YUKON ENERGY CORPORATION

APPLICATION FOR APPROVALS REGARDING THE
VGC GROUP POWER PURCHASE AGREEMENT
INTERROGATORY RESPONSES FILED

December 11, 2017

John Maissan

(JM)

TOPIC: **YEC-VGC PPA Application**

REFERENCE: **Page 1: VGC on-site diesel generation less than 5 MW**

PREAMBLE:

QUESTION:

a) What number and sizes of diesel generators does Victoria Gold plan to install?

ANSWER:

(a)

VGC Group plans to install 3 units [1.65 MW for each unit].

TOPIC: **YEC-VGC PPA Application**

REFERENCE: **Page 2 and elsewhere:**

PREAMBLE:

QUESTION:

a) Please explain why YEC is having VGC build the McQuesten substation – is it because VGC can do it at lower cost or faster than YEC, has fewer contracting constraints, has better access to capital, etc.?

b) The PPA Schedule B on page 5 (Appendix B1) indicates that VGC will be having ATCO tender the long lead equipment.
   i. Is the ATCO referred to here ATCO Electric Yukon, or ATCO Electric in Alberta?
   ii. Please explain the relationship between VGC and ATCO on this project.
   iii. Please explain the relationship between YEC and ATCO on this project.

ANSWER:

(a)

YEC and VGC Group have worked together to finalize detailed design of the McQuesten Substation and are continuing to work together, pursuant to the MOU and the PPA, on the tendering, procurement, construction, commissioning and turnover of the substation to YEC.

As the timing for completion of the substation is a key risk item for VGC Group to be able to connect to the grid and receive grid power, and VGC Group is also responsible for funding most of the McQuesten Substation capital costs, a decision was made for VGC Group to undertake tendering and construction management pursuant to MOU terms. VGC Group is able to proceed with these activities, as required to protect its in-service schedule, prior to the YUB approval of PPA provisions as required under Section 3.1(a) of the PPA.

(b)

Please see response to YUB-YEC-1-27(a). The ATCO referred to is ATCO Power Canada Limited.

ATCO Power Canada Limited was selected through an RFP process and retained by VGC Group to undertake detailed design of the substation and to provide Issued for Construction (IFC) drawings and technical specifications for a construction RFP document for tendering this work. As noted in the response to UCG-YEC-1-23 (a-b), Yukon Energy funded 50% of these costs to ensure the McQuesten Substation was designed to operate at the 138 KV standard required by YEC.

Pursuant to the MOU provided in Schedule B of the PPA, ATCO Power Canada Limited and Yukon Energy have worked together with VGC Group to complete the required substation design in order to advance the project towards the construction stage.

TOPIC: **YEC-VGC PPA Application**

REFERENCE: **Page 5: VGC approximate 90 day period of reduced electrical demand in winter between December 1 and March 31.**

PREAMBLE:

QUESTION:

a) Is VGC to inform YEC of the dates for this reduced demand or will YEC set the dates?

b) A 90 day period could well run from January 1 to March 31 leaving YEC to meet peak system demands during November or December with the mine load at it high level. For the November 1 to December 31 period of each of the years 2012 to 2016 and November 2017 please provide:
   i. The peak load (in MW) each year, and
   ii. The peak load in the November – December period.

c) If the VGC mine runs at full load during November and much of December is there not a high probability that a substantial portion of their 10.4 to 13.3 MW normal load would contribute to peak system loads?

d) What are the peak system loads projected by YEC for the 2019-2020 and 2020-2021 winters?

e) At these peak loads what would be the anticipated contributions of hydro, LNG, and diesel generation absent new renewable energy additions?

ANSWER:

(a)

Pursuant to Section 5.2 of the PPA, VGC Group will inform YEC of the specific 90-day period for each year.

(b)

The 90-day period is expected to be from early December to early March each year. VGC Group's planning assumes that this occurs during the period of coldest temperatures.

System hourly peak load for the year and the November/December period over the 2012-2016 period are presented in Table 1 below. Except for 2017 YTD (when December is not yet over), the peak occurred in December of each of these years.

Table 1. Comparison of hourly peak load and the peak load over the November-December period for a given year (2012-2017 YTD).

YEAR	HOURLY PEAK LOAD [MW]	NOVEMBER HOURLY PEAK LOAD [MW]	DECEMBER HOURLY PEAK LOAD [MW]
2012	82.24	79.45	82.24
2013	82.69	77.24	82.69
2014	76.52	73.52	74.17
2015	82.06	73.23	77.93
2016	87.51	74.33	87.51
2017YTD	85.21	83.07	77.12

(c)

As noted in response to (b) above, VGC Group is not expected to run at peak load during the coldest periods in December. Yukon Energy does not forecast a high probability that a substantial portion of the VGC Group normal peak load (i.e., materially more than 45% to 50% of the 10.0 to 12.7 MW peak sales per Table 1 of PPA Application) will contribute to winter peak system loads.

(d)

Although Yukon Energy has received forecast VGC Group loads for each of the first six years of operation, the overall winter peak load impacts will be driven by the extent of other industrial mine loads on the grid in each of these years – and YEC does not have useful information today as to likely forecasts for each year for Minto or Alexco.

Table 2 below presents a scenario for the forecast peak demand for 2019-2020 and 2020-2021 winters that is consistent with load assumptions for 2020 and 2021 as per Table 3 in the PPA Application, broken down by major classes.

Table 2. Forecasted hourly Peak demand for 2019-2020 and 2020-2021 winters

CLASS	2019-2020 Winter [MW]	2020-2021 Winter [MW]
NON-INDUSTRIAL	90.89	92.92
INDUSTRIAL	11.73	12.29
TOTAL	102.62	105.21

(e)

YEC can provide comment on the potential dependable capacity by different generation sources in the winters of 2020/21 and 2021/22. This analysis does not assess the single contingency (N-1) dependable capacity with the loss of 37 MW at Aishihik.

Based on the 2016 Resource Plan and current information, Table 3 below provides the maximum dependable capacity available to meet the peak demand in these future years based on existing YEC resources and including the 3rd LNG engine and ATCO Electric Yukon thermal capacity. As noted in the 2016 Resource Plan, a number of changes that may affect this maximum dependable capacity are being assessed under YEC's ongoing resource planning, including development of additional thermal capacity (new thermal plant of up to 20 MW), the potential energy storage project, uprates and/or refurbishments to existing hydro facilities (e.g., assume work carried out in summer and not affect winter capacity), and the planned retirement of FD1 and WD3 diesel units (8.5 MW) at the end of 2020.

Table 3. Maximum dependable capacity by generation source: 2020/21 and 2021/22

GENERATION SOURCE	MAXIMUM DEPENDABLE CAPACITY [MW]
HYDRO	70.5
THERMAL NATURAL GAS	13.2
THERMAL DIESEL	35.7
TOTAL	119.4

TOPIC: **YEC-VGC PPA Application**

REFERENCE: **Page 6 Section 4.2 1:**

PREAMBLE:

QUESTION:

a) The second paragraph contains a reference to Minto and Alexco paying rates under Rate Schedule 42, should this read Rate Schedule 39?

ANSWER:

(a)

Correct. The reference to Rate Schedule 42 is a typographical error. It should read Rate Schedule 39.

TOPIC: **YEC-VGC PPA Application**

REFERENCE: **Page 11 top paragraph:**

PREAMBLE:

QUESTION:

a) If YEC does not get the necessary approvals and cannot build the proposed transmission facilities how would electrical service to VGC be affected?

ANSWER:

(a)

Yukon grid enhancements and facilities are required to connect the Mine to the existing transmission, to maintain acceptable 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. Initial new facilities and enhancements are to be funded by VGC Group, with the exception of the YEC McQuesten Substation Costs of approximately $0.93 million as described in Schedule B, Table B-2.

With these initial measures, the Yukon grid can likely only deliver to the Mine up to 10,100 kVA until further grid improvements (i.e., the Transmission Facilities Development) are implemented. This limit allows for existing Keno region power loads plus some renewed Alexco loads. However, the VGC Group Mine would likely need to use its on-site diesel generation to supply some of its peak load (per Table 1 in the PPA Application, VGC Group Mine peak loads are 10.0 to 12.7 MW; or 10,400 to 13,300 kVA per footnote 17 of the PPA Application) from approximately mid-March through November in years before the Transmission Facilities Development Operation Date.

TOPIC: **YEC-VGC PPA Application**

REFERENCE: **Page 17 Table 1:**

PREAMBLE:

QUESTION:

a) The footnote indicates that the losses are set at 8.8% (system average) yet the loss figures in the table appear to be about 8.08% of the generation figures, please explain.

ANSWER:

(a)

The question appears to be calculating the percentage of losses based on the total generation, i.e., looking at Year 1 in Table 1, the losses of 4,559 MWh would be 8.08% of the total generation [of 56,360 MWh]. However, this is incorrect, as total generation includes losses.

The losses indicated in Table 1 are calculated based on multiplying the total sales energy [51,802 MWh in Year 1 of Table 1] by 8.8% to get 4,559 MWh of losses. This would provide the total generation of 56,360 in year 1.

TOPIC: **YEC-VGC PPA Application**

REFERENCE: **Page 21: Costs of future thermal generation:**

PREAMBLE:

QUESTION:

a) What inflation factors were used for unit fuel costs beyond the 2018 test year?

b) When new renewable generation facilities are built would YEC expect the new energy supply costs to be lower or higher than the forecast thermal generation cost?

ANSWER:

(a)

Inflation factors were not used for unit fuel costs beyond the 2018 GRA test year. Please see Table 3 at page 23 of the PPA Application; Note 2 indicates that YEC added thermal generation costs assumed an average cost per 2017/18 GRA at $0.1583/kWh (90% LNG, 10% diesel).

(b)

Energy supply costs for new renewable generation facilities are expected to derive from fixed capital costs rather than variable fuel costs and will depend on the nature of the specific facilities, as well as any specific circumstances regarding project financing or other factors that might impact. Beyond information provided in the 2016 Resource Plan, YEC currently has no specific assessments of potential costs for new renewables as compared with the 2018 GRA test year thermal fuel cost.

TOPIC: **YEC-VGC PPA Application**

REFERENCE: **Page 22: Projections on revenue requirements:**

PREAMBLE:

QUESTION:

a) Will there be reductions in secondary sales as a result of the VGC mine load?

b) Assuming that there must be reductions, how were the reduced revenues from secondary sales factored into the calculations?

ANSWER:

(a) and **(b)**

As the firm non-industrial and industrial loads grow, YEC anticipates a material reduction in the energy available for secondary sales. YEC also anticipates the energy to be available only during the summer months. Secondary sales in any year will also continue to be sensitive to actual water conditions relative to the LTA. Should the load decrease in the future, YEC would re-evaluate the volume and timing of the energy available for secondary sales.

In light of the factors affecting secondary sales, YEC has not developed forecasts of secondary sales change relative to growth of firm loads. Accordingly, no attempt has been made to factor changes in secondary sales into the ratepayer impact assessments in Table 3 of the PPA Application. The following information is provided for context:

- YEC secondary sales from 2013 to 2016 averaged $0.4 million per year, varying from $0.275 million/year to $0.544 million per year; the 2017-18 GRA test year forecast is $0.642 million/year. Water conditions were better than LTA during the 2013-2016 period, while loads were generally depressed. (Table 2.1 of GRA).

- Actual secondary sales in the first seven months of 2017 were approximately 73.5% of the GRA forecast, suggesting that the 2017 amount may end up approximating $0.47 million. (Response to YUB-YEC-1-59 of the GRA).

- Estimated VGC Group Mine reduction in YEC net costs (added costs less added revenues) per Table 3 of the PPA Application ranges from $0.69 million to $0.87 million for 2020-2021 when Alexco and Minto mine loads are assumed with the VGC Group Mine load, and $2.02 million for 2025 when the only industrial load assumed is the VGC Group Mine load. Potential secondary sales revenue reduction related specifically to the VGC Group Mine load would need to be assessed net of reductions linked to other load growth and/or LTA water conditions. The maximum potential impact on secondary sales revenue reduction, however, is clearly less than the Table 3 ratepayer savings from VGC Group sales (for both the Table 3 as originally filed with the PPA Application, and the revised Table 3 provided as Attachment 1 to YUB-YEC-1-28).

TOPIC: **YEC-VGC PPA Application**

REFERENCE: **Page 22: If it becomes necessary to add $25 million to YEC rate base:**

PREAMBLE:

QUESTION:

a) What would be the projected life of the transmission facilities?

b) The calculations show a net benefit to all ratepayers when the VGC mine is operating, however after the VGC mine has shut down in about 10 years would overall impact on all ratepayers still be positive?

ANSWER:

(a)

Page 22 of the PPA Application notes an assumed 55-year average depreciation for the Transmission Facilities. This assumes transmission assets at a 65 year life (67% of total cost); YEC McQuesten Substation Costs at a 54 year life; and the balance of facilities assumed conservatively at a 40 year life.

(b)

When the VGC Group Mine closes, its sales can no longer provide the net benefits to all ratepayers that occur with the Mine operating. Aside from loss of these net benefits, there are no “hang-over” transmission facilities costs directly due to the Mine that would adversely impact remaining ratepayers. As with other recent PPAs, the industrial customer is directly bearing and funding up front all transmission facilities rate base costs directly due to the development and connection of the industrial customer mine.

In this regard, costs related to the Stewart Keno City Transmission Line Project (SKTP) are not directly due to the VGC Group Mine.

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.[1]

As reviewed in the PPA Application, the VGC Group Mine is providing added impetus for the SKTP now to proceed, in whole (the full SKTP) or at least (with the default option) for the ‘end of life’ line from Mayo to McQuesten Substation. If external funding is confirmed sufficient for the full SKTP to proceed, there will be no material new rate base costs to affect ratepayers. If only the default option is developed, the rate base costs for this required line replacement will directly affect YEC rates.

In the event that the default option is what is implemented, there is an opportunity over the period that the Eagle Gold mine is operating for this industrial customer 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 new Transmission Facilities. Specifically, absent the connection of the Eagle Gold mine, the cost for upgrade to, and/or replacement of, these facilities would be paid fully by all other ratepayers. In this respect, the VGC Group Mine connection provides an added overall benefit to ratepayers during its operation by reducing the costs that other ratepayers would otherwise have to contribute towards the line in its initial years of operation. After these initial years of operation, the rate base cost for this new line will also have been reduced by the depreciation to date, and consequently the return costs to be borne by other ratepayers will be reduced compared to the initial years of operation.

[1] See PPA Application page 7 and in particular footnotes 10, 11 and 12.

TOPIC: **YEC-VGC PPA Application**

REFERENCE: **Page 23: Long term average thermal generation:**

PREAMBLE:

QUESTION:

a) YEC's 2017-2018 GRA indicated 14.48 GWh of thermal generation in 2018. Table 3 in the PPA application indicated that absent the VGC load thermal generation in 2020 would be 32.2 GWh. The PPA figure appears to be inconsistent with GRA forecasted load growth (less than 1% for 2017 to 2018) and expected incremental thermal usage (Table 3.4-1). Please explain.

ANSWER:

(a)

As reviewed below, there is no inconsistency in the Table 3 LTA thermal generation estimates as originally filed when compared with the GRA.

The question appears to have taken only the 2020 sales load of 416.9 GW.h, prior to adding 8.8% for losses to get the firm grid generation requirement. Looking only at sales load, the added LTA thermal generation would not be consistent with the GRA estimates. However, when 8.8% losses are included, the assumed 2020 load without VGC Group Mine is 7.7% higher than the 2018 grid load GRA forecast, and the related LTA thermal generation in the original PPA Application is fully explained by Table 3.4-1 of the GRA. Details are provided below:

- The YEC GRA estimates YEC LTA thermal at 14.48 GW.h for 2018 and 14.146 GW.h for 2017, based on YEC firm grid load forecast at 421.185 GW.h for 2018 and 420.398 GW.h for 2017; in each case, the LTA thermal is derived from Table 3.4-1 in the GRA (after deduction of 0.58 GW.h assumed LTA wind generation).

- Table 3 as originally filed in the PPA Application estimated YEC LTA thermal generation for 2020, without the VGC Group Mine load, at 32.2 GW.h for an assumed grid load (including 8.8% losses) of 453.587 GW.h. This LTA thermal estimate was also derived from Table 3.4-1 in the GRA.

Estimates of LTA thermal generation for each of the discussed grid loads (e.g., the test years in the GRA and the 2020 year in Table 3 of the PPA Application) are each estimated based on analysis from the same updated YECSIM model.

As reviewed in Attachment 1 to YUB-YEC-1-28 and as demonstrated above, Table 3 estimates for thermal generation as originally filed with the PPA Application in effect extended the GRA DCF Term Sheet Table 3.4-1 without taking into account material changes in the annual grid load shape. The revised Table 3 in Attachment 1 to YUB-YEC-1-28 has now provided incremental thermal generation estimates that take into account changes in annual load shape related to mine load changes.

Overall, the assumptions affecting grid load size and shape for the 2017 and 2018 GRA test years and the assumptions for 2020 and 2021 [as outlined in Table 3 of the PPA Application, as revised] are materially different, and these differences affect the differing thermal generation requirements in 2020 compared to the test years.

- **Industrial Load Assumptions**: The 2017/2018 GRA test year forecast assumes Minto mine load at 38.2 MWh for each test year, and no Alexco load; while Table 3 in the PPA Application assumes Minto Mine load in 2020 of 38.2 GWh; and Alexco load of 19 GWh.

- **Non-industrial Load Assumptions**: The 2017/2018 GRA test year forecast non-industrial firm load at 348.2 GWh for 2017 and 348.9 GWh for 2018. Table 3 in the PPA Application assumed non-industrial sales per the YEC 2016 Resource Plan, Medium Industrial Forecast [359.7 GWh for 2020].

The YECSIM analysis as revised in Attachment 1 to YUB-YEC-1-28 for 2020 takes into account the impact of the higher grid loads as well as the change in load shape (by week) due to such a material growth in the industrial load, including impacts related to VGC Group's load shape over the year.

