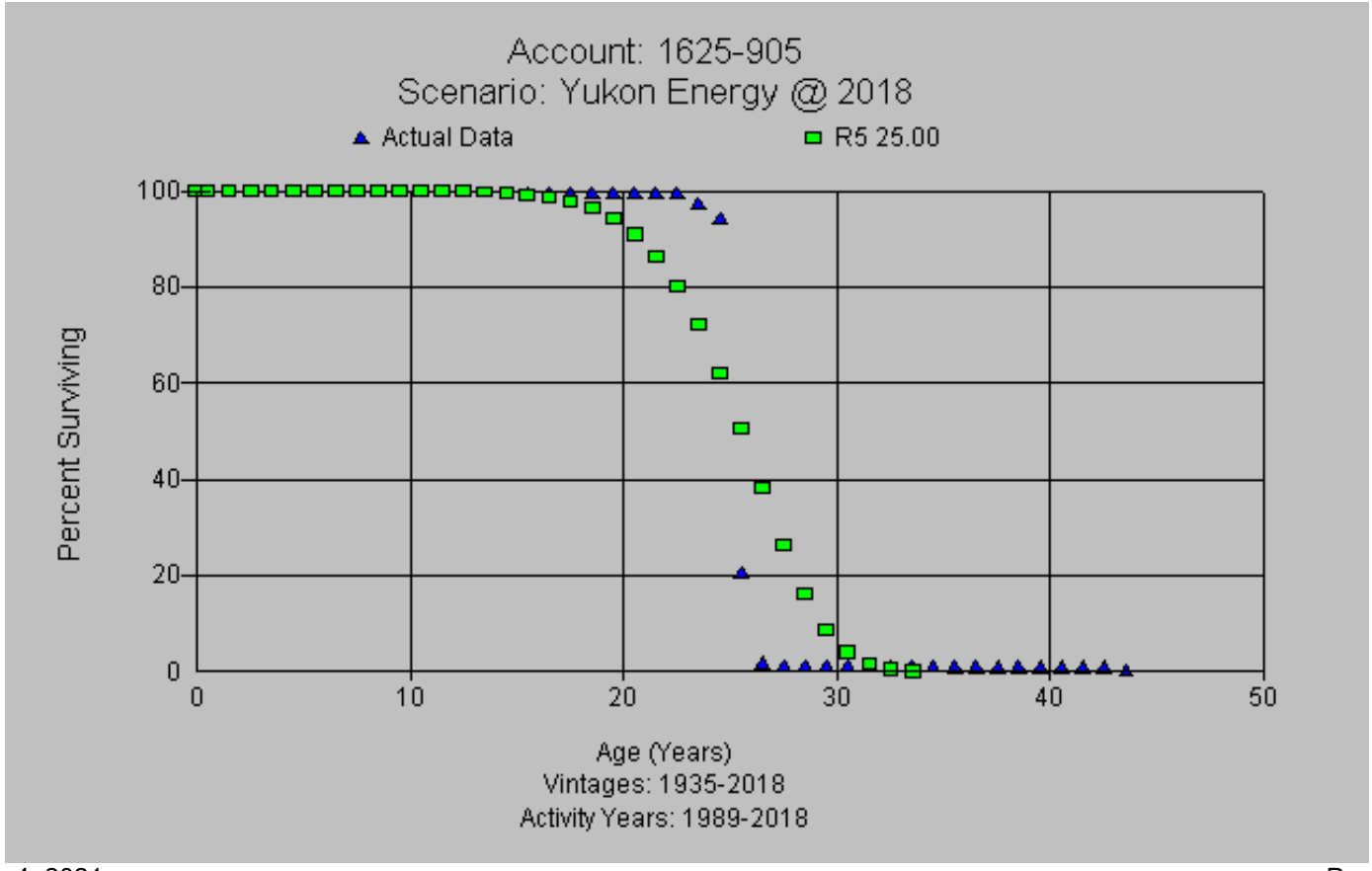
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1990 -1994	12.5	0.00	0.00000000	S5	0.30
1991 -1995		1.00			
1992 -1996		1.00			
1993 -1997		1.00			
1994 -1998		1.00			
1995 -1999		1.00			
1996 -2000		1.00			
1997 -2001		1.00			
1998 -2002		1.00			
1999 -2003		1.00			
2000 -2004		1.00			
2001 -2005	23.5	0.00	0.00000000	SQ	23.20
2002 -2006	24.5	0.00	0.00000000	SQ	23.20
2003 -2007	25.5	0.00	0.00000000	SQ	23.20
2004 -2008	26.5	0.00	0.00000000	SQ	23.20
2005 -2009	27.5	0.00	0.00000000	SQ	23.20
2006 -2010		1.00			
2007 -2011		1.00			
2008 -2012		1.00			
2009 -2013		1.00			
2010 -2014	32.5	79.88	0.09006218	L0	68.58
2011 -2015	33.5	87.45	0.03631476	L0	98.54
2012 -2016	34.5	90.35	0.02239003	L0	120.85
2013 -2017	35.5	90.74	0.02153830	L0	125.93
2014 -2018	36.5	91.04	0.02114250	L0	130.51

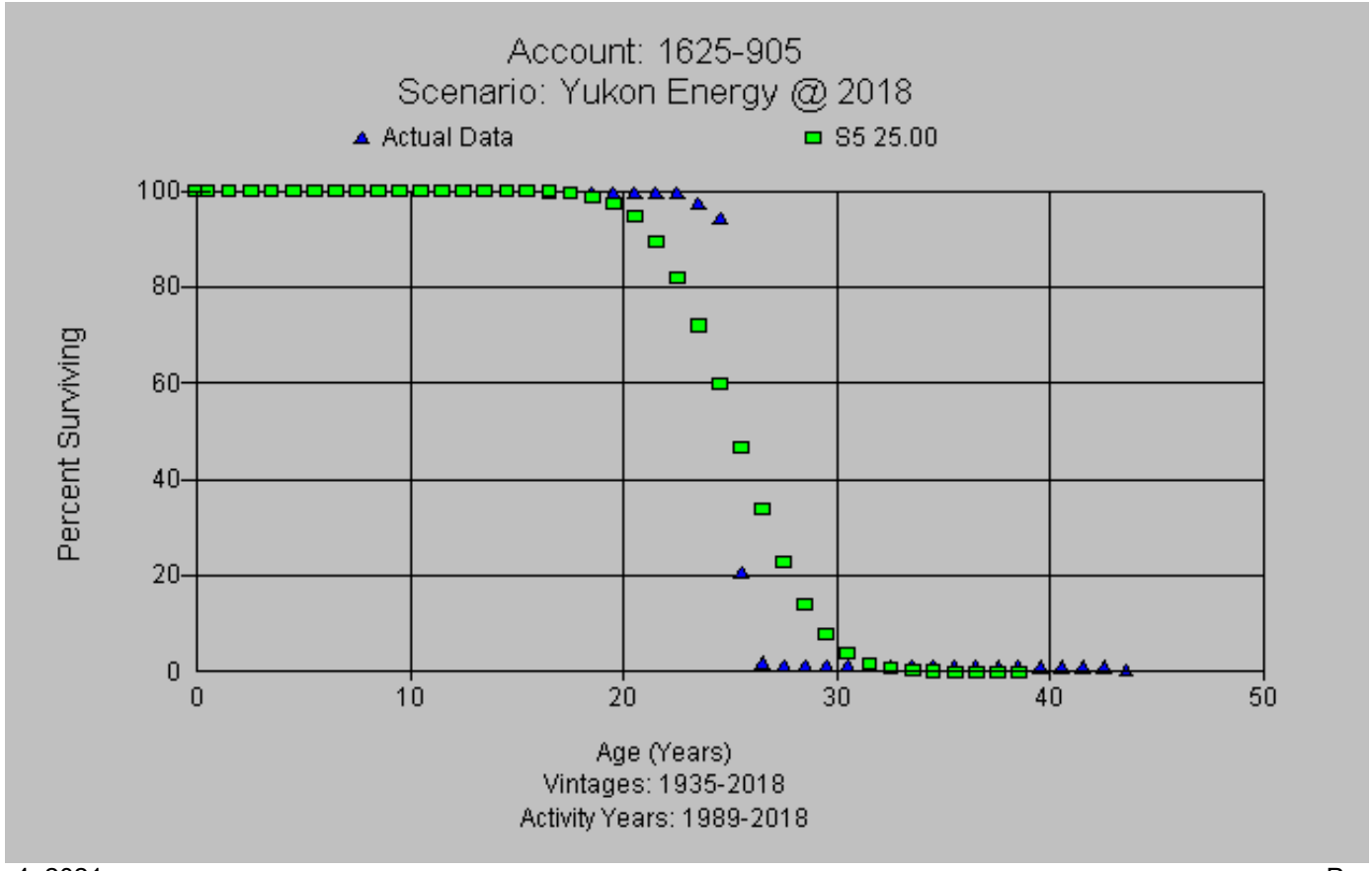
Actuarial Life Analysis

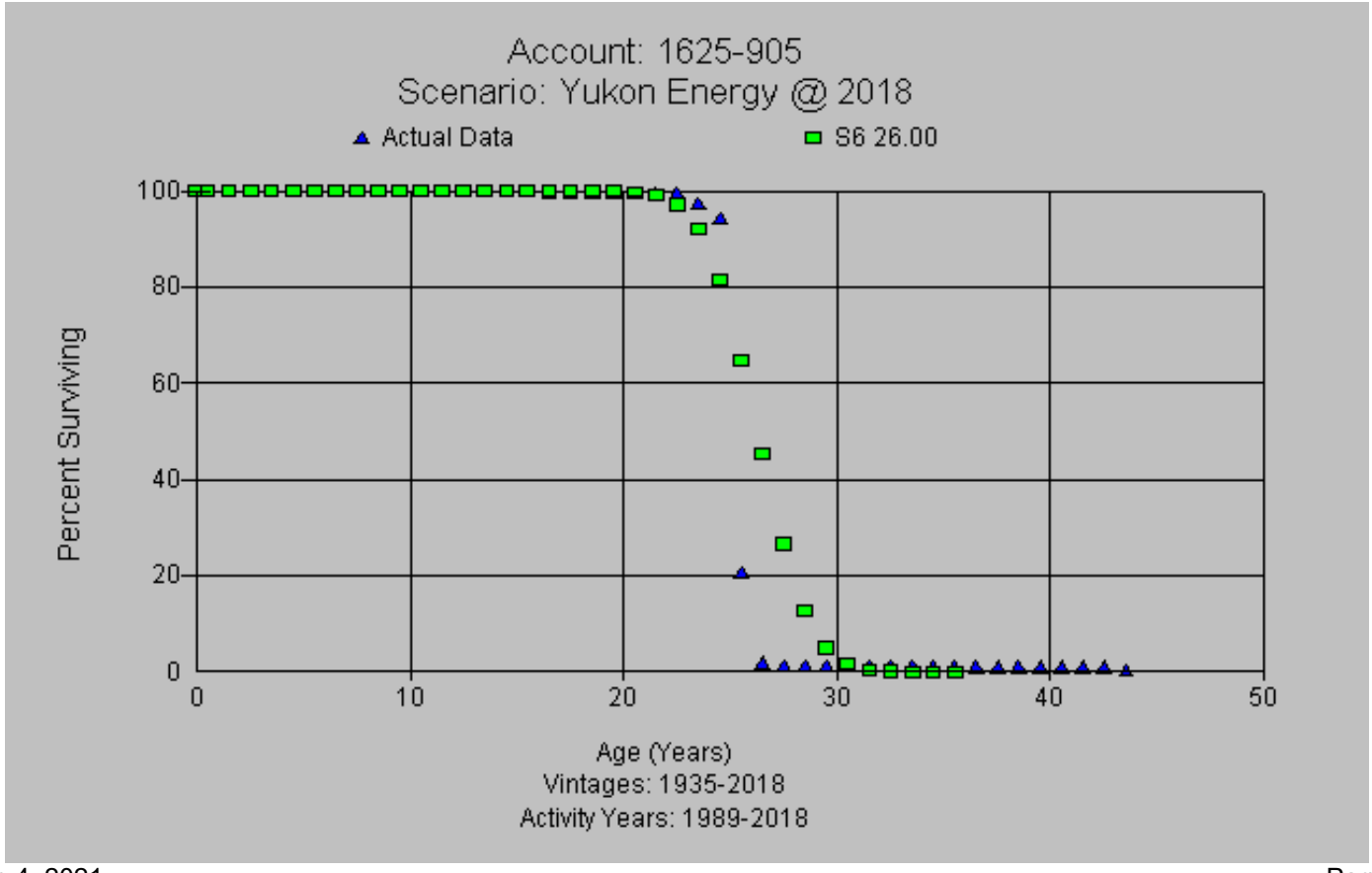
Account: 1625-815
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1990 -2018	38.5	0.00	0.43121746	S6	24.10
1995 -2018	38.5	0.00	0.39290573	S6	24.30
2000 -2018	38.5	0.00	0.38617536	SQ	24.34
2005 -2018	38.5	0.00	0.38617536	SQ	24.34
2010 -2018	38.5	91.04	0.02262101	R0.5	144.93
2015 -2018		1.00			


Account: 1625-905
Scenario: Yukon Energy @ 2018
Actual Data
R2.5 40.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1935-2018
Activity Years: 1989-2018


Account: 1625-905
Scenario: Yukon Energy @ 2018
Actual Data
R5 25.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1935-2018
Activity Years: 1989-2018


Account: 1625-905
Scenario: Yukon Energy @ 2018
Actual Data
S5 25.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1935-2018
Activity Years: 1989-2018


Account: 1625-905
Scenario: Yukon Energy @ 2018
Actual Data
S6 26.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1935-2018
Activity Years: 1989-2018

Observed Life Table

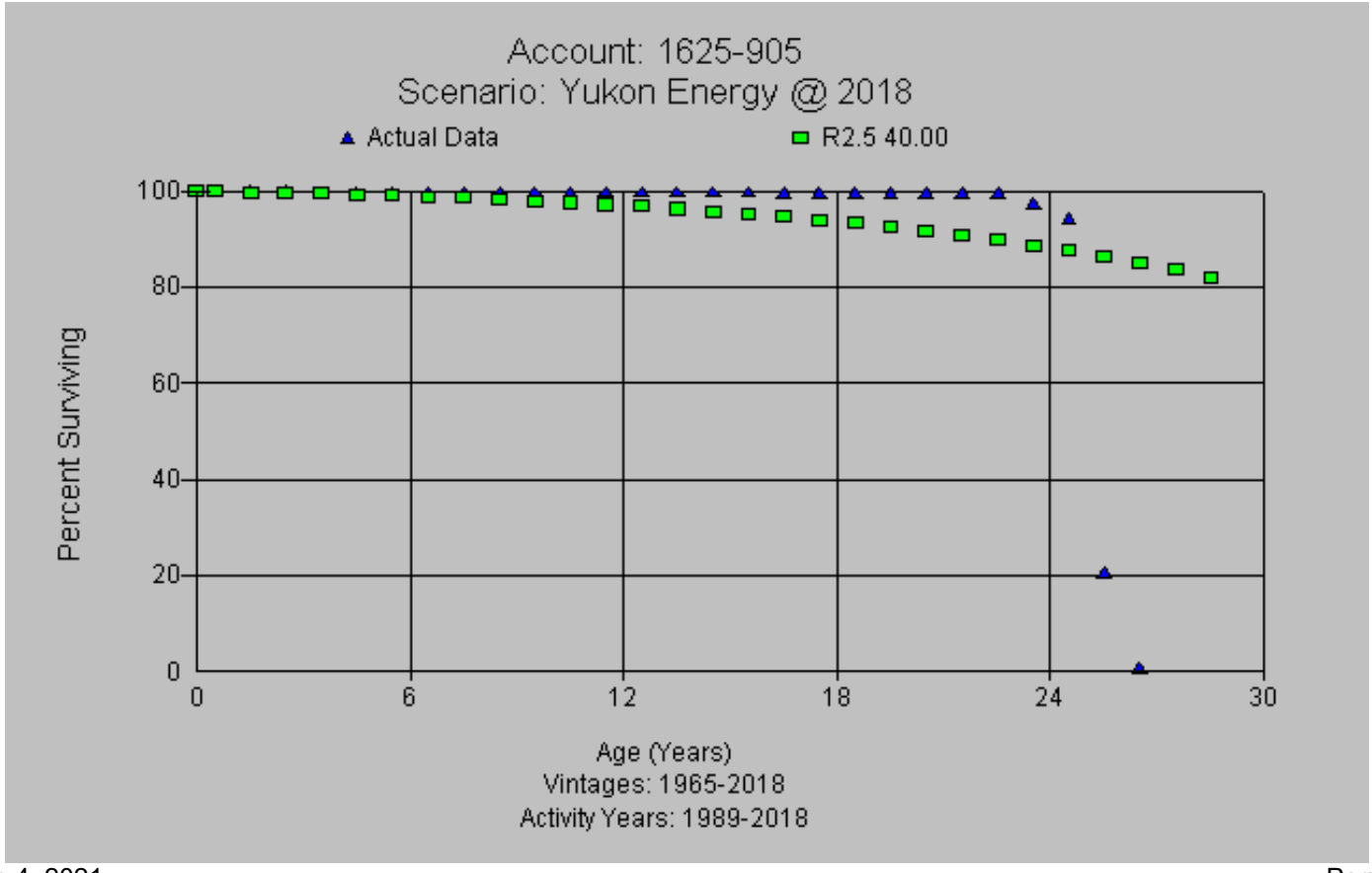
Scenario: Yukon Energy @ 2018
Account: 1625-905
Placement Band: 1935 - 2018 **Observation Band:** 1989 - 2018

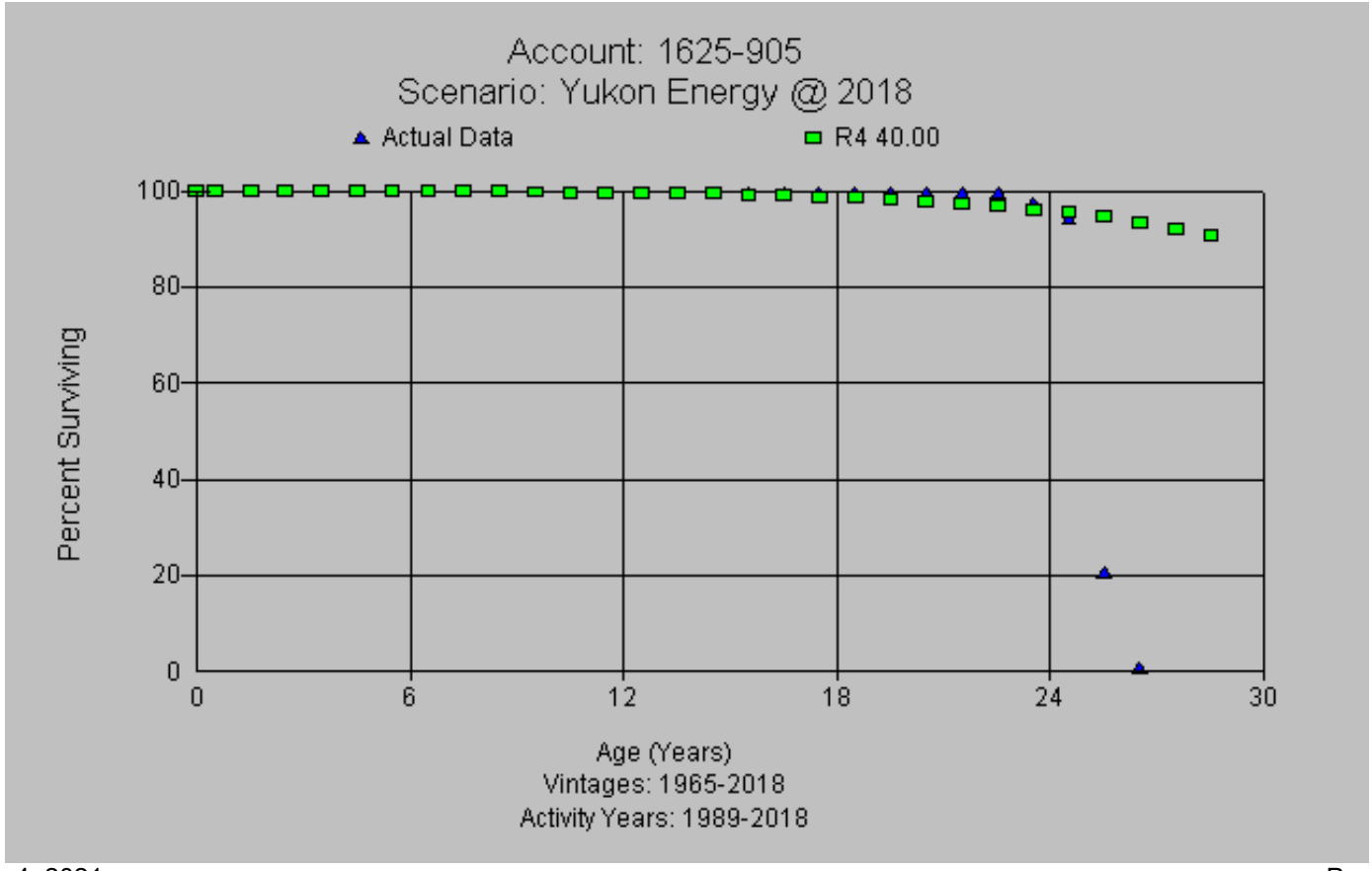
Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	3,876,401.39	615.00	0.00016	0.99984	100.00
0.5	3,950,443.24	0.00	0.00000	1.00000	99.98
1.5	3,920,254.09	478.00	0.00012	0.99988	99.98
2.5	3,781,849.62	3,593.00	0.00095	0.99905	99.97
3.5	3,690,683.27	331.00	0.00009	0.99991	99.88
4.5	3,690,352.27	0.00	0.00000	1.00000	99.87
5.5	3,690,352.27	331.00	0.00009	0.99991	99.87
6.5	3,690,021.27	239.00	0.00006	0.99994	99.86
7.5	3,683,185.04	0.00	0.00000	1.00000	99.85
8.5	3,313,023.96	0.00	0.00000	1.00000	99.85
9.5	3,249,366.24	0.00	0.00000	1.00000	99.85
10.5	3,213,952.39	0.00	0.00000	1.00000	99.85
11.5	3,116,015.93	0.00	0.00000	1.00000	99.85
12.5	3,060,034.69	0.00	0.00000	1.00000	99.85
13.5	2,960,089.24	0.00	0.00000	1.00000	99.85
14.5	2,900,367.49	0.00	0.00000	1.00000	99.85
15.5	2,625,626.57	689.00	0.00026	0.99974	99.85
16.5	2,603,434.57	0.00	0.00000	1.00000	99.83
17.5	2,603,434.57	0.00	0.00000	1.00000	99.83
18.5	2,429,230.19	0.00	0.00000	1.00000	99.83
19.5	1,417,920.00	0.00	0.00000	1.00000	99.83
20.5	33,502.26	0.00	0.00000	1.00000	99.83
21.5	33,502.26	0.00	0.00000	1.00000	99.83
22.5	33,502.26	838.07	0.02502	0.97498	99.83
23.5	32,664.19	952.82	0.02917	0.97083	97.33
24.5	31,711.37	24,748.36	0.78043	0.21957	94.49
25.5	7,435.41	6,769.01	0.91037	0.08963	20.75
26.5	666.40	194.00	0.29112	0.70888	1.86
27.5	472.40	0.00	0.00000	1.00000	1.32
28.5	647.40	0.00	0.00000	1.00000	1.32
29.5	647.40	0.00	0.00000	1.00000	1.32
30.5	647.40	0.00	0.00000	1.00000	1.32
31.5	647.40	0.00	0.00000	1.00000	1.32
32.5	647.40	0.00	0.00000	1.00000	1.32
33.5	647.40	0.00	0.00000	1.00000	1.32
34.5	647.40	175.00	0.27031	0.72969	1.32
35.5	472.40	0.00	0.00000	1.00000	0.96
36.5	472.40	0.00	0.00000	1.00000	0.96
37.5	472.40	0.00	0.00000	1.00000	0.96

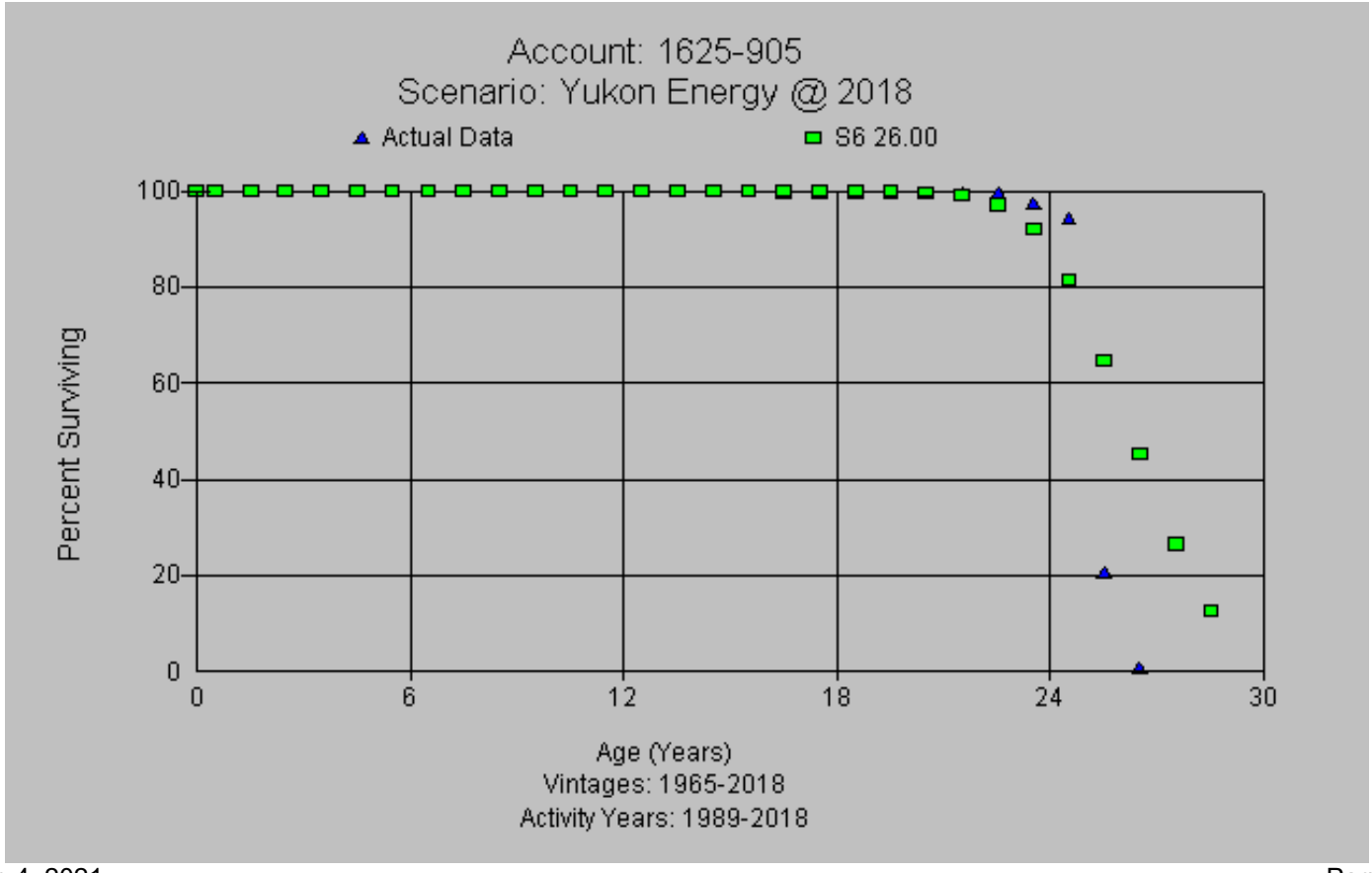
Observed Life Table

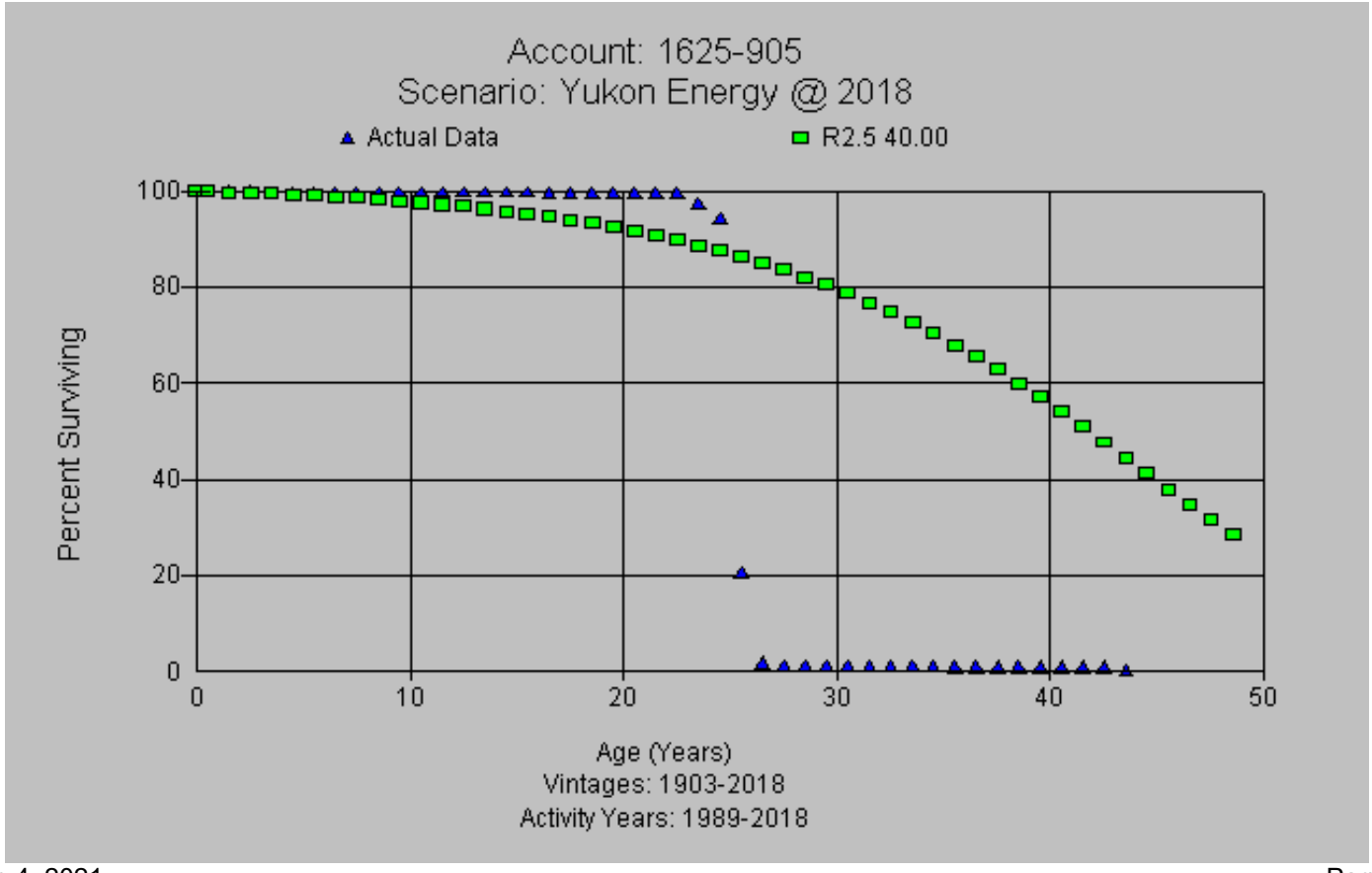
Scenario: Yukon Energy @ 2018
Account: 1625-905
Placement Band: 1935 - 2018 **Observation Band:** 1989 - 2018

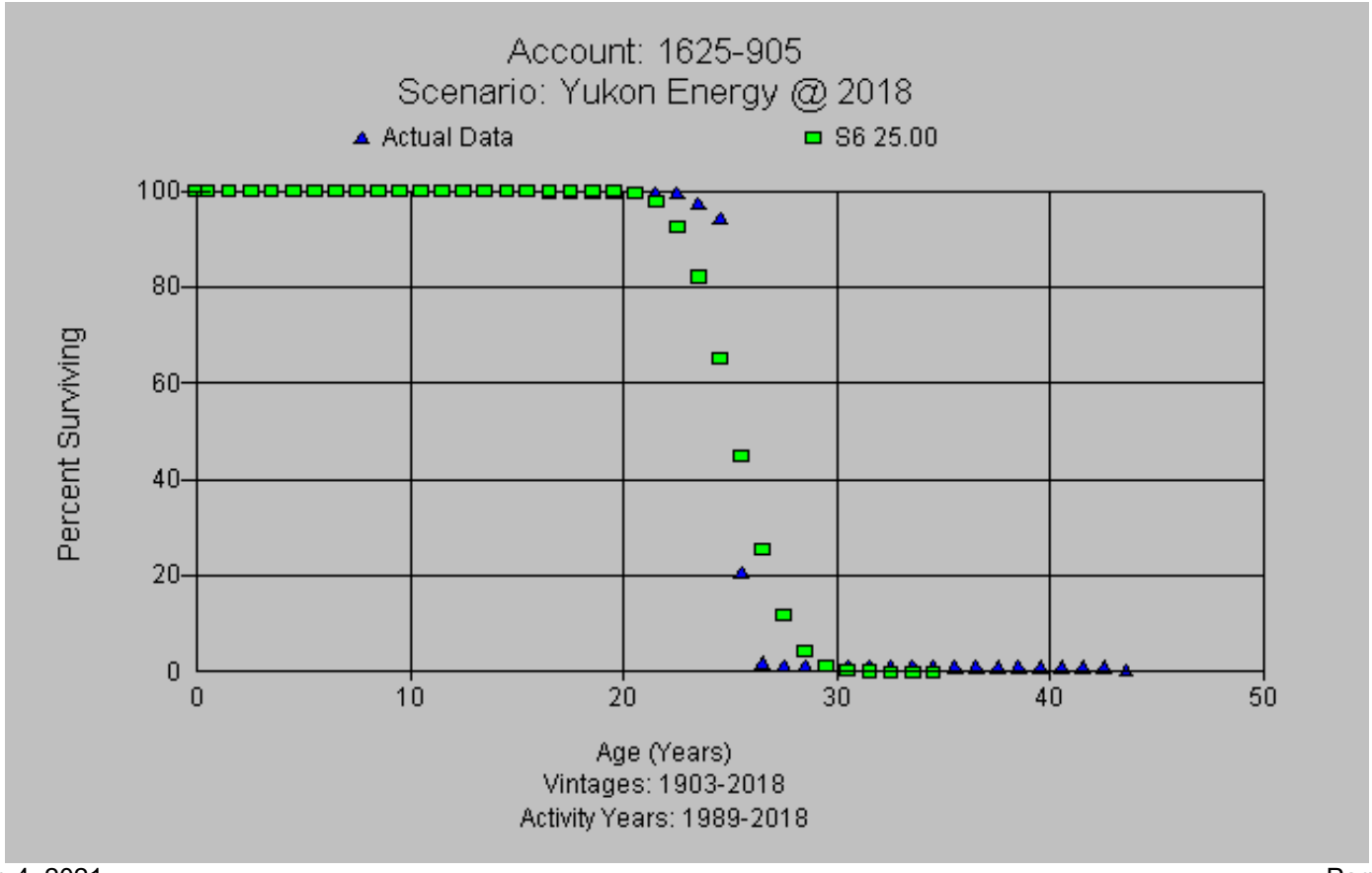
Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
38.5	472.40	0.00	0.00000	1.00000	0.96
39.5	472.40	0.00	0.00000	1.00000	0.96
40.5	472.40	0.00	0.00000	1.00000	0.96
41.5	472.40	0.00	0.00000	1.00000	0.96
42.5	472.40	281.10	0.59505	0.40495	0.96
43.5	191.30	191.30	1.00000	0.00000	0.39
44.5	0.00	0.00	0.00000	1.00000	0.00

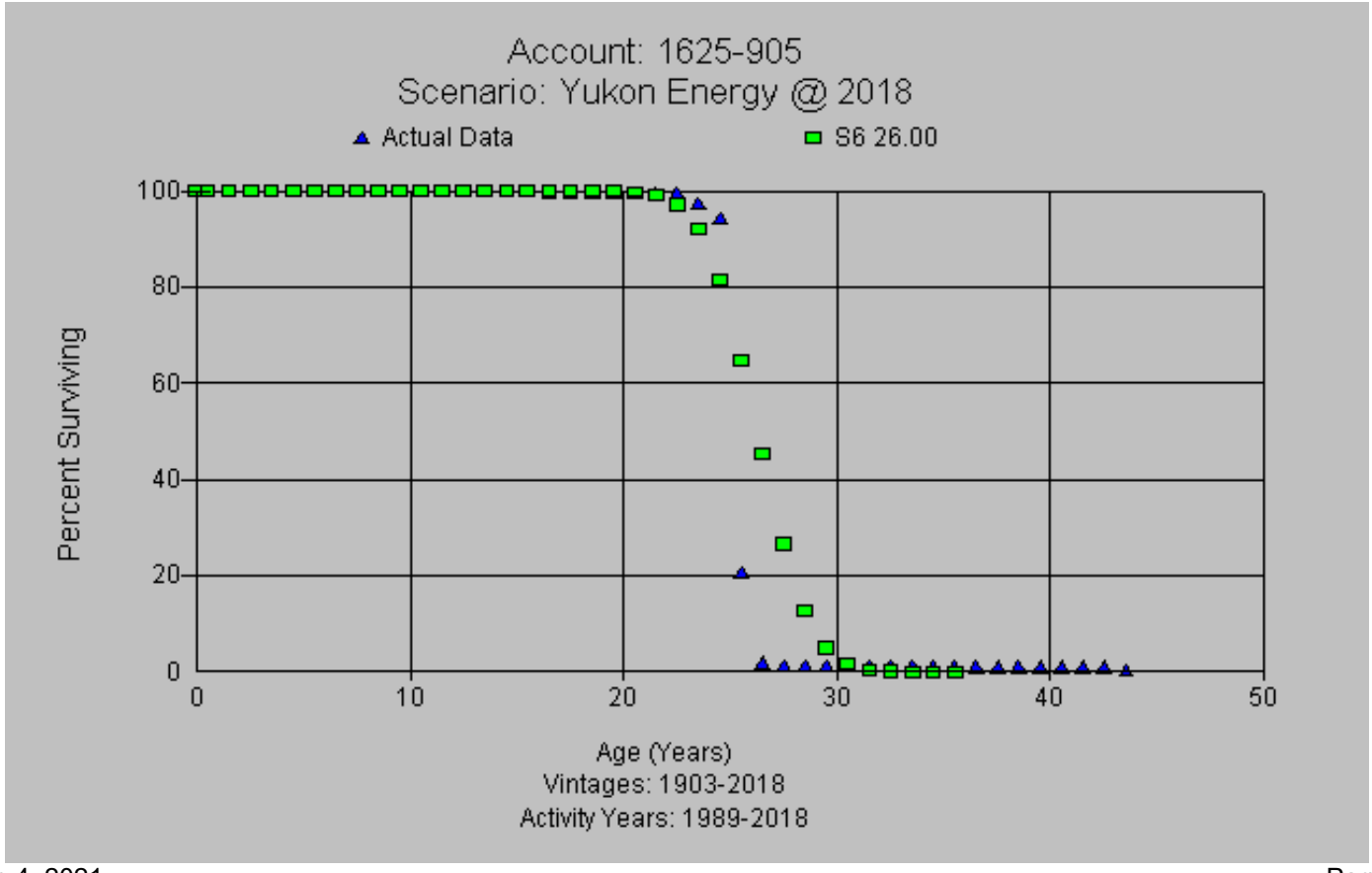

Account: 1625-905
Scenario: Yukon Energy @ 2018
Actual Data
R2.5 40.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1965-2018
Activity Years: 1989-2018


Account: 1625-905
Scenario: Yukon Energy @ 2018
Actual Data
R4 40.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1965-2018
Activity Years: 1989-2018


Account: 1625-905
Scenario: Yukon Energy @ 2018
Actual Data
S6 26.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1965-2018
Activity Years: 1989-2018


Account: 1625-905
Scenario: Yukon Energy @ 2018
Actual Data
R2.5 40.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1903-2018
Activity Years: 1989-2018


Account: 1625-905
Scenario: Yukon Energy @ 2018
Actual Data
S6 25.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1903-2018
Activity Years: 1989-2018


Account: 1625-905
Scenario: Yukon Energy @ 2018
Actual Data
S6 26.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1903-2018
Activity Years: 1989-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1625-905
Placement Band: 1903 - 2018 **Observation Band:** 1989 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	3,876,401.39	615.00	0.00016	0.99984	100.00
0.5	3,950,443.24	0.00	0.00000	1.00000	99.98
1.5	3,920,254.09	478.00	0.00012	0.99988	99.98
2.5	3,781,849.62	3,593.00	0.00095	0.99905	99.97
3.5	3,690,683.27	331.00	0.00009	0.99991	99.88
4.5	3,690,352.27	0.00	0.00000	1.00000	99.87
5.5	3,690,352.27	331.00	0.00009	0.99991	99.87
6.5	3,690,021.27	239.00	0.00006	0.99994	99.86
7.5	3,683,185.04	0.00	0.00000	1.00000	99.85
8.5	3,313,023.96	0.00	0.00000	1.00000	99.85
9.5	3,249,366.24	0.00	0.00000	1.00000	99.85
10.5	3,213,952.39	0.00	0.00000	1.00000	99.85
11.5	3,116,015.93	0.00	0.00000	1.00000	99.85
12.5	3,060,034.69	0.00	0.00000	1.00000	99.85
13.5	2,960,089.24	0.00	0.00000	1.00000	99.85
14.5	2,900,367.49	0.00	0.00000	1.00000	99.85
15.5	2,625,626.57	689.00	0.00026	0.99974	99.85
16.5	2,603,434.57	0.00	0.00000	1.00000	99.83
17.5	2,603,434.57	0.00	0.00000	1.00000	99.83
18.5	2,429,230.19	0.00	0.00000	1.00000	99.83
19.5	1,417,920.00	0.00	0.00000	1.00000	99.83
20.5	33,502.26	0.00	0.00000	1.00000	99.83
21.5	33,502.26	0.00	0.00000	1.00000	99.83
22.5	33,502.26	838.07	0.02502	0.97498	99.83
23.5	32,664.19	952.82	0.02917	0.97083	97.33
24.5	31,711.37	24,748.36	0.78043	0.21957	94.49
25.5	7,435.41	6,769.01	0.91037	0.08963	20.75
26.5	666.40	194.00	0.29112	0.70888	1.86
27.5	472.40	0.00	0.00000	1.00000	1.32
28.5	647.40	0.00	0.00000	1.00000	1.32
29.5	647.40	0.00	0.00000	1.00000	1.32
30.5	647.40	0.00	0.00000	1.00000	1.32
31.5	647.40	0.00	0.00000	1.00000	1.32
32.5	647.40	0.00	0.00000	1.00000	1.32
33.5	647.40	0.00	0.00000	1.00000	1.32
34.5	647.40	175.00	0.27031	0.72969	1.32
35.5	472.40	0.00	0.00000	1.00000	0.96
36.5	472.40	0.00	0.00000	1.00000	0.96
37.5	472.40	0.00	0.00000	1.00000	0.96

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1625-905
Placement Band: 1903 - 2018 **Observation Band:** 1989 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
38.5	472.40	0.00	0.00000	1.00000	0.96
39.5	472.40	0.00	0.00000	1.00000	0.96
40.5	472.40	0.00	0.00000	1.00000	0.96
41.5	472.40	0.00	0.00000	1.00000	0.96
42.5	472.40	281.10	0.59505	0.40495	0.96
43.5	191.30	191.30	1.00000	0.00000	0.39
44.5	0.00	0.00	0.00000	1.00000	0.00
45.5	0.00	0.00	0.00000	1.00000	
46.5	0.00	0.00	0.00000	1.00000	
47.5	0.00	0.00	0.00000	1.00000	
48.5	0.00	0.00	0.00000	1.00000	
49.5	0.00	0.00	0.00000	1.00000	
50.5	0.00	0.00	0.00000	1.00000	
51.5	0.00	0.00	0.00000	1.00000	
52.5	0.00	0.00	0.00000	1.00000	
53.5	0.00	0.00	0.00000	1.00000	
54.5	0.00	0.00	0.00000	1.00000	
55.5	0.00	0.00	0.00000	1.00000	
56.5	0.00	0.00	0.00000	1.00000	
57.5	0.00	0.00	0.00000	1.00000	
58.5	0.00	0.00	0.00000	1.00000	
59.5	0.00	0.00	0.00000	1.00000	
60.5	0.00	0.00	0.00000	1.00000	
61.5	0.00	0.00	0.00000	1.00000	
62.5	0.00	0.00	0.00000	1.00000	
63.5	0.00	0.00	0.00000	1.00000	
64.5	0.00	0.00	0.00000	1.00000	
85.5	154.46	0.00	0.00000	1.00000	
86.5	154.46	0.00	0.00000	1.00000	
87.5	154.46	0.00	0.00000	1.00000	
88.5	154.46	0.00	0.00000	1.00000	
89.5	154.46	0.00	0.00000	1.00000	
90.5	154.46	0.00	0.00000	1.00000	
91.5	154.46	0.00	0.00000	1.00000	
92.5	154.46	0.00	0.00000	1.00000	
93.5	154.46	0.00	0.00000	1.00000	
94.5	154.46	0.00	0.00000	1.00000	
95.5	154.46	0.00	0.00000	1.00000	
96.5	154.46	0.00	0.00000	1.00000	

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1625-905
Placement Band: 1903 - 2018 **Observation Band:** 1989 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
97.5	154.46	0.00	0.00000	1.00000	
98.5	154.46	0.00	0.00000	1.00000	
99.5	154.46	0.00	0.00000	1.00000	
100.5	154.46	0.00	0.00000	1.00000	
101.5	154.46	0.00	0.00000	1.00000	
102.5	154.46	0.00	0.00000	1.00000	
103.5	154.46	154.46	1.00000	0.00000	
104.5	0.00	0.00	0.00000	1.00000	

Actuarial Life Analysis

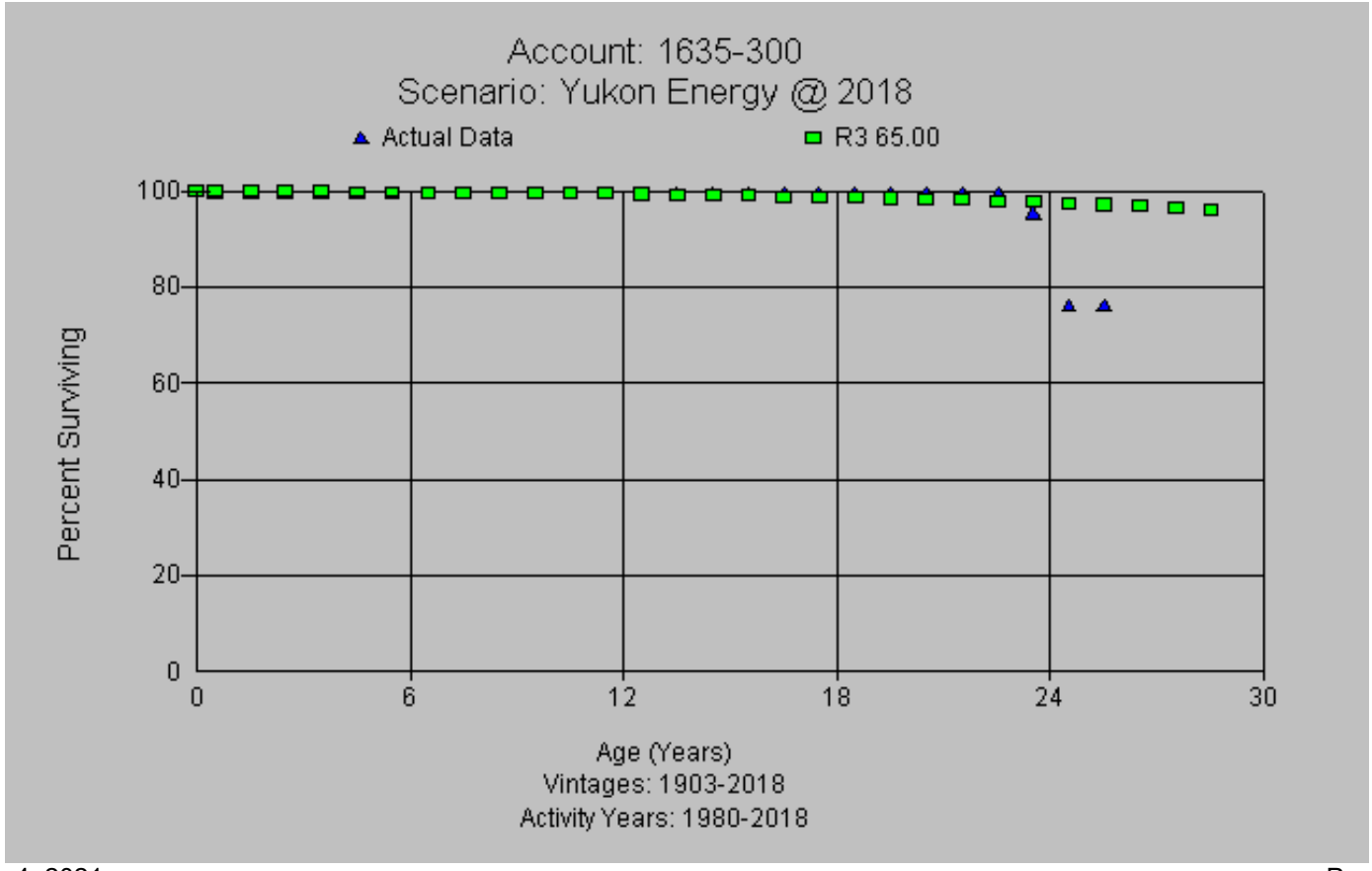
Account: 1625-905
Scenario: Yukon Energy @ 2018
Placement Band: 1903 - 1993
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

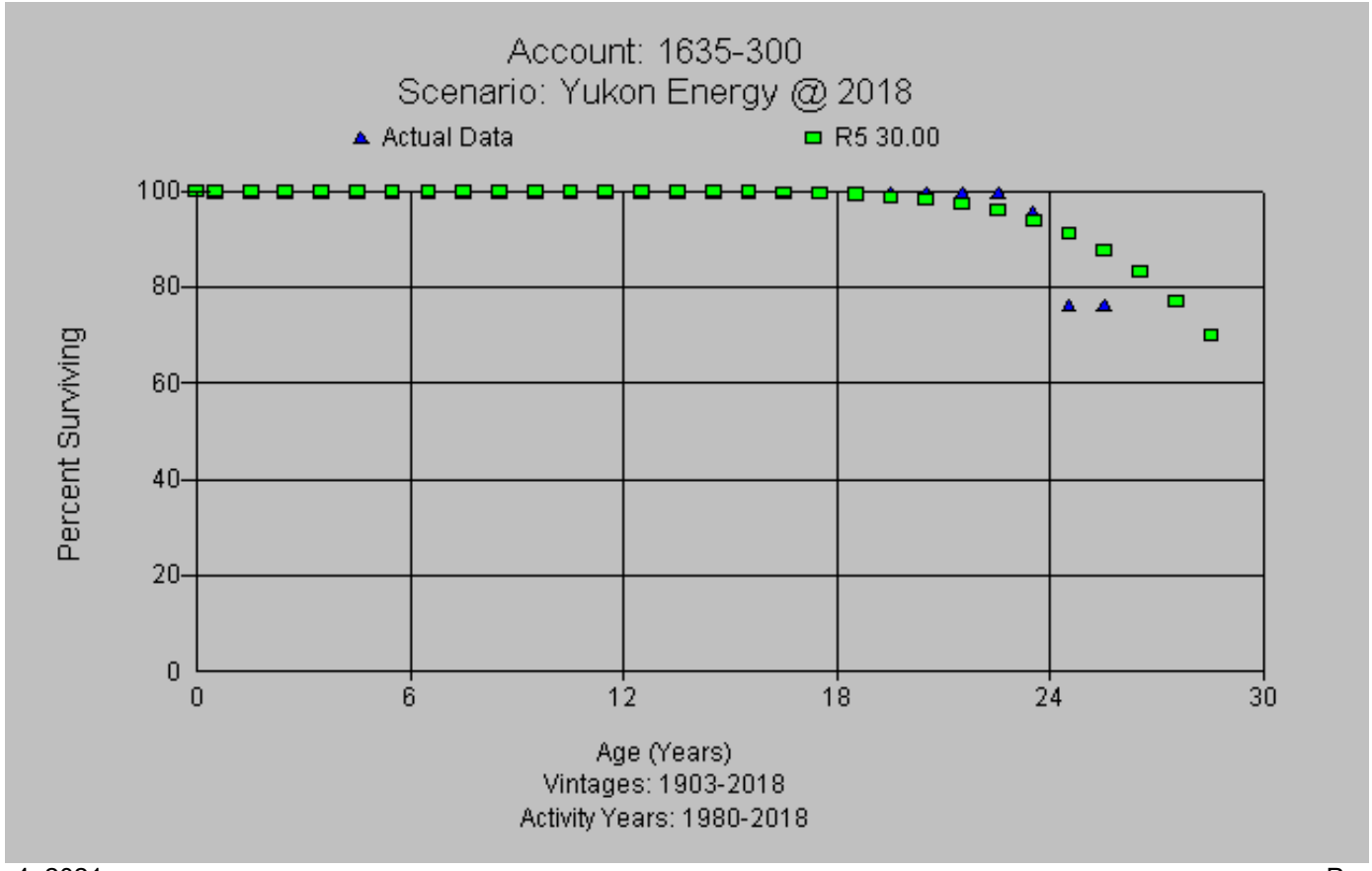
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1989 -1993	34.5	2.99	0.30663980	L2	4.20
1990 -1994	35.5	0.00	0.10483126	L4	3.56
1991 -1995	36.5	0.00	0.04473175	R4	5.52
1992 -1996	37.5	0.00	0.00723392	S6	6.50
1993 -1997	38.5	0.00	0.00000000	S5	0.30
1994 -1998	39.5	0.00	0.00000112	SQ	7.05
1995 -1999	40.5	0.00	0.00000000	SQ	7.39
1996 -2000	41.5	0.00	0.00000000	SQ	7.39
1997 -2001	42.5	0.00	0.00000000	SQ	7.39
1998 -2002		1.00			
1999 -2003	44.5	97.48	0.00210808	R2	201.48
2000 -2004	45.5	94.62	0.00838873	L0	244.16
2001 -2005	46.5	20.34	1.09903786	L3	27.85
2002 -2006	47.5	0.00	0.03885945	SQ	23.27
2003 -2007	48.5	0.00	0.03885945	SQ	23.27
2004 -2008	49.5	0.00	0.00283761	SQ	23.33
2005 -2009	50.5	0.00	0.03689381	SQ	23.36
2006 -2010	51.5	0.00	0.00000000	SQ	24.20
2007 -2011	52.5	0.00	0.00000000	SQ	35.10
2008 -2012		1.00			
2009 -2013		1.00			
2010 -2014		1.00			
2011 -2015		1.00			
2012 -2016		1.00			
2013 -2017		1.00			
2014 -2018		1.00			

Actuarial Life Analysis

Account: 1625-905
Scenario: Yukon Energy @ 2018
Placement Band: 1903 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1989 -2018	95.5	0.00	0.04375302	SQ	25.35
1994 -2018	95.5	0.00	0.01430166	SQ	25.27
1999 -2018	95.5	0.00	0.01563872	SQ	25.27
2004 -2018	95.5	0.00	0.01155654	SQ	25.33
2009 -2018		1.00			
2014 -2018		1.00			


Account: 1635-300
Scenario: Yukon Energy @ 2018
Actual Data
R3 65.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1903-2018
Activity Years: 1980-2018


Account: 1635-300
Scenario: Yukon Energy @ 2018
Actual Data
R5 30.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1903-2018
Activity Years: 1980-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1635-300
Placement Band: 1903 - 2018 **Observation Band:** 1980 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	60,708,398.73	165,914.31	0.00273	0.99727	100.00
0.5	53,355,813.11	0.00	0.00000	1.00000	99.73
1.5	52,449,251.80	0.00	0.00000	1.00000	99.73
2.5	51,518,824.88	0.00	0.00000	1.00000	99.73
3.5	50,834,900.19	0.00	0.00000	1.00000	99.73
4.5	50,047,469.88	0.00	0.00000	1.00000	99.73
5.5	49,015,994.74	0.00	0.00000	1.00000	99.73
6.5	47,793,803.78	0.00	0.00000	1.00000	99.73
7.5	35,563,937.70	0.00	0.00000	1.00000	99.73
8.5	34,930,671.55	0.00	0.00000	1.00000	99.73
9.5	34,551,124.65	0.00	0.00000	1.00000	99.73
10.5	18,747,953.59	0.00	0.00000	1.00000	99.73
11.5	16,196,566.44	0.00	0.00000	1.00000	99.73
12.5	15,893,485.32	0.00	0.00000	1.00000	99.73
13.5	15,893,485.32	0.00	0.00000	1.00000	99.73
14.5	15,650,693.88	0.00	0.00000	1.00000	99.73
15.5	5,876,496.37	0.00	0.00000	1.00000	99.73
16.5	5,500,654.09	0.00	0.00000	1.00000	99.73
17.5	5,451,098.72	0.00	0.00000	1.00000	99.73
18.5	5,389,228.04	0.00	0.00000	1.00000	99.73
19.5	2,773,722.25	0.00	0.00000	1.00000	99.73
20.5	98,194.42	0.00	0.00000	1.00000	99.73
21.5	98,194.42	0.00	0.00000	1.00000	99.73
22.5	98,194.42	4,229.52	0.04307	0.95693	99.73
23.5	93,964.90	18,913.61	0.20128	0.79872	95.43
24.5	75,051.29	0.00	0.00000	1.00000	76.22
25.5	75,051.29	75,051.29	1.00000	0.00000	76.22
26.5	0.00	0.00	0.00000	1.00000	0.00
27.5	0.00	0.00	0.00000	1.00000	
28.5	0.00	0.00	0.00000	1.00000	
29.5	0.00	0.00	0.00000	1.00000	
30.5	0.00	0.00	0.00000	1.00000	
31.5	0.00	0.00	0.00000	1.00000	
32.5	0.00	0.00	0.00000	1.00000	
33.5	0.00	0.00	0.00000	1.00000	
34.5	0.00	0.00	0.00000	1.00000	
35.5	0.00	0.00	0.00000	1.00000	
36.5	0.00	0.00	0.00000	1.00000	
37.5	0.00	0.00	0.00000	1.00000	

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1635-300
Placement Band: 1903 - 2018 **Observation Band:** 1980 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
76.5	24,552.75	0.00	0.00000	1.00000	
77.5	24,552.75	0.00	0.00000	1.00000	
78.5	24,552.75	0.00	0.00000	1.00000	
79.5	24,552.75	0.00	0.00000	1.00000	
80.5	24,552.75	0.00	0.00000	1.00000	
81.5	24,552.75	0.00	0.00000	1.00000	
82.5	24,552.75	0.00	0.00000	1.00000	
83.5	24,552.75	0.00	0.00000	1.00000	
84.5	24,552.75	0.00	0.00000	1.00000	
85.5	24,552.75	0.00	0.00000	1.00000	
86.5	24,552.75	0.00	0.00000	1.00000	
87.5	24,552.75	0.00	0.00000	1.00000	
88.5	24,552.75	0.00	0.00000	1.00000	
89.5	24,552.75	0.00	0.00000	1.00000	
90.5	24,552.75	0.00	0.00000	1.00000	
91.5	24,552.75	0.00	0.00000	1.00000	
92.5	24,552.75	0.00	0.00000	1.00000	
93.5	24,552.75	0.00	0.00000	1.00000	
94.5	24,552.75	0.00	0.00000	1.00000	
95.5	24,552.75	0.00	0.00000	1.00000	
96.5	24,552.75	0.00	0.00000	1.00000	
97.5	24,552.75	0.00	0.00000	1.00000	
98.5	24,552.75	0.00	0.00000	1.00000	
99.5	24,552.75	0.00	0.00000	1.00000	
100.5	24,552.75	0.00	0.00000	1.00000	
101.5	24,552.75	0.00	0.00000	1.00000	
102.5	24,552.75	0.00	0.00000	1.00000	
103.5	24,552.75	24,552.75	1.00000	0.00000	
104.5	0.00	0.00	0.00000	1.00000	

Actuarial Life Analysis

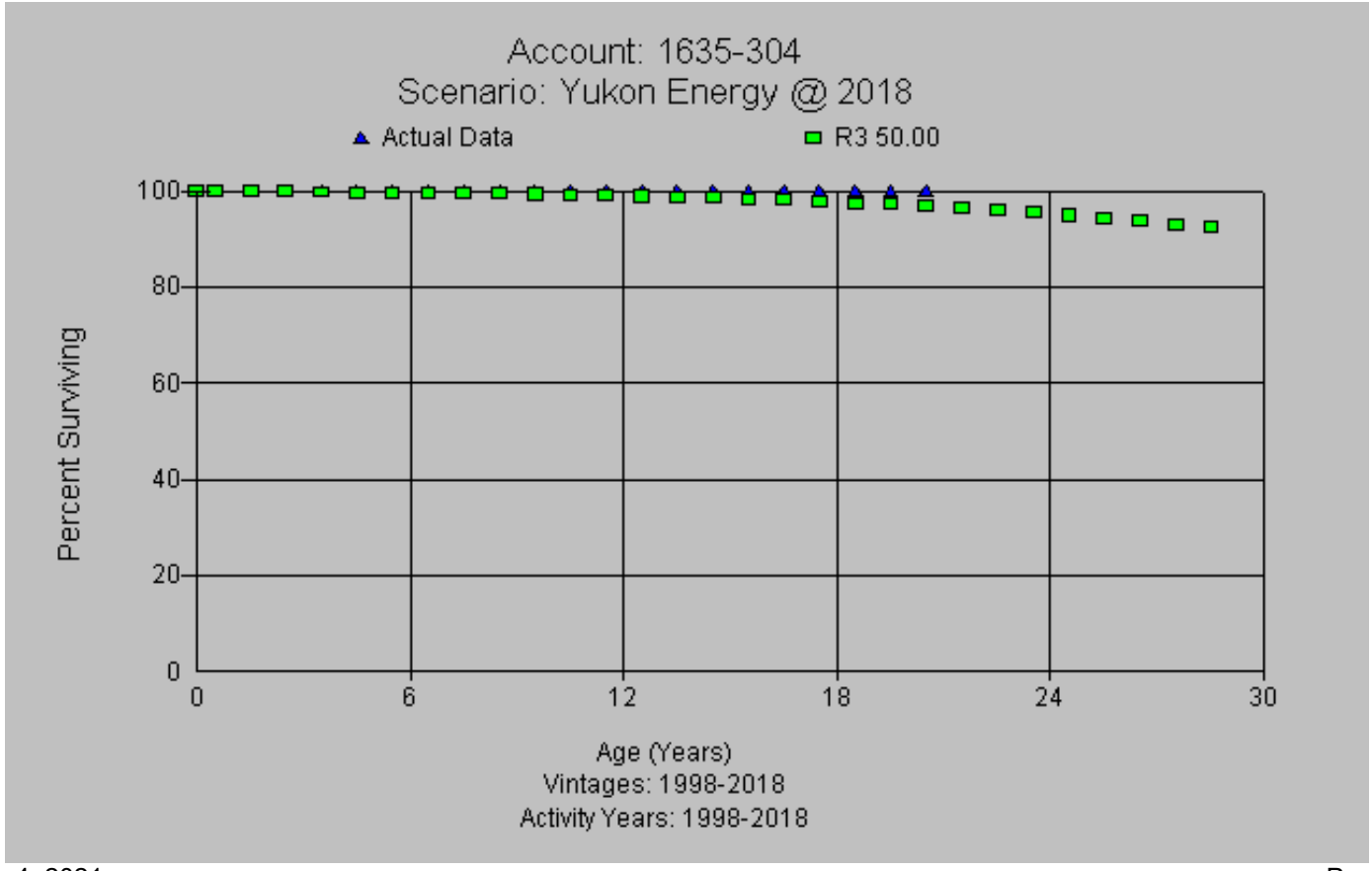
Account: 1635-300
Scenario: Yukon Energy @ 2018
Placement Band: 1903 - 1984
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

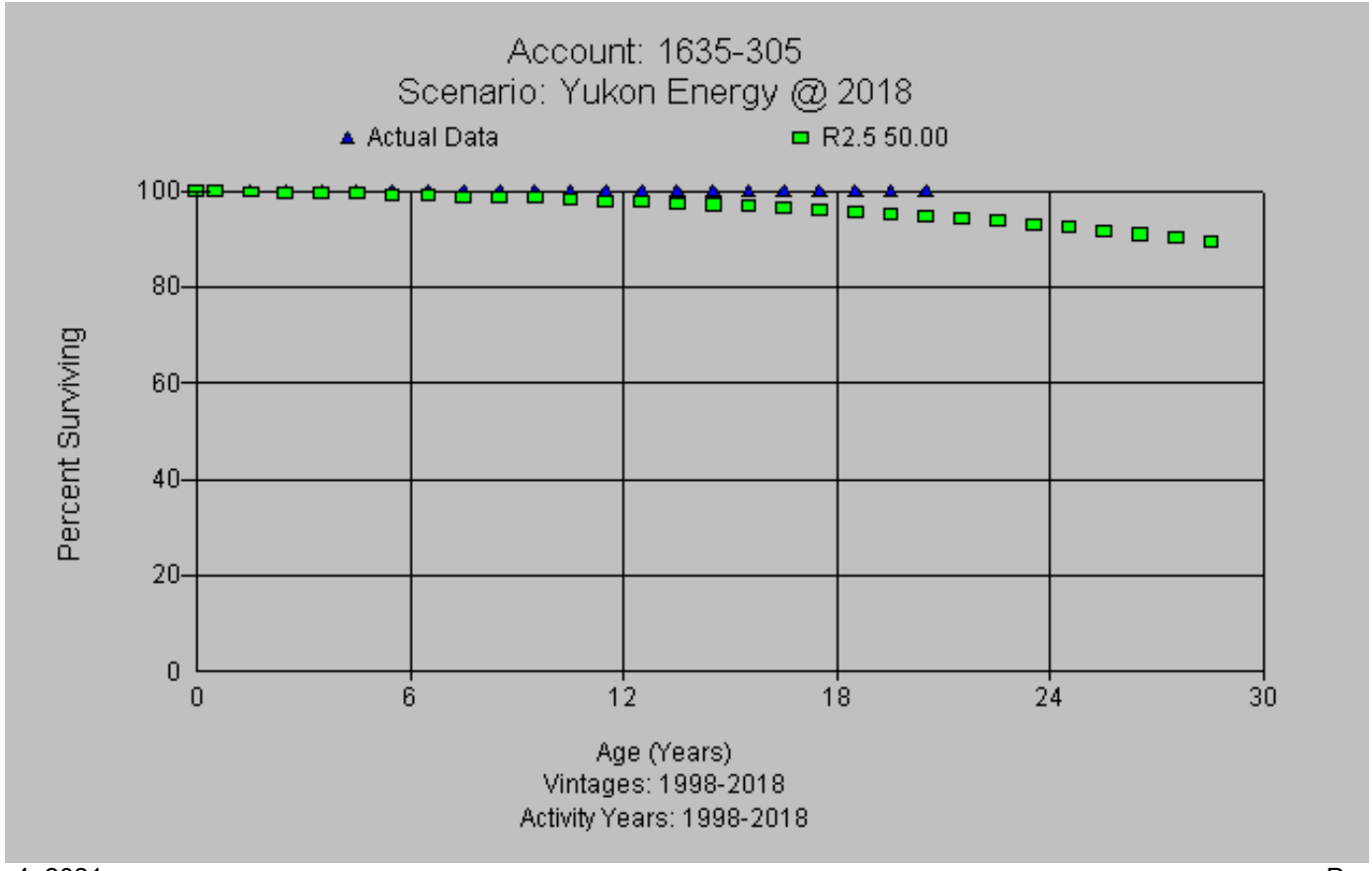
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -1984		1.00			
1981 -1985		1.00			
1982 -1986		1.00			
1983 -1987		1.00			
1984 -1988		1.00			
1985 -1989		1.00			
1986 -1990		1.00			
1987 -1991		1.00			
1988 -1992		1.00			
1989 -1993		1.00			
1990 -1994		1.00			
1991 -1995		1.00			
1992 -1996		1.00			
1993 -1997		1.00			
1994 -1998		1.00			
1995 -1999		1.00			
1996 -2000		1.00			
1997 -2001		1.00			
1998 -2002		1.00			
1999 -2003	15.5	95.69	0.00162807	S1	41.09
2000 -2004	16.5	76.43	0.04225010	S1.5	20.58
2001 -2005	17.5	76.43	0.04796337	S1	22.71
2002 -2006	18.5	0.00	0.09710776	S6	12.53
2003 -2007	19.5	0.00	0.09710776	S6	12.53
2004 -2008	20.5	0.00	0.08752706	SQ	12.54
2005 -2009	21.5	0.00	0.00096148	SQ	12.94
2006 -2010	22.5	0.00	0.00091729	SQ	12.94
2007 -2011	23.5	0.00	0.00051377	SQ	18.95
2008 -2012	24.5	99.45	0.00032397	R2.5	153.13
2009 -2013		1.00			
2010 -2014		1.00			
2011 -2015		1.00			
2012 -2016		1.00			
2013 -2017		1.00			
2014 -2018		1.00			

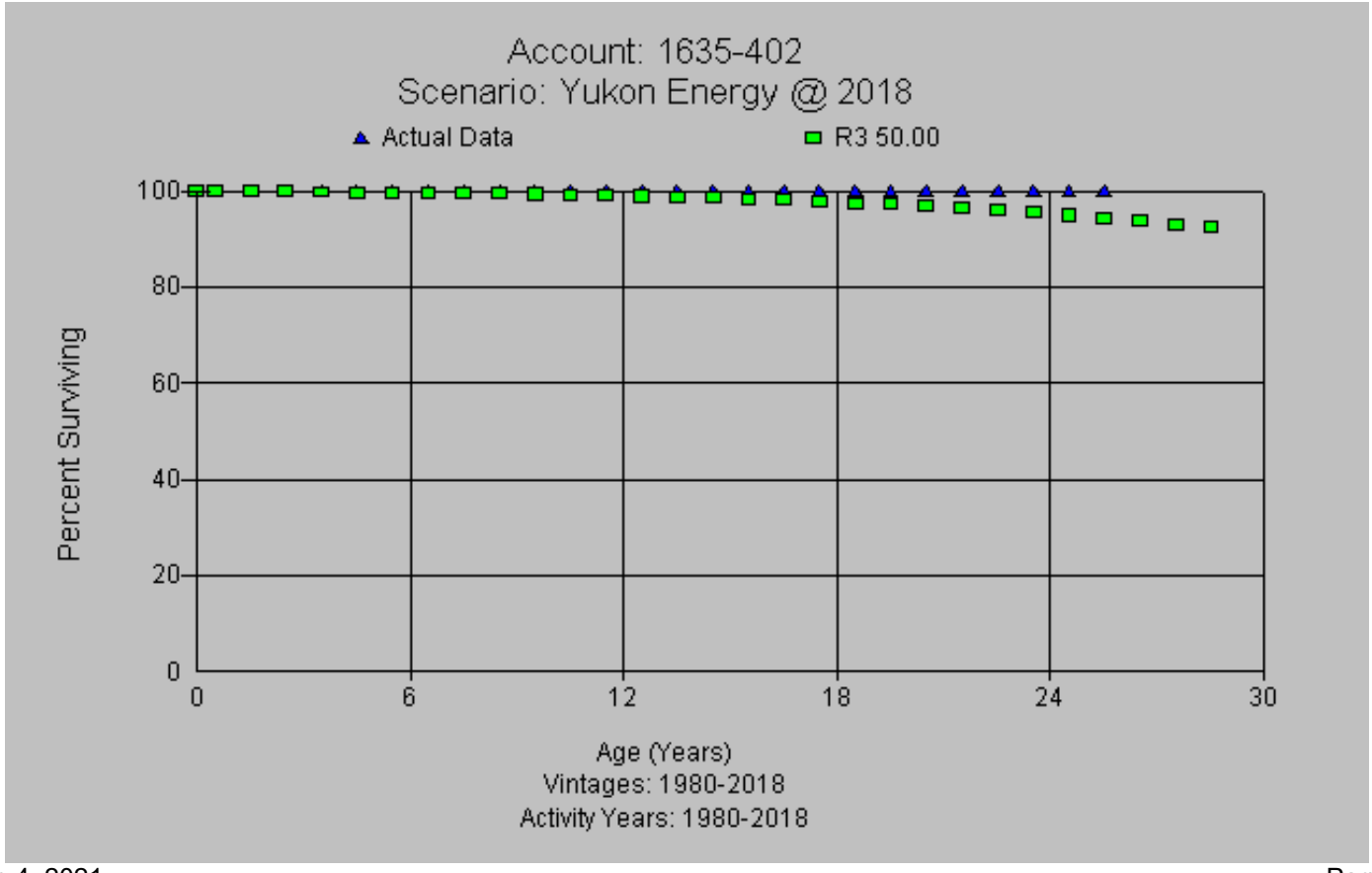
Actuarial Life Analysis

Account: 1635-300
Scenario: Yukon Energy @ 2018
Placement Band: 1903 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -2018	77.5	0.00	0.06976544	SQ	25.47
1985 -2018	77.5	0.00	0.06976544	SQ	25.47
1990 -2018	77.5	0.00	0.06976544	SQ	25.47
1995 -2018	77.5	0.00	0.06976544	SQ	25.47
2000 -2018	77.5	0.00	0.06468634	SQ	25.46
2005 -2018	77.5	0.00	0.00030118	SQ	21.97
2010 -2018		1.00			
2015 -2018		1.00			


Account: 1635-304
Scenario: Yukon Energy @ 2018
Actual Data
R3 50.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1998-2018
Activity Years: 1998-2018


Account: 1635-305
Scenario: Yukon Energy @ 2018
Actual Data
R2.5 50.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1998-2018
Activity Years: 1998-2018


Account: 1635-402
Scenario: Yukon Energy @ 2018
Actual Data
R3 50.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1980-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1635-402
Placement Band: 1980 - 2018 **Observation Band:** 1980 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	20,576,820.43	0.00	0.00000	1.00000	100.00
0.5	20,576,820.43	0.00	0.00000	1.00000	100.00
1.5	20,576,820.43	0.00	0.00000	1.00000	100.00
2.5	20,576,820.43	0.00	0.00000	1.00000	100.00
3.5	20,576,820.43	0.00	0.00000	1.00000	100.00
4.5	20,497,936.68	0.00	0.00000	1.00000	100.00
5.5	20,378,652.28	0.00	0.00000	1.00000	100.00
6.5	20,378,652.28	0.00	0.00000	1.00000	100.00
7.5	15,744,778.69	0.00	0.00000	1.00000	100.00
8.5	15,744,778.69	0.00	0.00000	1.00000	100.00
9.5	15,744,778.69	0.00	0.00000	1.00000	100.00
10.5	10,113,146.67	0.00	0.00000	1.00000	100.00
11.5	10,097,120.18	0.00	0.00000	1.00000	100.00
12.5	9,257,489.30	0.00	0.00000	1.00000	100.00
13.5	9,257,489.30	0.00	0.00000	1.00000	100.00
14.5	7,602,580.11	0.00	0.00000	1.00000	100.00
15.5	1,430,718.73	0.00	0.00000	1.00000	100.00
16.5	1,430,718.73	0.00	0.00000	1.00000	100.00
17.5	830,736.38	0.00	0.00000	1.00000	100.00
18.5	830,736.38	0.00	0.00000	1.00000	100.00
19.5	455,302.01	0.00	0.00000	1.00000	100.00
20.5	15,545.31	0.00	0.00000	1.00000	100.00
21.5	15,545.31	0.00	0.00000	1.00000	100.00
22.5	15,545.31	0.00	0.00000	1.00000	100.00
23.5	15,545.31	0.00	0.00000	1.00000	100.00
24.5	15,545.31	0.00	0.00000	1.00000	100.00
25.5	15,545.31	15,545.31	1.00000	0.00000	100.00
26.5	0.00	0.00	0.00000	1.00000	0.00

Actuarial Life Analysis

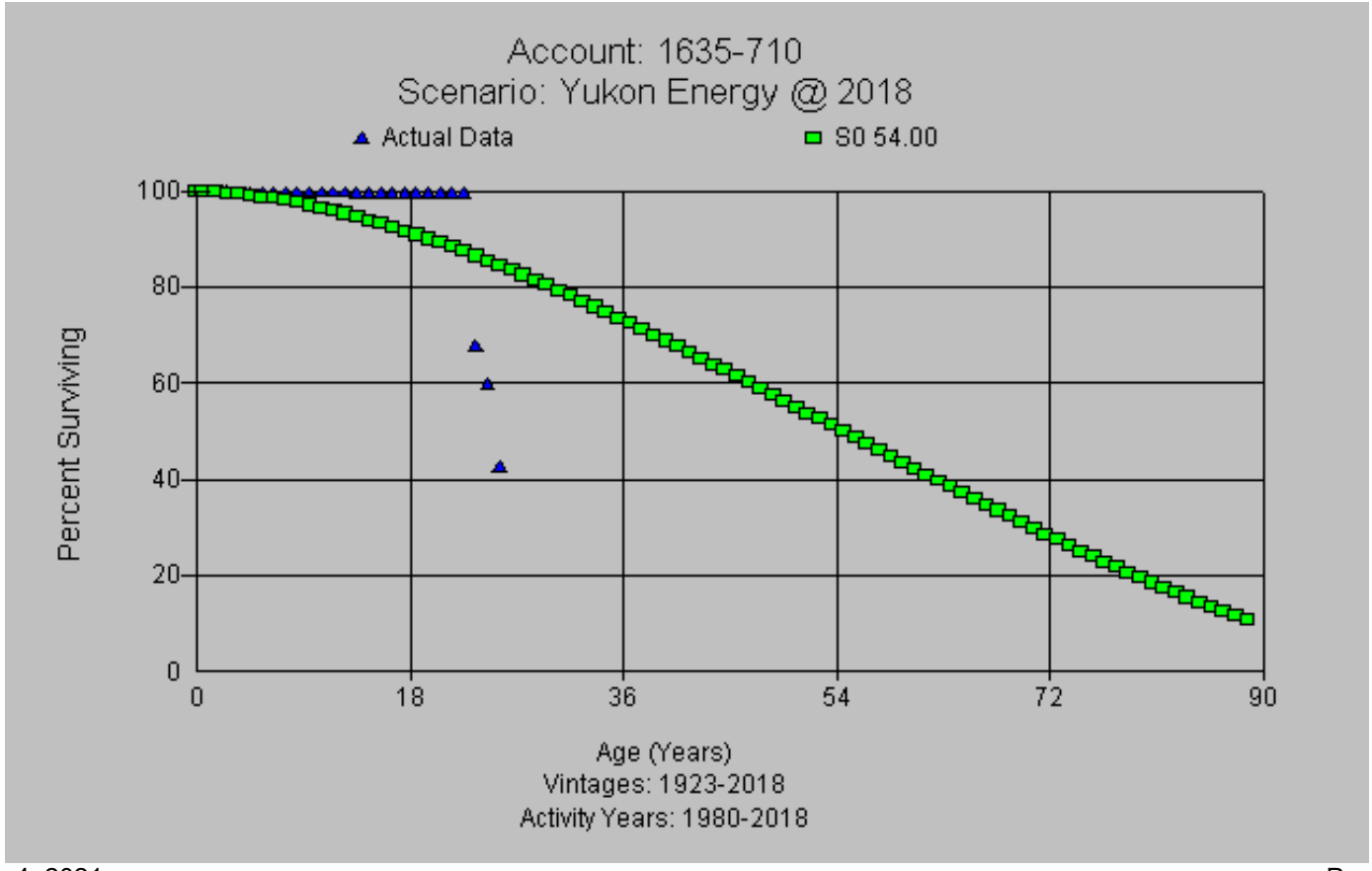
Account: 1635-402
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 1984
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -1984		1.00			
1981 -1985		1.00			
1982 -1986		1.00			
1983 -1987		1.00			
1984 -1988		1.00			
1985 -1989		1.00			
1986 -1990		1.00			
1987 -1991		1.00			
1988 -1992		1.00			
1989 -1993		1.00			
1990 -1994		1.00			
1991 -1995		1.00			
1992 -1996		1.00			
1993 -1997		1.00			
1994 -1998		1.00			
1995 -1999		1.00			
1996 -2000		1.00			
1997 -2001		1.00			
1998 -2002		1.00			
1999 -2003		1.00			
2000 -2004		1.00			
2001 -2005		1.00			
2002 -2006	13.5	0.00	0.00000000	SQ	13.20
2003 -2007	14.5	0.00	0.00000000	SQ	13.20
2004 -2008	15.5	0.00	0.00000000	SQ	13.20
2005 -2009	16.5	0.00	0.00000000	SQ	13.20
2006 -2010	17.5	0.00	0.00000000	SQ	13.20
2007 -2011		1.00			
2008 -2012		1.00			
2009 -2013		1.00			
2010 -2014		1.00			
2011 -2015		1.00			
2012 -2016		1.00			
2013 -2017		1.00			
2014 -2018		1.00			

Actuarial Life Analysis

Account: 1635-402
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -2018	38.5	0.00	0.00000000	SQ	26.20
1985 -2018	38.5	0.00	0.00000000	SQ	26.20
1990 -2018	38.5	0.00	0.00000000	SQ	26.20
1995 -2018	38.5	0.00	0.00000000	SQ	26.20
2000 -2018	38.5	0.00	0.00000000	SQ	26.20
2005 -2018	38.5	0.00	0.00000000	SQ	22.20
2010 -2018		1.00			
2015 -2018		1.00			


Account: 1635-710
Scenario: Yukon Energy @ 2018
Actual Data
S0 54.00
Percent Surviving
100
80
60
40
20
0
0
18
36
54
72
90
Age (Years)
Vintages: 1923-2018
Activity Years: 1980-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1635-710
Placement Band: 1923 - 2018 **Observation Band:** 1980 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	66,994,087.03	57,668.55	0.00086	0.99914	100.00
0.5	66,912,603.21	0.00	0.00000	1.00000	99.91
1.5	66,422,290.00	0.00	0.00000	1.00000	99.91
2.5	66,383,320.09	30,739.06	0.00046	0.99954	99.91
3.5	60,452,510.16	0.00	0.00000	1.00000	99.87
4.5	59,868,345.11	0.00	0.00000	1.00000	99.87
5.5	59,174,268.42	0.00	0.00000	1.00000	99.87
6.5	48,214,370.56	0.00	0.00000	1.00000	99.87
7.5	21,606,390.16	0.00	0.00000	1.00000	99.87
8.5	20,981,343.47	0.00	0.00000	1.00000	99.87
9.5	20,883,618.14	0.00	0.00000	1.00000	99.87
10.5	17,478,490.31	0.00	0.00000	1.00000	99.87
11.5	17,216,945.44	0.00	0.00000	1.00000	99.87
12.5	17,131,905.29	9,043.34	0.00053	0.99947	99.87
13.5	17,075,216.61	0.00	0.00000	1.00000	99.82
14.5	16,961,843.39	0.00	0.00000	1.00000	99.82
15.5	11,346,839.46	0.00	0.00000	1.00000	99.82
16.5	11,346,839.46	0.00	0.00000	1.00000	99.82
17.5	11,346,839.46	0.00	0.00000	1.00000	99.82
18.5	11,026,323.67	0.00	0.00000	1.00000	99.82
19.5	9,848,295.24	34,345.08	0.00349	0.99651	99.82
20.5	261,635.98	0.00	0.00000	1.00000	99.47
21.5	261,635.98	0.00	0.00000	1.00000	99.47
22.5	261,635.98	82,708.47	0.31612	0.68388	99.47
23.5	178,927.51	21,026.43	0.11751	0.88249	68.02
24.5	157,901.08	45,167.54	0.28605	0.71395	60.03
25.5	112,733.54	112,733.54	1.00000	0.00000	42.86
26.5	36,057.65	0.00	0.00000	1.00000	0.00
27.5	36,057.65	0.00	0.00000	1.00000	0.00
28.5	36,057.65	0.00	0.00000	1.00000	0.00
29.5	36,057.65	0.00	0.00000	1.00000	0.00
30.5	36,057.65	0.00	0.00000	1.00000	0.00
31.5	36,057.65	0.00	0.00000	1.00000	0.00
32.5	36,057.65	0.00	0.00000	1.00000	0.00
33.5	36,057.65	0.00	0.00000	1.00000	0.00
34.5	36,057.65	0.00	0.00000	1.00000	0.00
35.5	36,057.65	0.00	0.00000	1.00000	0.00
36.5	46,890.77	0.00	0.00000	1.00000	0.00
37.5	46,890.77	0.00	0.00000	1.00000	0.00

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1635-710
Placement Band: 1923 - 2018 **Observation Band:** 1980 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
38.5	46,890.77	0.00	0.00000	1.00000	0.00
39.5	46,890.77	0.00	0.00000	1.00000	0.00
40.5	46,890.77	0.00	0.00000	1.00000	0.00
41.5	46,890.77	0.00	0.00000	1.00000	0.00
42.5	46,890.77	0.00	0.00000	1.00000	0.00
43.5	46,890.77	0.00	0.00000	1.00000	0.00
44.5	46,890.77	0.00	0.00000	1.00000	0.00
45.5	46,890.77	0.00	0.00000	1.00000	0.00
46.5	46,890.77	0.00	0.00000	1.00000	0.00
47.5	46,890.77	0.00	0.00000	1.00000	0.00
48.5	46,890.77	0.00	0.00000	1.00000	0.00
49.5	46,890.77	0.00	0.00000	1.00000	0.00
50.5	46,890.77	0.00	0.00000	1.00000	0.00
51.5	46,890.77	0.00	0.00000	1.00000	0.00
52.5	46,890.77	0.00	0.00000	1.00000	0.00
53.5	46,890.77	36,057.65	0.76897	0.23103	0.00
54.5	10,833.12	0.00	0.00000	1.00000	0.00
55.5	10,833.12	0.00	0.00000	1.00000	0.00
56.5	54,505.27	0.00	0.00000	1.00000	0.00
57.5	54,505.27	0.00	0.00000	1.00000	0.00
58.5	54,505.27	0.00	0.00000	1.00000	0.00
59.5	54,505.27	0.00	0.00000	1.00000	0.00
60.5	54,505.27	0.00	0.00000	1.00000	0.00
61.5	54,505.27	0.00	0.00000	1.00000	0.00
62.5	54,505.27	0.00	0.00000	1.00000	0.00
63.5	54,505.27	10,833.12	0.19875	0.80125	0.00
64.5	43,672.15	0.00	0.00000	1.00000	0.00
65.5	43,672.15	0.00	0.00000	1.00000	0.00
66.5	43,672.15	0.00	0.00000	1.00000	0.00
67.5	43,672.15	0.00	0.00000	1.00000	0.00
68.5	43,672.15	0.00	0.00000	1.00000	0.00
69.5	43,672.15	0.00	0.00000	1.00000	0.00
70.5	43,672.15	0.00	0.00000	1.00000	0.00
71.5	43,672.15	0.00	0.00000	1.00000	0.00
72.5	43,672.15	0.00	0.00000	1.00000	0.00
73.5	43,672.15	0.00	0.00000	1.00000	0.00
74.5	43,672.15	0.00	0.00000	1.00000	0.00
75.5	43,672.15	0.00	0.00000	1.00000	0.00
76.5	43,672.15	0.00	0.00000	1.00000	0.00

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1635-710
Placement Band: 1923 - 2018 **Observation Band:** 1980 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
77.5	43,672.15	0.00	0.00000	1.00000	0.00
78.5	43,672.15	0.00	0.00000	1.00000	0.00
79.5	43,672.15	0.00	0.00000	1.00000	0.00
80.5	43,672.15	0.00	0.00000	1.00000	0.00
81.5	43,672.15	0.00	0.00000	1.00000	0.00
82.5	43,672.15	0.00	0.00000	1.00000	0.00
83.5	43,672.15	43,672.15	1.00000	0.00000	0.00
84.5	0.00	0.00	0.00000	1.00000	0.00