TOPIC: **Power Purchase Agreement (PPA)**

REFERENCE: **Page 16 section 8.1:**

PREAMBLE:

QUESTION:

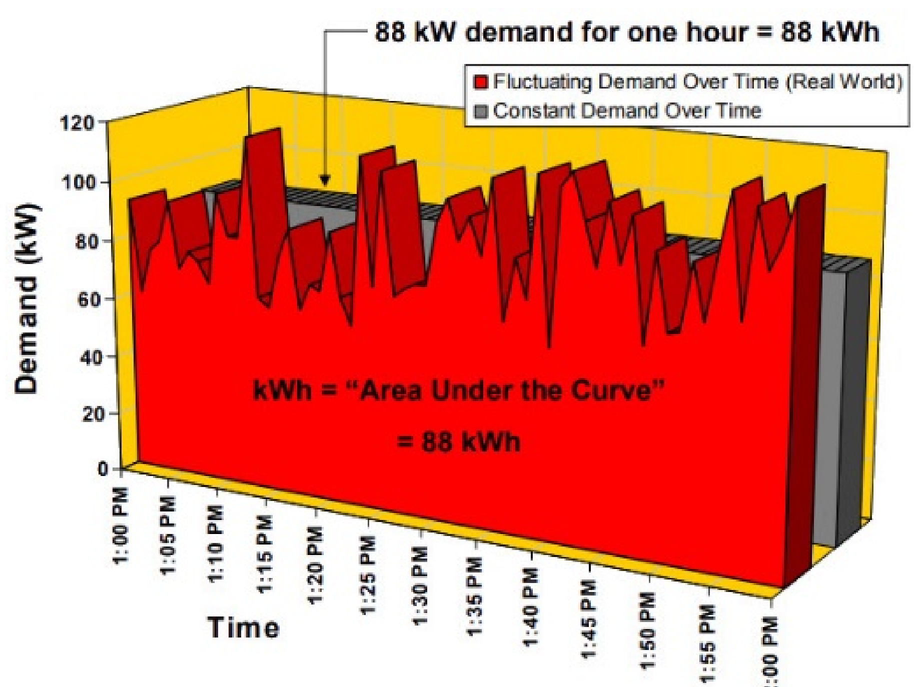
a) With respect to meters please explain the term “one hour integrating intervals”.

b) How is the above related to the “Electric Demand” definition which says that it is a “rolling 15 minute average”?

ANSWER:

(a)

Mathematically the term “one hour integrating interval” means the area under the kWh curve for one hour. This is best visualized with the following graphic:



(b)

Electric Demand is a measure of Power, this is given in kilowatts. The metered energy is the one hour integrating interval which is power per hour, also known as kilowatt hours.

The one hour measurement is for energy usage (kWh), the 15 minute measurement is for demand (kW). The meter is capable of measuring both.

TOPIC: **Power Purchase Agreement (PPA)**

REFERENCE: **Schedule B page 5 No.4:**

PREAMBLE:

QUESTION:

a) Please explain the acronym “VIT”.

b) Please explain VIT’s role in the substation construction and their relationship with VGC, ATCO, and YEC.

ANSWER:

(a)

“VIT” is the stock symbol for VGC on the TSX Venture Exchange.

(b)

Since VIT and VGC are the same entity, VIT has no distinct role in substation construction from VGC Group or different relationship than VGC Group with ATCO and YEC.

TOPIC: **Power Purchase Agreement (PPA)**

REFERENCE: **Schedule C:**

PREAMBLE:

QUESTION:

a) This schedule contains what appears to be a comprehensive review of the integrated system protection schemes. Is there any part of the integrated system that was not reviewed?

b) Were YEC staff able to complete this review or was a third party required? If so who was that third party?

c) Will any of the protection schemes need to be changed from summer to winter as the loading on the hydro plants (Aishihik and Whitehorse Rapids in particular) vary significantly? If so how will this be accomplished?

ANSWER:

(a)

All parts of the integrated system considered likely to be potentially affected by this new load were considered.

(b)

The review of system protection schemes was completed by Hatch Engineering, with oversight by YEC engineering staff.

(c)

Not known at this time. The work required to determine the answer to this question is included in the scope of Initial YEC System Improvements as defined in the PPA.

TOPIC: **Power Purchase Agreement (PPA)**

REFERENCE: **Schedule D page 1:**

PREAMBLE:

QUESTION:

a) Noted that VGC has under frequency load shedding, will there be situations in which industrial loads such as VGC on the integrated system are shed in advance or in preference to Whitehorse area loads? Please explain.

ANSWER:

(a)

The Schedule D provisions identify situations where VGC Group load could be shed due to specific conditions at the VGC Group Mine Facilities and/or on the grid transmission or generation. Overall protocols used by YEC address load shedding under conditions when dependable capacity is inadequate to supply grid load. In emergency conditions, industrial load shedding reflects on-site generation capacity to address emergency power requirements.

Utilities Consumers' Group

(UCG)

TOPIC:

REFERENCE: **November 10, 2017 Application, page 1**

PREAMBLE:

YEC states that it is seeking an Order from the Yukon Utilities Board for required approvals related to the implementation of the proposed Power Purchase Agreement that YEC has recently concluded with the VGC Group.

QUESTION:

a) Please confirm that YEC is asking the YUB to approve the proposed Power Purchase Agreement as well as customer contribution payments by VGC Group to YEC, an the initial Transmission Facilities Fixed Cost of $118,621 per year, and the amendment process for the Transmission Facilities Fixed Cost after the Transmission Facilities Development Operation Date.

b) Please provide details of any other approvals being requested by YEC from the YUB or any other party.

c) Please confirm that YEC will be applying to the YUB for approval of any Transmission Facilities Fixed Cost charge before charging the VGC Group.

ANSWER:

(a) and **(b)**

Yukon Energy is seeking Board approval of those elements of the PPA that impact customer rates. These requested approvals are outlined in Section 3 of the Application [pages 3 and 4] and include the following:

- The customer contribution payments by VGC Group to YEC under Section 6.1 of the PPA for YEC Capital Costs, including payments for:
  - Actual YEC Capital Costs for negotiation and conclusion of the PPA Agreement;

  - Actual YEC Capital Costs for the Initial YEC System Improvements;

  - Actual YEC Owner's Costs for the McQuesten Substation;

  - Actual YEC costs reasonably required for design, engineering, procurement, construction and commissioning of the Step Down Transformer at the McQuesten Substation, should one be determined to be required.

- The Fixed Charge provisions as set out in Section 7.7 of the PPA, including the initial Transmission Facilities Fixed Cost of $118,621 per year, as documented in Attachment B to this Application, for use in determining the Fixed Charge under Section 7.7.

- Any related amendments to the Rate Schedule 39 Firm Mine Rate as required to conform with Attachment A to this Application and to accommodate the PPA.

(c)

Confirmed. As noted in Section 7.7(b) of the PPA, after the Transmission Facilities Development Operation Date, YEC will apply to the Board 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 and the SVC/Statcom and YEC's McQuesten Substation Costs. The adjusted Transmission Facilities Fixed Cost will apply until otherwise amended by the Board.

TOPIC:

REFERENCE: **November 10, 2017 Application, page 1**

PREAMBLE:

YEC states that the VGC Group has successfully completed environmental and Yukon Water Board reviews and permitting for the Eagle Gold Project and that permitting for the mine assumed electricity supply from the YEC grid, with diesel generation of less than 5 MW on site for emergency and other use as required.

QUESTION:

a) Please provide a copy of those parts of VGC Group's permit applications and related materials related to the assumed electricity supply from the YEC grid.

b) Please provide decisions and orders related to the VGC Group environmental, Yukon Water Board and other permitting reviews. Please highlight those areas of the decisions and orders that refer to issues related to the supply of electricity.

ANSWER:

(a)

The Screening Report and Recommendations issued by the Yukon Environmental and Socio-economic Assessment Board (YESAB) pursuant to the Yukon Environmental and Socio-economic Act (YESAA) assessed the construction, operation and closure of the Eagle Gold Mine and also the connection of the Mine to the Yukon Energy Corp. grid and recommended to the Decision Bodies that the Project be allowed to proceed. The report can be accessed on the YESAB website through document number 2010-0267-358-2 and the relevant section is primarily section 14.6 (pages 213 – 221) and also 2.2.2 (page 16), 8.4.6.1 (page 134 - 136), 8.6 (page 144), 8.7 (page 146), 13.6 (page 201).

The Decision Bodies issued Decision Documents allowing the Project to proceed. The Decision Documents can be accessed on the YESAB website through document numbers 2010-0267-361-1 and 2010-0267-362-2.

(b)

The Quartz Mining License (QML-011) and Type A Water Use License (QZ14-041) do not specifically include any requirement for a certain supply of electricity to be provided to the Project; however, they do incorporate VGC's commitment to have backup power generation equipment on the site to supply power to the heap leach facility pumps in the event of issues with the supply from YEC. VGC indicated that it would have a total of 4.5 MW of backup power generating equipment[1] (Yukon Water Board Waterline Website – Exhibit 1.2.1.2 Section 4.2.8.5, Exhibit 1.9.2 Section 3.10.1, 3.10.2, 5.1) (Energy, Mines and Resources Website – Section 4.3).

[1] More recent information indicates that VGC Group is planning for 3 backup generator units on site at 1.65 MW each (see response to JM-YEC-1-1).

TOPIC:

REFERENCE: **November 10, 2017 Application, page 1**

PREAMBLE:

YEC states "*VGC Group completed $40 million of site civil works in 2017, and site construction is currently targeted to resume by Q2 2018 with earliest potential operation of the Mine in Q2 2019. Mine operation based on existing reserves is forecast for ten years. When Mine operations end, rinsing the Heap Leach Pad will occur for one to two years followed by active closure activities for approximately three years*".

QUESTION:

a) Please confirm whether any of the civil work completed in 2017 was related to connections to the electricity grid and/or on-site back-up generation. If there was some related work, please provide details of these expenditures by VGC and any costs incurred to date by YEC.

b) Please confirm whether facilities being installed to supply the VGC Group operations will allow VGC to provide surplus electricity from their on-site generation back into the electricity grid.

c) Please provide an explanation of the risks to other firm ratepayers of the VGC Group operations being connected to the grid.

d) Please provide specific details of when the VGC Group operations will qualify them to be considered an industrial customer (i.e., when after the initiation of the March 2019 commissioning activities will VGC Group's operations be ramped up to industrial customer levels and when is it expected to decline to below industrial customer levels). Please provide details of the timeline and expected load of the VGC Group.

e) Please explain what rates will be charged to the VGC Group operations before it qualifies for the industrial rate.

f) Please confirm that the annual slowdown in Eagle Gold Mine's operations in December, January and February will see its demand for electricity drop to about half of its summer needs (from 10 MW to 5 MW) and that the mine's operations will still meet the load threshold of a major industrial customer during these months.

g) Please provide details of all customer and stakeholder consultations conducted by Yukon Energy Corporation during development of the proposed Power Purchase Agreement and this application prior to submitting it to the YUB.

h) Please confirm how and when the leadership / owners of YEC approved the proposed Power Purchase Agreement and Application as provided to the YUB. Please identify the dates on which these approvals were provided.

ANSWER:

(a)

No civil work was completed in 2017 relating to the connections to the electricity grid or on-site back-up generation.

(b)

The VGC Group is not planning to supply electricity back to the grid.

(c)

The PPA addresses YEC system improvements (Schedule C), VGC Group power facilities requirements (Schedule D) and operating agreement requirements (Schedule E) needed to deal with identified risks related to operation of the power system with the VGC Group load.

(d) and **(e)**

It is expected that VGC Group's initial demand will be in excess of 1 MW and it will be served under Rate Schedule 39 at Commencement of Delivery [currently estimated to be March 2019].

(f)

Confirmed.

(g)

No customer or stakeholder consultations were conducted by Yukon Energy Corporation during development of the proposed Power Purchase Agreement or application [outside of negotiations with VGC Group].

(h)

The PPA was reviewed and approved by Yukon Energy’s Board of Directors at a meeting on November 8, 2017.

TOPIC:

REFERENCE: November 10, 2017 Application, page 1

PREAMBLE:

YEC states in the footnote that OIC 1995/90 defines a major industrial customer as "a customer engaged in manufacturing, processing or mining, whose demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer".

QUESTION:

a) Please provide an explanation of what is meant by "isolated industrial customer" and why the VGC Group mine would not be classified as isolated. Please provide documentation which supports YEC's interpretation of the regulation.

ANSWER:

(a)

The term "isolated industrial customer" is defined in Rate Policy OIC 1995/90 as follows:

> "means a customer engaged in manufacturing, processing, or mining and whose electrical service is not inter-connected with electrical service provided to any other customer;"

VGC Group would not be classified as an isolated industrial customer as it will be connected to the grid through the mine facilities spur line that is to be developed pursuant to the PPA.

TOPIC:

REFERENCE: **November 14, 2017 YEC Announcement**
http://yukonenergy.ca/about-us/news-events/yukon-energy-and-victoria-gold-sign-power-purchase-agreement

PREAMBLE:

YEC's web site announcement indicates that if the YUB approves the proposed Power Purchase Agreement, sales to the VGC Group operations would contribute $100 million or more in additional revenues to YEC over the expected 10 year mine life, that this new revenue will benefit all Yukon electricity consumers and will result in a 1-2 percent reduction in rates for other electricity customers.

QUESTION:

a) Please provide details of the anticipated additional annual revenues from the VGC Group from initiation of service and over the expected 10 year life of the mine, the associated costs of providing the required electricity, the net revenue benefit, and how and in what year rates will be lowered for all other Yukon ratepayers.

b) Please provide details of the costs to be paid by the VGC Group related to system improvements that will benefit all on-grid Yukon communities.

c) Please provide details of and documentation related to the First Nation of Na-Cho Nyak Dun's support for both the Eagle Gold Mine and an upgrade to the Stewart to Keno City transmission line. Please provide an update on the project agreement with the First Nation of Na-Cho Nyak Dun for the proposed transmission line.

ANSWER:

(a)

The referenced web site announcement reflected the PPA Application information. Table 1 of the PPA Application provides VGC Group Mine projected power loads and related YEC generation over the first six years of operation. Table 2 estimates related revenues for three years (2020, 2021 and 2025) based on current rates and YEC's 2017-18 GRA – assuming VGC Group Mine loads for years 7 to 10 remain at the year 6 level, this information supports the estimate of at least $100 million added revenues to YEC over 10 years of operation. Table 3 of the PPA Application as originally filed shows net rate revenue impacts from the VGC Group Mine for the three years examined, indicating potential rate revenue requirement reductions ranging from $0.69 million to $2.02 million, i.e., the lower end of this range falls in a 1-2% reduction in overall rates. [As reviewed in Attachment 1 to YUB-YEC-1-28, Table 3 of the PPA Application has been revised. It now indicates potential rate revenue requirement reductions ranging from $1.93 million to $3.33 million, i.e., the lower end of this range now falls in a 4-5% reduction in overall rates.]

Yukon Energy is not able at this time, however, to provide the requested analysis for each of the first ten years of VGC Group Mine operation. Aside from not having VGC Group load forecasts beyond year six of Mine operation, Yukon Energy also does not have reliable forecasts of other industrial loads for each of these years, and such loads can materially affect the assessment requested for each of the operating years.

As noted above, Table 3 in the PPA Application provides an assessment of potential ratepayer impacts associated with the VGC Group Mine, including revenue impacts and the YEC LTA thermal generation costs and net revenue impact for 2020, 2021 and 2025. The analysis outlines the added thermal generation costs in these years as well as the added revenues [excluding the Fixed Charge].

The Table 3 analysis focused on these three years in order to provide an indication of ratepayer impacts over a range of relatively high potential grid load conditions that could occur in the initial six years of VGC Group operation, and absent any new renewable generation capability. The analysis was not intended to provide a forecast of what load is likely in each year, i.e., the loads in 2020 and 2021 in this analysis assumed material industrial mine requirements at both Minto and Alexco, neither of which has been committed at this time.

Table 3 as revised in Attachment 1 to YUB-YEC-1-28 provides the VGC Group mine net impact on YEC net costs and indicates added revenues are expected to exceed added costs under the assumptions adopted in each of the three years. The analysis highlights the extent to which overall industrial load levels are determinative of material changes in LTA thermal generation impacts among each of the first six years of VGC Group Mine operation. YEC does not have useful information today as to likely forecasts for each year for Minto or Alexco, and therefore cannot provide useful analysis that shows how ratepayer impacts are likely to vary separately for each year of VGC Group Mine operation. Given the number of factors that may impact Yukon Energy's revenue requirement in a given year, Yukon Energy also cannot specify whether or not overall rates will be lower for ratepayers in a given year.

Please see also response to YUB-YEC-1-28.

(b)

The PPA Application outlines the PPA details on the costs to be funded by the VGC Group related to system improvements that will benefit all Yukon ratepayers, including funding for the McQuesten Substation ($8.5 to $8.9 million of VGC Group estimated funding) and the Initial YEC System Improvements ($1.678 million of VGC Group estimated funding).

The VGC Group will provide additional benefits to all Yukon ratepayers by Fixed Charge payments during the Mine operations for 85% of YEC's annual depreciation and return on rate base expenses related to the Transmission Facilities (including any new YEC costs for Transmission Facilities Development) and the SVC/Stacom at Stewart Crossing South Substation. Please also see response to JM-YEC-1-9.

(c)

YEC does not have a record of communications FNNND may have published in support for the Eagle Gold Mine. YEC has signed an MOU with FNNND wherein YEC pledges certain things in exchange for the First Nation support for the project. Negotiations on a project agreement have not been concluded to date.

Attachment 1 to this response provides a letter from FNNND Chief Mervyn to Premier Pasloski [dated June 2016] indicating support for the SKTP.

First Nation of Na-Cho Nyäk Dun
P.O. Box 220
Mayo, Yukon Y0B 1M0
Tel: (867) 996-2265
Fax: (867) 996-2267
E-mail: main@nndfn.com
Website: www.nndfn.com

June 9, 2016

Premier Darrell Pasloski
Yukon Government Administration Building
2071 Second Avenue, PO Box 2703
Whitehorse YT Y1A 2C6

Via e-mail premier@gov.yk.ca

Dear Premier Pasloski

Re: Federal Infrastructure Funding: Stewart to Keno Transmission Line

I was surprised to recently learn the Yukon Government is not more actively pursuing federal Infrastructure funding to support an upgrade to the Stewart Keno Transmission Project. This is particularly disappointing given your statement in a Yukon Government news release, dated February 4, in which you emphasized "...partnerships are important to developing energy, infrastructure and telecommunications that will promote long-term prosperity..." in relation to scheduled government to government meetings with Ottawa. We understand there has been significant effort by YG to secure federal funding for road development including multiple trips to Ottawa and yet to our knowledge there has not been any focus on the Stewart Keno Transmission Project.

The lack of attention to this project is perplexing as it seems to cover off the key project funding metrics including:

1) a ***shovel ready project*** with the environmental assessment nearing completion and detailed design underway;
2) ***lower carbon emissions*** (without which two mines will otherwise need to burn diesel to generate on site power);
3) the Mayo to Keno line needs upgrading irrespective of federal funding so federal funding for the Stewart Keno Transmission Project would have a ***benefit to existing YEC rate payers;***
4) a ***strong business case*** supporting ***direct and indirect employment and business opportunities to the First Nation*** of Nacho Nyak Dun, two permitted potential industrial customers and better infrastructure to support future projects; and
5) ***First Nation of Nacho Nyak Dun support*** for the project.

In our preliminary discussions with the federal government they appear very supportive of the project and early indications suggest there is a strong opportunity to secure federal funding to support the Stewart Keno Transmission Project. However, we have also heard without strong support by the local Yukon Government there is little chance funding would get approval.

With this in mind I would like to request Yukon Government's support for the project and more specifically your attention and leadership to drive federal funding and make this important project a reality for the First Nation of Nacho Nyak Dun and all Yukoners.

I look forward to your earliest reply,

Yours truly,

S Mervyn

Chief Simon Mervyn
First Nation of Nacho Nyak Dunn

Cc:

Brad Cathers, Minister Responsible for Yukon Energy Corporation
Currie Dixon, Minister of Community Services
Andrew Hall, CEO, Yukon Energy Corp
Jim Tredger, MLA – Mayo-Tatchun
Larry Bagnell, Member of Parliament Yukon
John McConnell, CEO, Victoria Gold
Clynt Nauman, CEO, Alexco Resources

TOPIC:

REFERENCE: August 15, 2017, Whitehorse Star, Power for Mines is Plentiful

YEC's president Andrew Hall is quoted in this article saying that providing grid power to both the Eagle Gold Project and Alexco Resource Corp.'s silver operation in Keno City won't be an issue.

November 14, 2017 YEC Announcement
http://yukonenergy.ca/about-us/news-events/yukon-energy-and-victoria-gold-sign-power-purchase-agreement

In its announcement, YEC states that the Victoria Gold mine will connect initially to the existing Stewart to Keno City transmission line which YEC states can meet the majority of Victoria Gold's power needs for the first one to two years of its operation. However, YEC goes on to say that the existing line is at end of life and must be replaced as soon as possible and that YEC is continuing to work with the Yukon Development Corporation and the Yukon government to secure funding for a new transmission line.

QUESTION:

a) Please explain how YEC's president can be confident that supplying electricity from the grid to these mining operations will not be an issue.

b) Is the ability to supply these mines with electricity based on the assumption that a new transmission line will be built and the mines will have on-site generation as well?

ANSWER:

(a) and **(b)**

The ability to supply the VGC Group Mine with electricity is based on the PPA and the assessments set out in the PPA Application.

TOPIC:

REFERENCE: **YEC 2017-2018 GRA, Response to UCG-YEC-1-23(g)**

PREAMBLE:

LNG will be used in future when feasible to displace higher fuel cost diesel generation that would otherwise be required to meet grid loads (including industrial/ mine loads). A material share of any new loads at this time will be supplied by existing LTA hydro generation resources (see Table 3.4-1 in the GRA Application, which indicates the share of new load [in 5 GWh increments] to be supplied by LTA thermal generation with existing hydro resources as loads increase from current GRA forecasts [about 420 GWh/year] up to 485 GWh/year). The 2016 Resource Plan identifies various resource projects that are being examined to enhance hydro and other renewable generation availability within the next decade.

QUESTION:

a) Please explain where the load of the proposed VGC Group operations will place YEC's generation mix as detailed on Table 3.4-1 in YEC's 2017-2018 GRA.

b) Please provide details of how much of the required thermal generation will be LNG-based.

c) Please provide details of the LNG-related plant and operations costs that are being driven by the proposed VGC Group operations.

ANSWER:

(a)

Table 3.4-1 is the DCF table adopted to determine annual expected YEC thermal generation based on long-term average YEC hydro generation at YEC grid loads (net of expected wind and expected Fish Lake generation) as forecast in the GRA. The version included in Appendix 3.4 of the GRA assumes mine loads connected as forecast in the GRA for 2017 and 2018 [i.e., only Minto mine load is assumed in the test year forecasts].

As reviewed in JM-YEC-1-10 and in YUB-YEC-1-28, the original Table 3 as filed in the PPA Application in effect extended Table 3.4-1 from the GRA to assess the different grid loads assumed for 2020, 2021 and 2025. However, Attachment 1 to YUB-YEC-1-28 has revised Table 3 as required to take into account the changes to weekly load shapes with the addition of other mine loads.

As noted in the DCF Term Sheet [provided in Appendix 3.4 of the 2017/18 GRA], this table is required to be updated to address material changes in LTA hydro system capability due to changes in loads, installed capacity, licensing/permits or other factors. The addition of the Eagle Gold mine (or any other mine in combination with the Minto mine) to grid loads would require such an update to Table 3.4-1.

Table 3 in the PPA Application as revised in Attachment 1 to YUB-YEC-1-28 provides YECSIM model assessments of LTA thermal generation for three specific potential grid load cases in 2020, 2021 and 2025 with and without the VGC Group Mine load. These YECSIM assessments in effect take into account the modifications to the DCF Term Sheet needed to address these changes. Development of an updated DCF Term Sheet, however, is only done for GRA purposes and/or when a mine load is actually connecting to the grid or being removed from the grid.

(b) and **(c)**

Thermal generation for YEC revenue requirement and rate determinations is based on LTA hydro and thermal generation (versus actual thermal generation). Yukon Energy's 2017-18 Generation Rate Application has proposed that forecast test year LTA thermal generation be assumed to be supplied 90% by LNG generation and 10% by diesel generation. This assumption was adopted for the PPA Application Table 3 assessment of ratepayer impacts related to the VGC Group Mine connecting to the grid.

No new LNG or other thermal plant development is currently forecast to be required specifically due to connection of the VGC Group Mine.

TOPIC:

REFERENCE: **November 10, 2017 Application, page 2**

PREAMBLE:

YEC states that it has "completed environmental review and permitting for the McQuesten Substation, as an element of the successfully completed Stewart Keno City Transmission Line Project ("SKTP") environmental review and permitting".

QUESTION:

a) Please provide a copy of those parts of YEC's environmental review and permitting applications and related material related to the McQuesten Substation.

b) Please explain any differences in the assumed design / operation of the McQuesten Substation from the time YEC included it in the Stewart Keno City Transmission project until the current proposed use for the VGC Group project.

c) Please provide decisions and orders related to the YEC environmental review and permitting reviews. Please highlight those areas of the decisions and orders that refer to issues related to the McQuesten Substation.

ANSWER:

(a)

YEC's YESAA Project Proposal for the Stewart-Keno City Transmission Project is available on YESAB's public registry under project number 2015-0209.

www.yesabregistry.ca

Section 6.4.2 provides a description of the substations, including the proposed substation at McQuesten. The following description is provided for the McQuesten Substation:

- **New substation at McQuesten:** A new 138 kV to 69 kV substation will be constructed at the South McQuesten Road take off on the Silver Trail directly in line with the existing transmission line. It is directly across from the South McQuesten Road turn-off from the Silver Trail. The site is on the east (uphill) side of the road. The substation will be located and constructed entirely within the existing transmission line ROW with a footprint about 57 metres by 66 metres (not including clearing outside the fence). For the McQuesten substation, there will be a secondary containment around the 138/69 kV transformer. All oil containment and materials handling/ spill response standards and protocols will be applied through the design, construction and operations phase.

(b)

As is typically the case, the YESAA Project Proposal for the SKTP was filed before final engineering was completed. The fundamental features of the McQuesten Substation as described for the YESAA Project Proposal relevant to the environmental assessment remain unchanged. Differences in design or assumed operation details relate to the level of engineering and information available when the assessment was undertaken versus what is available after detailed engineering has been completed.

(c)

Please see Attachment 1 for YESAB's Screening Report and Recommendation and Attachment 2 for the Government of Yukon's Decision Document.

Screening Report and Recommendation

Project Assessment 2015-0209

Yukon Energy Corporation Ltd. Stewart–Keno City Transmission Project

YESAB
Yukon Environmental and Socio-economic Assessment Board

May 31, 2016
Prepared by
Executive Committee
Yukon Environmental and Socio-economic Assessment Board

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PREFACE

Yukon Energy Corporation (YEC) is proposing the installation of a new transmission line and the construction and expansion of substations between Stewart Crossing and Keno City and the removal of the existing transmission line between the Mayo substation and Keno City.

The Project lies within the traditional territories of the First Nation of Na-Cho Nyak Dun (NND) and Selkirk First Nation (SFN). The Project will be approximately 112 km in length and will be located mainly within the existing right of way with the exception of five substantive deviations along the way.

The Project involves the installation of a new 138 kV transmission line and infrastructure, including substations, and the removal of the old 69 kV transmission line between the Mayo substation and Keno City. YEC anticipates starting clearing and construction in the fall of 2016.

The Executive Committee of the Yukon Environmental and Socio-economic Assessment Board (YESAB) has completed a screening report that assesses the environmental and socio-economic effects of the proposed project pursuant to the *Yukon Environmental and Socio-economic Assessment Act* (YESAA).

The screening report is available on the YESAB Online Registry (www.yesab.ca/registry, YESAB Project No. 2015-0209) or from the YESAB Head Office at Suite 200 – 309 Strickland Street, Whitehorse YT.

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EXECUTIVE SUMMARY

This screening report is the outcome of the Yukon Environmental and Socio-economic Assessment Board (YESAB) Executive Committee's assessment of the Stewart-Keno City Transmission Project (the Project) proposed by Yukon Energy Corporation (YEC). It contains the conclusions of the Executive Committee screening, which is that the Project be allowed to proceed subject to specified terms and conditions. The Executive Committee determined that the Project will have, or is likely to have, significant adverse effects to wildlife, environmental quality, land and resource use and heritage resources, which can be mitigated by those terms and conditions.

The Stewart-Keno City Transmission Project involves the installation of a new transmission line from Stewart Crossing to Keno City along with the decommissioning of the existing transmission line between Mayo and Keno City. The Project will require accessory activities such as the construction of new and modified sub-stations. Project activities are proposed to occur starting in October 2016 to October 2017.

The purpose of this report is to:

- describe the Project and the screening methodology;
- summarize matters considered during the screening;
- identify and evaluate potential adverse effects of the Project;
- require mitigation measures that reduce the significance of potential effects of the Project;
- consider comments and concerns; and
- provide the Decision Body (Government of Yukon) with a recommendation resulting from the screening process along with the reasons for that determination

Prior to commencing its screening, the Executive Committee determined that the Proponent had provided adequate information to commence a screening and that the Proponent had met its consultation obligations as described in s. 50(3) of the *Yukon Environmental and Socio-economic Act*. Specifically, the Executive Committee determined that the Proponent had sufficiently consulted with the affected First Nations, First Nation of Na-Cho Nyak Dun and Selkirk First Nation, and residents of Mayo, Keno City, and Stewart Crossing.

The Executive Committee completed an effects assessment of the Project that considered the significance of potential effects to wildlife and wildlife habitat, environmental quality, land and resource use and heritage resources. Where the Executive Committee determined the Project will have, or is likely to have, significant adverse environmental or socio-economic effects, it applied mitigation measures to reduce effects below the threshold of significance.

On April 25, 2016, the Executive Committee issued a draft screening report, followed by a public comment period on the draft report. The Executive Committee considered stakeholder and public comments and concerns when finalizing its recommendation.

Recommendation

Under s. 58(1)(b) of the *Yukon Environmental and Socio-economic Assessment Act*, the Executive Committee recommends to Government of Yukon, the Decision Body, that the Stewart-Keno City Transmission Project be allowed to proceed, subject to terms and conditions specified in this report. The Executive Committee determined that the Project will have, or is likely to have, significant

adverse environmental or socio-economic effects in or outside Yukon that can be mitigated by those terms and conditions. Recommended terms and conditions are listed in Section 11.

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ACRONYMS AND ABBREVIATIONS

DSR	Draft screening report
Executive Committee	Executive Committee of the YESAB
km	Kilometre
kV	Kilovolt
LSA	Local Study Area
NCPC	Northern Canada Power Commission
NND	First Nation of Na-Cho Nyak Dun
Project	Stewart-Keno City Transmission Project
Proponent	Yukon Energy Corporation Ltd.
ROW	Right of way
RRC	Renewable Resources Council
RSA	Regional Study Area
SFN	Selkirk First Nation
UCG	Utilities Consumers' Group
VESEC	Valued Environmental and Socio-economic Component
WKA	Wildlife Key Area
YEC	Yukon Energy Corporation Ltd.
YESAA	*Yukon Environmental and Socio-economic Assessment Act*
YESAB	Yukon Environmental and Socio-economic Assessment Board
YG	Government of Yukon
YOR	YESAB Online Registry

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Part A PROJECT INTRODUCTION AND OVERVIEW

The *Yukon Environmental Socio-economic Assessment Act* (YESAA) requires that Decision Bodies consider the recommendation arising from a screening conducted under YESAA, and issue a decision document, prior to taking any action that would enable a project to be undertaken.

The purposes of this report are to provide the Decision Body with a recommendation arising out of the screening and the reasons for that recommendation.

In this report, the Executive Committee:

- describes the Project and the screening approach;
- summarizes the matters considered during the screening;
- identifies potential impacts of the Project and outlines terms and conditions that mitigate potentially significant adverse environmental and/or socio-economic effects of the Project;
- considers the comments received on the project proposal and draft screening report; and
- provides a recommendation to the Decision Body, including recommended terms and conditions, and the reasons for that determination.

1. ASSESSMENT PROCESS

1.1 REQUIREMENT FOR AN ASSESSMENT

Under s. 47 of YESAA, the Project is subject to an assessment by YESAB due to the following circumstances:

- The project involves activities listed in column 1 of Schedule 1 of the Assessable Activities, Exceptions and Executive Committee Projects Regulations (Activity Regulations); and is not listed in column 2 as excepted. Specifically, the Proponent proposes to undertake activities identified in Part 4, Item 1, of the Activity Regulations. The specific activity is listed as:

  Construction, installation, operation, modification, decommissioning or abandonment of, or other activity in relation to, a power line or a telecommunications line.

- The listed activity is proposed to be undertaken in Yukon; and,
- An authorization or the grant of an interest in land by a government agency, independent regulatory agency, municipal government or First Nation is required for the activity to be undertaken.

Section 50(1) of YESAA requires that the Project be submitted to the Executive Committee as the project meets the criteria set out in Schedule 3 of the Activity Regulations, “Projects to Be Submitted to the Executive Committee”, specifically:

> *Construction or installation of a power line with a voltage of 138 kV or more or of a length of more than 50 km if the power line is not on a right of way developed for a power line, pipeline, railway line or road nor on a right of way contiguous to, for its whole length, a right of way developed for a power line, pipeline, railway line or road.*

Based on information provided in the project proposal, the Government of Yukon has been identified as the Decision Body for the Project. The potential authorizations required for the Project are listed in Table 1.

Table 1: Project Authorizations and Authorizing Bodies

Responsible Agency	Act/Regulation	Authorization(s) Required
Government of Yukon Department of Community Services	*Building Standards Act*	Building Permit
Government of Yukon Department of Energy, Mines and Resources	*Territorial Lands (Yukon) Act* *Land Use Regulation* *Lands Act*	Land Use Permits (for clearing or installing a utility ROW, conducting geotechnical studies, burning refuse) Licences of occupation
Government of Yukon Department of Highways and Public Works	*Highways Act* *Highways Regulation*	Access Permit Licences of Occupation Work in ROW Permit Sign Permit
Government of Yukon Department of Environment	*Environment Act* *Storage Tank Regulations* *Solid Waste Regulations* *Special Waste Regulations*	Storage of fuel Storage, handling and disposal of solid wastes Storage, handling and disposal of special wastes

1.2 SCREENING CHRONOLOGY

The assessment process and screening timelines are set out in the *Rules for Screenings Conducted by the Executive Committee.*

The chronology of the Stewart-Keno City Transmission Project screening is set out in Table 2, which provides an outline of key assessment dates and stages. For more detailed assessment information, please visit the YESAB Online Registry (YOR) at www.yesab.ca/registry or the YESAB Document Registry located at the YESAB Head Office.

Table 2: Project Assessment Chronology

Adequacy Review Period	
December 31, 2015	YEC submits proposal to the Executive Committee
February 25, 2016	The Executive Committee notifies YEC that it has met its consultation requirements under s. 50(3) of YESAA. In addition, the Executive Committee determines that the proposal is adequate to commence screening.
Screening	
February 25, 2016	The Executive Committee issues preliminary statement of scope of project
February 25, 2016	The Executive Committee commences public comment period (February 25 – March 25, 2016)
March 25, 2016	Public comment period ends, the Executive Committee begins considering comments received
April 25, 2016	The Executive Committee issues a draft screening report and commences public comment period on draft screening report
May 25, 2016	Public comment period ends, the Executive Committee begins considering comments received
Report and Recommendation	
May 31, 2016	The Executive Committee issues a screening report and its recommendation to the Decision Body

1.3 CONSULTATION REQUIREMENTS UNDER YESAA

Pursuant to s. 50(3) of YESAA, a proponent is required to consult any First Nation in whose traditional territory the project will be located or might have significant environmental or socio-economic effects, as well as the residents of any community in which the project will be located or might have significant environmental or socio-economic effects, before submitting a proposal to the Executive Committee. This duty to consult is to be exercised in the manner described in s. 3 of YESAA.

Before commencing a screening of a project, the Executive Committee must determine whether, in its opinion, the proponent has consulted First Nations and the residents of communities in accordance with s. 50(3) of YESAA.

Based on the information provided in the proposal, the Executive Committee determined that for the purposes of s. 50(3) of YESAA, the Proponent was required to consult:

- the First Nation of Na-Cho Nyak Dun (NND) and Selkirk First Nation (SFN), being the First Nations in whose territories the Project "will be located or might have significant environmental or socio-economic effects"; and
- the residents of Mayo, Keno City and Stewart Crossing, being the communities in which the Project “will be located or might have significant environmental or socio-economic effects.”

The Executive Committee considered the information provided by the Proponent in the project proposal, which included a summary of consultation efforts and documentation with NND and SFN. The Executive Committee determined that, in its opinion, the Proponent had consulted with the above-noted First Nations and community residents of Mayo, Keno City and Stewart Crossing in accordance with s. 50(3) of YESAA. The Executive Committee notified the Proponent in writing of its determination on February 25, 2016.

1.4 Access to Assessment Documentation

Section 118 of YESAA requires that the Board maintain:

a) a register containing all documents that are produced, collected or received by the executive committee, panels of the Board and joint panels in relation to assessments, together with any documents provided to them under section 91(1);

b) a list of the project, existing projects, other activities and plans for which an assessment is pending before, or has been completed by, the designated offices, the executive committee, panels of the Board and joint panels, together with their location and stage of assessment; and

c) a record of authorizations, grants of interest in land and provisions of financial assistance as reported to it pursuant to section 89.

YESAB maintains a Public Registry, which contains all documents related to assessments, a list of projects, activities and plans, project location and stage of assessment, and lists of any authorizations, grants of interest in land and financial assistance. These records are stored in such a way as to facilitate public access to them.

The YESAB Public Registry is comprised of two components:

1. The YOR – this is an entirely electronic registry and document management system that is accessible through the internet. This is considered the primary means through which project-related information is made available to the public.
2. Document Registry – This is primarily a paper-based registry of files maintained by YESAB staff.

Files on the YOR are available 24 hours a day via the internet, while the document registry is accessible during working hours.

1.5 Environmental and Socio-economic Assessment Methodology

The Executive Committee employed a valued component based assessment methodology to assess the environmental and socio-economic effects of the Stewart-Keno City Transmission Project. The assessment methodology is outlined below.