Actuarial Life Analysis

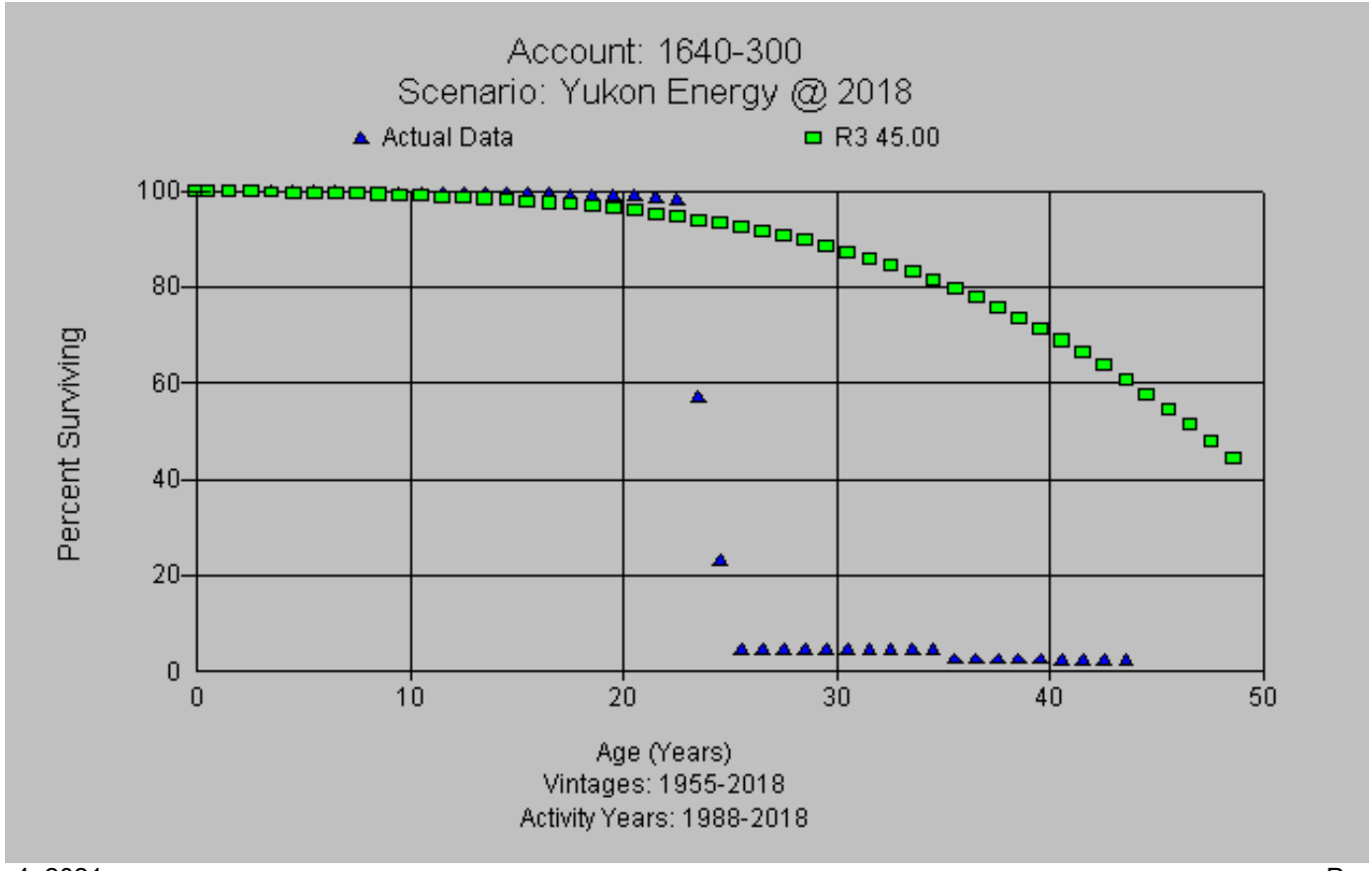
Account: 1635-710
Scenario: Yukon Energy @ 2018
Placement Band: 1923 - 1984
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

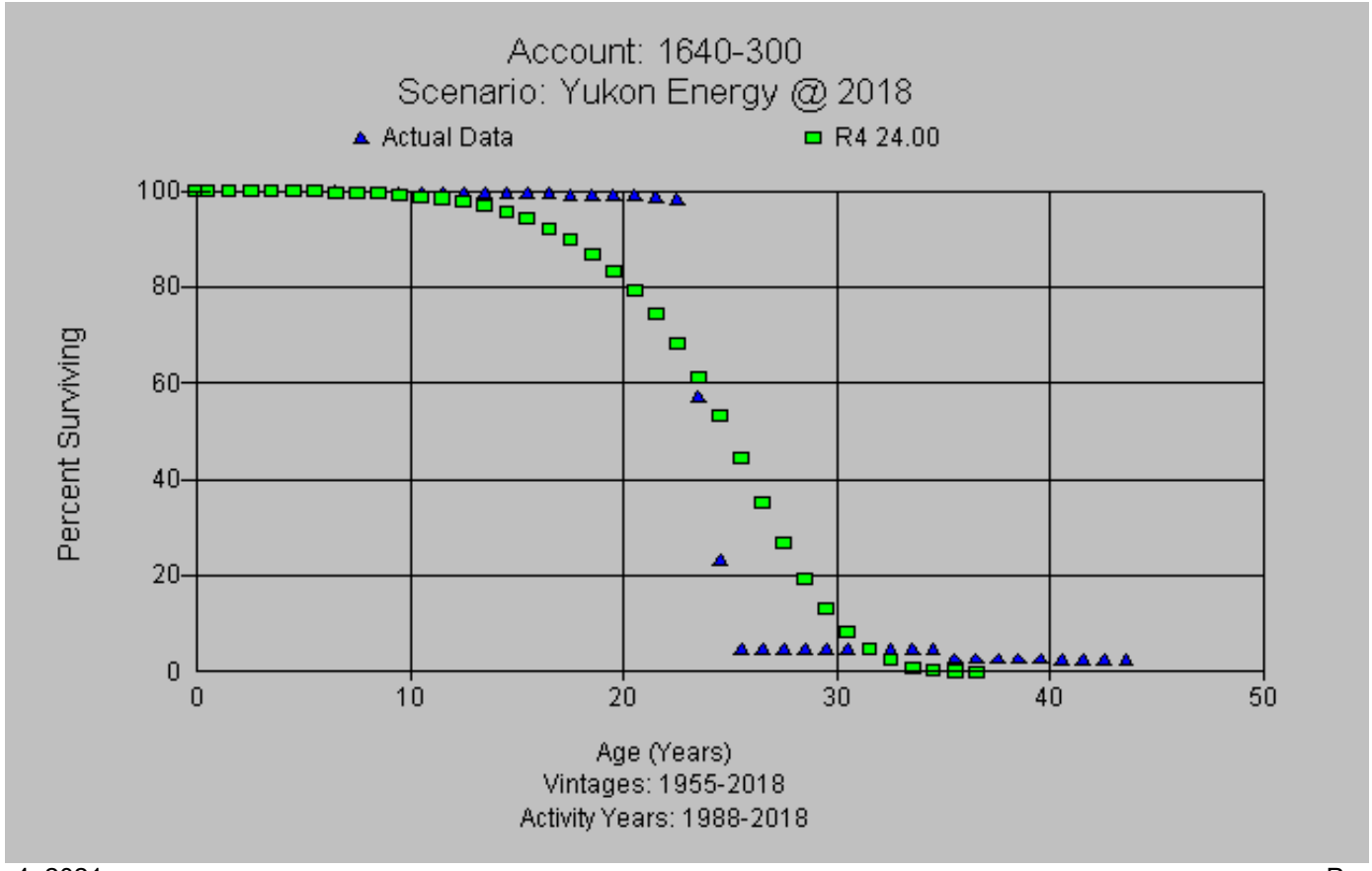
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -1984		1.00			
1981 -1985		1.00			
1982 -1986		1.00			
1983 -1987		1.00			
1984 -1988		1.00			
1985 -1989		1.00			
1986 -1990		1.00			
1987 -1991		1.00			
1988 -1992		1.00			
1989 -1993		1.00			
1990 -1994		1.00			
1991 -1995		1.00			
1992 -1996		1.00			
1993 -1997		1.00			
1994 -1998		1.00			
1995 -1999		1.00			
1996 -2000		1.00			
1997 -2001		1.00			
1998 -2002		1.00			
1999 -2003	25.5	68.39	0.18618760	L0	32.66
2000 -2004	26.5	60.35	0.27288158	L0	27.80
2001 -2005	27.5	43.09	0.45126808	L0	20.94
2002 -2006	28.5	0.00	0.04469274	R5	11.73
2003 -2007	29.5	0.00	0.04452917	R5	11.72
2004 -2008	30.5	0.00	0.04979803	SQ	12.43
2005 -2009	31.5	0.00	0.07651394	S6	12.53
2006 -2010	32.5	0.00	0.00358147	SQ	12.84
2007 -2011	33.5	0.00	0.00006859	SQ	19.01
2008 -2012	34.5	99.86	0.00005492	R3	234.40
2009 -2013		1.00			
2010 -2014		1.00			
2011 -2015		1.00			
2012 -2016		1.00			
2013 -2017		1.00			
2014 -2018	40.5	99.49	0.00005988	R3	195.12

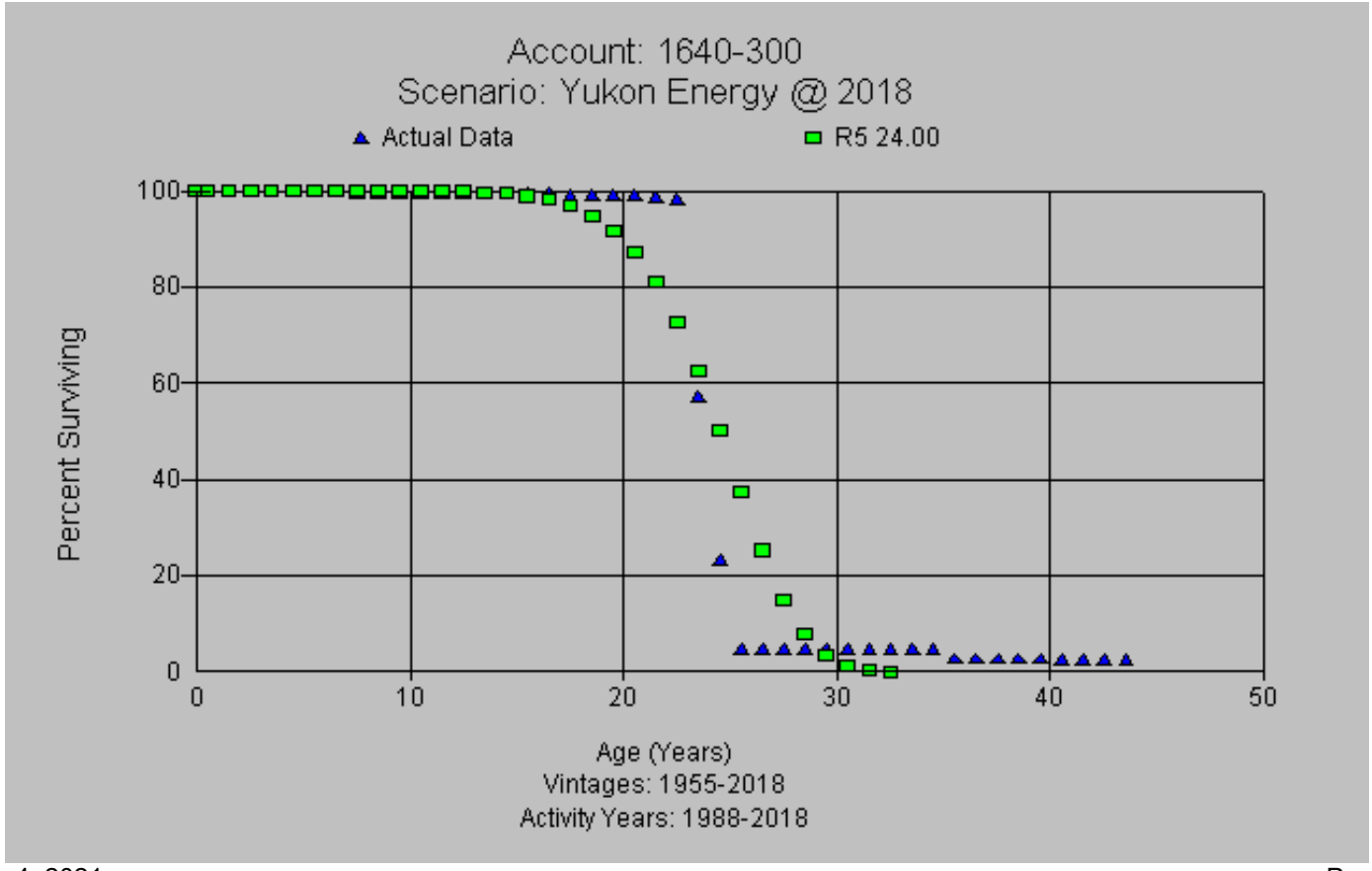
Actuarial Life Analysis

Account: 1635-710
Scenario: Yukon Energy @ 2018
Placement Band: 1923 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -2018	95.5	0.00	0.06329951	S6	24.71
1985 -2018	95.5	0.00	0.06329951	S6	24.71
1990 -2018	95.5	0.00	0.06329951	S6	24.71
1995 -2018	95.5	0.00	0.06330520	S6	24.71
2000 -2018	95.5	0.00	0.06325869	S6	24.71
2005 -2018	95.5	0.00	0.08431993	SQ	21.72
2010 -2018	95.5	0.00	0.00069097	SQ	60.88
2015 -2018	95.5	0.00	0.00108434	SQ	60.83


Account: 1640-300
Scenario: Yukon Energy @ 2018
Actual Data
R3 45.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1955-2018
Activity Years: 1988-2018


Account: 1640-300
Scenario: Yukon Energy @ 2018
Actual Data
R4 24.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1955-2018
Activity Years: 1988-2018


Account: 1640-300
Scenario: Yukon Energy @ 2018
Actual Data
R5 24.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1955-2018
Activity Years: 1988-2018

Observed Life Table

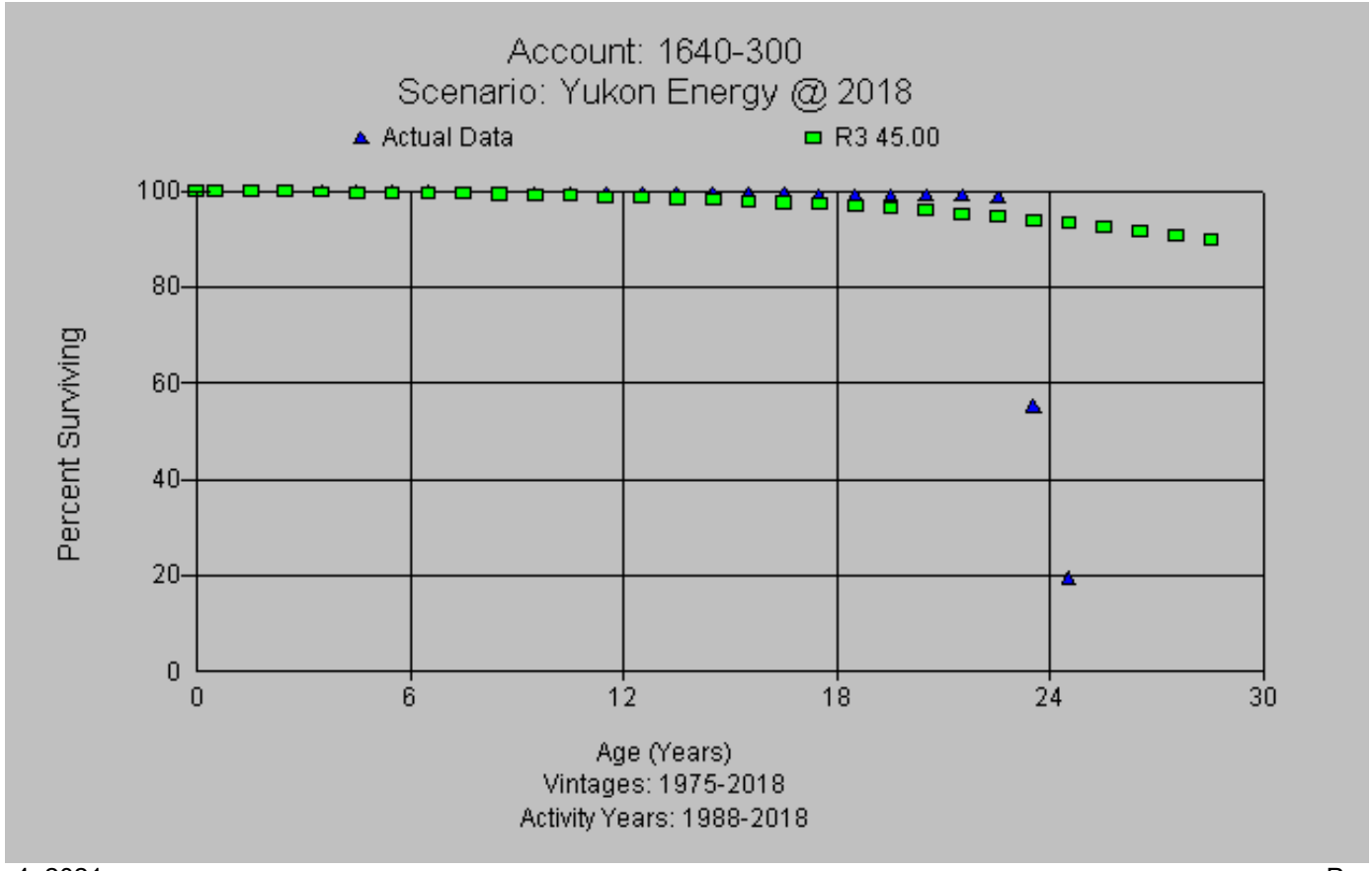
Scenario: Yukon Energy @ 2018
Account: 1640-300
Placement Band: 1955 - 2018 **Observation Band:** 1988 - 2018

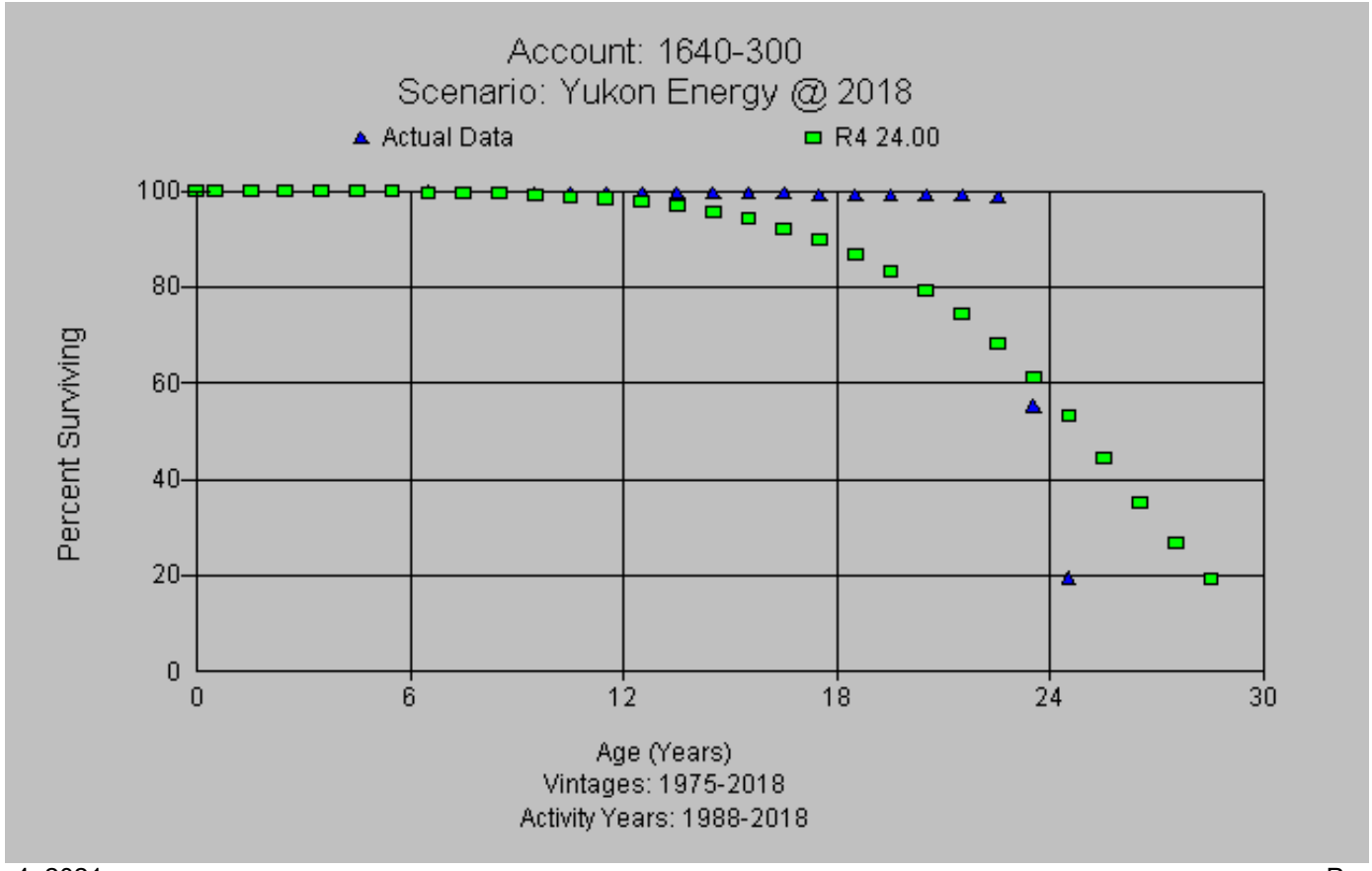
Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,118,741.57	939.00	0.00023	0.99977	100.00
0.5	4,100,231.57	2,131.00	0.00052	0.99948	99.98
1.5	4,098,100.57	0.00	0.00000	1.00000	99.93
2.5	4,098,100.57	436.00	0.00011	0.99989	99.93
3.5	3,626,046.57	329.00	0.00009	0.99991	99.91
4.5	3,625,717.57	150.00	0.00004	0.99996	99.91
5.5	3,625,567.57	190.00	0.00005	0.99995	99.90
6.5	3,631,431.57	10,348.00	0.00285	0.99715	99.90
7.5	3,661,807.07	0.00	0.00000	1.00000	99.61
8.5	3,661,807.07	0.00	0.00000	1.00000	99.61
9.5	3,661,876.07	0.00	0.00000	1.00000	99.61
10.5	3,628,737.50	0.00	0.00000	1.00000	99.61
11.5	3,628,737.50	1.00	0.00000	1.00000	99.61
12.5	3,628,980.50	0.00	0.00000	1.00000	99.61
13.5	3,618,985.33	0.00	0.00000	1.00000	99.61
14.5	3,579,739.09	0.00	0.00000	1.00000	99.61
15.5	3,506,260.21	1,081.00	0.00031	0.99969	99.61
16.5	3,493,741.90	9,024.00	0.00258	0.99742	99.58
17.5	3,486,447.90	0.00	0.00000	1.00000	99.32
18.5	3,295,154.58	69.00	0.00002	0.99998	99.32
19.5	2,169,604.14	0.00	0.00000	1.00000	99.32
20.5	35,204.50	164.00	0.00466	0.99534	99.32
21.5	35,040.50	244.00	0.00696	0.99304	98.86
22.5	34,851.50	14,564.01	0.41789	0.58211	98.17
23.5	20,287.49	12,010.96	0.59204	0.40796	57.15
24.5	10,239.77	8,137.53	0.79470	0.20530	23.31
25.5	2,102.24	0.00	0.00000	1.00000	4.79
26.5	2,102.24	84.00	0.03996	0.96004	4.79
27.5	3,408.24	0.00	0.00000	1.00000	4.60
28.5	3,408.24	0.00	0.00000	1.00000	4.60
29.5	3,408.24	0.00	0.00000	1.00000	4.60
30.5	3,408.24	0.00	0.00000	1.00000	4.60
31.5	3,408.24	55.00	0.01614	0.98386	4.60
32.5	3,467.24	0.00	0.00000	1.00000	4.52
33.5	3,467.24	0.00	0.00000	1.00000	4.52
34.5	3,467.24	1,390.00	0.40090	0.59910	4.52
35.5	2,077.24	0.00	0.00000	1.00000	2.71
36.5	2,077.24	0.00	0.00000	1.00000	2.71
37.5	2,077.24	0.00	0.00000	1.00000	2.71

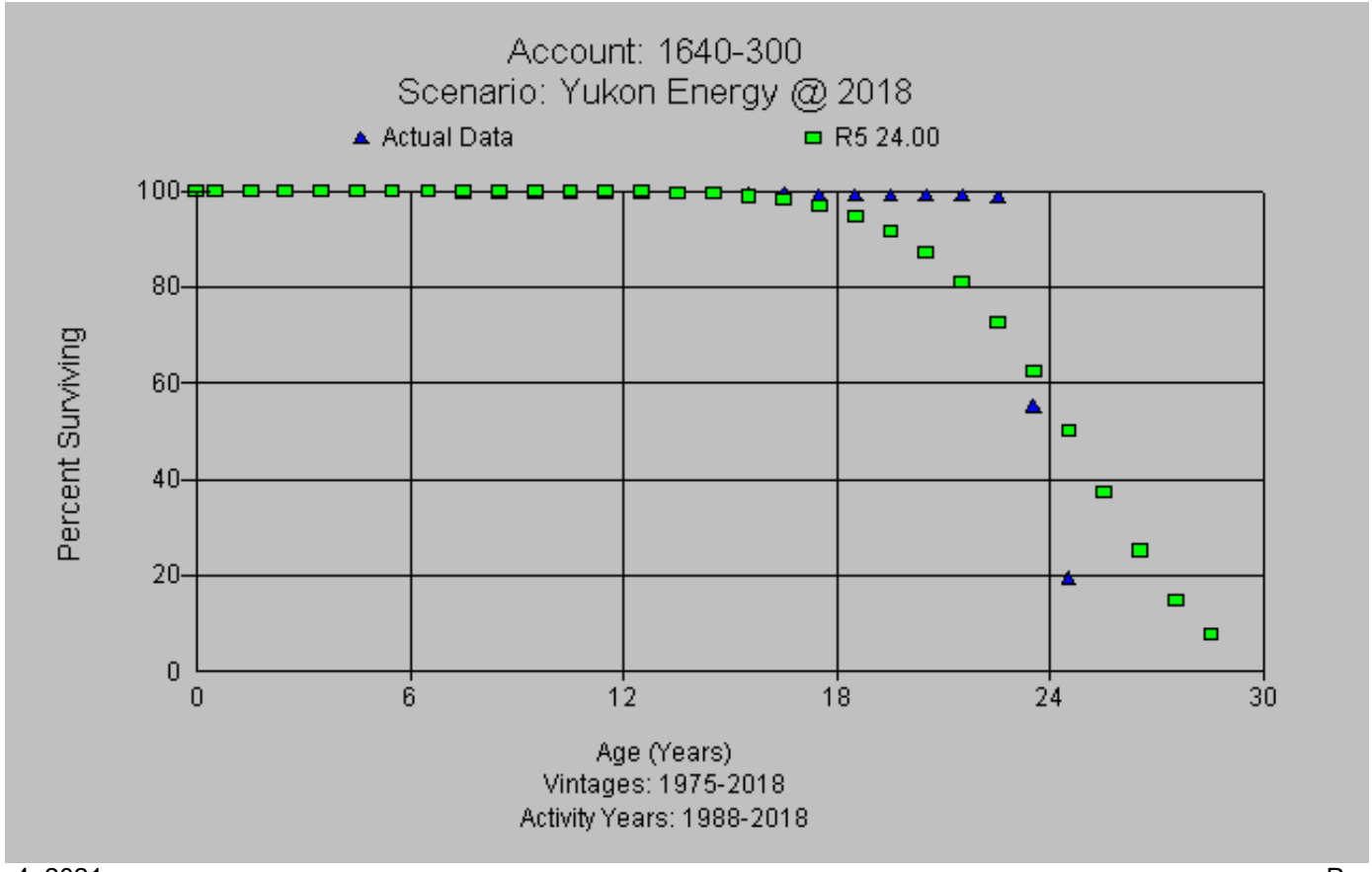
Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1640-300
Placement Band: 1955 - 2018 **Observation Band:** 1988 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
38.5	2,077.24	0.00	0.00000	1.00000	2.71
39.5	2,077.24	114.00	0.05488	0.94512	2.71
40.5	1,963.24	0.00	0.00000	1.00000	2.56
41.5	1,963.24	0.00	0.00000	1.00000	2.56
42.5	1,963.24	0.00	0.00000	1.00000	2.56
43.5	1,963.24	1,963.24	1.00000	0.00000	2.56
44.5	0.00	0.00	0.00000	1.00000	0.00


Account: 1640-300
Scenario: Yukon Energy @ 2018
Actual Data
R3 45.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1975-2018
Activity Years: 1988-2018


Account: 1640-300
Scenario: Yukon Energy @ 2018
Actual Data
R4 24.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1975-2018
Activity Years: 1988-2018


Account: 1640-300
Scenario: Yukon Energy @ 2018
Actual Data
R5 24.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1975-2018
Activity Years: 1988-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1640-300
Placement Band: 1975 - 2018 **Observation Band:** 1988 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,118,741.57	939.00	0.00023	0.99977	100.00
0.5	4,100,231.57	2,131.00	0.00052	0.99948	99.98
1.5	4,098,100.57	0.00	0.00000	1.00000	99.93
2.5	4,098,100.57	436.00	0.00011	0.99989	99.93
3.5	3,626,046.57	329.00	0.00009	0.99991	99.91
4.5	3,625,717.57	150.00	0.00004	0.99996	99.91
5.5	3,625,567.57	190.00	0.00005	0.99995	99.90
6.5	3,631,431.57	10,348.00	0.00285	0.99715	99.90
7.5	3,661,807.07	0.00	0.00000	1.00000	99.61
8.5	3,661,807.07	0.00	0.00000	1.00000	99.61
9.5	3,661,876.07	0.00	0.00000	1.00000	99.61
10.5	3,628,737.50	0.00	0.00000	1.00000	99.61
11.5	3,628,737.50	1.00	0.00000	1.00000	99.61
12.5	3,628,980.50	0.00	0.00000	1.00000	99.61
13.5	3,618,985.33	0.00	0.00000	1.00000	99.61
14.5	3,579,739.09	0.00	0.00000	1.00000	99.61
15.5	3,506,096.21	1,081.00	0.00031	0.99969	99.61
16.5	3,493,577.90	9,024.00	0.00258	0.99742	99.58
17.5	3,484,553.90	0.00	0.00000	1.00000	99.32
18.5	3,293,260.58	69.00	0.00002	0.99998	99.32
19.5	2,167,710.14	0.00	0.00000	1.00000	99.32
20.5	33,310.50	0.00	0.00000	1.00000	99.32
21.5	33,310.50	244.00	0.00733	0.99267	99.32
22.5	33,066.50	14,530.01	0.43942	0.56058	98.59
23.5	18,536.49	12,010.96	0.64796	0.35204	55.27
24.5	6,525.53	6,525.53	1.00000	0.00000	19.46
25.5	0.00	0.00	0.00000	1.00000	0.00

Actuarial Life Analysis

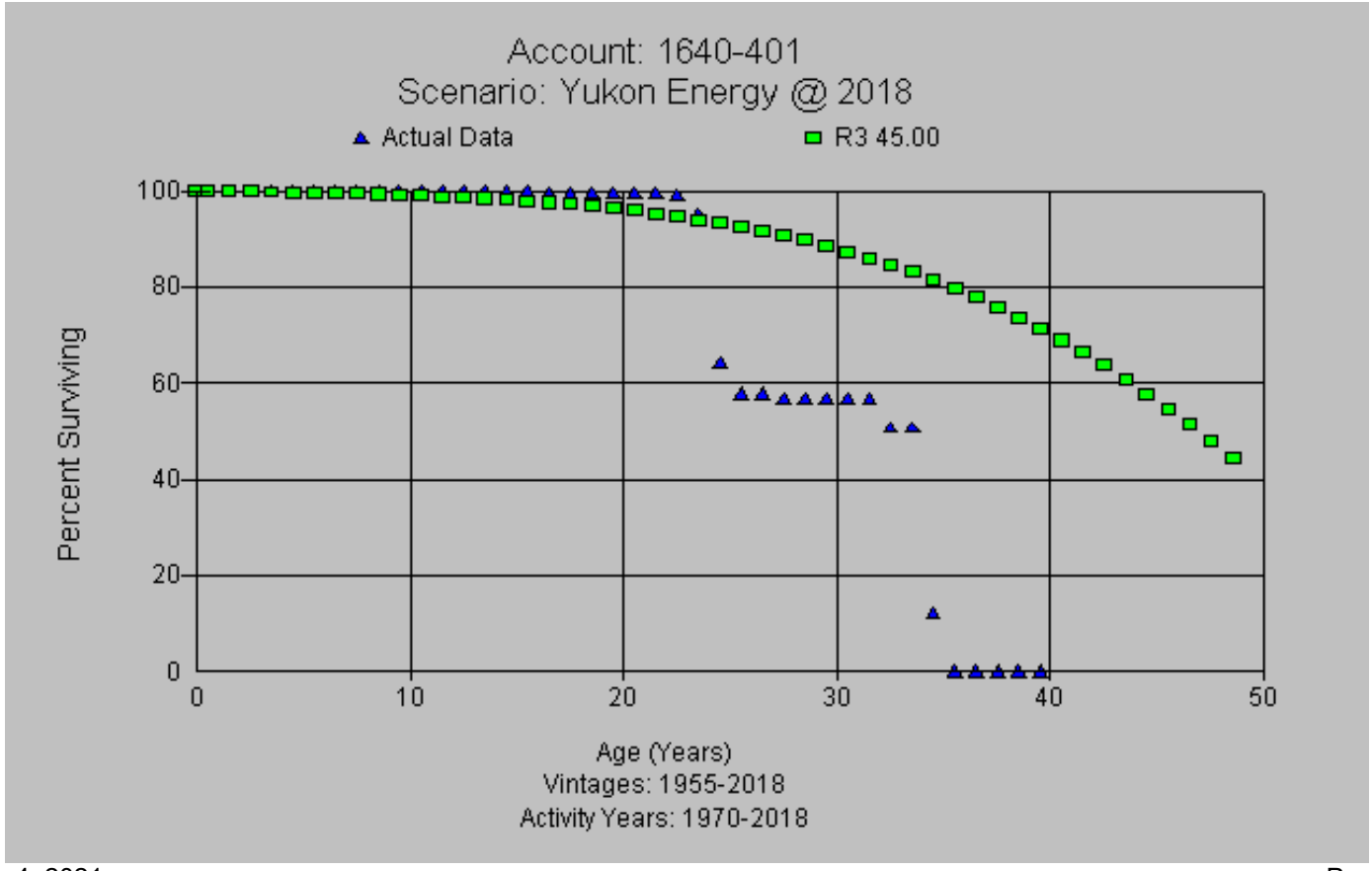
Account: 1640-300
Scenario: Yukon Energy @ 2018
Placement Band: 1955 - 1992
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

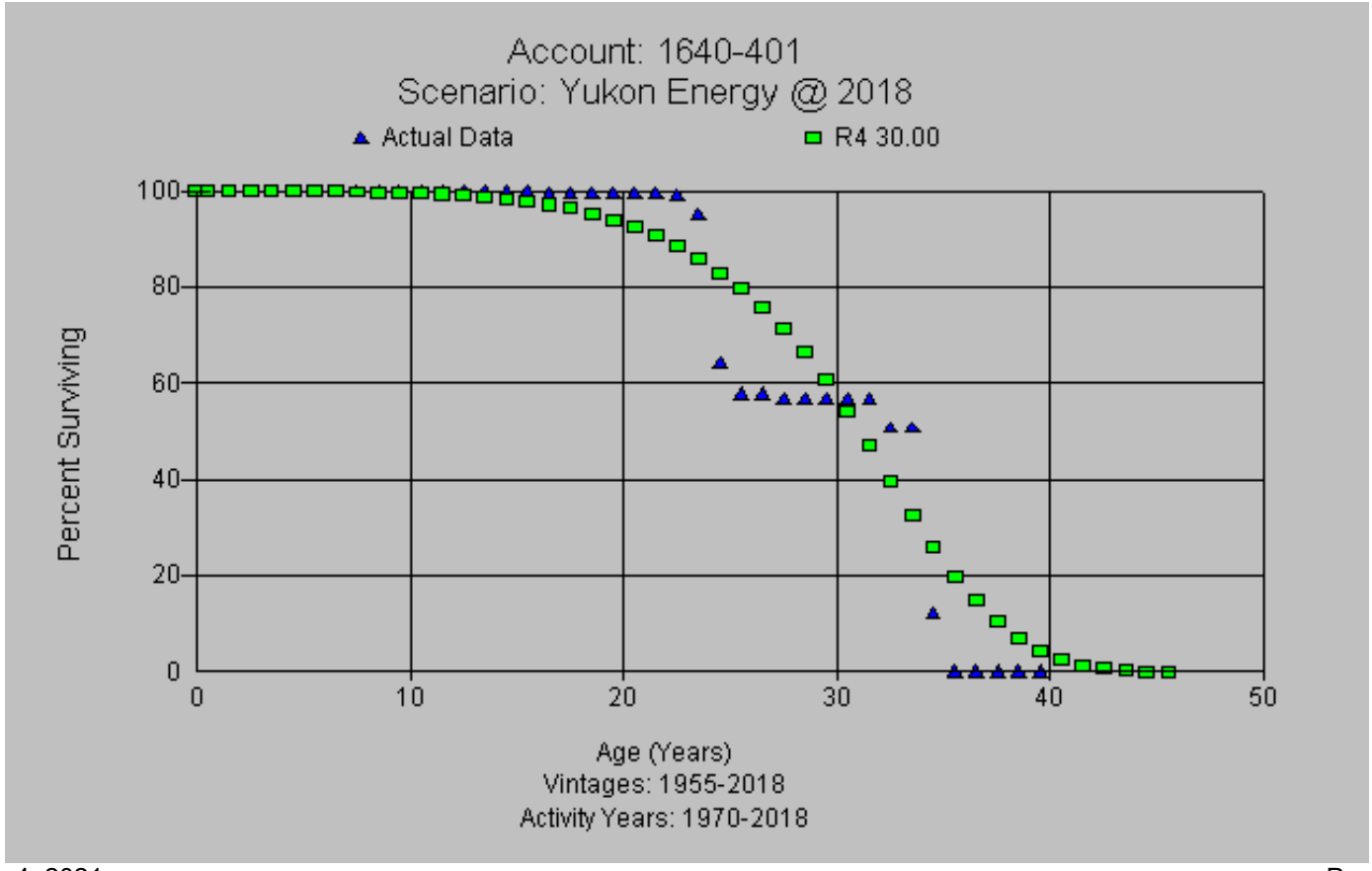
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1988 -1992	37.5	57.70	2.37632264	L0	23.77
1989 -1993	38.5	79.17	0.07073852	R0.5	56.15
1990 -1994	39.5	9.18	0.82621377	L0	7.34
1991 -1995	40.5	0.00	0.44942272	L0	5.41
1992 -1996	41.5	0.00	0.23423789	L0	1.90
1993 -1997	42.5	0.00	0.22563686	L0	1.88
1994 -1998	43.5	0.00	0.03552885	S5	1.39
1995 -1999	44.5	0.00	0.00000008	SQ	3.05
1996 -2000	45.5	0.00	0.00000000	SQ	3.39
1997 -2001	46.5	0.00	0.00000000	SQ	7.39
1998 -2002	47.5	0.00	0.00000000	SQ	12.20
1999 -2003	48.5	0.00	0.00000000	SQ	12.20
2000 -2004	49.5	0.00	0.00000000	SQ	12.20
2001 -2005	50.5	0.00	0.00000000	SQ	17.20
2002 -2006	51.5	0.00	0.12535860	S6	23.81
2003 -2007	52.5	0.00	0.12535860	S6	23.81
2004 -2008	53.5	0.00	0.05835546	SQ	24.40
2005 -2009	54.5	0.00	0.00000000	SQ	25.20
2006 -2010	55.5	0.00	0.00000000	SQ	44.05
2007 -2011	56.5	0.00	0.00000000	SQ	44.05
2008 -2012		1.00			
2009 -2013		1.00			
2010 -2014		1.00			
2011 -2015		1.00			
2012 -2016		1.00			
2013 -2017		1.00			
2014 -2018		1.00			

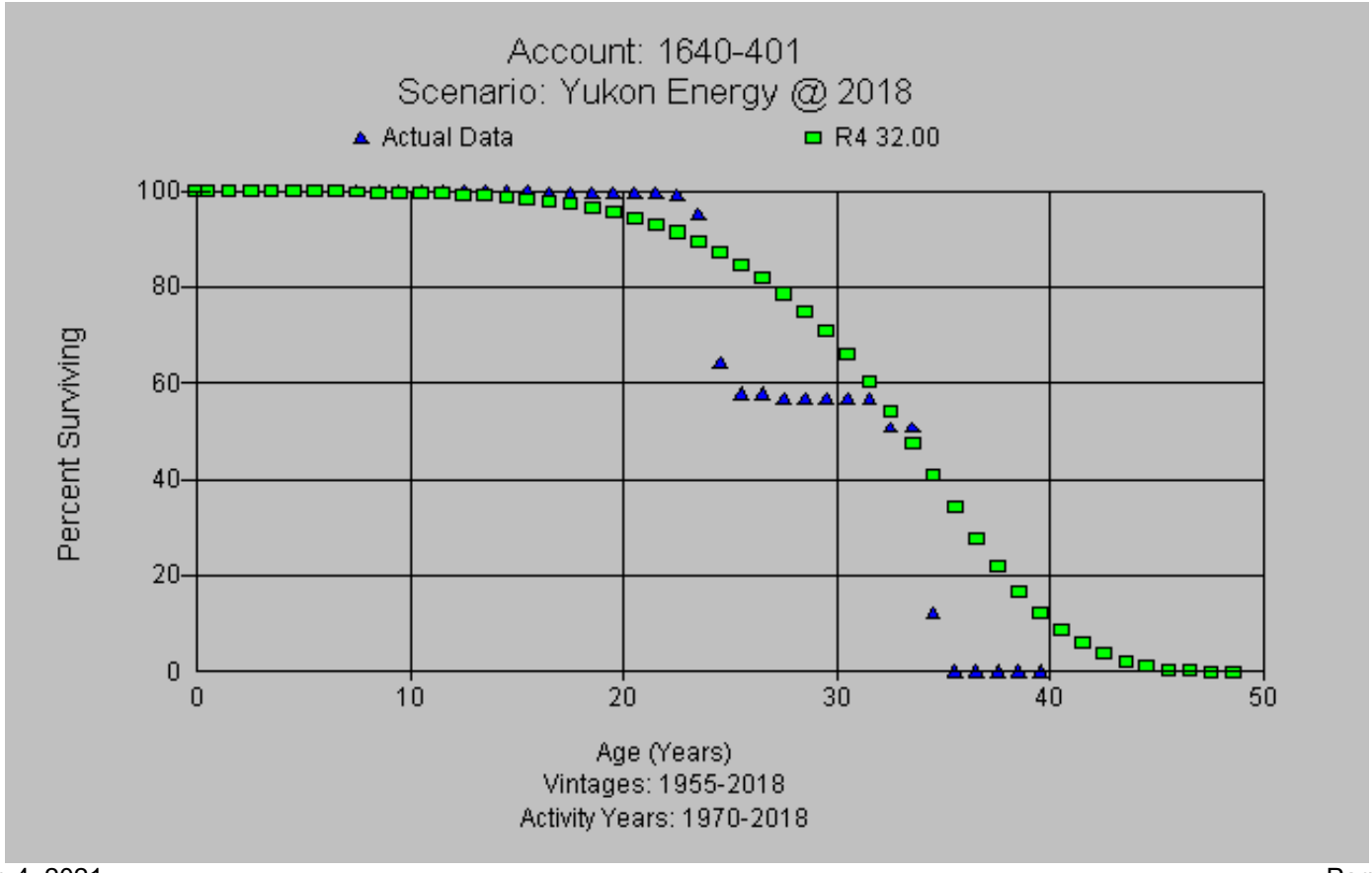
Actuarial Life Analysis

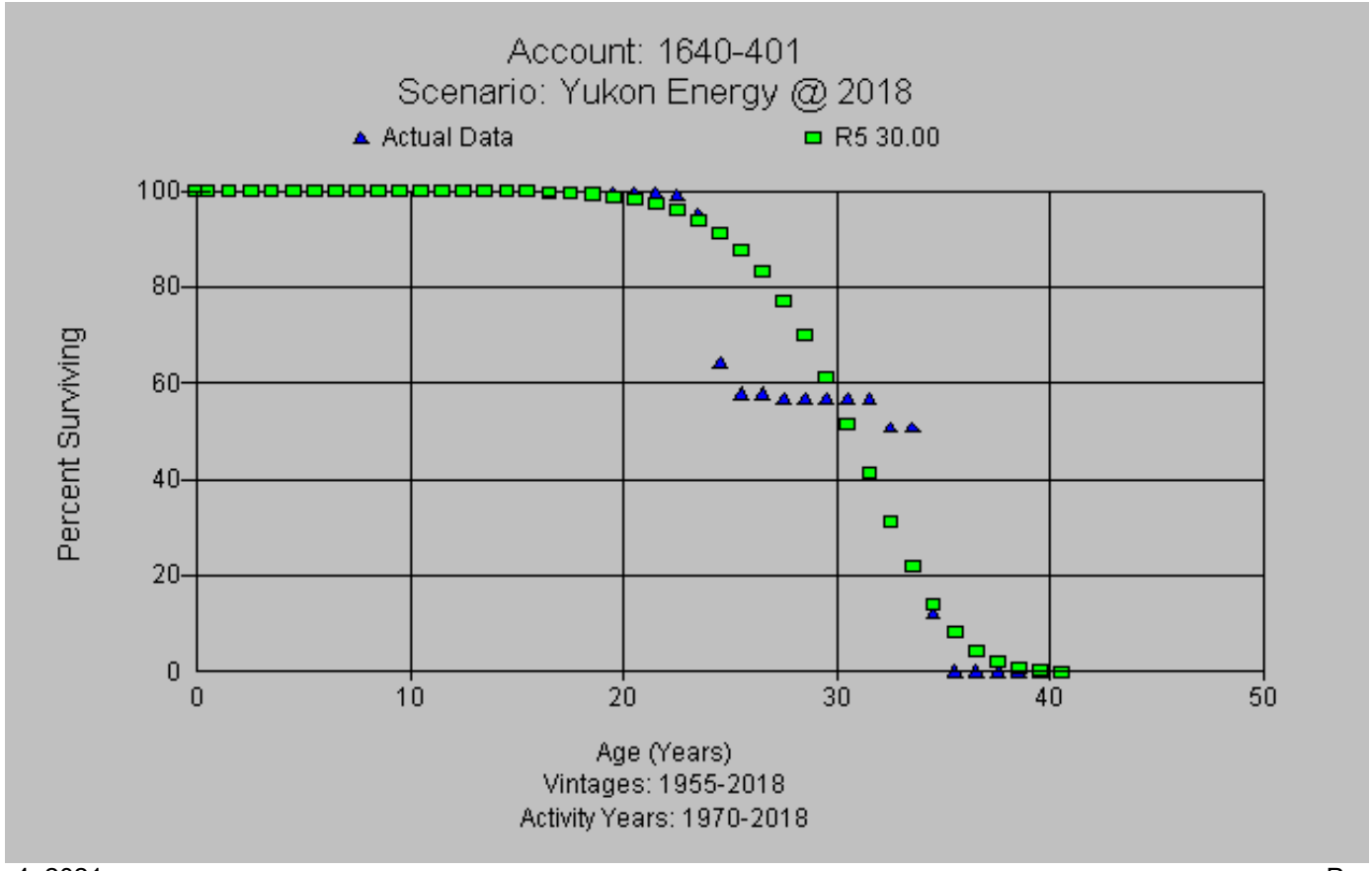
Account: 1640-300
Scenario: Yukon Energy @ 2018
Placement Band: 1955 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

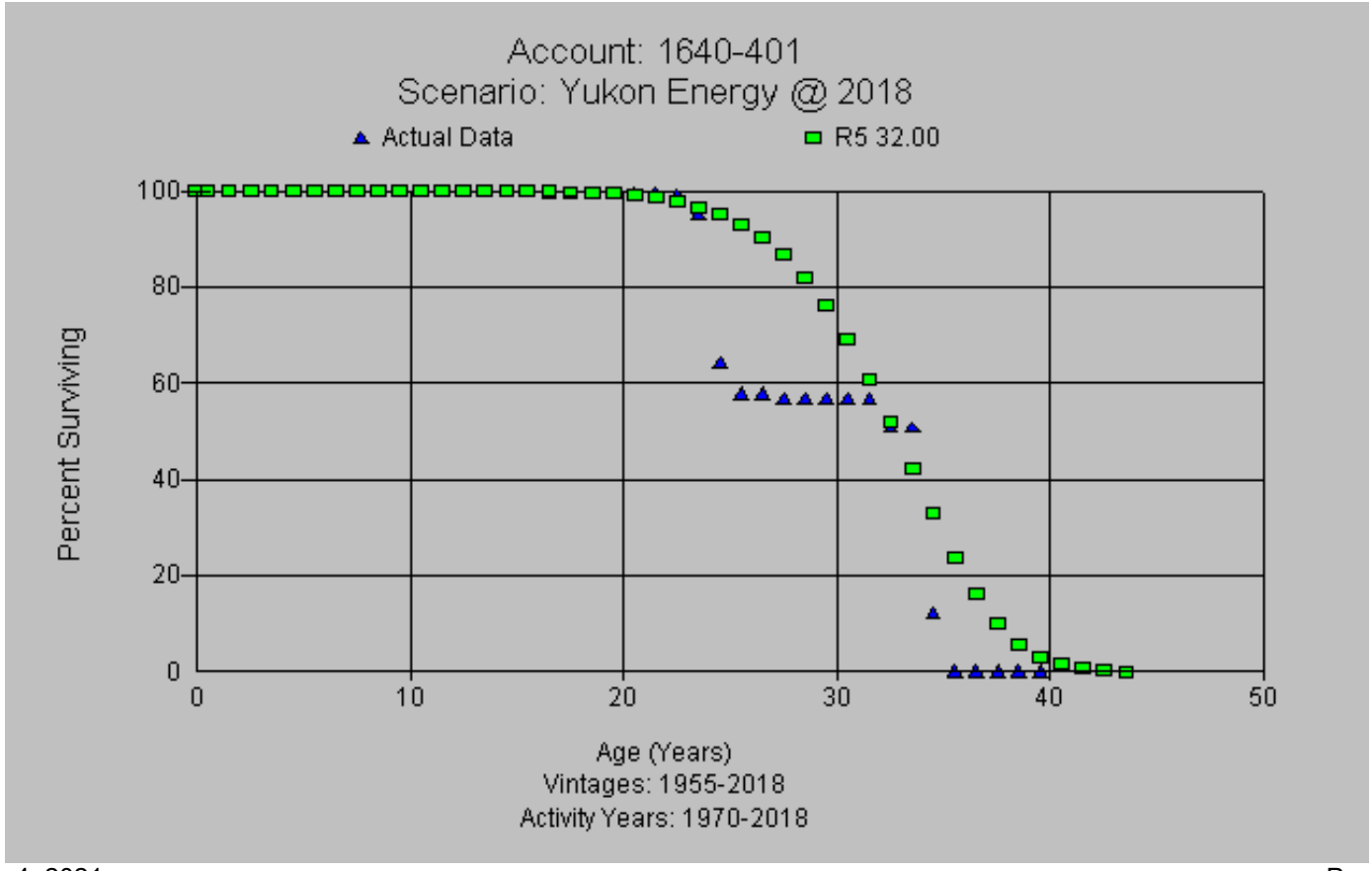
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1988 -2018	63.5	0.00	0.18349281	S6	24.45
1993 -2018	63.5	0.00	0.10329109	S6	23.76
1998 -2018	63.5	0.00	0.12470660	S6	23.80
2003 -2018	63.5	0.00	0.12535860	S6	23.81
2008 -2018		1.00			
2013 -2018		1.00			
2018 -2018		1.00			


Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R3 45.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1955-2018
Activity Years: 1970-2018


Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R4 30.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1955-2018
Activity Years: 1970-2018


Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R4 32.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1955-2018
Activity Years: 1970-2018


Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R5 30.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1955-2018
Activity Years: 1970-2018


Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R5 32.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1955-2018
Activity Years: 1970-2018

Observed Life Table

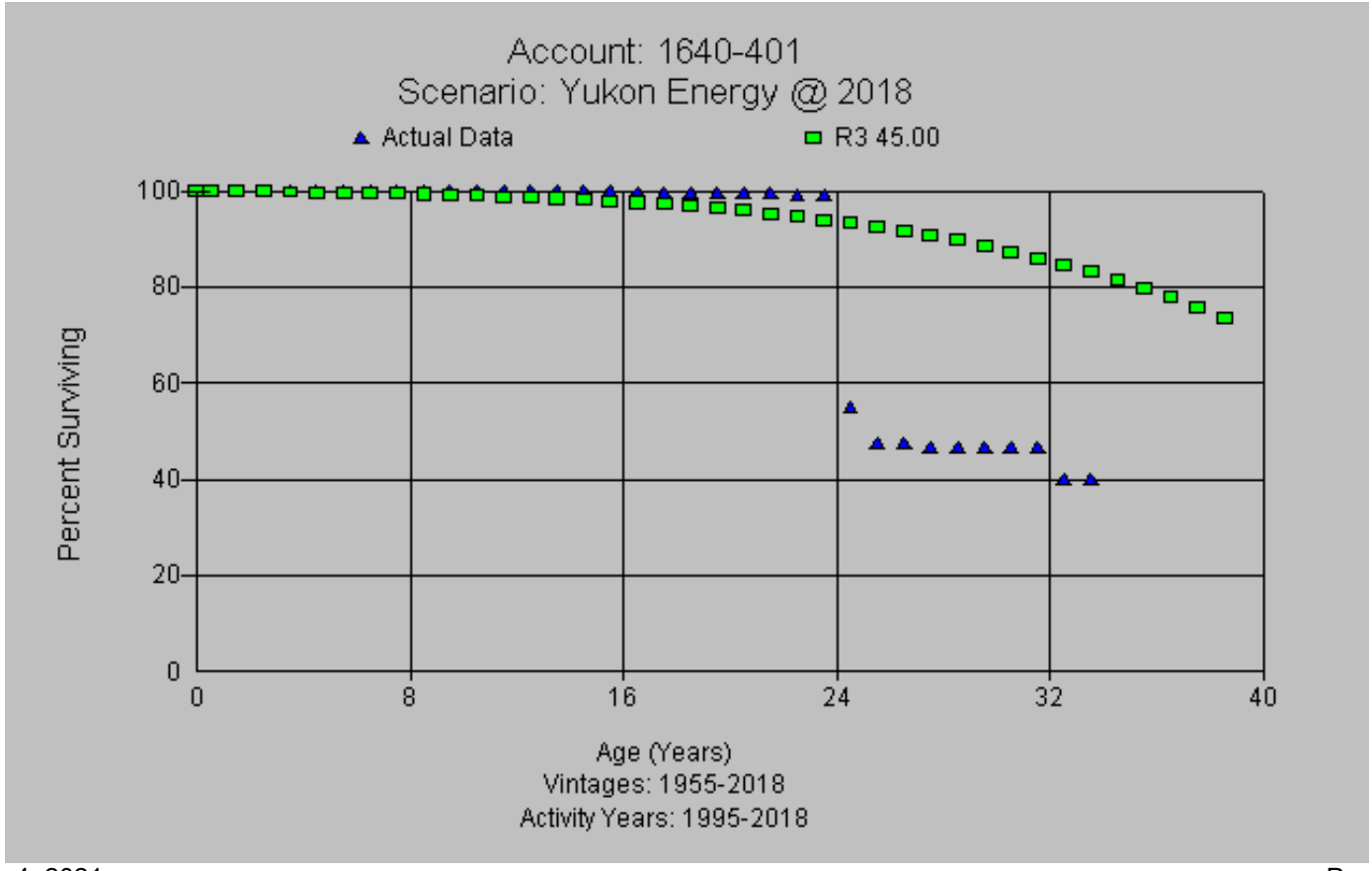
Scenario: Yukon Energy @ 2018
Account: 1640-401
Placement Band: 1955 - 2018 **Observation Band:** 1970 - 2018

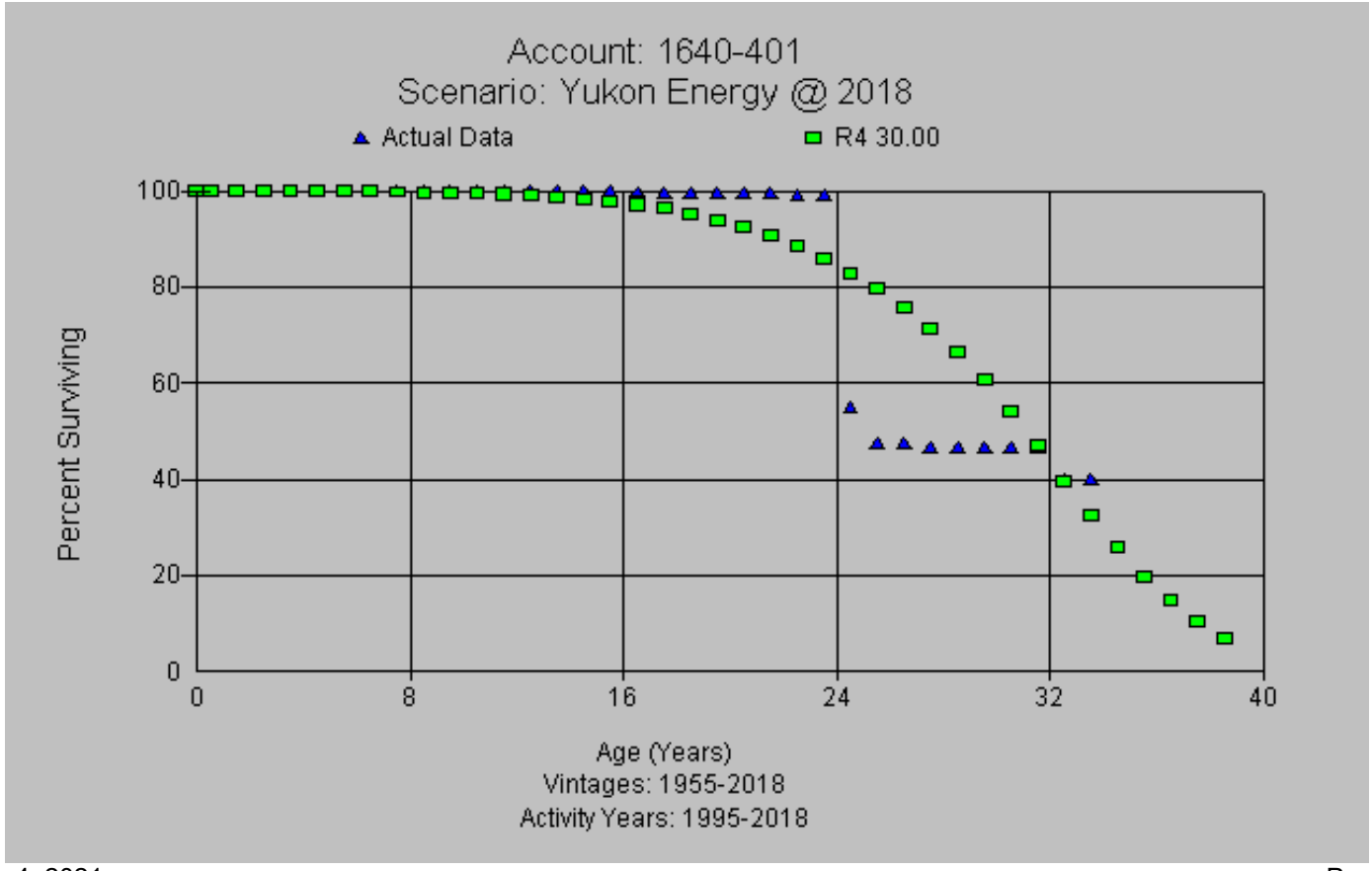
Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	1,845,301.48	0.00	0.00000	1.00000	100.00
0.5	1,046,827.14	0.00	0.00000	1.00000	100.00
1.5	1,046,827.14	0.00	0.00000	1.00000	100.00
2.5	1,046,827.14	0.00	0.00000	1.00000	100.00
3.5	994,060.14	0.00	0.00000	1.00000	100.00
4.5	994,256.14	11.00	0.00001	0.99999	100.00
5.5	994,245.14	492.00	0.00049	0.99951	100.00
6.5	993,753.14	227.00	0.00023	0.99977	99.95
7.5	993,526.14	0.00	0.00000	1.00000	99.93
8.5	993,526.14	0.00	0.00000	1.00000	99.93
9.5	993,908.14	0.00	0.00000	1.00000	99.93
10.5	993,908.14	0.00	0.00000	1.00000	99.93
11.5	993,908.14	0.00	0.00000	1.00000	99.93
12.5	993,908.14	0.00	0.00000	1.00000	99.93
13.5	983,729.86	0.00	0.00000	1.00000	99.93
14.5	983,731.86	0.00	0.00000	1.00000	99.93
15.5	983,731.86	1,031.00	0.00105	0.99895	99.93
16.5	982,700.86	352.00	0.00036	0.99964	99.82
17.5	982,348.86	0.00	0.00000	1.00000	99.79
18.5	955,219.67	245.00	0.00026	0.99974	99.79
19.5	549,274.43	0.00	0.00000	1.00000	99.76
20.5	3,154.67	8.00	0.00254	0.99746	99.76
21.5	3,146.67	13.00	0.00413	0.99587	99.51
22.5	3,133.67	127.00	0.04053	0.95947	99.10
23.5	3,006.67	974.63	0.32416	0.67584	95.08
24.5	2,032.04	199.00	0.09793	0.90207	64.26
25.5	1,833.04	0.00	0.00000	1.00000	57.97
26.5	1,833.04	30.00	0.01637	0.98363	57.97
27.5	1,803.04	0.00	0.00000	1.00000	57.02
28.5	1,803.04	0.00	0.00000	1.00000	57.02
29.5	1,803.04	0.00	0.00000	1.00000	57.02
30.5	1,803.04	0.00	0.00000	1.00000	57.02
31.5	1,803.04	196.00	0.10871	0.89129	57.02
32.5	1,607.04	0.00	0.00000	1.00000	50.82
33.5	1,607.04	1,223.04	0.76105	0.23895	50.82
34.5	384.00	382.00	0.99479	0.00521	12.14
35.5	2.00	0.00	0.00000	1.00000	0.06
36.5	2.00	0.00	0.00000	1.00000	0.06
37.5	2.00	0.00	0.00000	1.00000	0.06

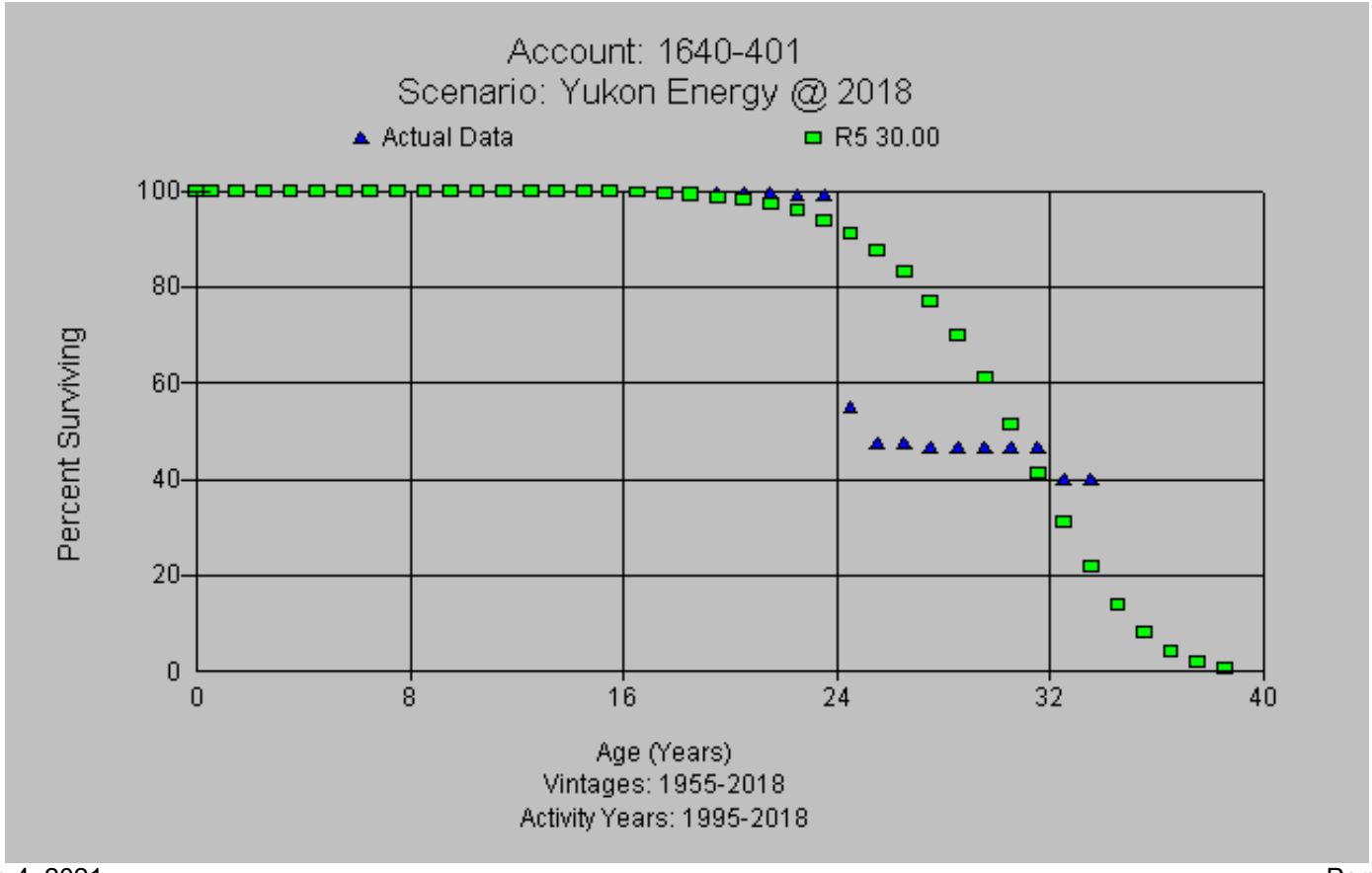
Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1640-401
Placement Band: 1955 - 2018 **Observation Band:** 1970 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
38.5	2.00	0.00	0.00000	1.00000	0.06
39.5	2.00	2.00	1.00000	0.00000	0.06
40.5	0.00	0.00	0.00000	1.00000	0.00


Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R3 45.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1955-2018
Activity Years: 1995-2018


Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R4 30.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1955-2018
Activity Years: 1995-2018


Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R5 30.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1955-2018
Activity Years: 1995-2018

Observed Life Table

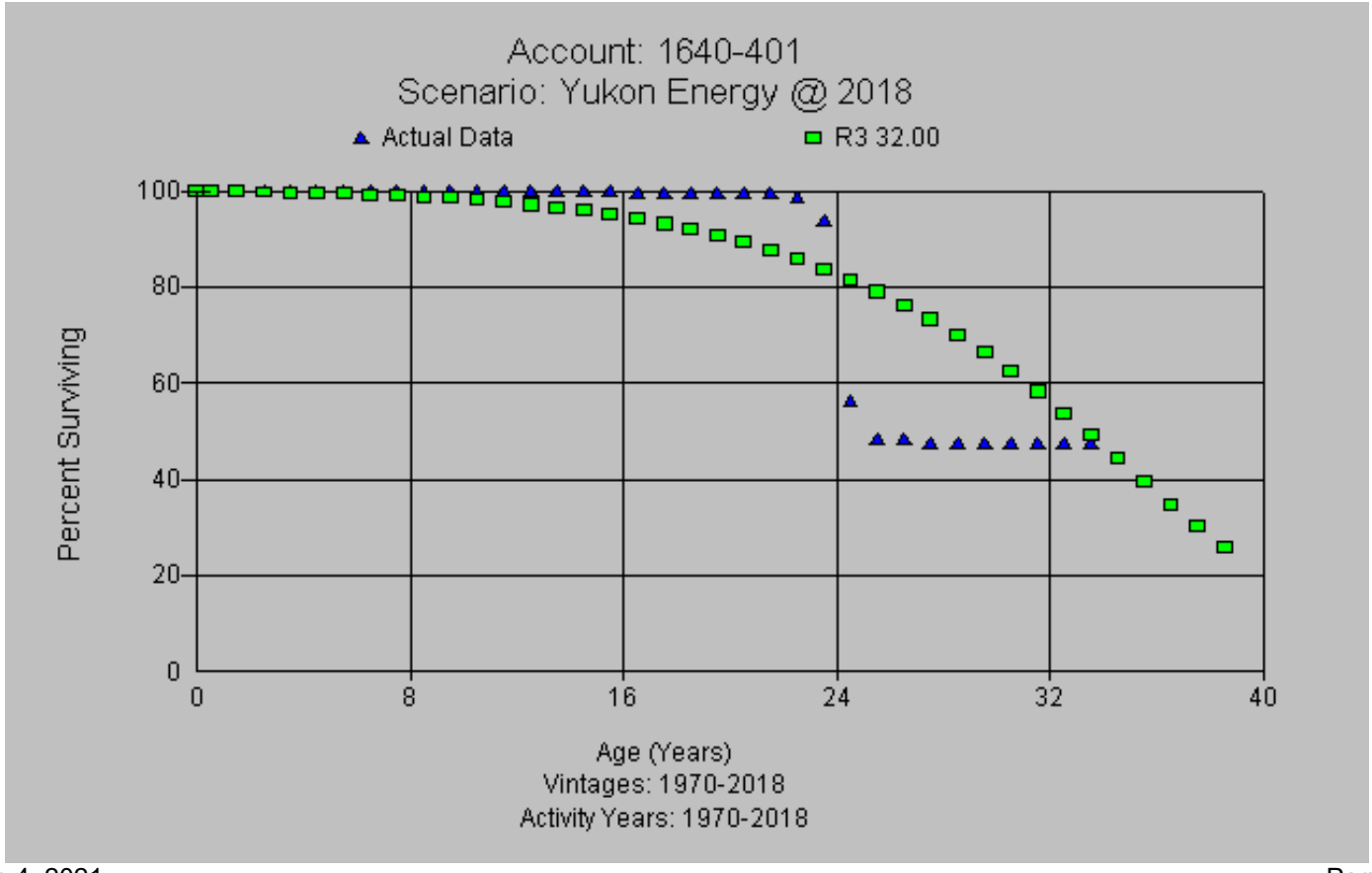
Scenario: Yukon Energy @ 2018
Account: 1640-401
Placement Band: 1955 - 2018 **Observation Band:** 1995 - 2018

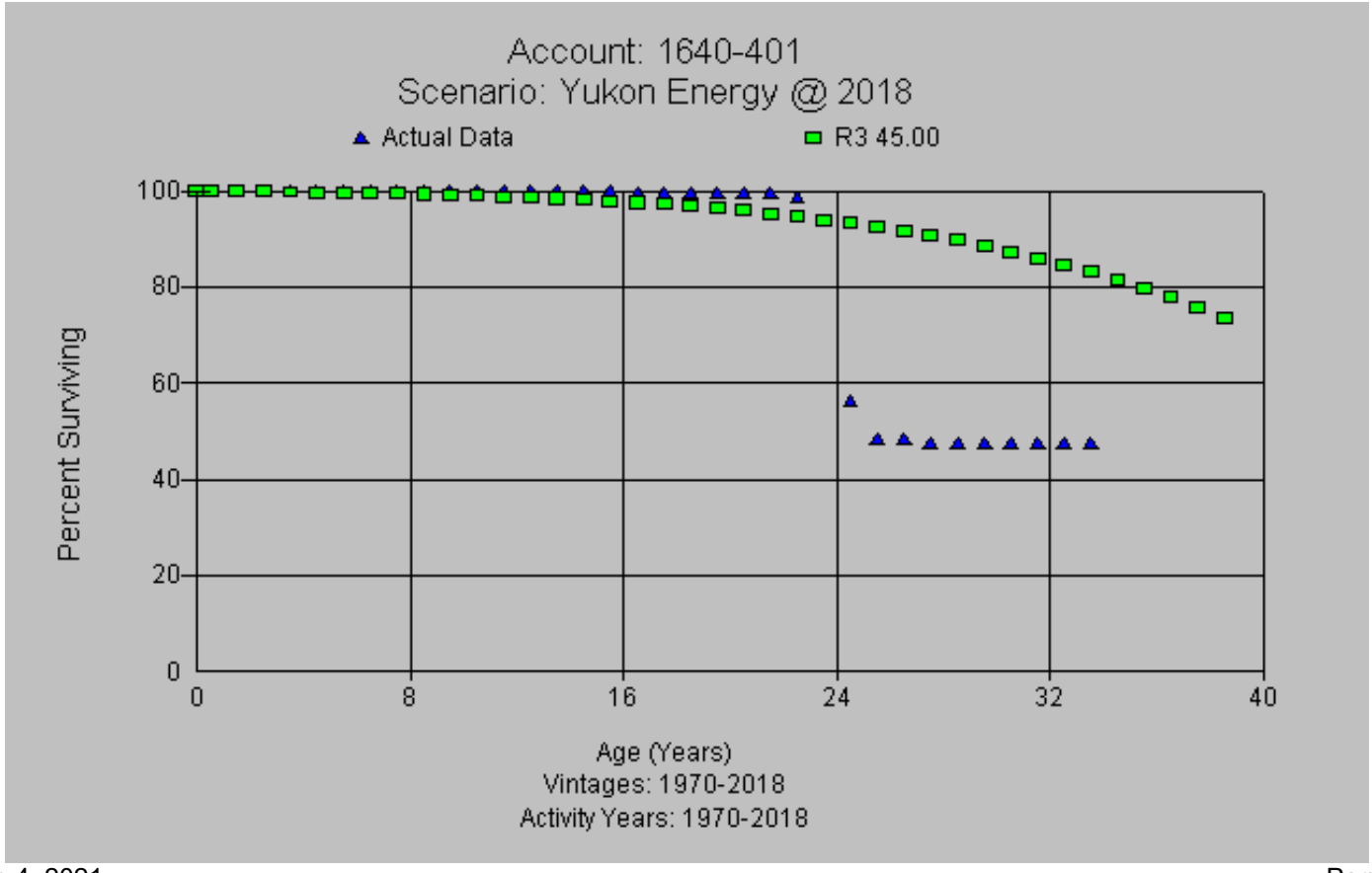
Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	1,840,368.81	0.00	0.00000	1.00000	100.00
0.5	1,041,894.47	0.00	0.00000	1.00000	100.00
1.5	1,041,894.47	0.00	0.00000	1.00000	100.00
2.5	1,041,894.47	0.00	0.00000	1.00000	100.00
3.5	989,127.47	0.00	0.00000	1.00000	100.00
4.5	989,538.47	11.00	0.00001	0.99999	100.00
5.5	989,527.47	200.00	0.00020	0.99980	100.00
6.5	989,327.47	200.00	0.00020	0.99980	99.98
7.5	989,127.47	0.00	0.00000	1.00000	99.96
8.5	989,127.47	0.00	0.00000	1.00000	99.96
9.5	989,127.47	0.00	0.00000	1.00000	99.96
10.5	989,127.47	0.00	0.00000	1.00000	99.96
11.5	989,127.47	0.00	0.00000	1.00000	99.96
12.5	989,127.47	0.00	0.00000	1.00000	99.96
13.5	978,949.19	0.00	0.00000	1.00000	99.96
14.5	981,306.82	0.00	0.00000	1.00000	99.96
15.5	981,306.82	1,031.00	0.00105	0.99895	99.96
16.5	980,520.82	352.00	0.00036	0.99964	99.85
17.5	980,168.82	0.00	0.00000	1.00000	99.82
18.5	953,039.63	245.00	0.00026	0.99974	99.82
19.5	547,107.39	0.00	0.00000	1.00000	99.79
20.5	987.63	0.00	0.00000	1.00000	99.79
21.5	2,210.67	13.00	0.00588	0.99412	99.79
22.5	2,197.67	0.00	0.00000	1.00000	99.21
23.5	2,197.67	974.63	0.44348	0.55652	99.21
24.5	1,452.04	199.00	0.13705	0.86295	55.21
25.5	1,253.04	0.00	0.00000	1.00000	47.64
26.5	1,253.04	30.00	0.02394	0.97606	47.64
27.5	1,223.04	0.00	0.00000	1.00000	46.50
28.5	1,223.04	0.00	0.00000	1.00000	46.50
29.5	1,419.04	0.00	0.00000	1.00000	46.50
30.5	1,419.04	0.00	0.00000	1.00000	46.50
31.5	1,419.04	196.00	0.13812	0.86188	46.50
32.5	1,223.04	0.00	0.00000	1.00000	40.08
33.5	1,223.04	1,223.04	1.00000	0.00000	40.08
34.5	382.00	382.00	1.00000	0.00000	0.00
35.5	0.00	0.00	0.00000	1.00000	0.00
36.5	0.00	0.00	0.00000	1.00000	
37.5	0.00	0.00	0.00000	1.00000	

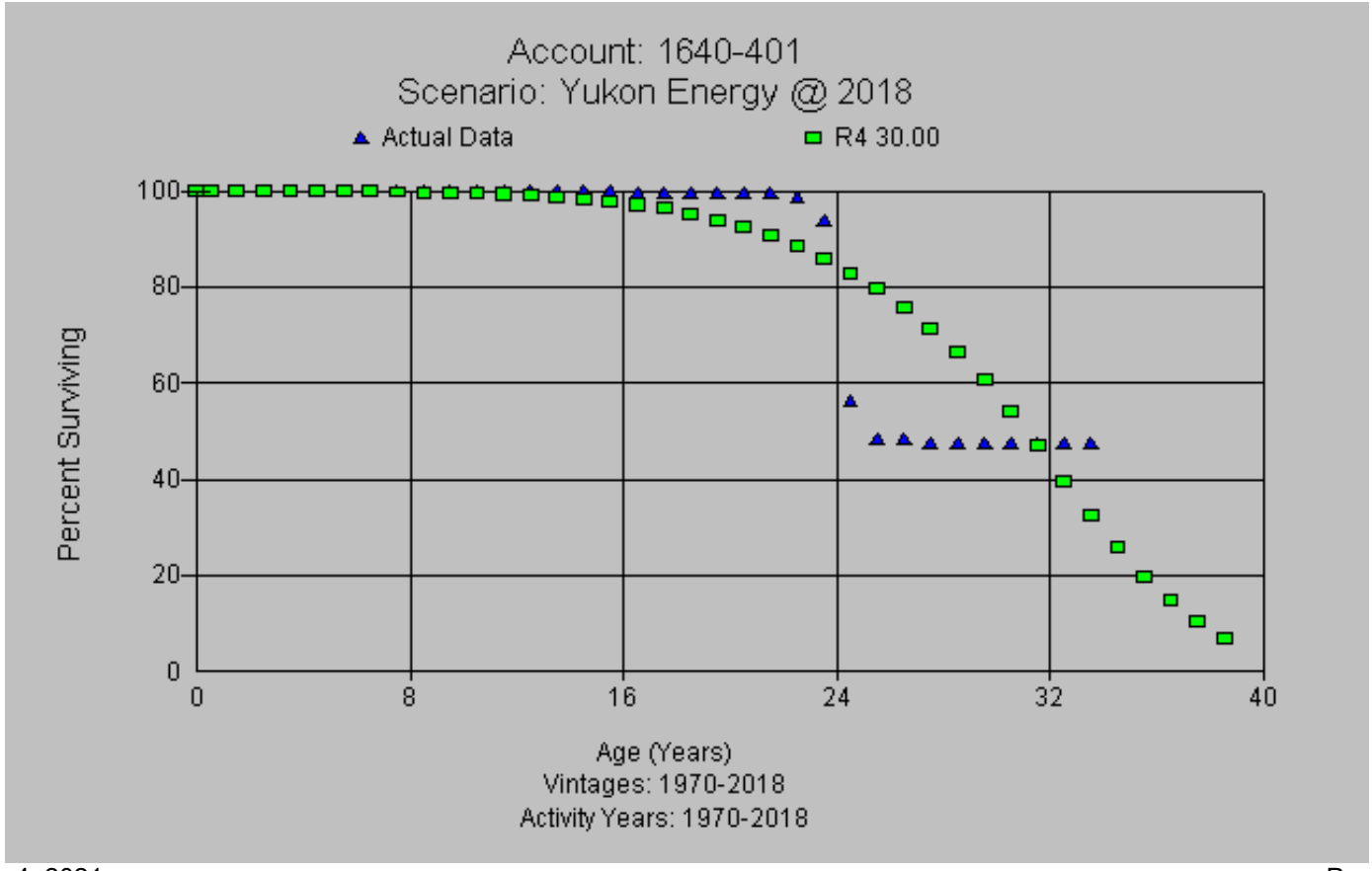
Observed Life Table

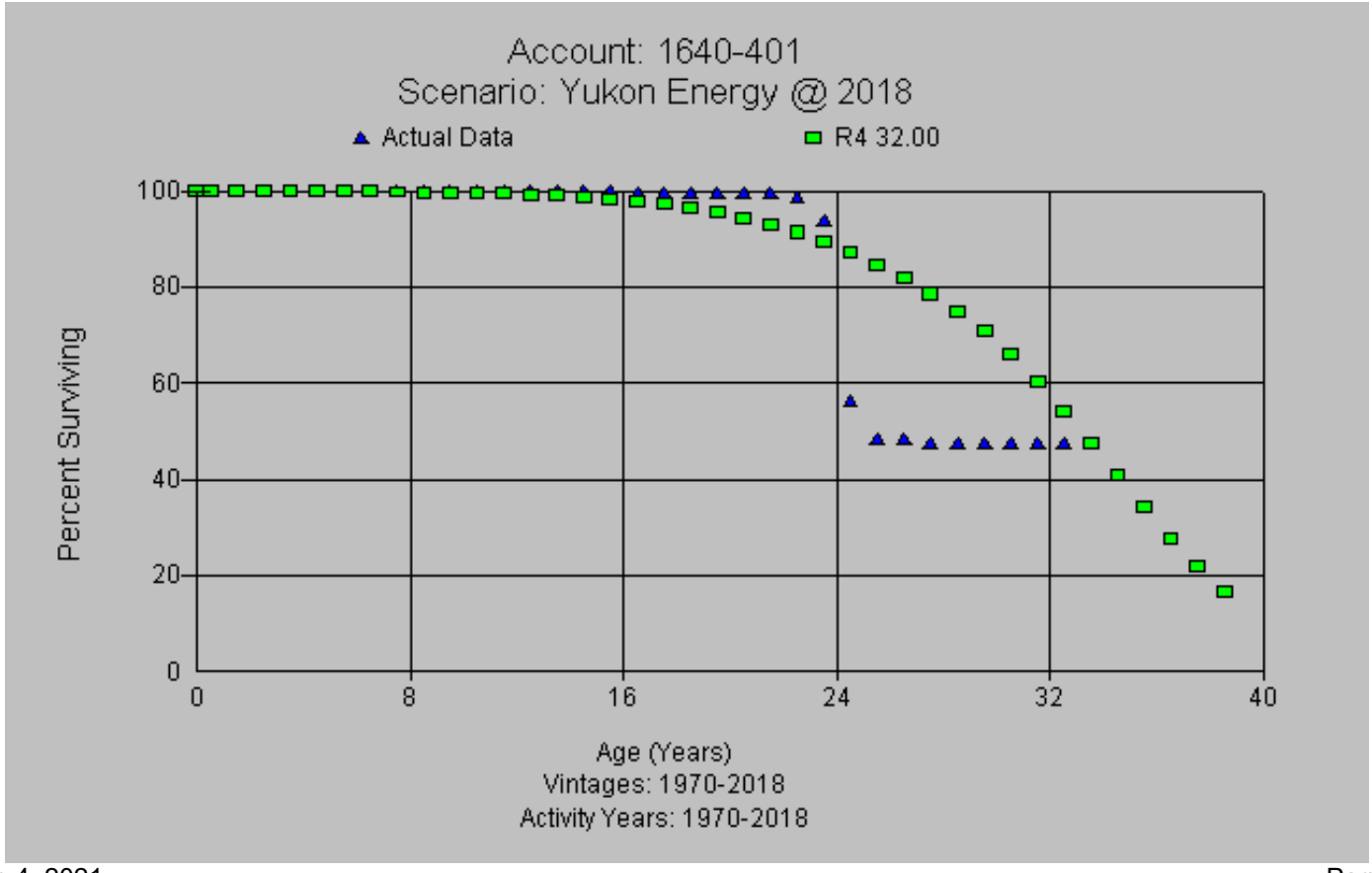
Scenario: Yukon Energy @ 2018
Account: 1640-401
Placement Band: 1955 - 2018 **Observation Band:** 1995 - 2018

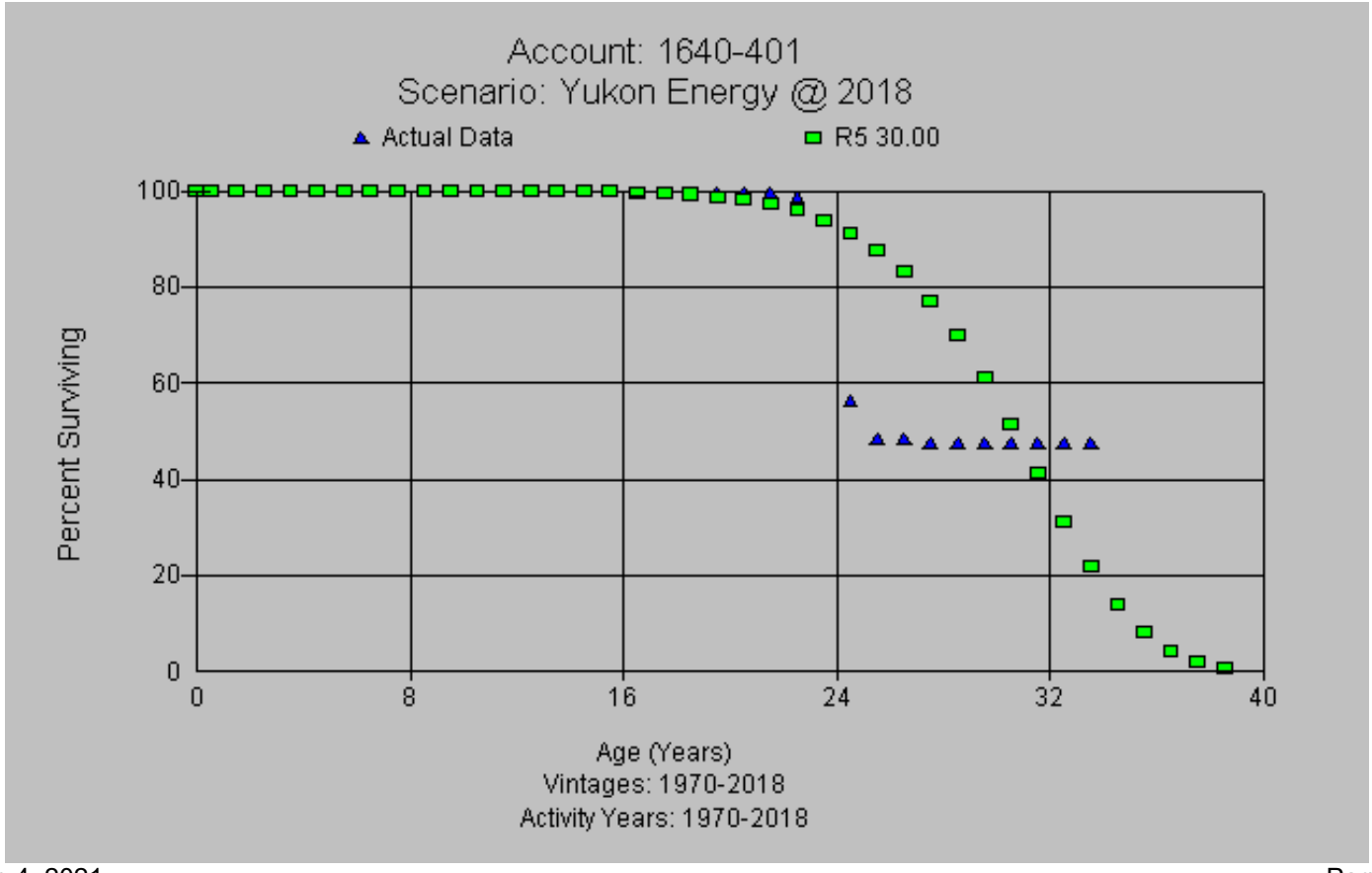
Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
38.5	0.00	0.00	0.00000	1.00000	
39.5	2.00	2.00	1.00000	0.00000	
40.5	0.00	0.00	0.00000	1.00000	