- Determine project scope that accounts for all proposed activities through all stages of the Project (i.e. construction and operation).
- Include activities identified in the proposal and any other activity that the Executive Committee considers likely to be undertaken in relation to an activity so identified and sufficiently related to it, to be included in the Project.
- Give full and fair consideration to scientific information, traditional knowledge and other information provided during the assessment (s. 39 of YESAA).
- Determine the scope of assessment based on:
    - Matters to be considered (as described further in Section 1.6)
    - Views and information provided during the assessment.
    - Key issues identified.
    - Valued Environmental and Socio-economic Components (VESECs).
- Consider baseline information.
- Evaluate the proponent's approach to predicting changes from baseline caused by project activities.
- Determine spatial and temporal overlap between project activities and values. For example, the use of heavy machinery may occur spatially within wildlife habitat and temporally when wildlife is known to be using that habitat (e.g. summer habitat).
- Characterize potential project effects.
- Evaluate the consequences of overlap between activities and values.
- Consider the proponent's assessment of adverse effects and its conclusions.
- Evaluate the effectiveness of mitigation measures proposed by the proponent and non-discretionary legislation that may mitigate these effects.
- Determine the significance of adverse project effects.
- Specify terms and conditions to mitigate significant adverse project effects so that they are no longer significant. Terms and conditions may include:
    - alternatives to the project or alternative ways of undertaking or operating it;
    - mitigative measures; and,
    - measures to compensate.
- Characterize the residual effects of project activities, and how they interact.

- Determine whether there are residual significant adverse effects that require additional terms and conditions.
- Identify the spatial and temporal boundaries for cumulative effects to particular VESECs.
- Identify projects for which proposals have been submitted to YESAB and other existing or proposed activities occurring within these boundaries.
- Determine the spatial and temporal overlap between all activities and VESECs.
- Conduct a cumulative effects assessment.
- Consider the proponent's assessment of adverse cumulative effects and their conclusions.
- Evaluate the effectiveness of mitigation measures proposed by the proponent and non-discretionary legislation that may mitigate these cumulative effects.
- Specify terms and conditions to mitigate significant adverse cumulative effects.
- Determine whether there are residual significant adverse cumulative effects that require additional terms and conditions.

1.6 Matters to Be Considered

The scope of the assessment encompasses the matters considered in the screening. Consistent with s. 42 of YESAA, the Executive Committee considers:

- the purpose of the project;
- all stages of the project;
- the significance of any environmental or socio-economic effects of the project that have occurred or might occur in or outside Yukon, including the effects of malfunctions or accidents;
- the significance of any adverse cumulative environmental or socio-economic effects that have occurred or might occur in connection with the project in combination with the effects of:
    - other projects for which proposals have been submitted under s. 50 (1); or
    - other existing or proposed activities in or outside Yukon that are known to the Executive Committee from information provided to it or obtained by it under YESAA.
- any studies or research undertaken under subsection 112(1) that are relevant to the project or existing project;
- the needs for effects monitoring;
- alternatives to the project, or alternative ways of undertaking or operating it, that would avoid or minimize any significant adverse environmental or socio-economic effects;
- mitigative measures and measures to compensate for any significant adverse environmental or socio-economic effects;

- the need to protect the rights of Yukon Indian persons under final agreements, the special relationship between Yukon Indian persons and the wilderness environment of Yukon, and the cultures, traditions, health and lifestyles of Yukon Indian persons and other residents of Yukon;
- the interest of first nations;
- the interests of residents of Yukon and of Canadian residents outside Yukon;
- any matter that a decision body has asked it to take into consideration; and
- the capacity of any renewable resources likely to be significantly affected by the project to meet present and future needs.

1.7 Determining the Significance of Adverse Effects

To determine if a particular effect is significant, the Executive Committee examines the characteristics of the effect as well as the context, or circumstances, within which the effect would occur. Criteria for determining what may constitute a significant effect include the following factors:

Magnitude: The intensity of an effect or extent of change, where "effect" is defined as the change from baseline conditions resulting from an activity.

Probability: The likelihood that an adverse effect will occur.

Geographic Extent: The geographic extent of project effects (e.g. the distance from the project and/or the area in which effects are detectable). The geographic extent of effects can be local or regional.

Duration and Frequency: The length of time the effect lasts and how often the effect occurs. The duration of an effect can be short term or long term. The frequency of an effect can be frequent or infrequent.

Reversibility: The degree to which the effect is reversible. Effects can be reversible or permanent. Reversible effects may have lower impacts than irreversible or permanent effects.

Context: The particular environmental and/or socio-economic context within which the project occurs. Context is related to the importance of valued environmental and socio-economic components, their resiliency to potential effects and the extent to which those valued components may successfully adapt to change.

YESAA requires that the Executive Committee recommend mitigations to address significant adverse effects of a project, including cumulative effects, in order to recommend that a project proceed. This screening report contains the Executive Committee's recommended mitigations for all significant adverse effects of the proposed project.

At the conclusion of screening, the Executive Committee must make one of the following four possible recommendations as per s. 58(1) of YESAA. Subject to subsection (2), at the conclusion of its screening, the Executive Committee shall:

a) Recommend to the decision bodies for the project that the project be allowed to proceed without a review, if it determines that the project will not have significant adverse environmental or socio-economic effects in or outside Yukon;
b) Recommend to the decision bodies that the project be allowed to proceed without a review, subject to specified terms and conditions, if it determines that the project will have, or is likely to have, significant adverse environmental or socio-economic effects in or outside Yukon that can be mitigated by those terms and conditions;
c) Recommend to the decision bodies that the project not be allowed to proceed and not be subject to a review, if it determines that the project will have, or is likely to have, significant adverse environmental or socio-economic effects in or outside Yukon that cannot be mitigated; or
d) Require a review of the project if, after taking into account any mitigative measures included in the project proposal, it cannot determine whether the project will have, or is likely to have, significant adverse environmental or socio-economic effects.

The Executive Committee recommends in this screening report that the Project be allowed to proceed without a review, subject to specified terms and conditions. The specified terms and conditions are listed in Section 11 of this report.

2. PROJECT OVERVIEW

2.1 PROPONENT INFORMATION

Yukon Energy Corporation (YEC) is a public utility owned by the Government of Yukon through the Yukon Development Corporation, subject to rate regulation by the Yukon Utilities Board. YEC owns and operates the integrated transmission system of Yukon and is the electric utility with primary responsibility for planning and development of new generation and transmission facilities in Yukon.

Yukon Energy management reports to a Board of Directors through its President and CEO.

Contact Person:

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2.2 PROJECT DESCRIPTION

Information in this section is either directly reproduced or summarized from the project proposal (YOR 2015-0209-005-2) and subsequent additional proposal information.

2.2.1 Project Components

The Project includes construction and operation of a new 138 kV transmission line mainly within or adjacent to the existing 69 kV transmission line ROW between Stewart Crossing and Keno City, as shown in Figure 1. The Proponent anticipates the new transmission line to be approximately 112 km in length. It includes connection of the Stewart Crossing South substation (S251) to the existing 138 kV grid, construction of a new substation (S250) adjacent to existing Mayo substation (S249), and development of a new substation (S258) at the South McQuesten River Road (McQuesten) intersection with the Silver Trail to step down the voltage from 138 kV to 69 kV.

The Project consists of the following components:

- A 138 kV transmission line from Stewart Crossing South substation to Keno City;
- Modifications to, and expansion of, the Stewart Crossing South substation (S251) that will increase the footprint for the substation by approximately 50 m outside of the existing ROW which will require a land use permit.
- Construction of a new Mayo substation (S250) that will occur on Yukon Energy property within or near the existing Mayo substation (S249) footprint; and,
- Construction of a new substation (S258) directly across the road from the South McQuesten River Road turn-off from the Silver Trail Highway, and on the east (uphill) side of the road directly in line with the existing transmission line.

The Proponent will construct the new transmission line to the same 138 kV design standard for its entire length; however, the portion of the line between Stewart Crossing South substation and the new substation at the McQuesten River Road will operate at 138 kV, and the portion of the line between McQuesten and Keno City will operate initially at 69 kV. The voltage conversion from 138 to 69 kV will take place at the new McQuesten substation (S258).

The existing 69 kV transmission line (L176) between Stewart Crossing South substation and Mayo substation will remain in place after the Project is complete and continue to operate. The 30 m wide cleared area within the existing 60 m ROW in this segment will be widened by approximately 20 m to accommodate continued operation of both transmission lines.

The existing 69 kV transmission line between Mayo and Keno City will be removed and salvaged once the new 138 kV transmission line is in service. The cleared portion of the ROW of the new line in this segment will generally be 30 m in width throughout its operating life.

The Project also includes provision to install a new aerial fibre optic communication line on the 138 kV transmission line from S251 to S257 (Stewart Crossing South to Keno City substations).

2.2.2 Project Footprint

The Project is to be constructed within or adjacent to the existing 138 kV or 69 kV transmission line ROW, with widening of cleared areas as required to accommodate the new facilities. All new or expanded substations are either within or contiguous to the existing ROW; and the proposed routing between the Stewart Crossing South and Mayo substations is entirely within or contiguous to the existing ROW, except for a small deviation entering and leaving the YEC property at the Mayo substation. Figure 1, below, shows the project location and footprint.

There are a small number of minor deviations from the existing 69 kV ROW, primarily north of Mayo, in order to avoid potential land use conflicts, and to improve line routing for improved access and reducing exposure to wet ground, difficult terrain and permafrost. Deviations from the existing 69 kV ROW or the Silver Trail ROW are all within approximately 500 m of the current 69 kV transmission line ROW. The extent to which routing and siting is proposed beyond areas within, or contiguous to, the existing transmission line ROW is summarized in Table 3 below. Relatively minor deviations to improve tree cover between the project ROW and the Silver Trail are not outlined in the table. Section 6.3.2 of the project proposal contains further information on transmission line routing deviations from the existing transmission line ROW (YOR 2015-0209-005-2).

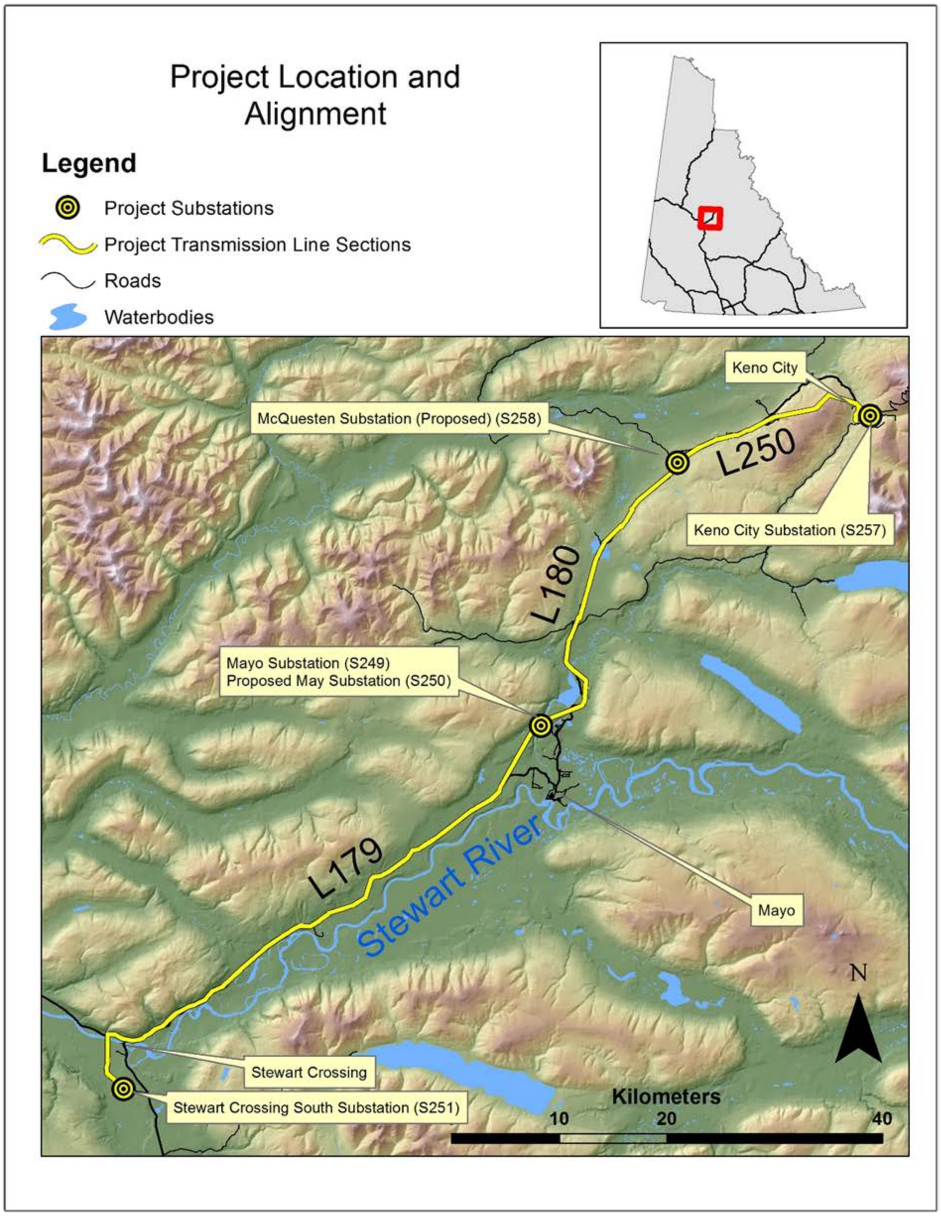

Figure 1: Project Overview Map

Table 3: Routing or Siting Outside and Not Contiguous to Existing Transmission ROW

Transmission Line Segment	Line segments outside existing 138 kV or 69 kV ROW and not contiguous to existing 138 kV or 69 kV ROW
Mayo to McQuesten Line (L180) – 31.6 km	• First deviation: Along or near highway ROW for slightly over 3km. Starts shortly before crossing the Mayo River (river crossing at km 64 on Silver Trail). • Second deviation: Along highway ROW for about 6 km. Starts about 2.5 km north of the first deviation, then the 69 kV ROW once again joins the highway.
McQuesten to Keno City Line (L250) – 20.4 km	• Third deviation: South of 69 kV and highway ROWs for about 2.2 km. Starts shortly after exiting the McQuesten substation and after km 8.5 on the Silver Trail. • Fourth deviation: South of 69 kV and highway ROWs for about 1 km. Starts about 2 km after the end of the third deviation. • Fifth deviation: Entering Keno City area and substation for less than 0.5 km. The final part of the line entering the existing substation at Keno City.

(Source: YOR 2015-0209-005-2)

2.3 Scope of the Project

Project scoping is conducted in accordance with s. 51 of YESAA and Part 4 of the Rules for Screenings Conducted by the Executive Committee. Section 51 of YESAA states, in part:

> *…the executive committee shall determine the scope of a project to be assessed by it, and shall include within the scope of the project, in addition to any activities identified in the proposal, any other activities that it considers likely to be undertaken in relation to an activity so identified and sufficiently related to it to be included in the project.*

Table 4 presents the scope of the Project assessed by the Executive Committee in this screening.

Table 4: Statement of Project Scope

Project Component	Activities
General Project	• Construction and operation of a 138 kV transmission line (approximately 112 km in length) between Stewart Crossing and Keno City • Decommissioning of existing 69 kV line • Project is largely based within or adjacent to the existing ROW, deviations are noted in Section 2.4

Transmission Line Construction	Clearing, brushing and burning of vegetation: • Flagging new ROW edges • Clearing and brushing of >15 m on each side of the centreline of the ROW during winter months • Clearing extra 20 m width within ROW between Stewart Crossing and Mayo • Hand clearing near watercourses and on steep slopes • Removal of 'danger trees' • Firewood salvage plan to be put into place • Burning slash piles from mechanical clearing activities Access and installation of 138 kV transmission line: • Establishing access points • Establishing pole foundations; dependent on soil conditions. Potential foundations include augered holes, rock anchors, and vertical culverts filled with rock • Hauling poles, insulators, hardware, and reels of conductor to ROW • Assembling and erecting structures and installing anchors • Installation of insulators, stringing of conductors and overhead ground wires • Clean up, grading of ruts left by ROW travel Use of equipment: • Heavy equipment, tandem axle trucks and trailers, one and three ton fuel trucks, crew trucks, helicopter, compressors and hard drills, manlift, propane fan burners, chainsaws and brush saws, and spill kits
Construction or Modification of Three Substations	Modification to, and expansion of, the Stewart Crossing South substation: • Expansion between 50 m to 100 m on western boundary • Fence line extended between 30 m to 50 m • Construction of new Mayo substation within existing YEC Mayo Hydro property adjacent to existing substation • Construction of the new McQuesten substation within existing transmission line ROW • Clearing of >15 m around the perimeter of substations • Removal of vegetation and topsoil from the site • Excavation of 1 – 2.4 m based on foundation requirements for transformers

	• Running of copper wire through foundation • Addition and compaction of fill material to foundation sites • Pouring of concrete foundations • Installation of equipment, filling with insulating oil, and clean-up • Installation of fencing, gates, and locks • Ongoing operation of substations, including inspection, maintenance, and emergency repairs as needed Use of Equipment: • Heavy equipment, chainsaws, survey equipment, spill kits • Salvaged organic material will be used for re-vegetation. Surplus non-organic material will be used for berm construction
Decommissioning, Removal and Salvage of Existing Line between Mayo and Keno City	• Removal and salvage of existing 69 kV transmission line between Mayo and Keno City once new 138 kV line is in place • Collection and removal of all conductors, insulators, counterpoise and other materials to be collected and removed • Excavation and removal of tower foundations • Filling and grading of holes/ruts from foundation removal and travel through the ROW • Disking and ploughing where necessary; re-seeding in areas subject to erosion • Disposal of construction waste, poles, • Unused ROW segments from old line between Mayo and Keno City to be left to revegetate
Decommissioning Access Roads/Trails	• Upon consultation with NND/YG, some access roads will be decommissioned • Removal of drainage structures and road material • Remediation of any contaminated soils • Grading of roads and ditches to promote natural re-vegetation • Installation/grading to create barriers for preventing vehicle access

Operation and Maintenance	• Annual line patrols, completed by vehicle or helicopter • Maintenance work as required • Recurrent brushing every 7-10 years based on vegetative growth
Camps	Establishment of a temporary 30-40 person camp on existing YEC property near the Mayo Hydro facility, including: • Storage of construction material and equipment • Mobilizing temporary buildings, office, waste containers • Water to be trucked from Mayo or drilled from new well • Grey water and sewage to be disposed of in permitted septic system or trucked to existing treatment facility in Mayo • Storage of up to 4 000 L of petroleum fuels

2.4 Temporal and Spatial Boundaries

In addition to specifying the activities included in the scope of the Project, it is important to have a clear understanding of the temporal and spatial boundaries of the Project. These boundaries define the periods and sequencing of activities as well as the area within which activities, and their effects, are proposed to occur.