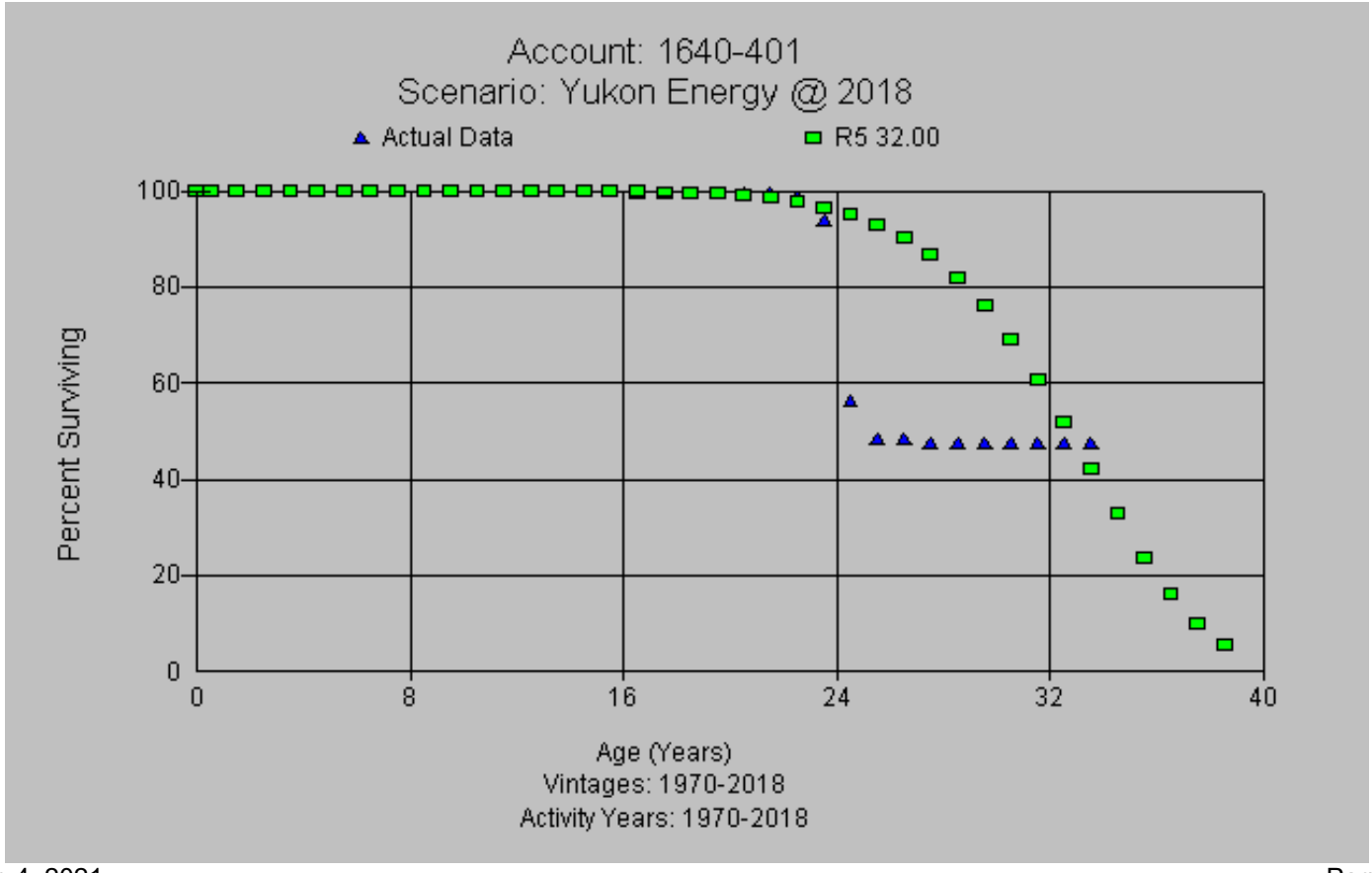

Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R3 32.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1970-2018
Activity Years: 1970-2018


Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R3 45.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1970-2018
Activity Years: 1970-2018


Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R4 30.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1970-2018
Activity Years: 1970-2018


Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R4 32.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1970-2018
Activity Years: 1970-2018

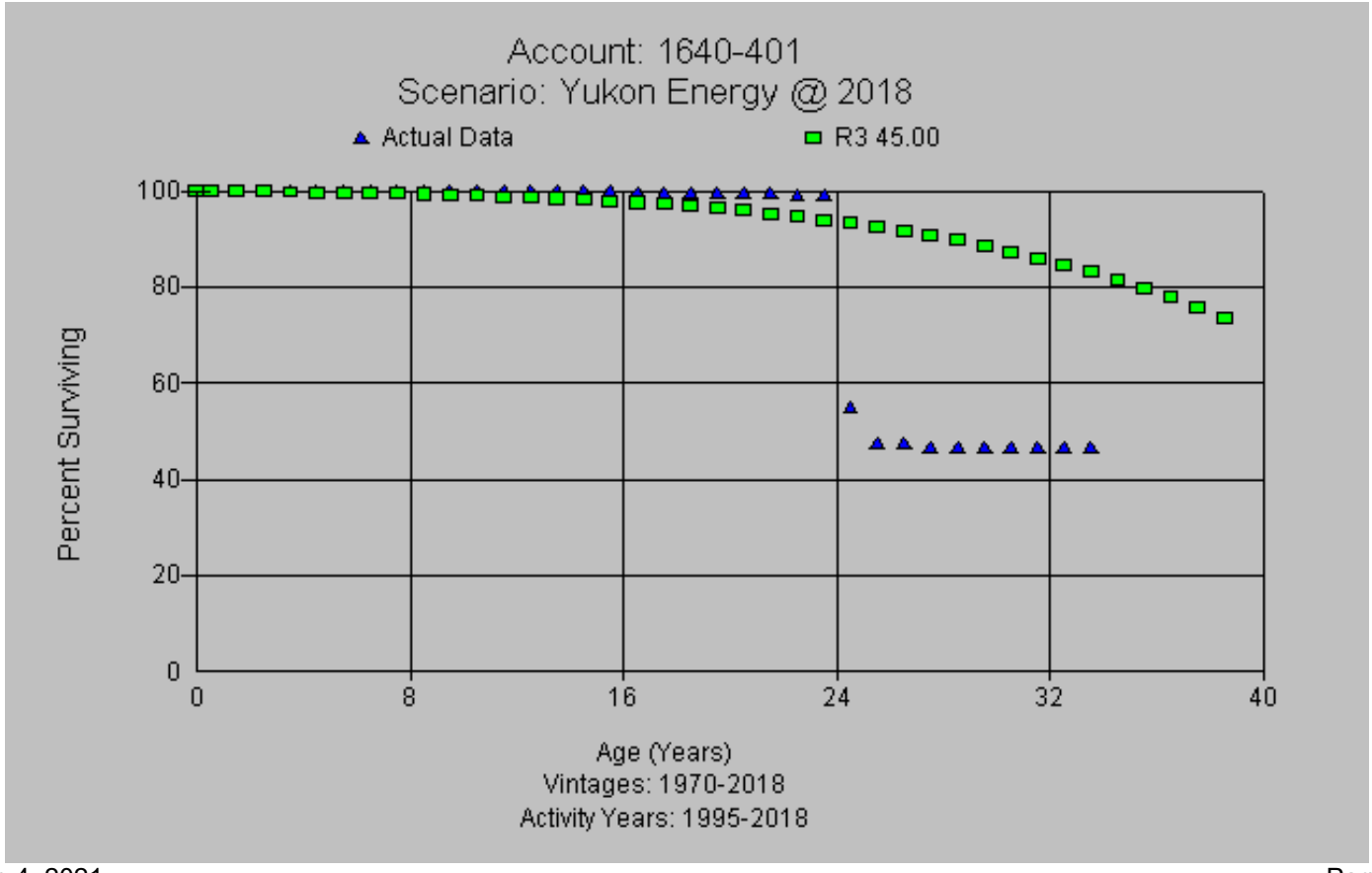

Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R5 30.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1970-2018
Activity Years: 1970-2018

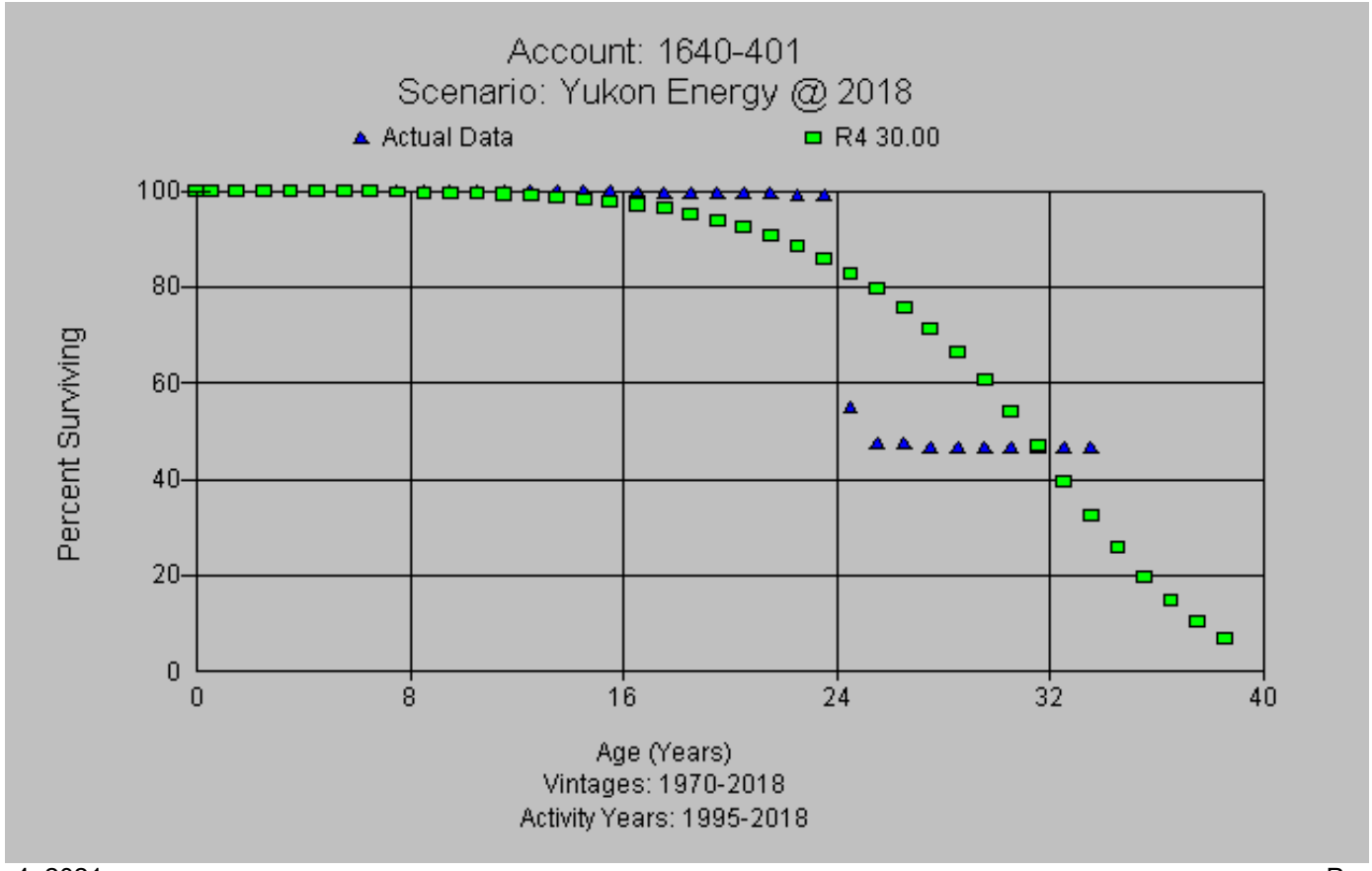

Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R5 32.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1970-2018
Activity Years: 1970-2018

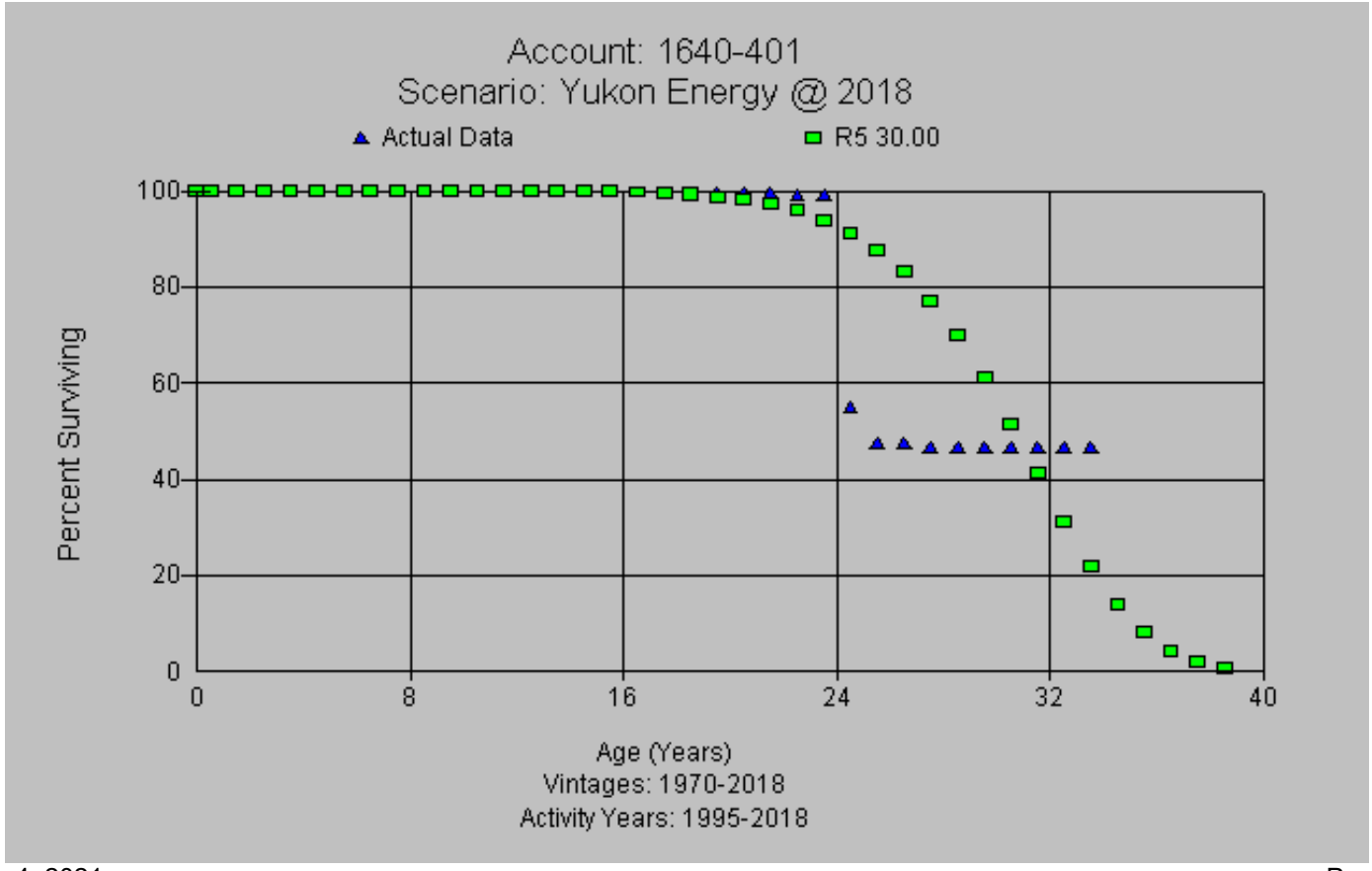
Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1640-401
Placement Band: 1970 - 2018 **Observation Band:** 1970 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	1,845,301.48	0.00	0.00000	1.00000	100.00
0.5	1,046,827.14	0.00	0.00000	1.00000	100.00
1.5	1,046,827.14	0.00	0.00000	1.00000	100.00
2.5	1,046,827.14	0.00	0.00000	1.00000	100.00
3.5	994,060.14	0.00	0.00000	1.00000	100.00
4.5	994,060.14	11.00	0.00001	0.99999	100.00
5.5	994,049.14	492.00	0.00049	0.99951	100.00
6.5	993,557.14	227.00	0.00023	0.99977	99.95
7.5	993,330.14	0.00	0.00000	1.00000	99.93
8.5	993,330.14	0.00	0.00000	1.00000	99.93
9.5	993,330.14	0.00	0.00000	1.00000	99.93
10.5	993,330.14	0.00	0.00000	1.00000	99.93
11.5	993,330.14	0.00	0.00000	1.00000	99.93
12.5	993,330.14	0.00	0.00000	1.00000	99.93
13.5	983,151.86	0.00	0.00000	1.00000	99.93
14.5	983,151.86	0.00	0.00000	1.00000	99.93
15.5	983,151.86	1,031.00	0.00105	0.99895	99.93
16.5	982,120.86	352.00	0.00036	0.99964	99.82
17.5	981,768.86	0.00	0.00000	1.00000	99.79
18.5	954,639.67	245.00	0.00026	0.99974	99.79
19.5	548,694.43	0.00	0.00000	1.00000	99.76
20.5	2,574.67	8.00	0.00311	0.99689	99.76
21.5	2,566.67	13.00	0.00506	0.99494	99.45
22.5	2,553.67	127.00	0.04973	0.95027	98.95
23.5	2,426.67	974.63	0.40163	0.59837	94.03
24.5	1,452.04	199.00	0.13705	0.86295	56.26
25.5	1,253.04	0.00	0.00000	1.00000	48.55
26.5	1,253.04	30.00	0.02394	0.97606	48.55
27.5	1,223.04	0.00	0.00000	1.00000	47.39
28.5	1,223.04	0.00	0.00000	1.00000	47.39
29.5	1,223.04	0.00	0.00000	1.00000	47.39
30.5	1,223.04	0.00	0.00000	1.00000	47.39
31.5	1,223.04	0.00	0.00000	1.00000	47.39
32.5	1,223.04	0.00	0.00000	1.00000	47.39
33.5	1,223.04	1,223.04	1.00000	0.00000	47.39
34.5	0.00	0.00	0.00000	1.00000	0.00


Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R3 45.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1970-2018
Activity Years: 1995-2018


Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R4 30.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1970-2018
Activity Years: 1995-2018


Account: 1640-401
Scenario: Yukon Energy @ 2018
Actual Data
R5 30.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1970-2018
Activity Years: 1995-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1640-401
Placement Band: 1970 - 2018 **Observation Band:** 1995 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	1,840,368.81	0.00	0.00000	1.00000	100.00
0.5	1,041,894.47	0.00	0.00000	1.00000	100.00
1.5	1,041,894.47	0.00	0.00000	1.00000	100.00
2.5	1,041,894.47	0.00	0.00000	1.00000	100.00
3.5	989,127.47	0.00	0.00000	1.00000	100.00
4.5	989,538.47	11.00	0.00001	0.99999	100.00
5.5	989,527.47	200.00	0.00020	0.99980	100.00
6.5	989,327.47	200.00	0.00020	0.99980	99.98
7.5	989,127.47	0.00	0.00000	1.00000	99.96
8.5	989,127.47	0.00	0.00000	1.00000	99.96
9.5	989,127.47	0.00	0.00000	1.00000	99.96
10.5	989,127.47	0.00	0.00000	1.00000	99.96
11.5	989,127.47	0.00	0.00000	1.00000	99.96
12.5	989,127.47	0.00	0.00000	1.00000	99.96
13.5	978,949.19	0.00	0.00000	1.00000	99.96
14.5	981,306.82	0.00	0.00000	1.00000	99.96
15.5	981,306.82	1,031.00	0.00105	0.99895	99.96
16.5	980,520.82	352.00	0.00036	0.99964	99.85
17.5	980,168.82	0.00	0.00000	1.00000	99.82
18.5	953,039.63	245.00	0.00026	0.99974	99.82
19.5	547,107.39	0.00	0.00000	1.00000	99.79
20.5	987.63	0.00	0.00000	1.00000	99.79
21.5	2,210.67	13.00	0.00588	0.99412	99.79
22.5	2,197.67	0.00	0.00000	1.00000	99.21
23.5	2,197.67	974.63	0.44348	0.55652	99.21
24.5	1,452.04	199.00	0.13705	0.86295	55.21
25.5	1,253.04	0.00	0.00000	1.00000	47.64
26.5	1,253.04	30.00	0.02394	0.97606	47.64
27.5	1,223.04	0.00	0.00000	1.00000	46.50
28.5	1,223.04	0.00	0.00000	1.00000	46.50
29.5	1,223.04	0.00	0.00000	1.00000	46.50
30.5	1,223.04	0.00	0.00000	1.00000	46.50
31.5	1,223.04	0.00	0.00000	1.00000	46.50
32.5	1,223.04	0.00	0.00000	1.00000	46.50
33.5	1,223.04	1,223.04	1.00000	0.00000	46.50
34.5	0.00	0.00	0.00000	1.00000	0.00

Actuarial Life Analysis

Account: 1640-401
Scenario: Yukon Energy @ 2018
Placement Band: 1955 - 1974
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1970 -1974		1.00			
1971 -1975		1.00			
1972 -1976		1.00			
1973 -1977		1.00			
1974 -1978		1.00			
1975 -1979		1.00			
1976 -1980		1.00			
1977 -1981		1.00			
1978 -1982		1.00			
1979 -1983		1.00			
1980 -1984		1.00			
1981 -1985		1.00			
1982 -1986		1.00			
1983 -1987		1.00			
1984 -1988		1.00			
1985 -1989		1.00			
1986 -1990		1.00			
1987 -1991		1.00			
1988 -1992		1.00			
1989 -1993	36.5	5.32	0.84031182	L2.5	8.14
1990 -1994	37.5	0.00	0.00715716	SQ	6.43
1991 -1995	38.5	0.00	0.00718357	SQ	6.41
1992 -1996	39.5	0.00	0.00457205	S6	6.34
1993 -1997	40.5	0.00	0.00318559	S6	6.33
1994 -1998	41.5	0.00	0.00092164	S6	6.51
1995 -1999	42.5	0.00	0.00092164	S6	6.51
1996 -2000	43.5	0.00	0.00251412	S6	6.55
1997 -2001	44.5	0.00	0.00000000	SQ	7.39
1998 -2002		1.00			
1999 -2003		1.00			
2000 -2004	47.5	0.00	0.00000000	SQ	22.20
2001 -2005	48.5	0.00	0.00000000	SQ	22.20
2002 -2006	49.5	0.00	0.00000000	SQ	22.20
2003 -2007	50.5	0.00	0.00000000	SQ	22.20
2004 -2008	51.5	0.00	0.00000000	SQ	22.20
2005 -2009	52.5	0.00	0.00000000	SQ	32.10
2006 -2010		0.00			
2007 -2011		0.00			
2008 -2012		0.00			
2009 -2013		0.00			
2010 -2014		0.00			
2011 -2015		1.00			
2012 -2016		1.00			
2013 -2017		1.00			

Actuarial Life Analysis

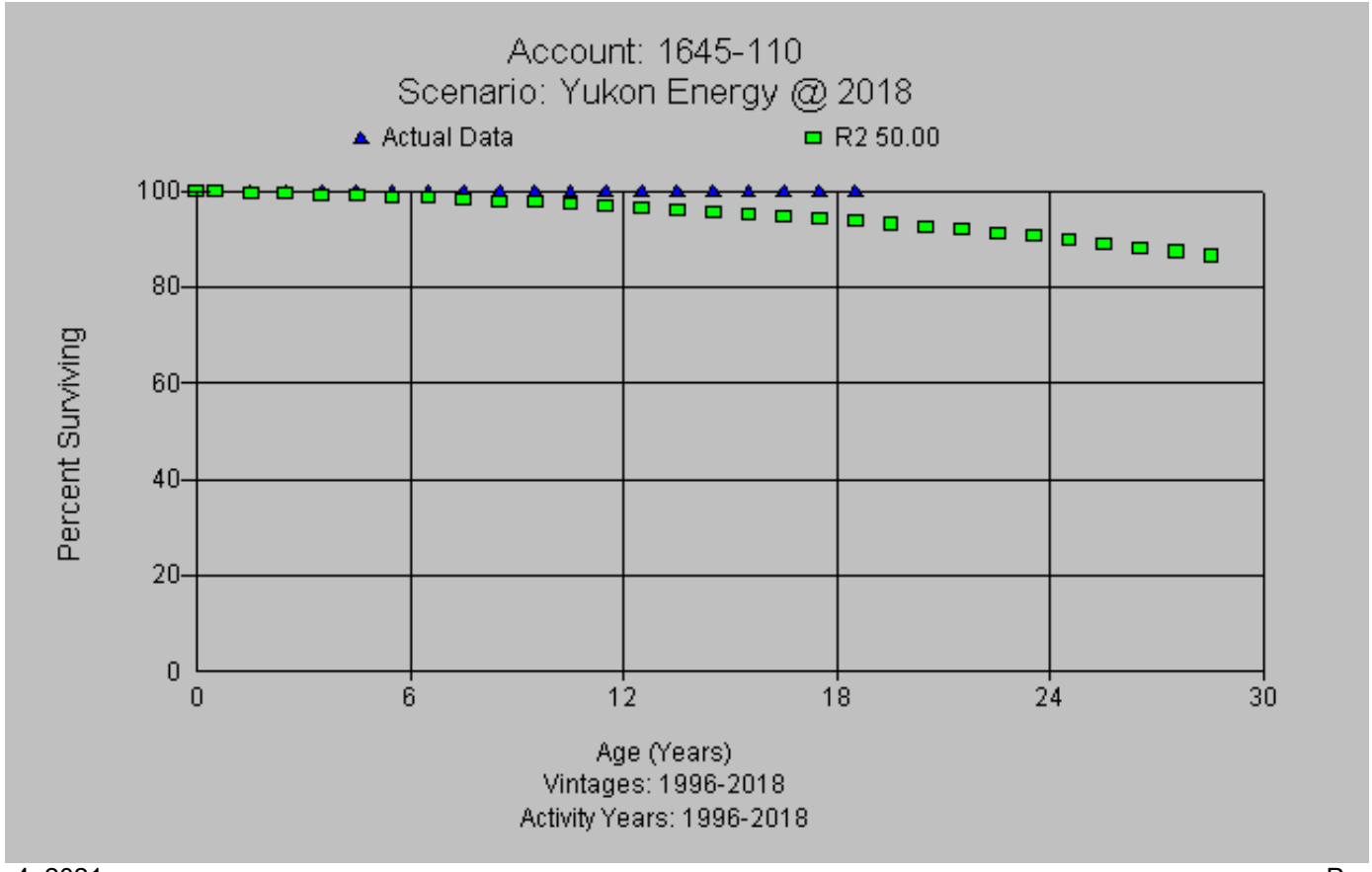
Account: 1640-401
Scenario: Yukon Energy @ 2018
Placement Band: 1955 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
2014 -2018		1.00			

Actuarial Life Analysis

Account: 1640-401
Scenario: Yukon Energy @ 2018
Placement Band: 1955 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

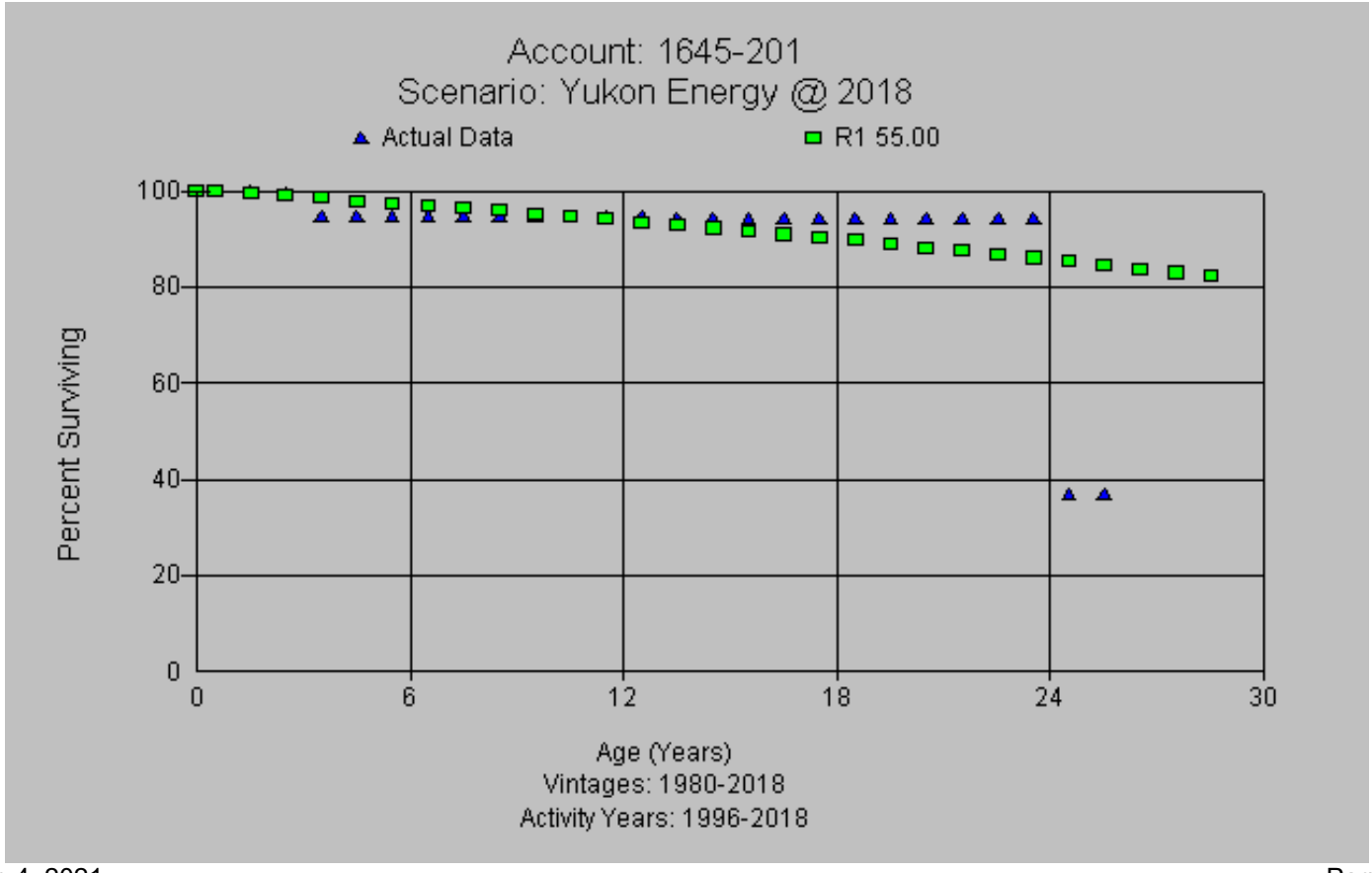
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1970 -2018	63.5	0.00	0.32214737	R4	29.76
1975 -2018	63.5	0.00	0.32214737	R4	29.76
1980 -2018	63.5	0.00	0.32216196	R4	29.76
1985 -2018	63.5	0.00	0.34378544	R4	29.31
1990 -2018	63.5	0.00	0.35485830	S4	28.90
1995 -2018	63.5	0.00	0.37324577	S4	28.65
2000 -2018	63.5	0.00	0.00000000	SQ	24.20
2005 -2018	63.5	0.00	0.00000000	SQ	34.10
2010 -2018		1.00			
2015 -2018		1.00			

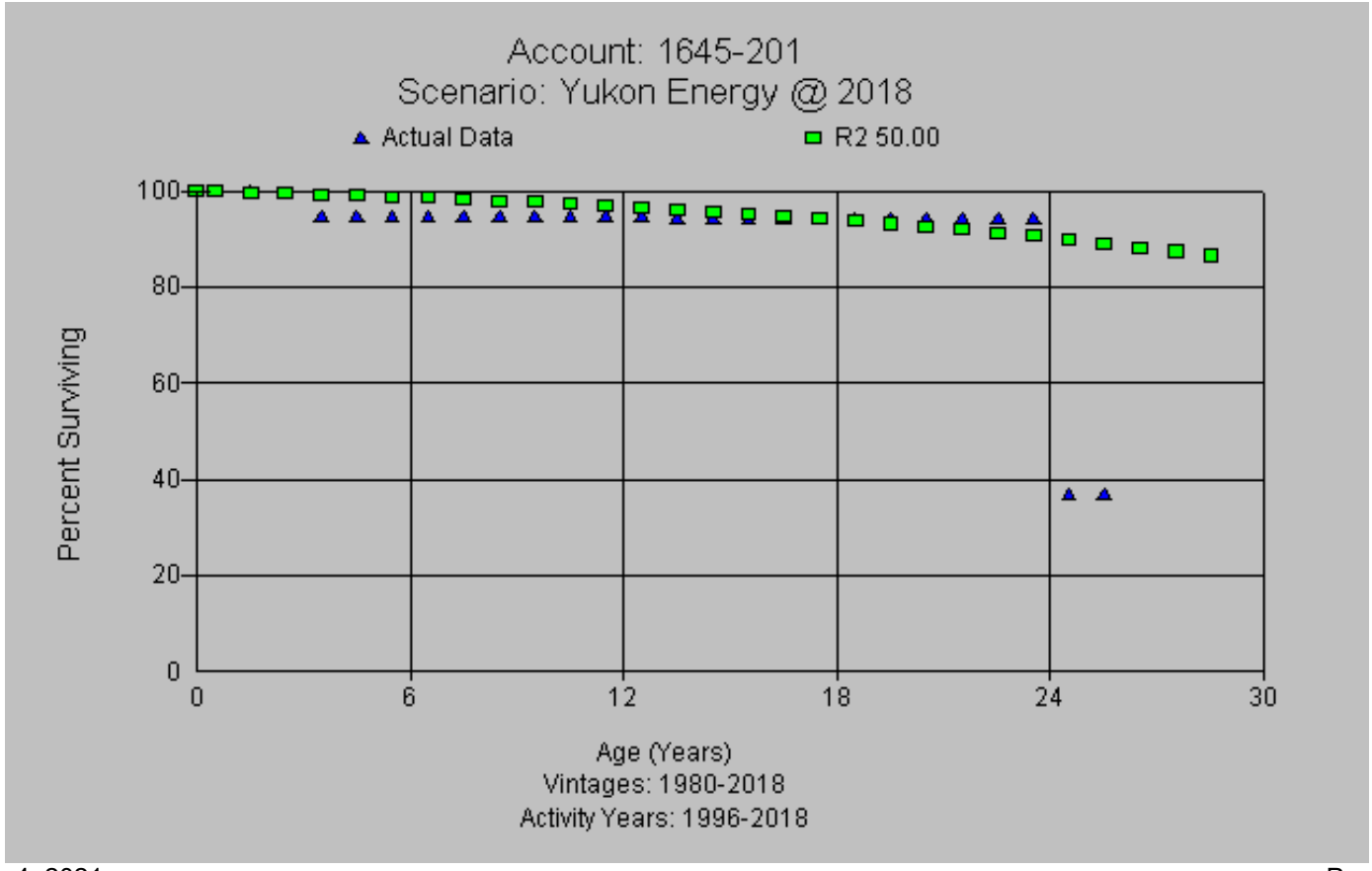

Account: 1645-110
Scenario: Yukon Energy @ 2018
Actual Data
R2 50.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1996-2018
Activity Years: 1996-2018

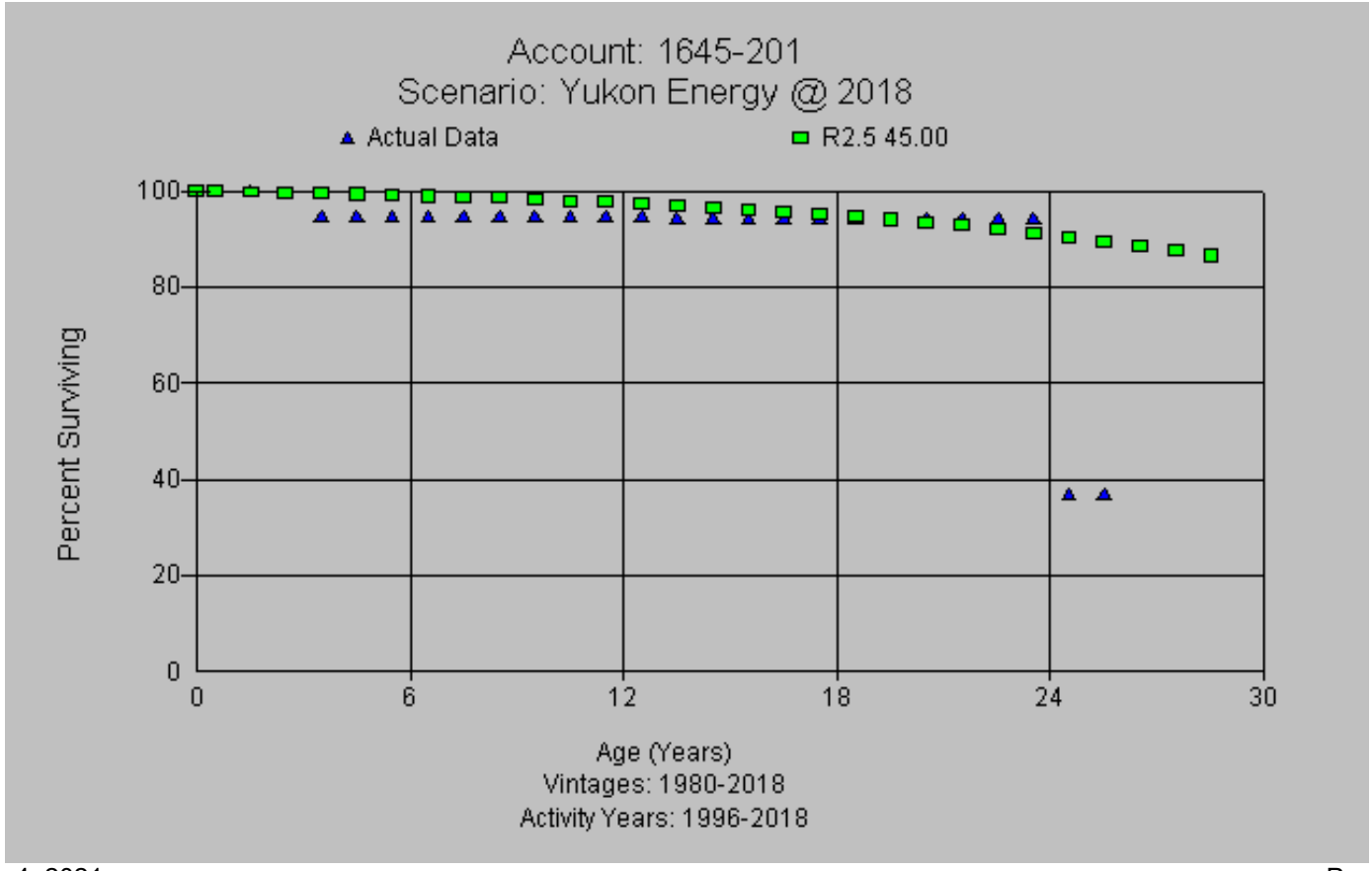
Actuarial Life Analysis

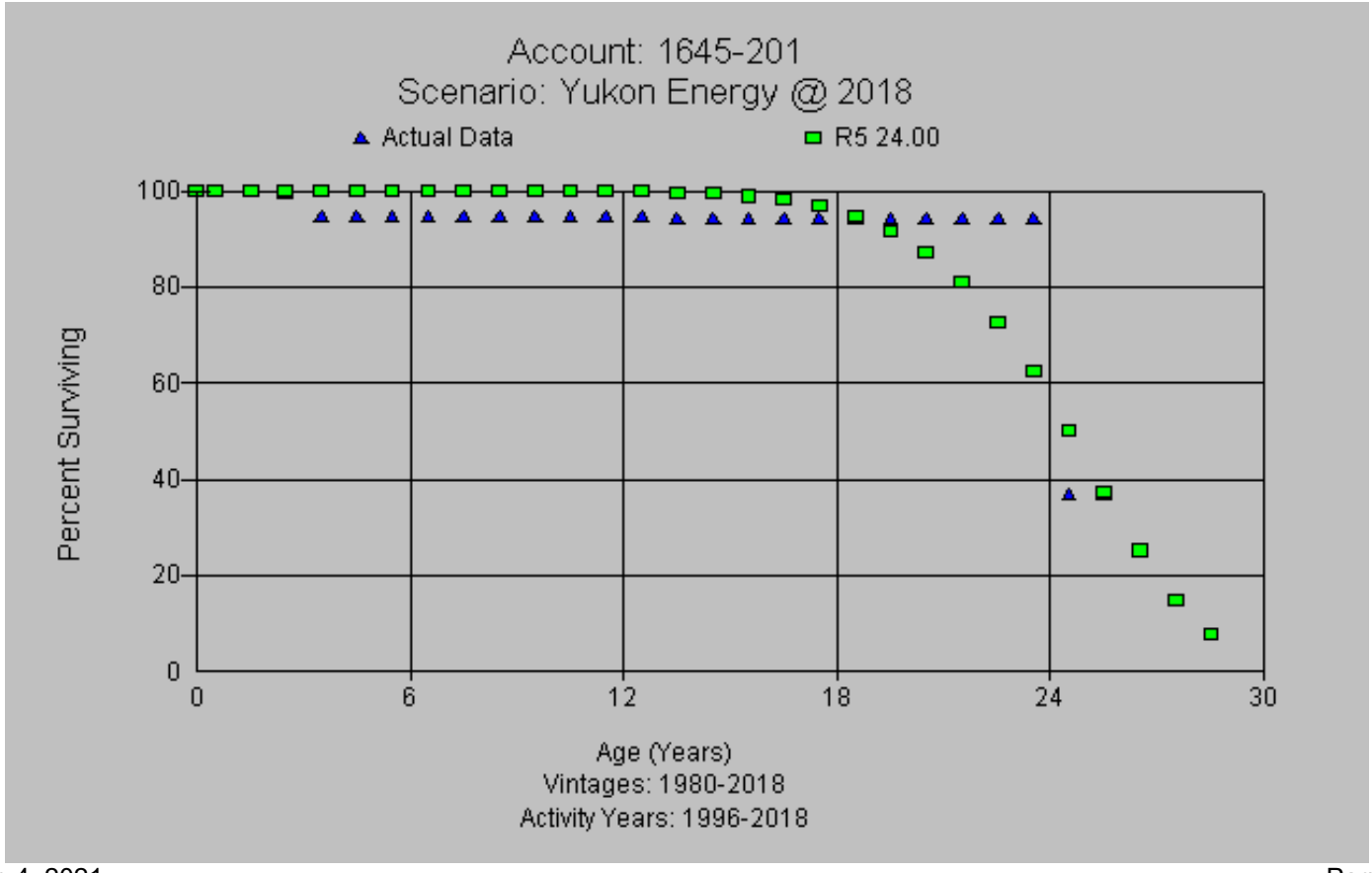
Account: 1645-110
Scenario: Yukon Energy @ 2018
Placement Band: 1996 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

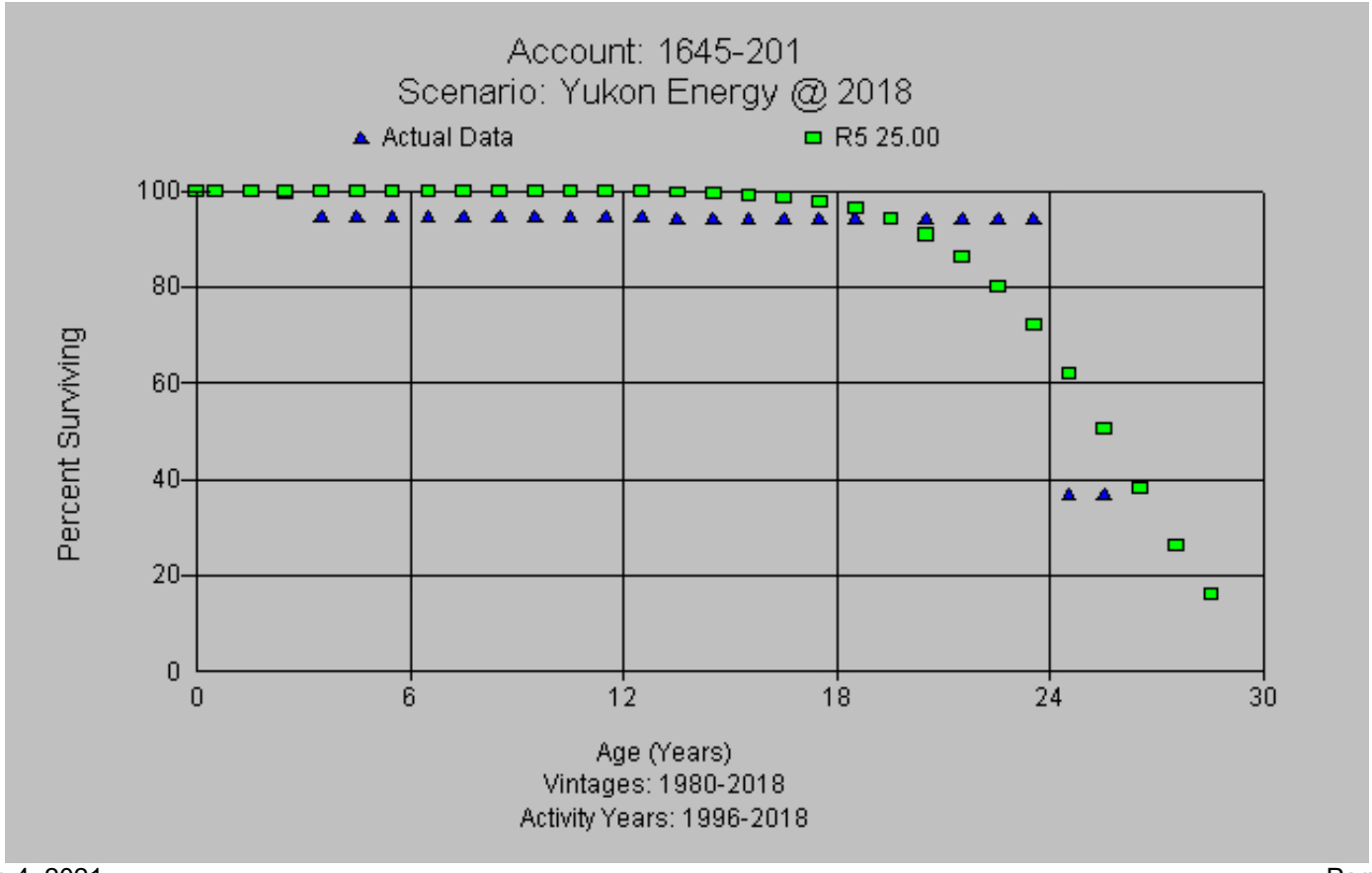
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1996 -2018		1.00			


Account: 1645-201
Scenario: Yukon Energy @ 2018
Actual Data
R1 55.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1996-2018


Account: 1645-201
Scenario: Yukon Energy @ 2018
Actual Data
R2 50.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1996-2018


Account: 1645-201
Scenario: Yukon Energy @ 2018
Actual Data
R2.5 45.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1996-2018


Account: 1645-201
Scenario: Yukon Energy @ 2018
Actual Data
R5 24.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1996-2018


Account: 1645-201
Scenario: Yukon Energy @ 2018
Actual Data
R5 25.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1996-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-201
Placement Band: 1980 - 2018 **Observation Band:** 1996 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	10,930,400.73	0.00	0.00000	1.00000	100.00
0.5	10,550,041.68	1,482.00	0.00014	0.99986	100.00
1.5	10,476,083.26	26,900.00	0.00257	0.99743	99.99
2.5	10,374,933.62	493,010.00	0.04752	0.95248	99.73
3.5	8,909,507.33	0.00	0.00000	1.00000	94.99
4.5	8,777,834.24	0.00	0.00000	1.00000	94.99
5.5	8,656,583.07	24,043.00	0.00278	0.99722	94.99
6.5	8,489,021.39	0.00	0.00000	1.00000	94.73
7.5	8,458,407.04	0.00	0.00000	1.00000	94.73
8.5	8,286,671.60	0.00	0.00000	1.00000	94.73
9.5	7,681,227.59	0.00	0.00000	1.00000	94.73
10.5	7,377,306.24	0.00	0.00000	1.00000	94.73
11.5	7,198,255.55	0.00	0.00000	1.00000	94.73
12.5	7,072,263.44	39,306.46	0.00556	0.99444	94.73
13.5	6,758,176.83	0.00	0.00000	1.00000	94.20
14.5	6,285,969.40	0.00	0.00000	1.00000	94.20
15.5	6,225,164.82	0.00	0.00000	1.00000	94.20
16.5	5,590,895.06	0.00	0.00000	1.00000	94.20
17.5	5,084,639.65	0.00	0.00000	1.00000	94.20
18.5	3,970,459.82	0.00	0.00000	1.00000	94.20
19.5	3,502,320.05	0.00	0.00000	1.00000	94.20
20.5	9,219.33	0.00	0.00000	1.00000	94.20
21.5	9,219.33	0.00	0.00000	1.00000	94.20
22.5	9,219.33	0.00	0.00000	1.00000	94.20
23.5	9,219.33	5,597.76	0.60718	0.39282	94.20
24.5	3,621.57	0.00	0.00000	1.00000	37.00
25.5	3,621.57	3,621.57	1.00000	0.00000	37.00
26.5	0.00	0.00	0.00000	1.00000	0.00

Actuarial Life Analysis

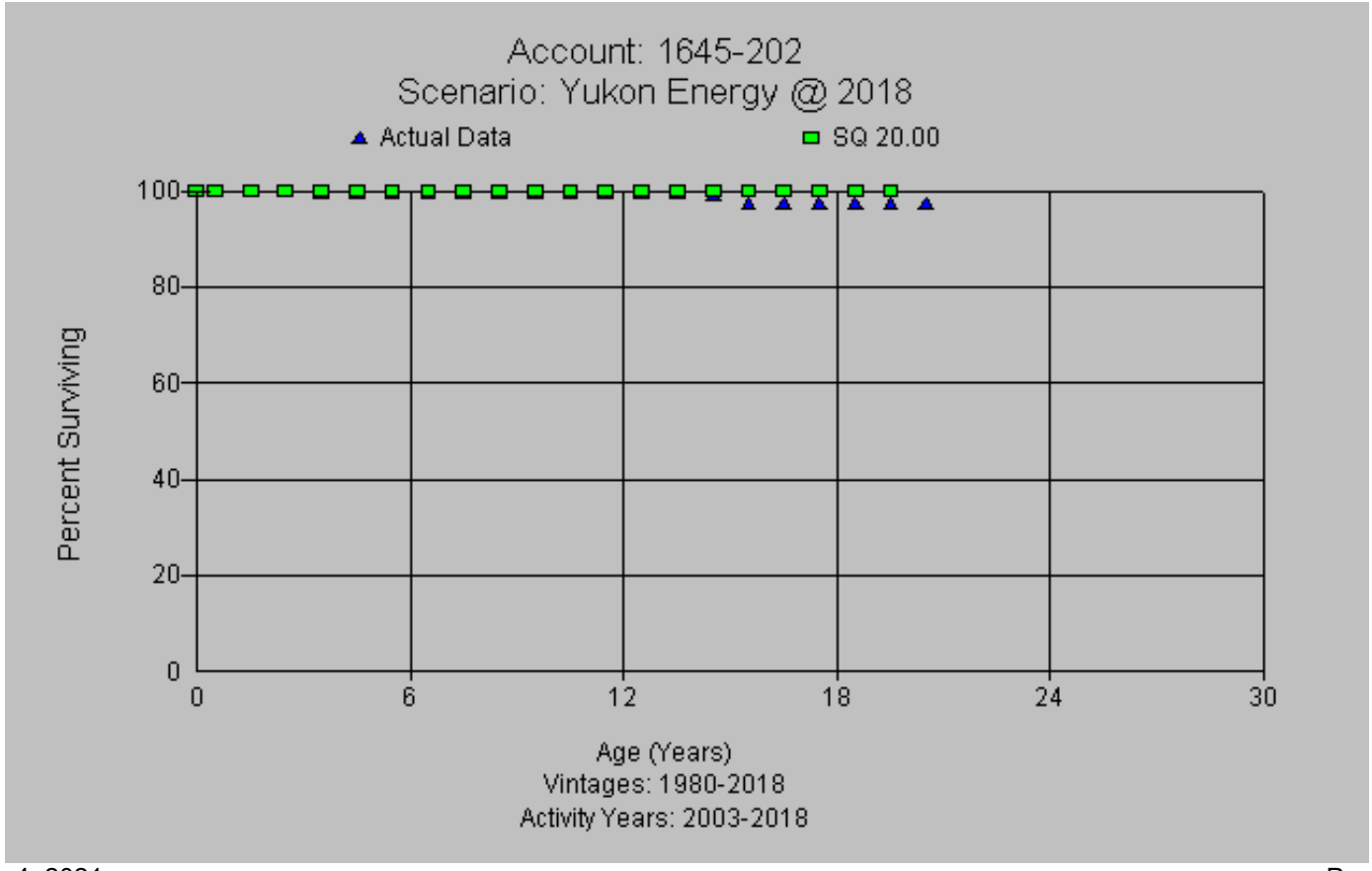
Account: 1645-201
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2000
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

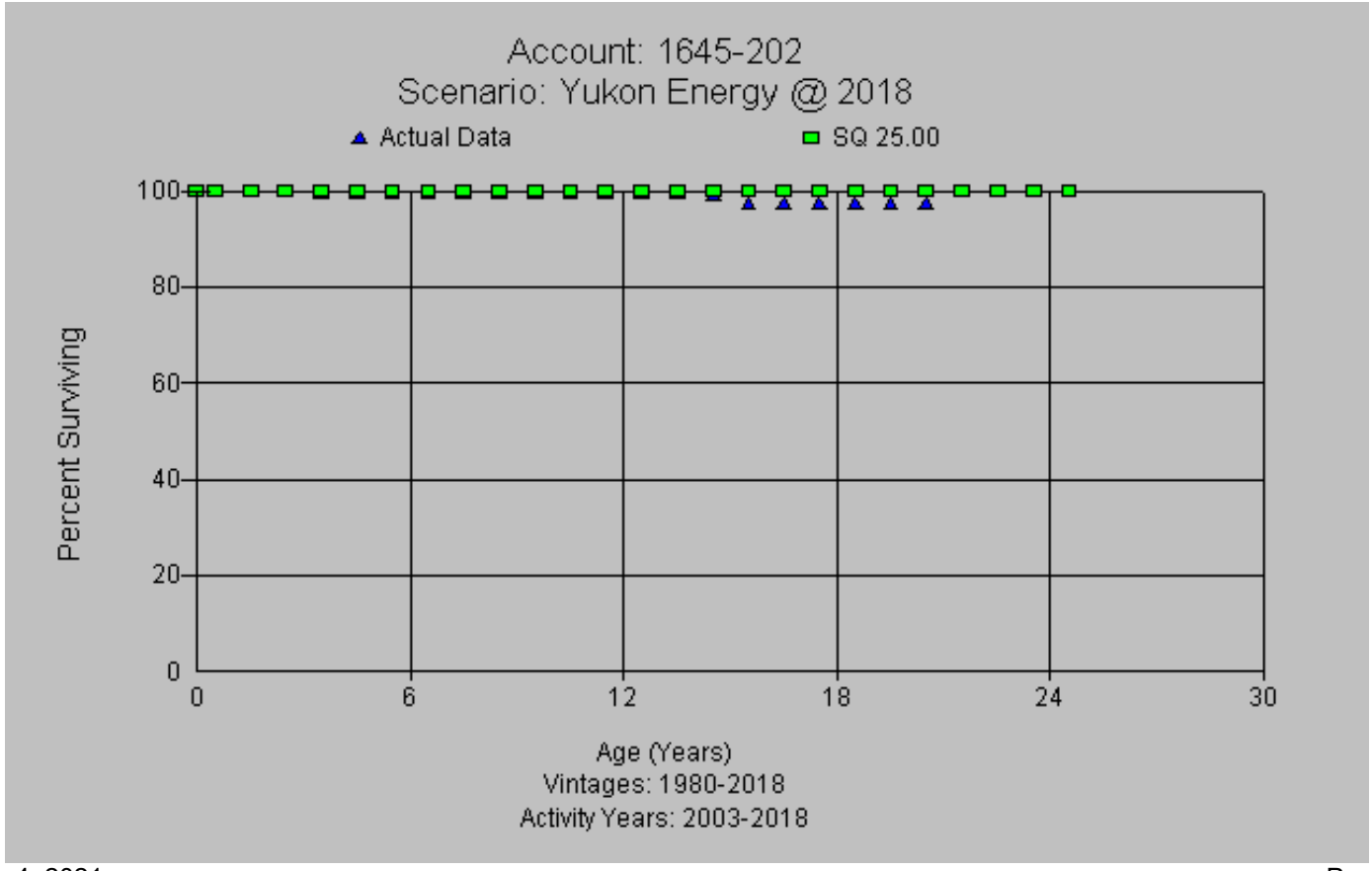
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1996 -2000	18.5	0.00	0.00006937	SQ	3.44
1997 -2001	19.5	0.00	0.05011768	SQ	5.65
1998 -2002	20.5	0.00	0.03983921	SQ	5.70
1999 -2003	21.5	0.00	0.02602788	SQ	5.76
2000 -2004	22.5	39.28	0.00921667	SQ	22.34
2001 -2005	23.5	39.28	0.09722548	S6	23.13
2002 -2006	24.5	0.00	0.12551245	S6	22.93
2003 -2007	25.5	0.00	0.12476595	S6	22.83
2004 -2008	26.5	0.00	0.12502669	S6	22.83
2005 -2009	27.5	0.00	0.00000000	SQ	24.20
2006 -2010	28.5	0.00	0.00000000	SQ	24.20
2007 -2011		1.00			
2008 -2012		1.00			
2009 -2013		1.00			
2010 -2014		1.00			
2011 -2015		1.00			
2012 -2016		1.00			
2013 -2017		1.00			
2014 -2018	36.5	98.03	0.00122985	R2	171.73

Actuarial Life Analysis

Account: 1645-201
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1996 -2018	38.5	0.00	0.32230131	S6	23.63
2001 -2018	38.5	0.00	0.13955902	S6	24.77
2006 -2018	38.5	0.00	0.00040768	SQ	25.98
2011 -2018	38.5	99.44	0.00017451	R3	158.82
2016 -2018	38.5	95.41	0.00628986	R0.5	237.28

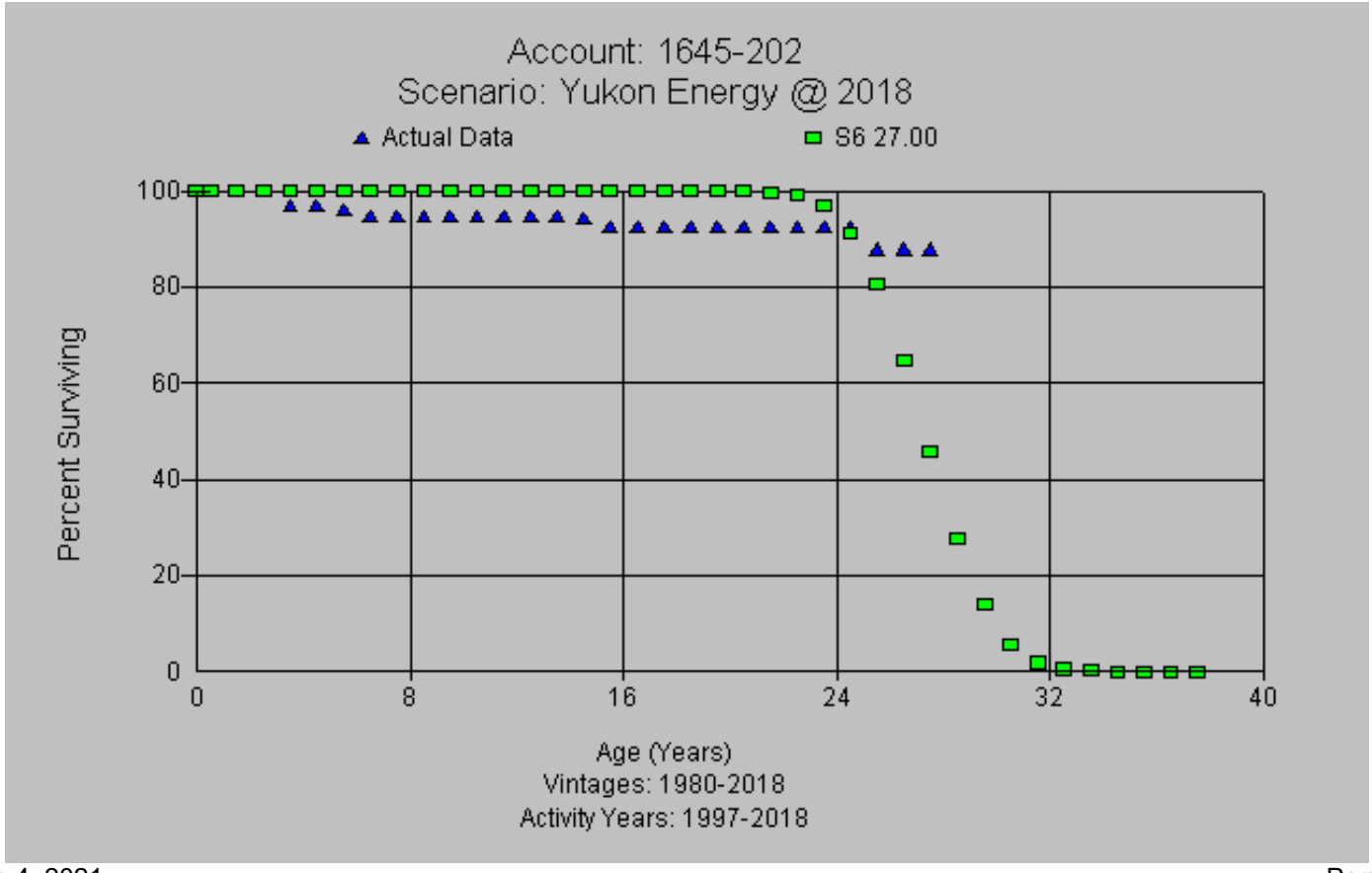

Account: 1645-202
Scenario: Yukon Energy @ 2018
Actual Data
SQ 20.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 2003-2018

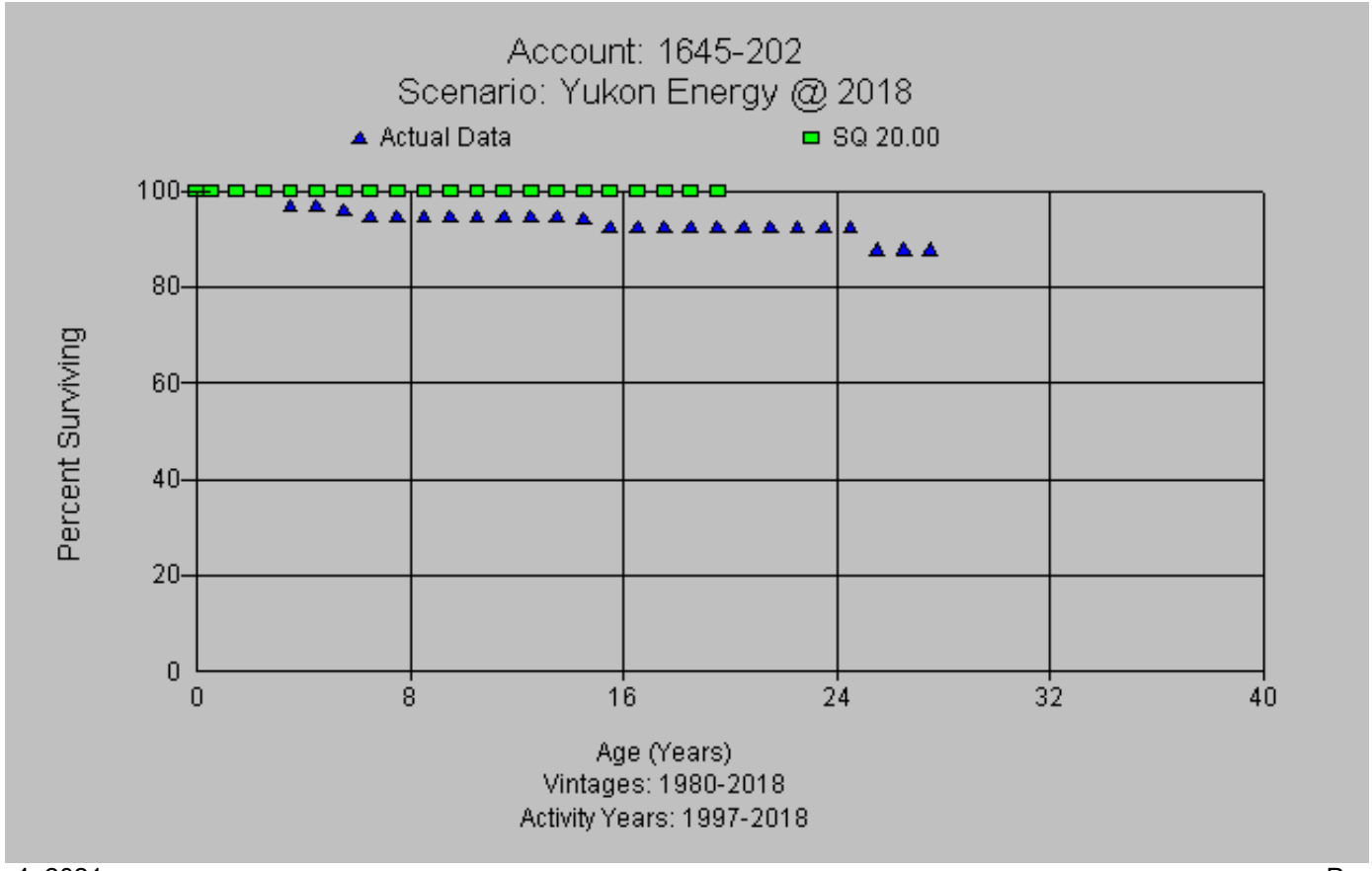

Account: 1645-202
Scenario: Yukon Energy @ 2018
Actual Data
SQ 25.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 2003-2018

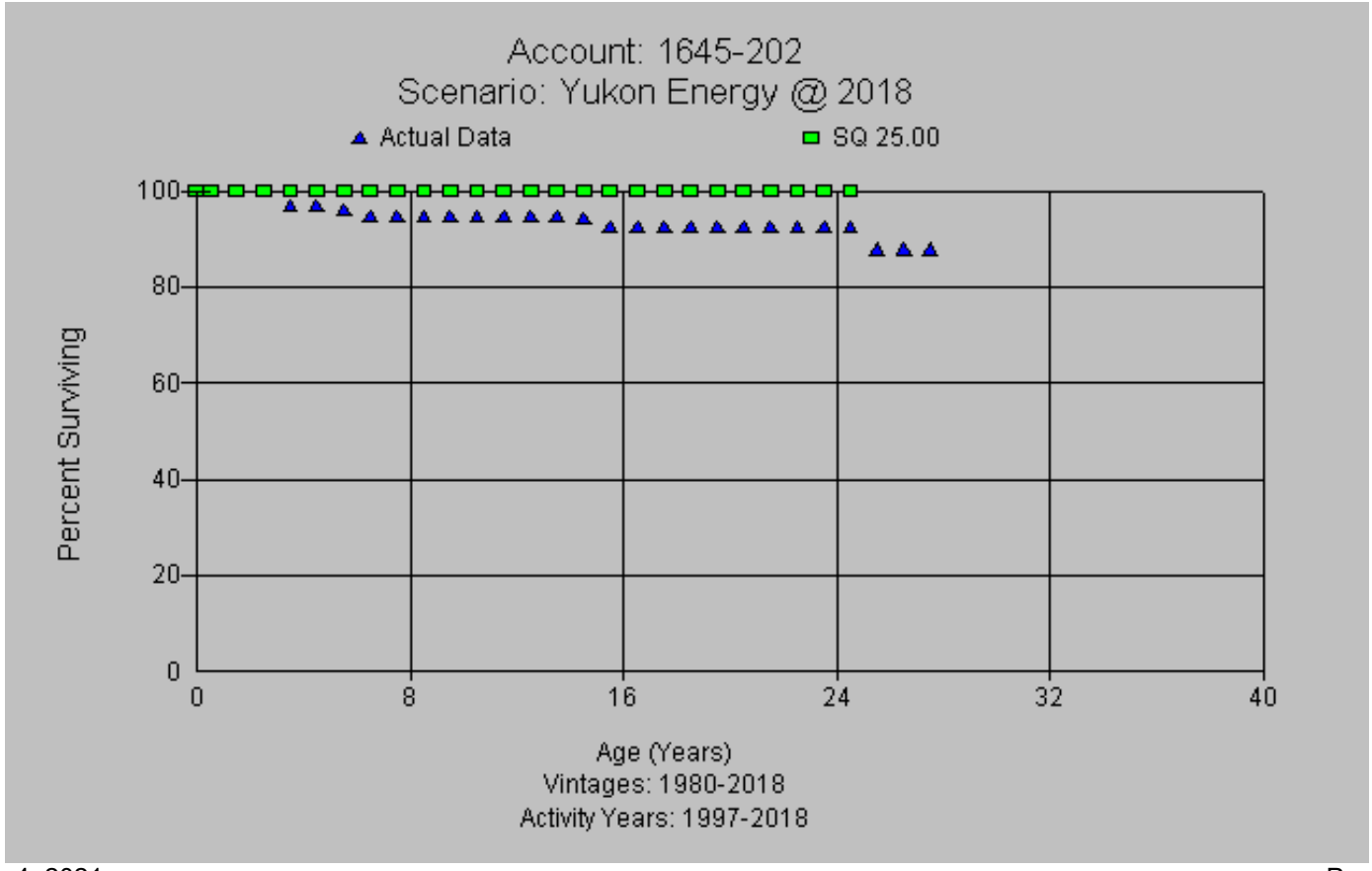
Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-202
Placement Band: 1980 - 2018 **Observation Band:** 2003 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	712,815.20	0.00	0.00000	1.00000	100.00
0.5	748,934.24	0.00	0.00000	1.00000	100.00
1.5	822,858.71	0.00	0.00000	1.00000	100.00
2.5	751,296.63	2,041.67	0.00272	0.99728	100.00
3.5	680,737.26	0.00	0.00000	1.00000	99.73
4.5	1,476,294.15	0.00	0.00000	1.00000	99.73
5.5	1,455,692.13	0.00	0.00000	1.00000	99.73
6.5	1,433,091.51	0.00	0.00000	1.00000	99.73
7.5	1,389,826.42	0.00	0.00000	1.00000	99.73
8.5	1,364,616.87	0.00	0.00000	1.00000	99.73
9.5	1,283,297.38	0.00	0.00000	1.00000	99.73
10.5	1,229,592.79	0.00	0.00000	1.00000	99.73
11.5	1,177,933.19	0.00	0.00000	1.00000	99.73
12.5	1,165,379.59	0.00	0.00000	1.00000	99.73
13.5	1,151,162.11	5,565.77	0.00483	0.99517	99.73
14.5	1,077,909.14	20,008.22	0.01856	0.98144	99.25
15.5	1,025,795.28	0.00	0.00000	1.00000	97.40
16.5	963,890.27	0.00	0.00000	1.00000	97.40
17.5	868,220.04	0.00	0.00000	1.00000	97.40
18.5	855,724.03	0.00	0.00000	1.00000	97.40
19.5	854,946.01	0.00	0.00000	1.00000	97.40
20.5	0.00	0.00	0.00000	1.00000	97.40
21.5	0.00	0.00	0.00000	1.00000	
22.5	224,370.89	0.00	0.00000	1.00000	
23.5	224,370.89	0.00	0.00000	1.00000	
24.5	224,370.89	11,509.24	0.05130	0.94870	
25.5	212,861.65	0.00	0.00000	1.00000	
26.5	212,861.65	0.00	0.00000	1.00000	
27.5	212,861.65	212,861.65	1.00000	0.00000	
28.5	0.00	0.00	0.00000	1.00000	


Account: 1645-202
Scenario: Yukon Energy @ 2018
Actual Data
S6 27.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1980-2018
Activity Years: 1997-2018


Account: 1645-202
Scenario: Yukon Energy @ 2018
Actual Data
SQ 20.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1980-2018
Activity Years: 1997-2018


Account: 1645-202
Scenario: Yukon Energy @ 2018
Actual Data
SQ 25.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1980-2018
Activity Years: 1997-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-202
Placement Band: 1980 - 2018 **Observation Band:** 1997 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	1,890,214.47	1,777.00	0.00094	0.99906	100.00
0.5	1,788,494.50	453.00	0.00025	0.99975	99.91
1.5	1,766,295.74	0.00	0.00000	1.00000	99.88
2.5	1,687,471.88	51,684.67	0.03063	0.96937	99.88
3.5	1,564,586.27	0.00	0.00000	1.00000	96.82
4.5	1,505,197.15	10,800.00	0.00718	0.99282	96.82
5.5	1,473,795.13	18,103.00	0.01228	0.98772	96.13
6.5	1,433,091.51	0.00	0.00000	1.00000	94.95
7.5	1,389,826.42	0.00	0.00000	1.00000	94.95
8.5	1,364,616.87	0.00	0.00000	1.00000	94.95
9.5	1,283,297.38	0.00	0.00000	1.00000	94.95
10.5	1,229,592.79	0.00	0.00000	1.00000	94.95
11.5	1,177,933.19	0.00	0.00000	1.00000	94.95
12.5	1,165,379.59	0.00	0.00000	1.00000	94.95
13.5	1,151,162.11	5,565.77	0.00483	0.99517	94.95
14.5	1,077,909.14	20,008.22	0.01856	0.98144	94.49
15.5	1,025,795.28	0.00	0.00000	1.00000	92.73
16.5	1,188,261.16	0.00	0.00000	1.00000	92.73
17.5	1,092,590.93	0.00	0.00000	1.00000	92.73
18.5	1,080,094.92	0.00	0.00000	1.00000	92.73
19.5	1,079,316.90	0.00	0.00000	1.00000	92.73
20.5	224,370.89	0.00	0.00000	1.00000	92.73
21.5	224,370.89	0.00	0.00000	1.00000	92.73
22.5	224,370.89	0.00	0.00000	1.00000	92.73
23.5	224,370.89	0.00	0.00000	1.00000	92.73
24.5	224,370.89	11,509.24	0.05130	0.94870	92.73
25.5	212,861.65	0.00	0.00000	1.00000	87.98
26.5	212,861.65	0.00	0.00000	1.00000	87.98
27.5	212,861.65	212,861.65	1.00000	0.00000	87.98
28.5	0.00	0.00	0.00000	1.00000	0.00

Actuarial Life Analysis

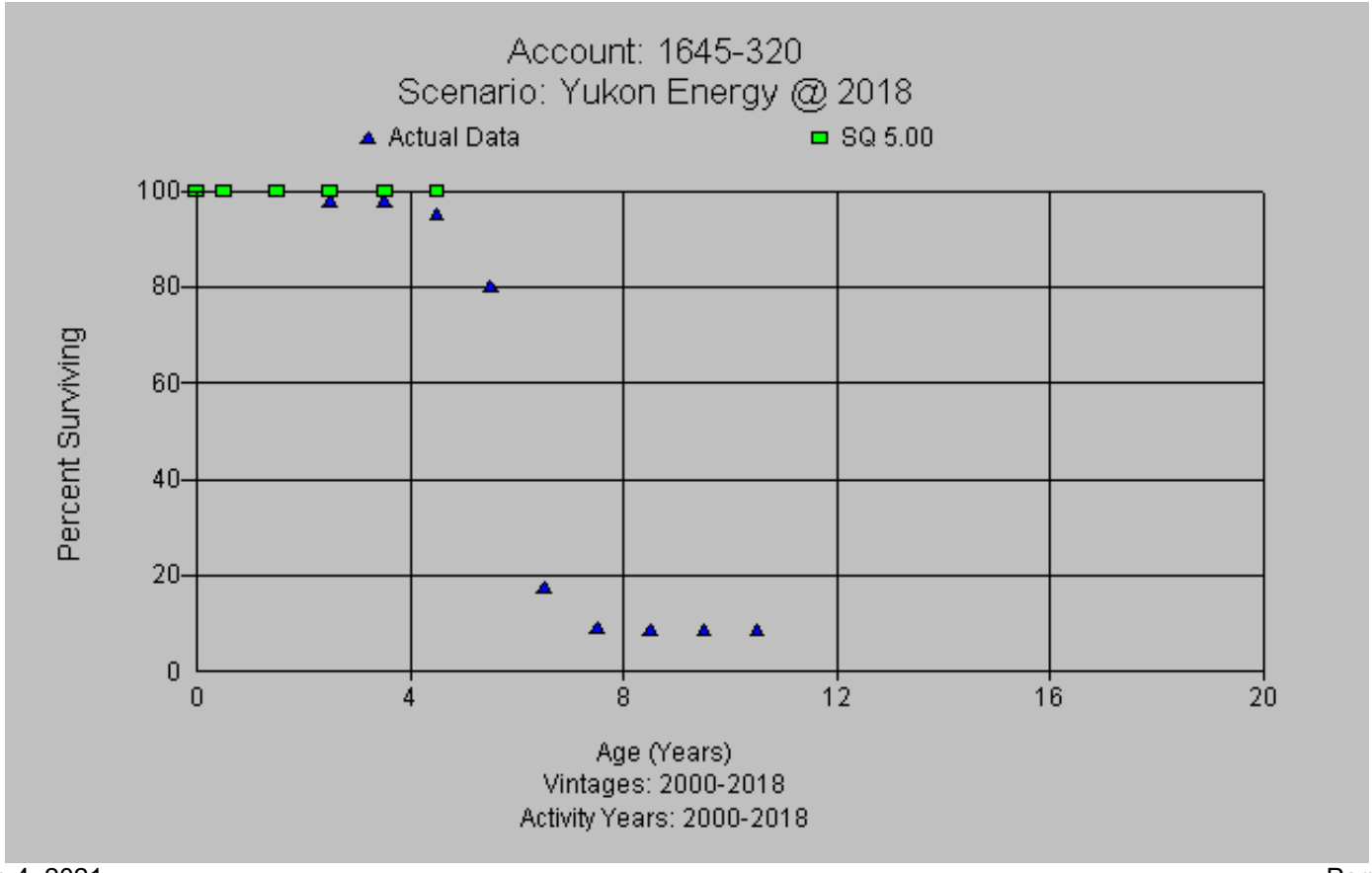
Account: 1645-202
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2001
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

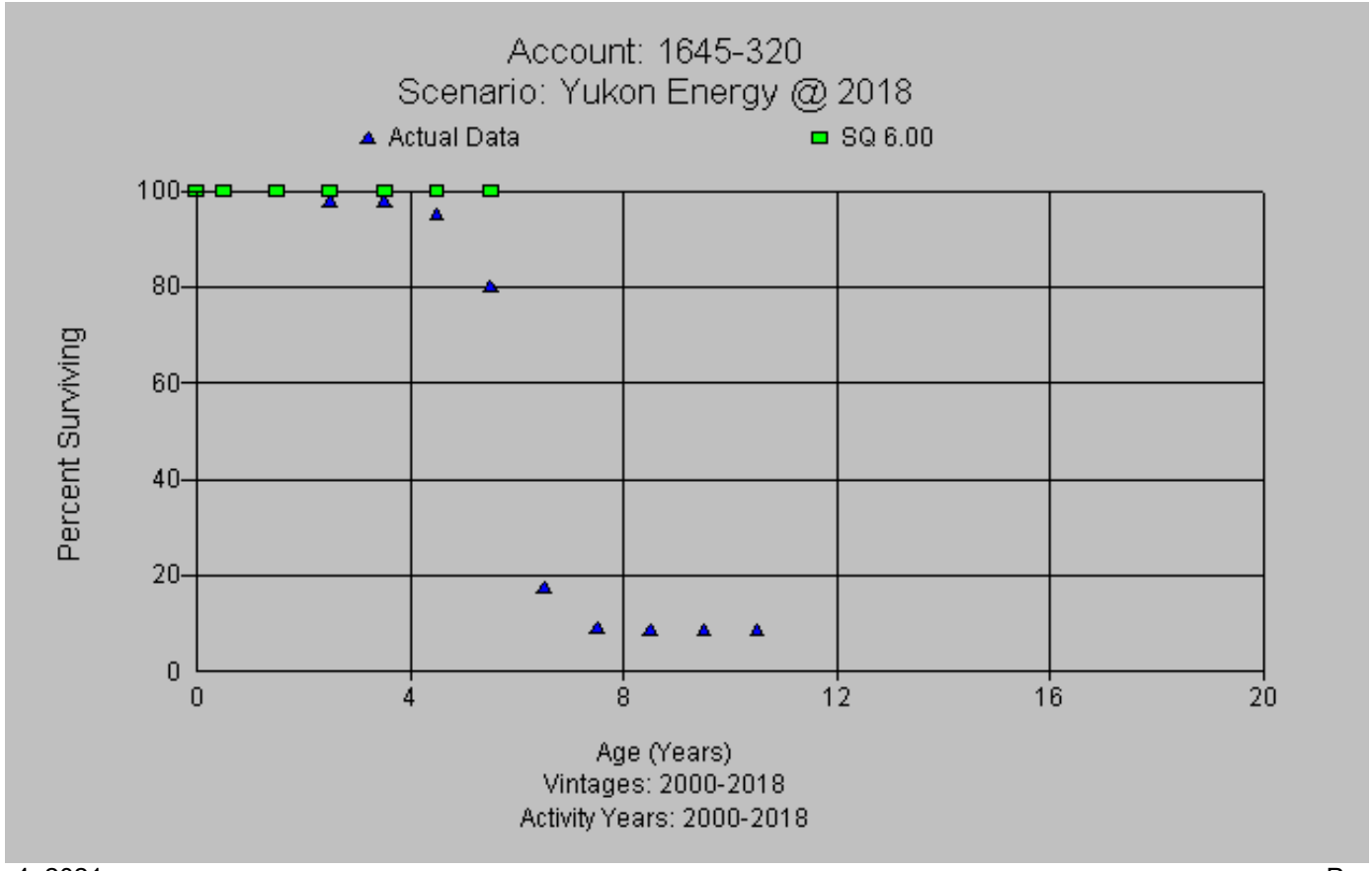
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1997 -2001	19.5	0.00	0.01062159	S6	5.52
1998 -2002	20.5	0.00	0.00924855	S6	5.53
1999 -2003	21.5	0.00	0.01064211	SQ	5.86
2000 -2004	22.5	99.77	0.00006487	L1.5	216.25
2001 -2005	23.5	94.65	0.00099203	S5	28.94
2002 -2006	24.5	94.87	0.00077751	S5	30.33
2003 -2007	25.5	94.17	0.00236201	R4	39.51
2004 -2008	26.5	0.00	0.01135667	SQ	25.72
2005 -2009	27.5	0.00	0.01363655	SQ	25.65
2006 -2010	28.5	0.00	0.00293688	SQ	25.79
2007 -2011	29.5	0.00	0.00234623	SQ	25.82
2008 -2012	30.5	0.00	0.00000000	SQ	26.20
2009 -2013		1.00			
2010 -2014	32.5	97.11	0.00185280	L0.5	202.15
2011 -2015	33.5	97.20	0.00183033	R1.5	208.03
2012 -2016	34.5	97.45	0.00155316	R1.5	228.38
2013 -2017	35.5	95.70	0.00437916	R1	193.73
2014 -2018	36.5	89.19	0.02943589	R0.5	113.01

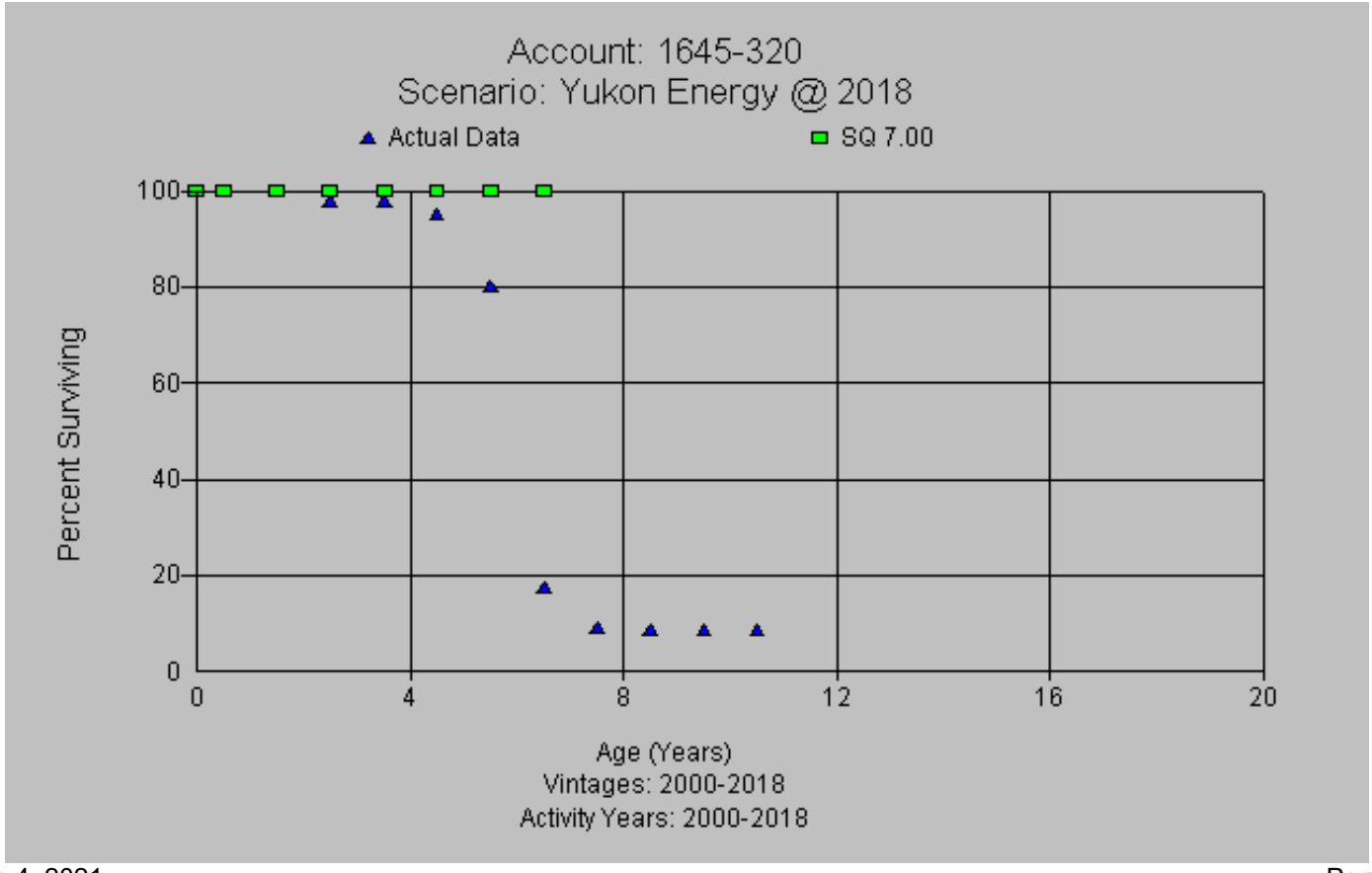
Actuarial Life Analysis

Account: 1645-202
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1997 -2018	38.5	0.00	0.65006496	S6	26.40
2002 -2018	38.5	0.00	0.02412115	SQ	27.53
2007 -2018	38.5	0.00	0.00970980	SQ	27.65
2012 -2018	38.5	97.67	0.00155645	R1.5	237.90
2017 -2018		1.00			


Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 5.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

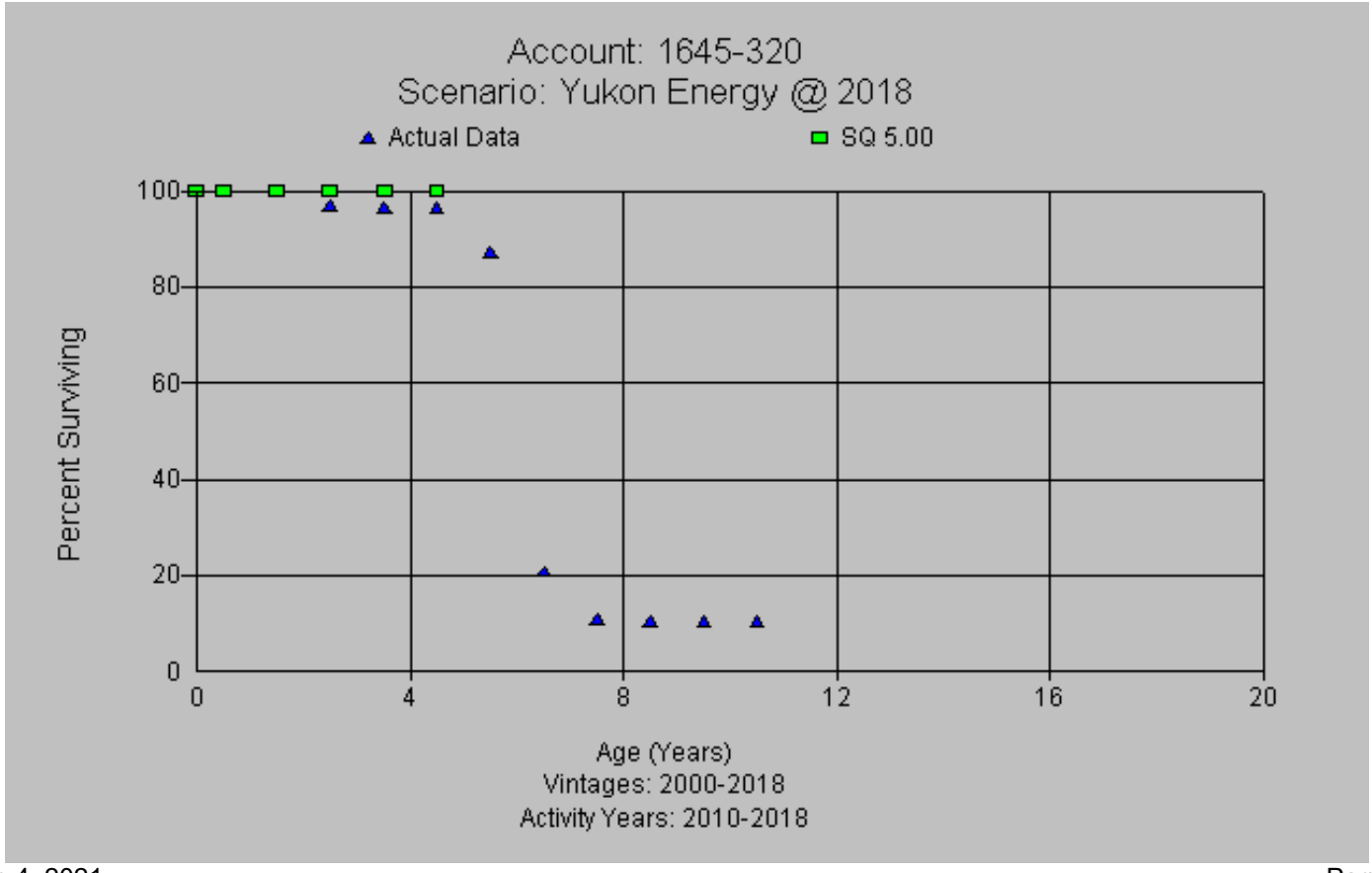

Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 6.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

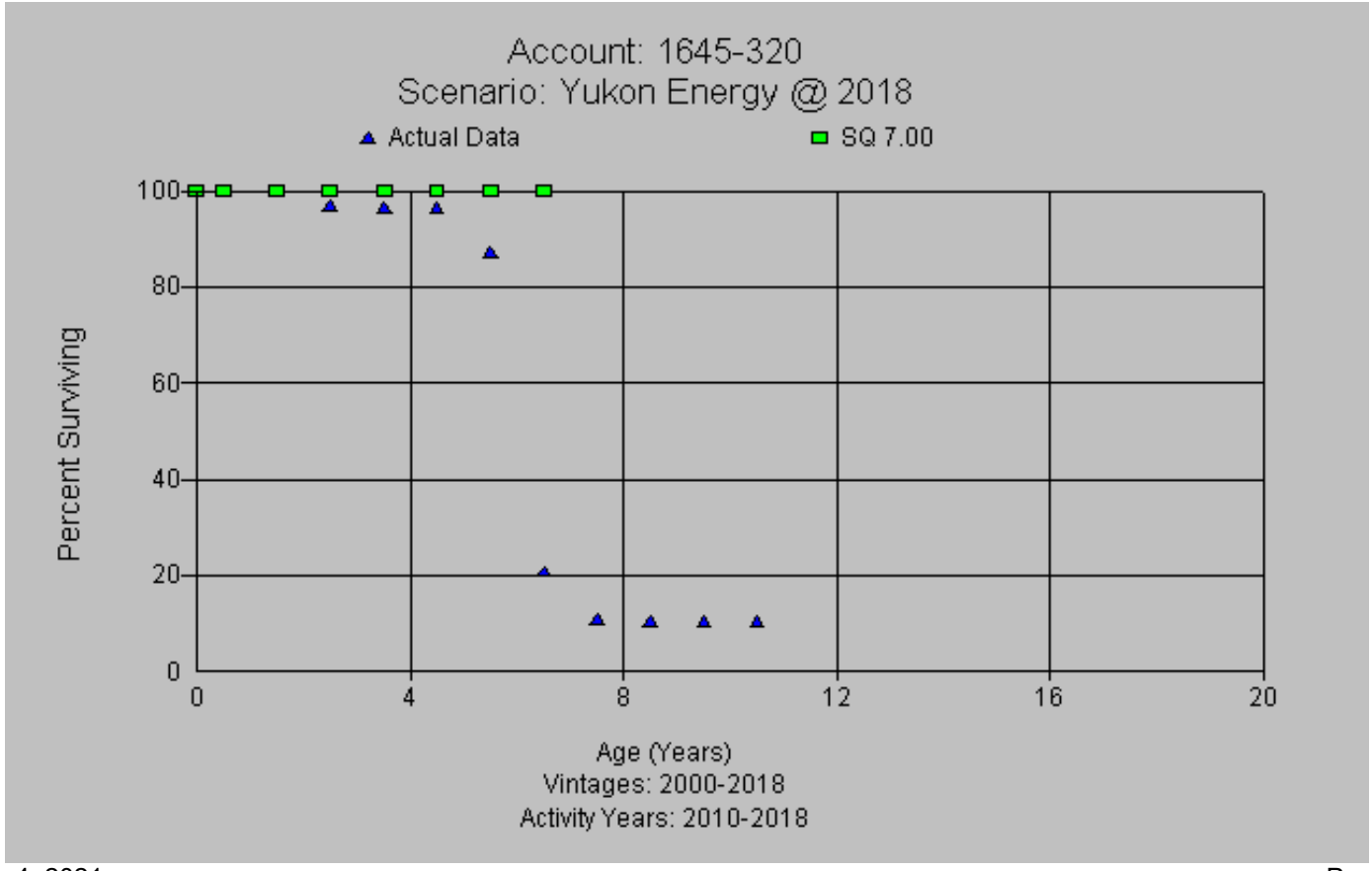

Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 7.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-320
Placement Band: 2000 - 2018 **Observation Band:** 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,875,454.78	0.00	0.00000	1.00000	100.00
0.5	4,696,604.73	2,128.00	0.00045	0.99955	100.00
1.5	4,412,999.57	86,082.33	0.01951	0.98049	99.96
2.5	4,153,118.29	4,523.95	0.00109	0.99891	98.01
3.5	3,961,207.53	104,719.42	0.02644	0.97356	97.90
4.5	3,690,975.36	584,614.43	0.15839	0.84161	95.31
5.5	2,780,430.48	2,169,322.27	0.78021	0.21979	80.21
6.5	409,797.61	194,505.73	0.47464	0.52536	17.63
7.5	190,591.88	11,134.67	0.05842	0.94158	9.26
8.5	179,457.21	0.00	0.00000	1.00000	8.72
9.5	52,441.29	0.00	0.00000	1.00000	8.72
10.5	0.00	0.00	0.00000	1.00000	8.72

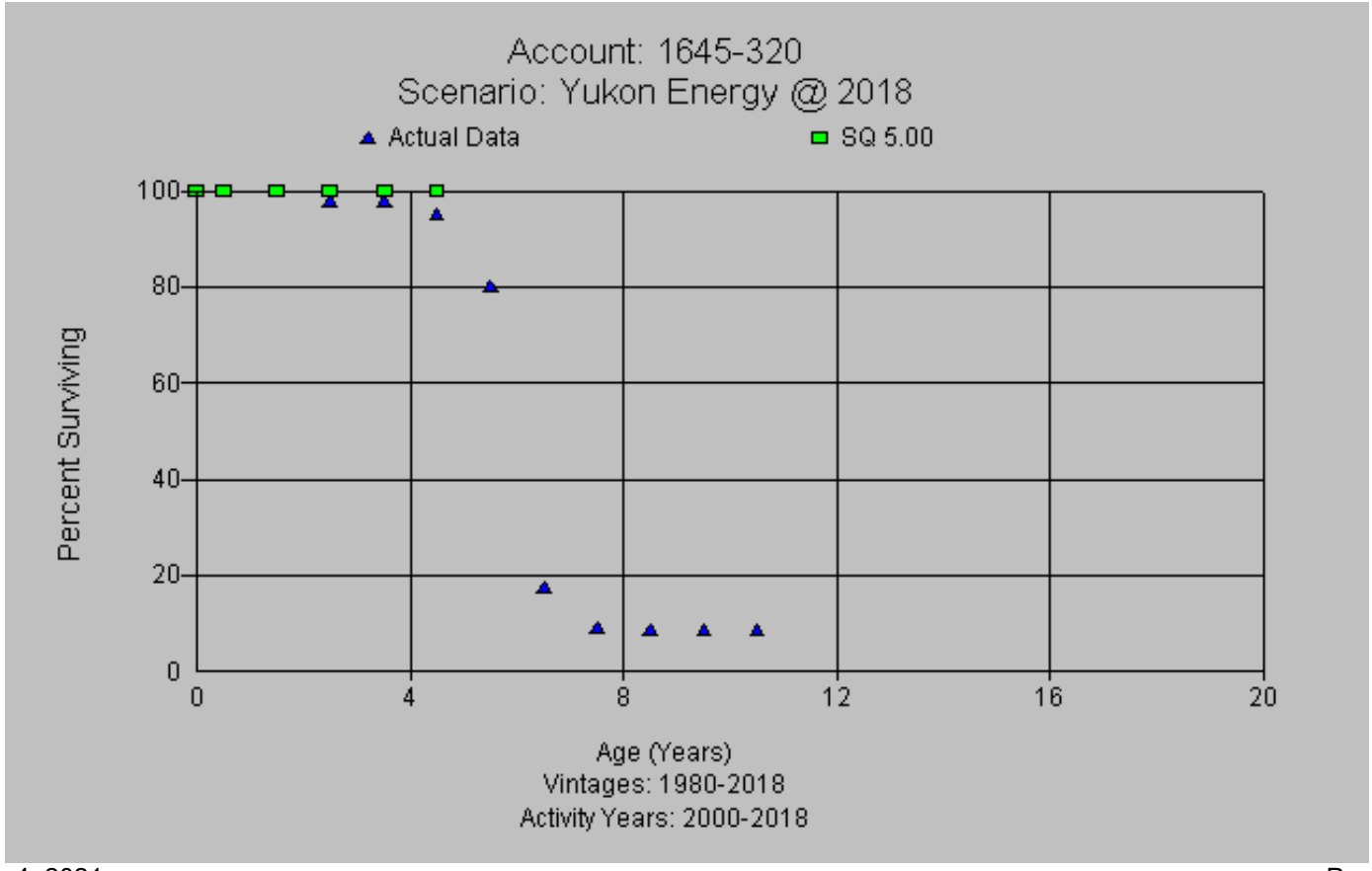

Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 5.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2010-2018

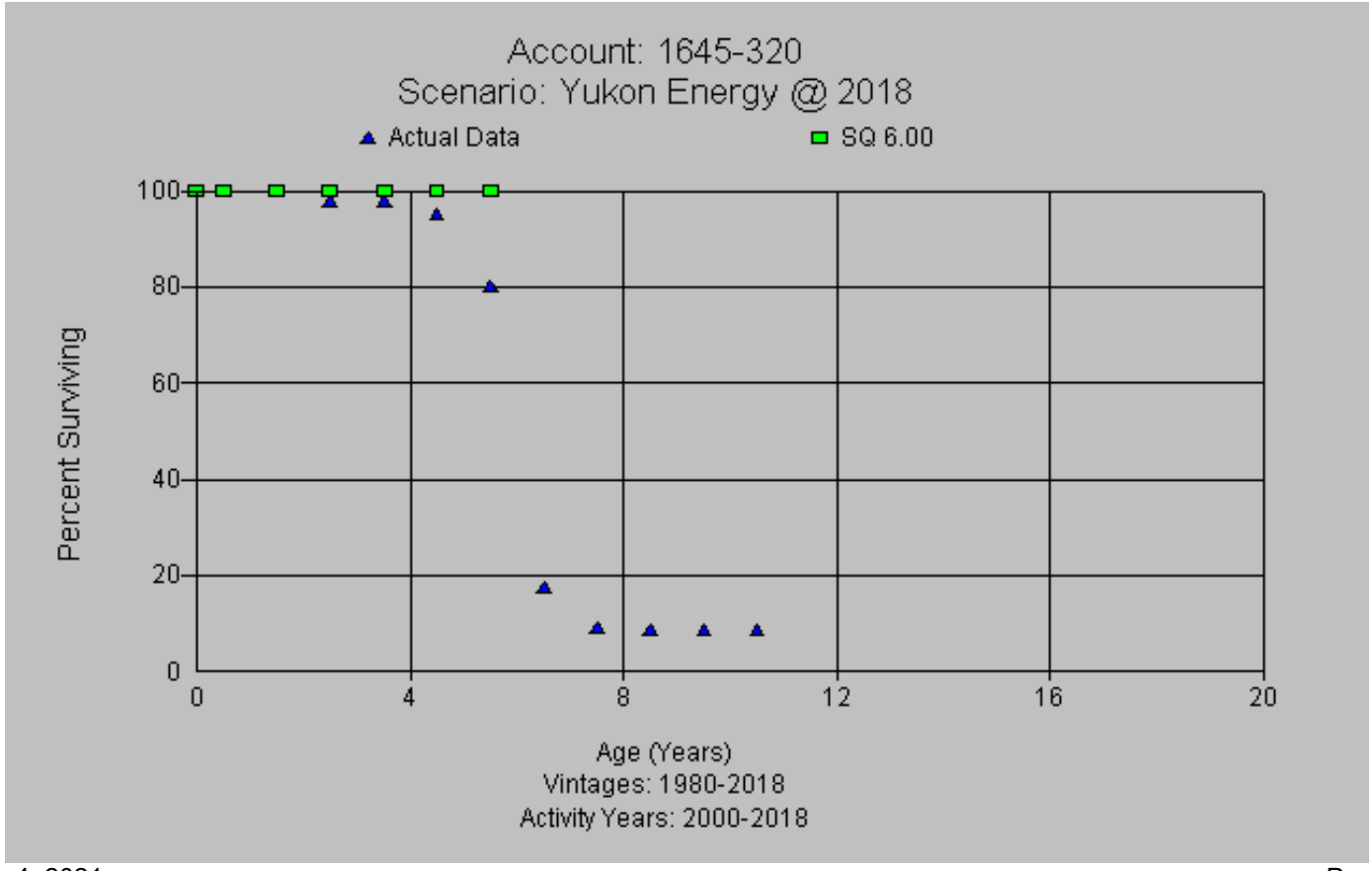

Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 7.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2010-2018

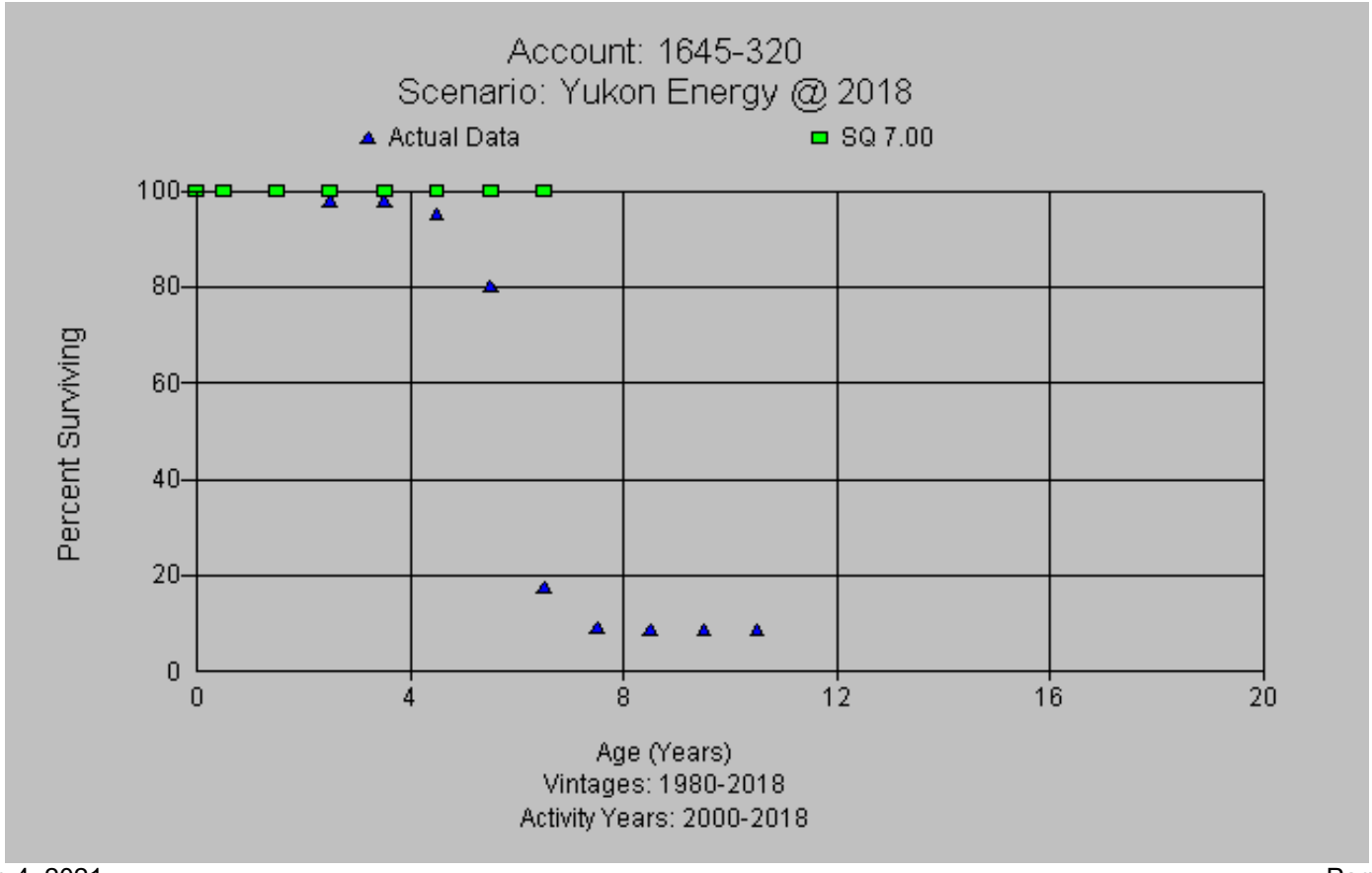
Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-320
Placement Band: 2000 - 2018 **Observation Band:** 2010 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	2,337,512.96	0.00	0.00000	1.00000	100.00
0.5	2,477,992.56	2,128.00	0.00086	0.99914	100.00
1.5	2,736,932.21	84,832.33	0.03100	0.96900	99.91
2.5	3,171,034.64	4,523.95	0.00143	0.99857	96.82
3.5	3,032,407.77	0.00	0.00000	1.00000	96.68
4.5	3,012,817.92	290,762.38	0.09651	0.90349	96.68
5.5	2,555,676.04	1,947,767.83	0.76213	0.23787	87.35
6.5	409,797.61	194,505.73	0.47464	0.52536	20.78
7.5	190,591.88	11,134.67	0.05842	0.94158	10.92
8.5	179,457.21	0.00	0.00000	1.00000	10.28
9.5	52,441.29	0.00	0.00000	1.00000	10.28
10.5	0.00	0.00	0.00000	1.00000	10.28


Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 5.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1980-2018
Activity Years: 2000-2018

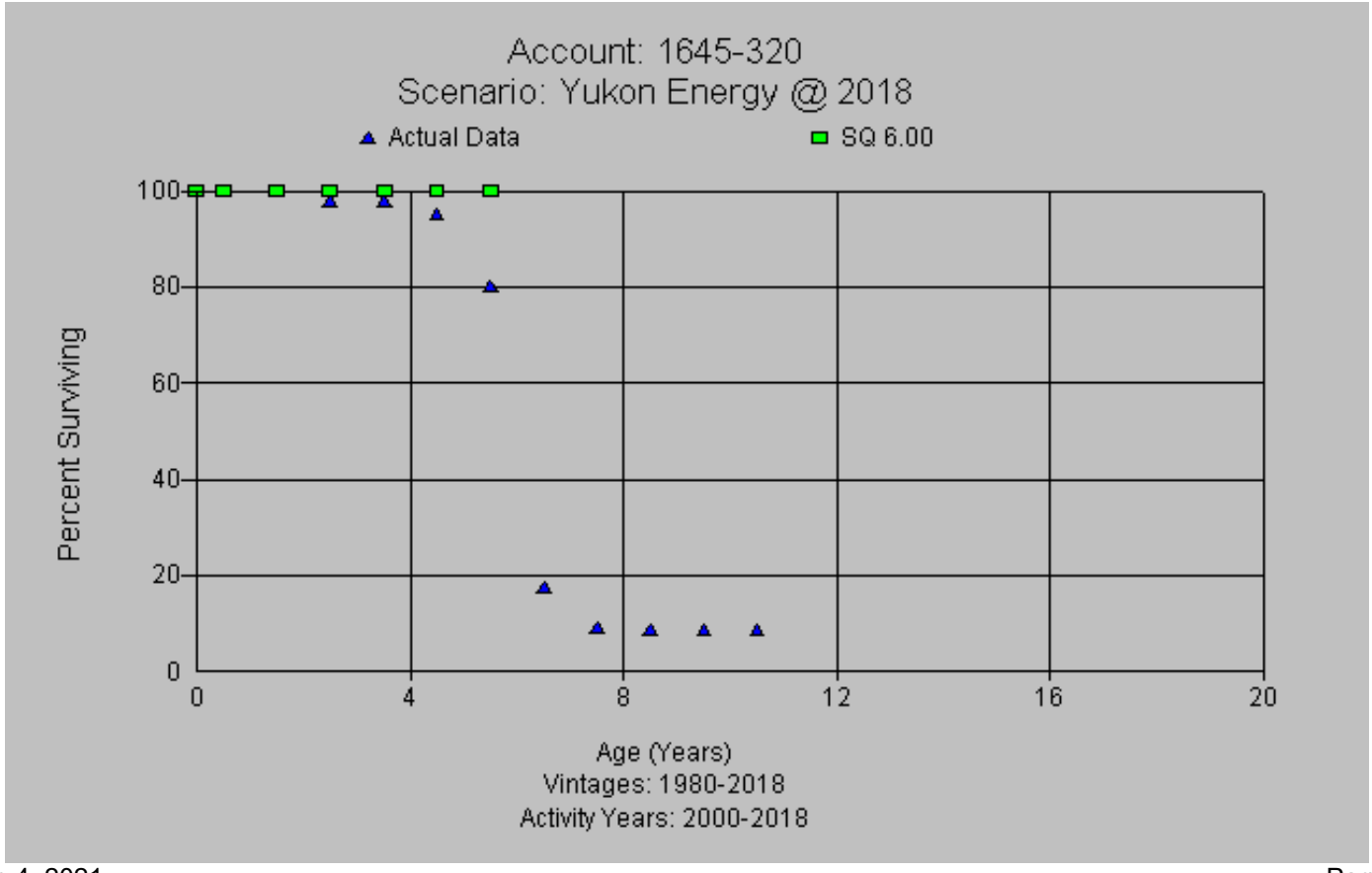

Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 6.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1980-2018
Activity Years: 2000-2018

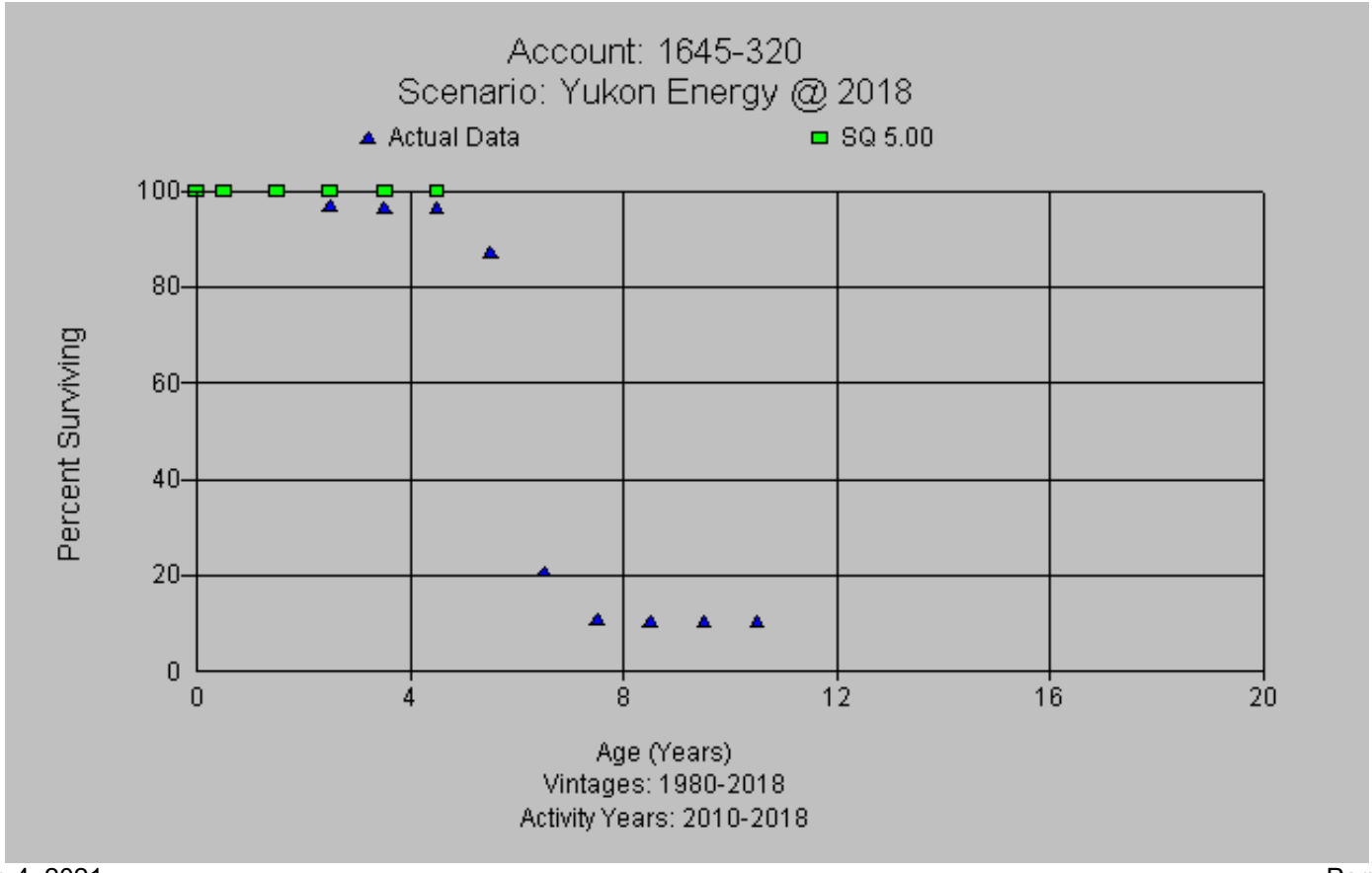

Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 7.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1980-2018
Activity Years: 2000-2018

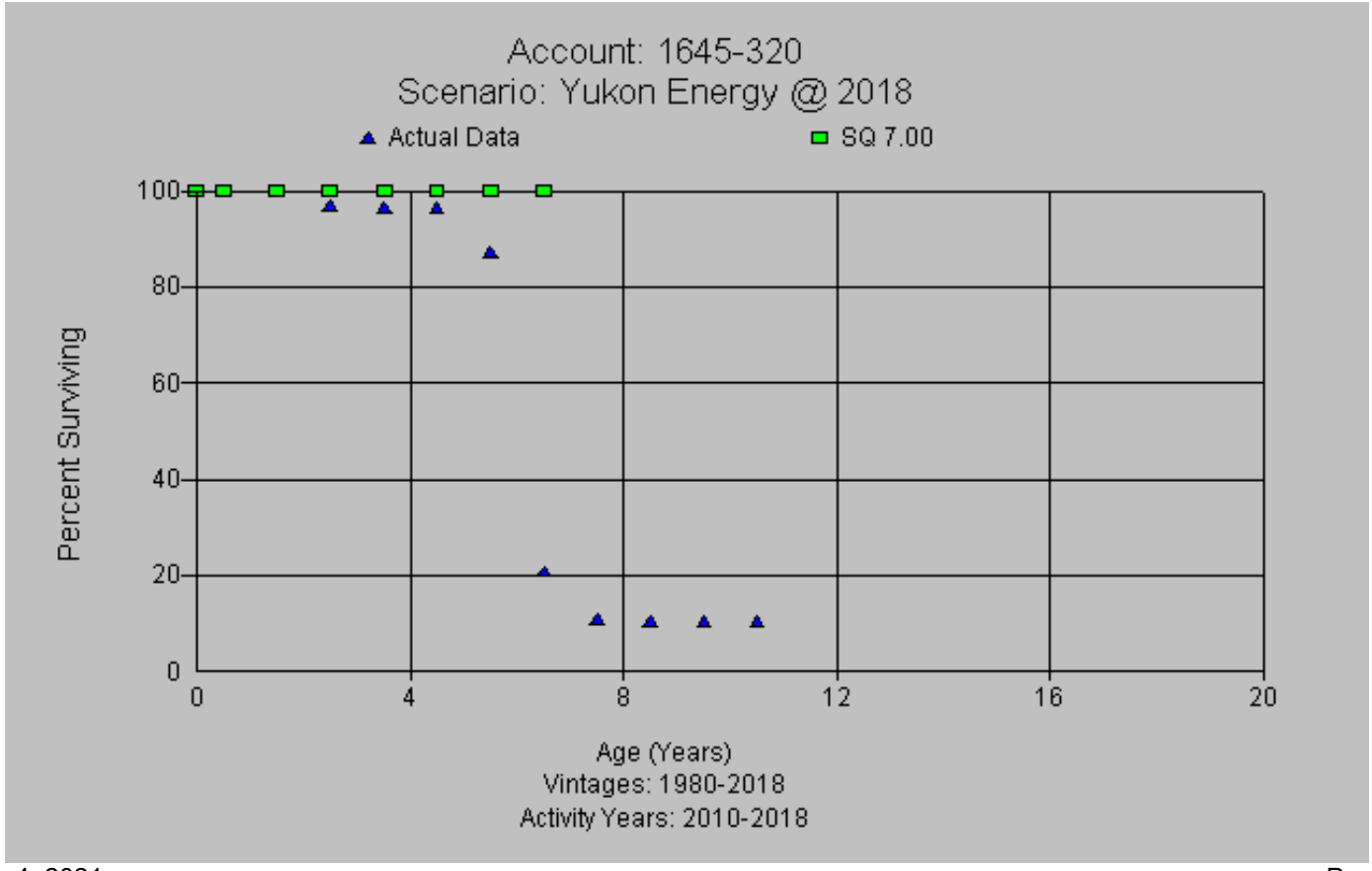
Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-320
Placement Band: 1980 - 2018 **Observation Band:** 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,875,454.78	0.00	0.00000	1.00000	100.00
0.5	4,696,604.73	2,128.00	0.00045	0.99955	100.00
1.5	4,412,999.57	86,082.33	0.01951	0.98049	99.96
2.5	4,153,118.29	4,523.95	0.00109	0.99891	98.01
3.5	3,961,207.53	104,719.42	0.02644	0.97356	97.90
4.5	3,690,975.36	584,614.43	0.15839	0.84161	95.31
5.5	2,780,430.48	2,169,322.27	0.78021	0.21979	80.21
6.5	409,797.61	194,505.73	0.47464	0.52536	17.63
7.5	190,591.88	11,134.67	0.05842	0.94158	9.26
8.5	179,457.21	0.00	0.00000	1.00000	8.72
9.5	52,441.29	0.00	0.00000	1.00000	8.72
10.5	0.00	0.00	0.00000	1.00000	8.72
11.5	0.00	0.00	0.00000	1.00000	
12.5	0.00	0.00	0.00000	1.00000	
13.5	0.00	0.00	0.00000	1.00000	
14.5	0.00	0.00	0.00000	1.00000	
15.5	0.00	0.00	0.00000	1.00000	
16.5	0.00	0.00	0.00000	1.00000	
17.5	0.00	0.00	0.00000	1.00000	
18.5	0.00	0.00	0.00000	1.00000	
19.5	405,769.20	0.00	0.00000	1.00000	
20.5	405,769.20	0.00	0.00000	1.00000	
21.5	405,769.20	0.00	0.00000	1.00000	
22.5	405,769.20	0.00	0.00000	1.00000	
23.5	405,769.20	0.00	0.00000	1.00000	
24.5	405,769.20	405,769.20	1.00000	0.00000	
25.5	0.00	0.00	0.00000	1.00000	


Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 6.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1980-2018
Activity Years: 2000-2018

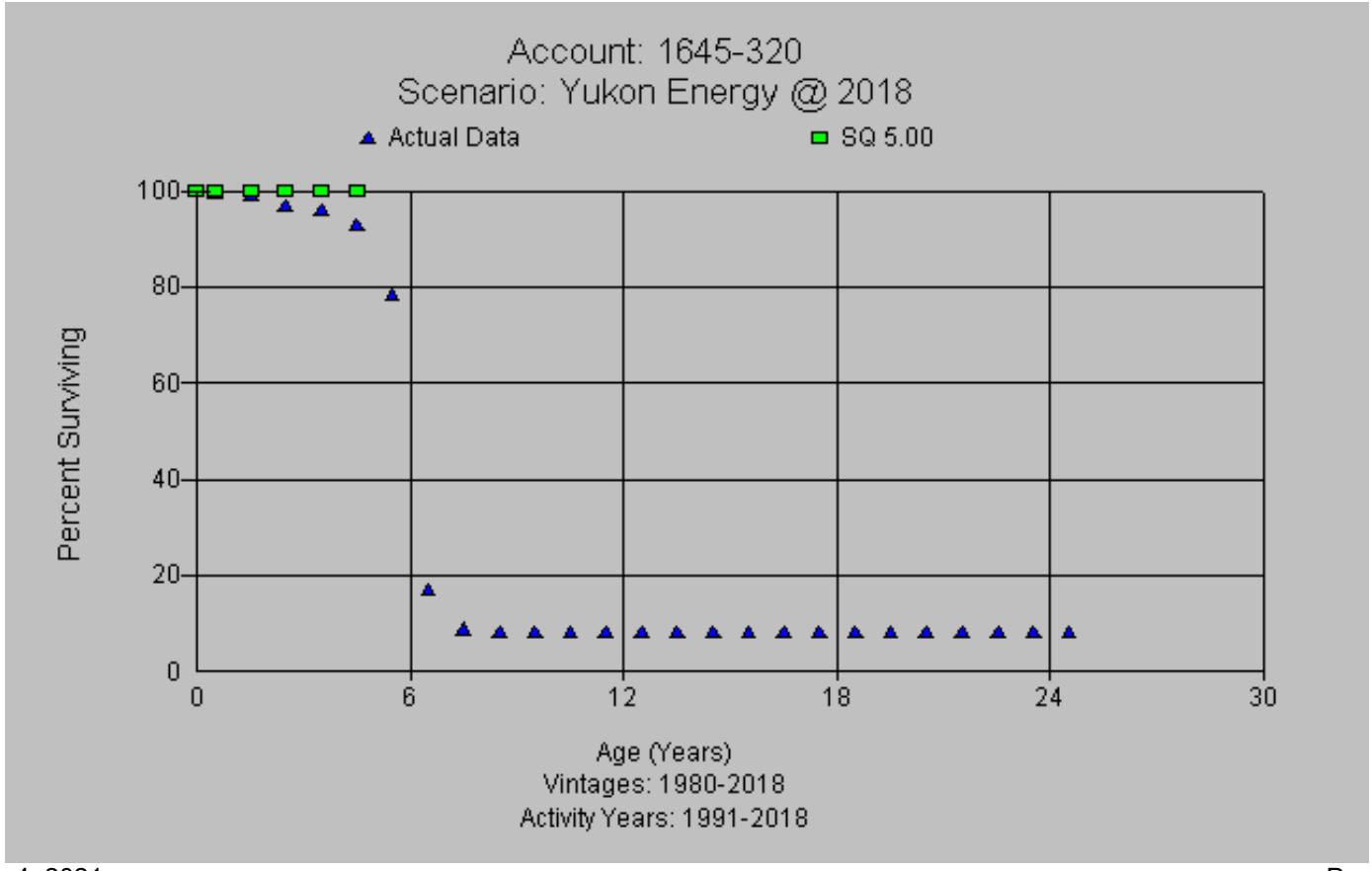

Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 5.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1980-2018
Activity Years: 2010-2018

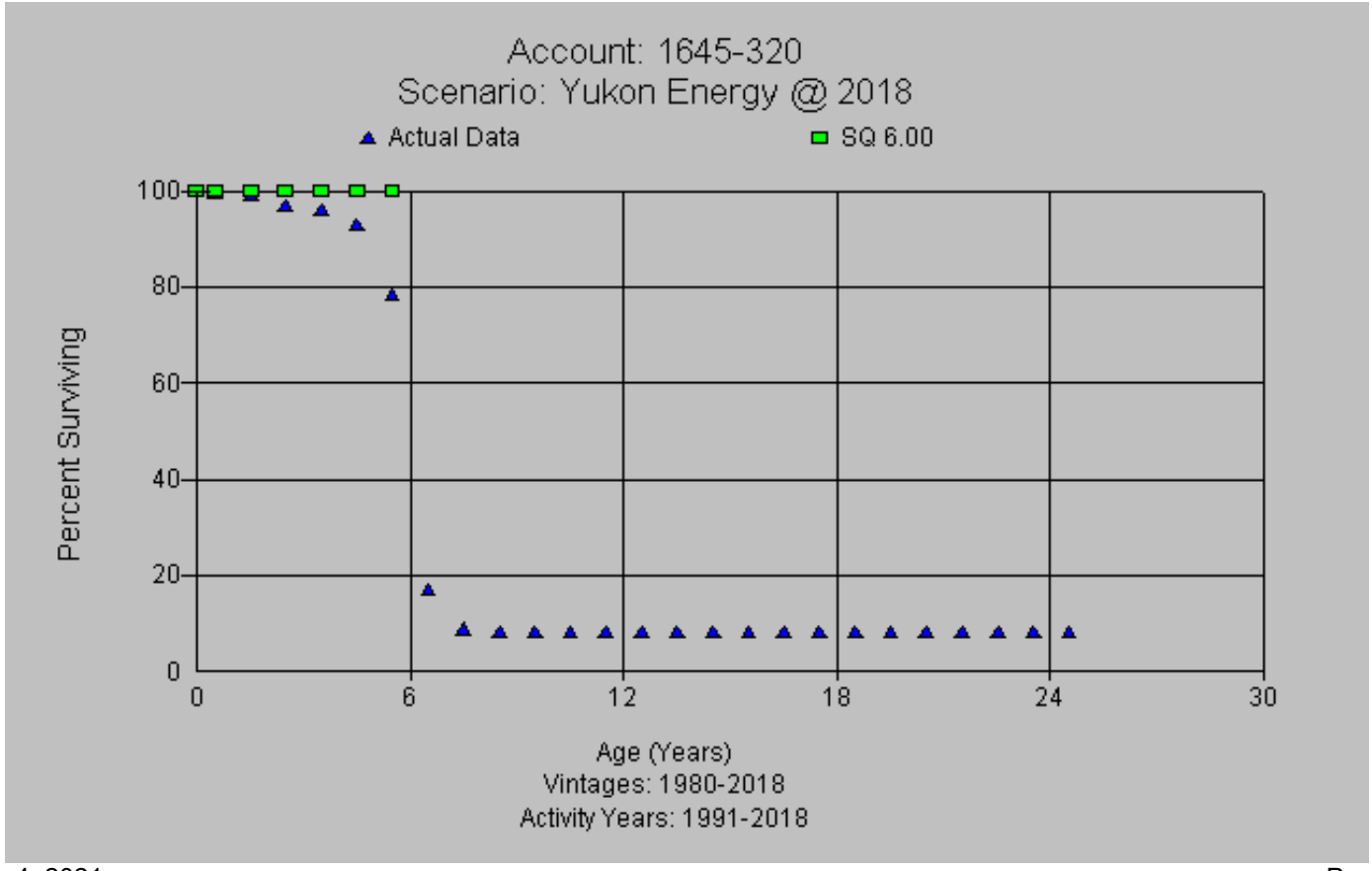

Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 7.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1980-2018
Activity Years: 2010-2018

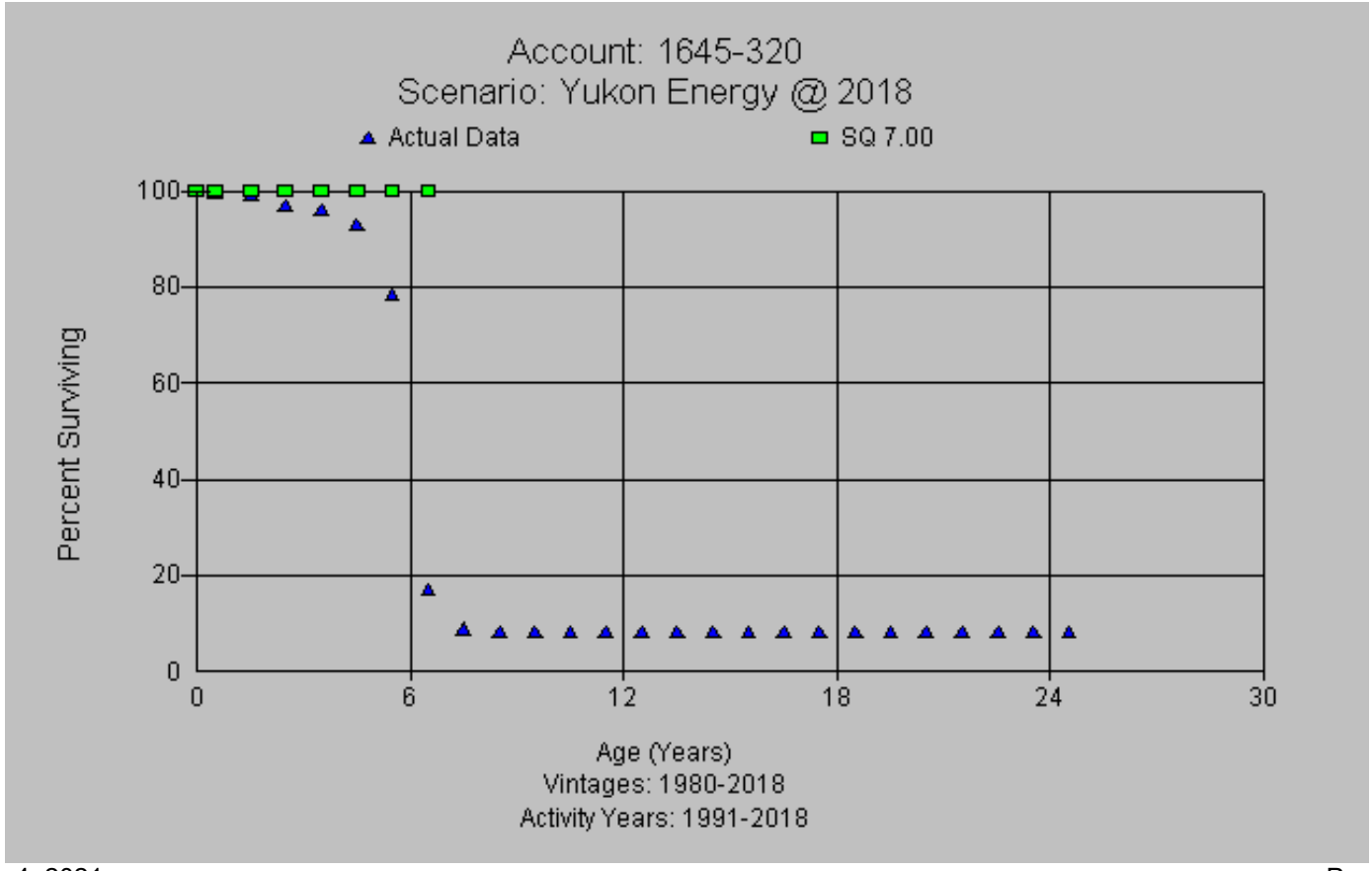
Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-320
Placement Band: 1980 - 2018 **Observation Band:** 2010 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	2,337,512.96	0.00	0.00000	1.00000	100.00
0.5	2,477,992.56	2,128.00	0.00086	0.99914	100.00
1.5	2,736,932.21	84,832.33	0.03100	0.96900	99.91
2.5	3,171,034.64	4,523.95	0.00143	0.99857	96.82
3.5	3,032,407.77	0.00	0.00000	1.00000	96.68
4.5	3,012,817.92	290,762.38	0.09651	0.90349	96.68
5.5	2,555,676.04	1,947,767.83	0.76213	0.23787	87.35
6.5	409,797.61	194,505.73	0.47464	0.52536	20.78
7.5	190,591.88	11,134.67	0.05842	0.94158	10.92
8.5	179,457.21	0.00	0.00000	1.00000	10.28
9.5	52,441.29	0.00	0.00000	1.00000	10.28
10.5	0.00	0.00	0.00000	1.00000	10.28


Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 5.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1991-2018

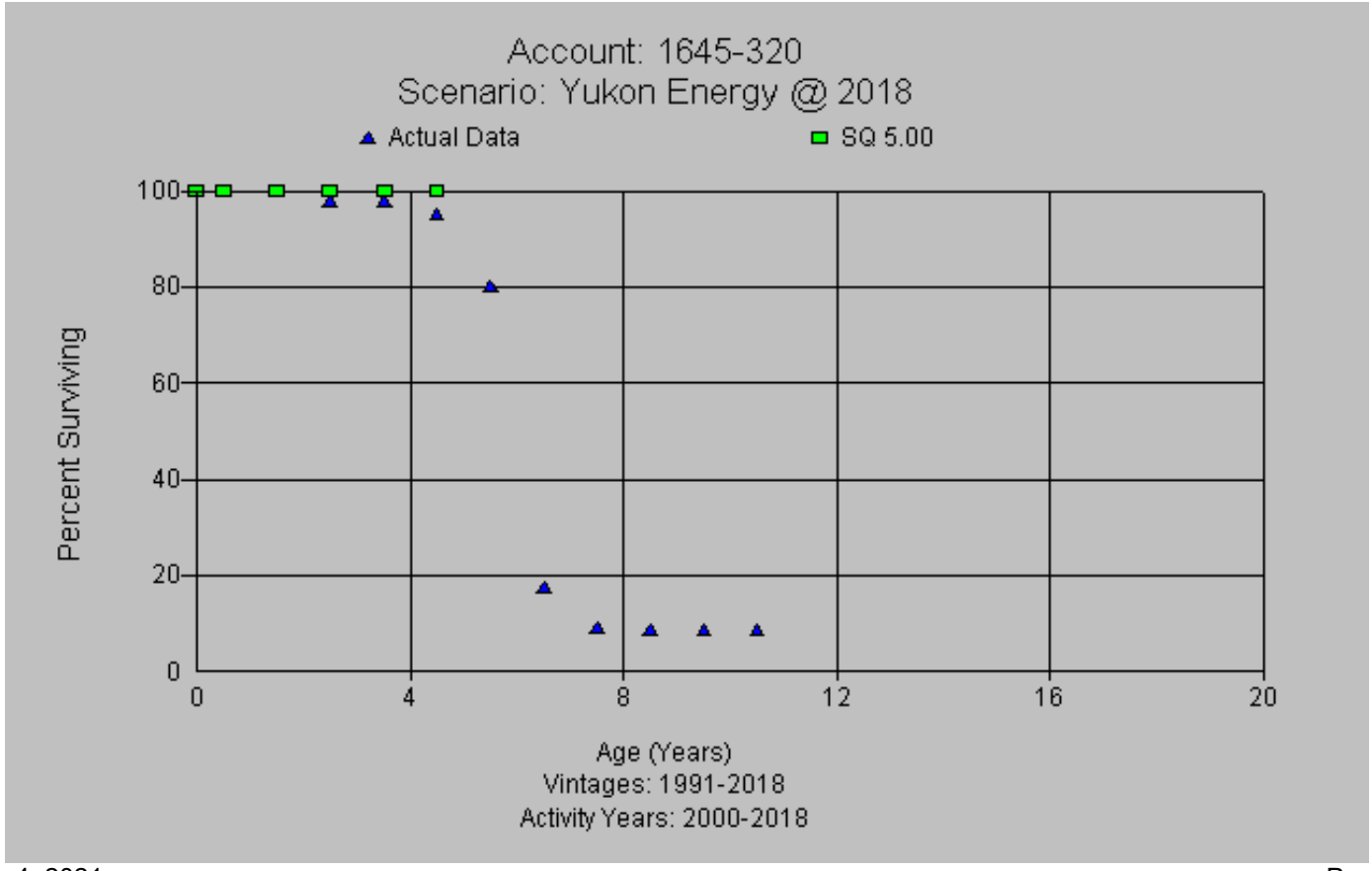

Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 6.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1991-2018

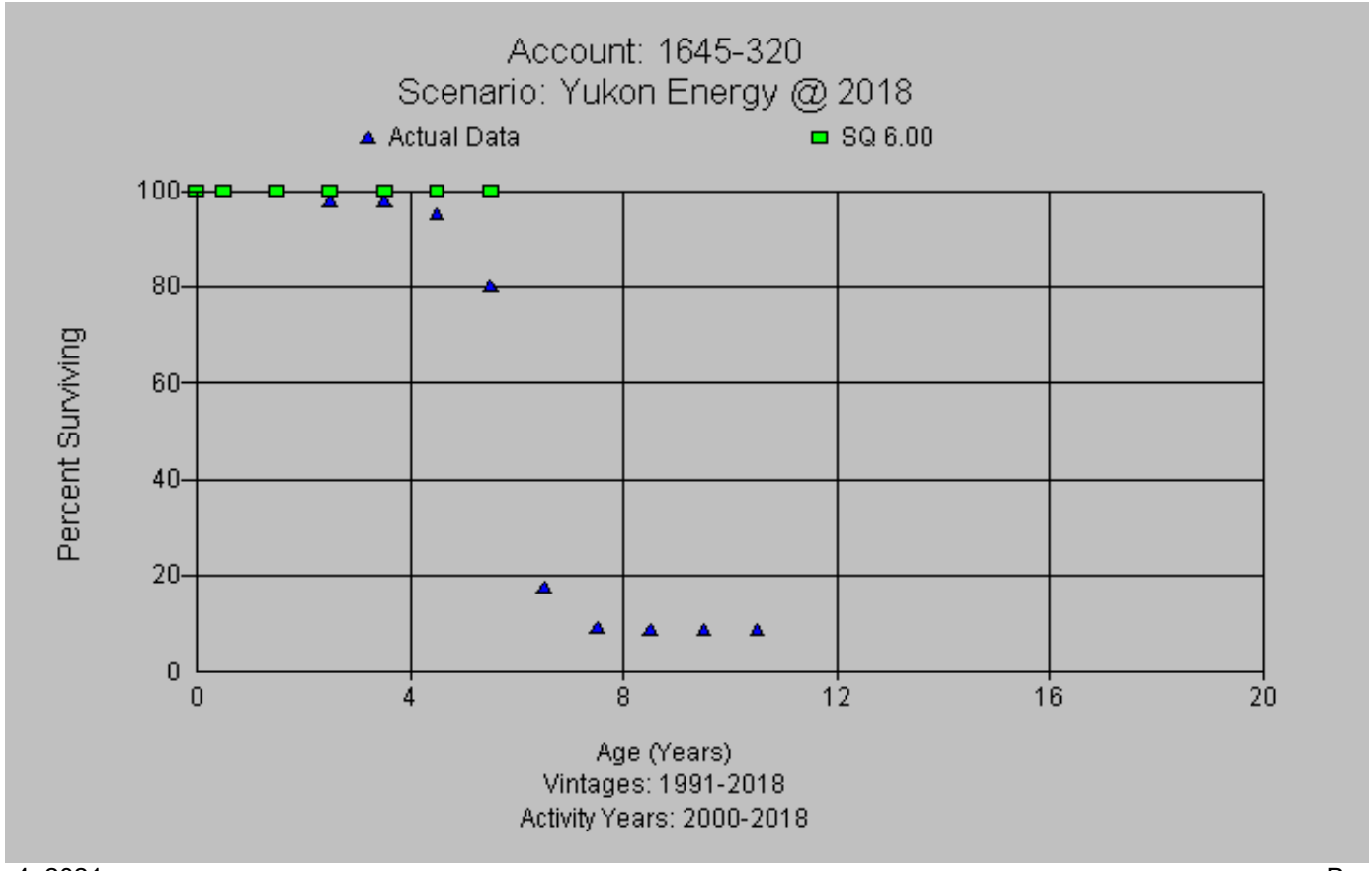

Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 7.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1991-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-320
Placement Band: 1980 - 2018 **Observation Band:** 1991 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	5,038,249.78	17,651.00	0.00350	0.99650	100.00
0.5	4,841,748.73	22,533.00	0.00465	0.99535	99.65
1.5	4,537,738.57	101,143.33	0.02229	0.97771	99.19
2.5	4,262,796.29	32,923.95	0.00772	0.99228	96.98
3.5	4,042,485.53	135,457.42	0.03351	0.96649	96.23
4.5	3,741,515.36	585,322.43	0.15644	0.84356	93.00
5.5	2,830,262.48	2,219,154.27	0.78408	0.21592	78.45
6.5	409,797.61	194,505.73	0.47464	0.52536	16.94
7.5	190,591.88	11,134.67	0.05842	0.94158	8.90
8.5	179,457.21	0.00	0.00000	1.00000	8.38
9.5	52,441.29	0.00	0.00000	1.00000	8.38
10.5	405,769.20	0.00	0.00000	1.00000	8.38
11.5	405,769.20	0.00	0.00000	1.00000	8.38
12.5	405,769.20	0.00	0.00000	1.00000	8.38
13.5	405,769.20	0.00	0.00000	1.00000	8.38
14.5	405,769.20	0.00	0.00000	1.00000	8.38
15.5	405,769.20	0.00	0.00000	1.00000	8.38
16.5	405,769.20	0.00	0.00000	1.00000	8.38
17.5	405,769.20	0.00	0.00000	1.00000	8.38
18.5	405,769.20	0.00	0.00000	1.00000	8.38
19.5	405,769.20	0.00	0.00000	1.00000	8.38
20.5	405,769.20	0.00	0.00000	1.00000	8.38
21.5	405,769.20	0.00	0.00000	1.00000	8.38
22.5	405,769.20	0.00	0.00000	1.00000	8.38
23.5	405,769.20	0.00	0.00000	1.00000	8.38
24.5	405,769.20	405,769.20	1.00000	0.00000	8.38
25.5	0.00	0.00	0.00000	1.00000	0.00


Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 5.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1991-2018
Activity Years: 2000-2018


Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 6.00
Percent Surviving
100
80
60
40
20
0
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4
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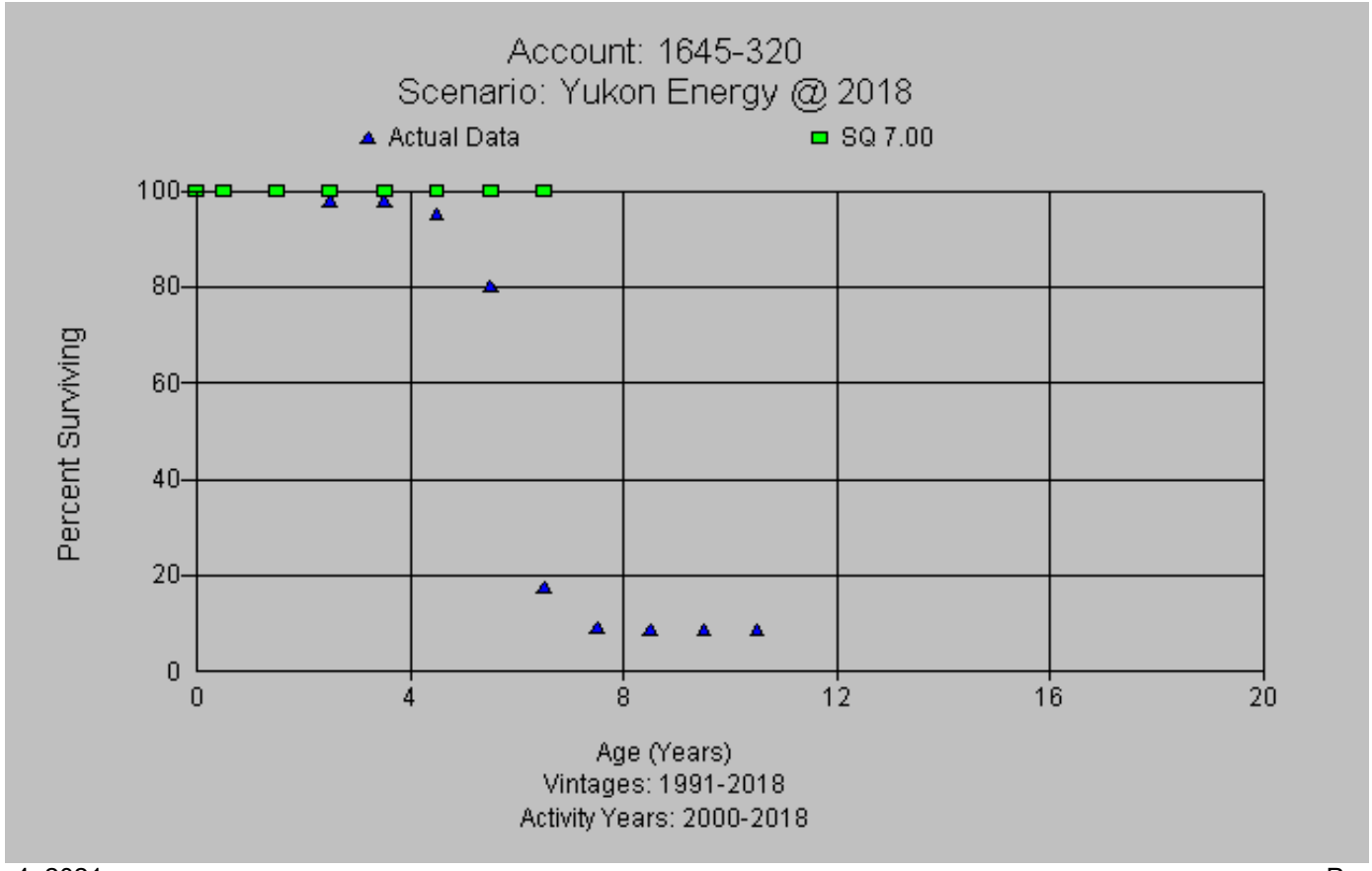
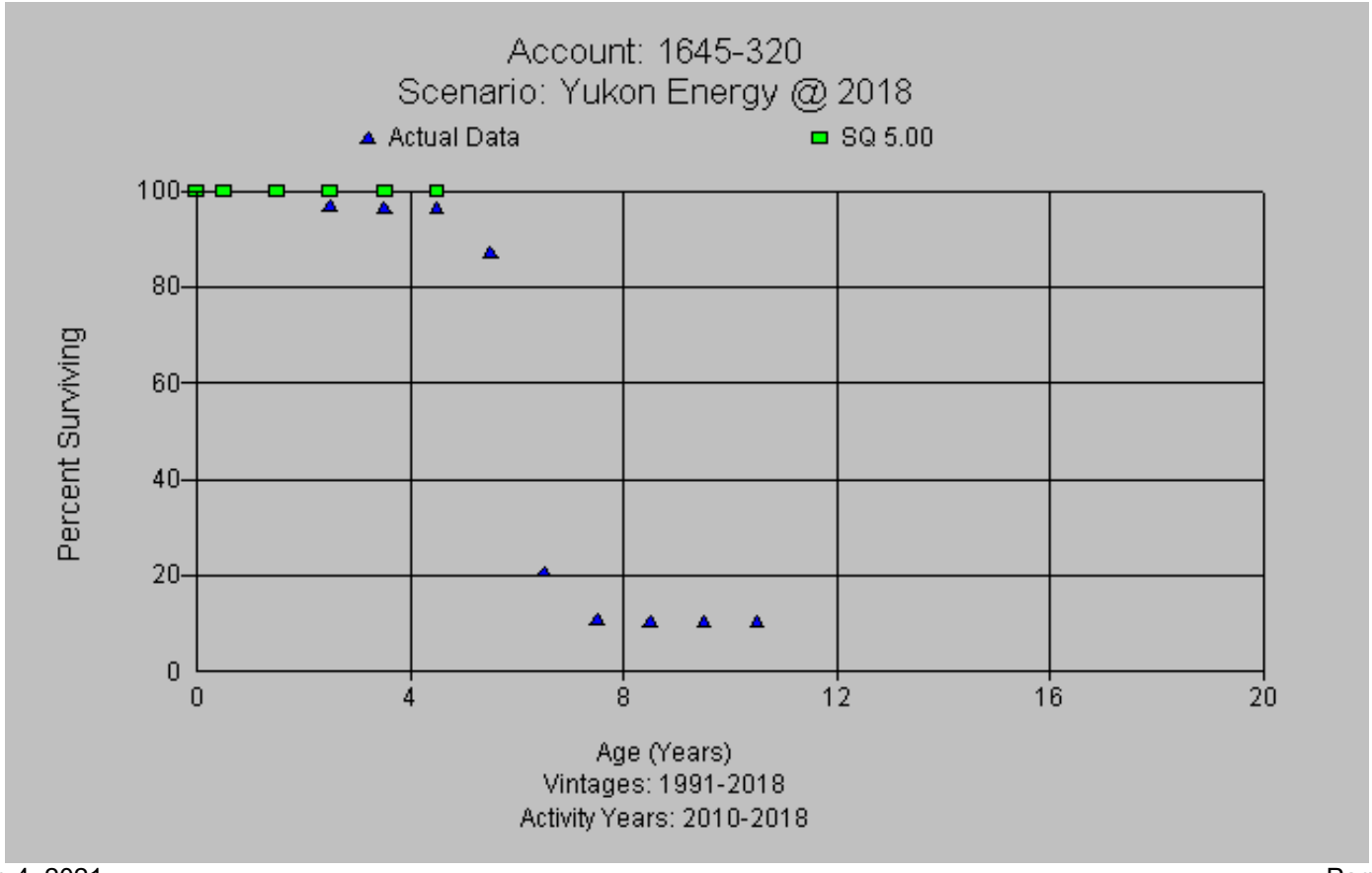
12
16
20
Age (Years)
Vintages: 1991-2018
Activity Years: 2000-2018

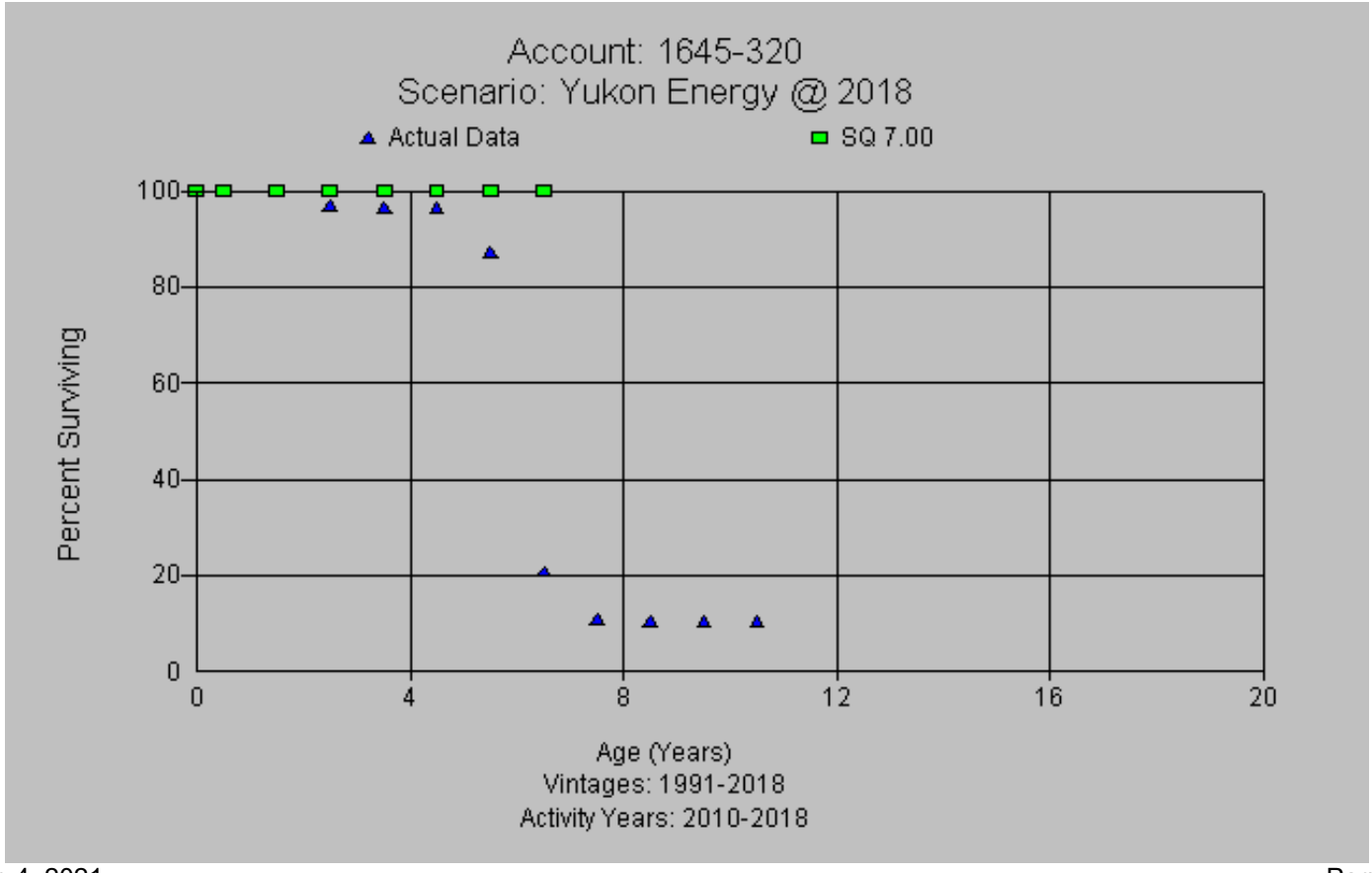

Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 7.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1991-2018
Activity Years: 2000-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-320
Placement Band: 1991 - 2018 **Observation Band:** 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,875,454.78	0.00	0.00000	1.00000	100.00
0.5	4,696,604.73	2,128.00	0.00045	0.99955	100.00
1.5	4,412,999.57	86,082.33	0.01951	0.98049	99.96
2.5	4,153,118.29	4,523.95	0.00109	0.99891	98.01
3.5	3,961,207.53	104,719.42	0.02644	0.97356	97.90
4.5	3,690,975.36	584,614.43	0.15839	0.84161	95.31
5.5	2,780,430.48	2,169,322.27	0.78021	0.21979	80.21
6.5	409,797.61	194,505.73	0.47464	0.52536	17.63
7.5	190,591.88	11,134.67	0.05842	0.94158	9.26
8.5	179,457.21	0.00	0.00000	1.00000	8.72
9.5	52,441.29	0.00	0.00000	1.00000	8.72
10.5	0.00	0.00	0.00000	1.00000	8.72

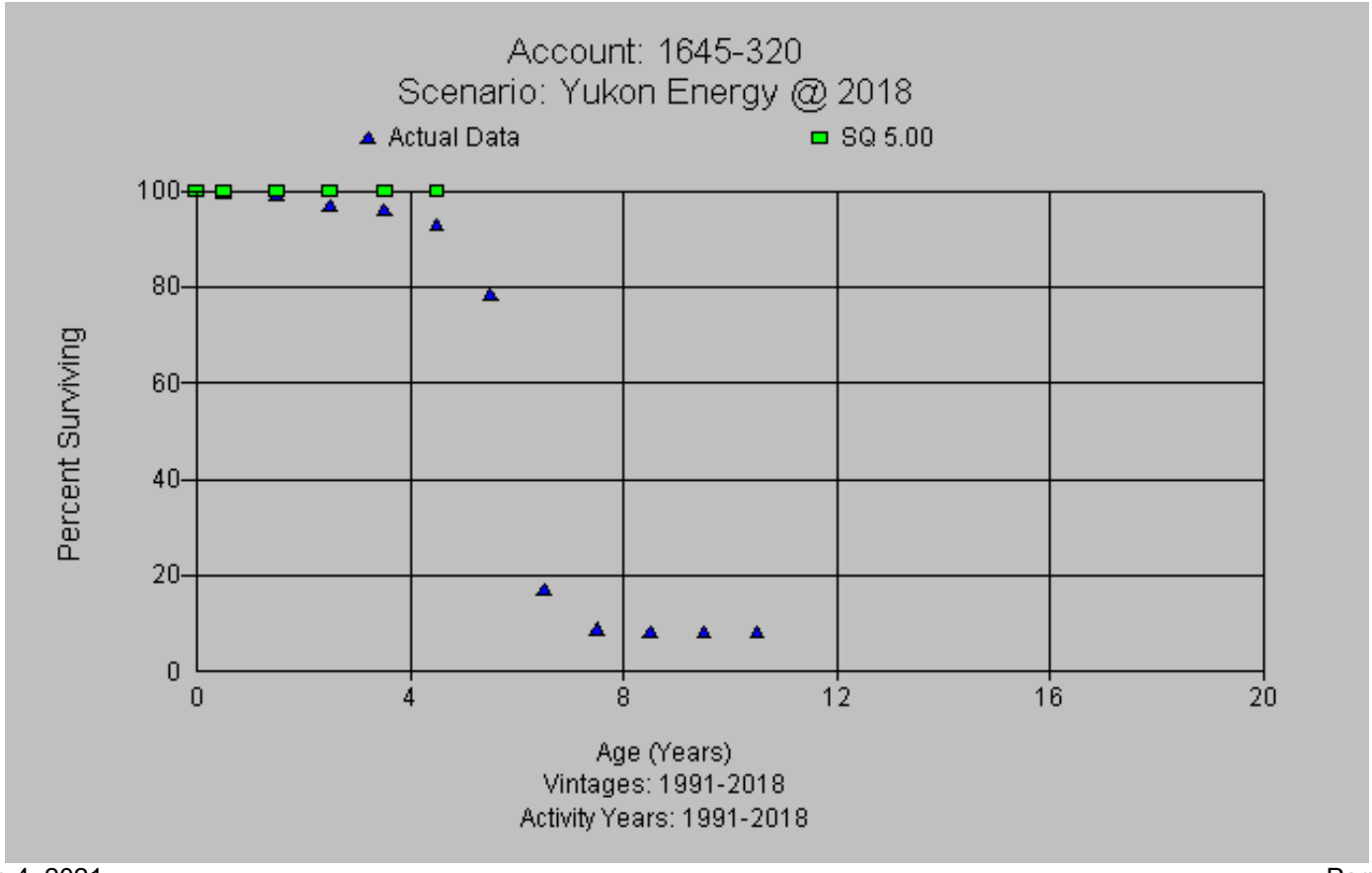

Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 5.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1991-2018
Activity Years: 2010-2018

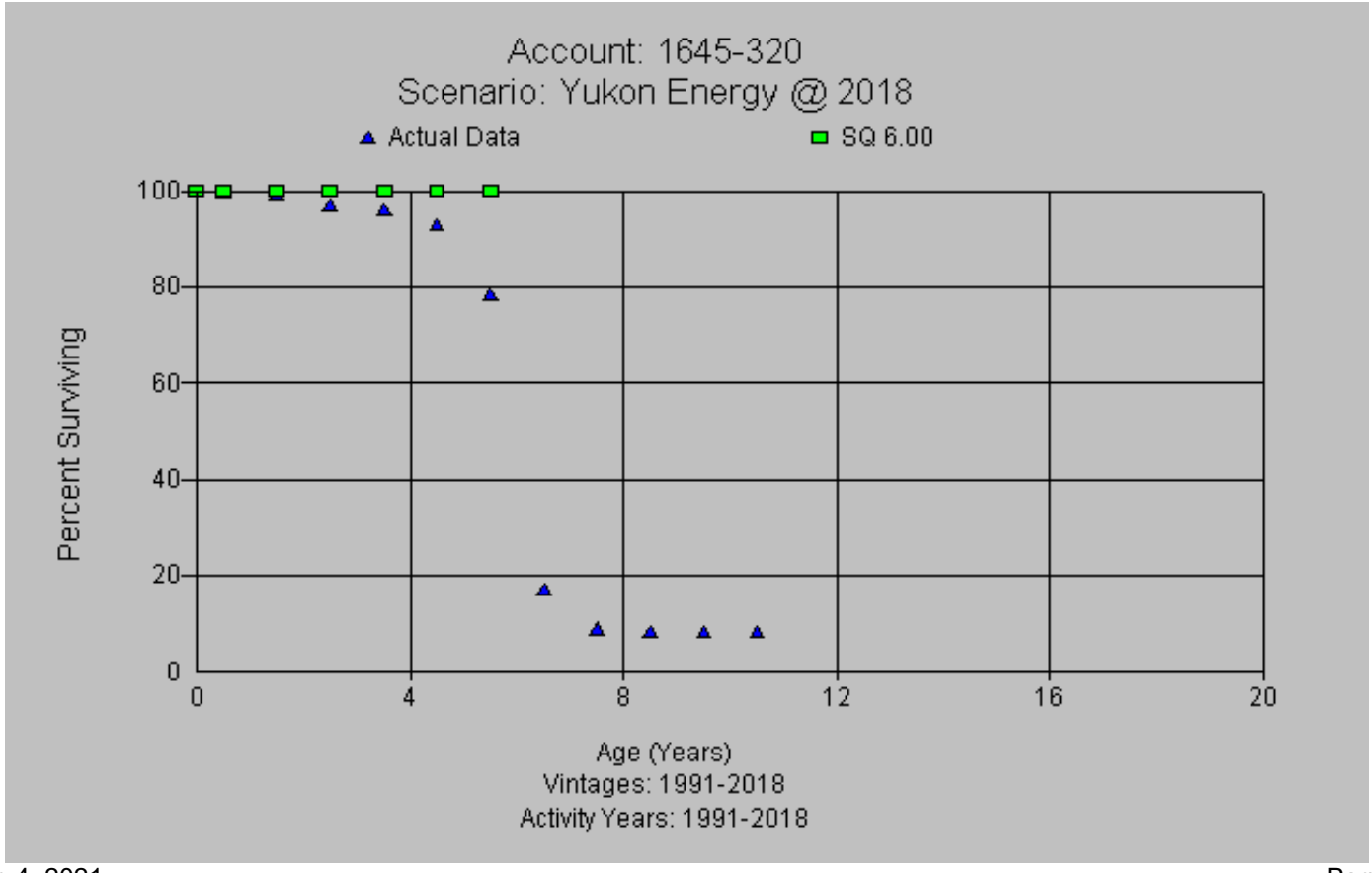

Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 7.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1991-2018
Activity Years: 2010-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-320
Placement Band: 1991 - 2018 **Observation Band:** 2010 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	2,337,512.96	0.00	0.00000	1.00000	100.00
0.5	2,477,992.56	2,128.00	0.00086	0.99914	100.00
1.5	2,736,932.21	84,832.33	0.03100	0.96900	99.91
2.5	3,171,034.64	4,523.95	0.00143	0.99857	96.82
3.5	3,032,407.77	0.00	0.00000	1.00000	96.68
4.5	3,012,817.92	290,762.38	0.09651	0.90349	96.68
5.5	2,555,676.04	1,947,767.83	0.76213	0.23787	87.35
6.5	409,797.61	194,505.73	0.47464	0.52536	20.78
7.5	190,591.88	11,134.67	0.05842	0.94158	10.92
8.5	179,457.21	0.00	0.00000	1.00000	10.28
9.5	52,441.29	0.00	0.00000	1.00000	10.28
10.5	0.00	0.00	0.00000	1.00000	10.28


Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 5.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1991-2018
Activity Years: 1991-2018


Account: 1645-320
Scenario: Yukon Energy @ 2018
Actual Data
SQ 6.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1991-2018
Activity Years: 1991-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-320
Placement Band: 1991 - 2018 **Observation Band:** 1991 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	5,038,249.78	17,651.00	0.00350	0.99650	100.00
0.5	4,841,748.73	22,533.00	0.00465	0.99535	99.65
1.5	4,537,738.57	101,143.33	0.02229	0.97771	99.19
2.5	4,262,796.29	32,923.95	0.00772	0.99228	96.98
3.5	4,042,485.53	135,457.42	0.03351	0.96649	96.23
4.5	3,741,515.36	585,322.43	0.15644	0.84356	93.00
5.5	2,830,262.48	2,219,154.27	0.78408	0.21592	78.45
6.5	409,797.61	194,505.73	0.47464	0.52536	16.94
7.5	190,591.88	11,134.67	0.05842	0.94158	8.90
8.5	179,457.21	0.00	0.00000	1.00000	8.38
9.5	52,441.29	0.00	0.00000	1.00000	8.38
10.5	0.00	0.00	0.00000	1.00000	8.38

Actuarial Life Analysis

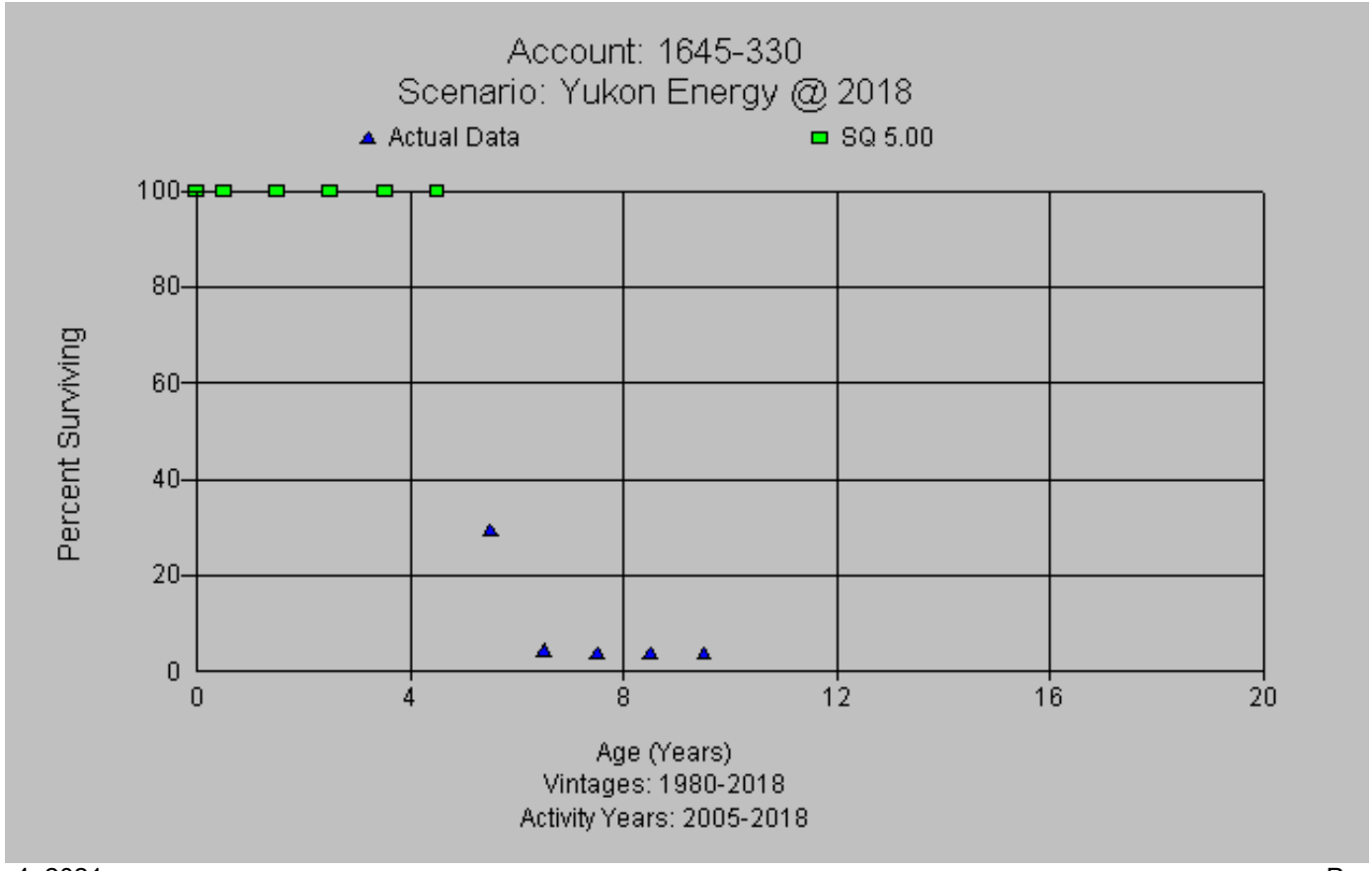
Account: 1645-320
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 1995
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1991 -1995	8.5	92.63	0.01810064	R0.5	23.76
1992 -1996	9.5	95.18	0.00840115	R0.5	39.77
1993 -1997	10.5	76.52	0.19571926	R0.5	10.58
1994 -1998	11.5	73.80	0.29200616	R0.5	10.44
1995 -1999	12.5	0.00	0.03254644	L0	3.31
1996 -2000	13.5	0.00	0.02048078	L0	3.38
1997 -2001	14.5	0.00	0.01968374	L1.5	3.48
1998 -2002	15.5	0.00	0.00162488	S4	3.49
1999 -2003	16.5	0.00	0.00384771	S6	3.83
2000 -2004		1.00			
2001 -2005	18.5	0.00	0.00000000	SQ	5.39
2002 -2006	19.5	0.00	0.63445876	L0	8.74
2003 -2007	20.5	0.00	0.00208332	S6	5.35
2004 -2008	21.5	0.00	0.00156658	S5	5.29
2005 -2009	22.5	0.00	0.00668134	R5	5.46
2006 -2010	23.5	0.00	0.01589657	R4	5.26
2007 -2011	24.5	0.00	0.00624641	R5	5.30
2008 -2012	25.5	0.00	0.02529530	S6	5.61
2009 -2013	26.5	0.00	0.01441616	S6	5.74
2010 -2014	27.5	0.00	0.01455110	S6	5.75
2011 -2015	28.5	25.31	1.28486231	L0	11.97
2012 -2016	29.5	8.27	0.68175830	L2.5	8.07
2013 -2017	30.5	8.95	0.77586195	L2	8.28
2014 -2018	31.5	17.30	1.26240306	L0	10.80

Actuarial Life Analysis

Account: 1645-320
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

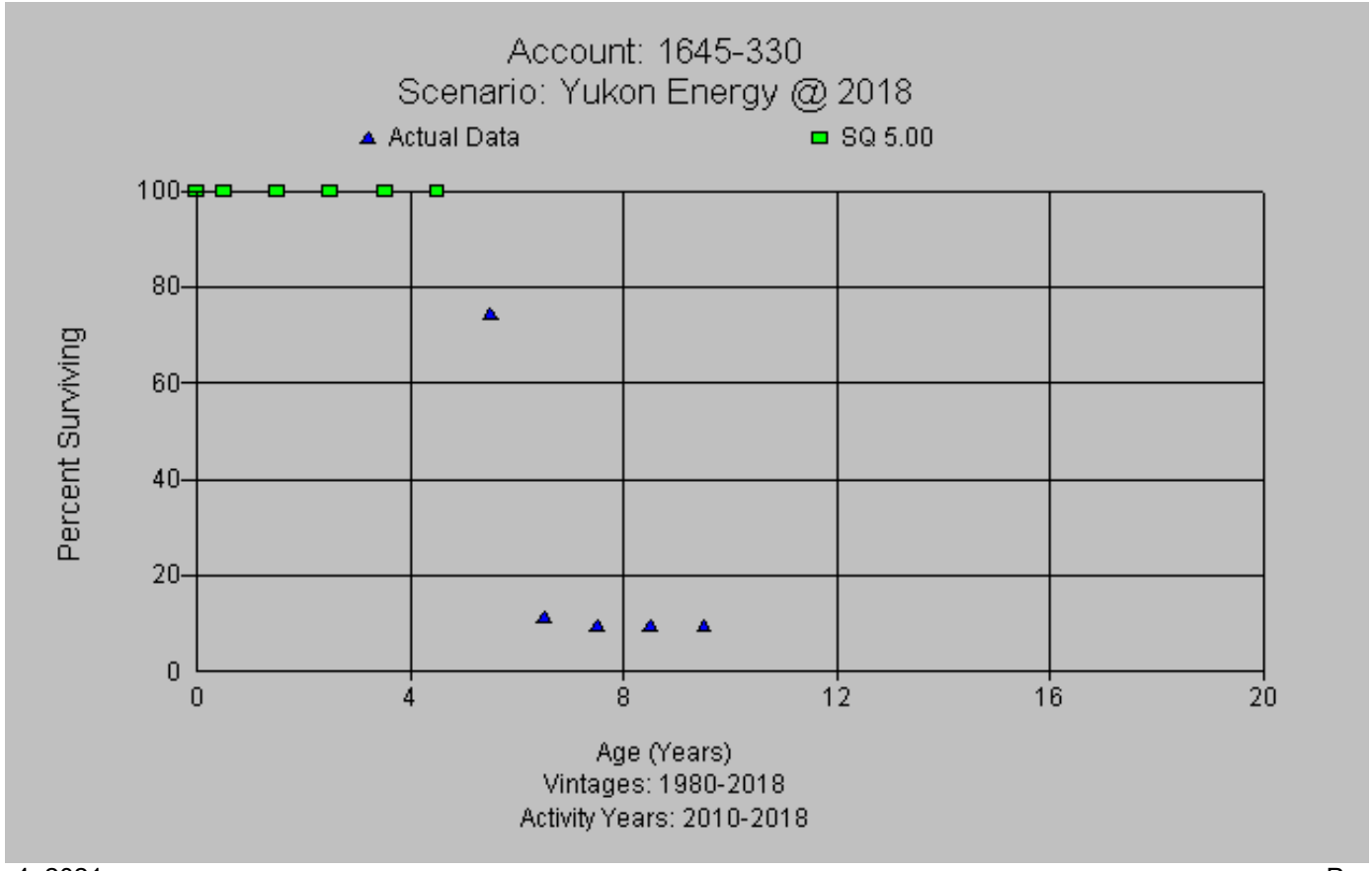
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1991 -2018	38.5	0.00	0.42467788	L3	7.37
1996 -2018	38.5	0.00	0.42694831	L3	7.38
2001 -2018	38.5	0.00	0.46912654	L3	7.51
2006 -2018	38.5	9.23	1.01767985	L2	8.90
2011 -2018	38.5	11.98	1.35642103	L1	10.01
2016 -2018	38.5	9.26	1.10478467	L2	9.15