Temporal Boundaries

The Proponent plans to obtain authorizations and approvals necessary to allow construction of the Project to commence in late 2016, with a projected in service date of late 2017. This timeline is dependent upon a number of factors, including duration of the YESAB assessment process, permitting, procurement and construction tendering. The phases of the Project include construction, operation and maintenance. The construction phase will include constructing the Project, commissioning the facilities, and decommissioning existing infrastructure (removal, salvage, and restoration of the old 69 kV transmission line from Mayo to Keno City). Construction is anticipated to start in fall 2016 and end in fall 2017. The operation and maintenance phase will extend from the end of construction throughout the life of the relevant components of the Project. Operation will begin when construction is completed. There is no timeline or plan for decommissioning of the Project.

Spatial Boundaries

The Project is located in the Yukon interior region. The 138 kV transmission line will be approximately 112 km in length, starting at an expansion of the existing Stewart Crossing South substation at the southern end and terminating at the existing Keno City substation at the northern end. The new transmission line, and its expanded and new substations and customer taps, will be mainly within or adjacent to the existing Yukon Energy 69 kV transmission line ROW between Stewart Crossing and Keno City. The ROW is slightly west of the Klondike Highway in the Stewart Crossing area and close to the Silver Trail (Highway 11) between Stewart Crossing and Keno City. Within the Project ROW, clearing will typically occur for a 30 m width centred on the project centreline (and in many instances, a material portion of this area has already been cleared to accommodate existing facilities).

Specific Local Study Areas (LSAs) and Regional Study Areas (RSAs) varied as appropriate for different baseline components examined. For example, according to the project proposal, the LSA for most biophysical components is defined as a 200 m corridor centered along the transmission line alignment. It includes the actual footprint of the Project and a buffer for some indirect effects to wildlife habitat, vegetation, and aquatic habitat. The RSA includes the LSA and an additional buffer for effects to habitat values, vegetation, and aquatic features. The proposal generally defines the RSA as a one kilometre wide corridor centred on the proposed route of the transmission line. The RSA used for each valued component may differ, but is focused on the extent to which project effects are expected to interact with valued components.

3. EXISTING ENVIRONMENTAL SETTING

Information in this section is either directly reproduced or summarized from the project proposal and subsequent additional proposal information.

3.1 Surficial Geology and Terrain

The Project is located in the Boreal Cordillera ecozone and the Yukon Plateau North ecoregion. The region is generally characterized by rolling hills, uplands and plateaus separated by deep and broad U-shaped valleys. Surficial geology and soils differ in depth and materials based on glacial deposits and modern creek drainages. Exposed bedrock is prominent in some convexities in the landscape.

The Project is within the Yukon River drainage, which encompasses approximately 66 percent of the Yukon Territory and is its largest drainage area.

A critical piece of the landscape is the discontinuous permafrost that lies beneath 50 to 90 percent of the ground. Between Mayo and Keno, permafrost is shallower and generally more widespread. Within the LSA, permafrost is typically less than two metres below the active layer of soil, though north-facing slopes, poor drainage, and thick organic cover can contribute to active layers of just tens of centimetres. Generalized distribution of terrain hazards and description of surficial geology are described in Table 5.2-1 of the project proposal.

3.2 Vegetation

Boreal and alpine vegetation characterizes the RSA. Lodge pole pine dominates previously burnt areas while moist to wet sites contain deciduous trees including aspen, birch, and alder. Shrub species, including willow, highbush cranberry, crowberry, Labrador tea, and wild rose cover a mostly continuous layer of mosses where conditions are moist. Black spruce forests dominate north-facing slopes. Understory species include crowberry, willow, Labrador tea, and lousewort.

Within the RSA, grassland and wetland ecosystems are considered sensitive due to their potential for rare species and value as wildlife habitat. Environment Yukon's Conservation Data Centre lists multiple rare plant species that could occur in the region. Table 5.2-3 of proposal documents summarizes these species. There is the potential for rare plants to occur in the LSA; however, none were found during the 2015 field study.

3.3 Wildlife

Wildlife found within the RSA is consistent with what is found throughout Yukon. Wildlife species that may be present within the RSA include black and grizzly bear, caribou, elk, moose, mountain goat, mule deer, thin-horn sheep, wolf, coyote, cougar, red fox, fisher, lynx, marten, mink, river otter, beaver, wolverine, hoary marmot, woodchuck, woodrat, weasel, chipmunk, shrew, groundhog, squirrels, pika, mice, bat, vole, lemming and groundhog.

Key large species in the RSA include moose, for which the Devil's Elbow Habitat Protection Area (See Figure 2) was developed to protect moose calving and rearing. To the east of the Klondike Highway, moose are present in average densities, while on the western side of the highway numbers are below average.

Migratory birds listed under the *Migratory Birds Convention Act*, or other bird species assessed under COSEWIC or protected under *SARA* may be found within the LSA and RSA. The project proposal provides a list of migratory and other bird species that may be found within the project area. The Project overlaps with habitat for species of conservation concern, including Bank Swallow (Threatened) and Rusty Blackbird (Special Concern).

Within the RSA, important wildlife habitat features include south facing slopes, which are used as winter range for moose and mule deer and spring habitat for all ungulates and bears. Deciduous shrubs which grow in the existing transmission line corridor are used as forage; these areas have increased wildlife usage.

Wildlife Key Areas (WKAs) provide important habitat for seasonal or year round functions for wildlife and are known through local, traditional and scientific knowledge. The Project overlaps with the following WKAs, as shown below in Figure 3:

- A Black Bear WKA located north of Stewart Crossing, used as a spring foraging area,
- Duck WKAs located along the Stewart River, in the area of the Devil's Elbow Habitat Protection Area, identified as important waterfowl areas, and
- Raptor WKAs located in the Mayo area, potentially used by bald eagle, goshawk, gyrfalcon, hawks, Peregrine falcons, owls, merlin and northern harrier.

3.4 Groundwater

Near surface groundwater and the water table in the RSA are expected to generally follow the topography. Groundwater is recharged from meteoric infiltration primarily in upland, hills and mountains; then moves down-gradient to where it typically discharges along valley bottoms forming wetlands, creeks and rivers of the RSA. Regional groundwater flow ultimately reports to the two major rivers in the watershed – the Stewart and McQuesten Rivers.

The land surface and associated near surface groundwater conditions in the RSA can be generally divided into areas that are dominated by sand and gravels at the surface, areas of organic rich sediments or lacustrine sediments, and areas dominated by permafrost. The project proposal contains further information on groundwater conditions.

The majority of groundwater usage is for community drinking water supply in Mayo and Keno City. Both communities have their public drinking water supplied from groundwater wells. In Mayo, potable water is extracted from the shallow alluvial aquifer underlying the village. The potable water is warmed by using deep warm groundwater to heat the cooler potable water. The warm water comes from a deep confined aquifer below the village. The community water supply for Keno City comes from a relatively low-yield water well completed in bedrock. Elsewhere it is anticipated that individual private water wells supply isolated residences along the Silver Trail and in Stewart Crossing.

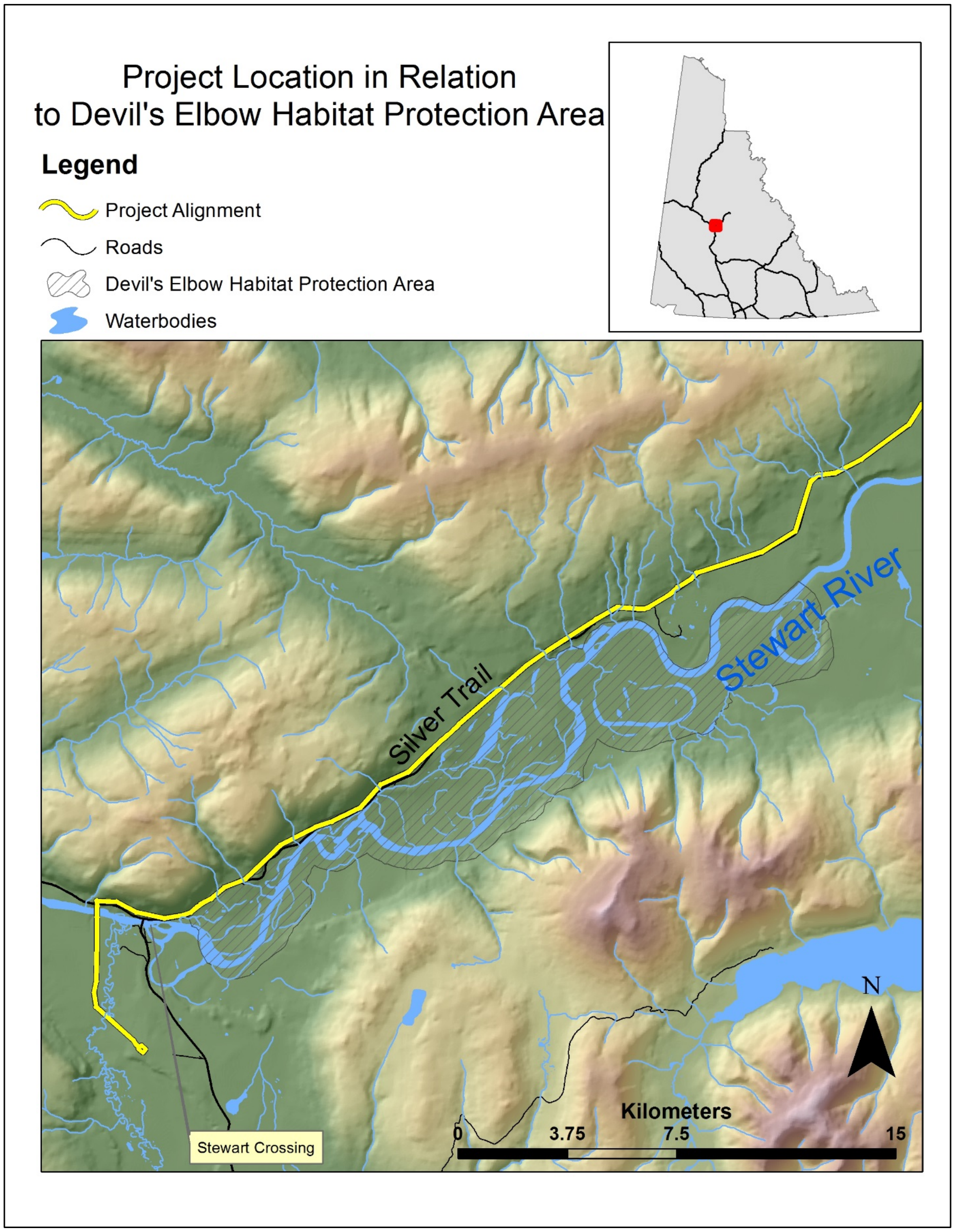

Figure 2: Project Location in Relation to Devil's Elbow Habitat Protection Area

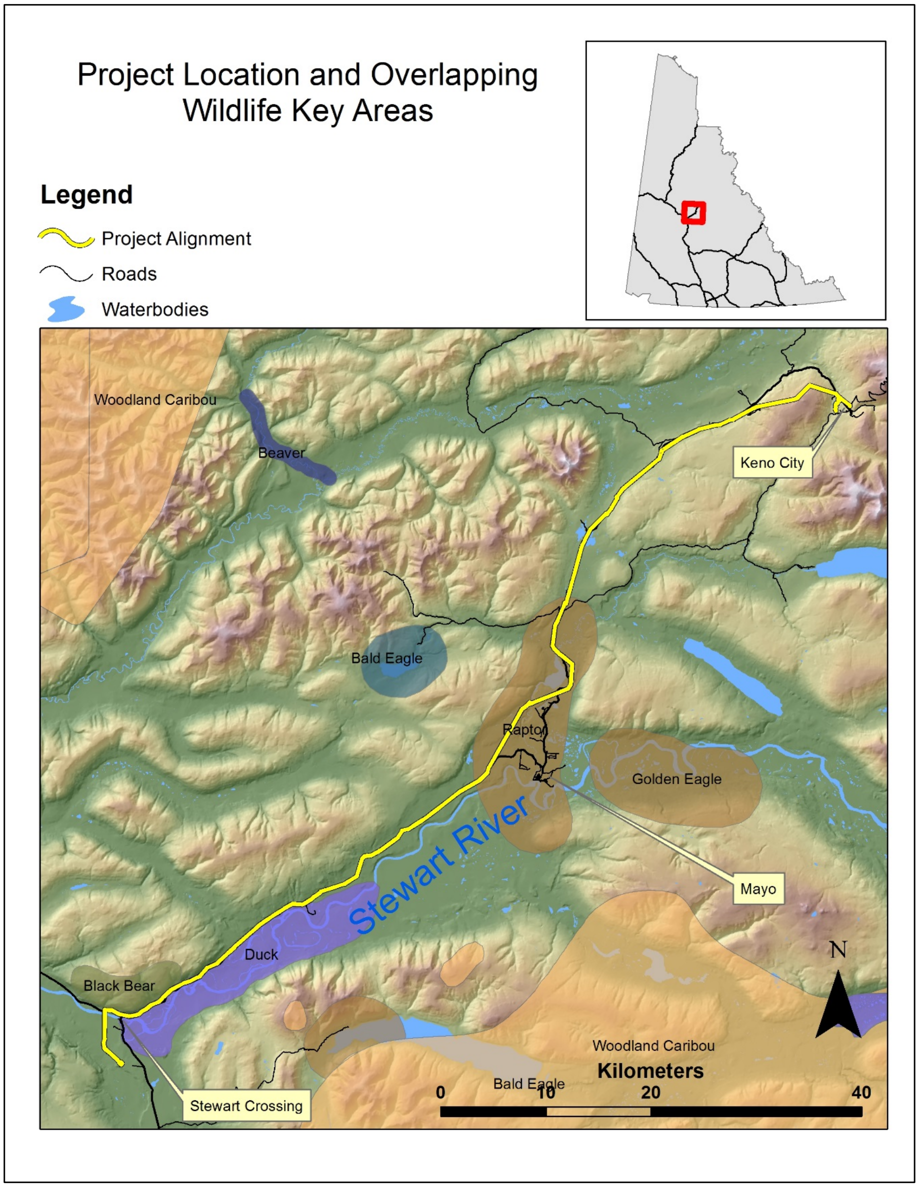

Figure 3: Wildlife Key Areas in Relation to the Project Location

3.5 Fish and Fish Habitat

The Project lies within the Stewart River and McQuesten River watersheds. The Stewart River flows west at Stewart Crossing and, further downstream, into the Yukon River, and is noted for populations of Arctic grayling, burbot, Chinook salmon, chum salmon, northern pike and whitefish. The three major watercourses crossings for the Project include the Stewart River at Stewart Crossing, the Lower Mayo River at Wareham dam, and the Mayo River at Minto Bridge/Minto Creek. An inventory of minor tributary crossings can be found in the project proposal.

Wetlands are permanently or temporarily submerged or permeated by water, and characterized by plants adapted to saturated-soil conditions. Wetlands are typically in shallow to sloping terrain and on floodplains in proximity to surface waters. Small wetland features along the RSA have been identified in the Preliminary Terrain Survey (Environment Yukon 2014).

Riparian zones are associated with water bodies and wetland areas and are the interface between land and water, typically characterized by hydrophilic vegetation and subject to flooding. Riparian zones are significant due to their role in soil conservation, high biodiversity and the influence they have on aquatic ecosystems. The riparian zones surrounding the large wetland areas in the RSA are associated with high quality habitat for many Yukon animal and bird species.

4. EXISTING SOCIO-ECONOMIC SETTING

The Project is located within the traditional territories of the First Nation of Na-Cho Nyak Dun (NND) and Selkirk First Nation (SFN). Communities closest to the proposed project, and considered in the assessment as part of the local study area, are Keno City, Stewart Crossing and Village of Mayo. The history and the socio-economic setting of this area have seen similar development activities such as construction and development of a transmission line, dating back to the 1950s when the Northern Canada Power Commission (NCPC) built a hydro facility at Mayo and the existing 69 kV transmission line from Mayo to Keno City. The following sections describe the existing socio-economic setting since then.

4.1 First Nation of Na-Cho Nyak Dun

The proposed transmission line is located in NND traditional territory. The name “Na-Cho Nyak Dun” translates as “big river people”. Beginning in the 1970s the NND were actively involved in the movement to settle its land claim and its Final Agreement was signed in 1993. Under the Agreement, NND has more than 4 740 square kilometers (1 830 square miles) of settlement lands and self-governs by making laws on its lands and for its citizens. The project footprint crosses one parcel of NND settlement land, parcel S-156B 1.

The NND, SFN and Little Salmon Carmacks First Nation make up the Northern Tutchone group and share a common culture and language. In addition to Northern Tutchone affiliation, some NND members also have Gwichin and Dene ancestry.

The number of registered NND members is 550; however, a majority of the members live outside of Mayo in Whitehorse and Stewart Crossing. In Mayo, NND represent 60 to 70 percent of the community’s population.

4.2 Selkirk First Nation

The Project's socio-economic setting includes the northern boundary of SFN's Traditional Territory south of the Stewart River. Like NND, SFN became a self-governing First Nation in 1997 after finalizing its Final Agreement, and now owns approximately 4 740 square kilometers (1 830 square miles) of settlement lands. While not considered as part of the socio-economic setting for the purpose of this assessment, Pelly Crossing is the home and administrative centre for the SFN government. As indicated by the Proponent, approximately 40 percent of the registered 635 members live in Pelly Crossing and the rest reside throughout Yukon and rest of Canada.

4.3 Communities: Village of Mayo, Keno City and Stewart Crossing

The largest community in the project setting is the Village of Mayo, located at the confluence of the Mayo and Stewart Rivers. In 2015, the reported population for the community was 477, which has seen steady and moderate decline since 2013 despite years of growth since 2007 (Yukon Bureau of Statistics, 2015). People that live in Mayo are generally multigenerational residents, with fewer than 10 percent being new residents that are from outside of Yukon.

Two other communities considered in the assessment are Keno City and Stewart Crossing. Keno City is a small, unincorporated community with approximately 20 to 28 residents located at the end of the Silver Trail Highway. Keno City's current population is less than half of its population in the 1970s, which was approximately 60 and which was largely supported by the nearby mining company town of Elsa at the time. Stewart Crossing, with approximately the same population as Keno City of only 25 people, is located on the Klondike Highway and the Stewart River, and serves as a service station stop for traffic between Dawson, Mayo, Keno and Whitehorse.