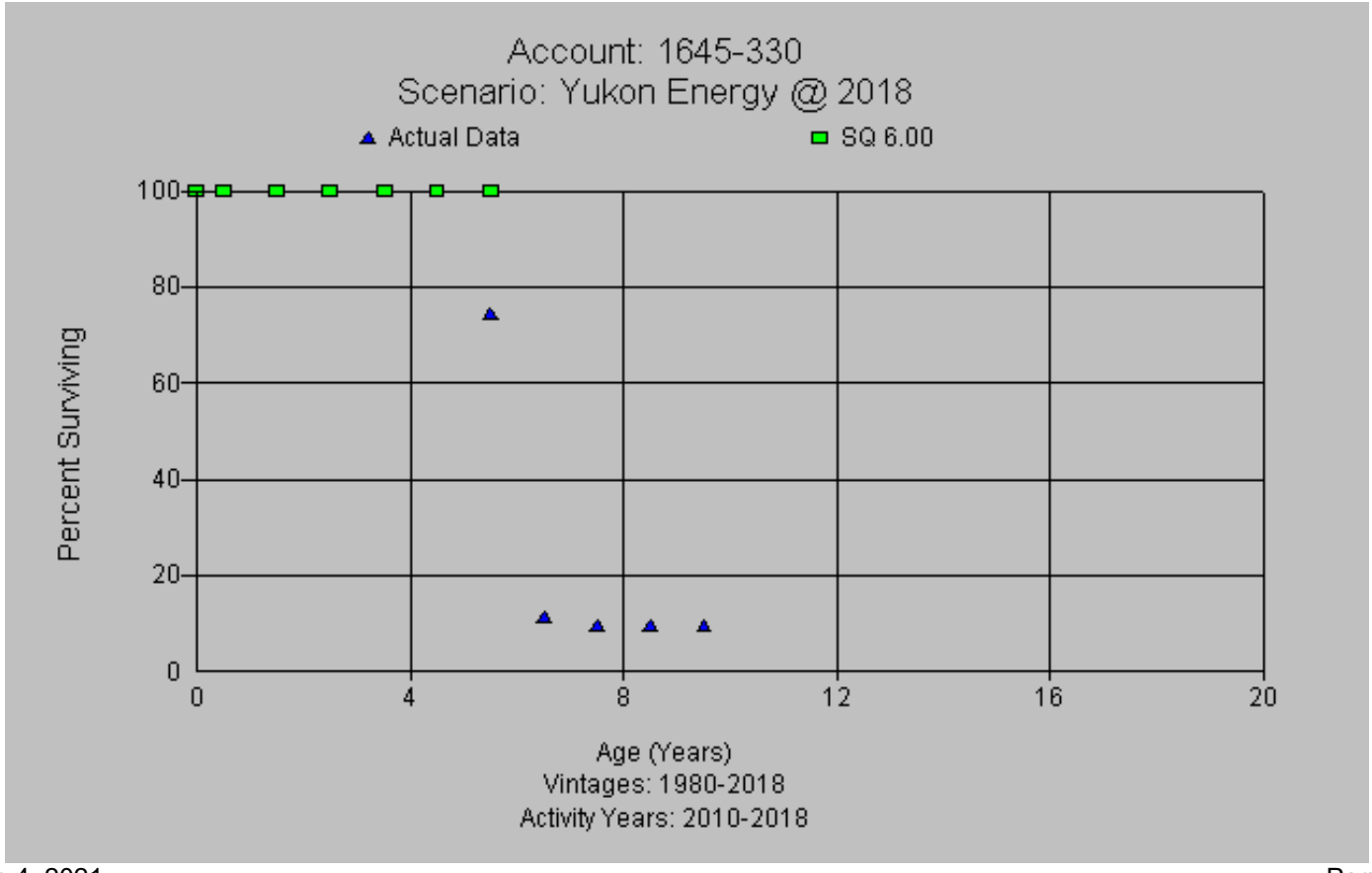

Account: 1645-330
Scenario: Yukon Energy @ 2018
Actual Data
SQ 5.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1980-2018
Activity Years: 2005-2018

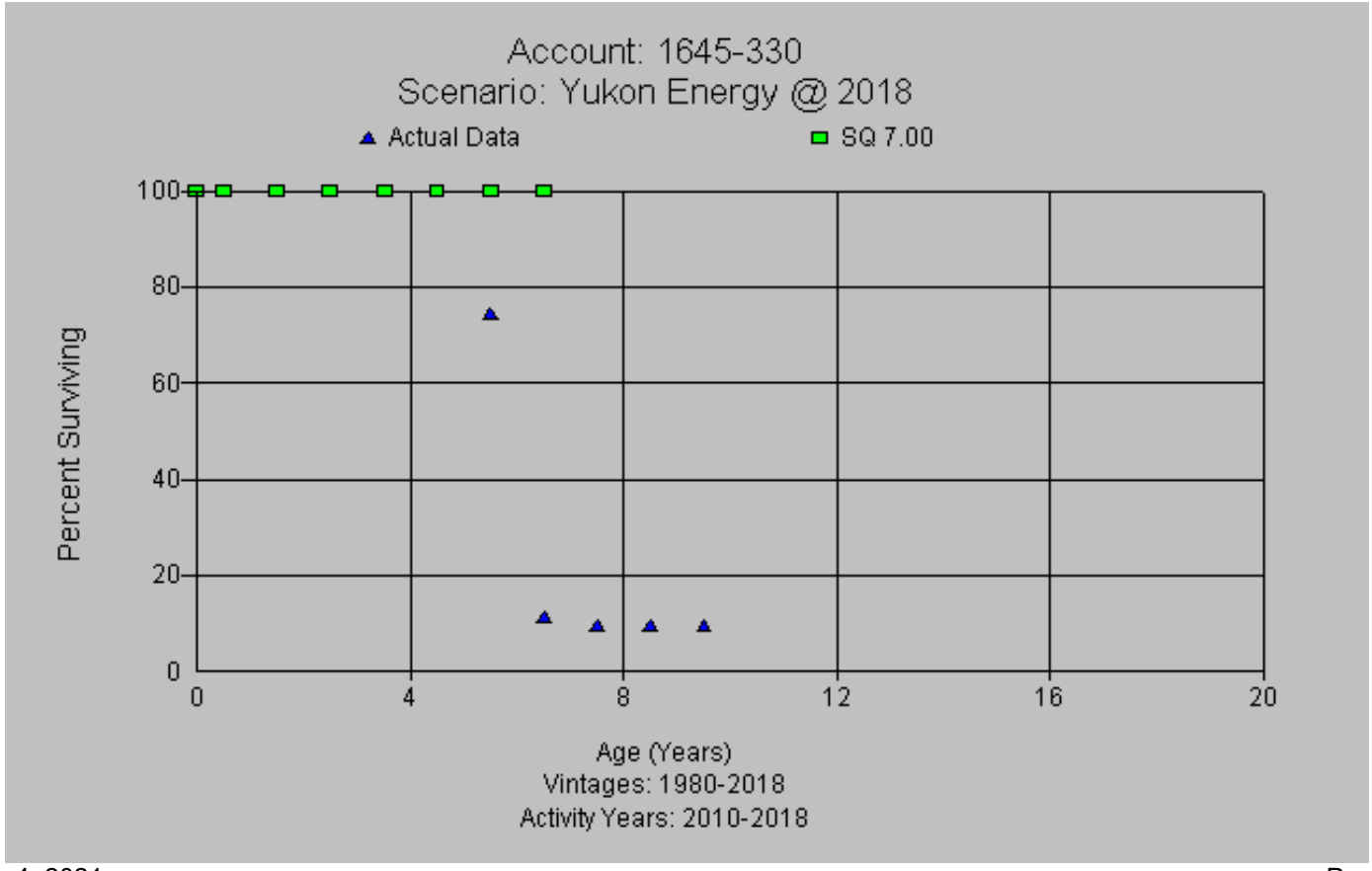
Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-330
Placement Band: 1980 - 2018 **Observation Band:** 2005 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	1,089,782.37	0.00	0.00000	1.00000	100.00
0.5	1,264,914.01	0.00	0.00000	1.00000	100.00
1.5	1,094,520.28	0.00	0.00000	1.00000	100.00
2.5	1,246,532.83	0.00	0.00000	1.00000	100.00
3.5	1,456,849.99	1,504.17	0.00103	0.99897	100.00
4.5	2,232,673.63	1,575,033.95	0.70545	0.29455	99.90
5.5	657,639.68	559,163.53	0.85026	0.14974	29.43
6.5	98,476.15	16,070.00	0.16319	0.83681	4.41
7.5	64,406.15	0.00	0.00000	1.00000	3.69
8.5	25,311.79	0.00	0.00000	1.00000	3.69
9.5	0.00	0.00	0.00000	1.00000	3.69
10.5	0.00	0.00	0.00000	1.00000	
11.5	0.00	0.00	0.00000	1.00000	
12.5	0.00	0.00	0.00000	1.00000	
13.5	0.00	0.00	0.00000	1.00000	
14.5	0.00	0.00	0.00000	1.00000	
15.5	0.00	0.00	0.00000	1.00000	
16.5	0.00	0.00	0.00000	1.00000	
17.5	0.00	0.00	0.00000	1.00000	
18.5	0.00	0.00	0.00000	1.00000	
24.5	8,693.51	8,693.51	1.00000	0.00000	
25.5	0.00	0.00	0.00000	1.00000	


Account: 1645-330
Scenario: Yukon Energy @ 2018
Actual Data
SQ 5.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1980-2018
Activity Years: 2010-2018

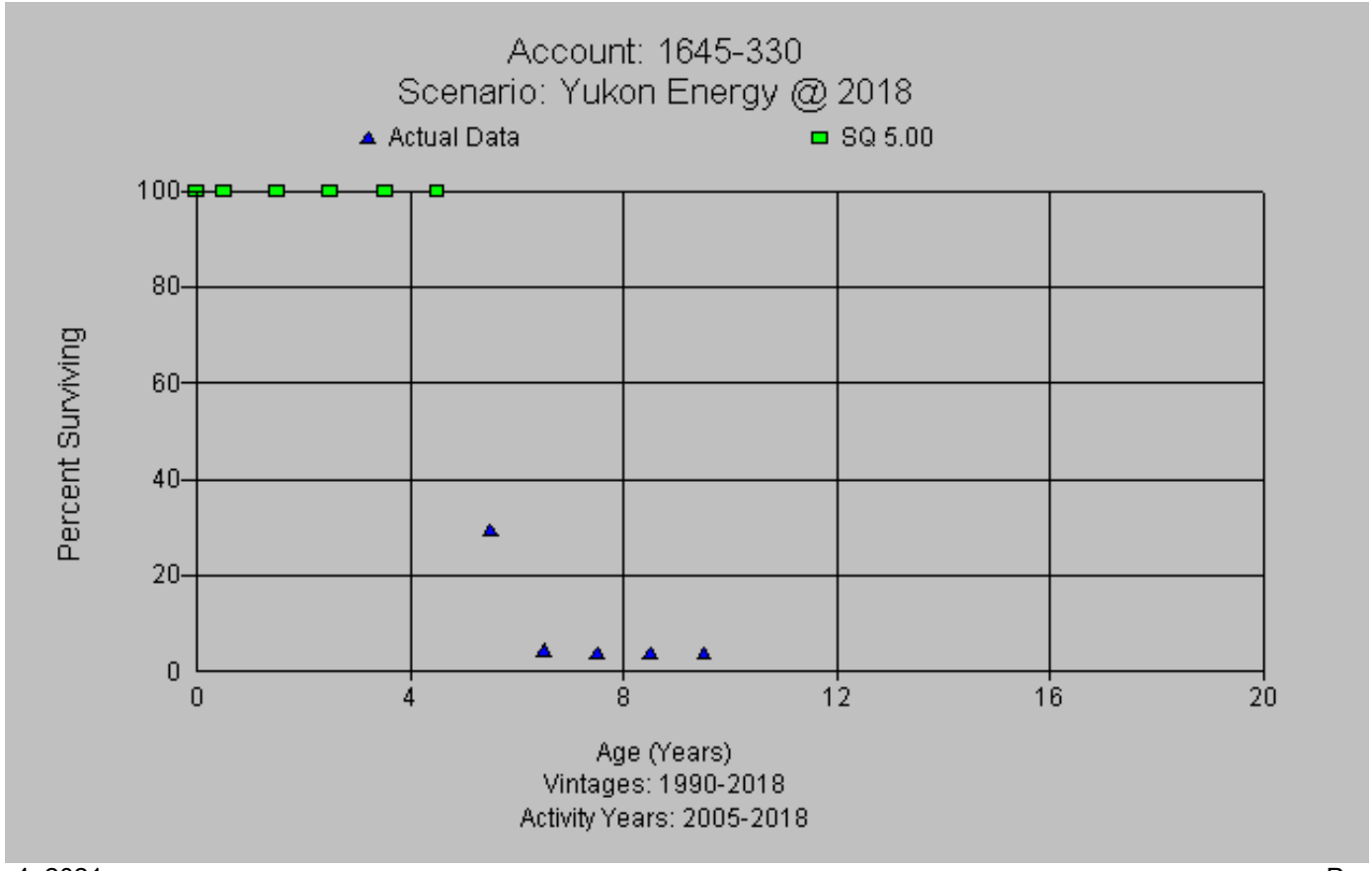

Account: 1645-330
Scenario: Yukon Energy @ 2018
Actual Data
SQ 6.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1980-2018
Activity Years: 2010-2018

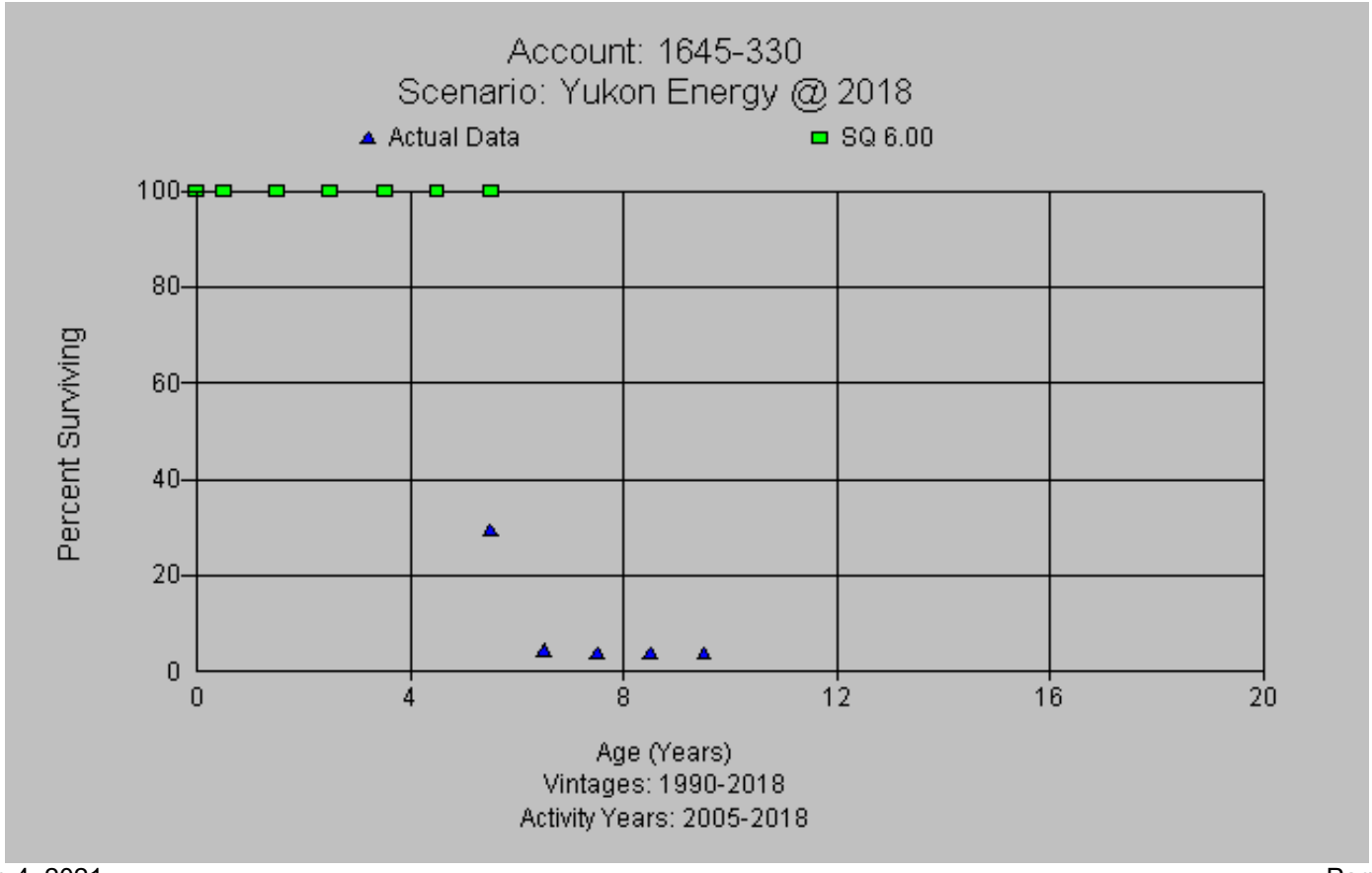

Account: 1645-330
Scenario: Yukon Energy @ 2018
Actual Data
SQ 7.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1980-2018
Activity Years: 2010-2018

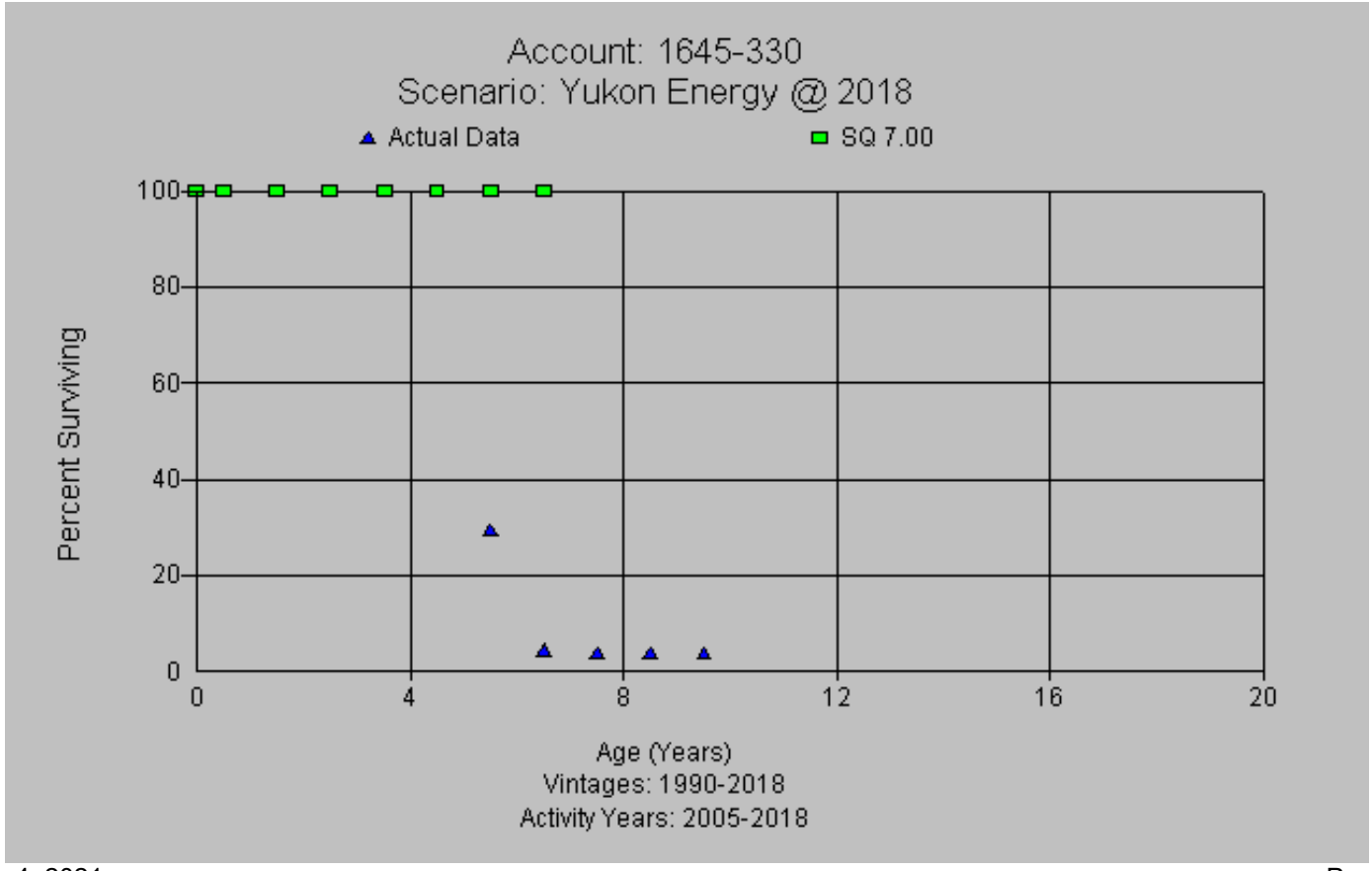
Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-330
Placement Band: 1980 - 2018 **Observation Band:** 2010 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	278,692.16	0.00	0.00000	1.00000	100.00
0.5	510,618.98	0.00	0.00000	1.00000	100.00
1.5	838,426.36	0.00	0.00000	1.00000	100.00
2.5	854,496.36	0.00	0.00000	1.00000	100.00
3.5	854,496.36	0.00	0.00000	1.00000	100.00
4.5	868,184.57	220,303.24	0.25375	0.74625	100.00
5.5	657,639.68	559,163.53	0.85026	0.14974	74.63
6.5	98,476.15	16,070.00	0.16319	0.83681	11.17
7.5	64,406.15	0.00	0.00000	1.00000	9.35
8.5	25,311.79	0.00	0.00000	1.00000	9.35
9.5	0.00	0.00	0.00000	1.00000	9.35


Account: 1645-330
Scenario: Yukon Energy @ 2018
Actual Data
SQ 5.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1990-2018
Activity Years: 2005-2018

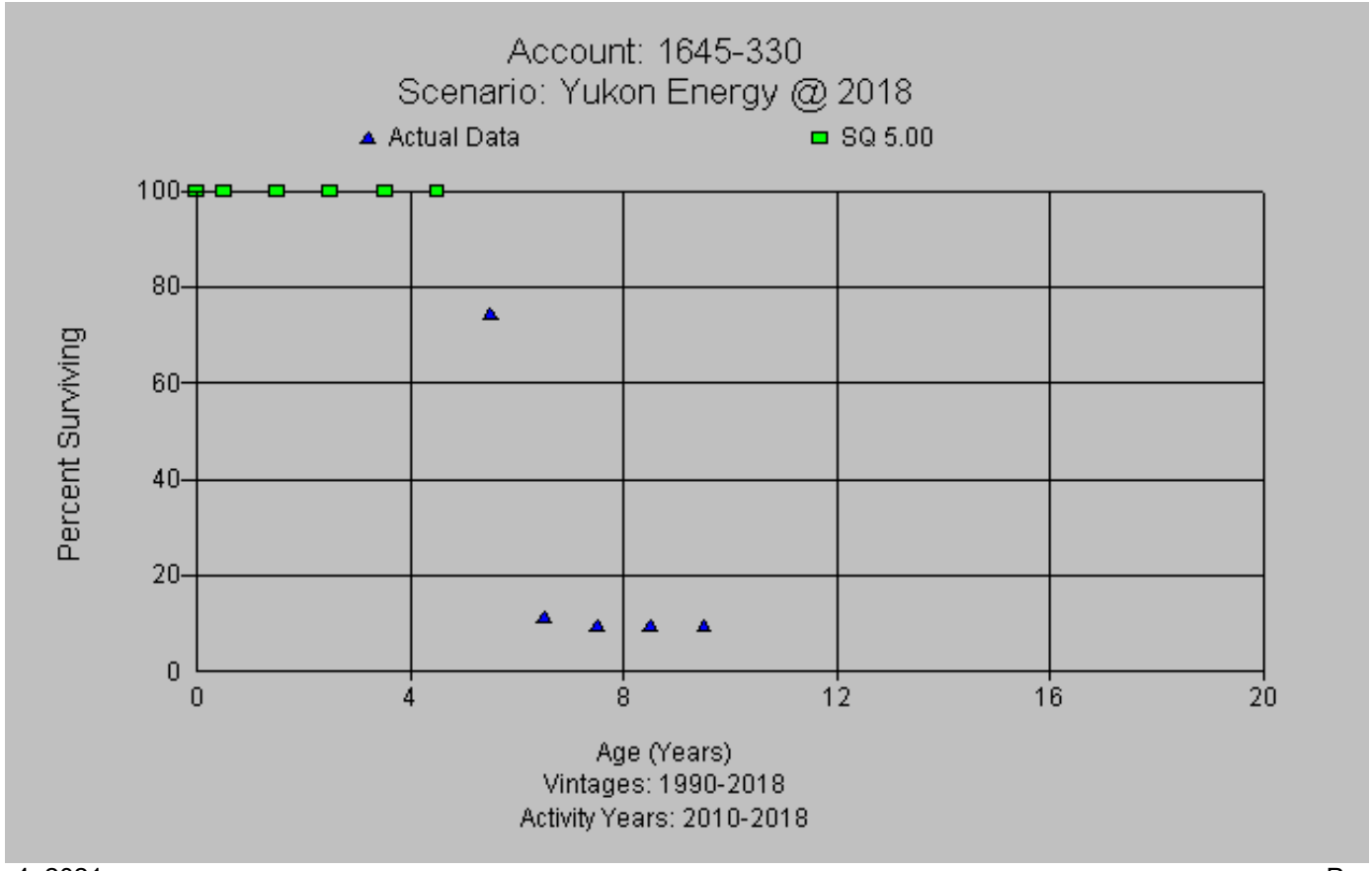

Account: 1645-330
Scenario: Yukon Energy @ 2018
Actual Data
SQ 6.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1990-2018
Activity Years: 2005-2018

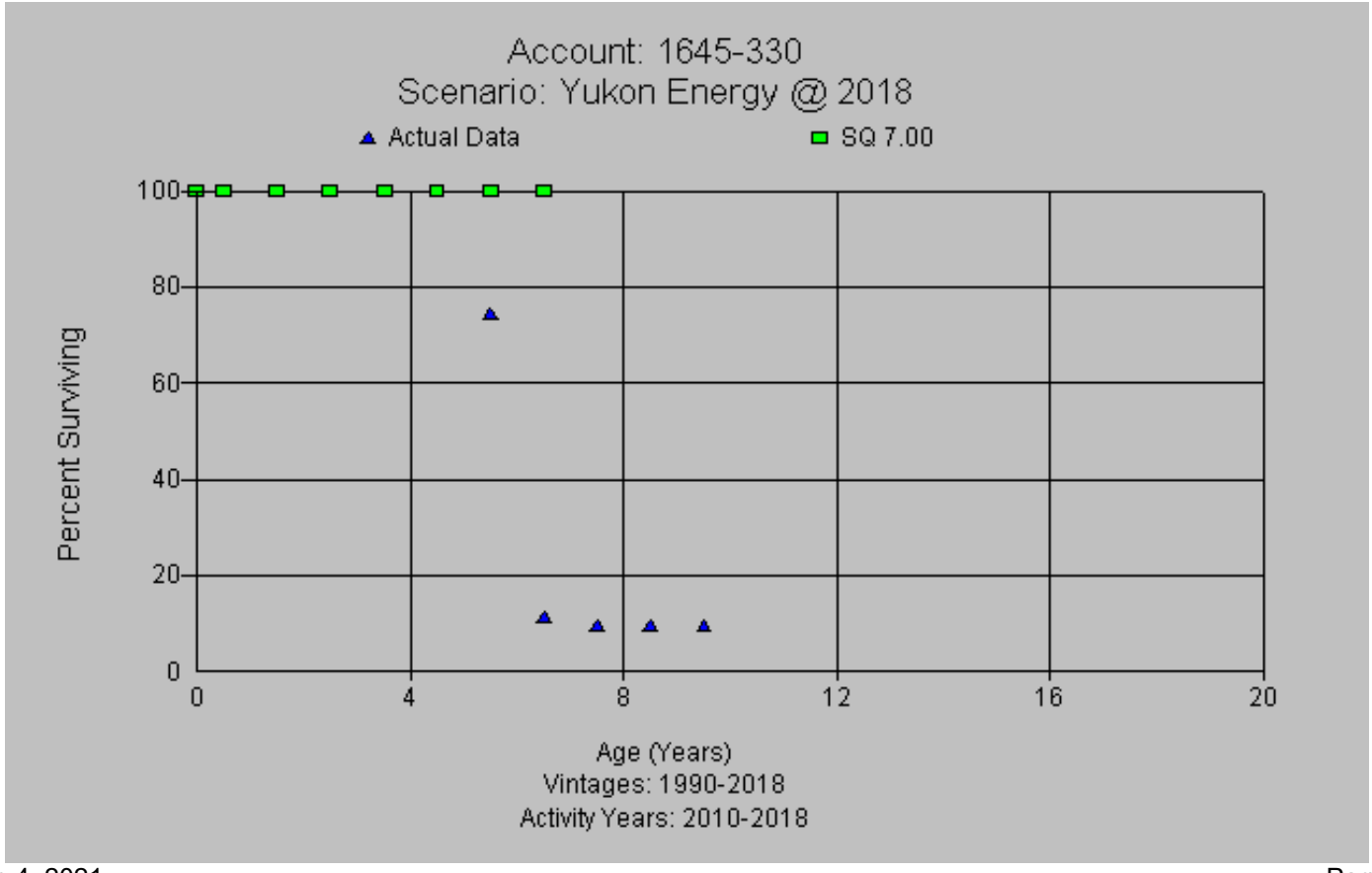

Account: 1645-330
Scenario: Yukon Energy @ 2018
Actual Data
SQ 7.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1990-2018
Activity Years: 2005-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-330
Placement Band: 1990 - 2018 **Observation Band:** 2005 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	1,089,782.37	0.00	0.00000	1.00000	100.00
0.5	1,264,914.01	0.00	0.00000	1.00000	100.00
1.5	1,094,520.28	0.00	0.00000	1.00000	100.00
2.5	1,246,532.83	0.00	0.00000	1.00000	100.00
3.5	1,456,849.99	1,504.17	0.00103	0.99897	100.00
4.5	2,232,673.63	1,575,033.95	0.70545	0.29455	99.90
5.5	657,639.68	559,163.53	0.85026	0.14974	29.43
6.5	98,476.15	16,070.00	0.16319	0.83681	4.41
7.5	64,406.15	0.00	0.00000	1.00000	3.69
8.5	25,311.79	0.00	0.00000	1.00000	3.69
9.5	0.00	0.00	0.00000	1.00000	3.69


Account: 1645-330
Scenario: Yukon Energy @ 2018
Actual Data
SQ 5.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1990-2018
Activity Years: 2010-2018


Account: 1645-330
Scenario: Yukon Energy @ 2018
Actual Data
SQ 7.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1990-2018
Activity Years: 2010-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-330
Placement Band: 1990 - 2018 **Observation Band:** 2010 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	278,692.16	0.00	0.00000	1.00000	100.00
0.5	510,618.98	0.00	0.00000	1.00000	100.00
1.5	838,426.36	0.00	0.00000	1.00000	100.00
2.5	854,496.36	0.00	0.00000	1.00000	100.00
3.5	854,496.36	0.00	0.00000	1.00000	100.00
4.5	868,184.57	220,303.24	0.25375	0.74625	100.00
5.5	657,639.68	559,163.53	0.85026	0.14974	74.63
6.5	98,476.15	16,070.00	0.16319	0.83681	11.17
7.5	64,406.15	0.00	0.00000	1.00000	9.35
8.5	25,311.79	0.00	0.00000	1.00000	9.35
9.5	0.00	0.00	0.00000	1.00000	9.35

Actuarial Life Analysis

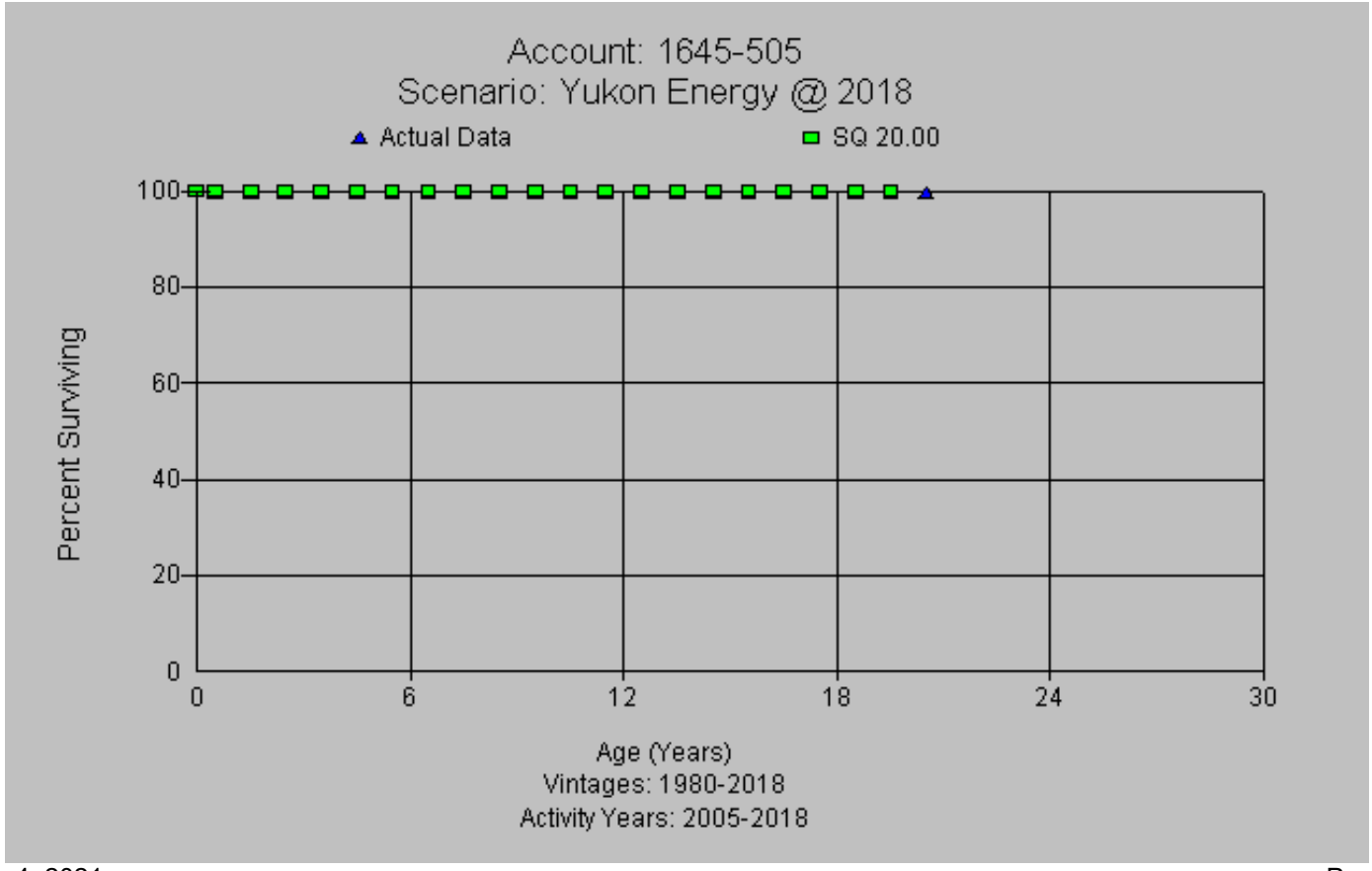
Account: 1645-330
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 1984
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

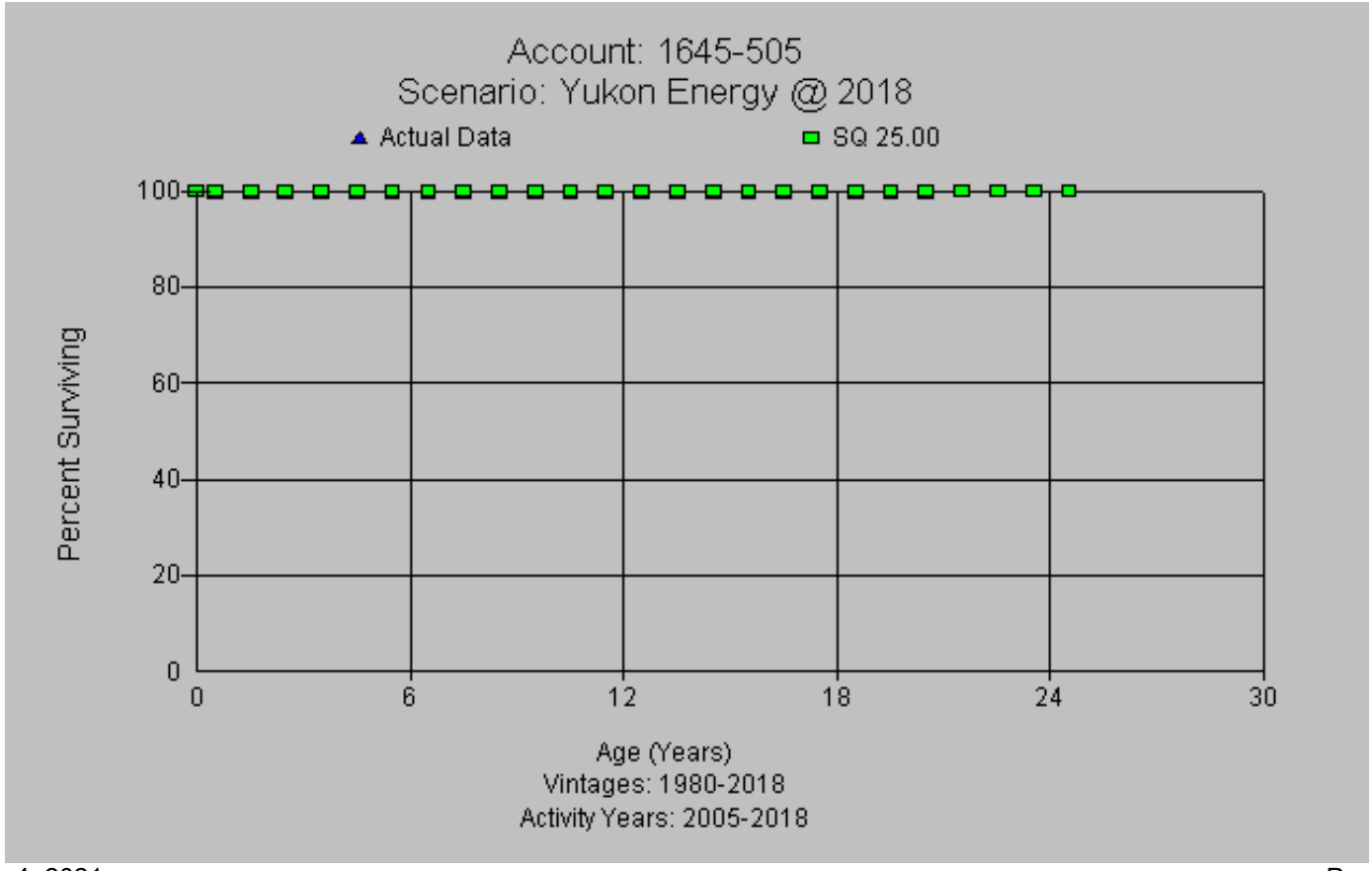
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -1984		1.00			
1981 -1985		1.00			
1982 -1986		1.00			
1983 -1987		1.00			
1984 -1988		1.00			
1985 -1989		1.00			
1986 -1990		1.00			
1987 -1991		1.00			
1988 -1992		1.00			
1989 -1993		1.00			
1990 -1994		1.00			
1991 -1995		1.00			
1992 -1996		1.00			
1993 -1997		1.00			
1994 -1998		1.00			
1995 -1999		1.00			
1996 -2000		1.00			
1997 -2001		1.00			
1998 -2002		1.00			
1999 -2003		1.00			
2000 -2004		1.00			
2001 -2005	11.5	0.00	0.00000000	SQ	5.39
2002 -2006	12.5	0.00	0.00000000	SQ	5.39
2003 -2007	13.5	0.00	0.00000000	SQ	5.39
2004 -2008	14.5	0.00	0.00000121	SQ	5.05
2005 -2009	15.5	0.00	0.02242236	S6	5.09
2006 -2010	16.5	0.00	0.01014974	SQ	5.45
2007 -2011	17.5	0.00	0.01515250	S6	5.07
2008 -2012	18.5	0.00	0.00891526	S6	5.15
2009 -2013	19.5	47.54	0.41014737	L0	13.79
2010 -2014	20.5	0.00	0.00163086	S6	5.80
2011 -2015	21.5	0.00	0.00157734	S6	5.85
2012 -2016		0.00			
2013 -2017	22.5	9.17	0.51034921	L2	6.43
2014 -2018	23.5	3.11	0.20134349	L4	4.92

Actuarial Life Analysis

Account: 1645-330
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -2018	38.5	0.00	0.27994082	L4	6.12
1985 -2018	38.5	0.00	0.27994082	L4	6.12
1990 -2018	38.5	0.00	0.25252514	L4	6.05
1995 -2018	38.5	0.00	0.25252514	L4	6.05
2000 -2018	38.5	0.00	0.25252514	L4	6.05
2005 -2018	38.5	0.00	0.17684883	L5	5.87
2010 -2018	38.5	9.35	1.09845732	L1.5	8.85
2015 -2018		1.00			

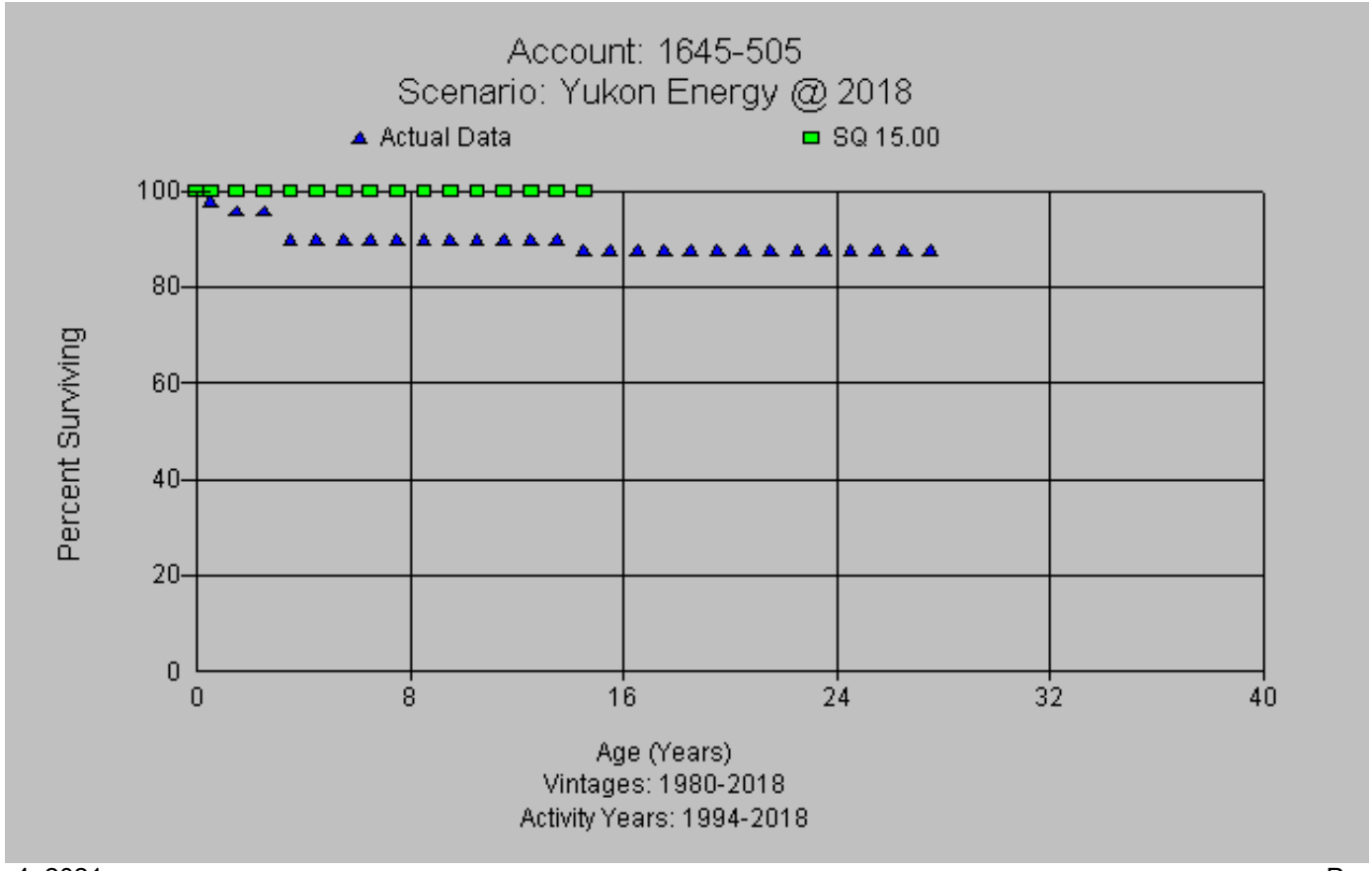

Account: 1645-505
Scenario: Yukon Energy @ 2018
Actual Data
SQ 20.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 2005-2018

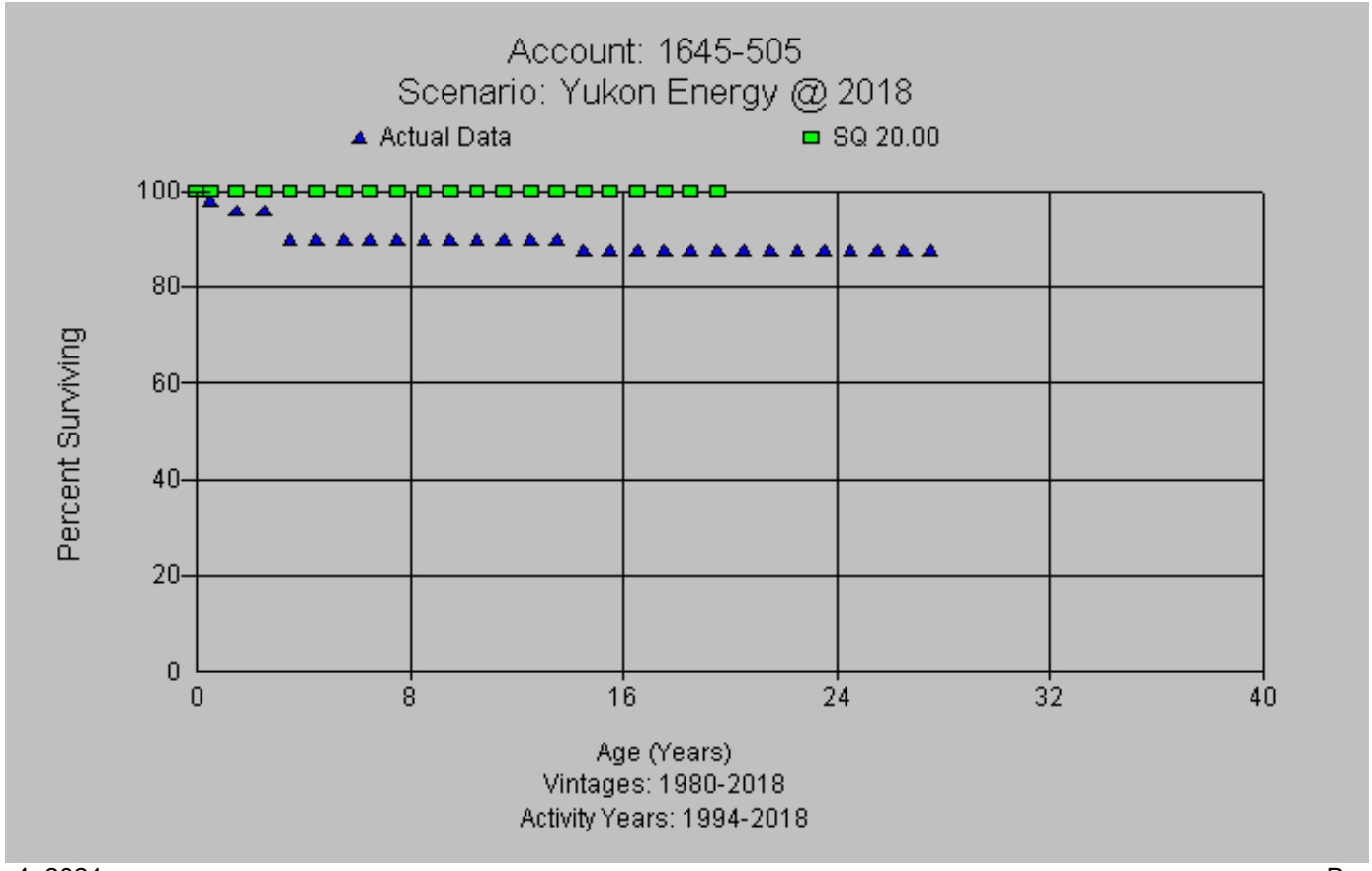

Account: 1645-505
Scenario: Yukon Energy @ 2018
Actual Data
SQ 25.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 2005-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-505
Placement Band: 1980 - 2018 **Observation Band:** 2005 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	1,002,356.33	4,360.72	0.00435	0.99565	100.00
0.5	902,823.99	0.00	0.00000	1.00000	99.57
1.5	998,848.44	0.00	0.00000	1.00000	99.57
2.5	977,169.22	0.00	0.00000	1.00000	99.57
3.5	945,692.87	0.00	0.00000	1.00000	99.57
4.5	951,869.35	0.00	0.00000	1.00000	99.57
5.5	1,023,343.35	0.00	0.00000	1.00000	99.57
6.5	1,050,427.61	0.00	0.00000	1.00000	99.57
7.5	998,579.20	0.00	0.00000	1.00000	99.57
8.5	950,882.15	0.00	0.00000	1.00000	99.57
9.5	917,655.80	0.00	0.00000	1.00000	99.57
10.5	834,435.90	0.00	0.00000	1.00000	99.57
11.5	714,382.51	0.00	0.00000	1.00000	99.57
12.5	686,425.93	0.00	0.00000	1.00000	99.57
13.5	656,986.53	0.00	0.00000	1.00000	99.57
14.5	593,730.61	0.00	0.00000	1.00000	99.57
15.5	439,623.91	344.00	0.00078	0.99922	99.57
16.5	389,762.44	0.00	0.00000	1.00000	99.49
17.5	357,115.68	0.00	0.00000	1.00000	99.49
18.5	280,789.36	0.00	0.00000	1.00000	99.49
19.5	162,972.35	0.00	0.00000	1.00000	99.49
20.5	0.00	0.00	0.00000	1.00000	99.49
21.5	0.00	0.00	0.00000	1.00000	
22.5	0.00	0.00	0.00000	1.00000	
23.5	0.00	0.00	0.00000	1.00000	
24.5	245,166.64	0.00	0.00000	1.00000	
25.5	245,166.64	0.00	0.00000	1.00000	
26.5	245,166.64	0.00	0.00000	1.00000	
27.5	245,166.64	245,166.64	1.00000	0.00000	
28.5	0.00	0.00	0.00000	1.00000	

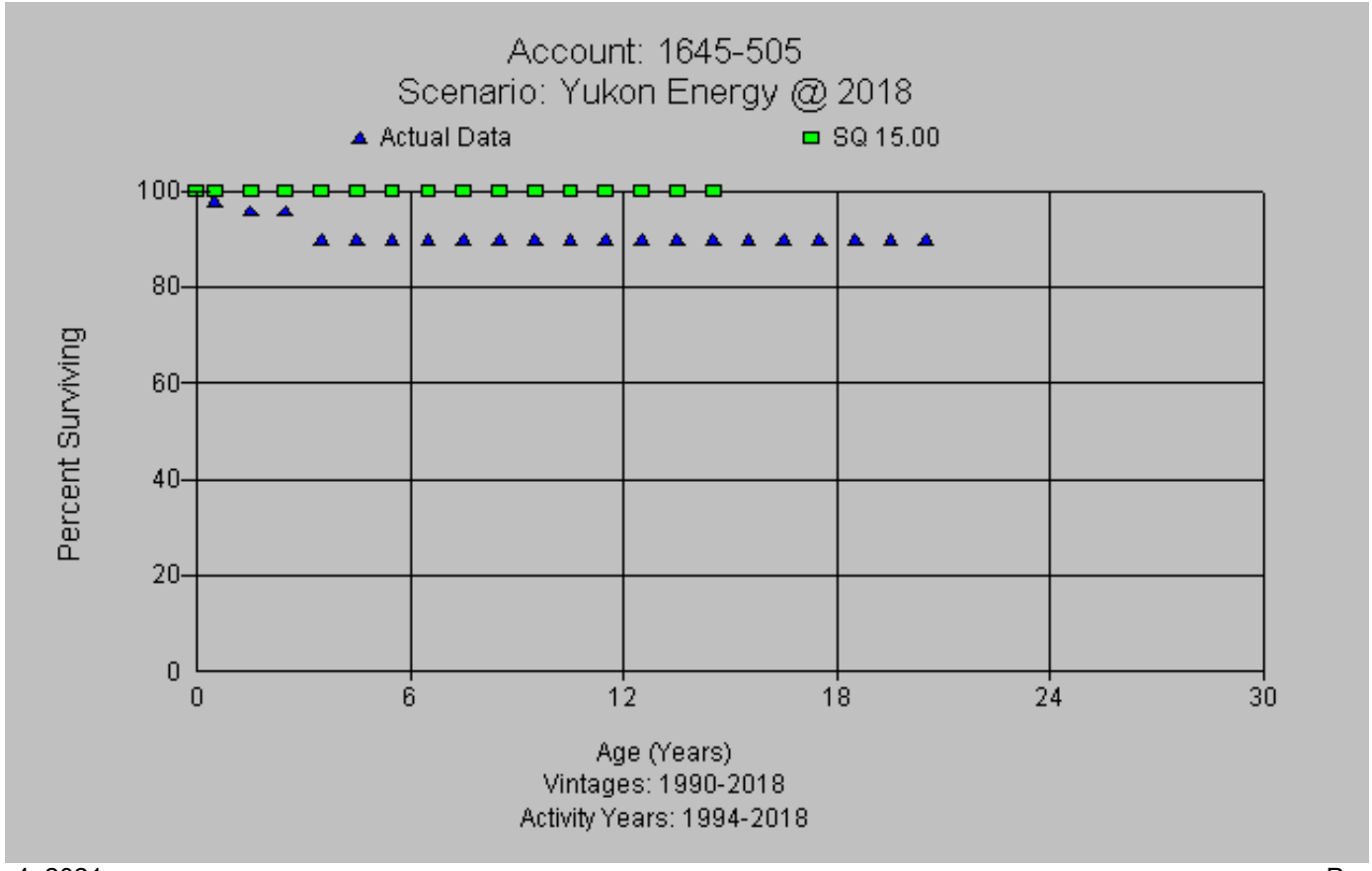

Account: 1645-505
Scenario: Yukon Energy @ 2018
Actual Data
SQ 15.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1980-2018
Activity Years: 1994-2018

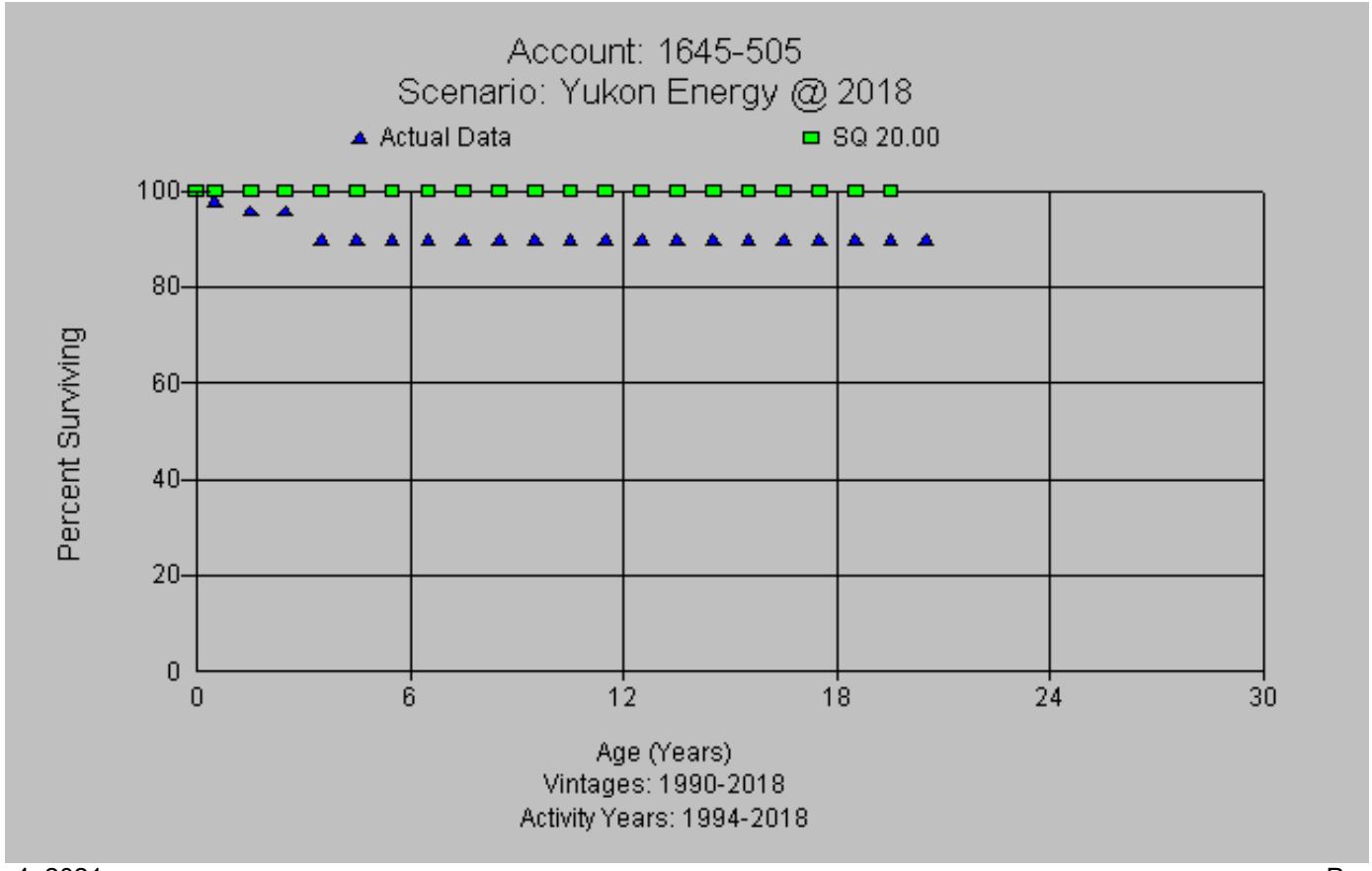

Account: 1645-505
Scenario: Yukon Energy @ 2018
Actual Data
SQ 20.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1980-2018
Activity Years: 1994-2018

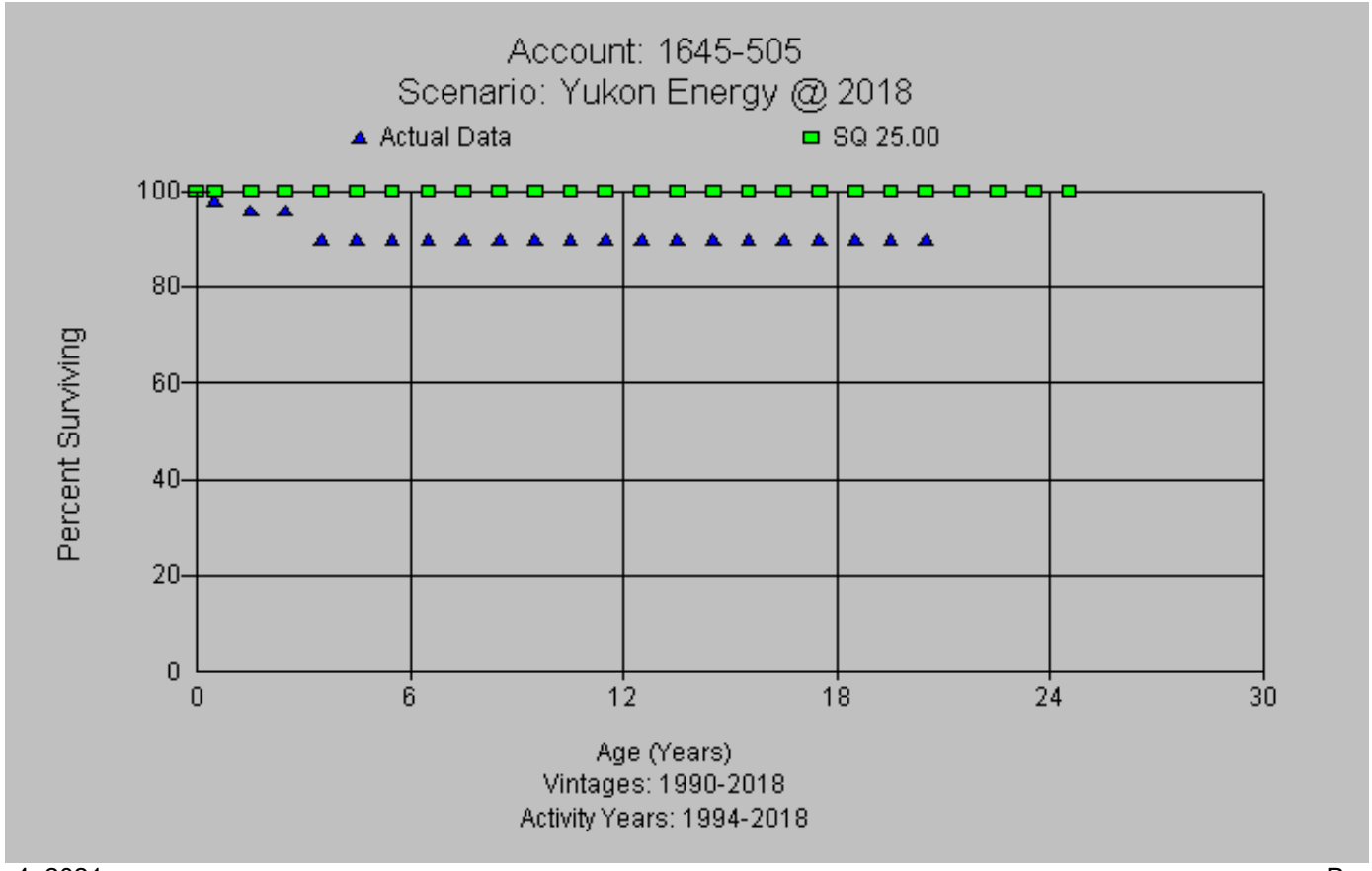
Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-505
Placement Band: 1980 - 2018 **Observation Band:** 1994 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	1,813,247.86	34,511.72	0.01903	0.98097	100.00
0.5	1,620,871.60	36,367.00	0.02244	0.97756	98.10
1.5	1,526,422.35	0.00	0.00000	1.00000	95.90
2.5	1,454,881.66	87,950.00	0.06045	0.93955	95.90
3.5	1,302,808.55	0.00	0.00000	1.00000	90.10
4.5	1,232,658.71	0.00	0.00000	1.00000	90.10
5.5	1,186,315.70	0.00	0.00000	1.00000	90.10
6.5	1,076,485.61	0.00	0.00000	1.00000	90.10
7.5	1,024,637.20	0.00	0.00000	1.00000	90.10
8.5	976,940.15	0.00	0.00000	1.00000	90.10
9.5	943,713.80	0.00	0.00000	1.00000	90.10
10.5	860,493.90	0.00	0.00000	1.00000	90.10
11.5	740,440.51	0.00	0.00000	1.00000	90.10
12.5	712,483.93	0.00	0.00000	1.00000	90.10
13.5	928,211.17	26,058.00	0.02807	0.97193	90.10
14.5	838,897.25	0.00	0.00000	1.00000	87.57
15.5	684,790.55	344.00	0.00050	0.99950	87.57
16.5	634,929.08	0.00	0.00000	1.00000	87.53
17.5	602,282.32	0.00	0.00000	1.00000	87.53
18.5	525,956.00	0.00	0.00000	1.00000	87.53
19.5	408,138.99	0.00	0.00000	1.00000	87.53
20.5	245,166.64	0.00	0.00000	1.00000	87.53
21.5	245,166.64	0.00	0.00000	1.00000	87.53
22.5	245,166.64	0.00	0.00000	1.00000	87.53
23.5	245,166.64	0.00	0.00000	1.00000	87.53
24.5	245,166.64	0.00	0.00000	1.00000	87.53
25.5	245,166.64	0.00	0.00000	1.00000	87.53
26.5	245,166.64	0.00	0.00000	1.00000	87.53
27.5	245,166.64	245,166.64	1.00000	0.00000	87.53
28.5	0.00	0.00	0.00000	1.00000	0.00


Account: 1645-505
Scenario: Yukon Energy @ 2018
Actual Data
SQ 15.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1990-2018
Activity Years: 1994-2018


Account: 1645-505
Scenario: Yukon Energy @ 2018
Actual Data
SQ 20.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1990-2018
Activity Years: 1994-2018


Account: 1645-505
Scenario: Yukon Energy @ 2018
Actual Data
SQ 25.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1990-2018
Activity Years: 1994-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-505
Placement Band: 1990 - 2018 **Observation Band:** 1994 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	1,813,247.86	34,511.72	0.01903	0.98097	100.00
0.5	1,620,871.60	36,367.00	0.02244	0.97756	98.10
1.5	1,526,422.35	0.00	0.00000	1.00000	95.90
2.5	1,454,881.66	87,950.00	0.06045	0.93955	95.90
3.5	1,302,808.55	0.00	0.00000	1.00000	90.10
4.5	1,232,658.71	0.00	0.00000	1.00000	90.10
5.5	1,186,315.70	0.00	0.00000	1.00000	90.10
6.5	1,050,427.61	0.00	0.00000	1.00000	90.10
7.5	998,579.20	0.00	0.00000	1.00000	90.10
8.5	950,882.15	0.00	0.00000	1.00000	90.10
9.5	917,655.80	0.00	0.00000	1.00000	90.10
10.5	834,435.90	0.00	0.00000	1.00000	90.10
11.5	714,382.51	0.00	0.00000	1.00000	90.10
12.5	686,425.93	0.00	0.00000	1.00000	90.10
13.5	656,986.53	0.00	0.00000	1.00000	90.10
14.5	593,730.61	0.00	0.00000	1.00000	90.10
15.5	439,623.91	344.00	0.00078	0.99922	90.10
16.5	389,762.44	0.00	0.00000	1.00000	90.03
17.5	357,115.68	0.00	0.00000	1.00000	90.03
18.5	280,789.36	0.00	0.00000	1.00000	90.03
19.5	162,972.35	0.00	0.00000	1.00000	90.03
20.5	0.00	0.00	0.00000	1.00000	90.03

Actuarial Life Analysis

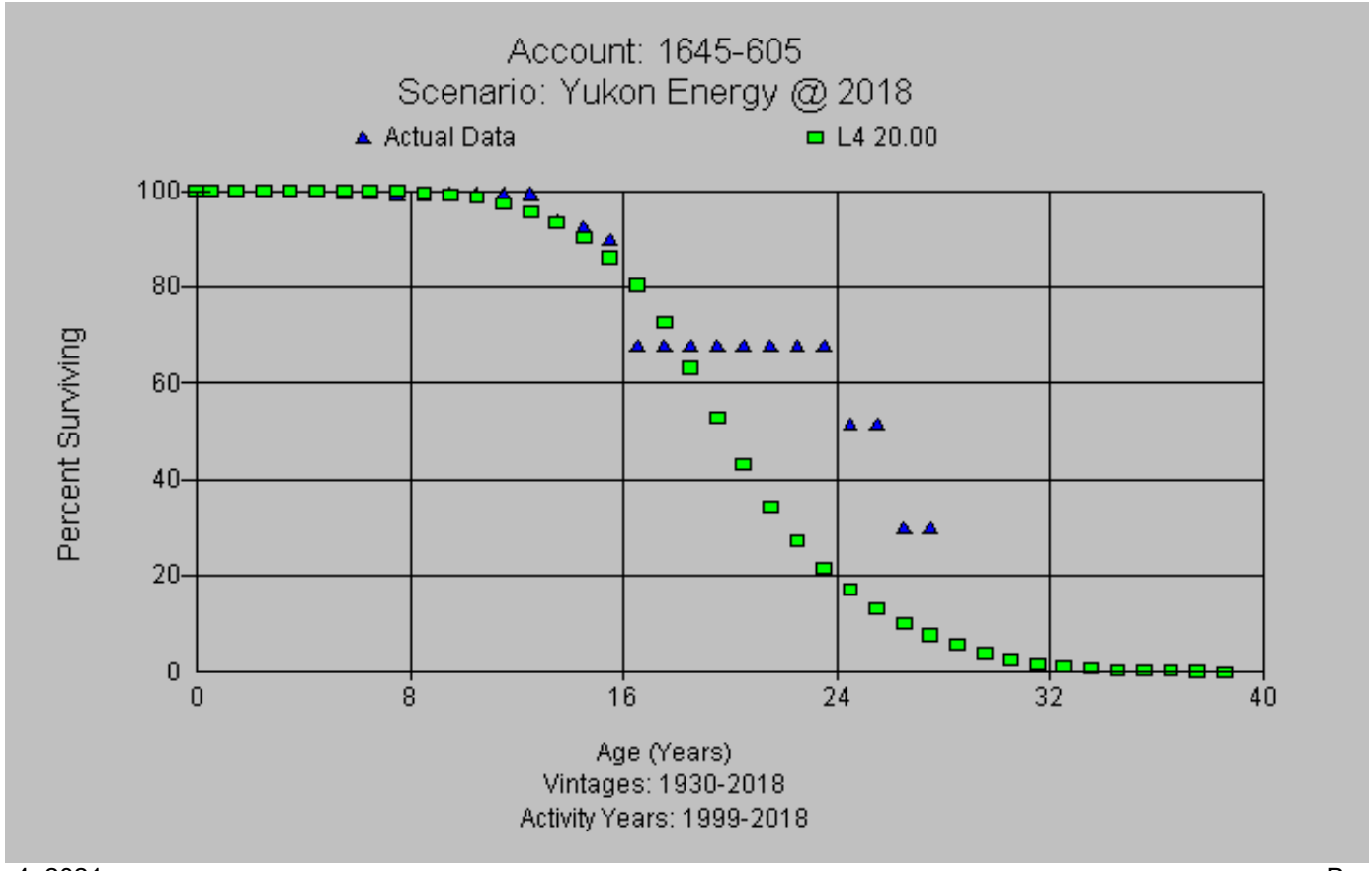
Account: 1645-505
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 1998
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

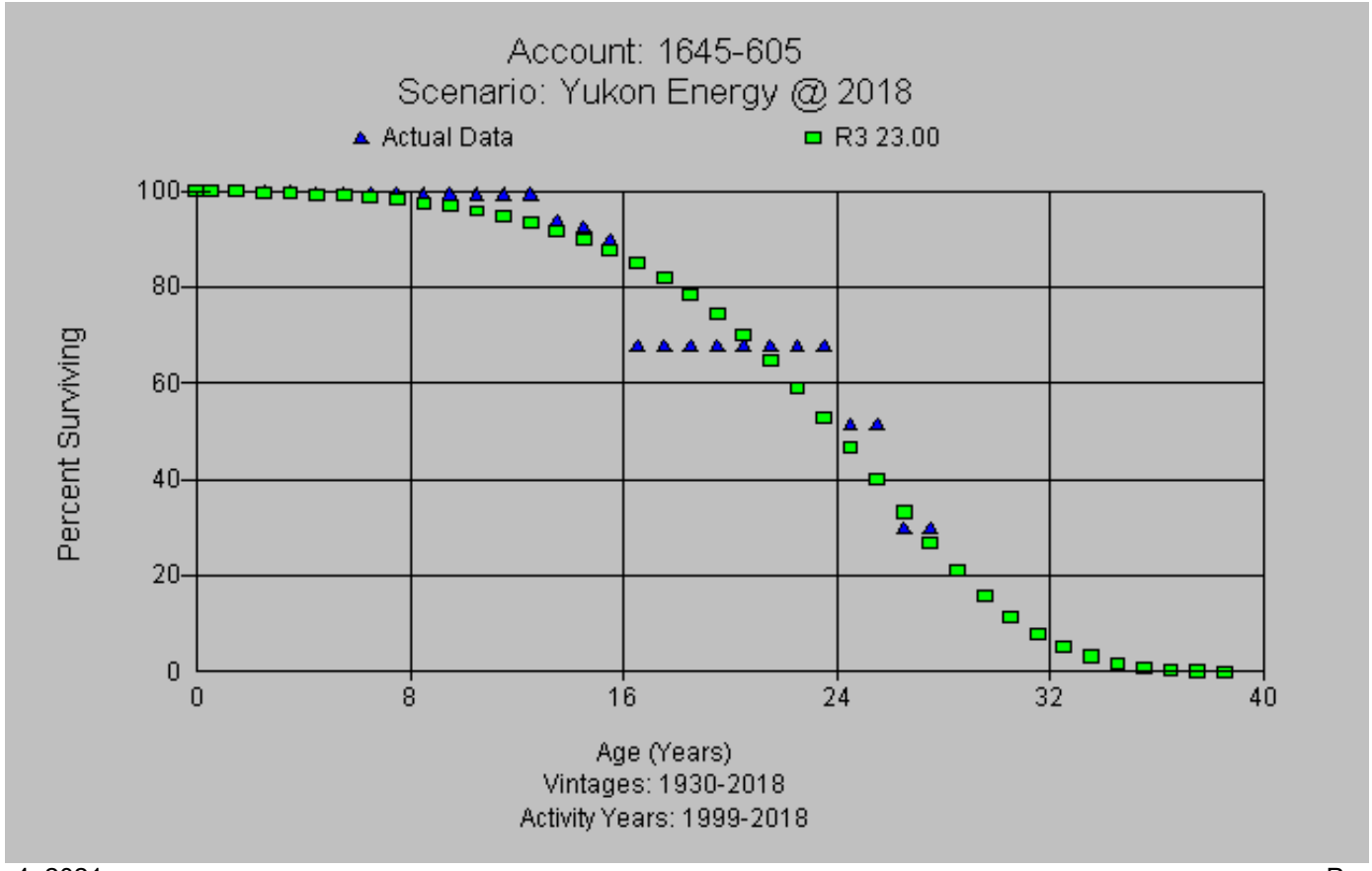
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1994 -1998	16.5	64.03	0.71714062	L0	12.76
1995 -1999	17.5	0.00	0.04324402	S6	2.63
1996 -2000	18.5	0.00	0.02293067	S6	2.73
1997 -2001	19.5	0.00	0.52172429	R0.5	8.87
1998 -2002	20.5	0.00	0.55909574	R2	11.43
1999 -2003	21.5	0.00	0.55573462	R2.5	11.88
2000 -2004	22.5	0.00	0.00000000	SQ	14.20
2001 -2005	23.5	0.00	0.00240255	SQ	13.87
2002 -2006	24.5	98.67	0.00164554	R1.5	177.94
2003 -2007	25.5	98.91	0.00113215	R1.5	222.44
2004 -2008	26.5	0.00	0.00459914	SQ	25.71
2005 -2009	27.5	0.00	0.00554214	SQ	25.67
2006 -2010	28.5	0.00	0.00000000	SQ	26.20
2007 -2011	29.5	0.00	0.00000000	SQ	26.20
2008 -2012	30.5	0.00	0.00000000	SQ	26.20
2009 -2013		1.00			
2010 -2014		1.00			
2011 -2015		1.00			
2012 -2016		1.00			
2013 -2017		1.00			
2014 -2018	36.5	99.92	0.00000393	R4	142.20

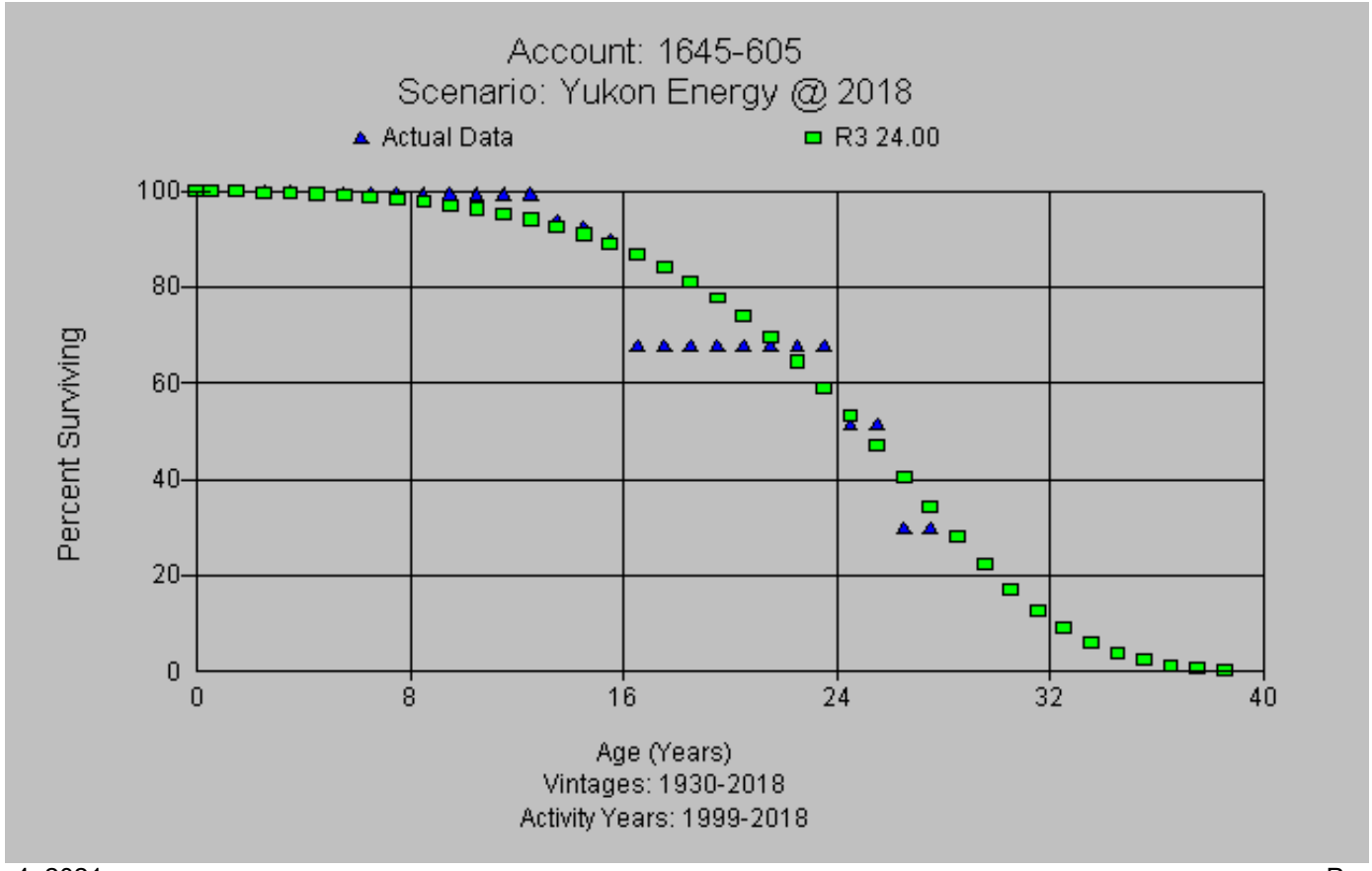
Actuarial Life Analysis

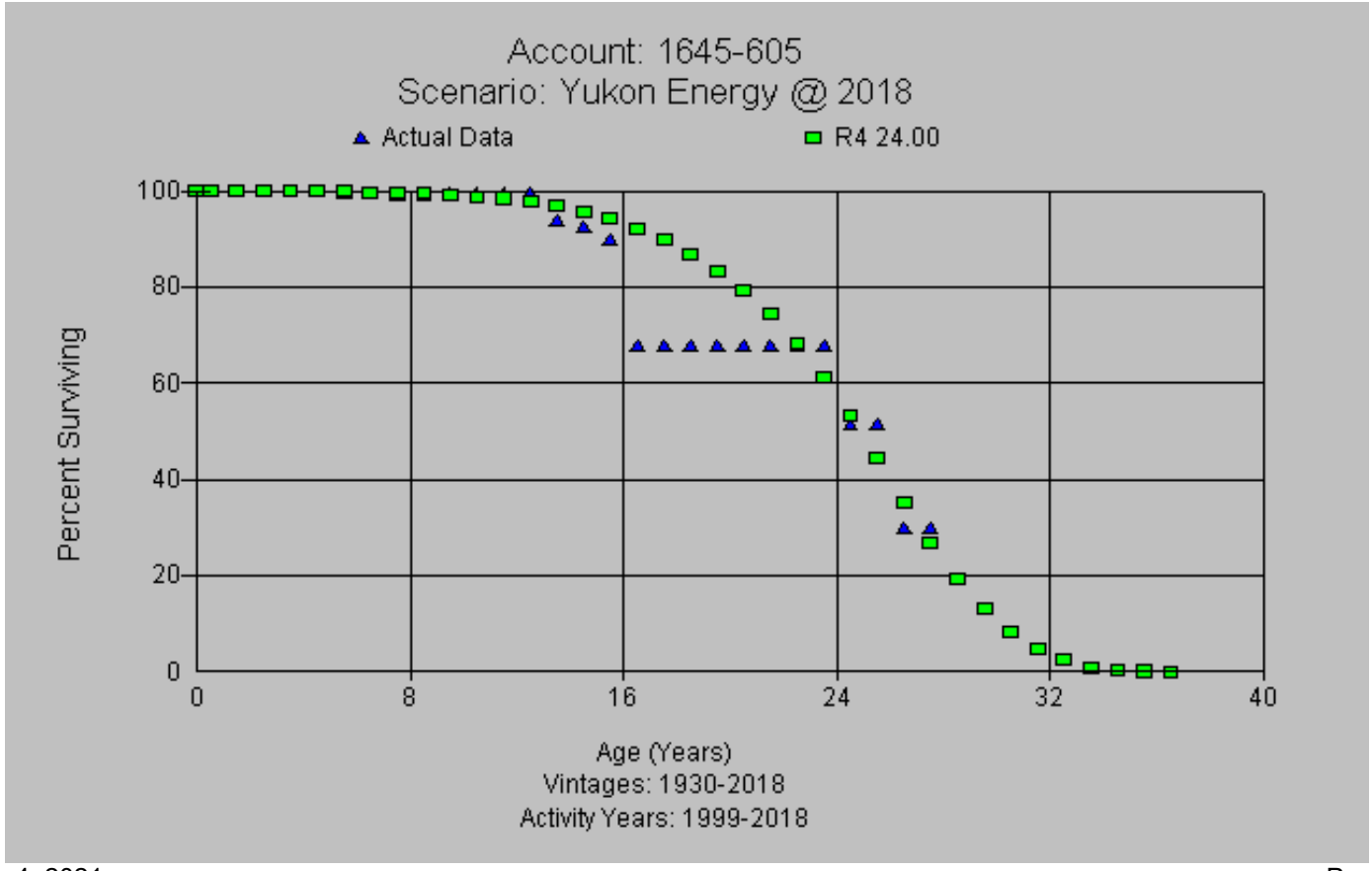
Account: 1645-505
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1994 -2018	38.5	0.00	0.99738105	R4	25.12
1999 -2018	38.5	0.00	0.81831295	R5	25.95
2004 -2018	38.5	0.00	0.00055708	SQ	27.93
2009 -2018	38.5	99.92	0.00000478	R4	147.71
2014 -2018	38.5	99.92	0.00000478	R4	147.71


Account: 1645-605
Scenario: Yukon Energy @ 2018
Actual Data
L4 20.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1930-2018
Activity Years: 1999-2018


Account: 1645-605
Scenario: Yukon Energy @ 2018
Actual Data
R3 23.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1930-2018
Activity Years: 1999-2018

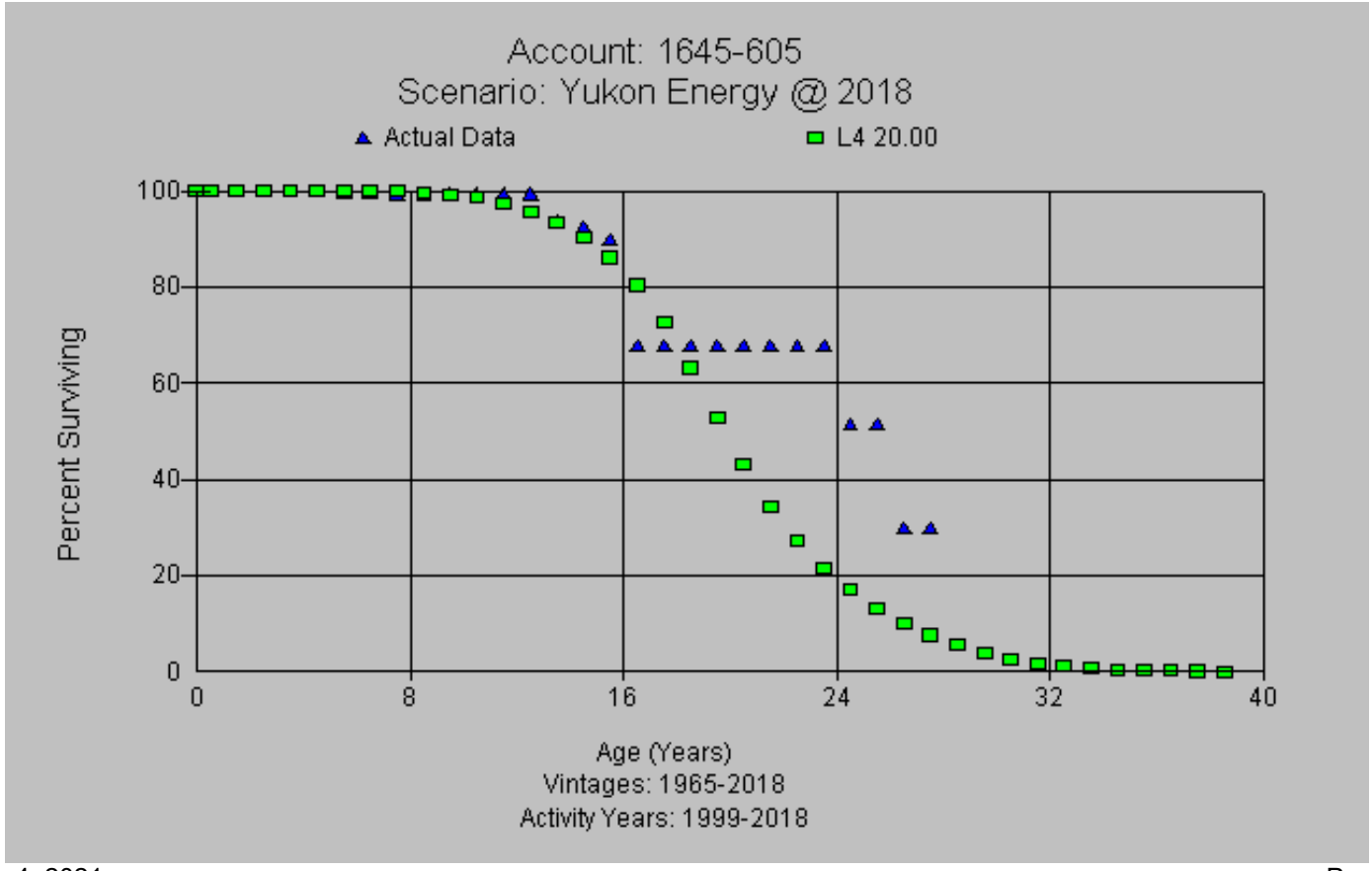

Account: 1645-605
Scenario: Yukon Energy @ 2018
Actual Data
R3 24.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1930-2018
Activity Years: 1999-2018