4.4 Land and Resource Use

There is long history of both traditional and commercial use of the lands and resources in the project setting, ranging from trapping, hunting, and fishing to commercial activities such as tourism and mining. Both traditional and commercial land-based activities provide a livelihood for many of the residents in the communities. Seven registered trapping concessions (Nos. 74, 75, 76, 81, 82, 84, 85) are adjacent to or overlap the proposed project, and include one community trapping concession near Mayo. While details of harvesting numbers are not available, the project proposal underscores the economic importance of trapping in Yukon as in the range of $250,000 to $1.5 million annually in the past two decades. The project is also in the vicinity of two Game Management Zones (Zones 2 and 4) and several Game Management Areas (Nos. 257, 258, 318, 401 and 404). Species of importance for land and resource use in the project area include moose, caribou, sheep, wolves, goose, grouse, beaver, muskrat, and squirrels.

4.5 Local and Regional Economy

The Village of Mayo is the main economic hub in the region and has been relied on to provide many of the economic and government services for the people of Mayo and surrounding communities. Mayo was originally established as a river settlement and then service centre for the surrounding mining activities in the area. One-third of the jobs in the community are in government services that include, but are not limited to, nursing, policing, health and social services, housing, etc. (Village of Mayo, 2006). Tourism is a growing and important sector outside of the public sector, and provides many of the spin-off economic opportunities in service industries such as accommodation, food, recreation and retail (Village of Mayo, 2006). Amongst the tourist activities and sites available in the region, there are the Silver Trail, a popular tourist attraction, which provides camping, hiking, hunting and fishing activities in the area, and the Minto Bridge Interpretive Site at km 64. Most of the facilities available to support the tourism sector are available in Mayo rather than Keno City and Stewart Crossing, such as hotel and motel accommodations, grocery stores, restaurants, and a gas station.

Local economic diversification and strengthening local businesses are identified as core community values in the Mayo Integrated Community Sustainability Plan (2006). To continue its role as the regional service centre, the community plan prioritizes local resources and local employment opportunities.

5. OTHER MATTERS CONSIDERED

5.1 Considerations of Comments Received

The Executive Committee solicited comments from Government of Yukon (YG), NND and SFN during the adequacy review stage to aid in determining if sufficient information was provided to conduct an assessment, as well as to identify information gaps and preliminary concerns. The public comment period for the Project was from February 25, 2016 to March 25, 2016.

The Executive Committee received four comments during the course of the public review from YG, the Mayo District Renewable Resources Council (RRC), the Silver Trail Chamber of Commerce and Tourism Association and the Utilities Consumer Group.

The public comment period on the draft screening report (DSR) was from April 25, 2016 to May 25, 2016. YG provided comments and suggestions on the draft report that have been considered by the Executive Committee.

The following sections discuss how the Executive Committee considered the comments and concerns raised during the assessment process.

5.2 Consideration of Rare and Endangered Species

YG submitted comments (YOR 2015-0209-047-1, YOR 2015-0209-060-1) during both the adequacy and draft screening report stages regarding the potential for rare plant species to be present. The Executive Committee considered the comments from Environment Yukon and added Section 7.2.3 to address this concern.

5.3 Consideration of Wildlife

Environment Yukon provided a mitigation in its comment submission on the DSR, to address concerns regarding potential negative effects to moose and bears (YOR 2015-0209-047-1, YOR 2015-0209-060-1). The mitigation suggested by Environment Yukon duplicated a commitment from the Proponent listed in Section 6.4 Proponent Commitments under Increased Access. The Executive Committee considered the commitment as adequate to address this issue and therefore did not include the mitigation proposed by Environment Yukon.

5.4 Consideration of Recreation Areas

Environment Yukon, the Mayo RRC, the Silver Trail Chamber of Commerce and Tourism Association identified concerns regarding recreation and wildlife viewing sites between Stewart and Keno City during the adequacy review stage (YOR 2015-0209-045-1, YOR 2015-0209-046-1, YOR 2015-0209-047-1).

Environment Yukon reiterated its concerns regarding two specific recreation sites in the project area in its comment submission on the draft screening report (YOR 2015-0209-060-1). The following sections discusses how these concerns were addressed.

Minto Bridge Interpretive Trail

The Project intersects with the trailhead for the Minto Bridge Interpretive Trail. Environment Yukon noted concerns regarding the Minto Bridge Interpretive Trail sites along the project corridor that may be affected by project activities. In its comment submission, Environment Yukon indicated that project activities could directly affect the parking lot, as a utility pole will be placed in the vicinity (YOR 2015-0209-060-1).

The Executive Committee notes that the Proponent has committed to minimizing impacts on the Minto Bridge Interpretive Trail. Specific proponent commitments include (YOR 2015-0209-005-2):

- Pole placement will avoid the trailhead infrastructure, walking trail and other associated infrastructure (i.e. parking lot, outhouses and garbage can).
- Yukon Energy's EMS best practices for ROW maintenance will be followed.
- Clearing and maintenance brushing activities will be conducted whenever feasible outside of peak tourist season and selective clearing will be used to remove only those trees, which will cause a hazard to the transmission line.
- Clearing width and height will be minimized to the extent feasible in order to minimize any aesthetic impacts to the trailhead and parking lot area.
- The Proponent will continue to consult with YG Cultural Services Branch leading up to and following project construction activities to ensure that construction-related disturbances are minimized and remediated to the extent practicable.

As a result of the commitment that pole placement will avoid the trailhead infrastructure, walking trail and other associated infrastructure, there is no spatial overlap and/or direct effects to the trail and trailhead infrastructure. Disruption to trail users will remain from construction and brushing maintenance activities; however, these activities will be short-term in duration. With implementation of the above-noted proponent commitments, the Executive Committee does not anticipate adverse effects to Minto Bridge Interpretive Trail users.

Devil's Elbow Wildlife Viewing Site and Interpretive Trail

In its comment submission, Environment Yukon noted that the existing transmission line is within about 50 m of the Devil's Elbow Wildlife Viewing Site and Interpretive Trail on the north side of the Silver trail Highway, and the proposed alignment of the new transmission line is farther away from the trail. YG further noted that land clearing and heavy equipment use have the potential to affect the trail and its users.

The Proponent described in the proposal that route selection has avoided known campground sites and trails such as the Devil's Elbow Habitat Protection Area Interpretive Trail (YOR 2015-0209-005-2). According to the project proposal, the project route is located adjacent to the north side of the Silver Trail and therefore does not intersect with the Devil's Elbow Habitat Protection Area, which is located to the south side of the Silver Trail. As the Project will occur further away from the trail than the existing power line, and lies on the opposite side of the trail's viewpoint than the features the viewpoint showcases, the Executive Committee does not anticipate adverse effects to recreational users of the Devil's Elbow Wildlife Viewing Site and Interpretive Trail.

Based on the above considerations, effects to recreational areas (viewing sites and trails) are not considered further in the screening report.

5.5 Consideration of Effects to Rate Payers

The Utilities Consumers' Group (UCG) submitted a comment (YOR 2015-0209-048-1), which included concerns on how the capital cost of the Project could be added to the ratebase, which would then affect ratepayers.

In that comment, the UCG included an undated excerpt from a correspondence between YEC and the UCG. In that excerpt, YEC allegedly stated:

> *Our working assumption is that government funding will cover the cost of the proposed project. As such we are not expecting ratepayers to pay for any portion of the line between Stewart Crossing and Keno City.*

YEC indicated in that same correspondence that if government funding is not available:

> *…it is possible that YEC could move forward with a staged approach to the project implementation, with investments and new infrastructure being added to ratebase.*

YEC also indicates that if investment in new infrastructure would affect ratepayers then the Project would likely require a Part 3 Energy Certificate subject to a Part 3 hearing by the Yukon Minister of Justice.

The Executive Committee considered these comments in relation to what YEC indicated in its proposal, which is that funding from the Yukon Development Corporation would cover the capital costs of the Project. The Executive Committee has scoped the Project as proposed (i.e. funded by Government of Yukon) and therefore no effects to ratepayers are expected and this matter is not considered further in this screening report.

5.6 Consideration of Effects to Environmental Monitoring Plots

The Mayo RRC and YG identified concerns regarding potential effects of the Project on environment monitoring plots along the existing transmission line right of way (ROW) (YOR 2015-0209-045-1, YOR 2015-0209-047-1).

Three continuous environmental monitoring plots are present along or in close vicinity to the Project. Two are within 30 m of the project's proposed ROW. These monitoring plots are used for three main purposes: "gaining information on undisturbed boreal forests; obtaining early warning for significant changes in these ecosystems; and measuring long term processes in boreal forests".

The Proponent engaged Environment Yukon prior to the commencement of assessment. The proposed alignment will cross through the 30 m buffer zone of one continuous environmental monitoring plot. The Project will use the same footprint as the existing transmission line. For a second plot, the Project proposes the decommissioning of the existing line where it passes through the plot buffer, reducing the physical footprint of infrastructure in the plot vicinity.

Environment Yukon indicated in its comment submission (YOR 2015-0209-060-1) that it is satisfied with the project alignment and proponent work to accommodate the environmental monitoring plots. Therefore, this matter is not considered further in this screening report.

5.7 Consideration of Other Comments from Government of Yukon

Environment Yukon proposed revised wording for terms and conditions 1 and 3 and added to the list of authorizations required in Table 1: Project Authorizations and Authorizing Bodies (YOR 2015-0209-060-1).

The Executive Committee has accepted those changes and amended Table 1 and the terms and conditions accordingly.

5.8 Consideration of Forestry Resources

The Mayo District RRC indicated that they were interested in how timber harvest and distribution would be handled for the Project (YOR 2015-0209-045-1). In its comment submission, Government of Yukon, Forestry Department reminded in its comment (YOR 2015-0209-047-1) that the Proponent must obtain a Forest Resources Permit prior to commencing timber harvesting operations as per Section 15(1) of the *Forest Resources Act*. Salvage requirements will be specified by the Terms and Conditions of the Forest Resources Permit, including a requirement to make salvaged timber available to the public.

The Proponent also provided a Timber Salvage Plan identifying the various types of forest resources that will be made available during the Project (YOR 2015-0209-016-1). The TSP will be finalized upon the completion of the permitting process.

As timber harvesting for the Project is addressed with adherence to legislative requirements, the Executive Committee is of the view that timber harvest and distribution of forestry resources is unlikely to be adversely affected and therefore this matter is not considered further in this screening report.

5.9 Consideration of Fish and Fish Habitat

The assessment of the aquatic environment carried out by the Proponent included consideration of aquatic ecosystems and resources. Standard mitigation measures proposed, such as spanning wetlands and riparian areas or selective placement of poles will minimize all direct effects of the Project on fish and fish habitat. Hand clearing of vegetation within riparian areas will also serve to mitigate any potential indirect effects. Crossings of the Mayo River are expected to span the river and riparian area and not affect populations of Arctic grayling, burbot, northern pike and whitefish. No fisheries are expected to be directly affected by the Project. The Executive Committee is of the view that fish and fish habitat are unlikely to be adversely affected and therefore this matter is not considered further in this screening report.

5.10 Consideration of Alternatives

When preparing a proposal, s. 50 (2) of YESAA requires a proponent to consider alternatives to the project, or alternative ways of undertaking or operating the project, that would avoid or minimize any significant adverse environmental or socio-economic effects. The Executive Committee has determined that the Project has potential significant adverse effects that can be mitigated. Therefore, the Executive Committee did not consider alternatives further in this screening report.

Part B EFFECTS ASSESSMENT

This section presents the Executive Committee's effects assessment for the Project. The valued environmental and socio-economic valued components set out in Table 5 have been considered.

Table 5: Environmental and Socio-economic Valued Components

Environmental Valued Components	Socio-economic Valued Components
• Wildlife (Section 6.0) • Environmental Quality (Section 7.0)	• Land and Resource Use (Section 8.0) • Heritage Resources (Section 9.0)

For each valued component, an overview of the value is provided, followed by the effects characterization analysis and significance determination. Subsequently, the Executive Committee recommends mitigative measures, as appropriate. The Executive Committee also examines potential cumulative effects and concludes with a final determination of the potential for significant adverse effects on the valued component.

6. WILDLIFE AND WILDLIFE HABITAT

This section addresses potential effects of the Project on wildlife and wildlife habitat. An understanding of the social and environmental setting for wildlife is provided, and potential adverse effects are characterized and discussed in the context of the project proposal, comments, relevant legislation and proposed mitigation strategies. The Executive Committee concludes that compliance with relevant legislation and the application of specific mitigative measures will effectively eliminate, reduce or control significant adverse effects on wildlife.

6.1 Overview

As noted previously, the transmission line is largely within the existing ROW; however, five substantive deviations are proposed to improve line routing, which are all north of Mayo. Smaller amounts of clearing will also be required to develop access roads and clearings for substations across the study area.

Wildlife is valued for its role in local and regional ecosystems, cultural importance, significance to subsistence harvesters, as well as its part in the local traditional economy. Some species of wildlife have particularly high conservation value because their local populations are in decline, or they are relatively rare regionally or nationally. Due to its long linear nature, the Project spans over (or near) a variety of terrain types and ecological features (e.g. wetlands, riparian areas, etc.) that may provide quality habitat for many different species.

As noted in Section 3.3, the Project overlaps or is in the direct vicinity of several WKAs identified by Environment Yukon including raptors, ducks, and black bears. In addition, the proposal further states that the RSA encompasses important habitat features for moose, mule deer, and grizzly bears. The Project is also on the edge of the Ethel Lake caribou herd range. Irregular movements of thinhorn sheep through the project area may occur. Other wildlife in the project area includes wolf, marten, other small mammals, and birds. The Project overlaps with the habitat of wildlife species that are of conservation concern, including Bank Swallow (Threatened) and Rusty Blackbird (Special Concern).

The Executive Committee notes that Environment Yukon's WKAs are a useful tool to identify key wildlife habitat; however, they cannot be exclusively relied upon because their absence may result from the lack of surveys rather than the absence of key habitat in an area. For example, within the RSA, is Devil's Elbow Protected Area, which along with the nearby Big Island area are very important for moose calving. Likewise, YEC suggests that the presence of a black bear WKA at Stewart River Crossing also offers suitable spring and early summer grizzly bear habitat; and that the presence of the nearby moose calving grounds likely results in grizzly bear use.

6.2 Effects Characterization

Both stages (construction and operations) of the Project include activities that may adversely affect wildlife and wildlife habitat in the LSA and RSA. The Executive Committee considered effects to wildlife due to:

- Habitat loss and alteration;
- Direct mortality/injury; and,
- Increased harvester and predator access.

6.2.1 Habitat Loss and Alteration

The clearing of land may result in the disturbance to vegetation, removal of riparian area ecosystems, and degradation or damage to habitat. Habitat can be lost or quality decreased, resulting in wildlife avoiding the area. Clearing activities can degrade limited topsoil resources, damage root and seed stock and change surface and subsurface hydrology decreasing the ability of the area to regenerate to pre-project conditions and affecting the long-term habitat productivity of the area. Wildlife habitat is characterized by its productivity, prevalence, and/or contribution to key requirements of certain wildlife species.

Wildlife may also avoid the area (i.e. habitat alienation) as a result of noise disturbances from various sources (e.g. the use of heavy equipment, increased traffic and human presence). Wildlife species have varying thresholds to tolerate disturbance. A threshold refers to the point at which an animal or species will alter natural behaviours relating to nutrition, reproduction, or habitat use to avoid experiencing negative impacts. Many conditions influence wildlife responses to perceived disturbances. Wildlife responses to disturbances depend on an animal's past experiences with disturbance, their physical and mental state (e.g. body condition, breeding status) and their proximity to shelter, food, water, offspring and/or mates

The Project requires the clearing of a large portion of the ROW, which will result in wildlife habitat alteration, and potential habitat loss in the LSA and RSA. The establishment and use of a temporary camp and the use of heavy equipment may further alter or remove wildlife habitat. Activities in both stages of the Project may result in adverse effects to wildlife and wildlife habitat through habitat loss and alteration. For example, during the construction phase, the clearing of new transmission line segments (for the most part, north of Mayo), as well as expanding portions of the existing transmission line ROWs and substation clearings will directly remove wildlife habitat. During the operations and maintenance phase, recurrent brushing every seven to ten years (based on vegetation growth), will change wildlife habitat quality on and adjacent to the ROW. Furthermore, both stages of the Project will result in increased human activity and noise from construction (e.g. use of heavy equipment, chain saws, etc.) which may temporarily displace wildlife or alter their movements in the area.

Habitat loss or alteration may also occur if plant communities are affected by project activities. This is particularly concerning if rare plants are affected by the Project.

The Executive Committee has considered that the majority of the Project is located in a previously disturbed ROW, and that proposed clearings will be near long established ROWs (i.e. Silver Trail Highway and the existing transmission line) or other existing disturbed sites (e.g. substations). During both the construction and operations phases, the level of human activity combined with equipment use is not expected to result in a noticeable increase in disturbance, as much of the transmission line is near the active Silver Trail Highway and other existing developments.

6.2.2 Direct Injury/Mortality

Project activities during the construction and operations stage have the potential to result in the direct mortality or injury of wildlife. For example, during the construction stage, the establishment and use of a temporary camp may attract wildlife resulting in human-wildlife conflicts. During the operations stage, birds may be killed or injured as a result of transmission line strikes and electrocution.

Human-wildlife Conflict

The Project is located in an area inhabited by numerous wildlife species, as described in Section 3.3. Therefore, the potential exists for human-wildlife interactions and/or conflicts to occur. Wildlife, such as bears, can very easily become accustomed to human activities and noise in both populated and remote areas. The inadequate storage and/or disposal of waste and petroleum products may attract bears and other wildlife to the project area. Grey water, petroleum products, food, kitchen waste, and garbage are strong bear attractants. Even small amounts of fuel (e.g. a jerry can) will attract bears. The likelihood of wildlife (e.g. bears) repeatedly visiting an area is directly linked to whether they obtain a food reward from inadequate attractant management or are immediately deterred on the first contact with the site. Bears habituated to food or garbage and/or conditioned to seeking food in areas where humans are (e.g. camps, work sites), become increasingly bold and are often killed in protection of property or life resulting in direct wildlife mortality.

Line Strikes and Electrocution

Once in operation, the proposed transmission line has the potential to result in bird fatalities due to line strikes and mortalities due to nesting of osprey on twin pole structures near water. Although no line impact studies have been conducted, the project proposal notes that there has been no indication of bird carcasses being found along the existing transmission line route.

Line strikes may be of particular concern where lines cross waterbodies or wetlands. As such, the Proponent has committed to installing the transmission line at heights similar to or below the existing forest canopy, where feasible, and including markers on lines in open areas (e.g., Halfway Lake and Minto Creek). Additionally, pre-clearing surveys for raptor nests on the ROW will be conducted, and nest deterrent structures may be used on pole structures near water to minimize osprey nests and potential line contacts/mortality.

6.2.3 Increased Harvester and Predator Access

Linear disturbance (e.g. transmission lines, roads, trails, etc.) can increase accessibility for predators of wildlife such as wolves. Some animals will use trails as travel corridors. Wolves are known to be successful in hunting animals such as moose along trails and roads. Trails may, therefore, create effective predator vectors that affect the number of ungulates removed during any stage of the species lifecycle.