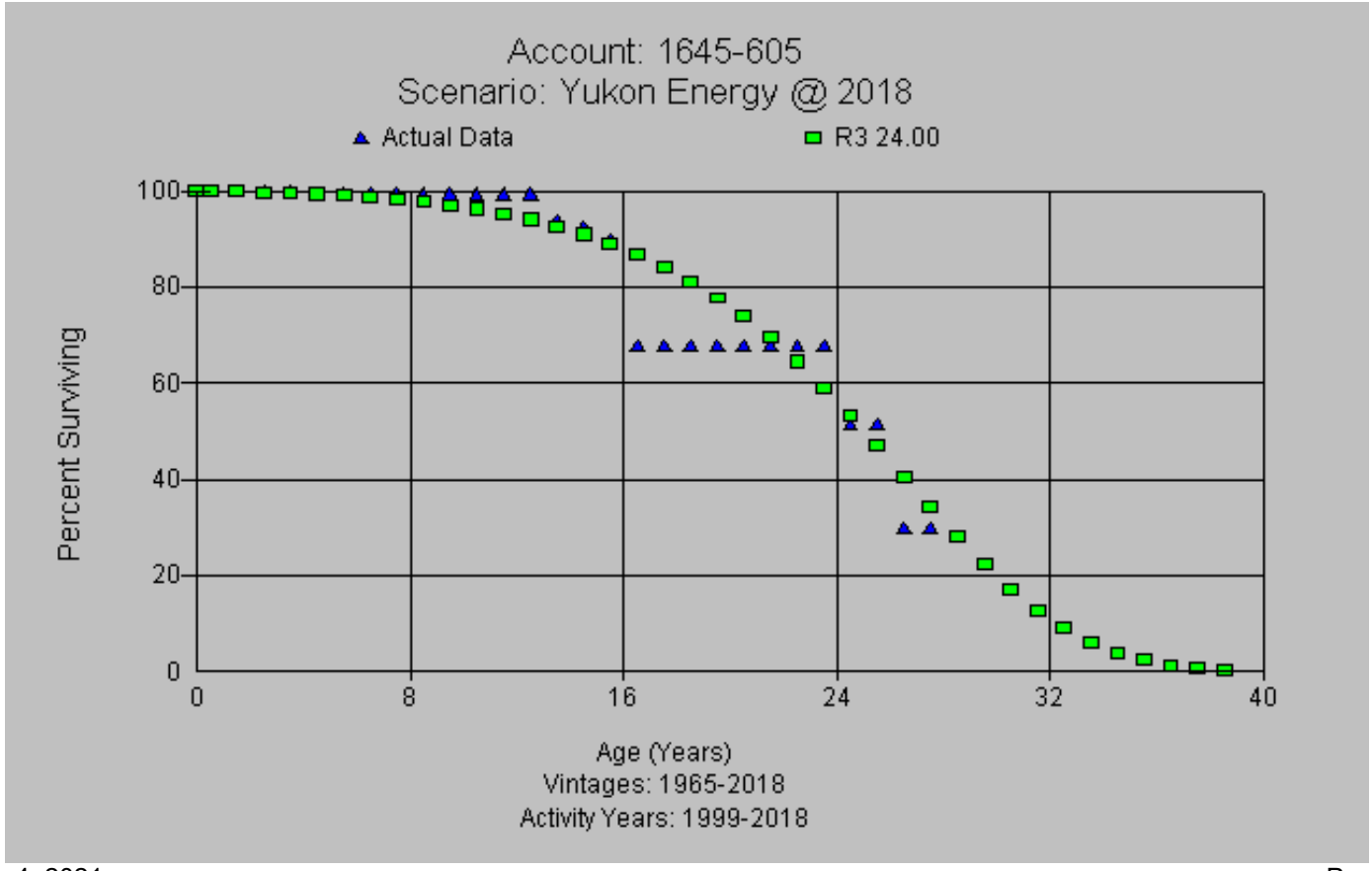

Account: 1645-605
Scenario: Yukon Energy @ 2018
Actual Data
R4 24.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1930-2018
Activity Years: 1999-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-605
Placement Band: 1930 - 2018 **Observation Band:** 1999 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	3,848,426.21	0.00	0.00000	1.00000	100.00
0.5	4,717,546.19	0.00	0.00000	1.00000	100.00
1.5	4,677,287.38	0.00	0.00000	1.00000	100.00
2.5	4,582,689.91	3,149.00	0.00069	0.99931	100.00
3.5	4,335,952.71	3,229.60	0.00074	0.99926	99.93
4.5	4,060,289.35	7,364.10	0.00181	0.99819	99.86
5.5	4,026,289.86	2,381.56	0.00059	0.99941	99.68
6.5	3,800,851.95	6,522.65	0.00172	0.99828	99.62
7.5	3,784,197.32	0.00	0.00000	1.00000	99.45
8.5	3,396,128.88	0.00	0.00000	1.00000	99.45
9.5	2,650,634.83	0.00	0.00000	1.00000	99.45
10.5	2,202,785.06	0.00	0.00000	1.00000	99.45
11.5	2,029,372.95	0.00	0.00000	1.00000	99.45
12.5	1,864,915.14	102,494.00	0.05496	0.94504	99.45
13.5	1,709,698.12	21,905.83	0.01281	0.98719	93.98
14.5	1,567,990.28	48,996.15	0.03125	0.96875	92.78
15.5	1,448,457.10	353,323.86	0.24393	0.75607	89.88
16.5	938,847.40	0.00	0.00000	1.00000	67.95
17.5	930,535.03	0.00	0.00000	1.00000	67.95
18.5	857,643.86	0.00	0.00000	1.00000	67.95
19.5	854,502.26	0.00	0.00000	1.00000	67.95
20.5	26,332.22	0.00	0.00000	1.00000	67.95
21.5	26,332.22	0.00	0.00000	1.00000	67.95
22.5	26,332.22	0.00	0.00000	1.00000	67.95
23.5	26,332.22	6,446.48	0.24481	0.75519	67.95
24.5	19,885.74	0.00	0.00000	1.00000	51.32
25.5	19,885.74	8,270.87	0.41592	0.58408	51.32
26.5	11,614.87	0.00	0.00000	1.00000	29.97
27.5	11,614.87	11,614.87	1.00000	0.00000	29.97
28.5	0.00	0.00	0.00000	1.00000	0.00

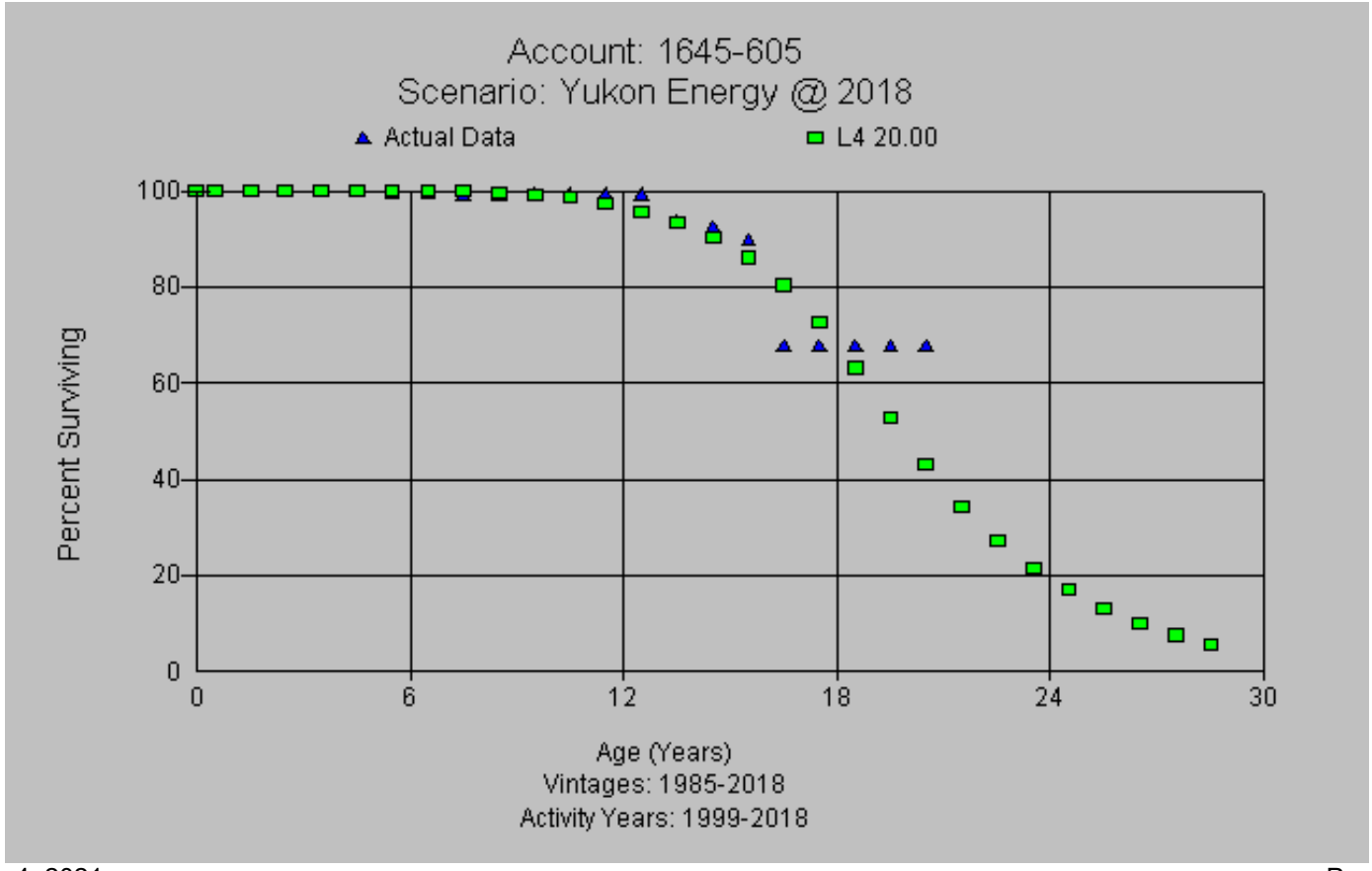

Account: 1645-605
Scenario: Yukon Energy @ 2018
Actual Data
L4 20.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1965-2018
Activity Years: 1999-2018

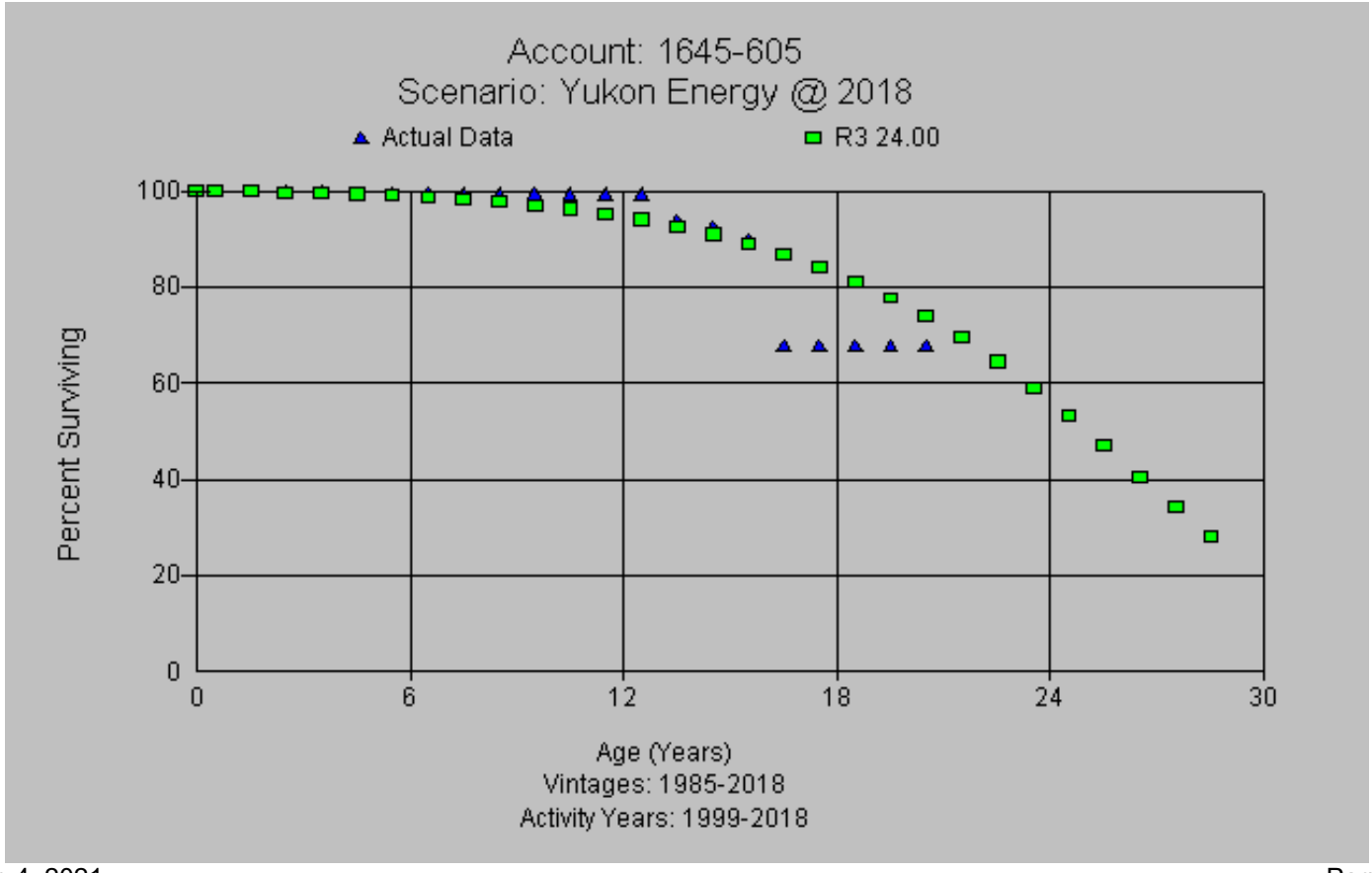

Account: 1645-605
Scenario: Yukon Energy @ 2018
Actual Data
R3 24.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1965-2018
Activity Years: 1999-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-605
Placement Band: 1965 - 2018 **Observation Band:** 1999 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	3,848,426.21	0.00	0.00000	1.00000	100.00
0.5	4,717,546.19	0.00	0.00000	1.00000	100.00
1.5	4,677,287.38	0.00	0.00000	1.00000	100.00
2.5	4,582,689.91	3,149.00	0.00069	0.99931	100.00
3.5	4,335,952.71	3,229.60	0.00074	0.99926	99.93
4.5	4,060,289.35	7,364.10	0.00181	0.99819	99.86
5.5	4,026,289.86	2,381.56	0.00059	0.99941	99.68
6.5	3,800,851.95	6,522.65	0.00172	0.99828	99.62
7.5	3,784,197.32	0.00	0.00000	1.00000	99.45
8.5	3,396,128.88	0.00	0.00000	1.00000	99.45
9.5	2,650,634.83	0.00	0.00000	1.00000	99.45
10.5	2,202,785.06	0.00	0.00000	1.00000	99.45
11.5	2,029,372.95	0.00	0.00000	1.00000	99.45
12.5	1,864,915.14	102,494.00	0.05496	0.94504	99.45
13.5	1,709,698.12	21,905.83	0.01281	0.98719	93.98
14.5	1,567,990.28	48,996.15	0.03125	0.96875	92.78
15.5	1,448,457.10	353,323.86	0.24393	0.75607	89.88
16.5	938,847.40	0.00	0.00000	1.00000	67.95
17.5	930,535.03	0.00	0.00000	1.00000	67.95
18.5	857,643.86	0.00	0.00000	1.00000	67.95
19.5	854,502.26	0.00	0.00000	1.00000	67.95
20.5	26,332.22	0.00	0.00000	1.00000	67.95
21.5	26,332.22	0.00	0.00000	1.00000	67.95
22.5	26,332.22	0.00	0.00000	1.00000	67.95
23.5	26,332.22	6,446.48	0.24481	0.75519	67.95
24.5	19,885.74	0.00	0.00000	1.00000	51.32
25.5	19,885.74	8,270.87	0.41592	0.58408	51.32
26.5	11,614.87	0.00	0.00000	1.00000	29.97
27.5	11,614.87	11,614.87	1.00000	0.00000	29.97
28.5	0.00	0.00	0.00000	1.00000	0.00

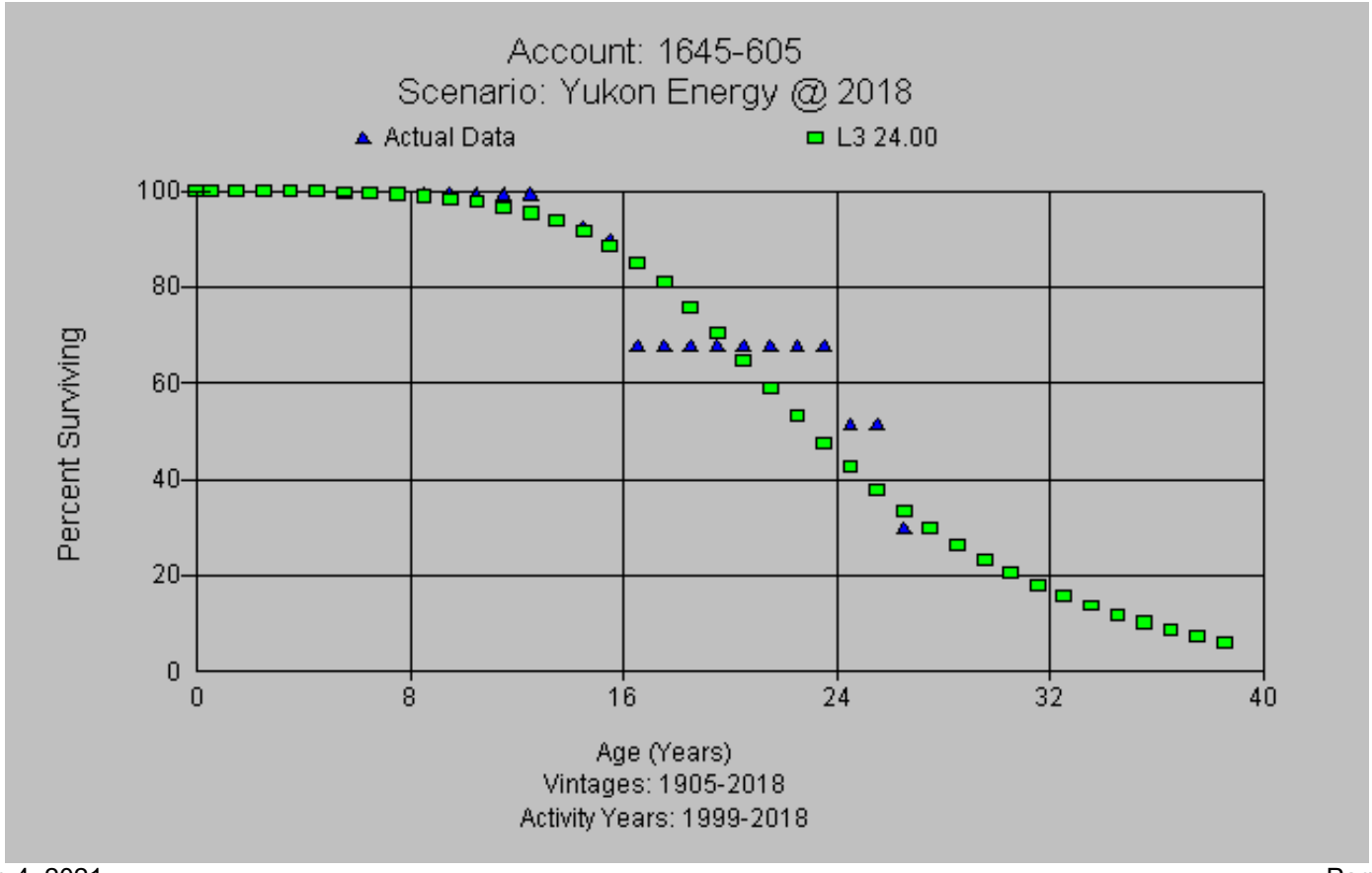

Account: 1645-605
Scenario: Yukon Energy @ 2018
Actual Data
L4 20.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1985-2018
Activity Years: 1999-2018

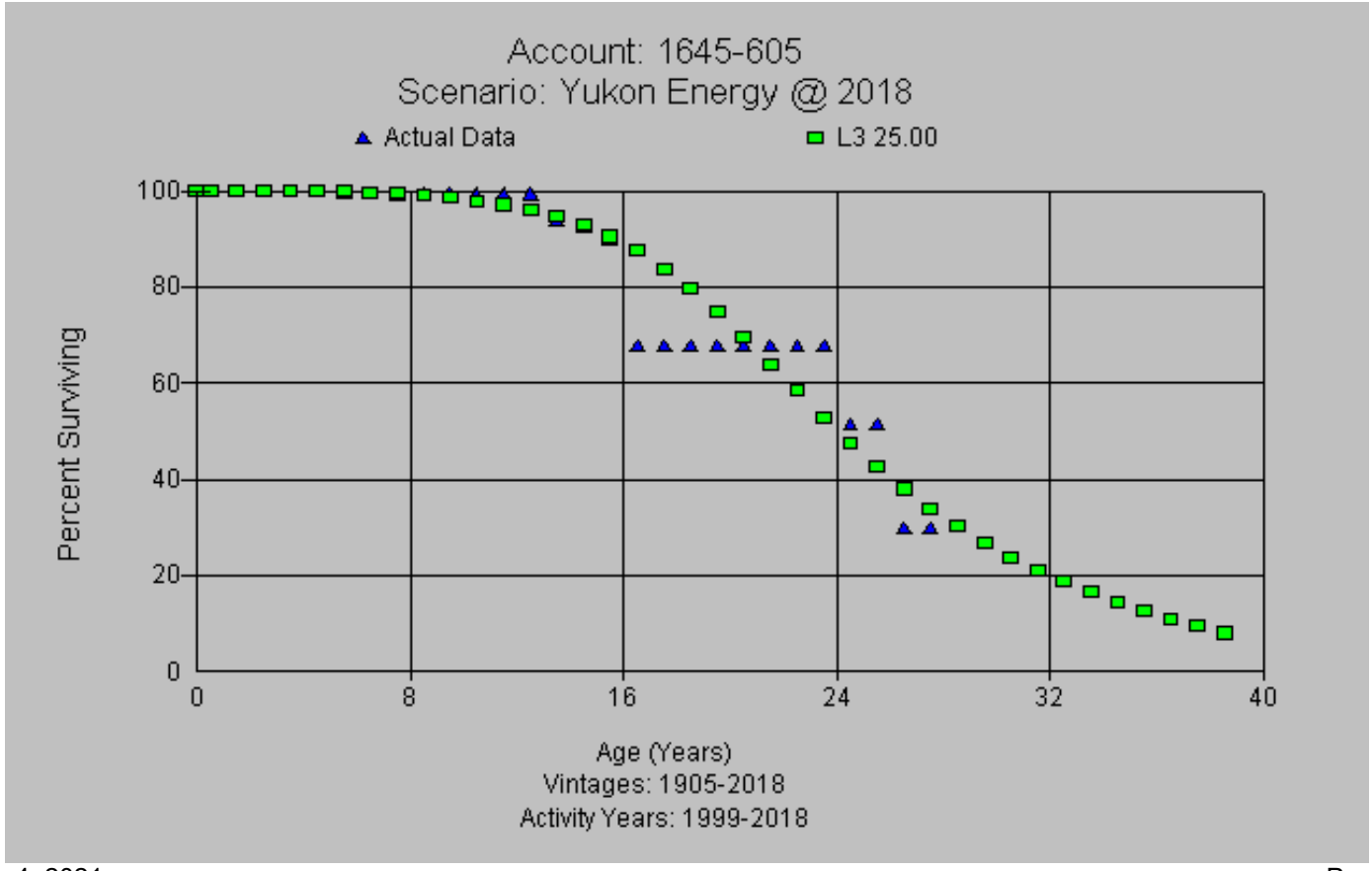

Account: 1645-605
Scenario: Yukon Energy @ 2018
Actual Data
R3 24.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1985-2018
Activity Years: 1999-2018

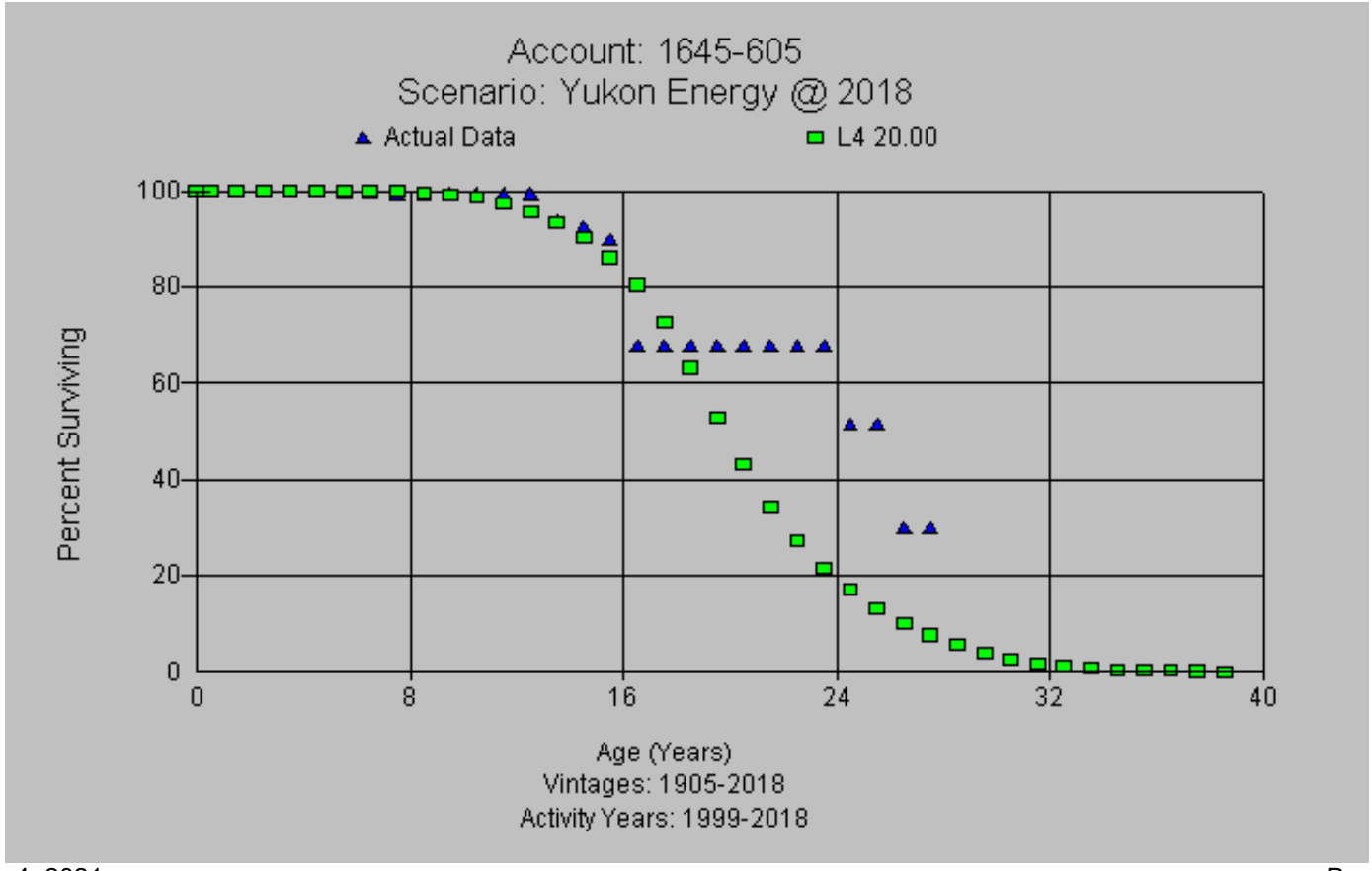
Observed Life Table

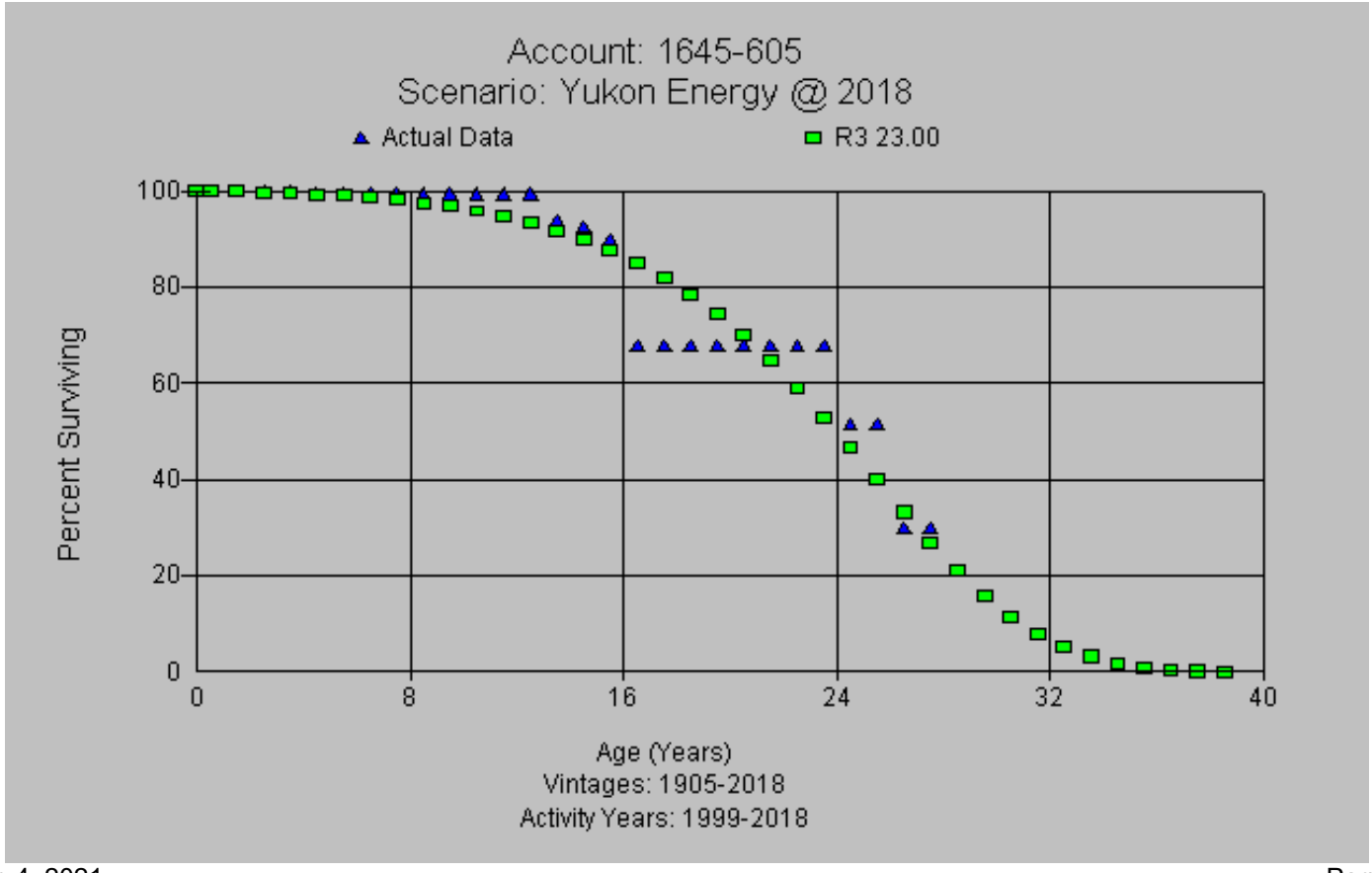
Scenario: Yukon Energy @ 2018
Account: 1645-605
Placement Band: 1985 - 2018 **Observation Band:** 1999 - 2018

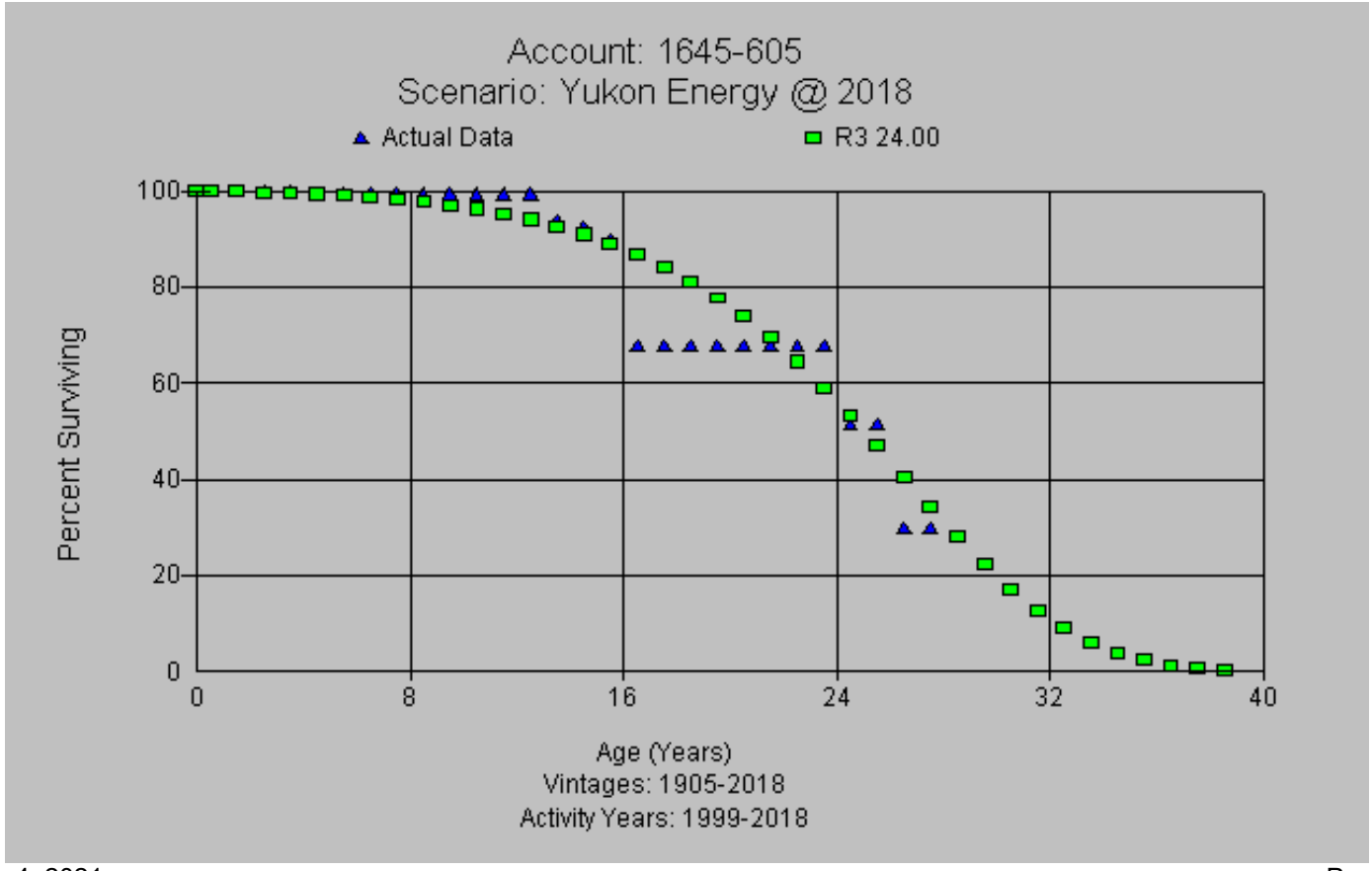
Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	3,848,426.21	0.00	0.00000	1.00000	100.00
0.5	4,717,546.19	0.00	0.00000	1.00000	100.00
1.5	4,677,287.38	0.00	0.00000	1.00000	100.00
2.5	4,582,689.91	3,149.00	0.00069	0.99931	100.00
3.5	4,335,952.71	3,229.60	0.00074	0.99926	99.93
4.5	4,060,289.35	7,364.10	0.00181	0.99819	99.86
5.5	4,026,289.86	2,381.56	0.00059	0.99941	99.68
6.5	3,800,851.95	6,522.65	0.00172	0.99828	99.62
7.5	3,784,197.32	0.00	0.00000	1.00000	99.45
8.5	3,396,128.88	0.00	0.00000	1.00000	99.45
9.5	2,650,634.83	0.00	0.00000	1.00000	99.45
10.5	2,202,785.06	0.00	0.00000	1.00000	99.45
11.5	2,029,372.95	0.00	0.00000	1.00000	99.45
12.5	1,864,915.14	102,494.00	0.05496	0.94504	99.45
13.5	1,709,698.12	21,905.83	0.01281	0.98719	93.98
14.5	1,567,990.28	48,996.15	0.03125	0.96875	92.78
15.5	1,448,457.10	353,323.86	0.24393	0.75607	89.88
16.5	938,847.40	0.00	0.00000	1.00000	67.95
17.5	930,535.03	0.00	0.00000	1.00000	67.95
18.5	831,311.64	0.00	0.00000	1.00000	67.95
19.5	828,170.04	0.00	0.00000	1.00000	67.95
20.5	0.00	0.00	0.00000	1.00000	67.95


Account: 1645-605
Scenario: Yukon Energy @ 2018
Actual Data
L3 24.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1905-2018
Activity Years: 1999-2018


Account: 1645-605
Scenario: Yukon Energy @ 2018
Actual Data
L3 25.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1905-2018
Activity Years: 1999-2018


Account: 1645-605
Scenario: Yukon Energy @ 2018
Actual Data
L4 20.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1905-2018
Activity Years: 1999-2018


Account: 1645-605
Scenario: Yukon Energy @ 2018
Actual Data
R3 23.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1905-2018
Activity Years: 1999-2018


Account: 1645-605
Scenario: Yukon Energy @ 2018
Actual Data
R3 24.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1905-2018
Activity Years: 1999-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-605
Placement Band: 1905 - 2018 **Observation Band:** 1999 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	3,848,426.21	0.00	0.00000	1.00000	100.00
0.5	4,717,546.19	0.00	0.00000	1.00000	100.00
1.5	4,677,287.38	0.00	0.00000	1.00000	100.00
2.5	4,582,689.91	3,149.00	0.00069	0.99931	100.00
3.5	4,335,952.71	3,229.60	0.00074	0.99926	99.93
4.5	4,060,289.35	7,364.10	0.00181	0.99819	99.86
5.5	4,026,289.86	2,381.56	0.00059	0.99941	99.68
6.5	3,800,851.95	6,522.65	0.00172	0.99828	99.62
7.5	3,784,197.32	0.00	0.00000	1.00000	99.45
8.5	3,396,128.88	0.00	0.00000	1.00000	99.45
9.5	2,650,634.83	0.00	0.00000	1.00000	99.45
10.5	2,202,785.06	0.00	0.00000	1.00000	99.45
11.5	2,029,372.95	0.00	0.00000	1.00000	99.45
12.5	1,864,915.14	102,494.00	0.05496	0.94504	99.45
13.5	1,709,698.12	21,905.83	0.01281	0.98719	93.98
14.5	1,567,990.28	48,996.15	0.03125	0.96875	92.78
15.5	1,448,457.10	353,323.86	0.24393	0.75607	89.88
16.5	938,847.40	0.00	0.00000	1.00000	67.95
17.5	930,535.03	0.00	0.00000	1.00000	67.95
18.5	857,643.86	0.00	0.00000	1.00000	67.95
19.5	854,502.26	0.00	0.00000	1.00000	67.95
20.5	26,332.22	0.00	0.00000	1.00000	67.95
21.5	26,332.22	0.00	0.00000	1.00000	67.95
22.5	26,332.22	0.00	0.00000	1.00000	67.95
23.5	26,332.22	6,446.48	0.24481	0.75519	67.95
24.5	19,885.74	0.00	0.00000	1.00000	51.32
25.5	19,885.74	8,270.87	0.41592	0.58408	51.32
26.5	11,614.87	0.00	0.00000	1.00000	29.97
27.5	11,614.87	11,614.87	1.00000	0.00000	29.97
28.5	0.00	0.00	0.00000	1.00000	0.00
29.5	0.00	0.00	0.00000	1.00000	
30.5	0.00	0.00	0.00000	1.00000	
31.5	0.00	0.00	0.00000	1.00000	
32.5	0.00	0.00	0.00000	1.00000	
33.5	0.00	0.00	0.00000	1.00000	
34.5	0.00	0.00	0.00000	1.00000	
35.5	0.00	0.00	0.00000	1.00000	
36.5	0.00	0.00	0.00000	1.00000	
37.5	0.00	0.00	0.00000	1.00000	

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-605
Placement Band: 1905 - 2018 **Observation Band:** 1999 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
93.5	13,623.13	0.00	0.00000	1.00000	
94.5	13,623.13	0.00	0.00000	1.00000	
95.5	13,623.13	0.00	0.00000	1.00000	
96.5	13,623.13	0.00	0.00000	1.00000	
97.5	13,623.13	0.00	0.00000	1.00000	
98.5	13,623.13	0.00	0.00000	1.00000	
99.5	13,623.13	0.00	0.00000	1.00000	
100.5	13,623.13	0.00	0.00000	1.00000	
101.5	13,623.13	13,623.13	1.00000	0.00000	
102.5	0.00	0.00	0.00000	1.00000	

Actuarial Life Analysis

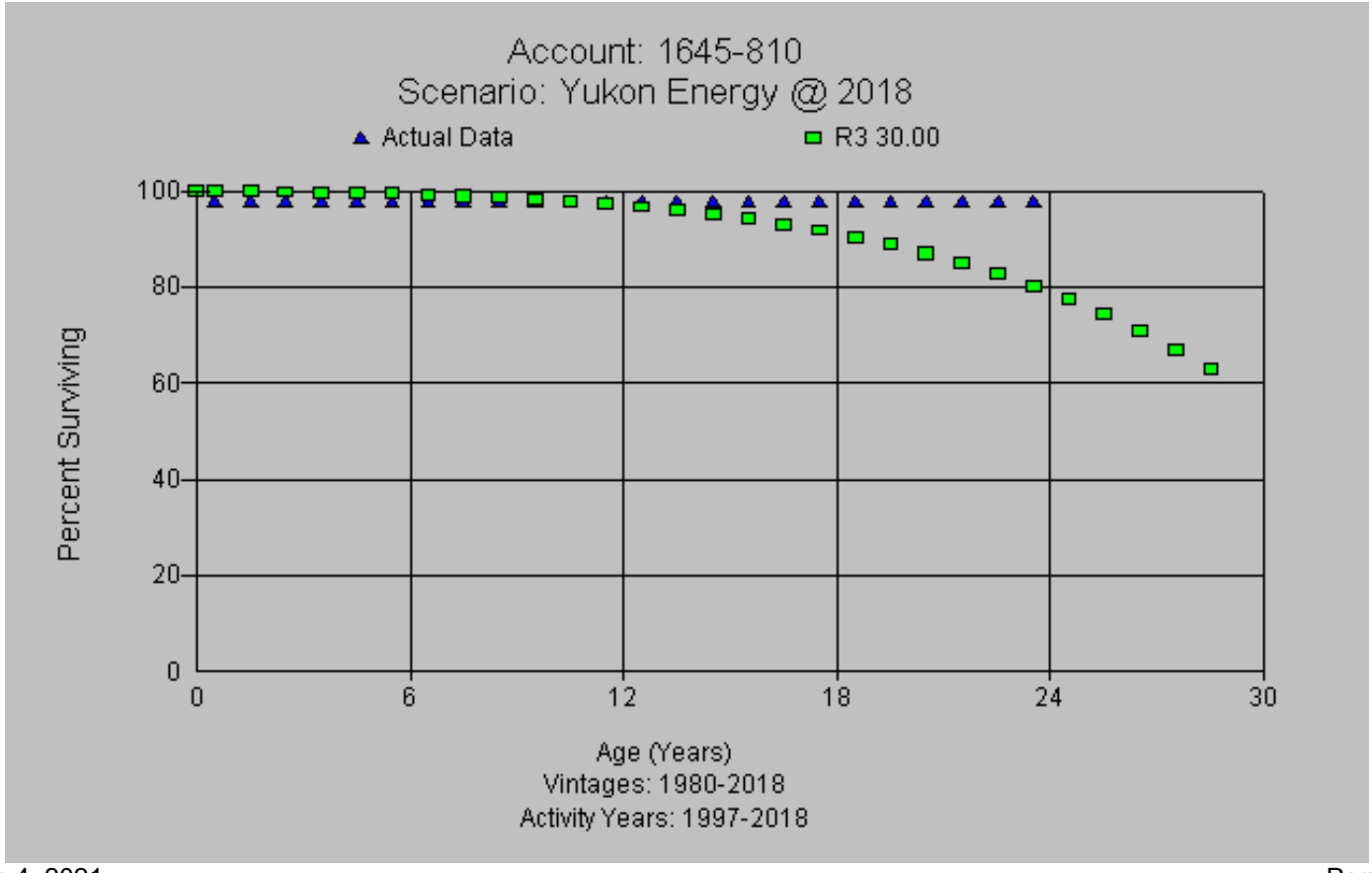
Account: 1645-605
Scenario: Yukon Energy @ 2018
Placement Band: 1905 - 2003
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1999 -2003	27.5	0.00	0.00000000	SQ	13.20
2000 -2004	28.5	75.52	0.05746112	S3	33.65
2001 -2005	29.5	75.52	0.06311200	S3	33.91
2002 -2006	30.5	44.11	0.15810696	S4	27.86
2003 -2007	31.5	0.00	0.18359325	S4	27.12
2004 -2008	32.5	0.00	0.14526755	S6	24.67
2005 -2009	33.5	0.00	0.21603292	S6	25.44
2006 -2010	34.5	0.00	0.26019931	S6	25.25
2007 -2011	35.5	0.00	0.49953206	S6	26.25
2008 -2012	36.5	0.00	0.00158949	SQ	26.86
2009 -2013		1.00			
2010 -2014	38.5	66.22	0.28513787	L0	47.87
2011 -2015	39.5	66.51	0.29390035	L0	48.80
2012 -2016	40.5	68.83	0.26965596	L0	52.38
2013 -2017	41.5	66.51	0.31191253	L0	49.57
2014 -2018	42.5	62.98	0.39170672	L0	45.90

Actuarial Life Analysis

Account: 1645-605
Scenario: Yukon Energy @ 2018
Placement Band: 1905 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1999 -2018	58.5	0.00	0.21099765	R3	22.83
2004 -2018	58.5	0.00	0.21270185	R4	23.38
2009 -2018	58.5	72.31	0.47008823	R0.5	63.42
2014 -2018	58.5	62.98	0.83510651	L0	55.59


Account: 1645-810
Scenario: Yukon Energy @ 2018
Actual Data
R3 30.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1997-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-810
Placement Band: 1980 - 2018 **Observation Band:** 1997 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	60,274.37	1,243.00	0.02062	0.97938	100.00
0.5	36,511.62	0.00	0.00000	1.00000	97.94
1.5	36,511.62	0.00	0.00000	1.00000	97.94
2.5	36,511.62	0.00	0.00000	1.00000	97.94
3.5	36,511.62	0.00	0.00000	1.00000	97.94
4.5	36,511.62	0.00	0.00000	1.00000	97.94
5.5	36,511.62	0.00	0.00000	1.00000	97.94
6.5	36,511.62	0.00	0.00000	1.00000	97.94
7.5	36,511.62	0.00	0.00000	1.00000	97.94
8.5	36,511.62	0.00	0.00000	1.00000	97.94
9.5	36,511.62	0.00	0.00000	1.00000	97.94
10.5	36,511.62	0.00	0.00000	1.00000	97.94
11.5	36,511.62	0.00	0.00000	1.00000	97.94
12.5	36,511.62	0.00	0.00000	1.00000	97.94
13.5	36,511.62	0.00	0.00000	1.00000	97.94
14.5	14,156.23	0.00	0.00000	1.00000	97.94
15.5	14,156.23	0.00	0.00000	1.00000	97.94
16.5	36,656.23	0.00	0.00000	1.00000	97.94
17.5	32,500.00	0.00	0.00000	1.00000	97.94
18.5	32,500.00	0.00	0.00000	1.00000	97.94
19.5	22,500.00	0.00	0.00000	1.00000	97.94
20.5	22,500.00	0.00	0.00000	1.00000	97.94
21.5	22,500.00	0.00	0.00000	1.00000	97.94
22.5	22,500.00	0.00	0.00000	1.00000	97.94
23.5	22,500.00	22,500.00	1.00000	0.00000	97.94
24.5	0.00	0.00	0.00000	1.00000	0.00

Actuarial Life Analysis

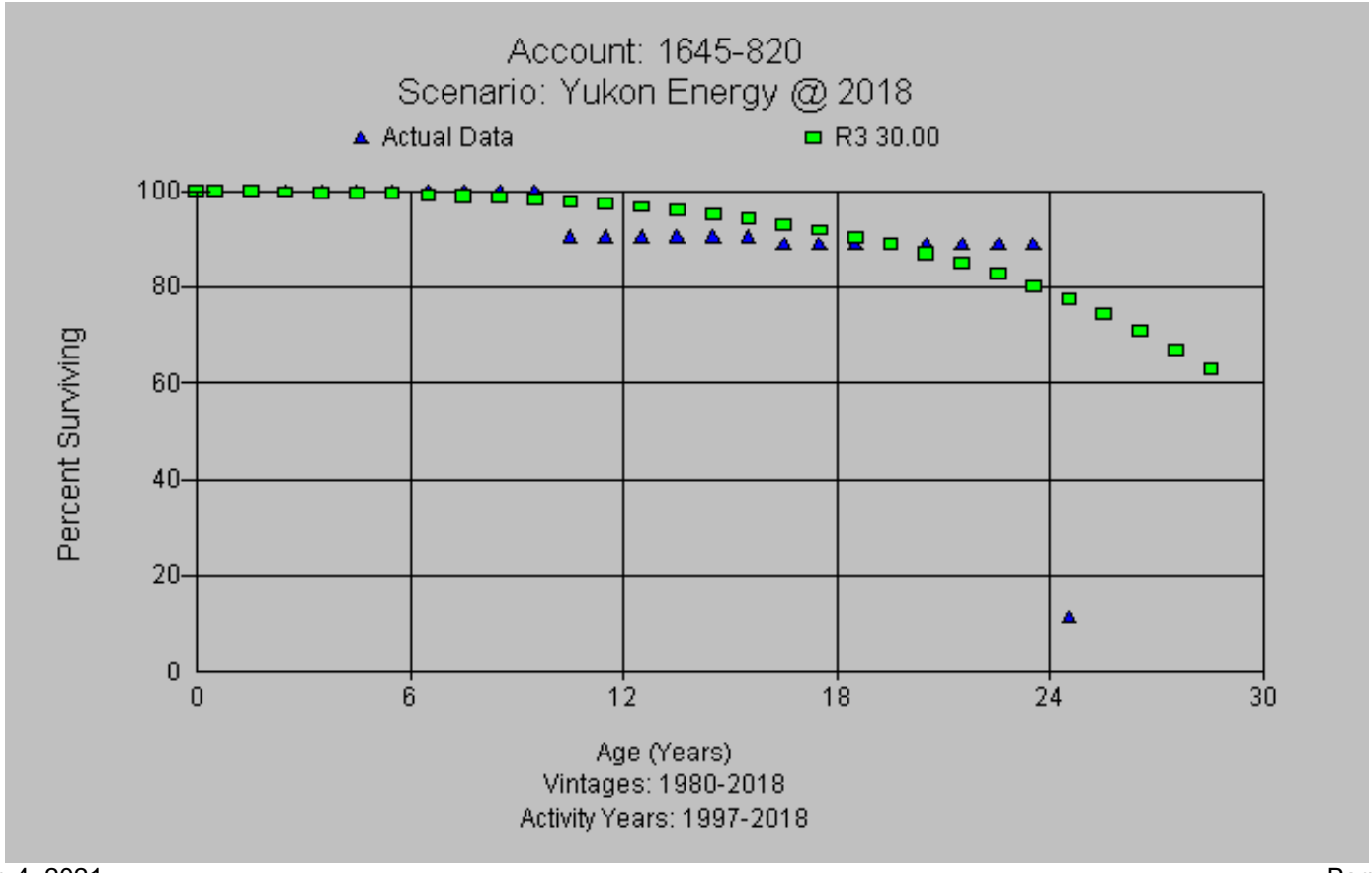
Account: 1645-810
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2001
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

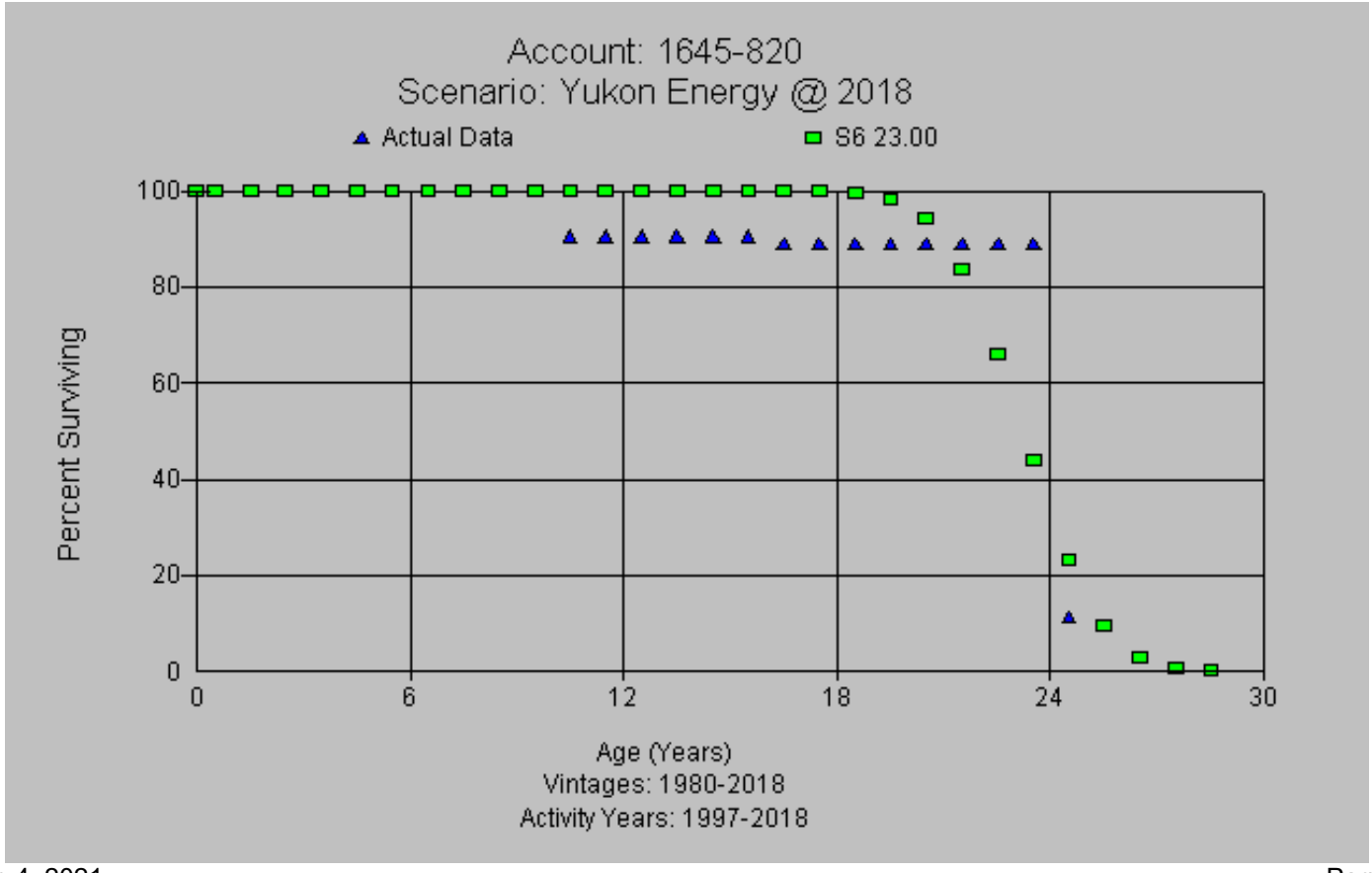
Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1997 -2001	17.5	91.93	0.04271874	R0.5	44.18
1998 -2002		1.00			
1999 -2003		1.00			
2000 -2004	20.5	0.00	0.00000000	SQ	20.20
2001 -2005	21.5	0.00	0.00000000	SQ	20.20
2002 -2006	22.5	0.00	0.00000000	SQ	20.20
2003 -2007	23.5	0.00	0.00000000	SQ	20.20
2004 -2008	24.5	0.00	0.00000000	SQ	20.20
2005 -2009		0.00			
2006 -2010		0.00			
2007 -2011		0.00			
2008 -2012		0.00			
2009 -2013		0.00			
2010 -2014		0.00			
2011 -2015		0.00			
2012 -2016		0.00			
2013 -2017		0.00			
2014 -2018		1.00			

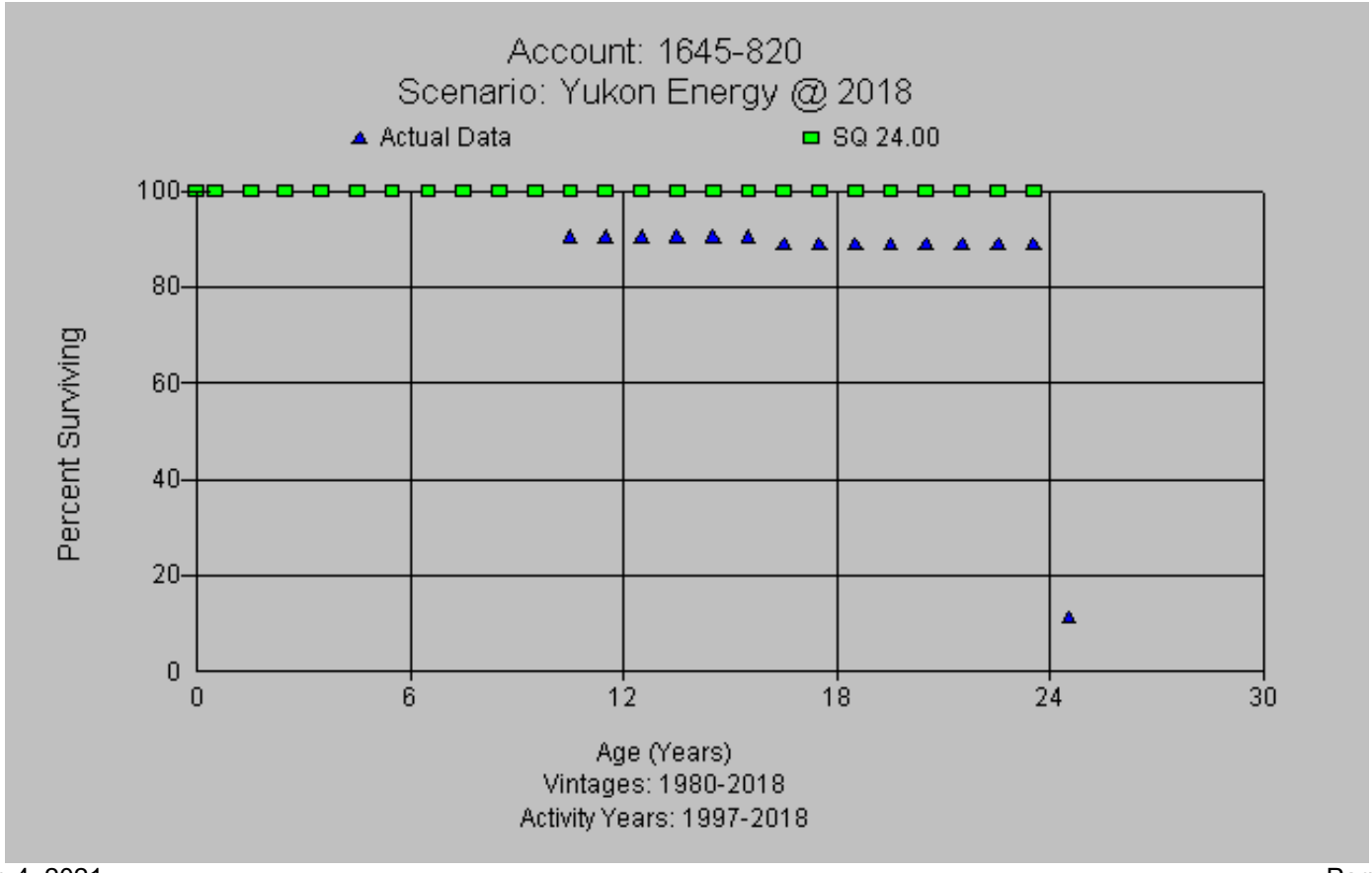
Actuarial Life Analysis

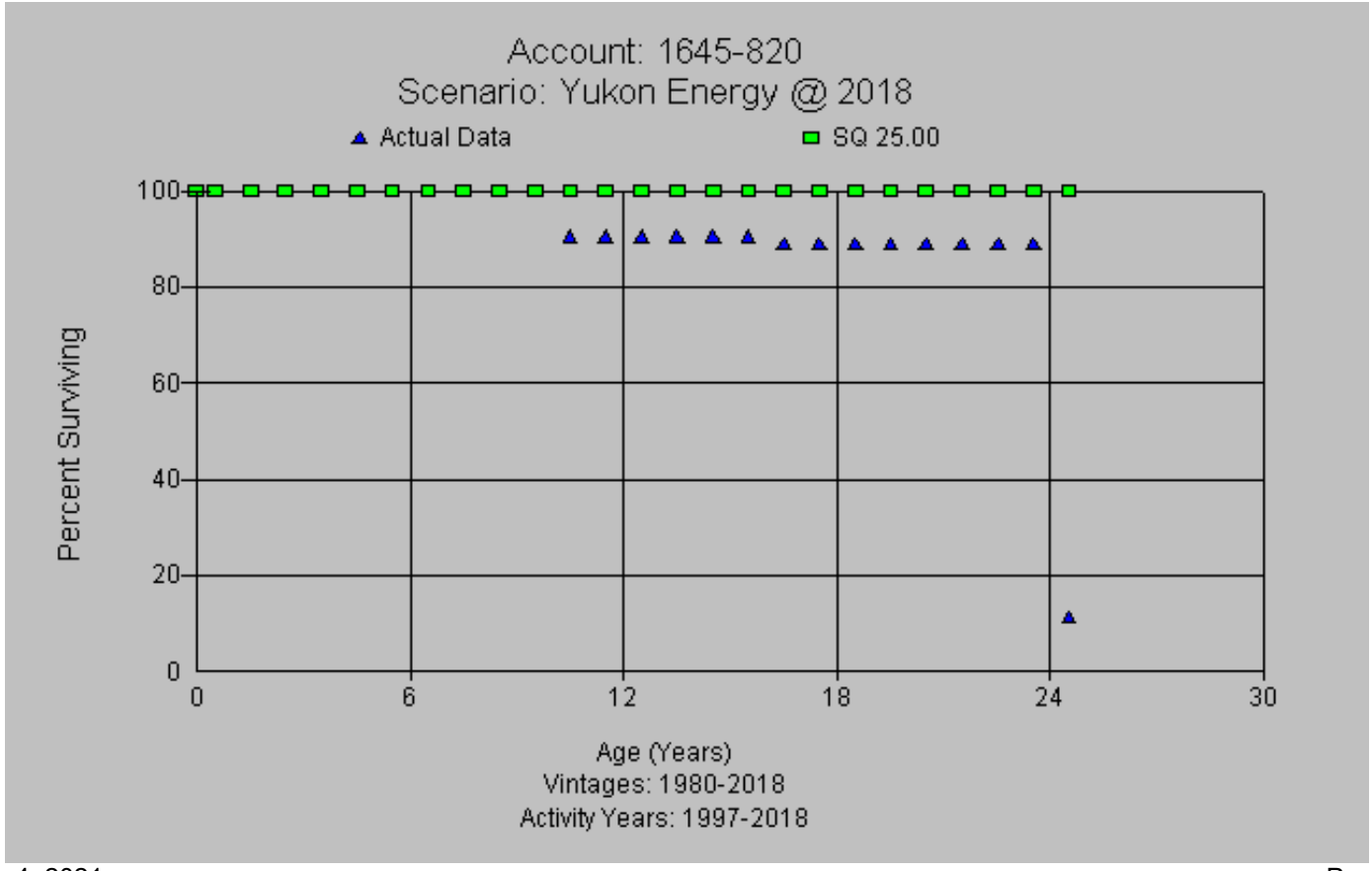
Account: 1645-810
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1997 -2018	38.5	0.00	0.01018466	SQ	23.56
2002 -2018	38.5	0.00	0.00000000	SQ	24.20
2007 -2018		1.00			
2012 -2018		1.00			
2017 -2018		1.00			


Account: 1645-820
Scenario: Yukon Energy @ 2018
Actual Data
R3 30.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1997-2018


Account: 1645-820
Scenario: Yukon Energy @ 2018
Actual Data
S6 23.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1997-2018


Account: 1645-820
Scenario: Yukon Energy @ 2018
Actual Data
SQ 24.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1997-2018


Account: 1645-820
Scenario: Yukon Energy @ 2018
Actual Data
SQ 25.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1997-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-820
Placement Band: 1980 - 2018 **Observation Band:** 1997 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	2,065,359.72	0.00	0.00000	1.00000	100.00
0.5	1,827,443.60	0.00	0.00000	1.00000	100.00
1.5	1,827,443.60	0.00	0.00000	1.00000	100.00
2.5	1,827,443.60	0.00	0.00000	1.00000	100.00
3.5	1,827,443.60	0.00	0.00000	1.00000	100.00
4.5	1,495,770.65	0.00	0.00000	1.00000	100.00
5.5	1,484,542.31	0.00	0.00000	1.00000	100.00
6.5	1,421,362.21	0.00	0.00000	1.00000	100.00
7.5	1,421,362.21	0.00	0.00000	1.00000	100.00
8.5	1,421,362.21	0.00	0.00000	1.00000	100.00
9.5	1,569,537.21	148,175.00	0.09441	0.90559	100.00
10.5	1,421,362.21	0.00	0.00000	1.00000	90.56
11.5	879,540.05	0.00	0.00000	1.00000	90.56
12.5	879,540.05	0.00	0.00000	1.00000	90.56
13.5	879,540.05	0.00	0.00000	1.00000	90.56
14.5	879,540.05	0.00	0.00000	1.00000	90.56
15.5	879,540.05	13,590.50	0.01545	0.98455	90.56
16.5	1,042,429.32	0.00	0.00000	1.00000	89.16
17.5	1,042,429.32	0.00	0.00000	1.00000	89.16
18.5	1,003,018.24	0.00	0.00000	1.00000	89.16
19.5	1,003,018.24	0.00	0.00000	1.00000	89.16
20.5	176,479.77	0.00	0.00000	1.00000	89.16
21.5	176,479.77	0.00	0.00000	1.00000	89.16
22.5	176,479.77	0.00	0.00000	1.00000	89.16
23.5	176,479.77	154,097.22	0.87317	0.12683	89.16
24.5	22,382.55	22,382.55	1.00000	0.00000	11.31
25.5	0.00	0.00	0.00000	1.00000	0.00

Actuarial Life Analysis

Account: 1645-820
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 1984
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -1984		1.00			
1981 -1985		1.00			
1982 -1986		1.00			
1983 -1987		1.00			
1984 -1988		1.00			
1985 -1989		1.00			
1986 -1990		1.00			
1987 -1991		1.00			
1988 -1992		1.00			
1989 -1993		1.00			
1990 -1994		1.00			
1991 -1995		1.00			
1992 -1996		1.00			
1993 -1997	15.5	0.00	0.00000000	SQ	10.39
1994 -1998	16.5	0.00	0.00000000	SQ	10.39
1995 -1999	17.5	0.00	0.00000000	SQ	10.39
1996 -2000	18.5	0.00	0.00000000	SQ	10.39
1997 -2001	19.5	0.00	0.00000000	SQ	10.39
1998 -2002		1.00			
1999 -2003		1.00			
2000 -2004	22.5	12.68	0.00010913	SQ	22.31
2001 -2005		12.68			
2002 -2006		12.68			
2003 -2007	23.5	0.00	0.05743508	SQ	20.37
2004 -2008	24.5	0.00	0.05743508	SQ	20.37
2005 -2009	25.5	0.00	0.00000000	SQ	21.20
2006 -2010		1.00			
2007 -2011		1.00			
2008 -2012		1.00			
2009 -2013		1.00			
2010 -2014	30.5	98.38	0.00059827	R2	194.54
2011 -2015	31.5	98.38	0.00061547	R2	196.40
2012 -2016	32.5	98.45	0.00058214	R2	206.09
2013 -2017	33.5	98.45	0.00060399	R2	208.44
2014 -2018	34.5	98.45	0.00062909	R2	210.99

Actuarial Life Analysis

Account: 1645-820
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -2018	38.5	0.00	0.49164993	S6	22.88
1985 -2018	38.5	0.00	0.49164993	S6	22.88
1990 -2018	38.5	0.00	0.49164993	S6	22.88
1995 -2018	38.5	0.00	0.50797648	R5	22.75
2000 -2018	38.5	0.00	0.01752201	SQ	24.25
2005 -2018	38.5	0.00	0.00216225	SQ	24.91
2010 -2018	38.5	98.45	0.00069359	R2	238.10
2015 -2018		1.00			

Sum of Amount				
Account	**Transaction**	**TR Year**	**Vintage**	**Total**
1620-200	**Retirement**	1991	1987	(12,139.00)
		2004	1980	(3,533.63)
		2005	1980	(7,902.28)
		2009	2008	(13,264.20)
1620-403	**Retirement**	1989	1987	(2,650.00)
		1991	1987	(9,223.00)
		1997	1997	(8,000.00)
1620-500	**Retirement**	1992	1987	(5,755.00)
		1996	1971	(36,260.00)
		2000	1987	(24,998.00)
		2004	1980	(4,281.81)
		2007	1903	(5,591.97)
		2010	1980	(40,371.98)
		2012	2011	(491,142.60)
		2014	1998	(664,937.58)
		2015	2000	(762.75)
			2002	(13,177.89)
			2008	(10,238.18)
1620-600	**Retirement**	1996	1970	(7,596.00)
		1997	1981	(59,569.00)
		2004	1980	(12,379.55)
		2005	1980	(4,561.86)
		2006	1980	(71,034.43)
		2007	1953	(103,064.19)
		2015	1998	(10,782.17)
1620-700	**Retirement**	2009	2009	(212,846.68)
		2015	1998	(10,841.08)
Grand Total				**(1,846,904.83)**

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-22**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1615-201 Hydro Buildings and Improvements 40 R2.5

This account is a newly created group. In 2019, an asset previously booked in account 1645-200, Buildings- Structures and Improvements. The asset is an elevator at Aishihik Hydro plant. The plant balance in this account will be $10.3 million. The approved life and curve for this account is 40 R2.5. Based on information provided by Company personnel and judgment, this study recommends retaining the existing 40 R2.5 for this account."

QUESTION:

a) Please provide further rationale for the proposed 40-R2.5 life and curve for Account 1615-201, which is a "newly created group" of assets that were previously within Account 1645-200 and for which YEC is now proposing a 50-R2 life and curve.

b) Please clarify the specific information provided by Company personnel that supports a 40-R2.5 life and curve for this account.

ANSWER:

(a)

The elevator that YEC moved to this new account is dissimilar (both in characteristics and life) to other building assets in the originating account such as berms, roads, boilers, etc. Mr. Dane Watson, Managing Partner of Alliance Consulting Group is a Professional Engineer in the State of Texas and Certified Depreciation Professional. In Mr. Watson's professional opinion, the majority of elevator components would have a shorter life than the 50 years in its original account. Mr. Watson inspected those facilities on a site visit in 2019. Using his professional judgment, Mr. Watson estimated a decrease in life of 10 years as compared to its originating account and increased the amplitude of the Iowa Curve from an R2 to an R2.5 to reflect slightly more homogeneous asset characteristics.

(b)

Other than the inspection, information on the transfer and description of the asset, no other information was received by Alliance Consulting Group.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-24**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1615-506 Hydro Water Wheels, Turbines, and Generators 60 R3

This account consists of water wheels, turbines, and other related assets used in hydro production including runners, gates, regulator systems, generator cooling systems, and generators. The plant balance in this account at December 31, 2018 is $26.3 million. The approved life and curve for this account is 85 R3. Operational personnel stated the approved life is too long, and that they have already replaced runners and rewound generators prior to reaching 60 years. There was insufficient transactional data for an actuarial life analysis. Based on information provided by Company personnel, this study recommends decreasing the life to 60 years and retaining the R3 curve for this account."

PREAMBLE: YEC is proposing a significant reduction (of 25 years) in average service life for this account.

QUESTION:

a) Please provide the dollar amount of retirements by transaction year and vintage for the years 1998-2018.

ANSWER:

(a)

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.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-25**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1615-600 Hydro Accessory Electrical Equipment 40 R2.5
This account consists of generator controls, bus equipment, and other related assets used in hydro production including auxiliary generators, switching equipment, excitation systems, and station control systems. The plant balance in this account at December 31, 2018 is $26.6 million. The approved life and curve for this account is 45 R3. Based on information provided by Company personnel and the indications from the actuarial analysis, this study recommends decreasing the life to 40 years and moving to an R2.5 curve for this account."

QUESTION:

a) Please clarify the specific information provided by Company personnel that supports a reduction (of five years) in average service life for this account.

ANSWER:

(a)

Documented information is shown below.

YEC's fixed asset catalog provides the following description of various assets in this account.

> This account shall include the installation costs of auxiliary generating apparatus, conversion equipment and equipment used primarily in connection with the control and switching of electric energy produced by hydraulic power and the protection of electric circuits and equipment, except electric motors used to drive equipment included in other accounts, such motors being included in the account in which the equipment with which they are associated is included.

Note A: do not include in this account transformers and other equipment used for changing the voltage or frequency of electricity for the purpose of transmission or distribution.

Note B: when any item of equipment listed herein is used wholly to furnish power to equipment, it shall be included in such equipment accounts.

Components of cost:

1. Auxiliary generators, including boards, compartments, switching equipment, control equipment and connections to auxiliary power bus.
2. Excitation system, including motor, turbine and dual-drive exciter sets and rheostats, storage batteries and charging equipment, circuit breakers, panels and accessories, knife switches and accessories, surge arrestors, instrument shunts, conductors and conduit, special supports for conduit generator field and exciter switch panels, exciter bus tie panels, generator and exciter rheostats, special housings, protective screens, etc.

3. Generator main connections, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks current transformers, potential transformers conductors and conduit special support for generator main leads, grounding switch, special housings, protective screens, etc. station buses, including main auxiliary, transfer, synchronizing and fault ground buses, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, reactors and accessories voltage regulators and accessories, compensators, resistors, starting transformers, current transformers potential transformers, protective relays, storage batteries and charging equipment; isolated panels and equipment, conductors and conduit, special supports, special fire extinguishing equipment and test equipment.

4. Station control system including station switchboards with panel wiring panels with instruments and control equipment only, panels with switching equipment mounted or mechanically connected, truck-type

switchboards complete, cubicles, station supervisory control devices, frequency control equipment, master clocks, watt-hour meter, station totalizing watt meter, storage batteries panels and charging sets, instrument and transformers for supervisory metering, conductors and conduit, special supports for conduit, switchboards, batteries, special housing for batteries, protective screens, etc.

During informal discussions in the interview process and site visits, Company SMEs related that they are seeing operational lives decreasing for many of the components (especially electronic) in this account. They concurred with the limited actuarial analysis indications that the overall operational life for assets in this account were decreasing slightly. The formal interview notes document that Company personnel indicated that given the components in this account, a slight reduction in the life of this account was appropriate.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-32**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1620-403 Diesel Fuel Holders, Producers, and Accessories 40 R2
This account consists of pumps, storage tanks, natural gas/fuel oil piping and other related assets at the diesel production plants. The plant balance in this account at December 31, 2018 is $1.7 million. The approved life and curve for this account is 25 R2. Discussions with operational personnel stated the existing life seems short, that many of the existing assets are approximately 15 to 20 years old, are still reliable, and not currently in need of replacement. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends increasing to a 40 year life and retaining the existing R2 curve for this account."

QUESTION:

a) Please clarify that the observations made by Company personnel supporting an increase (of 15 years) in average service life are generally applicable to all assets in this account.

ANSWER:

(a)

The statements above was not necessarily intended to apply to every component in this account. Below is an extract from the Company's capital assets accounting manual.

This account shall include the installation costs of fuel handling and storage equipment used between the point of fuel delivery to the station and the intake pipe through which fuel is directly drawn to the engine and the cost of gas producers and accessories devoted to the production of gas for use in prime movers driving main electric generators.

Components of cost:

1. Coils;

2. Heating piping and valves;

3. Pumps;

4. Fuel scrubbing equipment; and

5. Tanks and fuel oil storage.

With input from the SMEs that many of the assets are nearing the current average service life, there were no concerns with reliability and no plans in place to begin replacement, an extension in life was appropriate and found reasonable by Company SMEs. Based on SME input that some items would likely last 60 years (i.e., Nickel, double walled tanks with no moisture ingress) and Mr. Watson's experience with similar accounts over 35 years, using judgement, a 15-year increase was recommended. With group accounting for utility property, the goal is to establish an average service life for the entire group given the mix of assets and lives within the group.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-37**

ISSUE: **Depreciation expense**

QUOTE: "Account 1625-300 Dist. System - Poles and Fixtures 40 R2

This account consists of the installation costs of poles and fixtures used for supporting overhead distribution conductors and service wire. The plant balance in this account at December 31, 2018 is $8 million. The approved life and curve for this account is 35 R2. Discussions with operational personnel stated that right of ways are narrower for distribution, putting the poles closer to vehicles and making them more susceptible to being damaged. Additionally, permafrost puts more stress on the shorter, lower class poles. Overall, operations estimates the life of distribution poles to be 10 years less than transmission poles, which use a life of 50 years. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 40 R2 for this account.

PREAMBLE: Statements in the above quote appear to conflict with YEC's proposed increase (of 5 years) in average service life for this account.

QUESTION:

a) Please clarify how the increased susceptibility to damage from narrow rights-of-way and permafrost to YEC's distribution system poles and fixtures is consistent with a proposed increase (of five years) in average service life for this account.

ANSWER:

(a)

The discussion above is contrasting the life of distribution poles with those of transmission poles. The current (and proposed) life of transmission poles is 50 years. The discussion notes the reasons that distribution poles would have a shorter life than transmission poles. A 35-year life for distribution poles is low compared to industry experience based on

Alliance Consulting Group's work across North America. A slight increase in life was discussed with operations personnel. Based on the noted discussion, a 10-year spread between transmission and distribution pole life was thought appropriate both to the Company SMEs and Alliance. The 5-year increase was to move the distribution pole life to 40 years as compared to the 50-year life of transmission poles.

REFERENCE: **Application, Tab 9, Depreciation Study, pages 9-38 and 9-40**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1625-304 Dist. System - Brushing 50 R2
This account consists of costs associated with the brushing of the distribution system. The plant balance in this account at December 31, 2018 is $45 thousand. The approved life and curve for this account is 50 R2. The Company capitalizes the brush clearing of ROWs when installing new lines. Operations stated the existing life is reasonable and matches the life of O/H Conductor, which have a 50 year life."

"Account 1625-401 Dist. System – O/H Conductors 50 R2
This account consists of overhead conductors and other facilities associated with the distribution system. The plant balance in this account at December 31, 2018 is $75 thousand. The approved life and curve for this account is 35 R2. Discussions with operational personnel stated they would expect the life of distribution conductor to be shorter than transmission conductor. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends increasing the life to 50 years while retaining the R2 curve for this account."

QUESTION:

a) Notwithstanding YEC's operational personnel statement that distribution system O/H conductors should have a shorter life than transmission system O/H conductors, what other factors and rationale support a 50-R2 life and curve for this account?

ANSWER:

(a)

Factors contributing to the selection of a 50-year life include Alliance's experience in analyzing the life of conductor for numerous companies and the similarity between

transmission and distribution conductor adjusted for the higher level of exposure for distribution conductor to failure from third-party damage or trees. Typically, the characteristic of overhead conductor would suggest that the conductor would have a slightly longer life than the poles the conductor is strung on and also a slightly longer life than services. These factors, along with the input of Company SMEs all suggest that a 50-year life is reasonable for distribution conductor.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-39**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1625-305 Dist. System – Survey Costs 50 R2
This account consists of costs association with land surveys and assessments related to distribution easements. The plant balance in this account at December 31, 2018 is $600 thousand. The approved life and curve for this account is 50 R3. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends retention of the existing 50 year life with a slight change in the curve to an R2 for this account."

QUESTION:

a) On what basis is YEC able to propose a change to a 50-R2 life and curve from the approved 50-R3 life and curve without the benefit of an actuarial life analysis?

b) Please provide the directional impact of the change proposed in terms of an increase or decrease to depreciation expense for this account for the year 2021.

c) Please clarify if the proposed life and curve for this account is intended to match that of Account 1625-304 Dist. System – Brushing and Account 1625-401 Dist. System – O/H Conductors.

ANSWER:

(a)

The proposal to change the dispersion curve is based on Alliance Consulting Group's judgment and experience. We have performed more than 270 depreciation studies across North America and have had many opportunities to see the various retirement patterns of utility assets. Given the characteristics of these assets and the dispersion of the other related assets, moving to a slightly flatter dispersion would better reflect the retirement characteristics.

(b)

There is no change to depreciation as the life has not changed and YEC uses straight-line amortization.

(c)

Yes, in part. It is reasonable for the retirement pattern for survey costs to match the other asset groups mentioned in the question and the pattern matches the expectations for this type of asset.

REFERENCE: **Application, Tab 9, Depreciation Study, pages 9-41 and Comparison of Life Parameters, page 9-104**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1625-401 Dist. System – O/H Services 40 R2
This account consists of installation costs associated with overhead services such as transmission line installation and upgrades. The plant balance in this account at December 31, 2018 is $2.1 million. The approved life and curve for this account is 40 R2. Discussions with Company personnel indicated the majority of services are overhead. The Company is experiencing an increased number of new services and need to update aging infrastructure. Operations stated commercial services would have a shorter life than residential services. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends retention of the 40 R2 life and curve for this account."

QUESTION:

a) Please confirm whether Tab 9, Depreciation Study, page 9-41 contains a typographical error in referencing "Account 1625-401 Dist. System – O/H Services 40 R2" and should correctly state "Account 1625-410 Dist. System – O/H Services 40 R2" as indicated on page 9-104. If not confirmed, please explain.

b) Please describe at a high level the proportion of O/H service installations that are commercial versus residential for the years 1998-2018 and explain how this information does or does not influence retention of the 40-R2 life and curve for this account.

ANSWER:

(a)

The information life of the account 1625-401 is stated incorrectly on page 9-41. The information on page 9-104 is correct. The current life of this account is 35 R2. The

proposed life for this account is 50 years with a R2 dispersion. The graph depicted on page 41 is not correct for this account.

(b)

The proposed 40-year life referenced in the question is not correct as indicated in part (a). Alliance Consulting Group did not consider the commercial versus residential load specifically. There is no evidence that the life characteristics would be materially different between the two types of services. The interview notes with Company personnel stated:

> Distribution conductor – Load growth would be a primary driver for replacement of conductor. There are a few extra reasons for replacing distribution conductor as compared to transmission conductor. They would expect a slightly shorter life for distribution conductor. A 50-year life is reasonable.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-44**

ISSUE: **Depreciation Expense**

PREAMBLE: For each of Account 1625-610 Dist. System – Meters and Account 1625 620 Dist. System – Meter Equipment, YEC has proposed a change to a 16-SQ life and curve from the approved 30-R2 life and curve in part because it "pulls meters for testing at eight years and based on test results may use the meter up to 16 years."

QUESTION:

a) Please clarify whether the decision to pull meters for testing at eight years is a change in policy from any policy that was in place when a 30-R2 life and curve was approved for this account.

b) Referring to the response to part (a) above, was the change in policy based on internal or external factors? Please explain fully.

c) Please provide observed life tables and the plotted actual data points with the approved 30 R2 survivor curve for each of the two accounts referenced in the preamble.

ANSWER:

(a)

The decision to pull meters for testing at eight years was an operational decision based on experience of the Electrical department with use of these meters and was not based on any policy.

(b)

YEC has installed AMI meters in these accounts. The changes in meter life expectancy have occurred because the new meters are different in operation than electro-mechanical meters of the past. In Alliance Consulting Group's experience, no AMI meters across North

America have a life as long as the existing 30-year life. At the time of Mr. Watson's site visit in 2019, Company experts made the following observations:

> Meters – 100% digital (or close). Current life is 30 years. Move to 16 years. Industry Canada Have to pull at 8 years, and if tested good, get another 5 years, and if sample is good, another 3 years. Then done. 16 years is the maximum life.

(c)

In the case of assets where technology or regulation has changed, historical experience does not predict the future of the Company's existing assets. Notwithstanding the above, the requested information is provided in the following attachment:

- Attachment 1 - Acct 1625-620'; and
- Attachment 2 - Acct 1625-610'.