Increased linear developments also increase hunting pressure on wildlife and may disturb/displace wildlife. As transmission lines, roads and trails provide easier access to wilderness areas; people are more inclined to explore using off-road vehicles such as ATVs and snow machines and may extend the accessible zone beyond the project area. Moose, which are found throughout the RSA, are of particular concern, as demonstrated from the establishment of Devil's Elbow Protection Area, and through the development of plans such as the Community-Based Fish and Wildlife Work Plan for NND Traditional Territory 2014-2019.

An increase in hunting pressure on moose may cause individual disruption and lead to elevated stress, increased energy expenditures, and injury or mortality to species. The Proponent has committed to mitigations such as a no-hunting policy for construction and maintenance personnel and leaving a vegetation buffer between the Silver Trail Highway and the transmission line ROW to help manage these potential effects.

6.3 Relevant Legislation

In addition to YEC's commitments, the Executive Committee has considered the requirements of the following relevant legislation:

- *Migratory Birds Convention Act* and the Migratory Bird Regulations,
- *Species at Risk Act*,
- *Yukon Wildlife Act*; and,
- Solid Waste Regulations.

6.4 Proponent Commitments

The Executive Committee has reviewed the commitments proposed by the Proponent in the project proposal to mitigate potential adverse effects to wildlife and wildlife habitat. These commitments are instrumental in the Executive Committee's significance determination and demonstrate YEC's efforts under s. 42(1) of YESAA to consider adverse project effects and mitigation measures. These specific commitments mitigate adverse effects and in some cases may surpass the requirements of other legislation.

Habitat Loss and Alteration

- To the extent feasible, vegetation removal and decommissioning activities will be undertaken in winter, and will avoid sensitive times of year such as calving and rearing (May to mid-August) and nesting season for birds (May 1 to August 15).
- Animal awareness protocols will be included in regular safety and environmental orientations performed by construction and maintenance workers. Such protocols will indicate that if caribou are encountered within 500 metres of the ROW centreline, that work will cease and the caribou will be allowed to move on.
- Long term effects on woodland caribou due to construction and operation of the Project are mitigated primarily by routing the Project, i.e. in areas south of the Stewart River, where the Project potentially intersects the seasonal range of the Ethel Lake woodland caribou herd, the Project will be located within or adjacent to the existing Carmacks-Stewart Transmission Line ROW.
- Vegetation clearing and decommissioning activities will be undertaken during the winter and hand clearing will be used for vegetation within 50 metres of any waterbody (i.e. wetland, steam, seasonal creek, lake).
- Standard water body spanning measures will also be used for any waterbody (wetland, stream, seasonal creek and lake), and pole placement will avoid wet areas and minimize removal of riparian vegetation.
- Yukon Energy will follow DFO's Measures to Avoid Causing Harm to Fish and Fish Habitat (included as Appendix 6B) for all line construction activities in the vicinity of waterways and riparian habitat.
- Clearing, maintenance brushing and decommissioning activities will be timed to occur in winter and will avoid nesting season (May 1 to August 15).
- Pre-clearing surveys for raptor nets on the ROW will be conducted, and nest deterrent structures may be used on pole structures near water to minimize osprey nests and potential line contacts/mortality.
- If clearing takes place outside of winter, pre-clearing surveys for rare plants will be conducted.

Direct Injury/ Mortality

- Animal awareness protocols will be included in regular safety and environmental orientations performed by construction and maintenance workers.
- Temporary camps will remove and manage attractants to minimize potential encounters.

- Temporary camps will remove and manage potential attractants when activities are undertaken.
- Protocols will be in place to ensure that temporary camps remove or manage attractants.
- Bird fatalities due to line strikes will be mitigated through installing the transmission line at heights similar to or below the existing forest canopy, where feasible, and by including markers on lines in open areas (e.g. Halfway Lake and Minto Creek).
- Mitigation measures to reduce potential mortality hazards due to line strikes will include installing transmission lines at heights similar to or below the existing forest canopy, where feasible, and including markers on lines in open areas, (e.g. Halfway Lake and Minto Creek).
- Pre-clearing surveys for raptor nets on the ROW will be conducted, and nest deterrent structures may be used on pole structures near water to minimize osprey nests and potential line contacts/mortality. Standard water body spanning measures will also be used for any waterbody (wetland, stream, seasonal creek and lake), and pole placement will avoid wet areas and minimize removal of riparian vegetation.
- Marking of conductors will be undertaken at Halfway Lakes and Minto Creek crossing to mitigate potential bird strikes, and checks of pole structures for nesting osprey will be undertaken when line patrols are conducted.
- Post construction surveys will be conducted at Halfway Lakes for the first two years after construction to confirm the effectiveness of marking.
- Incidents of moose, caribou and mule deer mortality near the ROW and/or highway will be documented, relying on current practices involving local conservation officer reporting, and with adaptive mitigation provided as necessary (e.g. signage, additional planting).

Increased Access

- Woody debris may also be mulched to provide insulation to permafrost sites and sensitive soil areas to minimize melting and soil loss/instability and minimize duration of disturbance to brush/forage species.
- Yukon Energy's EMS best practices for ROW access will be followed, and there will be a no-hunting policy for construction and maintenance personnel.
- Animal awareness protocols will be included in regular safety and environmental orientations performed by construction and maintenance workers. Such protocols will indicate that if caribou are encountered within 500 m of the ROW centreline, that work will cease and the caribou will be allowed to move on.
- Where possible, a vegetative buffer (nominally 30 m) will be provided between the ROW and the Silver Trail to minimize disturbance from highway traffic, act as a protective cover and to reduce opportunistic hunting.
- To mitigate the adverse effects of increased hunting pressure due to access provided along the ROW, Yukon Energy's EMS best practices for ROW access will be adhered to and there will be a no-hunting policy for construction and maintenance personnel.

6.5 Significance Determination

In making a significance determination, the Executive Committee considered the activities associated with the Project, the spatial extent and temporal scope of the activities, and the overlap of project activities with other potential land users. Further, the Executive Committee considered comments received during the seeking views and information period, applicable legislation and the proponent's commitments.

Habitat Loss and Alteration

The Executive Committee determined that effects resulting from the physical loss of habitat will occur over the life of the Project and beyond. As previously noted, the proposed route is predominantly located within or adjacent to the existing 69 kV transmission line ROW. The Executive Committee considered that transmission line deviations are north of Mayo where habitat, for the most part, is not key, unique or highly valued for species in the LSA or RSA. Therefore, in terms of habitat loss/alteration, the Executive Committee has determined that the Project will have low magnitude effects to low quality habitat in relation to wildlife; although, the duration may be indefinite.

The Executive Committee also considered effects to wildlife due to habitat loss and alteration resulting from avoidance of the project area. Avoidance will likely result from the audible noise disturbances during the construction stage, resulting from land clearing, removing and installing transmission lines and general construction. Over this stage, disturbances to wildlife from human presence and use of heavy equipment are expected to be frequent (e.g. daily); however, due to the linear nature of the Project, disturbances will not occur in the same area for long periods and are reversible. During the operations phase, potential effects from human presence are anticipated to be negligible, particularly as the Executive Committee considered that wildlife in the LSA are likely use to the type of audible noises that may result from the Project based on the proximity to other developments and activities (e.g. the Silver Trail Highway).

Direct Injury/Mortality

The Executive Committee considered that direct injury and mortality of wildlife may result over the life of the Project from wildlife-human conflict (particularly bears) and line strikes and electrocution of birds. In terms of lines strikes and electrocution of birds, the Executive Committee determines that although bird fatality is irreversible and of high magnitude, the likelihood is low, or at minimum will not increase from current conditions, as an active transmission line already exists.

In consideration of potential wildlife-human conflicts, the Executive Committee notes that the Proponent has indicated that temporary camps will remove and manage attractants to minimize potential encounters; however, management details were not provided.

Habituated bears are not likely to be rehabilitated. They may be relocated but repeat offenders must often be destroyed. Strict adherence to legislation and regulations may discourage habituation of bears. However, due to the project’s location in a wilderness setting that contains favourable bear habitat and the unlikelihood of reducing all attractants, even the best run operation may still attract bears. Further, once bears are habituated, they may become more brazen and learn that camps/people can be a source of food. In turn, these habituated bears can become a threat to other land users. Due to the difficulty in rehabilitating nuisance bears and the permanence of some consequences (e.g. destroying bears), the project effects relating to direct injury and/or mortality have a low reversibility.

In consideration of this and the factors discussed above, the Executive Committee considers likely adverse effects to bears (and possibly humans) as a result of wildlife-human conflicts to be significant. In order to reduce the frequency of bear visits to camp, and thus reduce the potential for wildlife-human conflict and ultimately bear mortality, further mitigation is required.

Increased Harvester and Predator Access

The Executive Committee acknowledges that linear developments (e.g. transmission lines, roads, trails, etc.) may provide improved access for predators and hunters thereby resulting in increased wildlife mortalities. Although the project area spans 112 km, it predominately occurs over the existing transmission line ROW. The Project will result in short sections of new routing (i.e. access) which will, for the most part, be near existing ROWs (e.g. Silver Trail Highway and existing transmission line). In order to reduce sightline for both harvesters and predators, the Proponent will maintain a tree buffer.

The Executive Committee determined that although wildlife mortality is irreversible and the duration is long-term, the geographic extent is limited to the project footprint and the magnitude is low because of the existing transmission line ROW. Furthermore, the Proponent will allow natural revegetation along the portions of transmission line that are being re-routed. Proper reclamation should reduce the duration of the project effects; however, depending on the rate of regrowth, the reclaimed transmission line sections may still be passable to hunters and predators for several years.

6.6 Terms and Conditions

The Executive Committee has determined that the Project is likely to have significant adverse environmental effects on wildlife and wildlife habitat. These effects can be eliminated, reduced or controlled by the application of the following terms and conditions:

1. The Proponent shall develop an Attractants Management Plan for review and approval by the Manager of Land Use, Government of Yukon, Department of Energy, Mines and Resources.

The Proponent is encouraged to adhere to the following guidance documents:

- Proponent's Guide: Assessing and Mitigating the Risk of Human-Bear Encounters (http://www.env.gov.yk.ca/publicationsmaps/documents/proponents_guide_bear_risk.pdf)
- Guidelines for Industrial Activity in Bear Country (http://www.env.gov.yk.ca/publications-maps/documents/Guidelines_for_Industrial_Activity_in_Bear_Country.pdf)

6.7 Residual Effects

Residual effects are those project effects that remain following the application of legislation, proponent commitments and mitigations listed in this report. The residual effects from the Project to wildlife and wildlife habitat may include habitat loss, direct injury/mortality, and increased harvester and predator access. The Executive Committee is satisfied that residual effects resulting from the Project will not be significant.

6.8 Cumulative Effects Assessment

As noted above, the Executive Committee determined that the Project will result in residual effects to wildlife and wildlife habitat. The Executive Committee has determined that these residual effects would occur for all stages of the Project. The cumulative effects to wildlife and wildlife habitat are considered in the spatial and temporal context of their range and the spatial scope of any residual effects is specific to the wildlife species considered.

Section 5 of the project proposal describes the existing and planned developments (e.g. activities and projects) in the region. For the most part, these projects are related to municipal infrastructure, quartz and placer mining, and residential developments. Some of the projects include activities that are similar to the proposed project such as vegetation clearing, excavation of soils, use of camps, use of heavy equipment, use of petroleum products, management of waste and human presence.

Because the Project is, for the most part, located within an existing ROW and replacing an existing transmission line, the Executive Committee considers that it is unlikely that residual project effects will further interact with the residual effects of other activities within the identified spatial scope. Further, the Executive Committee is satisfied that implementation of mitigations listed in this report, in addition to strict adherence to relevant legislation, is sufficient to ensure that the proposed project will not contribute to significant adverse cumulative effects to wildlife in terms of habitat loss/alteration, direct injury/mortality, and increased harvester and predator access.

The Executive Committee is satisfied that the residual effects of the Project, in combination with the effects of other projects or activities will not result in significant adverse cumulative effects to wildlife.

7. ENVIRONMENTAL QUALITY

This section addresses potential effects of the Project on environmental quality. An understanding of the social and environmental setting for environmental quality is provided, and potential adverse effects are characterized and discussed in the context of the project proposal, comments, relevant legislation and proposed mitigation strategies. The Executive Committee concludes that compliance with relevant legislation and the application of specific mitigative measures will effectively eliminate, reduce or control significant adverse effects on environmental quality.

7.1 Overview

The Project is the construction and operation of a 138 kV transmission line (approximately 112 km in length) between Stewart Crossing and Keno City. Project activities, including the clearing of land and use of heavy equipment, the construction and decommissioning of a transmission line and transportation and use of fuel will result in adverse effects to environmental quality.

Environmental quality is defined as the heath and integrity of soil, vegetation and water resources. As noted in Section 3.0, the Project is located in the Boreal Cordillera ecozone and the Yukon Plateau North ecoregion, which is generally characterized by rolling hills, uplands and plateaus separated by deep and broad U-shaped valleys. Surficial geology and soils differ in depth and materials based on glacial deposits and modern creek drainages. Exposed bedrock is prominent in some convexities in the landscape.

Over the length of the transmission line, permafrost ranges from sparse to nearly continuous. Permafrost in the project area is discontinuous, lying beneath 50-90 percent of the ground. Between Mayo and Keno, permafrost is shallower and generally more widespread. For the most part within the LSA, permafrost is less than two metres below the active layer of soil, though north-facing slopes, poor drainage, and thick organic cover can contribute to active layers of just tens of centimetres.

The proposed transmission line route is largely within the existing right of way (ROW); however, five substantive deviations north of Mayo are proposed that will improve line routing. Smaller amounts of clearing will also be required to develop access roads and substations across the study area.

7.2 Effects Characterization

Both stages of the Project include activities that may adversely affect environmental quality in the LSA and RSA. The Executive Committee considered effects to environmental quality due to:

- Introduction of invasive species;
- Erosion and sedimentation; and,
- Rare and endangered plant species.

7.2.1 Introduction of Invasive Species

The Project involves the removal of vegetation, heavy equipment use, and the reclamation of portions of an existing ROW, all of which may result in the introduction of invasive plant species. General attributes of invasive plants include fast growth rates, prolific seed production, vegetative reproduction, irregular germination and ability to produce toxins to limit grazing by animals. Once established, invasive plants are costly and difficult to remove (YISC 2010).

The introduction of invasive species is of particular concern for the Project because linear developments are suspected pathways of introduction for invasive plants in Yukon (YISC 2010). Furthermore, seeds from invasive plants, plant material and soils potentially harbouring invasive species can be introduced to an area via work or recreational vehicles and equipment from affected areas. Linear developments such as power lines, are often used for recreational purposes (e.g. use of all-terrain vehicles, mountain biking, etc.), which may bring in seeds or plants of invasive species. Reclamation efforts may also introduce invasive species to disturbed areas.

Many invasive plants thrive in disturbed areas and rapidly displace native plants. Once invasive species are introduced; growth can be hard to contain; quickly spreading over the linear development. Because of this, there is potential for the Project to result in the unintentional spread of invasive species into the project area. The invasion of invasive species can result in land transformations and alterations in ecosystems and geophysical characteristics. Consequential effects include interruption and change of energy flow, food webs, biodiversity, successional patterns and biogeochemical cycling.

Invasive plants can stress wetlands and displace native vegetation (used as forage and shelter by wildlife and for nutritional, cultural and medicinal purposes by humans), which ultimately damages native ecosystems and reduces biodiversity. Disturbed areas, such as those that will be created by the Project (e.g. clearing/earthworks), create environments that are typically suitable for invasive plants, which may subsequently colonize the site (YISC 2010).

7.2.2 Erosion and Sedimentation

The Project involves the removal of vegetation, heavy equipment use, the installation of a transmission line, and the reclamation of portions of a transmission line, all of which may result in adverse effects to environmental quality from sedimentation and erosion. As described in proposal, the transmission line spans several watercourses over its length.

Removal of vegetation may expose underlying soils, increasing soil instability and the movement of sediment, which can result in erosion and sedimentation of nearby watercourses. Additionally, soil compaction, rutting and the removal of vegetation that would normally stabilize soils and reduce run-off, may alter surface drainage and runoff patterns. The result is increased surface run-off, erosion and sedimentation, particularly during high rainfall or freshet events. As noted above in Section 3.0, discontinuous permafrost exists over the 112 km long project area. In particular, the areas north of Mayo have nearly continuous permafrost. Permafrost areas are identified in terrain mapping (included in Appendix 5A and in the Project Atlas as “Areas of possible ice-rich or ice moderate permafrost”) of YEC’s submission (YOR 2015-0209-005-2). The installation and removal of transmission lines and use of heavy equipment may also disturb permafrost regimes, where present, resulting in permafrost degradation and/or melting. These effects to permafrost could lead to soil slumping, erosion and decreased soil stability. Concurrently, vegetation removal alters the ability of soil to absorb and retain water and can exacerbate erosion. Soil erosion can affect root growth making re-vegetation difficult and ultimately increase the potential for further erosion. Exposed root and seed stocks may be damaged by seasonal freezing and thawing, which can deteriorate the quality of seed stocks as well as degrade soil structure.

As noted previously, the Project involves the use of heavy equipment to carry out project activities including clearing and earthworks. As such, there is always potential for adverse effects to soil stability within the project area from project activities. Adverse effects to soils, through erosion and compaction, can ultimately result in altered site ecology and/or impede regeneration in the area as well as causing acute sedimentation of nearby watercourses.

7.2.3 Rare and Endangered Plant Species

The Project involves the removal of vegetation, heavy equipment use, and the installation of a transmission line. These activities may result in the removal or damage to endangered or rare plant species. Long-term survival threats to rare or endangered plant species due to direct project activities may be exacerbated by the potential introduction of invasive species as well.

Of particular concern in relation to the Project is the Halfway Lakes area, which the project passes through. Environment Yukon notes that this area “is a unique wetland ecosystem with known potential for rare species (YOR 2015-0209-060-1).” The species *Carex laxa* is known to occur in this area, it is listed as being vulnerable to possibly critically imperiled within Yukon.

The proposed project is adjacent to the existing transmission line; however, the proposed alignment of the Project brings it closer to the edge of one of the Halfway Lakes, while crossing wetland areas. Much of this area has not previously been cleared for the existing transmission line.

7.3 Relevant Legislation

In addition to YEC's commitments, the Executive Committee has considered the requirements of the following relevant legislation:

- *Environment Act,*
- *Fisheries Act, and*
- *Waters Act.*

There is no legislation in Yukon that is specific to invasive species.

7.4 Proponent Commitments

The Executive Committee has reviewed the commitments proposed by the Proponent in its proposal (YOR 2015-0209-005-2) to mitigate potential adverse effects to environmental quality. These commitments are instrumental in the Executive Committee's significance determination and demonstrate YEC's efforts under s. 42(1) of YESAA to consider adverse project effects and mitigation measures. These specific commitments mitigate adverse effects and in some cases may surpass the requirements of other legislation.