Observed Life Table

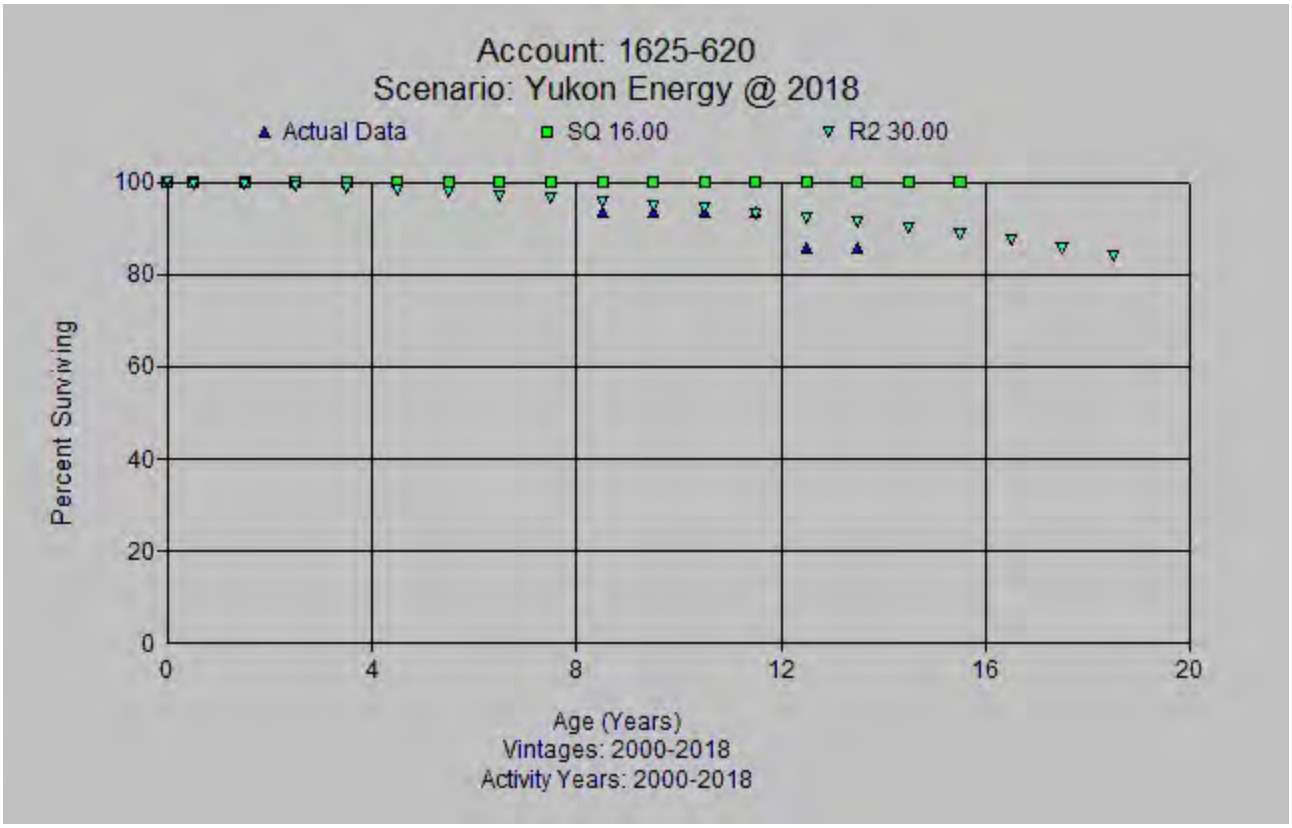
Scenario: Yukon Energy @ 2018
Account: 1625-620
Placement Band: 2000 - 2018 **Observation Band:** 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	228,641.93	0.00	0.00000	1.00000	100.00
0.5	228,641.93	0.00	0.00000	1.00000	100.00
1.5	228,641.93	0.00	0.00000	1.00000	100.00
2.5	228,641.93	0.00	0.00000	1.00000	100.00
3.5	228,641.93	0.00	0.00000	1.00000	100.00
4.5	228,641.93	0.00	0.00000	1.00000	100.00
5.5	228,641.93	0.00	0.00000	1.00000	100.00
6.5	228,641.93	0.00	0.00000	1.00000	100.00
7.5	228,641.93	14,302.44	0.06255	0.93745	100.00
8.5	214,339.49	0.00	0.00000	1.00000	93.75
9.5	164,175.29	0.00	0.00000	1.00000	93.75
10.5	135,357.34	0.00	0.00000	1.00000	93.75
11.5	135,357.34	11,441.25	0.08453	0.91547	93.75
12.5	105,530.44	0.00	0.00000	1.00000	85.82
13.5	0.00	0.00	0.00000	0.00000	85.82

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1625-620
Placement Band: 2000 - 2018 **Observation Band:** 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	228,641.93	0.00	0.00000	1.00000	100.00
0.5	228,641.93	0.00	0.00000	1.00000	100.00
1.5	228,641.93	0.00	0.00000	1.00000	100.00
2.5	228,641.93	0.00	0.00000	1.00000	100.00
3.5	228,641.93	0.00	0.00000	1.00000	100.00
4.5	228,641.93	0.00	0.00000	1.00000	100.00
5.5	228,641.93	0.00	0.00000	1.00000	100.00
6.5	228,641.93	0.00	0.00000	1.00000	100.00
7.5	228,641.93	14,302.44	0.06255	0.93745	100.00
8.5	214,339.49	0.00	0.00000	1.00000	93.75
9.5	164,175.29	0.00	0.00000	1.00000	93.75
10.5	135,357.34	0.00	0.00000	1.00000	93.75
11.5	135,357.34	11,441.25	0.08453	0.91547	93.75
12.5	105,530.44	0.00	0.00000	1.00000	85.82
13.5	0.00	0.00	0.00000	0.00000	85.82


Account: 1625-620
Scenario: Yukon Energy @ 2018
Actual Data
SQ 16.00
R2 30.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

Observed Life Table

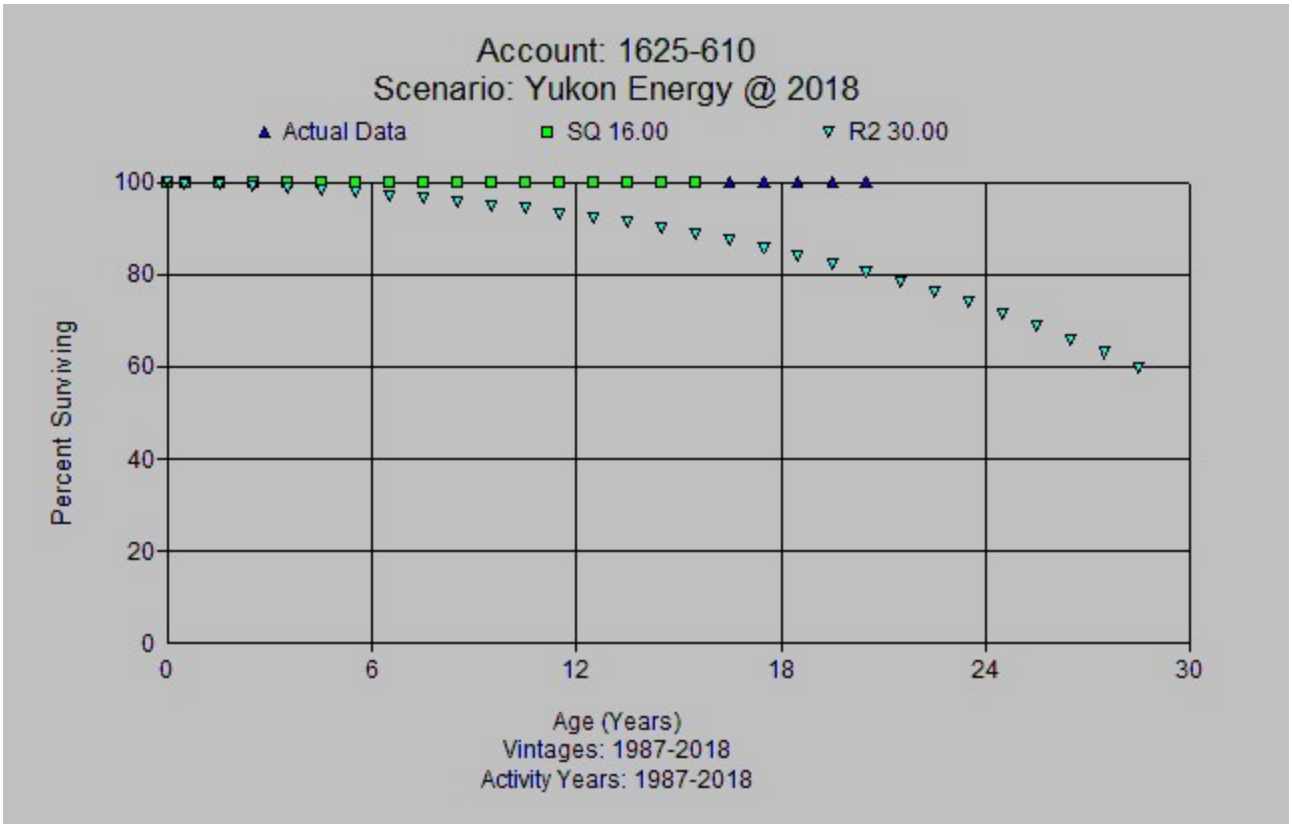
Scenario: Yukon Energy @ 2018
Account: 1625-610
Placement Band: 1987 - 2018 **Observation Band:** 1987 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	312,632.61	0.00	0.00000	1.00000	100.00
0.5	312,632.61	0.00	0.00000	1.00000	100.00
1.5	312,632.61	0.00	0.00000	1.00000	100.00
2.5	312,632.61	0.00	0.00000	1.00000	100.00
3.5	312,632.61	0.00	0.00000	1.00000	100.00
4.5	312,632.61	0.00	0.00000	1.00000	100.00
5.5	281,350.96	0.00	0.00000	1.00000	100.00
6.5	281,350.96	0.00	0.00000	1.00000	100.00
7.5	281,300.96	0.00	0.00000	1.00000	100.00
8.5	281,250.96	0.00	0.00000	1.00000	100.00
9.5	281,250.96	0.00	0.00000	1.00000	100.00
10.5	227,195.23	0.00	0.00000	1.00000	100.00
11.5	226,166.46	0.00	0.00000	1.00000	100.00
12.5	208,619.72	0.00	0.00000	1.00000	100.00
13.5	208,619.72	0.00	0.00000	1.00000	100.00
14.5	177,574.18	0.00	0.00000	1.00000	100.00
15.5	177,574.18	0.00	0.00000	1.00000	100.00
16.5	177,574.18	0.00	0.00000	1.00000	100.00
17.5	177,574.18	0.00	0.00000	1.00000	100.00
18.5	171,268.41	0.00	0.00000	1.00000	100.00
19.5	133,719.08	0.00	0.00000	1.00000	100.00
20.5	0.00	0.00	0.00000	1.00000	100.00

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1625-610
Placement Band: 1987 - 2018 **Observation Band:** 1987 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	312,632.61	0.00	0.00000	1.00000	100.00
0.5	312,632.61	0.00	0.00000	1.00000	100.00
1.5	312,632.61	0.00	0.00000	1.00000	100.00
2.5	312,632.61	0.00	0.00000	1.00000	100.00
3.5	312,632.61	0.00	0.00000	1.00000	100.00
4.5	312,632.61	0.00	0.00000	1.00000	100.00
5.5	281,350.96	0.00	0.00000	1.00000	100.00
6.5	281,350.96	0.00	0.00000	1.00000	100.00
7.5	281,300.96	0.00	0.00000	1.00000	100.00
8.5	281,250.96	0.00	0.00000	1.00000	100.00
9.5	281,250.96	0.00	0.00000	1.00000	100.00
10.5	227,195.23	0.00	0.00000	1.00000	100.00
11.5	226,166.46	0.00	0.00000	1.00000	100.00
12.5	208,619.72	0.00	0.00000	1.00000	100.00
13.5	208,619.72	0.00	0.00000	1.00000	100.00
14.5	177,574.18	0.00	0.00000	1.00000	100.00
15.5	177,574.18	0.00	0.00000	1.00000	100.00
16.5	177,574.18	0.00	0.00000	1.00000	100.00
17.5	177,574.18	0.00	0.00000	1.00000	100.00
18.5	171,268.41	0.00	0.00000	1.00000	100.00
19.5	133,719.08	0.00	0.00000	1.00000	100.00
20.5	0.00	0.00	0.00000	1.00000	100.00


Account: 1625-610
Scenario: Yukon Energy @ 2018
Actual Data
SQ 16.00
R2 30.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1987-2018
Activity Years: 1987-2018

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-45**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1625-710 Dist. System – Substation Equipment 40 S0
This account includes all distribution substation equipment such as bus compartments, control equipment, ground rods, foundations, and conversion equipment, switching equipment, and switchboards. The plant balance in this account at December 31, 2018 is $1.3 million. The approved life and curve for this account is 40 R2. Discussions with operations indicated the Company is experiencing a shorter life due to an increased number of faults, more short-lived electronic equipment, and the move to SF6 all decreasing the lives of existing assets. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends a 40 S0 life and curve for this account."

QUESTION:

a) On what basis is YEC able to propose a change to a 40-S0 life and curve from the approved 40-R2 life and curve without the benefit of an actuarial life analysis?

b) Please explain why YEC did not propose to decrease the average service life from 40 years as opposed to changing the curve (from R2 to S0) given the statement that YEC is experiencing a shorter life for these assets.

c) Please provide the directional impact of the change proposed in terms of an increase or decrease to depreciation expense for this account for the year 2021.

ANSWER:

(a)

The proposal to change the dispersion curve is based on Alliance Consulting Group's judgment and experience. We have performed more than 270 depreciation studies across North America and have had many opportunities to see the various retirement patterns of

utility assets. Given the increasingly wide range of lives for assets within this account, the investment mix is believed to be better modeled by a symmetrical and flatter dispersion. This allows a reflection of the additional short-lived electronic components in substations.

(b)

The statements above should be clarified to say the shorter life referred to above is difference between transmission substations in account 1635-710 and distribution substations. Distribution equipment would have a shorter life due in part to the faults that would reach distribution but not transmission, the number of operations on distribution would be higher, higher relative currents (and therefore more heat) in distribution, and the degree of attention that is focused on transmission brushing. Given the different types of equipment between the functions and differences in voltage, Alliance Consulting Group's proposal is similar to that of other North American utilities in our experience.

(c)

There is no change to depreciation as the life has not changed and YEC uses straight-line amortization.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-47**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1625-730 Dist. System – Substation Fences 30 R4
This account includes the costs of fences located at distribution substations. The plant balance in this account at December 31, 2018 is $100 thousand. The existing life for this account is 20 R4. The approved life for this account is 20 years. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 30 R4 life and curve for this account."

QUESTION:

a) Please clarify the specific information provided by Company personnel that supports an increase (of 10 years) in average service life for this account.

b) Please confirm whether Tab 9, Depreciation Study, page 9-104 contains a typographical error in referencing an existing SQ Iowa Curve for this account. If not confirmed, please explain.

ANSWER:

(a)

The statements made in Mr. Watson's interviews were opinions of experienced Company operations employees and engineers. No further documentation was provided other than the professional judgment of those individuals and the experience of Alliance.

(b)

Page 104 of Tab 9 shows the current life of this account to be 20 R4. Alliance Consulting Group does not see a reference to the SQ curve for this account.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-49**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1625-905 Dist. System – Line Transformers 35 R2.5
This account includes all line transformers, capacitors, lightning arrestors, and related equipment. The plant balance in this account at December 31, 2018 is $4 million. The approved life and curve for this account is 40 R2.5. Discussions with operations stated the transformers are subject to higher loading due to growth and expect the life of these assets to decrease as a result. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 35 R2.5 life and curve for this account."

QUESTION:

a) Please clarify whether the higher loading due to growth in the system has led to increased asset retirements.

b) Please clarify whether the higher loading due to growth in the system has resulted in exceeding the maximum load recommended for YEC's distribution line transformers.

c) Please provide the dollar amount of retirements by transaction year and vintage for the years 1998-2018.

ANSWER:

(a)

There has not been an increase in asset retirements to date. YEC monitors the power flow and demand on the larger system transformers feeding the communities, not distribution transformers. The large transformers are recording increased peak demands, and therefore, YEC assumes a portion of the distribution transformers are also at or above capacity.

(b)

YEC does not monitor real-time small distribution transformer loading. There are circumstances where distribution transformer failures can be attributed to overload. On new customer connects YEC is now installing 25 kva transformers, where in the past 10 kva transformers would have been installed. AEY is also doing similar up rates on transformers for new connects.

(c)

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.

REFERENCE: **Application, Tab 9, Depreciation Study, pages 9-51 and 9-59**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1635-300 Main Trx - Poles and Fixtures 50 R3
This account consists of poles and fixtures used for transmission purposes. The plant balance in this account at December 31, 2018 is $60 million. The approved life and curve for this account is 65 R3. Discussions with Company personnel indicated the Company has a Transmission Line Refurbishment program in place and has started replacing 50 year old poles. Yukon expects this to continue in the future to address its aging infrastructure. Periodically poles are replaced without having to replace the conductor. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 50 R3 for this account."

"Account 1640-300 Sub Trx – Poles & Fixtures 50 R3
This account consists of poles, fixtures, and other related assets used in transmission operations, including anchors, brackets, cross arms, braces, and foundations. The plant balance in this account at December 31, 2018 is $4.1 million. The approved life and curve for this account is 45 R3. Discussions with Company personnel indicated the Company has a Transmission Line Refurbishment program in place and has started replacing 50 year old poles. Yukon expects this program to continue in the future to address its aging infrastructure. Periodically poles are replaced without having to replace the conductor. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 50 R3 for this account."

QUESTION:

a) Please clarify whether YEC applies any treatment to its wooden poles as part of a capital maintenance program that would serve to lengthen the expected average

service life. If so, please identify the program under which this capital work is conducted.

b) Please fully explain whether it is the replacement of 50-year-old transmission poles that is the main rationale for the proposed change to a 50-R3 life and curve from the approved 65-R3 life and curve or some other factor.

c) Please provide the expected average service life of the new poles that are replacing the 50 year-old poles being retired due to the refurbishment program.

d) Please provide the dollar amount of retirements by transaction year and vintage for the years 1998-2018.

e) Given that it appears that YEC maintains O/H conductor accounts for each of the poles and towers, please clarify whether YEC is installing any towers as the pole replacement assets and, if so, identify in which account these transmission tower assets are being recorded.

f) Given that it appears that YEC maintains O/H conductor accounts for each of the poles and towers, please clarify whether YEC is installing any towers as part of a new transmission line, and identify in which account these transmission tower assets are being recorded.

g) Referring to the responses to part (e) and (f) above, please provide the expected average service life of YEC's transmission tower assets.

h) Please clarify whether there is any difference in the general type of assets in Account 1635 300 Main Trx – Poles and Fixtures 50-R3 and Account 1640-300 Sub Trx – Poles & Fixtures 50-R3. In the response, please address both poles and towers.

ANSWER:

(a)

YEC established the first Test and Treat in 2009. Test and treat is a process that determines the pole shell thickness above and below grade, treats cavities and eliminates insect infestations.

Remedial test and treat programs consist of the following:

- Test pole for shell thickness, presence of rot/pests/defects.
- Internally treat with preservative.
- Externally treat below ground ground-line with Pole-Wrap Cu Nap bandage.
- Treat exposed heartwood or cavities with Cu Nap.
- Treat and destroy existing insect infestations.
- Determine if any poles require replacement or close monitoring.

(b)

The replacement of poles at 50 years would be a factor in setting the 50-year life. The Company tests poles and routinely performs inspections. After detailed line inspections, YEC prioritizes which assets to replace factoring in those results. Expectations of Company SMEs and Alliance, as well as Alliance's experience across North America, would also be factors in setting the 50-year life.

(c)

Although there may be cases where the poles being replaced are possibly stronger old-growth trees and the replacement poles are from new-growth trees, Alliance's assumption is that new poles would generally have the same life as the poles being replaced.

(d)

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.

(e)

YEC has no plans to “replace” wooden structures with towers.

(f)

There is the potential to install a new tower structure for a future river crossing in Whitehorse Rapids to S171 Riverside substation. It’s too early in the project to confirm this.

(g)

As per the Depreciation Study, the expected life of Towers is 60 years.

(h)

Generally speaking, there is no significant difference in the general type of assets in account 1635-300 and 1640-300 other than one is connected to Main Transmission Facilities and the latter is connected to Sub Transmission Lines.

REFERENCE: **Application, Tab 9, Depreciation Study, pages 9-52 to 9-55**

ISSUE: **Depreciation Expense**

PREAMBLE: For each of Account 1635-402 Main Trx – O/H Conductors/Poles and Account 1635-404 Main Trx – O/H Conductors/Towers, YEC has proposed a 60-R3 life and curve from the approved 50-R3 life curve based on: "Discussions with operational personnel estimate the life of transmission conductor to be about 10 years longer than distribution conductor, which is moving to a 50 year life." Further, life and curves for Account 1635-304 Main Trx – Brushing and Account 1635-305 Main Trx – Survey Costs are proposed to "mirror the life of overhead conductor, which uses a 60 year life."

QUESTION:

a) Notwithstanding YEC's operational personnel statement that transmission system O/H conductors should have a longer life (by ten years) than distribution system O/H conductors, what other rationale supports a 60-R3 life and curve for these four transmission accounts?

ANSWER:

(a)

In addition to observations from Operations SMEs, Alliance also relied on its experience analyzing similar assets across the utility industry and the characteristics seen in those analyses.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-56**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1635-710 Main Trx – Substation Equipment 45 S0
This account consists of bus compartments, batteries, control equipment, transformers, breakers, and other related station equipment used in transmission operations. The plant balance in this account at December 31, 2018 is $66.6 million. The approved life and curve for this account is 54 S0. Discussions with Company personnel indicated they are experiencing a shorter life for the assets in this account due to the increasing amount of short lived electronic assets at the stations. Operations also stated that transformers typically last between 40 to 50 years; breakers have a 35 year life for OCB and 50 years for SF6. Several breakers have already been replaced in 2018 and 2019. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 45 S0 for this account."

QUESTION:

a) Please explain why substation equipment should not reflect a similar average service life between distribution and transmission function assets. For example, Account 1625-710 Dist. System – Substation Equipment (proposed 40-S0 life and curve) and Account 1635-710 Main Trx – Substation Equipment (proposed 45-S0 life and curve).

ANSWER:

(a)

From an engineering and operations perspective, transmission and distribution assets have materially different forces of retirement and life characteristics. Transmission assets generally have more system protection and designed with higher tolerances. Distribution assets are more subject to faults and voltage variations. Alliance Consulting Group does not normally see the same life between the two asset categories for other utilities. The

general pattern is for transmission substation accounts to have a slightly longer life than distribution substation asset accounts.

REFERENCE: **Application, Tab 9, Depreciation Study, pages 9-59 to 9-67 and 9-105**

ISSUE: **Depreciation Expense**

PREAMBLE: The Board requires further detail with respect to YEC's sub transmission accounts at the referenced pages.

QUESTION:

a) Please provide detail and rationale respecting the segregation of YEC's transmission assets into a further sub transmission category, which is further segregated into accounts designated as (Minto Mine) "Mnt Mn".

b) Please clarify that, with the exception of those accounts designated by "Mnt Mn" (1640-301, 1640-306, 1640-307, 1640-407 and 1640-711), the depreciation life and curve proposed for YEC's sub transmission asset accounts (1640-300, 1640-304, 1640-401, 1640-405 and 1640 710) are intended to mirror the equivalent main transmission assets under the "1635" series of transmission asset accounts because they generally include the same types of assets subject to the same types of operating conditions. If not confirmed, please explain further.

c) Referring to the sub transmission asset accounts designated by "Mnt Mn" (1640-301, 1640 306, 1640-307, 1640-407 and 1640-711), please explain the rationale for these accounts being amortized on the basis of a 12-SQ life and curve. Please also provide the dates upon which the Minto Mine assets were installed and commenced amortization and why a 12-SQ life and curve remains applicable.

ANSWER:

(a)

Sub-transmission lines have lines designations separate from the main transmission lines. This segregation provides improved and more comprehensive asset management of the lines. Sub-transmission systems are those circuits that supply distribution substations to communities or commercial customers. Common sub-transmission voltages include 34.5, 69, 115, and 138 kV. Further segregation of the Minto Mine was required as those assets

have a different life (life of the mine) in accordance with International Financial Reporting Standards.

(b)

Confirmed.

(c)

In accordance with International Financial Standards and to obtain a clean audit opinion from the Auditor General of Canada, it was determined that these assets were required to have a life equal to the life of the mine.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-69**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1645-200 Bldg & Otr – Structures and Improvements Hydro 50 R2
This account includes the cost associated with the structures and improvements associated with a hydro facility including berms, signage, roads, boilers, and other related assets used to support general operations. The plant balance in this account will be $2.2 million, which reflects a transfer of $10.3 million from this account into account 1615-201. The approved life and curve for this account is 40 R2.5. There is no historical activity to analyze. Discussions with Company personnel indicated these structures are on the water so they would have a little shorter life for various components. However, the existing 40 years is shorter than what would be expected. The newer buildings are more technology driven and have a little less longevity than the older built structures. There was insufficient transactional data for an actuarial life analysis. Based on the type and use of assets and judgment, this study proposes moving to 50 R2 at this time."

QUESTION:

a) Please clarify if the transfer of $10.3 million into Account 1615-201 was the main factor for the proposed increase (of 10 years) to a 50-R2 life and curve from the approved 40-R2.5 life and curve for this account.

b) If part (a) above is not confirmed, please provide further rationale for the increase in average service life given Company personnel statements that "these structures are on the water so they would have a little shorter life for various components" and that "the existing 40 years is shorter than what would be expected" and that "newer buildings are more technology driven and have a little less longevity than the older built structures".

ANSWER:

(a) and **(b)**

Yes, that was a material factor. The segregation of smaller, shorter-lived components into account 1645-201 would change the mix of assets in 1645-200 and would make the lives of the assets in the account more homogeneous. Increasing the life was to reflect the more homogeneous life in the account after the transfer. Input from Company SMEs and Alliance's experience also supported the move to a 50-year life.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-70**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1645-201 Bldg & Otr – Building and Improvements 50 R2
This account includes the cost associated with buildings and improvements that includes staff housing, warehouses, offices, fencing, building envelopes, fish hatchery, yard work, guard rails. The plant balance in this account at December 31, 2018 is $10.1 million. The approved life and curve for this account is 55 R1. There is very limited historical activity to analyze. Discussions with Company personnel indicated many of the assets in this account have shorter lives than the building. Based on the limited indications from the actuarial analysis, mix and type of assets, and judgment, this study proposes moving to 50 R2 at this time."

QUESTION:

a) Please clarify the types of assets that Company personnel indicated "have shorter lives than the building" and the approximate per cent proportion of these assets compared to all assets in the account.

b) Please provide the dollar amount of retirements by transaction year and vintage for the years 1998-2018 and indicate the proportion of assets being retired that have been identified as those having shorter lives than the building in part (a) above.

ANSWER:

(a)

The types of assets that might retire earlier than a large building might be facilities signage, fish hatchery upgrades, security systems, guard rail extensions, car plug-ins for electric vehicles, alternate road access, paving, and or water storage closets.

(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.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-77**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1645-507 Bldg & Otr – Wind Monitoring Equipment 15 SQ
This account includes costs associated with wind monitoring equipment. This includes tall towers and ultrasonic anemometers. The plant balance in this account at December 31, 2018 is $14 thousand. The approved life and curve for this account is 20 SQ. There is no historical data to analyze. Discussions with Company personnel indicated there is one wind monitoring site, which will likely be out of this process within a year. Company believes it might be 10 years old now. Based on the type of assets, existing life, Company input, and judgment, this study proposes moving to 15 SQ at this time."

QUESTION:

a) Please clarify if the reference to "one wind monitoring site, which will likely be out of this process within a year" is an indication that this asset will no longer be used and useful at the end of 2021.

b) If confirmed, please explain why YEC is proposing to continue to amortize the assets over 15 years rather than simply retire them and recover any remaining net book value at the end of 2021.

ANSWER:

(a)

All wind monitoring equipment has been disposed of, leaving no assets on record.

(b)

As disclosed in Tab 7, Schedule 3A, there is no forecast depreciation of Wind assets or Wind Monitoring Equipment as there are no assets on record. However, this does not mean YEC should not have a policy in the case it did have assets (as it did at the time of the Depreciation Study).

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-78**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1645-605 Bldg & Otr – Communication Equipment 20 L4
This account includes the installation costs of telephone, fibre optic and wireless equipment for general use in connection with utility operations and includes antennae, booths, cable, handsets, insulators, poles and fixtures, remote control equipment and line, storage batteries, switchboards, underground conduit and cable for telephone or fibre optics and other related equipment. The plant balance in this account at December 31, 2018 is $4.6 million. The approved life and curve for this account is 20 L4. Discussions with Company personnel indicated there is a variety of equipment types and varying lives. The life analysis indicates a life between 20-25 years. Based on the type and use of the equipment, Company input, life analysis indications, and judgment, this study proposes retention of 20 L4 at this time. A graph of the observed life table versus the recommended curve type is shown below."

QUESTION:

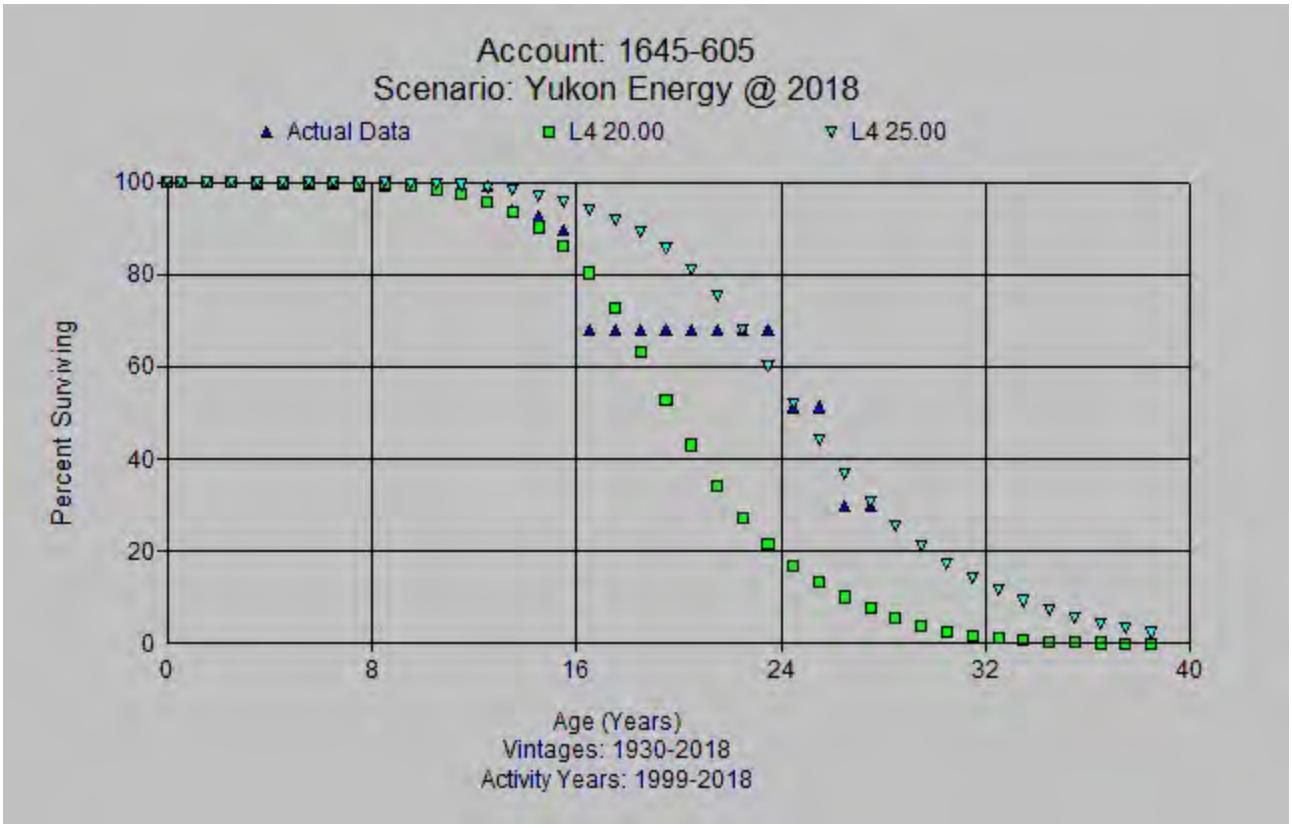
a) Please provide an observed life table and the plotted actual data points showing both a 20-L4 and 25-L4 survivor curve for this account.

ANSWER:

(a)

The requested information is provided in the following attachments:

- Attachment 1 provides the requested graphs;
- Attachment 2 provides the actual data points.
- Attachment 3 provides the actual data compared to the survivor curves propounded in the question.


Account: 1645-605
Scenario: Yukon Energy @ 2018
Actual Data
L4 20.00
L4 25.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1930-2018
Activity Years: 1999-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1645-605
Placement Band: 1930 - 2018 **Observation Band:** 1999 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	3,848,426.21	0.00	0.00000	1.00000	100.00
0.5	4,717,546.19	0.00	0.00000	1.00000	100.00
1.5	4,677,287.38	0.00	0.00000	1.00000	100.00
2.5	4,582,689.91	3,149.00	0.00069	0.99931	100.00
3.5	4,335,952.71	3,229.60	0.00074	0.99926	99.93
4.5	4,060,289.35	7,364.10	0.00181	0.99819	99.86
5.5	4,026,289.86	2,381.56	0.00059	0.99941	99.68
6.5	3,800,851.95	6,522.65	0.00172	0.99828	99.62
7.5	3,784,197.32	0.00	0.00000	1.00000	99.45
8.5	3,396,128.88	0.00	0.00000	1.00000	99.45
9.5	2,650,634.83	0.00	0.00000	1.00000	99.45
10.5	2,202,785.06	0.00	0.00000	1.00000	99.45
11.5	2,029,372.95	0.00	0.00000	1.00000	99.45
12.5	1,864,915.14	102,494.00	0.05496	0.94504	99.45
13.5	1,709,698.12	21,905.83	0.01281	0.98719	93.98
14.5	1,567,990.28	48,996.15	0.03125	0.96875	92.78
15.5	1,448,457.10	353,323.86	0.24393	0.75607	89.88
16.5	938,847.40	0.00	0.00000	1.00000	67.95
17.5	930,535.03	0.00	0.00000	1.00000	67.95
18.5	857,643.86	0.00	0.00000	1.00000	67.95
19.5	854,502.26	0.00	0.00000	1.00000	67.95
20.5	26,332.22	0.00	0.00000	1.00000	67.95
21.5	26,332.22	0.00	0.00000	1.00000	67.95
22.5	26,332.22	0.00	0.00000	1.00000	67.95
23.5	26,332.22	6,446.48	0.24481	0.75519	67.95
24.5	19,885.74	0.00	0.00000	1.00000	51.32
25.5	19,885.74	8,270.87	0.41592	0.58408	51.32
26.5	11,614.87	0.00	0.00000	1.00000	29.97
27.5	11,614.87	11,614.87	1.00000	0.00000	29.97
28.5	0.00	0.00	0.00000	1.00000	0.00

Surviving Percent Report

Scenario: Yukon Energy @ 2018
Account: 1645-605
Placement Band: 1930 - 2018 **Observation Band:** 1999 - 2018

Age	Actual	L4 20.00	L4 25.00
0.0	100.00	100.00	100.00
0.5	100.00	100.00	100.00
1.5	100.00	100.00	100.00
2.5	100.00	100.00	100.00
3.5	99.93	100.00	100.00
4.5	99.86	100.00	100.00
5.5	99.68	100.00	100.00
6.5	99.62	99.99	100.00
7.5	99.45	99.92	99.99
8.5	99.45	99.72	99.97
9.5	99.45	99.29	99.89
10.5	99.45	98.52	99.72
11.5	99.45	97.32	99.40
12.5	99.45	95.57	98.88
13.5	93.98	93.20	98.10
14.5	92.78	90.02	97.01
15.5	89.88	85.70	95.57
16.5	67.95	79.75	93.73
17.5	67.95	71.83	91.40
18.5	67.95	62.21	88.46
19.5	67.95	51.92	84.66
20.5	67.95	42.13	79.75
21.5	67.95	33.59	73.57
22.5	67.95	26.58	66.21
23.5	67.95	20.99	58.10
24.5	51.32	16.51	49.89
25.5	51.32	12.84	42.13
26.5	29.97	9.81	35.18
27.5	29.97	7.31	29.20
28.5	0	5.29	24.19

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-79**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1645-810 Bldg & Otr – Company Owned Houses/Land 40 R3 This account includes the costs of upgrades and maintenance associated with the land of houses owned by the company. The plant balance in this account at December 31, 2018 is $59 thousand. The approved life and curve for this account is 30 R3. Discussions with Company personnel indicated the newest house is from 2005 and the oldest is pre-1980. Company believes the existing life is too low. There is not enough historical experience for analysis. Based on the type of assets, Company input, and judgment this study proposes moving to 40 R3 for this account."

QUESTION:

a) Please clarify why "costs of upgrades and maintenance associated with the land of houses owned by the company" should be capitalized into rate base as opposed to expensed annually as an operating and maintenance cost.

ANSWER:

(a)

Consistent with YEC's capitalization policy previously provided to the YUB, and consistent with International Financial Reporting Standards as audited by the Auditor General of Canada, YEC capitalizes costs in excess of $1,000 that have a life longer than one year.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-82**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1650-411 Trxptn – Utility Vehicles 8 L2
This account includes the cost of utility trailers, cargo trailers, ATVs, snowmobiles, and boats. The plant balance in this account at December 31, 2018 is $344 thousand. The approved life and curve for this account is 7 L2. Discussions with Company personnel indicated the line crews use these types of vehicles for seven years before it is retired. Company indicated that occasionally, a quad or snow mobile will move to a plant and have a longer life, but an estimated 80% of these types of assets do not. However, the life analysis indicates a longer life than existing and longer than what the Company expects, which ranges from 10 to 15 years. Giving consideration to the type and use of assets, Company input and expectations, we propose moving the average out to eight years to reflect the 20% of assets that remain longer. This study proposes 8 L2 for this account."

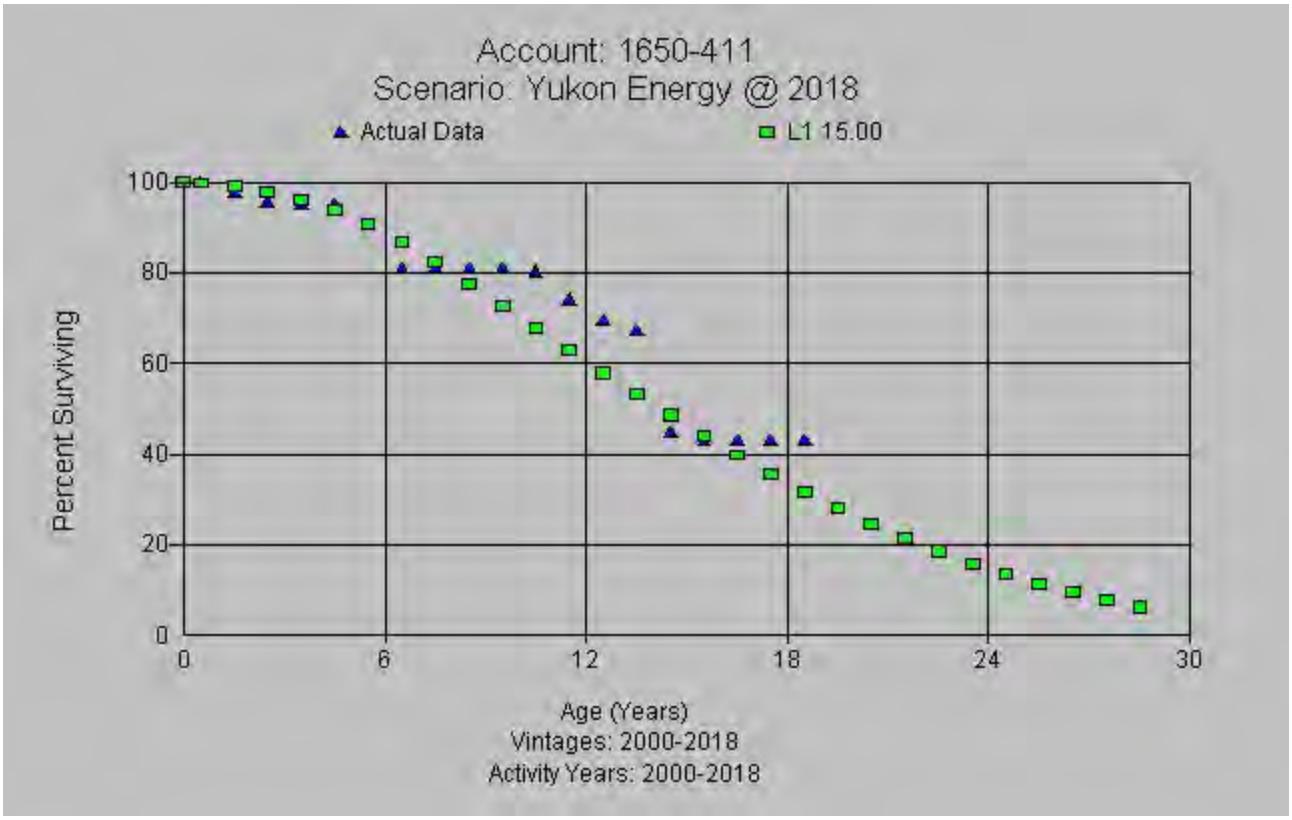
QUESTION:

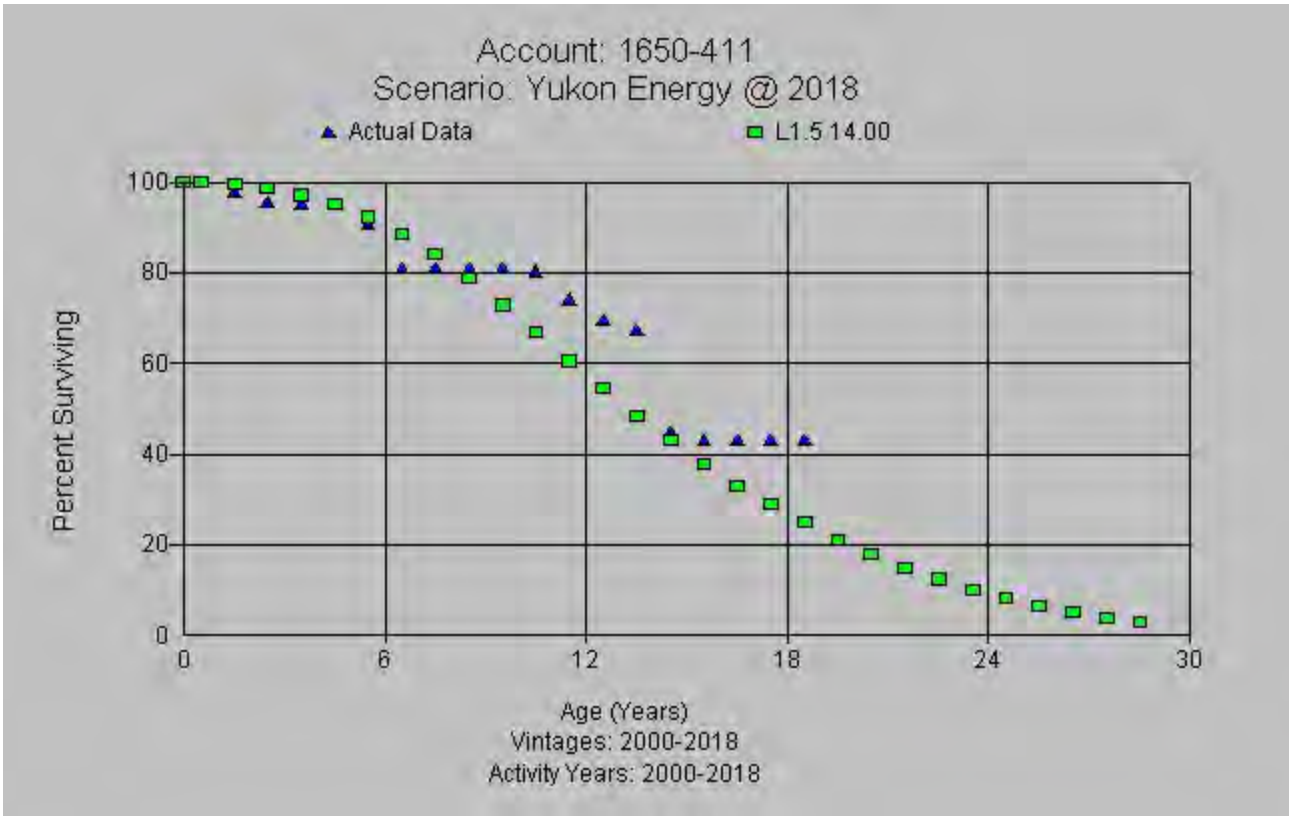
a) Please provide the "life analysis indicat[ing] a longer life than existing and longer than what the Company expects, which ranges from 10 to 15 years".

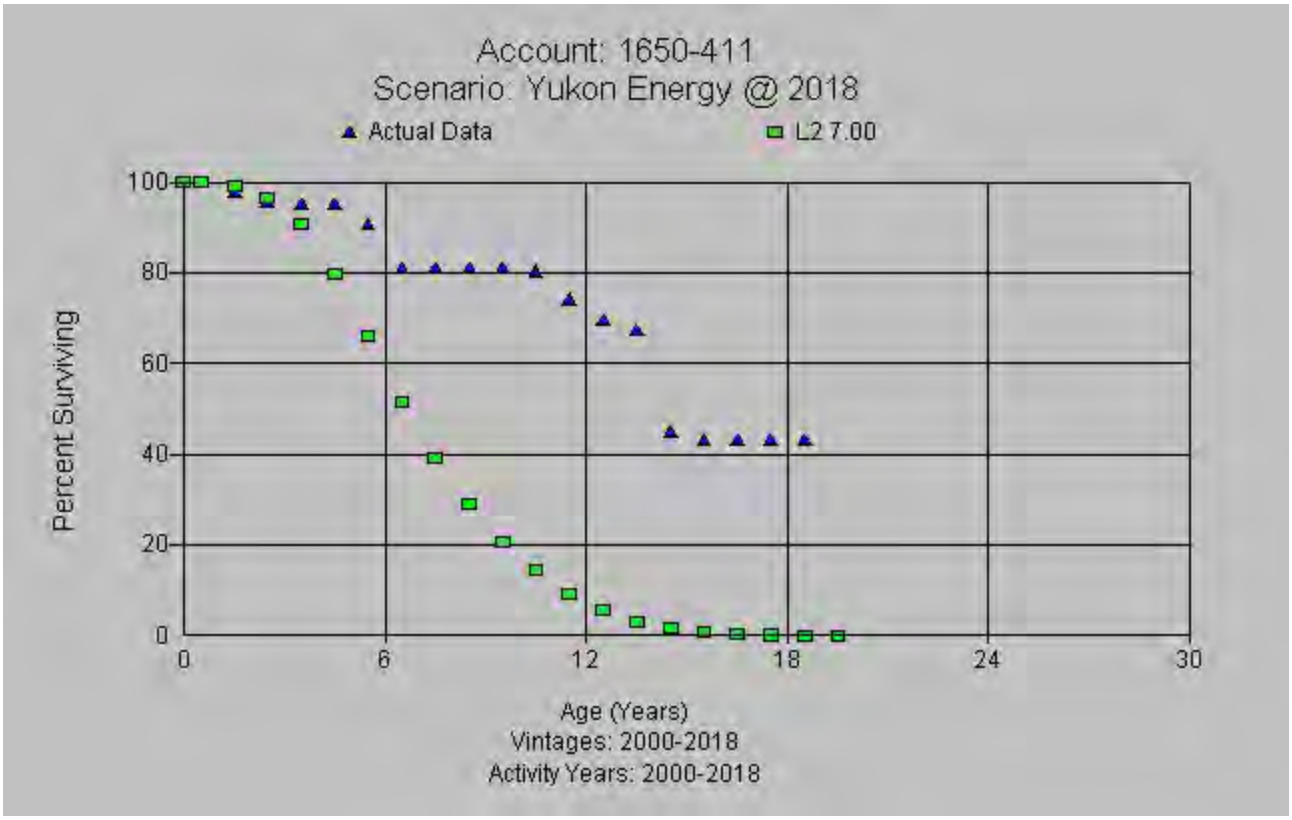
ANSWER:

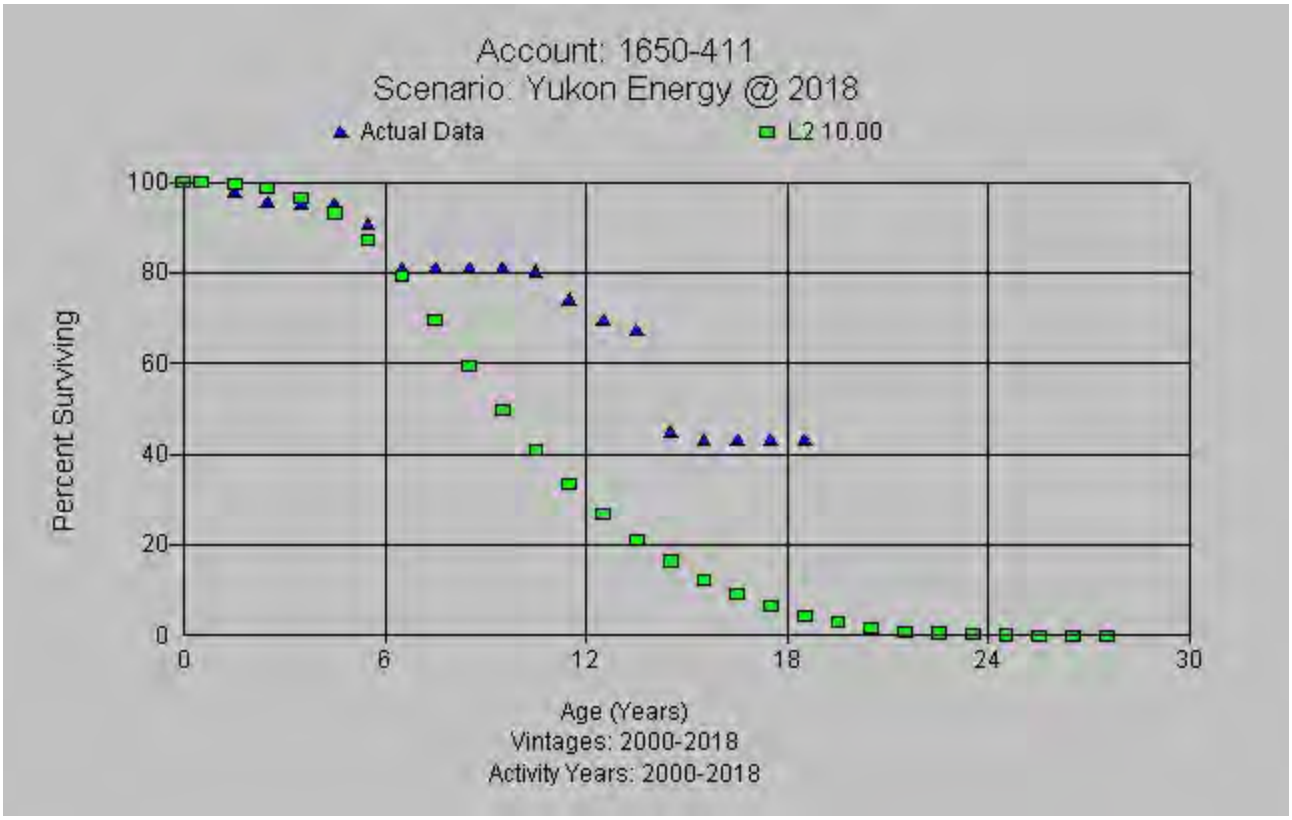
(a)

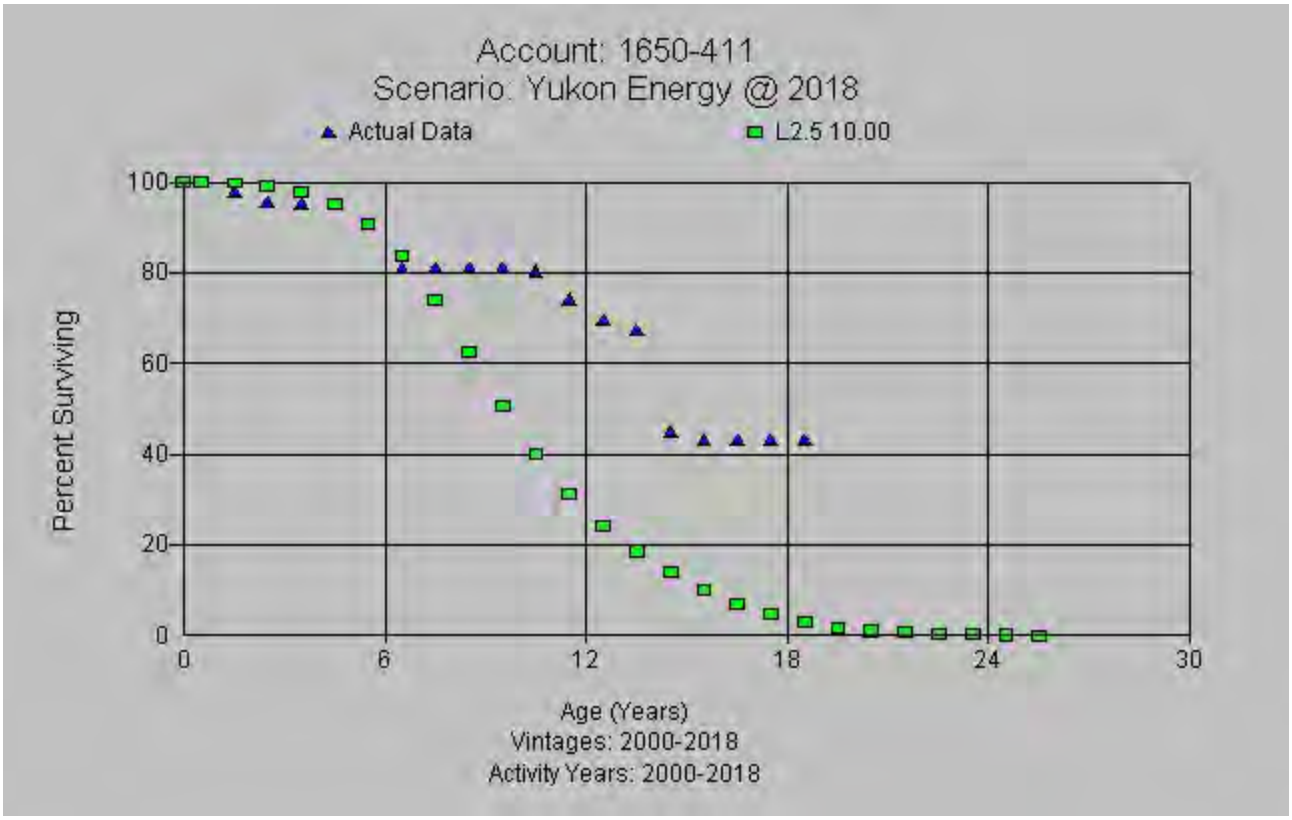
The requested information is provided as Attachment 1 to this response.


Account: 1650-411
Scenario: Yukon Energy @ 2018
Actual Data
L1 15.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018


Account: 1650-411
Scenario: Yukon Energy @ 2018
Actual Data
L1.5 14.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018


Account: 1650-411
Scenario: Yukon Energy @ 2018
Actual Data
L2 7.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

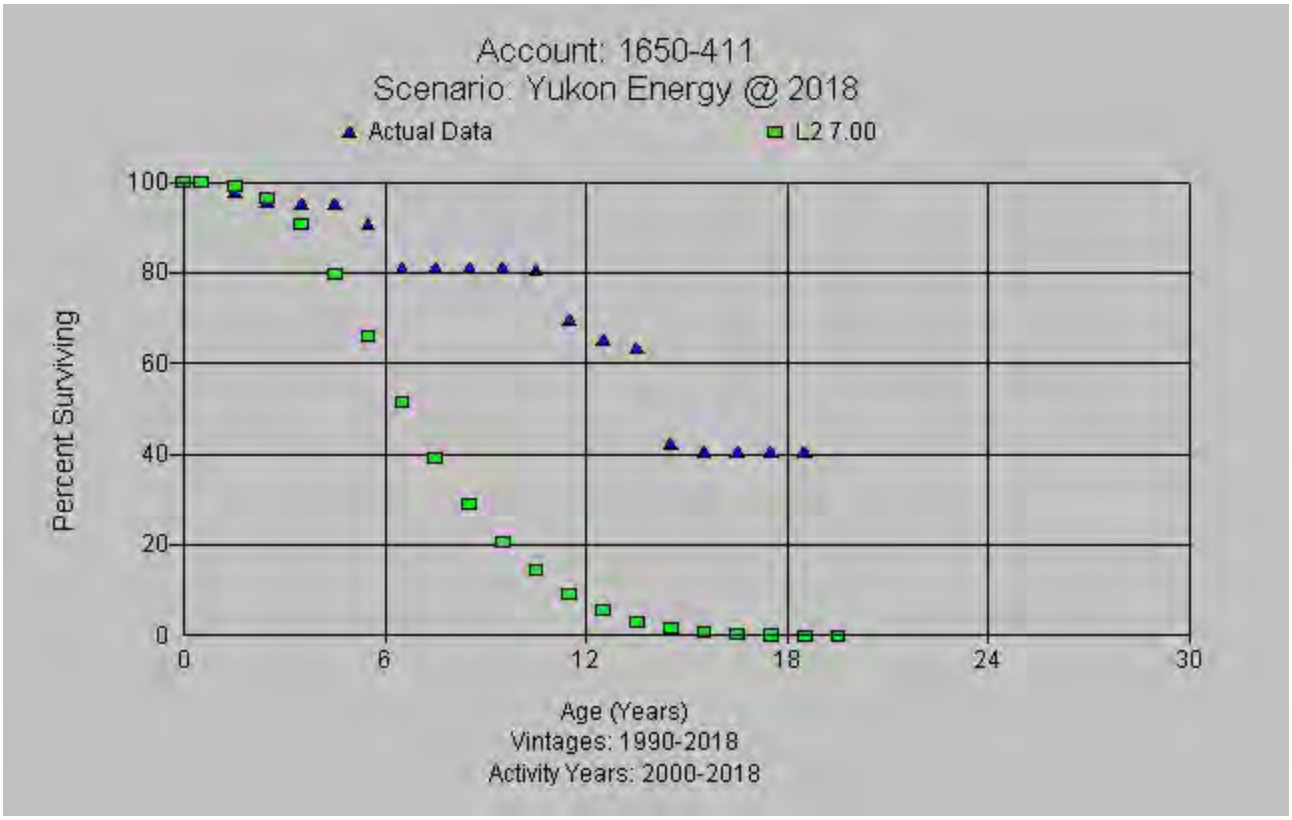

Account: 1650-411
Scenario: Yukon Energy @ 2018
Actual Data
L2 10.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018


Account: 1650-411
Scenario: Yukon Energy @ 2018
Actual Data
L2.5 10.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1650-411
Placement Band: 2000 - 2018 **Observation Band:** 2000 - 2018

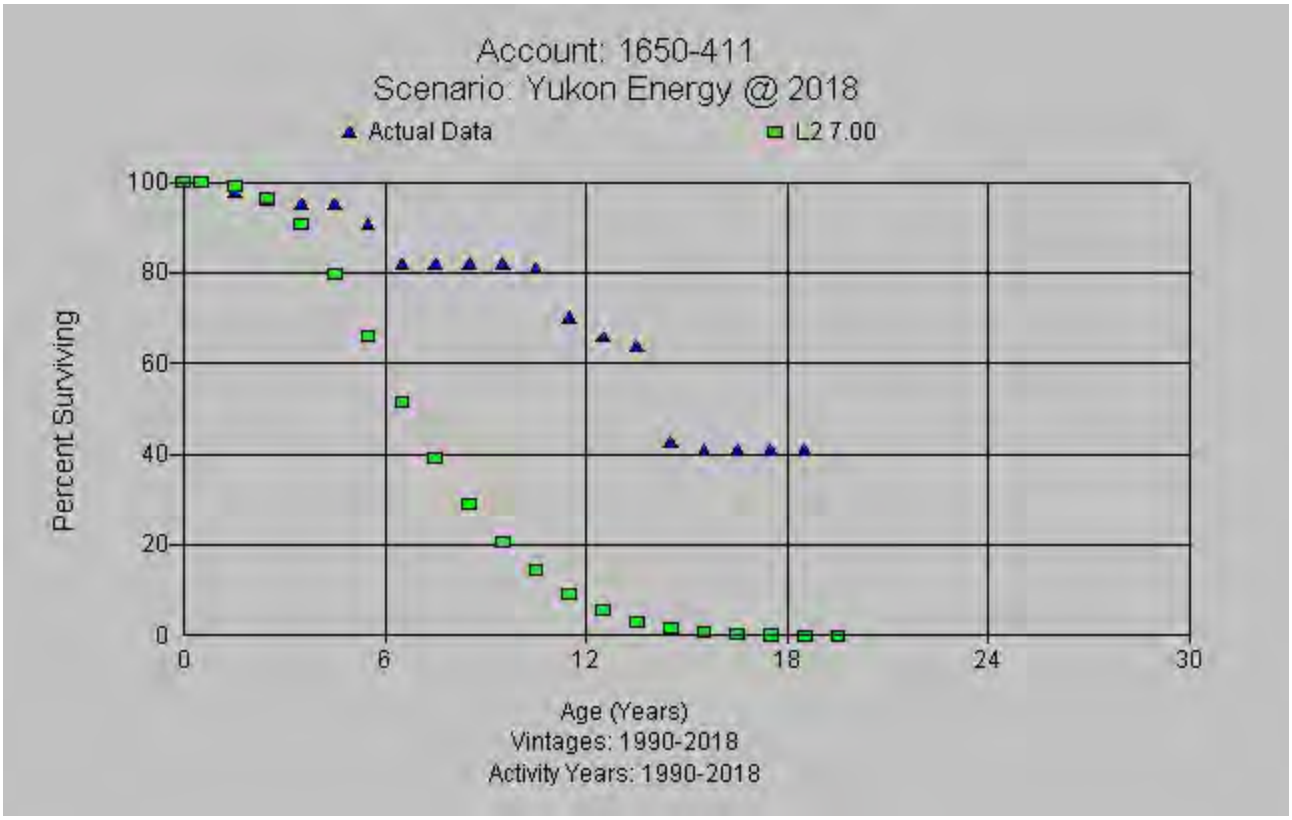
Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	448,042.18	0.00	0.00000	1.00000	100.00
0.5	405,592.18	8,463.00	0.02087	0.97913	100.00
1.5	397,129.18	8,400.00	0.02115	0.97885	97.91
2.5	358,967.13	2,465.00	0.00687	0.99313	95.84
3.5	327,841.44	0.00	0.00000	1.00000	95.18
4.5	230,470.67	11,068.60	0.04803	0.95197	95.18
5.5	181,452.27	18,938.70	0.10437	0.89563	90.61
6.5	162,513.57	0.00	0.00000	1.00000	81.16
7.5	162,513.57	0.00	0.00000	1.00000	81.16
8.5	162,513.57	0.00	0.00000	1.00000	81.16
9.5	162,513.57	1,460.77	0.00899	0.99101	81.16
10.5	129,871.48	9,951.37	0.07662	0.92338	80.43
11.5	108,550.11	6,849.00	0.06310	0.93690	74.26
12.5	96,125.17	2,800.00	0.02913	0.97087	69.58
13.5	93,325.17	31,328.73	0.33569	0.66431	67.55
14.5	61,996.44	2,244.25	0.03620	0.96380	44.87
15.5	59,752.19	0.00	0.00000	1.00000	43.25
16.5	31,356.70	0.00	0.00000	1.00000	43.25
17.5	26,192.29	0.00	0.00000	1.00000	43.25
18.5	0.00	0.00	0.00000	0.00000	43.25

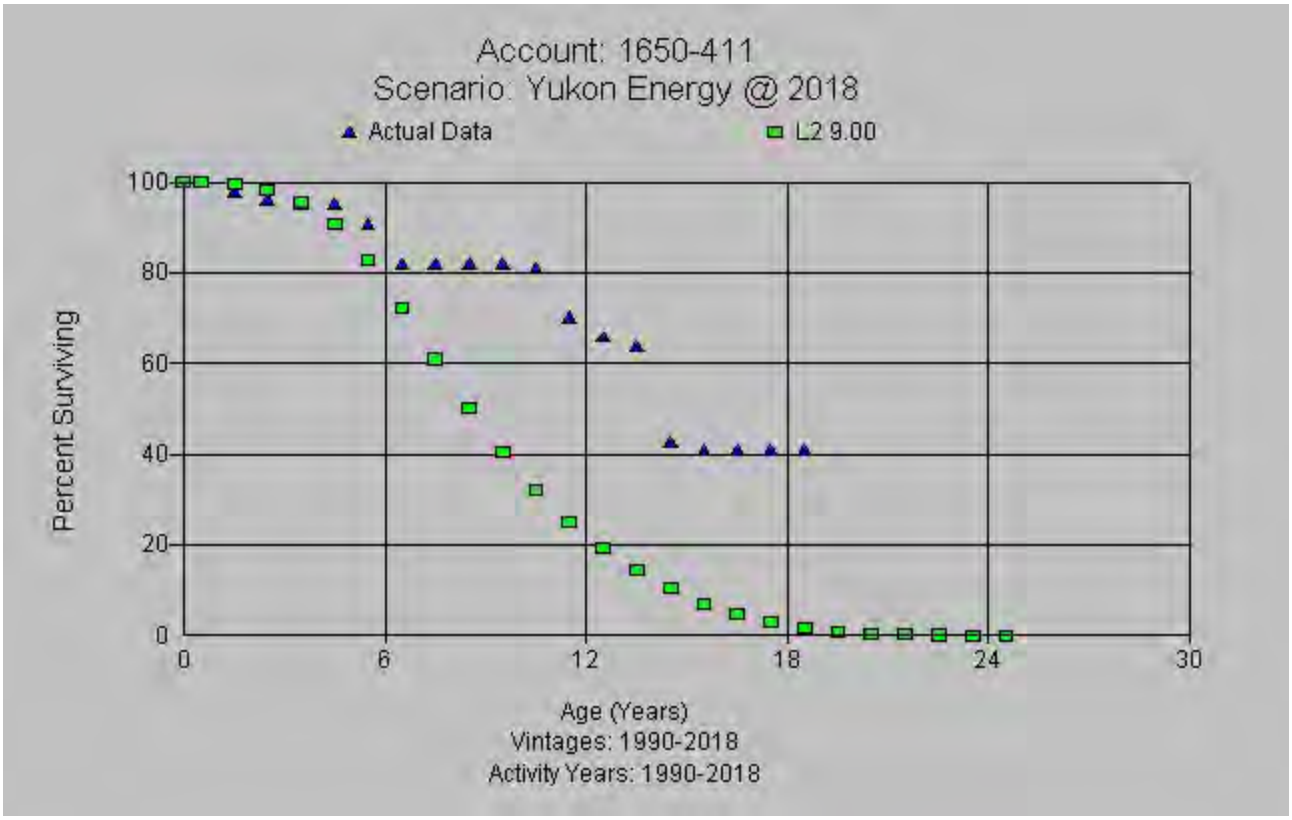

Account: 1650-411
Scenario: Yukon Energy @ 2018
Actual Data
L2 7.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1990-2018
Activity Years: 2000-2018

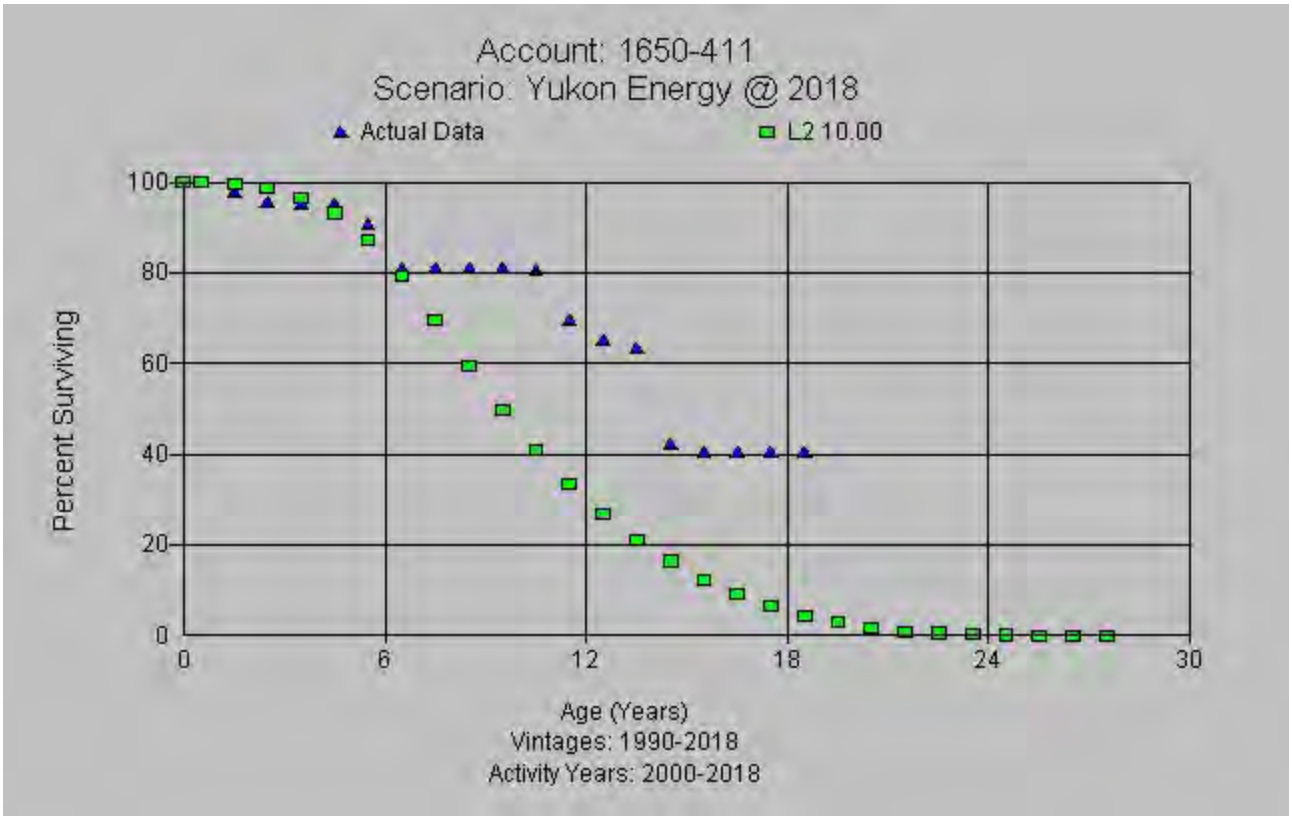
Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1650-411
Placement Band: 1990 - 2018 **Observation Band:** 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	448,042.18	0.00	0.00000	1.00000	100.00
0.5	405,592.18	8,463.00	0.02087	0.97913	100.00
1.5	397,129.18	8,400.00	0.02115	0.97885	97.91
2.5	358,967.13	2,465.00	0.00687	0.99313	95.84
3.5	327,841.44	0.00	0.00000	1.00000	95.18
4.5	230,470.67	11,068.60	0.04803	0.95197	95.18
5.5	181,452.27	18,938.70	0.10437	0.89563	90.61
6.5	162,513.57	0.00	0.00000	1.00000	81.16
7.5	162,513.57	0.00	0.00000	1.00000	81.16
8.5	162,513.57	0.00	0.00000	1.00000	81.16
9.5	171,063.57	1,460.77	0.00854	0.99146	81.16
10.5	138,421.48	18,501.37	0.13366	0.86634	80.46
11.5	108,550.11	6,849.00	0.06310	0.93690	69.71
12.5	96,125.17	2,800.00	0.02913	0.97087	65.31
13.5	93,325.17	31,328.73	0.33569	0.66431	63.41
14.5	61,996.44	2,244.25	0.03620	0.96380	42.12
15.5	59,752.19	0.00	0.00000	1.00000	40.60
16.5	31,356.70	0.00	0.00000	1.00000	40.60
17.5	26,192.29	0.00	0.00000	1.00000	40.60
18.5	0.00	0.00	0.00000	1.00000	40.60


Account: 1650-411
Scenario: Yukon Energy @ 2018
Actual Data
L2 7.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1990-2018
Activity Years: 1990-2018


Account: 1650-411
Scenario: Yukon Energy @ 2018
Actual Data
L2 9.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1990-2018
Activity Years: 1990-2018


Account: 1650-411
Scenario: Yukon Energy @ 2018
Actual Data
L2 10.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1990-2018
Activity Years: 2000-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1650-411
Placement Band: 1990 - 2018 **Observation Band:** 1990 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	456,592.18	0.00	0.00000	1.00000	100.00
0.5	414,142.18	8,463.00	0.02044	0.97956	100.00
1.5	405,679.18	8,400.00	0.02071	0.97929	97.96
2.5	367,517.13	2,465.00	0.00671	0.99329	95.93
3.5	336,391.44	0.00	0.00000	1.00000	95.28
4.5	239,020.67	11,068.60	0.04631	0.95369	95.28
5.5	190,002.27	18,938.70	0.09968	0.90032	90.87
6.5	171,063.57	0.00	0.00000	1.00000	81.81
7.5	171,063.57	0.00	0.00000	1.00000	81.81
8.5	171,063.57	0.00	0.00000	1.00000	81.81
9.5	171,063.57	1,460.77	0.00854	0.99146	81.81
10.5	138,421.48	18,501.37	0.13366	0.86634	81.11
11.5	108,550.11	6,849.00	0.06310	0.93690	70.27
12.5	96,125.17	2,800.00	0.02913	0.97087	65.84
13.5	93,325.17	31,328.73	0.33569	0.66431	63.92
14.5	61,996.44	2,244.25	0.03620	0.96380	42.46
15.5	59,752.19	0.00	0.00000	1.00000	40.92
16.5	31,356.70	0.00	0.00000	1.00000	40.92
17.5	26,192.29	0.00	0.00000	1.00000	40.92
18.5	0.00	0.00	0.00000	1.00000	40.92

Actuarial Life Analysis

Account: 1650-411
Scenario: Yukon Energy @ 2018
Placement Band: 1990 - 1994
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1990 -1994		1.00			
1991 -1995		1.00			
1992 -1996		1.00			
1993 -1997		1.00			
1994 -1998		1.00			
1995 -1999		1.00			
1996 -2000		1.00			
1997 -2001	8.5	0.00	0.27976196	R4	7.15
1998 -2002	9.5	0.00	0.26840527	R4	7.25
1999 -2003	10.5	0.00	0.02795968	SQ	7.61
2000 -2004	11.5	0.00	0.02444965	SQ	7.64
2001 -2005	12.5	0.00	0.25298458	R4	7.20
2002 -2006	13.5	92.01	0.01360181	R0.5	40.28
2003 -2007	14.5	80.47	0.05407438	R0.5	20.27
2004 -2008	15.5	78.43	0.08433457	R0.5	19.44
2005 -2009	16.5	72.06	0.21165142	R0.5	15.96
2006 -2010	17.5	85.14	0.03720481	R0.5	33.76
2007 -2011	18.5	83.04	0.05522118	R0.5	31.01
2008 -2012		1.00			
2009 -2013	20.5	41.67	0.35368213	L0	13.95
2010 -2014	21.5	32.32	0.11686053	L1	14.90
2011 -2015	22.5	31.95	0.12452472	L0.5	15.45
2012 -2016	23.5	32.93	0.14060641	L0.5	15.61
2013 -2017	24.5	28.02	0.18447275	L0	14.70
2014 -2018	25.5	55.13	0.19831800	L1	25.45

Actuarial Life Analysis

Account: 1650-411
Scenario: Yukon Energy @ 2018
Placement Band: 1990 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1990 -2018	28.5	40.93	0.19953081	L0	20.08
1995 -2018	28.5	40.88	0.19939398	L0	20.06
2000 -2018	28.5	40.60	0.20002144	L0	19.88
2005 -2018	28.5	43.66	0.18949751	L0	21.26
2010 -2018	28.5	38.56	0.25206453	L0	18.81
2015 -2018	28.5	76.36	0.10315800	L0	50.69

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-83**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1650-412 Trxptn – Sedans and Station Wagons 11 S4
This account includes the cost of vans, cars and smaller vehicles. The plant balance in this account at December 31, 2018 is $138 thousand. The approved life and curve for this account is 7 L2. Discussions with Company personnel indicated these vehicles are lasting longer than the existing seven years. Company policy is if a vehicle is 8 years or older, has 160,000 km, and has incurred maintenance costs greater than 15% in one year, they would retire. However, they have fallen behind on this schedule. The life analysis supports Company discussion that these vehicles are lasting longer and the slippage in the schedule, with a life indication of at least 12 years or more with a steeper dispersion pattern. Giving consideration to the Company policy, recent experience, expectations and judgment, this study proposes moving from 7 L2 to 11 S4 at this time."

QUESTION:

a) Please provide the "life analysis support[ing] Company discussion that these vehicles are lasting longer and the slippage in the schedule, with a life indication of at least 12 years or more with a steeper dispersion pattern".

b) If the life analysis discussed in part (a) above was not based on actuarial data, please clarify how YEC is able to propose a change to an 11-S4 life and curve from the approved 7-L2 life and curve without the benefit of an actuarial life analysis.

c) Please provide the directional impact of the change proposed in terms of an increase or decrease to depreciation expense for this account for the year 2021.

ANSWER:

(a) and **(b)**

The life analysis is provided as Attachment 1 to this response.

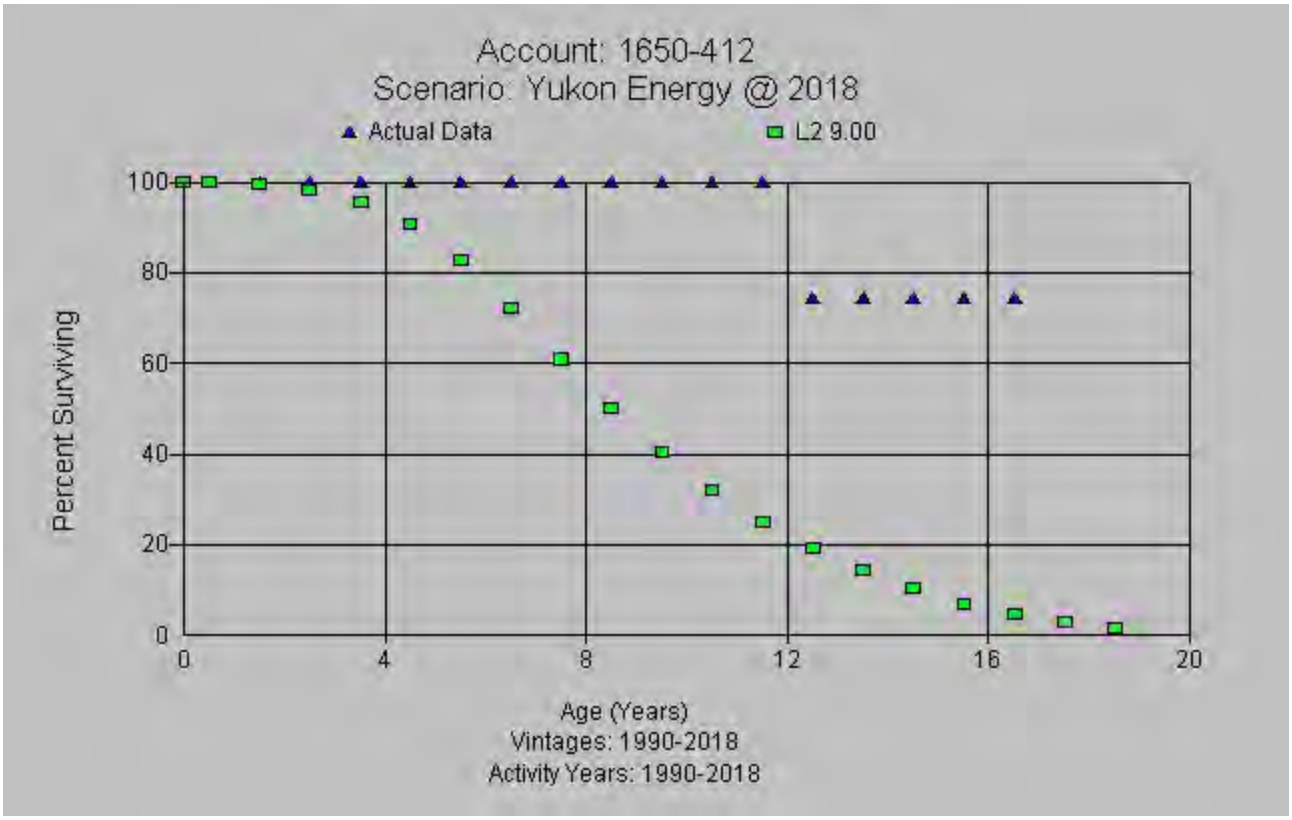
(c)

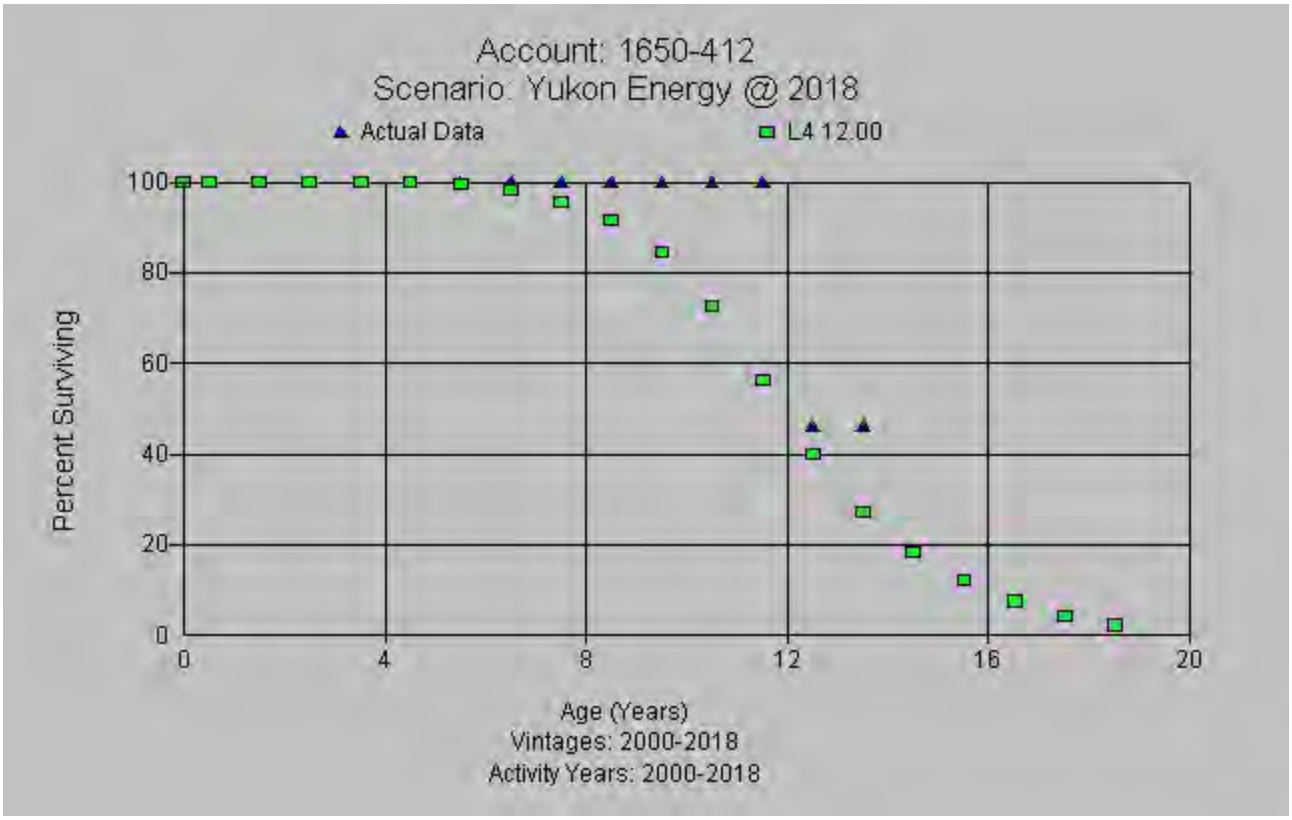
As the Depreciation Study proposes to increase the life of asset class from 7 years to 11 years, the directional impact on 2021 depreciation expense is a decrease.

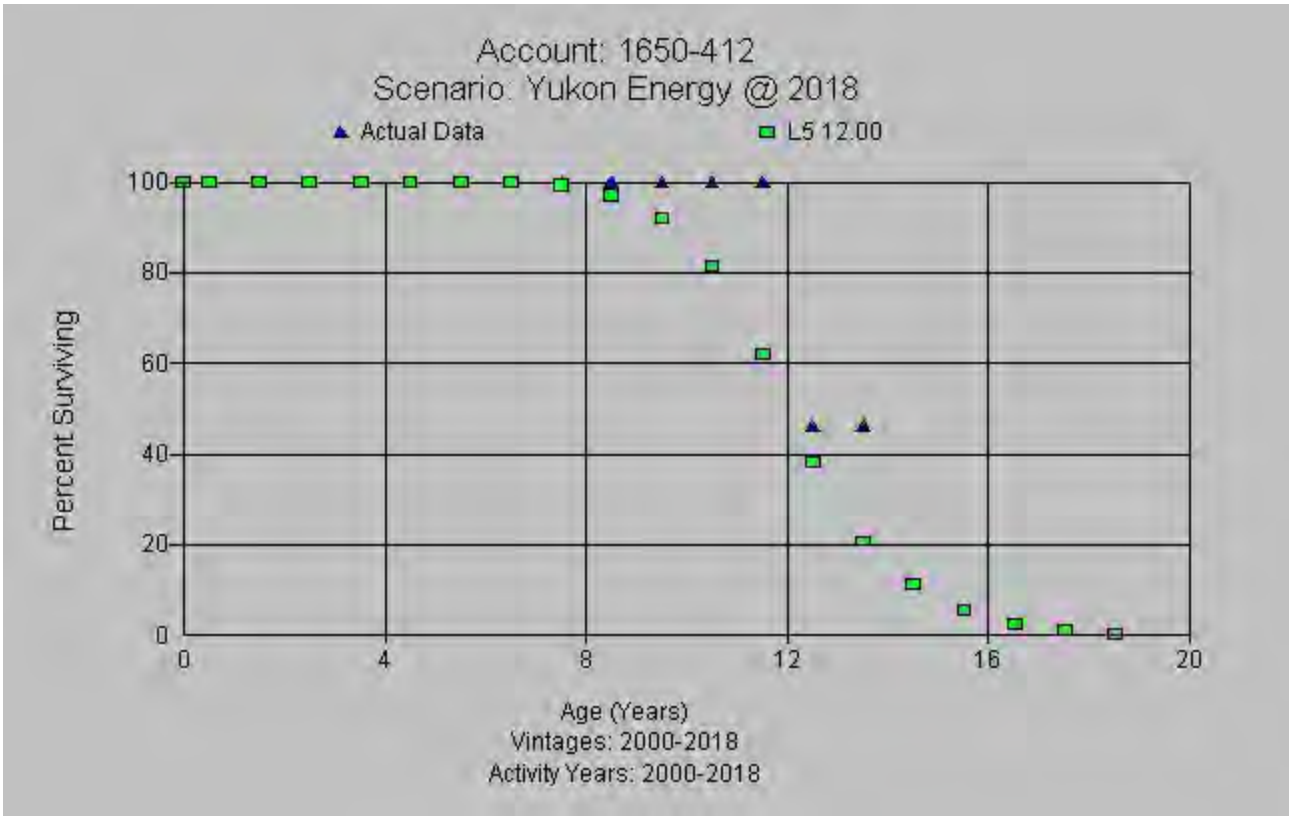
Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1650-412
Placement Band: 2000 - 2018 **Observation Band:** 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	168,107.25	0.00	0.00000	1.00000	100.00
0.5	168,107.25	0.00	0.00000	1.00000	100.00
1.5	168,107.25	0.00	0.00000	1.00000	100.00
2.5	168,107.25	0.00	0.00000	1.00000	100.00
3.5	168,107.25	0.00	0.00000	1.00000	100.00
4.5	83,295.55	0.00	0.00000	1.00000	100.00
5.5	83,295.55	0.00	0.00000	1.00000	100.00
6.5	83,295.55	0.00	0.00000	1.00000	100.00
7.5	83,295.55	0.00	0.00000	1.00000	100.00
8.5	56,355.66	0.00	0.00000	1.00000	100.00
9.5	56,355.66	0.00	0.00000	1.00000	100.00
10.5	56,355.66	0.00	0.00000	1.00000	100.00
11.5	56,355.66	30,343.66	0.53843	0.46157	100.00
12.5	26,012.00	0.00	0.00000	1.00000	46.16
13.5	0.00	0.00	0.00000	1.00000	46.16


Account: 1650-412
Scenario: Yukon Energy @ 2018
Actual Data
L2 9.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1990-2018
Activity Years: 1990-2018

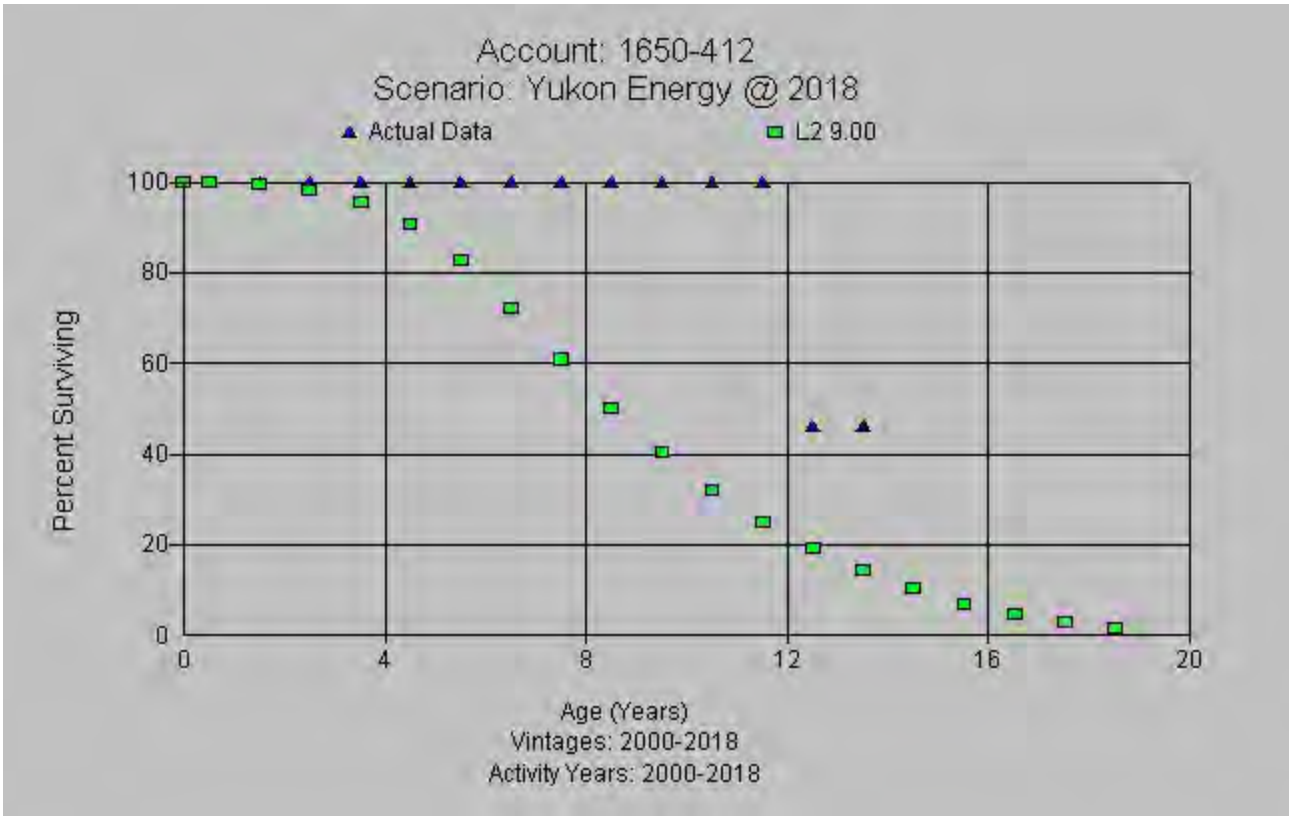

Account: 1650-412
Scenario: Yukon Energy @ 2018
Actual Data
L4 12.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

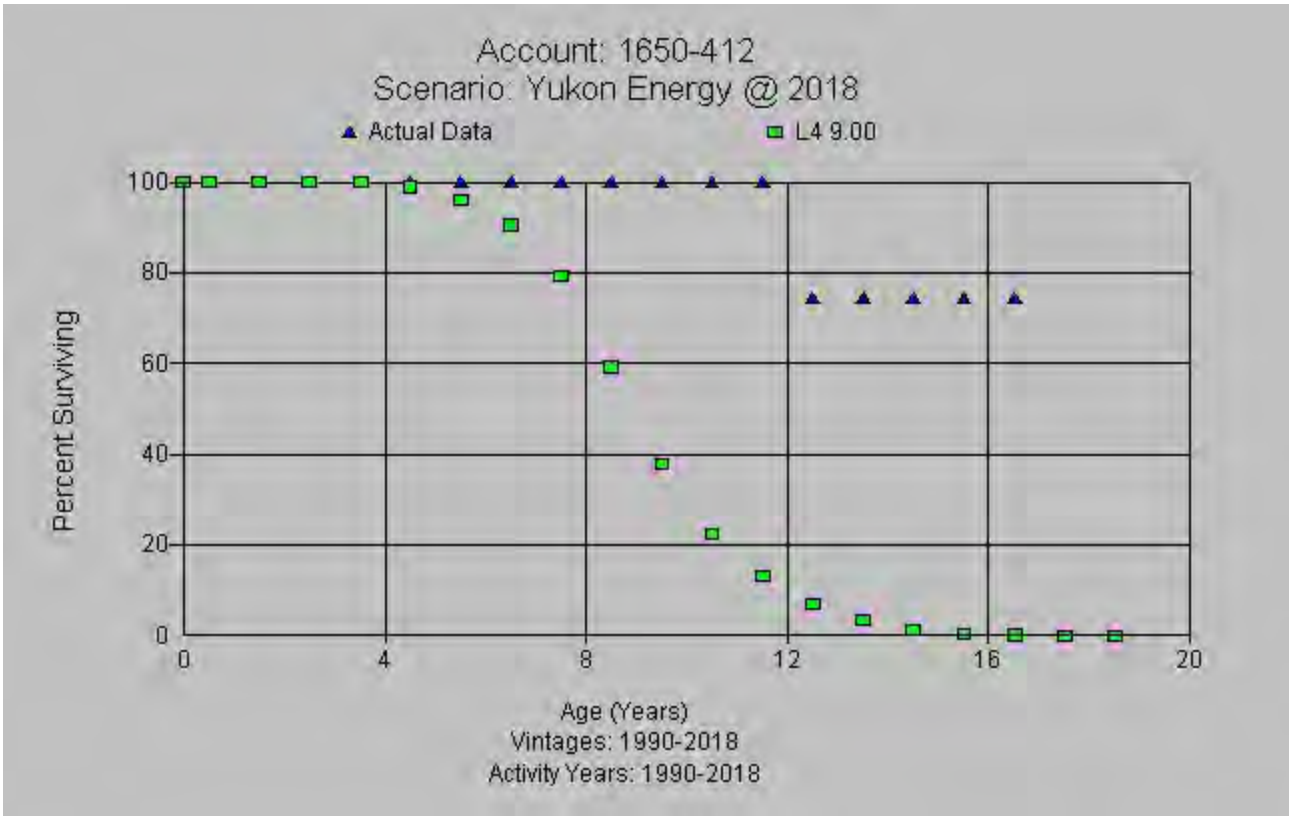

Account: 1650-412
Scenario: Yukon Energy @ 2018
Actual Data
L5 12.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

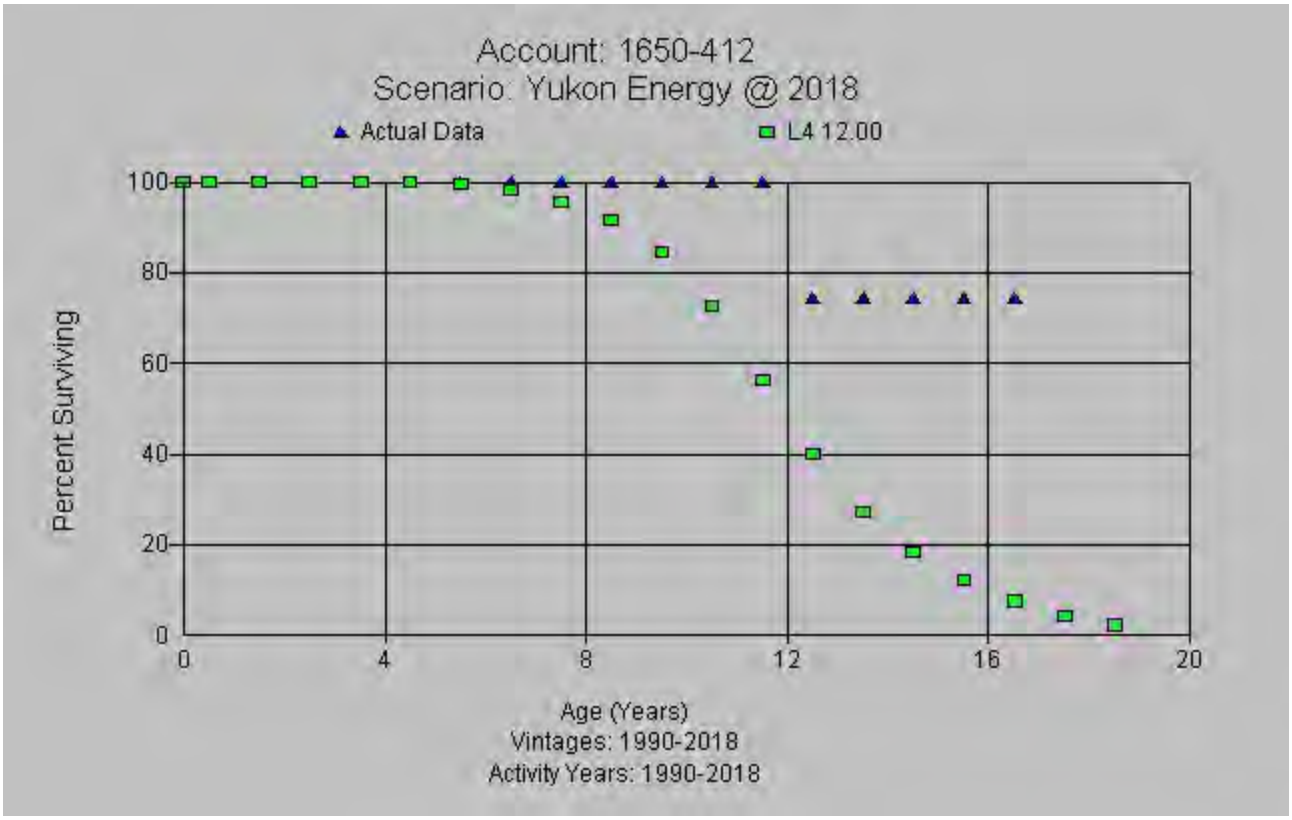
Observed Life Table

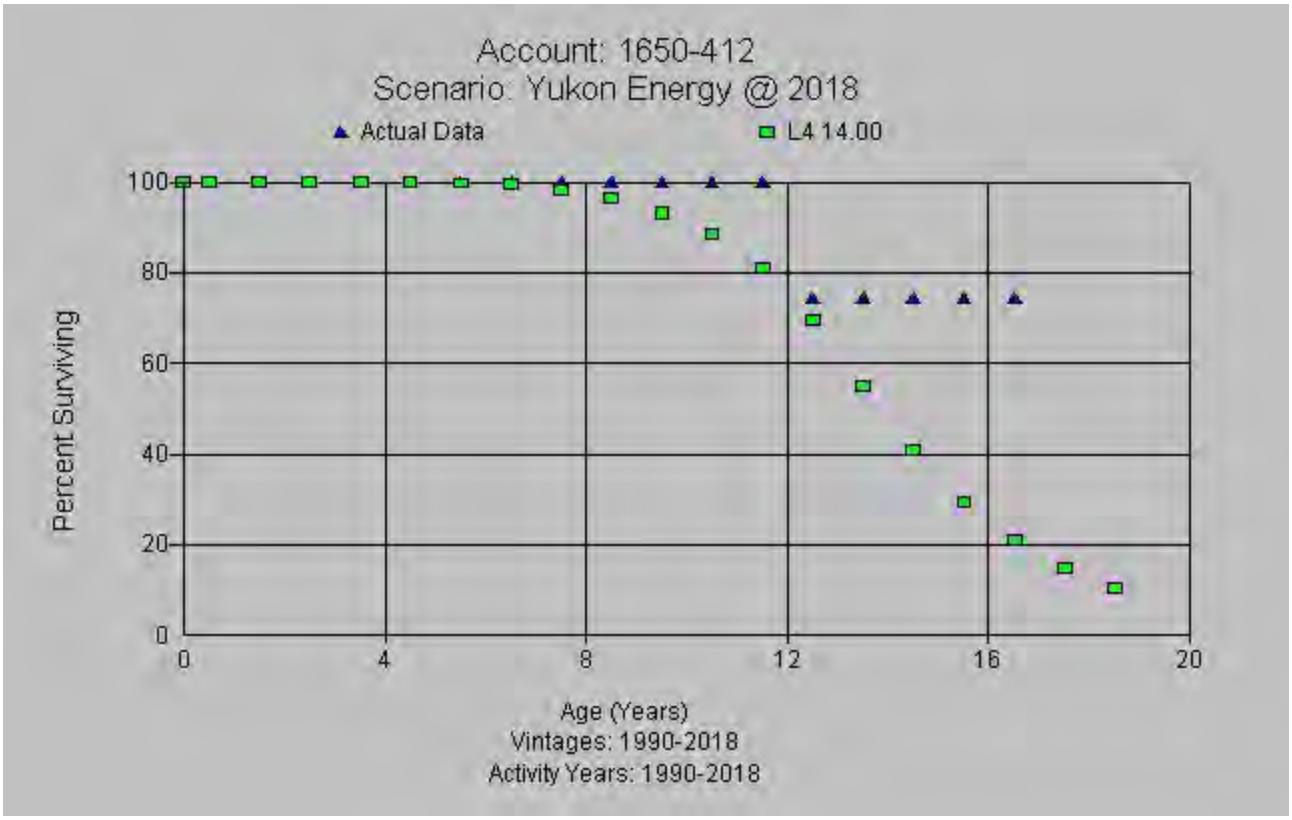
Scenario: Yukon Energy @ 2018
Account: 1650-412
Placement Band: 1990 - 2018 **Observation Band:** 1990 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	230,388.76	0.00	0.00000	1.00000	100.00
0.5	230,388.76	0.00	0.00000	1.00000	100.00
1.5	230,388.76	0.00	0.00000	1.00000	100.00
2.5	230,388.76	0.00	0.00000	1.00000	100.00
3.5	230,388.76	0.00	0.00000	1.00000	100.00
4.5	145,577.06	0.00	0.00000	1.00000	100.00
5.5	145,577.06	0.00	0.00000	1.00000	100.00
6.5	145,577.06	0.00	0.00000	1.00000	100.00
7.5	145,577.06	0.00	0.00000	1.00000	100.00
8.5	118,637.17	0.00	0.00000	1.00000	100.00
9.5	118,637.17	0.00	0.00000	1.00000	100.00
10.5	118,637.17	0.00	0.00000	1.00000	100.00
11.5	118,637.17	30,343.66	0.25577	0.74423	100.00
12.5	88,293.51	0.00	0.00000	1.00000	74.42
13.5	62,281.51	0.00	0.00000	1.00000	74.42
14.5	62,281.51	0.00	0.00000	1.00000	74.42
15.5	62,281.51	0.00	0.00000	1.00000	74.42
16.5	62,281.51	62,281.51	1.00000	0.00000	74.42
17.5	0.00	0.00	0.00000	1.00000	0.00


Account: 1650-412
Scenario: Yukon Energy @ 2018
Actual Data
L2 9.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018


Account: 1650-412
Scenario: Yukon Energy @ 2018
Actual Data
L4 9.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1990-2018
Activity Years: 1990-2018


Account: 1650-412
Scenario: Yukon Energy @ 2018
Actual Data
L4 12.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1990-2018
Activity Years: 1990-2018


Account: 1650-412
Scenario: Yukon Energy @ 2018
Actual Data
L4 14.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1990-2018
Activity Years: 1990-2018

Placement Band	Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -1984	1980 -1984		1.00			
1980 -1985	1981 -1985		1.00			
1980 -1986	1982 -1986		1.00			
1980 -1987	1983 -1987		1.00			
1980 -1988	1984 -1988		1.00			
1980 -1989	1985 -1989		1.00			
1980 -1990	1986 -1990		1.00			
1980 -1991	1987 -1991		1.00			
1980 -1992	1988 -1992		1.00			
1980 -1993	1989 -1993		1.00			
1980 -1994	1990 -1994		1.00			
1980 -1995	1991 -1995		1.00			
1980 -1996	1992 -1996		1.00			
1980 -1997	1993 -1997		1.00			
1980 -1998	1994 -1998		1.00			
1980 -1999	1995 -1999		1.00			
1980 -2000	1996 -2000		1.00			
1980 -2001	1997 -2001		1.00			
1980 -2002	1998 -2002		1.00			
1980 -2003	1999 -2003		1.00			
1980 -2004	2000 -2004	10.5	61.76	0.00205090	SQ	10.46
1980 -2005	2001 -2005	11.5	55.06	0.02917074	S5	11.43
1980 -2006	2002 -2006	12.5	55.06	0.05681257	S4	12.18
1980 -2007	2003 -2007	13.5	55.06	0.08222736	S3	13.12
1980 -2008	2004 -2008	14.5	55.06	0.10643770	L3	14.45
1980 -2009	2005 -2009	15.5	0.00	0.04708900	SQ	14.61
1980 -2010	2006 -2010	16.5	0.00	0.00000000	SQ	15.20
1980 -2011	2007 -2011	17.5	0.00	0.00000000	SQ	15.20
1980 -2012	2008 -2012	18.5	0.00	0.00000000	SQ	15.20
1980 -2013	2009 -2013	19.5	0.00	0.00000000	SQ	15.20
1980 -2014	2010 -2014		1.00			

Placement Band	Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -2015	2011 -2015	21.5	0.00	0.00000000	SQ	16.20
1980 -2016	2012 -2016	22.5	0.00	0.00000000	SQ	12.20
1980 -2017	2013 -2017	23.5	0.00	0.18016947	S4	13.90
1980 -2018	2014 -2018	24.5	0.00	0.18016947	S4	13.90

Actuarial Life Analysis

Account: 1650-412
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1980 -2018	38.5	0.00	0.18800405	L3	20.06
1985 -2018	38.5	0.00	0.18800405	L3	20.06
1990 -2018	38.5	0.00	0.18800405	L3	20.06
1995 -2018	38.5	0.00	0.17621727	L3	19.26
2000 -2018	38.5	0.00	0.24650638	R5	15.77
2005 -2018	38.5	0.00	0.24650638	R5	15.77
2010 -2018	38.5	0.00	0.24650638	R5	15.77
2015 -2018		0.00			

REFERENCE: **Application, Tab 9, Depreciation Study, pages 9-84 and 9-105**

ISSUE: **Depreciation expense**

QUOTE: "Account 1650-420 Trxptn – Trucks and Pole Trailers 25 R1.5
This account includes the cost of large trucks and pole trailers that carry less than 10,000 lbs. The plant balance in this account at December 31, 2018 is $11 thousand. The approved life and curve for this account is 25 R1.5. Discussions with Company personnel indicated the existing 25 year life is reasonable for the assets. There is no historical experience to analyze. Giving consideration to the type of assets, existing life, Company expectations, and judgment, this study proposes retention of the 25 R1.5 at this time."

QUESTION:

a) Given that page 9-105 indicates an existing 31-R1.5 life and curve, please clarify which is the correct approved depreciation parameters and confirm that YEC continues to propose a 25-R1.5 life and curve for this account.

ANSWER:

(a)

The current approved life for this account is 25 years with a R1.5 dispersion. The information on page 105 should be corrected to 25 R1.5. YEC is proposing to retain that curve and life for this account.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-86**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1650-440 Trxptn – Trucks ¾ to 2 Tons 9 L2
This account includes the cost of trucks that are ¾ to 2 Tons used by employees to perform day to day duties. The plant balance in this account at December 31, 2018 is $2.6 million. The approved life and curve for this account is 10 R2. Discussions with Company personnel indicated that electricians would drive 90,000 and operations 70,000 in approximately 10 years. Linemen would drive 115,000 and would hit the maximum mileage in 3-4 years but there are other factors that cause the Company to retain these vehicles longer. There are equal numbers of each type of vehicle. Company expects they will be replaced by 8 years. However, the life analysis indicates a life between 10 to 11 years. Giving consideration to Company policy, recent experience, expectations and judgment, this study proposes moving from 10 R2 to 9 L2 at this time."

QUESTION:

a) Please provide the "life analysis indicat[ing] a life between 10 to 11 years".

b) If the life analysis discussed in part (a) above was not based on actuarial data, please clarify how YEC is able to propose a change to a 9-L2 life and curve from the approved 10-R2 life and curve without the benefit of an actuarial life analysis.

c) Please provide the directional impact of the change proposed in terms of an increase or decrease to depreciation expense for this account for the year 2021.

d) Please provide an observed life table and the plotted actual data points showing both a 9-L2 and 10-R2 survivor curve for this account.

ANSWER:

(a) and **(b)**

The actuarial analysis for this account is provided as Attachment 1 to this response.

(c)

As the Depreciation Study proposes to decrease the life of asset class from 10 years to 9 years, the directional impact on 2021 depreciation expense is an increase.

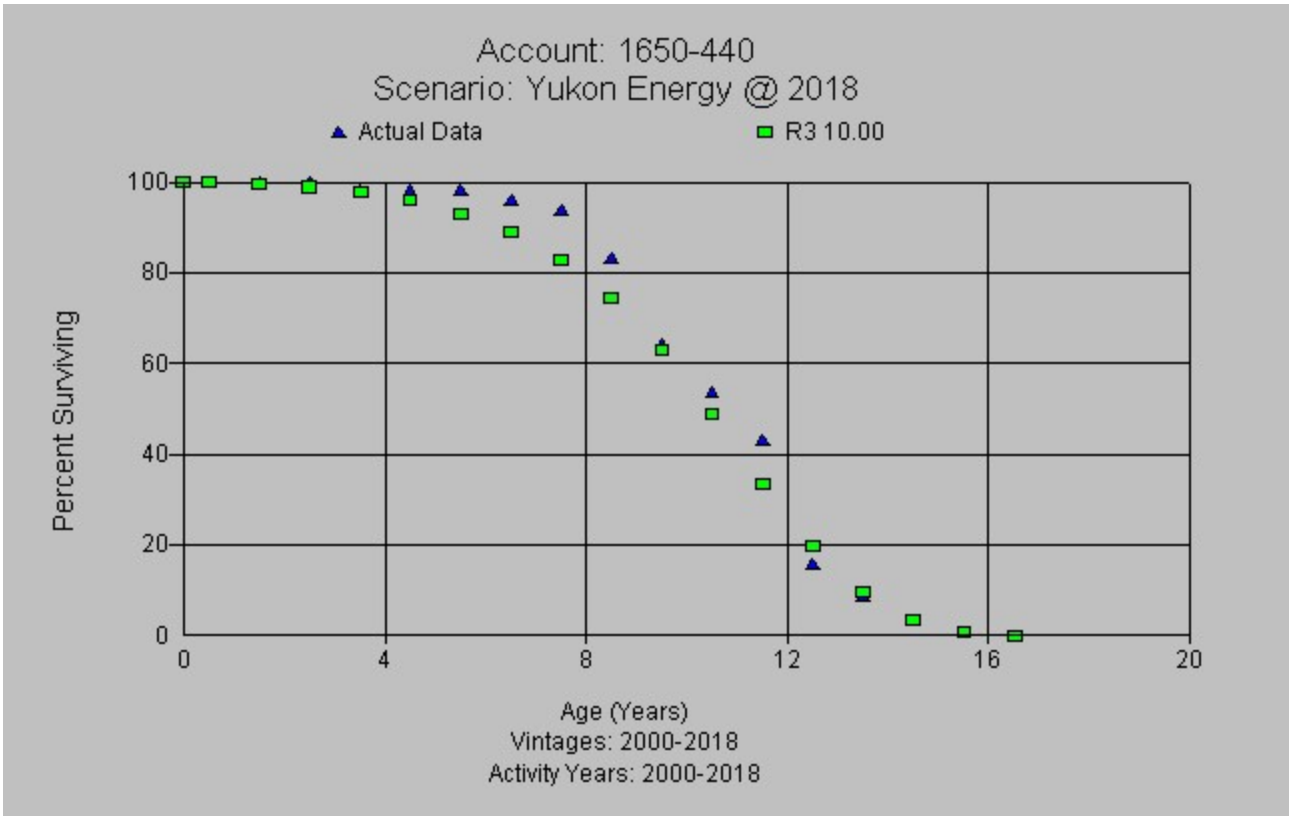
(d)

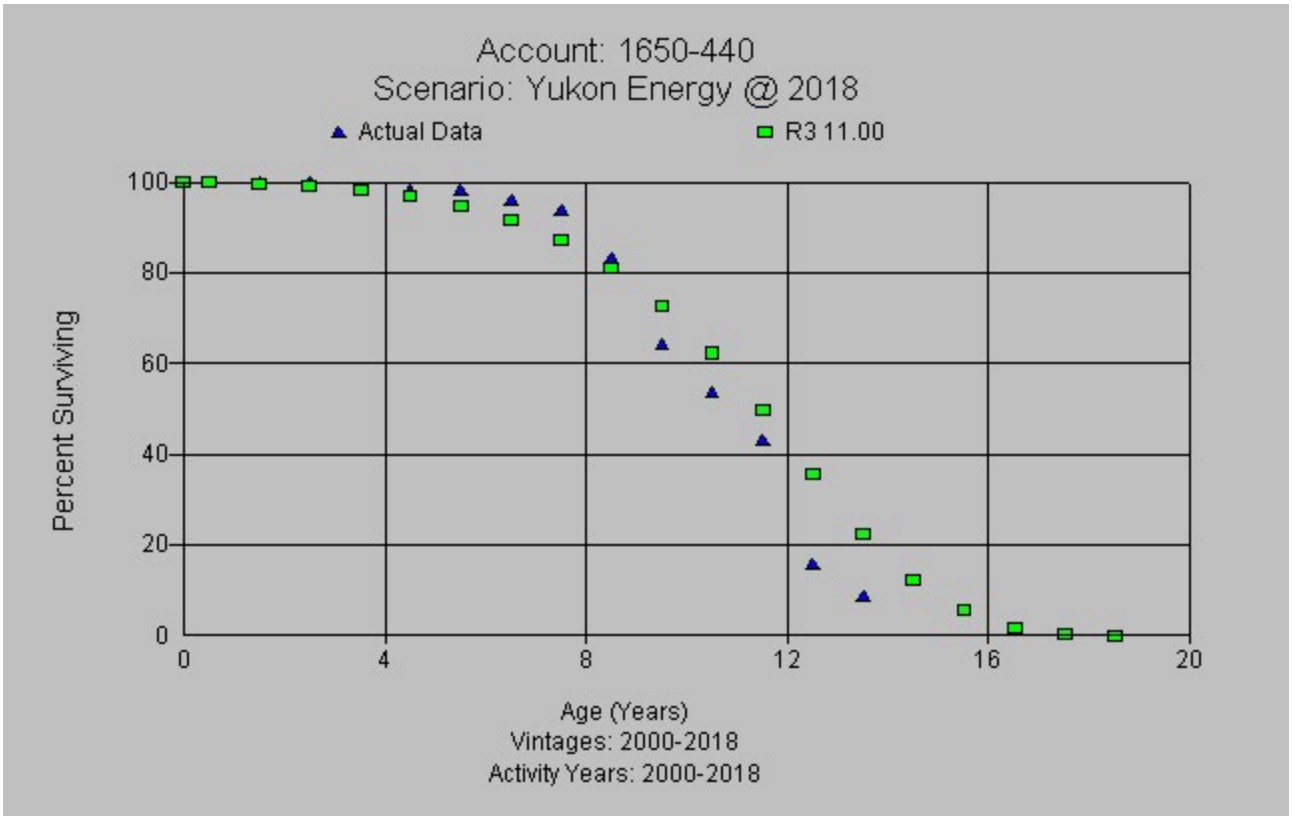
The data provided as YUB-YEC-1-136(a) Attachment 1 give the requested plot as well as the Iowa curves propounded in the question. It should be noted that the movement to a 9 L2 was based on operational feedback from company SMEs related to recent operations and would not necessarily be fully reflected in the long-term (20-year) historical actuarial analysis.

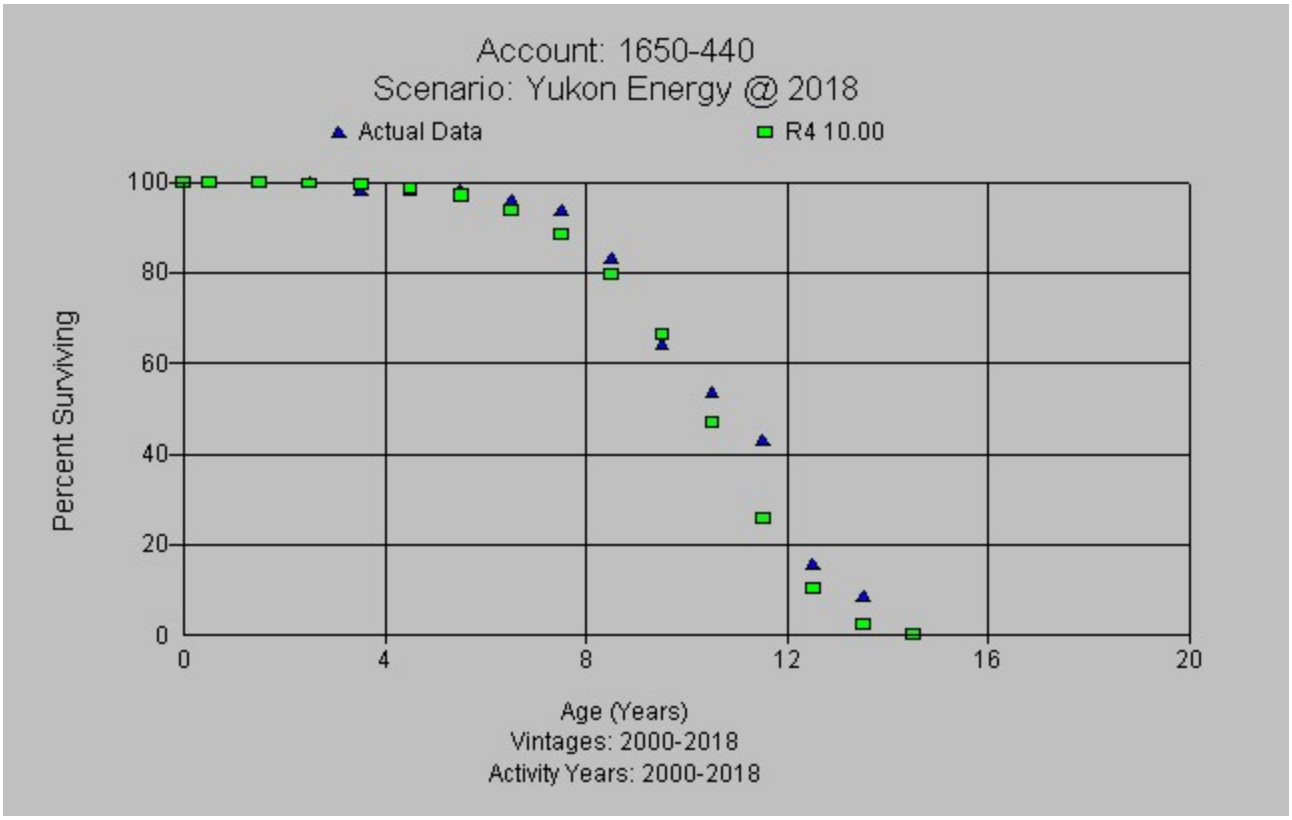
Observed Life Table

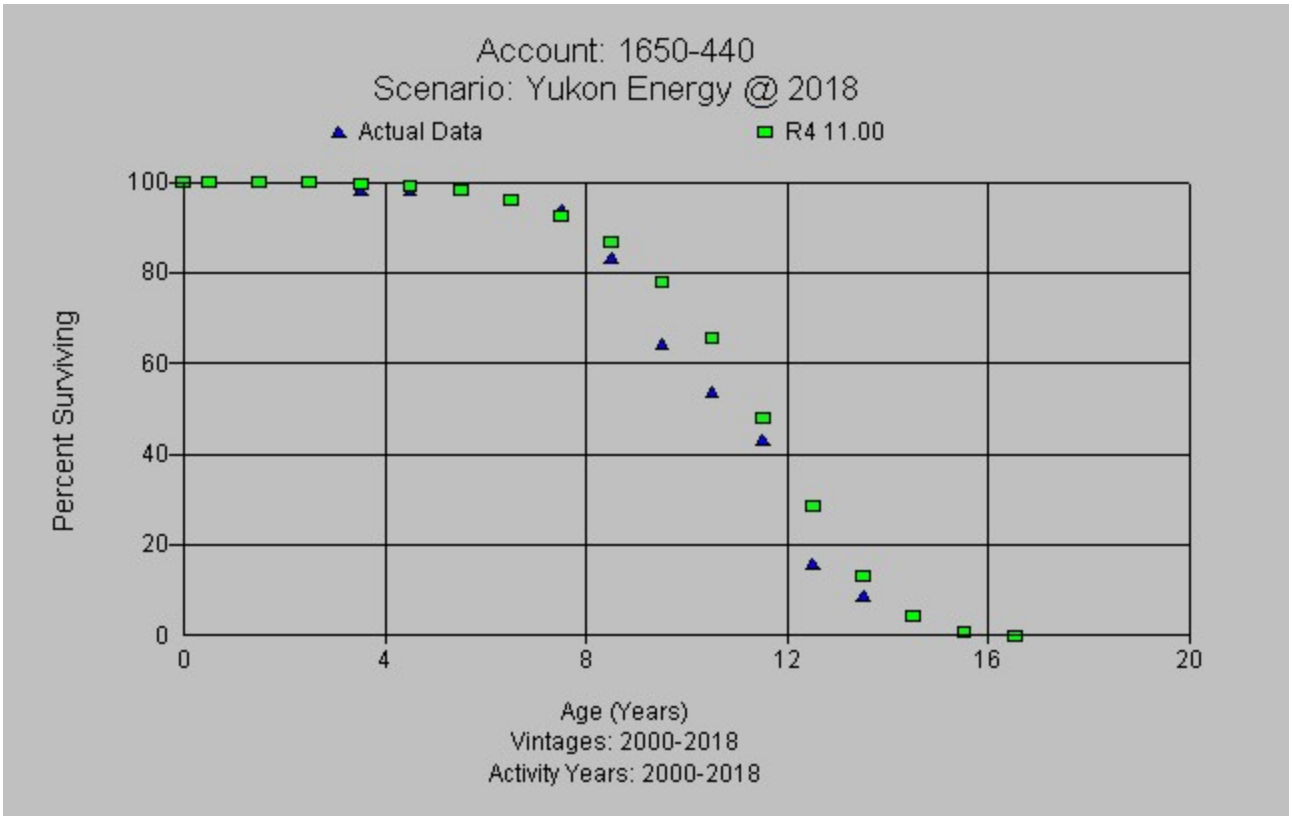
Scenario: Yukon Energy @ 2018
Account: 1650-440
Placement Band: 2000 - 2018 **Observation Band:** 2000 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,271,334.92	0.00	0.00000	1.00000	100.00
0.5	4,062,392.91	0.00	0.00000	1.00000	100.00
1.5	3,870,565.79	0.00	0.00000	1.00000	100.00
2.5	3,467,190.96	58,633.84	0.01691	0.98309	100.00
3.5	3,078,687.98	1,679.77	0.00055	0.99945	98.31
4.5	2,910,388.95	0.00	0.00000	1.00000	98.26
5.5	2,618,780.95	61,456.44	0.02347	0.97653	98.26
6.5	2,420,767.51	49,192.00	0.02032	0.97968	95.95
7.5	2,106,627.22	238,926.04	0.11342	0.88658	94.00
8.5	1,492,087.54	340,973.61	0.22852	0.77148	83.34
9.5	1,151,113.93	188,671.58	0.16390	0.83610	64.29
10.5	759,094.23	152,182.98	0.20048	0.79952	53.76
11.5	535,081.39	337,715.98	0.63115	0.36885	42.98
12.5	197,365.41	89,067.71	0.45128	0.54872	15.85
13.5	108,297.70	108,297.70	1.00000	0.00000	8.70
14.5	0.00	0.00	0.00000	1.00000	0.00


Account: 1650-440
Scenario: Yukon Energy @ 2018
Actual Data
R3 10.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018


Account: 1650-440
Scenario: Yukon Energy @ 2018
Actual Data
R3 11.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

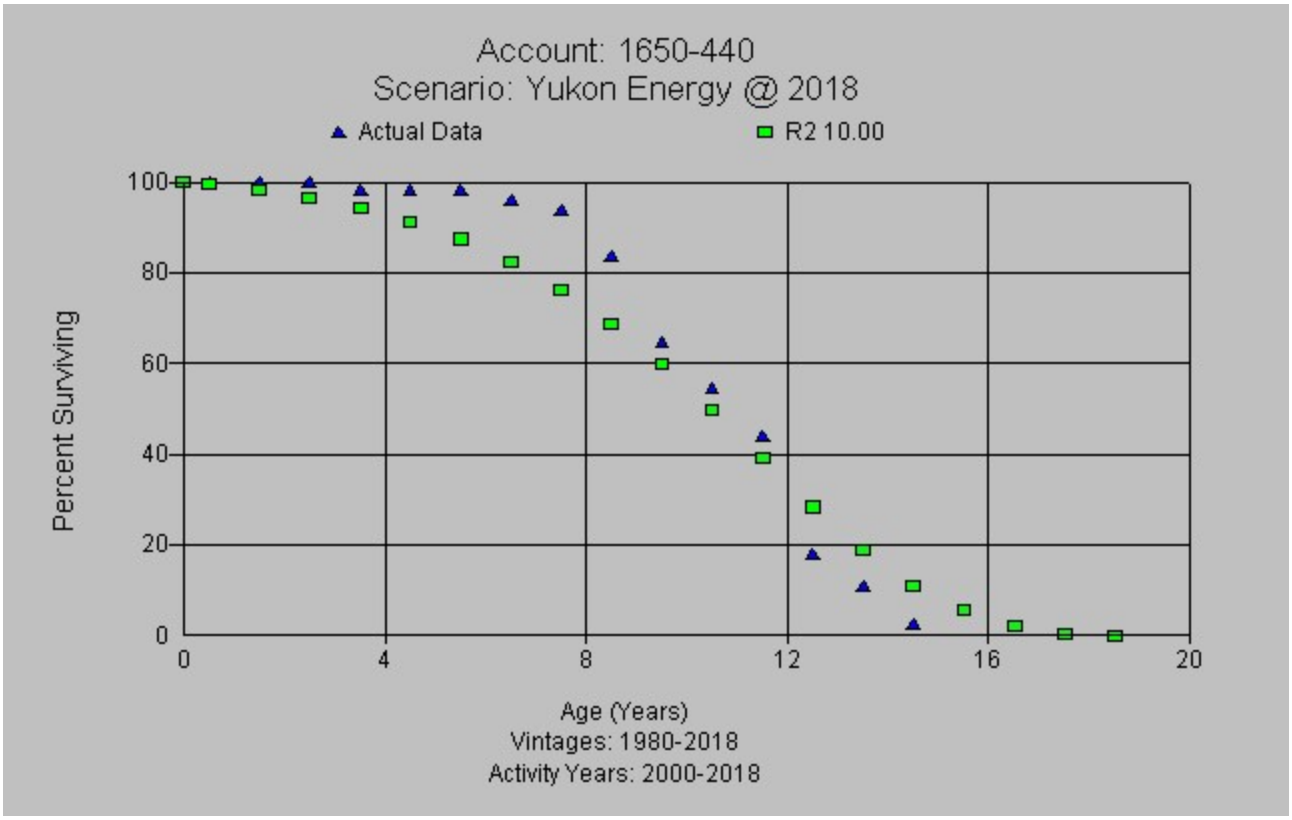

Account: 1650-440
Scenario: Yukon Energy @ 2018
Actual Data
R4 10.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

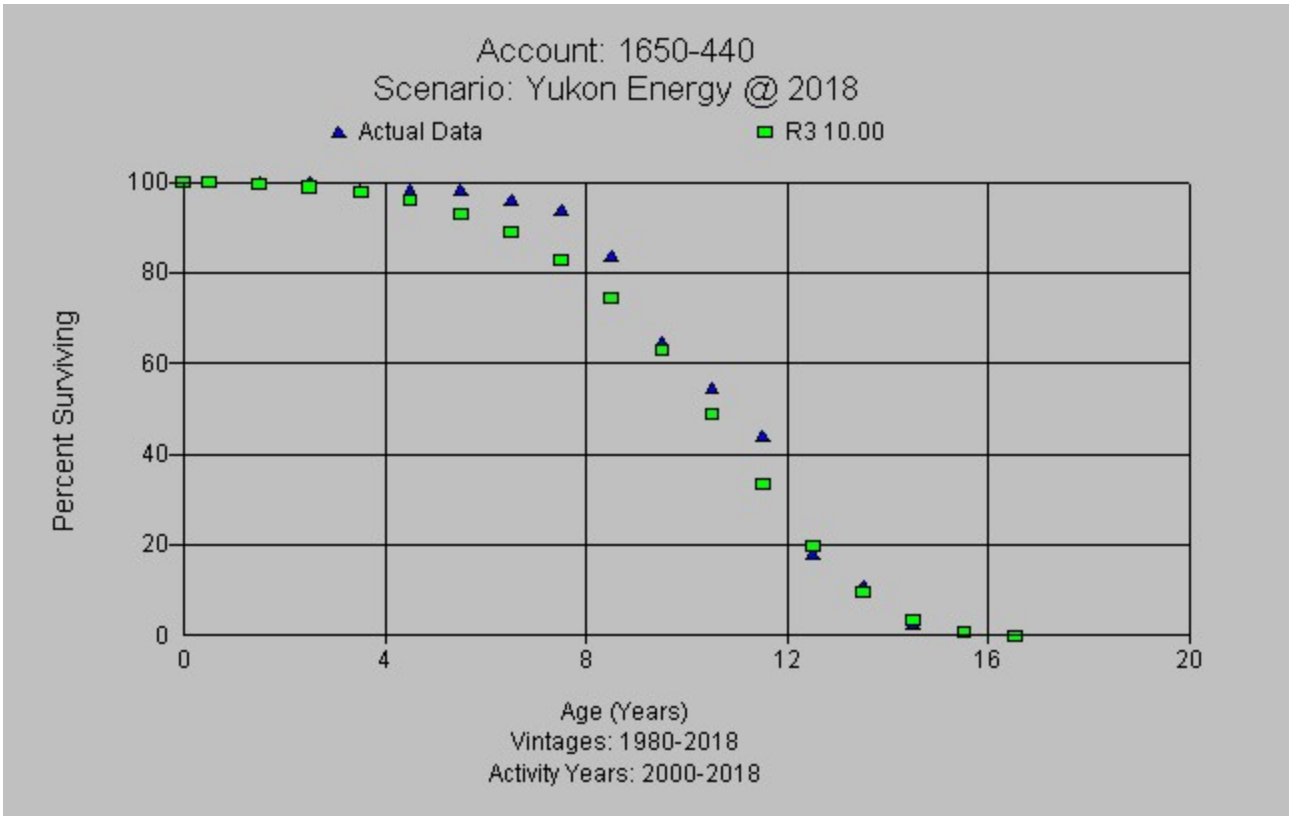

Account: 1650-440
Scenario: Yukon Energy @ 2018
Actual Data
R4 11.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 2000-2018
Activity Years: 2000-2018

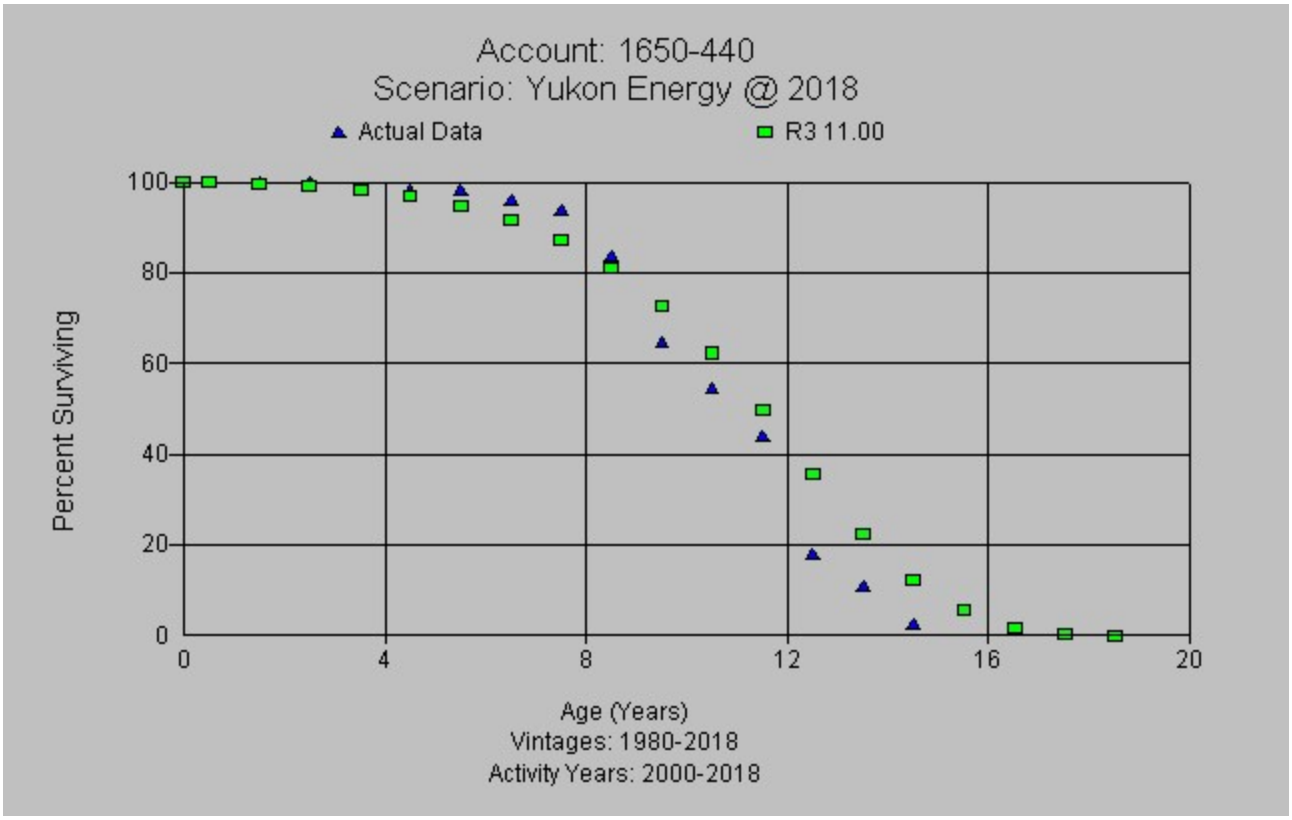
Observed Life Table

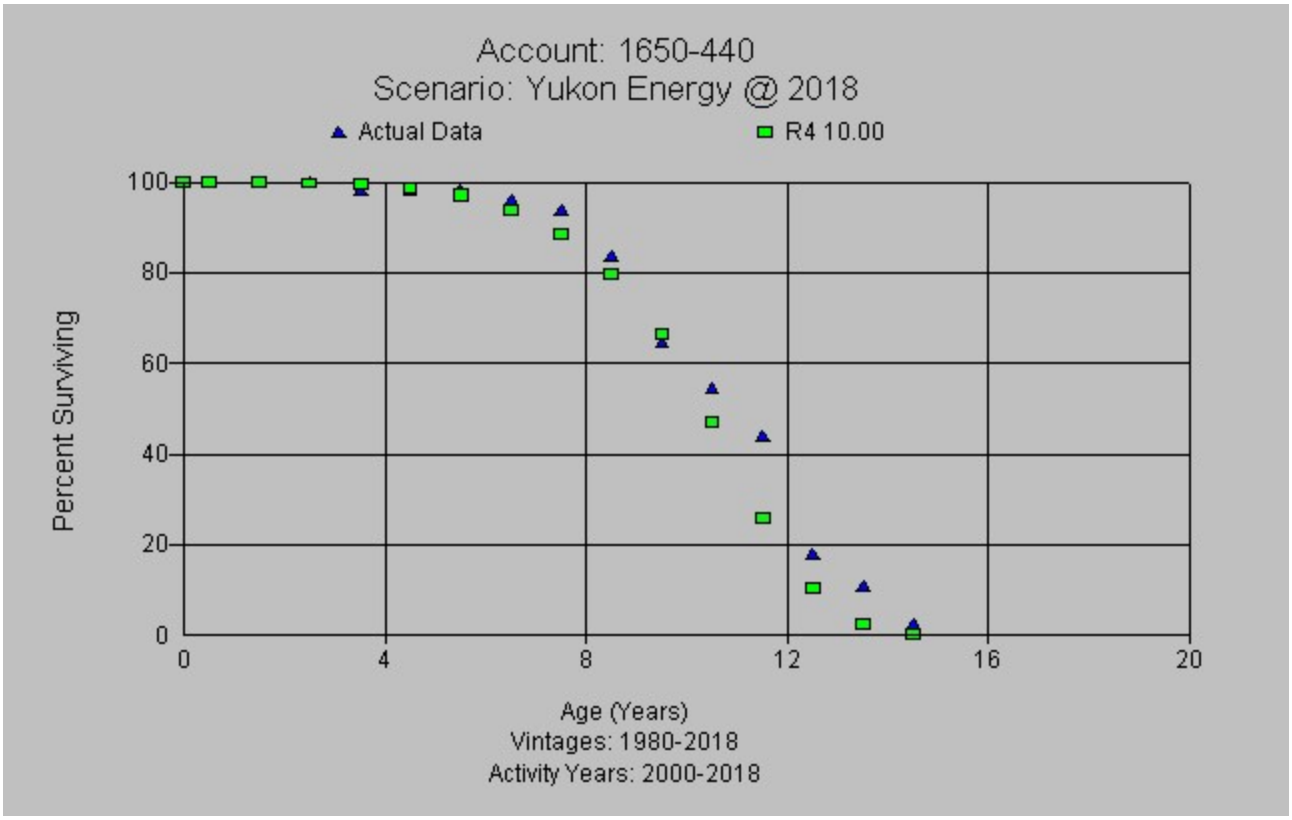
Scenario: Yukon Energy @ 2018
Account: 1650-440
Placement Band: 1980 - 2018 **Observation Band:** 2000 - 2018

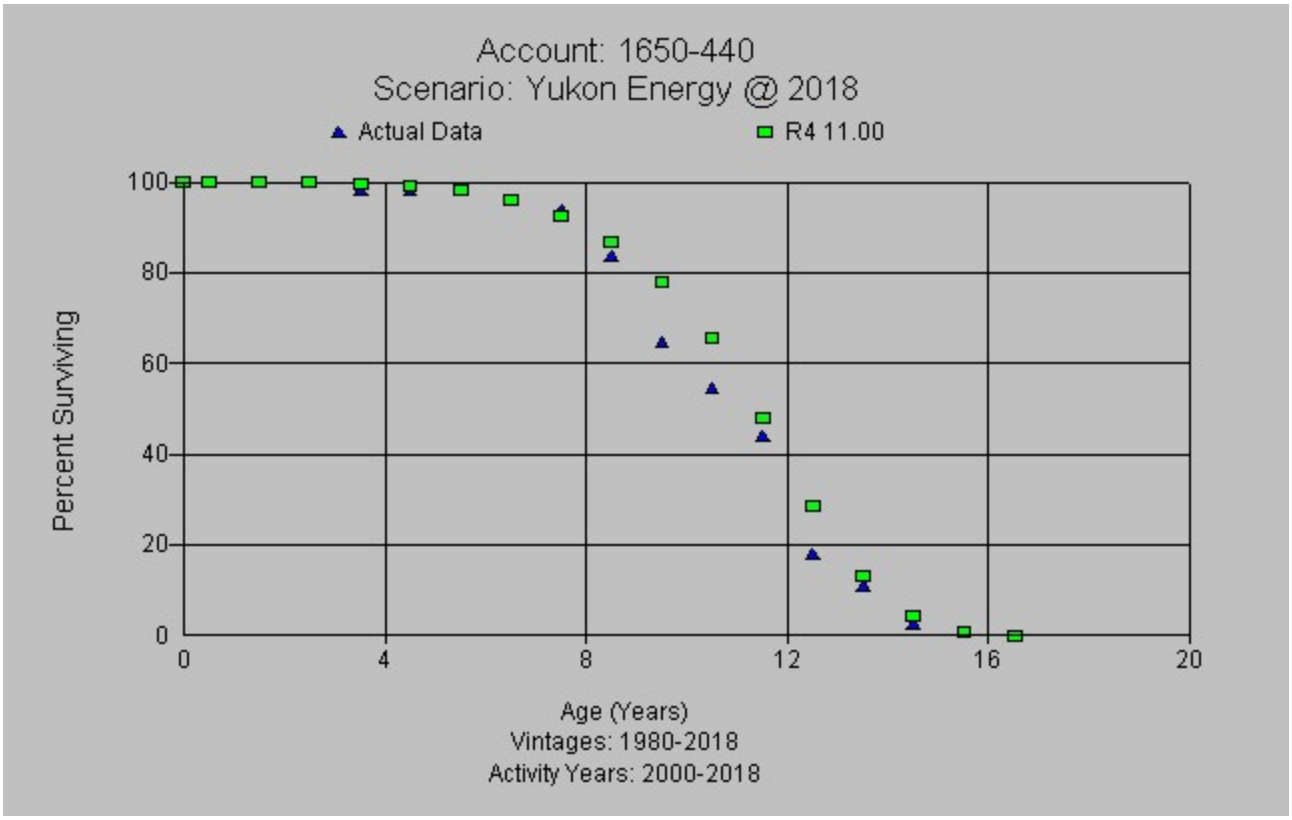
Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,271,334.92	0.00	0.00000	1.00000	100.00
0.5	4,062,392.91	0.00	0.00000	1.00000	100.00
1.5	3,904,185.71	0.00	0.00000	1.00000	100.00
2.5	3,500,810.88	58,633.84	0.01675	0.98325	100.00
3.5	3,112,307.90	1,679.77	0.00054	0.99946	98.33
4.5	2,944,008.87	0.00	0.00000	1.00000	98.27
5.5	2,652,400.87	61,456.44	0.02317	0.97683	98.27
6.5	2,454,387.43	49,192.00	0.02004	0.97996	96.00
7.5	2,140,247.14	238,926.04	0.11163	0.88837	94.07
8.5	1,526,410.46	340,973.61	0.22338	0.77662	83.57
9.5	1,189,235.85	189,374.58	0.15924	0.84076	64.90
10.5	796,513.15	152,182.98	0.19106	0.80894	54.57
11.5	572,500.31	341,514.98	0.59653	0.40347	44.14
12.5	230,985.33	89,067.71	0.38560	0.61440	17.81
13.5	141,917.62	108,297.70	0.76310	0.23690	10.94
14.5	33,619.92	33,619.92	1.00000	0.00000	2.59
15.5	0.00	0.00	0.00000	1.00000	0.00
16.5	0.00	0.00	0.00000	1.00000	
17.5	0.00	0.00	0.00000	1.00000	
18.5	0.00	0.00	0.00000	1.00000	
19.5	171,495.34	0.00	0.00000	1.00000	
20.5	171,495.34	0.00	0.00000	1.00000	
21.5	171,495.34	0.00	0.00000	1.00000	
22.5	171,495.34	39,180.95	0.22847	0.77153	
23.5	132,314.39	0.00	0.00000	1.00000	
24.5	132,314.39	132,314.39	1.00000	0.00000	
25.5	0.00	0.00	0.00000	1.00000	


Account: 1650-440
Scenario: Yukon Energy @ 2018
Actual Data
R2 10.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1980-2018
Activity Years: 2000-2018


Account: 1650-440
Scenario: Yukon Energy @ 2018
Actual Data
R3 10.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1980-2018
Activity Years: 2000-2018


Account: 1650-440
Scenario: Yukon Energy @ 2018
Actual Data
R3 11.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1980-2018
Activity Years: 2000-2018

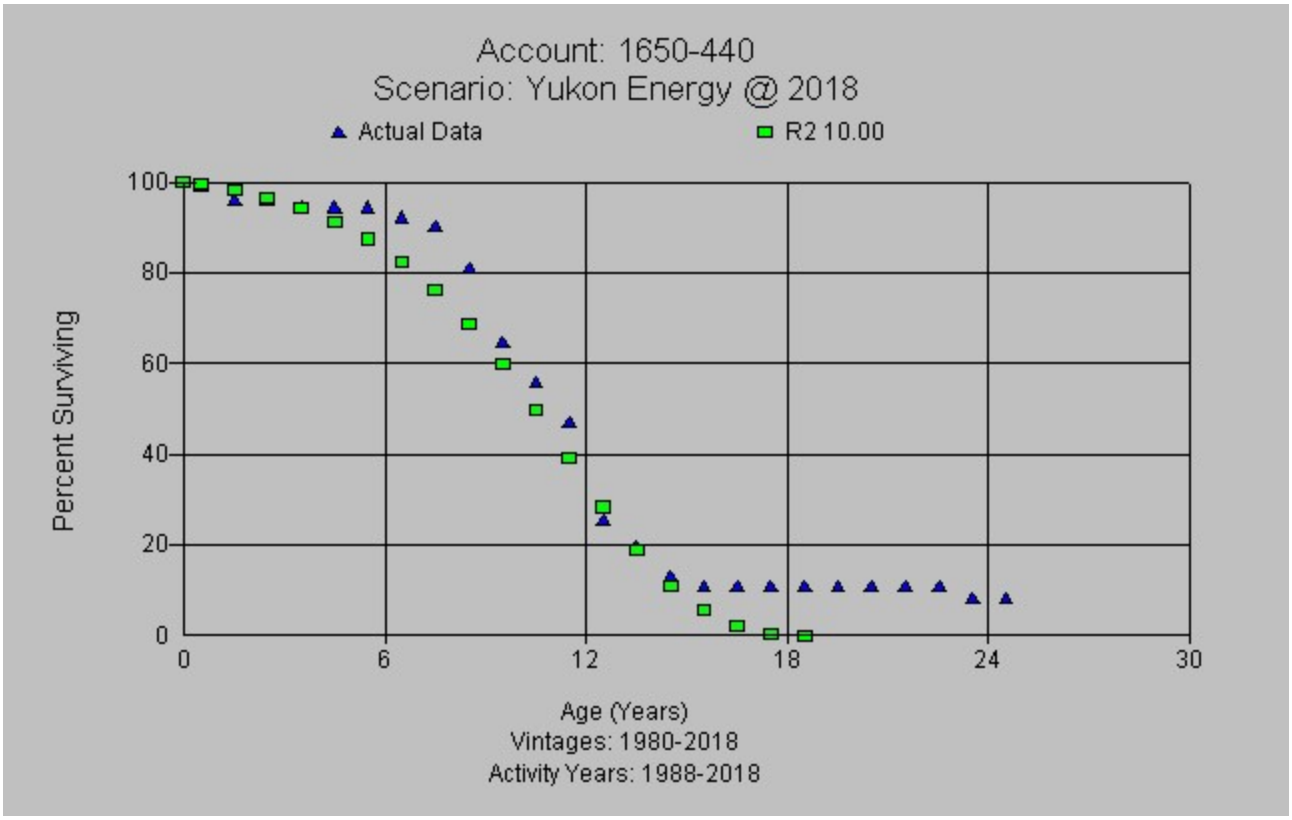

Account: 1650-440
Scenario: Yukon Energy @ 2018
Actual Data
R4 10.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1980-2018
Activity Years: 2000-2018

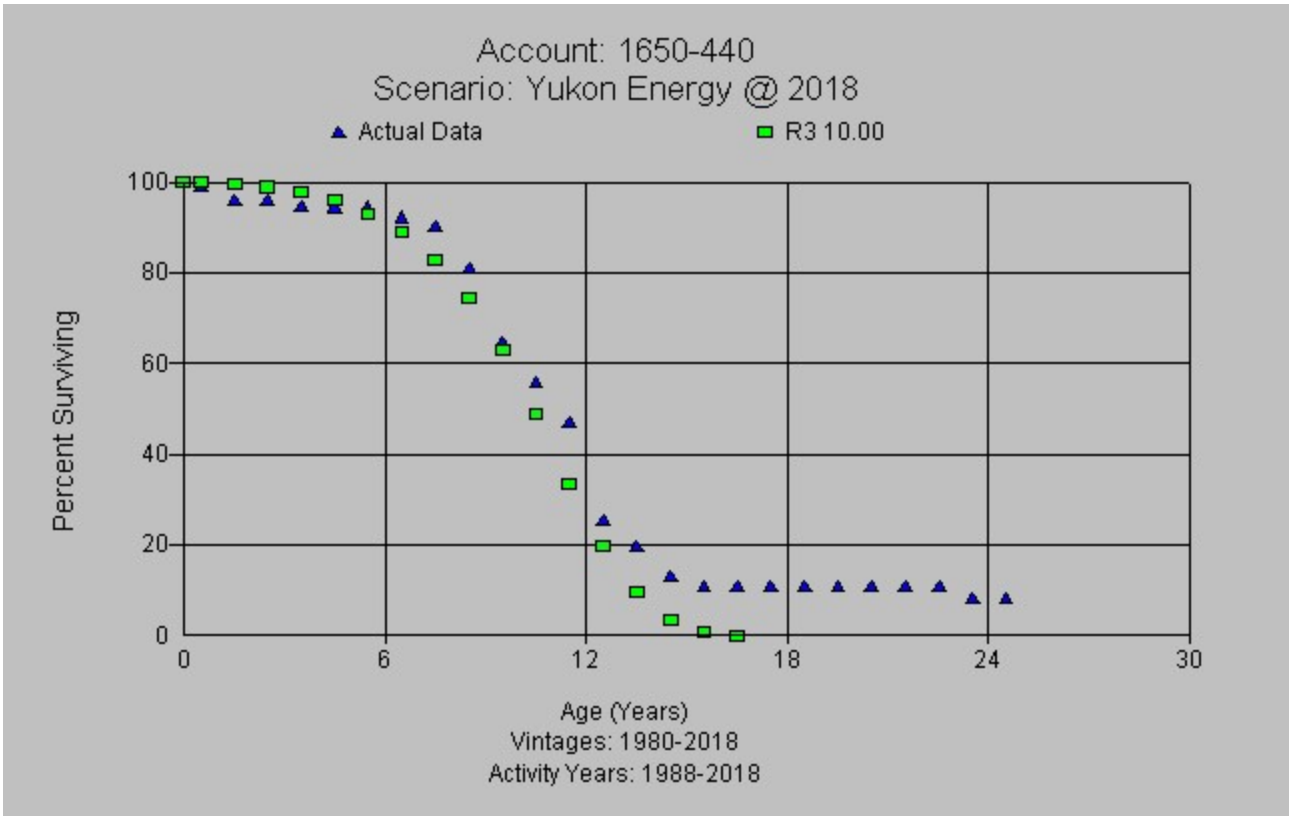

Account: 1650-440
Scenario: Yukon Energy @ 2018
Actual Data
R4 11.00
Percent Surviving
100
80
60
40
20
0
0
4
8
12
16
20
Age (Years)
Vintages: 1980-2018
Activity Years: 2000-2018

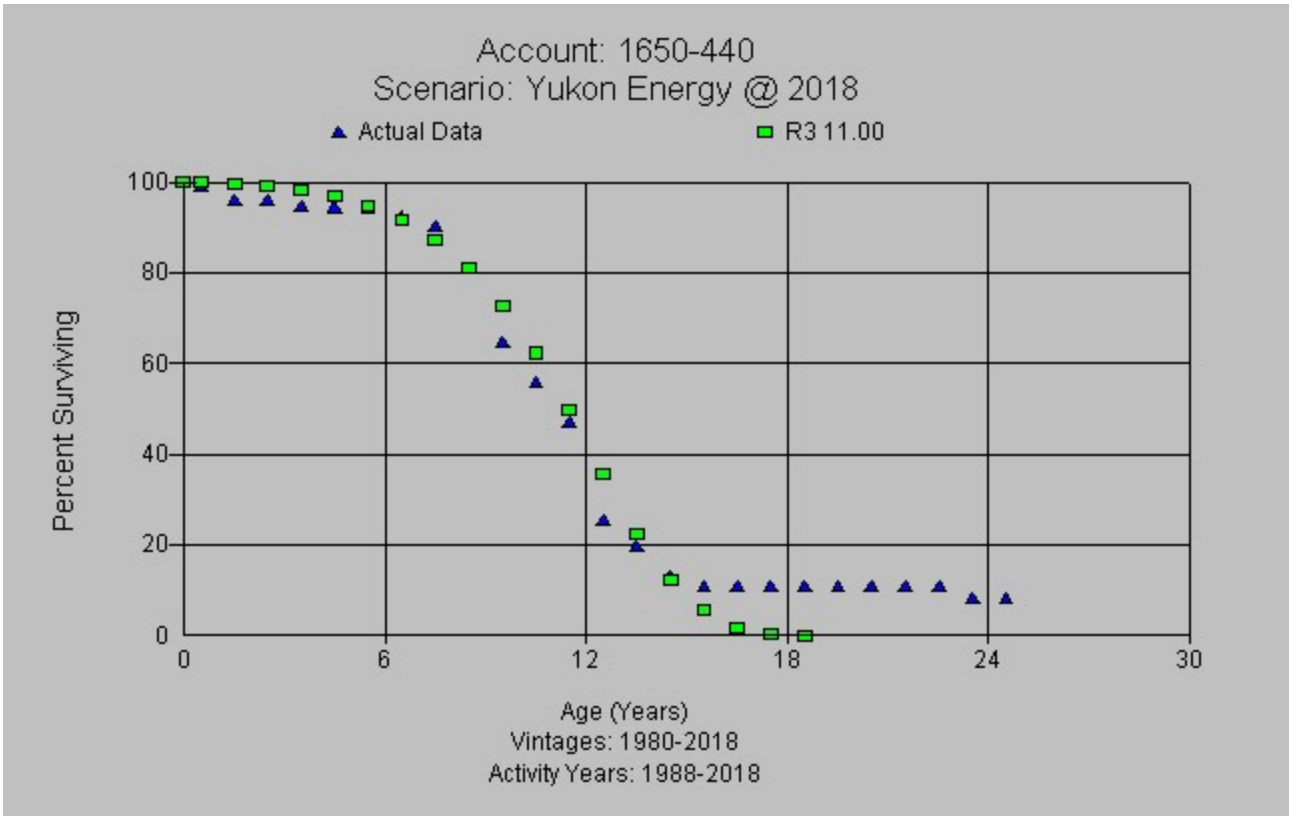
Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1650-440
Placement Band: 1980 - 2018 **Observation Band:** 1988 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,472,283.84	39,576.00	0.00885	0.99115	100.00
0.5	4,223,765.83	123,251.00	0.02918	0.97082	99.12
1.5	3,908,687.71	0.00	0.00000	1.00000	96.22
2.5	3,505,312.88	58,633.84	0.01673	0.98327	96.22
3.5	3,116,809.90	1,679.77	0.00054	0.99946	94.61
4.5	2,948,510.87	0.00	0.00000	1.00000	94.56
5.5	2,656,902.87	61,456.44	0.02313	0.97687	94.56
6.5	2,458,889.43	49,192.00	0.02001	0.97999	92.38
7.5	2,316,244.48	238,926.04	0.10315	0.89685	90.53
8.5	1,701,704.80	340,973.61	0.20037	0.79963	81.19
9.5	1,360,731.19	189,374.58	0.13917	0.86083	64.92
10.5	968,008.49	152,182.98	0.15721	0.84279	55.89
11.5	743,995.65	341,514.98	0.45903	0.54097	47.10
12.5	402,480.67	89,067.71	0.22130	0.77870	25.48
13.5	313,412.96	108,297.70	0.34554	0.65446	19.84
14.5	205,115.26	33,619.92	0.16391	0.83609	12.99
15.5	171,495.34	0.00	0.00000	1.00000	10.86
16.5	171,495.34	0.00	0.00000	1.00000	10.86
17.5	171,495.34	0.00	0.00000	1.00000	10.86
18.5	171,495.34	0.00	0.00000	1.00000	10.86
19.5	171,495.34	0.00	0.00000	1.00000	10.86
20.5	171,495.34	0.00	0.00000	1.00000	10.86
21.5	171,495.34	0.00	0.00000	1.00000	10.86
22.5	171,495.34	39,180.95	0.22847	0.77153	10.86
23.5	132,314.39	0.00	0.00000	1.00000	8.38
24.5	132,314.39	132,314.39	1.00000	0.00000	8.38
25.5	0.00	0.00	0.00000	1.00000	0.00


Account: 1650-440
Scenario: Yukon Energy @ 2018
Actual Data
R2 10.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1988-2018

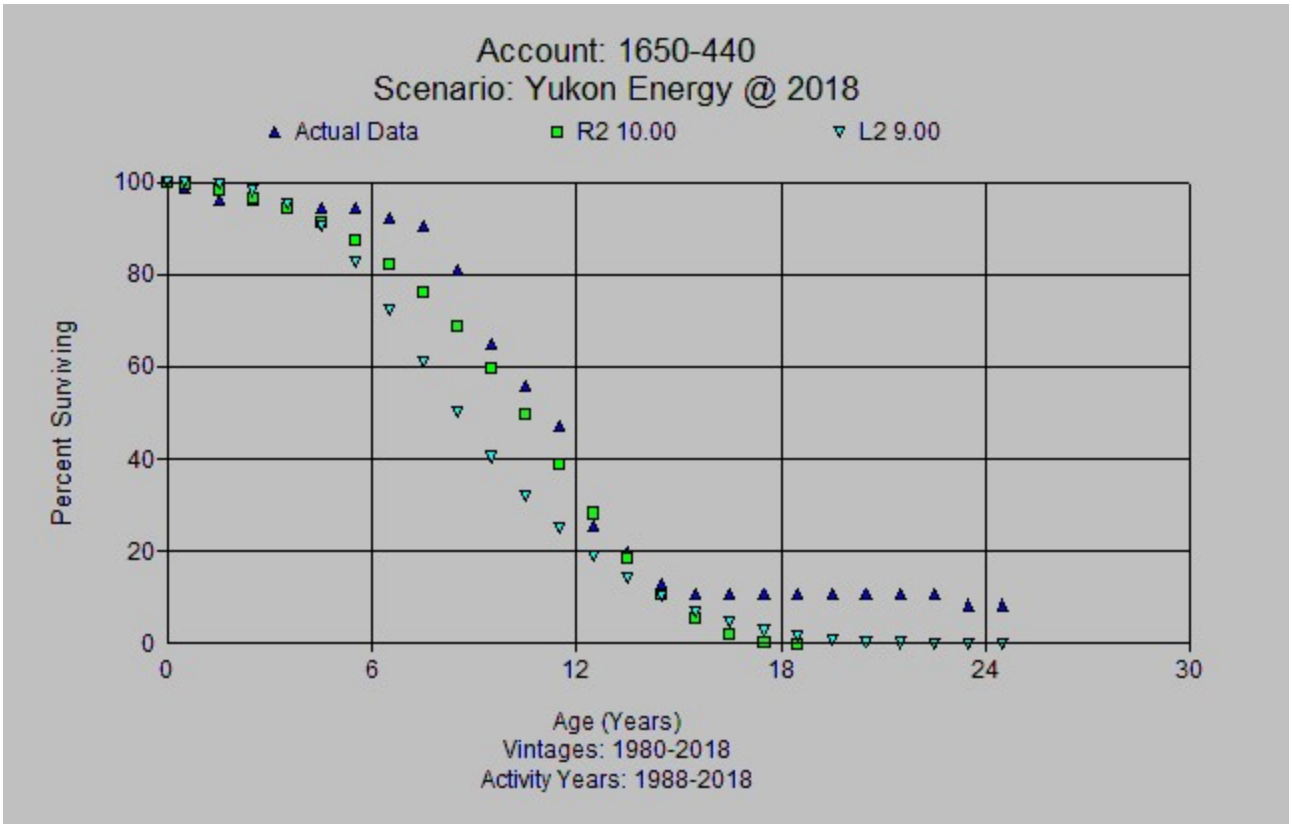

Account: 1650-440
Scenario: Yukon Energy @ 2018
Actual Data
R3 10.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1988-2018


Account: 1650-440
Scenario: Yukon Energy @ 2018
Actual Data
R3 11.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1988-2018

Observed Life Table

Scenario: Yukon Energy @ 2018
Account: 1650-440
Placement Band: 1980 - 2018 **Observation Band:** 1988 - 2018

Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Interval	Retirement Ratio	Survivor Ratio	Percent Surv at Beginning of Interval
0	4,472,283.84	39,576.00	0.00885	0.99115	100.00
0.5	4,223,765.83	123,251.00	0.02918	0.97082	99.12
1.5	3,908,687.71	0.00	0.00000	1.00000	96.22
2.5	3,505,312.88	58,633.84	0.01673	0.98327	96.22
3.5	3,116,809.90	1,679.77	0.00054	0.99946	94.61
4.5	2,948,510.87	0.00	0.00000	1.00000	94.56
5.5	2,656,902.87	61,456.44	0.02313	0.97687	94.56
6.5	2,458,889.43	49,192.00	0.02001	0.97999	92.38
7.5	2,316,244.48	238,926.04	0.10315	0.89685	90.53
8.5	1,701,704.80	340,973.61	0.20037	0.79963	81.19
9.5	1,360,731.19	189,374.58	0.13917	0.86083	64.92
10.5	968,008.49	152,182.98	0.15721	0.84279	55.89
11.5	743,995.65	341,514.98	0.45903	0.54097	47.10
12.5	402,480.67	89,067.71	0.22130	0.77870	25.48
13.5	313,412.96	108,297.70	0.34554	0.65446	19.84
14.5	205,115.26	33,619.92	0.16391	0.83609	12.99
15.5	171,495.34	0.00	0.00000	1.00000	10.86
16.5	171,495.34	0.00	0.00000	1.00000	10.86
17.5	171,495.34	0.00	0.00000	1.00000	10.86
18.5	171,495.34	0.00	0.00000	1.00000	10.86
19.5	171,495.34	0.00	0.00000	1.00000	10.86
20.5	171,495.34	0.00	0.00000	1.00000	10.86
21.5	171,495.34	0.00	0.00000	1.00000	10.86
22.5	171,495.34	39,180.95	0.22847	0.77153	10.86
23.5	132,314.39	0.00	0.00000	1.00000	8.38
24.5	132,314.39	132,314.39	1.00000	0.00000	8.38
25.5	0.00	0.00	0.00000	1.00000	0.00


Account: 1650-440
Scenario: Yukon Energy @ 2018
Actual Data
R2 10.00
L2 9.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1988-2018

Actuarial Life Analysis

Account: 1650-440
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 1992
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1988 -1992	10.5	10.21	0.68975718	L0	1.35
1989 -1993		1.00			
1990 -1994		1.00			
1991 -1995		1.00			
1992 -1996		1.00			
1993 -1997		1.00			
1994 -1998		1.00			
1995 -1999	15.5	21.43	1.15483505	L0	4.25
1996 -2000	16.5	21.43	1.20337491	L0	4.37
1997 -2001	17.5	65.85	0.27806821	R0.5	14.72
1998 -2002	18.5	0.00	0.29725330	R3	8.41
1999 -2003	19.5	0.00	0.29725330	R3	8.41
2000 -2004	20.5	0.00	0.15361943	SQ	9.45
2001 -2005	21.5	0.00	0.03698002	SQ	7.62
2002 -2006	22.5	0.00	0.04150302	SQ	9.51
2003 -2007	23.5	0.00	0.38836051	R5	19.30
2004 -2008	24.5	0.00	0.78600263	R4	18.78
2005 -2009	25.5	0.00	0.00000000	SQ	21.20
2006 -2010		1.00			
2007 -2011		1.00			
2008 -2012	28.5	39.78	0.51553728	L0.5	20.07
2009 -2013	29.5	0.00	0.02862725	R4	11.52
2010 -2014	30.5	0.00	0.02702481	R4	10.95
2011 -2015	31.5	0.00	0.05330391	L4	9.64
2012 -2016	32.5	0.00	0.03623875	L4	9.72
2013 -2017	33.5	0.00	0.00486246	L5	9.42
2014 -2018	34.5	0.00	0.01958660	S4	9.97

Actuarial Life Analysis

Account: 1650-440
Scenario: Yukon Energy @ 2018
Placement Band: 1980 - 2018
Function: Survivorship Annual Rate Method
Weighting: Unweighted
T-Cut: None

Observation Band	Censoring Age	Censoring Percent	Error Sum of Squares	Best Fit Disp	Best Fit ASL
1988 -2018	38.5	0.00	0.08881781	L3	11.74
1993 -2018	38.5	0.00	0.07852830	L3	11.20
1998 -2018	38.5	0.00	0.02058427	R3	10.40
2003 -2018	38.5	0.00	0.01535568	R4	10.68
2008 -2018	38.5	0.00	0.01783253	R4	10.74
2013 -2018	38.5	0.00	0.01871452	S4	9.78
2018 -2018		1.00			

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-88**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1650-490 Trxptn – Foremost 20 R3
This account includes the cost of large specialty vehicles which are usually tracked not wheeled vehicles. The plant balance in this account at December 31, 2018 is $1.0 million. The approved life for this account is 25 years. Discussions with Company personnel indicated that there is one tracked vehicle and a 2011 Kenworth truck equipped with an auger. Company personnel believe the life should match the life of the greater than 3 ton trucks of 20 years. There is no historical experience to analyze. Giving consideration to type of assets, Company input and expectations and judgment, this study proposes moving to 20 R3 at this time."

QUESTION:

a) Please explain why the life of the tracked vehicle should match that of the Kenworth truck.

b) Please clarify whether there have been any overhauls to either vehicle that would be expected to increase average service life at the time they were carried out. Please explain fully.

c) Please clarify whether there had been an Iowa Curve previously approved for this account and, if so, please provide that value.

ANSWER:

(a)

There have been no retirements in this account, so it was not possible to perform any actuarial life analysis. In the opinion of Company personnel, that asset was a reasonable proxy for items in this account.

(b)

There has been no overhaul to the tracked vehicle. However, a complete service on this unit was performed in 2017. Other than that, it has just received regular servicing as considered necessary.

The 2011 Kenworth had its 10-year overhaul in 2019. This consisted of overhaul service on the boom and outriggers. Other than that, it has just received regular servicing as considered necessary.

(c)

In the last depreciation study, no Iowa curve was specified.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-92**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1665-403 LNG Plant – Fuel Holders 60 R2
This account includes the installed cost of fuel handling and storage equipment used between the point of fuel delivery to the station and the intake pipe including boilers, pumps, produces, regenerators, tanks, and vaporizers. The plant balance in this account at December 31, 2018 is $13.2 million. The approved life for this account is 32 years. The assets are new so there is limited historical data. Discussions with Company personnel indicated the tanks are nickel, double walled with no moisture ingress. The existing fuel holder life of 32 years is considered to be low and with reasonable maintenance, a 60 year life is expected. Considering the type of assets, information provided by Company personnel and judgment, this study recommends moving the life to 60 years with the R2 for this account."

PREAMBLE: YEC is proposing a significant increase (of 28 years) in average service life for this account.

QUESTION:

a) Please provide any objective evidence such as manufacturers' information available to YEC that further supports the increase (of 28 years) in average service life for this account.

ANSWER:

(a)

The designer of the LNG skid has stated:

- 10+ years ago we moved large high pressure ASME vessels (non-cryogenic) built in the 1960's for the race to the moon to the NASA Marshall Space Center that are still in service (50 years).

- I recall seeing ASME cryogenic vessels built in the 1980's still in service but could not recall where. (40 years).

- The first LNG tank install I was involved with was 1999 and it is still in-service w/o any issues. (22 years).

From an engineering perspective, LNG is noncorrosive to stainless steel, so as long as the tank is maintained properly, it should last 60 years.

REFERENCE: **Application, Tab 9, Depreciation Study, page 9-93**

ISSUE: **Depreciation Expense**

QUOTE: "Account 1665-500 LNG Plant – Generators 40 SQ
This account includes the installed cost of other prime movers including engines, piping, air-filtering system, towers, pumps, hoists, compressors, tanks, waste heat boilers, antifluctuators and other related equipment. The plant balance in this account at December 31, 2018 is $20.9 million. The approved life for this account is 40 years. The assets are new so there is limited historical data. Discussions with Company personnel indicated the current life is still applicable for this account. Considering the type of assets, information provided by Company personnel and judgment, this study retaining the life of 40 years and using a SQ dispersion for this account."

QUESTION:

a) Given that no other LNG asset class (within the 1665 series) has incorporated the use of a SQ curve, please explain why, for Account 1665-500 LNG Plant – Generators, it is appropriate to maintain an SQ curve as opposed to the R2 curve used for all other LNG accounts.

ANSWER:

(a)

No historical analytical information existed to determine a specific retirement dispersion for LNG generators and an SQ dispersion was assigned. In retrospect, modeling this account in the same way as Account 1620-500 – Diesel Generators and Prime Movers (40 R2) would also have been a reasonable approach. Using the R2 dispersion would have slightly increased the depreciation expense for the 1665-500 account.

REFERENCE: **Application, Tab 9, Depreciation Study, pages 9-22, 9-24, 9-69 and 9-102; Tab 7, Schedule 3A, Calculation of depreciation expense for Hydro overhauls and Diesel production overhauls, page 7-6**

ISSUE: **Depreciation Expense**

Note: The following accounts were excluded from the depreciation study:
1615-504 Hydro Assets Overhaul
1620-504 Diesel Assets Overhaul
1620-504 Diesel Assets Overhaul
Asset 7060 removed from asset group 1615-506
Asset 8856 transferred from asset group 1645-200 to 1615-201

QUOTE:

Note: The following accounts were excluded from the depreciation study:
1615-504 Hydro Assets Overhaul
1620-504 Diesel Assets Overhaul
1620-504 Diesel Assets Overhaul
Asset 7060 removed from asset group 1615-506
Asset 8856 transferred from asset group 1645-200 to 1615-201

PREAMBLE: Tab 7, Schedule 3A indicates that amortization periods for Hydro overhauls, Diesel production overhauls and LNG production overhauls are 10, five, and two years respectively.

QUESTION:

a) Please confirm that the amortization periods for Hydro overhauls, Diesel production overhauls and LNG production overhauls of 10, five and two years respectively, as shown on Tab 7, Schedule 3A, remain valid.

b) Referring to part (a) above, please explain how each of the amortization periods was determined and what specifically is proposed to be overhauled under each Hydro, Diesel and LNG category.

c) Please identify Asset 7060, its historical cost, and why it is necessary to remove it from asset group 1615-506 (Hydro-Wtrwhls, Trbines & Gen's) on Tab 7, Schedule 3A given that there is no indication on page 9-24 (Hydro-Wtrwhls, Trbines & Gen's) of YEC's Tab 9, Depreciation Study that any asset was excluded from consideration in the depreciation study for Account 1615-506.

i. Please clarify if Asset 7060 is depreciable and, if so, provide a complete reference to where the basis for its depreciation and related depreciation expense amount for 2021 can be confirmed within YEC's supporting Tabs; and

ii. If part (b)(i) above confirms that Asset 7060 is not depreciable, please confirm that Asset 7060 is not included in the $26,904.6 thousand cost at 2021 year end as shown on Tab 7, Schedule 3A for the Waterwheels, Turbines & Generation account and clarify whether or not Asset 7060 forms a component of rate base that is subject to a return calculation.

d) Please identify Asset 8856 and confirm that it is the elevator at Aishihik Hydro plant discussed on pages 9-22 (Hydro Buildings and Improvements) and 9-69 (Bldg & Itr – Structures and Improvements Hydro) of YEC's Tab 9, Depreciation Study.

ANSWER:

(a)

Confirmed.

(b)

Hydro and Diesel overhauls were approved in previous GRA's and YEC has no basis for requesting a change to these amortization periods.

LNG overhauls were rounded to 2 years based on an analysis of expected LNG run-time and scheduled overhauls. LNG generation is relatively new to YEC and run-time is weather dependent so it may be appropriate to perform additional analysis in the future.

(c)

Asset 7060 is Whitehorse WH4 Overhaul performed in 2007. Rather than a Hydro-Wtrwhls, Trbines & Gen's category, it is more appropriately classified as an Overhaul and subject to the hydro overhaul amortization period. This Overhaul is fully amortized, so the net book value is $0. There is no amortization forecast in 2021.

(d)

Asset 8856 is the Aishihik Elevator Shaft Structural Steel Rehabilitation as discussed on pages 9-22 (Hydro Buildings and Improvements) and 9-69 (Bldg & Itr – Structures and Improvements Hydro) of YEC's Tab 9, Depreciation Study.

REFERENCE: **Application, Section 3.4, Table 3.14.3, page 3-24; and Appendix 5.2, Section 5.2-5, Overhauls & reserve for site restoration projects, page 5.2-11**

ISSUE: **Reserve for Site Restoration Continuity Schedule**

QUESTION:

a) Please clarify whether the FD7 overhaul is related to YEC's reserve for site restoration projects and, if so, explain why the $580,000 forecast for 2021 was not included in Table 3.14.3.

b) If part (a) above is not confirmed, please fully explain how YEC proposes to treat the $580,000 expenditure for regulatory purposes in the year 2021.

ANSWER:

(a)

The FD7 Overhaul is not related to YEC's reserve for site restoration projects. It is categorized in the Application as an Overhaul.

(b)

YEC proposes to treat the FD7 Overhaul consistently with other overhauls in this Application (LNG) and other overhauls in previous Applications. The FD7 Overhaul is treated similar to other additions of Property, Plant and Equipment, and is specifically identified as being added to Rate Base in the Application in Table 5.2-1 on page 5-33.

REFERENCE: **Application, Tab 2, Section 2.2.2, page 2-6**

ISSUE: **Industrial Demand**

QUESTION:

a) Please explain how other ratepayers are protected from the effects of significant large industrial loads and potential swings in demand if those industrial loads come on and off line.

b) What are the requirements in the power purchase agreements, or other industrial electricity purchase agreements, to manage peak demand?

c) Please confirm how many times the mine load supply was curtailed due to generation issues.

d) Please provide the monthly demand for VGC since the beginning of the operation.

e) Are the requirements to manage peak demand the same for all industrial customers? Please explain.

ANSWER:

(a)

Other ratepayers can experience rate effects from significant large industrial loads, and the potential swings in demand if those large industrial loads come on and off line, only through new GRA filings to adjust existing rates. Prior to a new GRA response to such events, the revenue requirement related impacts from changes in large industrial loads are all borne by the utility.

Yukoners experienced such effects in the 1990s when the Faro mine, accounting for about 40% of overall Yukon loads, shut down its operations in 1993, then reopened it operations in 1995, and then closed permanently in early 1998. As directed by the Board, YEC addressed these significant changes through timely new GRA applications. In 1995, when the Faro mine reopened, the Board issued Order 1995-01 declaring that all YEC and YECL rates are made as interim refundable and retroactively adjustable effective July 1,

1995 other than RS 39 which continued to be interim refundable and retroactively adjustable.

As documented in the 1990s, restoration of Faro mine loads reduced rates significantly for other ratepayers; as a result, loss of the large Faro mine industrial load led to a need to increase rates significantly to other ratepayers. Restoration of much smaller industrial loads since the 1990s has tended to reduce rates for other ratepayers – but the magnitude of potential rate swings related to such loads coming on and off line are currently much smaller than the impacts associated with Faro mine load swings in the 1990s.

(b)

Power purchase agreements with industrial customers set maximum load limits and power quality requirements for each customer, absent agreement with the utility to accommodate higher peak loads, and also require each customer to provide forecast of load requirements. Otherwise, these agreements do not provide for management of the customer peak demand.

RS 39 includes provision for agreement with an industrial customer for a Winter Contract Load that enables a Peak Shaving Credit to be arranged. No industrial customer has elected to pursue this option. The VGC Group PPA specifies that this mine's operations are forecast to have a much lower peak load during the key winter period.

The N-1 dependable capacity planning criterion for Yukon Energy excludes consideration of major industrial customer peak demands. These industrial customers have on-site diesel generation capability sufficient to address emergency electricity requirements in the event that utility electricity supply is curtailed. In the event of a grid N-1 loss of generation, electricity deliveries to major industrial customers are expected to be curtailed.

(c)

Grid splits occur from lightning or failed equipment. There is insufficient generation in the north for the mine loading. During system restorations the mines are curtailed until system security is re-established. High load or events that involve Aishihik can also limit YEC's ability to feed the mines.

Total events in 2019 and 2020 was 19.

Date	Event	Duration
April 22, 2019	Major Outage	2 hr
June 8, 2019	Lightning	3 hr
June 12, 2019	Lightning	2 hr
June 25, 2019	L250 fault	30 mins
July 1, 2019	L180 fault	8 hr
July 10, 2019	L180 fault	4 hr
July 22, 2019	Lightning	1 hr
Sep 10, 2019	L180 fault	1 hr
Dec 2, 2019	L180 fault	4 hr
~Jan 14 2020	Very High Load	not sure on duration/dates.
Feb 7, 2020	WH4 Trip	10 hrs Minto 2 hr Eagle
Feb 13, 2020	WH4 Trip	2 hr
July 5, 2020	L178 outage	1 hr
July 11, 2020	Lightning	1 hr
Oct 26, 2020	Grid Split	10 hrs
Nov 14, 2020	P130 issues	1 hr
Dec 2, 2020	Grid Split	10 hrs
Dec 4, 2020	Grid Split	1 hr
Dec 26, 2020	Grid Split	120 hrs

(d)

Monthly demand for VGC since the beginning of operation is as follows:

		KVA
2019	MAY	840
	JUN	748
	JUL	3,360
	AUG	4,200
	SEP	4,480
	OCT	5,180
	NOV	5,180
	DEC	5,460
2020	JAN	5,740
	FEB	5,880
	MAR	5,880
	APR	6,440
	MAY	5,880
	JUN	5,040
	JUL	5,320
	AUG	6,160
	SEP	6,720
	OCT	7,560
	NOV	7,140
	DEC	6,440

(e)

There is no requirement to manage peak demand for industrial customers. Each mine's power purchase agreement includes terms that define the Maximum Electrical Demand allowed under the agreement.