Invasive Species

- Yukon Energy's EMS best practices for Transmission ROW/Distribution Corridor Vegetation Management will be followed at all times.
- Project-related vegetation removal and decommissioning activities will be timed to occur in winter under frozen conditions.
- To the extent feasible, removal of understory vegetation and disturbance of soils and ground vegetation will be minimized. Efforts to minimize the removal of understory vegetation and disturbance to the vegetative mat will mitigate the intrusion of exotic species due to soil disturbance.
- In sensitive areas, such as permafrost and riparian areas, use of heavy equipment will be minimized, and hand clearing methods may be used.
- YEC clearing and construction tenders will include a requirement for out of territory equipment to be steam cleaned, as per existing tender requirements and best management practices, prior to use on site, to minimize the likelihood of invasive species introduction. This requirement will apply during construction as well as during periodic brushing maintenance activities.
- Clearing will be undertaken in winter months whenever feasible and removal of understory vegetation and disturbance of ground vegetation and soils will be minimized to the extent possible.

Sedimentation and Erosion

- Areas of terrain stability concern (e.g. permafrost or wetlands) will be given particular attention, including non-standard spans to improve foundations, and construction will be undertaken during the winter to limit disturbance of the terrain.
- Particular care will also be applied in permafrost areas mapped with potentially moderate to high ice content (see Appendix 5A).
- Additional mitigative measures to reduce impacts on these permafrost rich areas may include: minimizing the cleared ROW, use of hand clearing, and/or light vehicle only, ensuring wood-chip piles are scattered (not thick piles that could create exothermic decomposition) and follow up visual monitoring for exposed soils and/or signs of permafrost thaw.
- Clearing on steep slopes and the approach to any watercourse will be done by hand.
- All root stock will be retained within the riparian clearing buffer areas.
- There will be no work done in streams – structures will be selected and placed so that any watercourse will be crossed with a single span.
- Any stream crossing by equipment would only be undertaken in accordance with DFO's Measures to Avoid Causing Harm to Fish and Fish Habitat (included in Appendix 6B).
- One stream crossing is required at Crooked Creek. For this crossing an ice bridge will be used for construction access in winter. All other locations will, be accessed from either side of the watercourse (avoiding any other crossings).

Furthermore, the Executive Committee considers many of the commitments outlined under Section 6.4 apply to the Environmental Quality section. For example,

- Vegetation clearing and decommissioning activities will be undertaken during the winter and hand clearing will be used for vegetation within 50 metres of any waterbody (i.e. wetland, steam, seasonal creek, lake).
- Standard water body spanning measures will also be used for any waterbody (wetland, stream, seasonal creek and lake), and pole placement will avoid wet areas and minimize removal of riparian vegetation.

7.5 Significance Determination

In making a significance determination, the Executive Committee considered the activities associated with the Project, the spatial extent and temporal scope of the activities, and the overlap of project activities with other potential land users. Further, the Executive Committee considered comments received during the seeking views and information period, applicable legislation and the Proponent's commitments.

Invasive Species

In Canada, Yukon is second only to Nunavut and the Northwest Territories for the least number of introduced plants (Environment Yukon, 2015). As noted above, linear features such as transmission lines and roads function as prime habitats and corridors for invasive plant species and can contribute significantly to the spread and establishment of invasive species. In efforts to eliminate or reduce the effects of the introduction of invasive species, proponents must be familiar with what particular invasive species have the potential to invade and what the implications of an invasion would be. Effective management and control of invasive species relies on immediate communication and reporting when invasive species are discovered. At this time, there is no legislation about the introduction of invasive species in Yukon.

The Executive Committee considers YEC's commitments of using best management practices and steam cleaning out of territory equipment to be positive efforts to reduce the potential for invasive species being introduced in the project area. However, according to the Yukon Invasive Species Council, there are already 154 introduced plant species in Yukon of which 20 are considered invasive (2010). As noted above, the project area is likely to be used for recreational purposes. As previously noted, plants or seeds may be introduced to the project areas via bike or all-terrain vehicle tires that have been used in other regions inside or outside of the territory. As a result, there is increased likelihood of invasive plants being introduced.

Because it has so few invasive plants, Yukon is in an enviable position of being able to manage invasive plant infestations before they become established and difficult to eradicate. The Executive Committee considers that because invasive species are notoriously difficult to eradicate and that once established themselves, can result in altered site ecology and changes in local biodiversity, the duration is long, magnitude is high and reversibility is low. Lastly, if not properly managed and monitored, the geographic extent has the potential to be regional. The Executive Committee has reviewed Yukon Energy's commitments, including the EMS best practices for Transmission ROW/Distribution Corridor Vegetation Management; however, the management of invasive species are not addressed in this plan.

As such, the Executive Committee has determined that the Project is likely to have significant adverse environmental effects on environmental quality through the introduction of invasive species. These effects can be eliminated, reduced or controlled by the application of the terms and conditions outlined in Section 7.6.

Sedimentation and Erosion

The Project occurs over a 112 km corridor, spanning over several watercourses and occurring in areas of discontinuous permafrost. If the Project is completed incorrectly, the probability of sedimentation and erosion in the LSA increases.

The Executive Committee has reviewed YEC's commitments, relevant non-discretionary legislation, including the EMS best practices for Transmission ROW/Distribution Corridor Vegetation Management. The Executive Committee considers that these measures will effectively reduce the likelihood and magnitude of potential effects. Although the project area is long, the geographic extent of clearing, as well as transmission line decommissioning and realignment is local and limited. As such, the Executive Committee has determined that the Project is not likely to have significant adverse environmental effects on vegetation through sedimentation and erosion.

Rare and endangered plant species

The Project overlaps with an important wetland and aquatic complex, the Halfway Lakes. Project activities will result in the clearing of land adjacent to the existing transmission line in wetland areas, which likely host rare or endangered plant species due to the unique ecosystem of the

Halfway Lakes and known presence of *Carex laxa*. Effects to rare or endangered plant species may be long lived as relative scarcity may indicate limited opportunities for population growth or long reproduction cycles. Removal or destruction of rare or endangered plants are of a higher relative magnitude as compared against other plants as a decreased abundance increases the value of each individual within the population.

The Executive Committee has determined that the Project is likely to have significant adverse environmental effects on environmental quality in relation to rare and endangered plant species through vegetative clearing and other project activities in an area that likely hosts rare and endangered plants. These effects can be eliminated, reduced, or controlled by the application of the terms and conditions outlined in 7.6.

7.6 Terms and Conditions

The Executive Committee has determined that the Project is likely to have significant adverse environmental effects on vegetation. These effects can be eliminated, reduced or controlled by the application of the following terms and conditions:

2. The Proponent shall ensure equipment is free of foreign soil and plant material before moving it to the project site.
3. The Proponent shall develop an Invasive Species Management and Monitoring Plan for review and approval by the Manager of Land Use, Government of Yukon, Department of Energy, Mines and Resources.
4. The Proponent shall report the presence of any invasive plants that are listed on the website (http://www.env.gov.yk.ca/wildlifebiodiversity/invasiveplants.php) to the Yukon Conservation Data Centre (at 867-667-5331 or Toll-free at 1-800-661-0408 local 5331), should they be encountered.
5. The Proponent shall conduct a rare plant survey at the Halfway Lakes. The survey shall be conducted during the month of July, and shall cover the right of way within two kilometres on either side of Halfway Lakes. The survey will be completed by a qualified biologist.
6. Where rare plants are found the Proponent shall:
    a. avoid disturbance of the plant and its habitat;
    b. hand clear the right of way;
    c. place poles and access trails to avoid the plant and its habitat; and
    d. reroute as necessary the transmission line within the right of way.

The Proponent is encouraged to familiarize itself with the following guidance documents:

- the Yukon Invasive Species Council (YISC) document "Why Should I Care About Invasive Species?" located at: http://www.yukoninvasives.com/pdf_docs/WhyshouldIcare2011_sm.pdf

7.7 Residual Effects

Residual effects are those project effects that remain following the application of legislation, proponent commitments and mitigations listed in this report. The residual effects from the Project to environmental quality may include the introduction of invasive species as well as sedimentation and erosion. The Executive Committee is satisfied that residual effects resulting from the Project will not be significant.

7.8 Cumulative Effects Assessment

The spatial scope for cumulative effects to environmental quality consists of RSA, tributaries, and the surrounding areas. This area was selected as effects from the introduction of invasive species and sedimentation may extend past the borders of where work is to be carried out. Temporally, the cumulative effects of projects in this area have the potential for adverse impacts. The proposed timeline of the Project is indefinite which overlaps and exceeds the temporal scope of most other projects in the area.

Section 5 of the project proposal (YOR 2015-0209-005-2) describes the existing and planned developments (e.g. activities and projects) in the region. For the most part, these projects are related to municipal infrastructure, quartz and placer mining, and residential developments. Some of these projects include activities that are similar to the proposed project such as vegetation clearing, excavation of soils, use of camps, use of heavy equipment, use of petroleum products, management of waste and human presence.

Invasive Species

Much of the Project occurs in an existing transmission line ROW and in proximity to industrial developments and the Silver Trail Highway. The project area will undoubtedly be used for recreational purposes (e.g. snowmobiling, ATV use, hiking, mountain biking, etc.) for the life of the Project. These activities involving the use of vehicles of any sort or equipment/hand tools have the potential to introduce invasive species. Traditional, recreational and trapping activities occurring in this area may have residual effects to vegetation; however, these are expected to be minor.

Based on the high level of disturbance and proximity to another ROW (e.g. the Silver Trail Highway), and road use, there will be exposed ground that could be vulnerable to invasive species' colonization within the spatial scope. The residual effects of the Project are not expected to be significant following implementation of mitigations listed above. Many recent Designated Office assessments for projects in the region include similar mitigations as the ones listed above, which can aid in reducing or controlling invasive species colonization. It is not possible to eliminate the possibility of invasive species, but the Executive Committee is satisfied that the project's residual effects will not contribute to significant adverse cumulative effects to environmental quality from the introduction of invasive species.

Sedimentation and Erosion

In terms of sedimentation and erosion, residual effects to environmental quality have the potential to interact with the residual effects of other projects in the area. However, the Executive Committee considers that the project design and mitigations (e.g. to the extent possible clearing will be in winter, standard mitigation measures for spanning water courses will be followed including DFO operational standards, etc.), in combination with the project's location (e.g. within an existing transmission line ROW, and in proximity to industrial developments and the Silver Trail Highway) potential cumulative effects will be limited and minor.

As such, the Executive Committee is satisfied that the project's residual effects will not result in significant adverse cumulative effects to environmental quality from sedimentation and erosion.

8. LAND AND RESOURCE USE

This section addresses potential effects of the Project on land and resource use. An understanding of the social and environmental setting for land and resource use is provided, and potential adverse effects are characterized and discussed in the context of the project proposal, comments, relevant legislation and proposed mitigation strategies. The Executive Committee concludes that compliance with relevant legislation and the application of specific mitigative measures will effectively eliminate, reduce or control significant adverse effects on land and resource use.

8.1 OVERVIEW

While the project right of way (ROW) largely overlaps with the existing ROW, a number of issues regarding land and resource use may result from project activities. The Project will interact with several components of land and resource use:

- Harvesting (Plants and Wildlife)
- Property Users
- Granular Resources

The Executive Committee received a number of comments regarding the Project in relation to land and resource use. These comments express a number of concerns on project activities and mitigations.

The Executive Committee determined that the Project is likely to lead to significant adverse effects without the application of mitigation measures in relation to land and resource use.

Harvesting

As noted in Section 4.4, seven registered trapline concessions overlap with the project footprint, including one community trapline near Mayo. Five game management areas overlap the Project over two game management zones. In addition, due to its linear nature, the Project overlaps or passes in close proximity to several waterbodies including the Stewart and Mayo Rivers, Wareham Lake, Five Mile Lakes, Halfway Lakes and Haldane Lakes. Plant harvesting in the area includes berries and medicinal plants among others.

Details about harvesting intensity and distribution are not available in proposal documents.

Property Users

There are several parcels of private property in overlapping or in close proximity to the Project. Two overlap the proposed ROW while another two are immediately adjacent to the ROW. A fifth parcel is in close proximity to the proposed ROW.

Of the two parcels that overlap the proposed ROW, one is an existing transmission easement across NND Settlement Land block S-156B 1, the other parcel is owned by Alexco Resource Corporation; no easement exists on this property.

The Project also crosses an easement for a micro-hydro. This easement contains an old, but currently used, water main.

Granular Resources

The proposed ROW of the Project overlaps with two gravel pits used primarily for highways maintenance. These include the gravel pit at km 38.5 of the Silver Trail, the main pit in the area, and km 42.1, which is a gravel pit reservation. The existing 69 kV transmission line passes through both gravel pits. Three gravel pits are located within 500 m of the proposed alignment.

8.2 Effects Characterization

Harvesting

Construction and maintenance activities will displace wildlife that prefer a closed canopy, but may attract other species that prefer open habitats. The creation and maintenance of habitat edges may favour generalist species and predators. A full consideration of effects to wildlife is contained in Section 6.0 of this screening report.

The Proponent proposes to reimburse trappers for two or three years of lost income due to disruption to furbearer behaviour and presence from construction activities. This is proposed in consultation with trappers. However, no mitigation information is provided for how the community trapline will be handled in this regard.

During construction and maintenance activities, displacement of wildlife may adversely affect hunting success. However, increased development of access roads and trails to develop the Project may increase access to hunting areas. This may be both adverse and beneficial.

The proposed ROW may provide suitable habitat for certain species of berries, compared to closed forest. The Proponent states that blueberries are particularly well suited for power line right of ways. However, medicinal plants in the region appear to be dependent on boreal forest, which the Project will remove. In the long term, with the reclamation of the removed portions of transmission line, the overall distribution and quantity of habitat types will be largely unchanged in relation to wildlife and plant species including berries.

Property Users

The presence of an existing easement minimizes the effect of the Project on the NND Settlement Land block, as the transmission line will remain within this easement. The other property, which the Project proposes to cross, is neither a settlement block nor a residential parcel. As such, effects to enjoyment of property are limited in nature, especially considering the property's owner is a potential beneficiary of the proposed transmission line.

The properties that the proposed transmission line abuts or is in close proximity to may be affected by construction noise and the lack of a visual buffer between the property and the ROW.

Granular Resources

The Department of Highways and Public Works noted in its comment submission that the Project could interfere with continued safe operations of the pit at km 38.5 of the Silver Trail Highway in particular (YOR 2015-0209-.

The crossing of the gravel pit at km 38.5 of the Silver Trail Highway, as well as the granular reserve, may limit accessibility of granular resources in these pits, particularly if transmission lines and infrastructure inhibit movement of machinery and extraction of resources. While the proposed transmission line will follow the ROW of the existing transmission line, the increased voltage increases the distance machinery and personnel must be from the transmission line itself by roughly one metre.

8.3 Relevant Legislation

Based on the items identified within the effects characterization, the Executive Committee did not need to reference specific legislation when reviewing effects to land and resource use.

8.4 Proponent Commitments

The Executive Committee has reviewed the commitments proposed by the Proponent in its proposal (YOR 2015-0209-005-2) to mitigate potential adverse effects to land and resource use. These commitments are instrumental in the Executive Committee's significance determination and demonstrate YEC's efforts under s. 42(1) of YESAA to consider adverse project effects and mitigation measures. These specific commitments mitigate adverse effects and in some cases may surpass the requirements of other legislation.

- Consultation with landowners on construction timing
- Maintenance of a vegetative buffer between private property and the ROW
- Hand clearing within the water main easement to avoid damage to the micro hydro main

8.5 Significance Determination

In making a significance determination, the Executive Committee considered the activities associated with the Project, the spatial extent and temporal scope of the activities, and the overlap of project activities with other potential land users. Further, the Executive Committee considered comments received during the seeking views and information period, applicable legislation and the Proponent's commitments.

Harvesting

Effects to harvesting will largely be caused by project construction as opposed to operations. Construction activities will displace wildlife during construction while access roads created for project construction will facilitate increased access afterwards. Operations will displace wildlife only infrequently during maintenance activities.

The proponent's commitment to compensate trappers, who are bound to spatially-fixed trapping concessions that overlap project activities, reduces the magnitude of socio-economic effects to trappers. Effects to hunters may have a higher magnitude effect during construction, which the Proponent estimates at four months, as wildlife is displaced from the construction area. However, access to hunting areas along the proposed alignment will likely be improved due to development of new access trails.

Construction of the Project will result in changes to vegetative communities and abundance of plants that may be harvested. However, the extent of this change is limited as much of the project area is already clear and thus will not be changed in terms of vegetation cover. Areas where the existing line will be decommissioned will revert to a natural state in the long term, while those areas where the Project crosses undisturbed forest will be cleared. Given the limited geographic scope of new clearing, and that with the reclamation of the previous transmission line, the collective area required to be cleared to maintain transmission lines will remain nearly identical. This low magnitude and small geographic scope will prevent significant adverse effects in relation to the harvesting of plants.

The relatively short duration of effects due to construction to harvesting, combined with a high degree of reversibility, suggest that the direct effects of construction and maintenance of the Project are not significant. This determination is supported by the low intensity of activities involved with construction of a transmission line as compared against other land uses. The Executive Committee has determined that the Project will not result in significant effects due to the construction and maintenance of the Project. However, this does not infer that the presence of the line will be without effect, significant or otherwise.

Property Users

The Project proposes to largely follow the alignment of the existing transmission line. This reduces the effects of the proposed transmission line's presence drastically. The section from Mayo to Keno City will deviate more from the current alignment than the section from Stewart Crossing to Mayo. The potential for interference with property rights and resource use is the greatest impact due to the presence of the proposed transmission line. The temporal period of this effect is permanent, intensifying regularly with maintenance and is irreversible. However, the proponent's commitments to maintain a visual buffer reduce the likelihood of potential effects such that they are not significant.

Granular Resources

The presence of the transmission line may interfere with access to granular resources and/or the enjoyment of property. This effect is of a permanent nature and one, which could be of a greater magnitude than other effects examined here. Despite largely following the existing alignment, the widened ROW and greater setback distances mandated by a higher voltage means that there is a greater likelihood of the Project interfering with a primary granular resource source along the Silver Trail. While the Proponent has suggested mitigations, it has not committed to mitigations regarding reducing effects of this nature.

Interference with granular resources may result in requirements to develop new sources of granular resources sooner and at greater expense than currently. The Executive Committee has determined that the Project is likely to result in significant adverse effects to land and resource use and that these effects can be mitigated by the application of the specified mitigation measures.

8.6 Terms and Conditions

The Executive Committee has determined that the Project is likely to have significant adverse socio-economic effects on land and resource use. These effects can be eliminated, reduced or controlled by the application of the following terms and conditions:

7. The Proponent shall coordinate with HPW to design, build, construct, and maintain the Project in a manner that does not reduce the predicted lifetime of granular resources nor restrict safe operation of granular resources operators.

8.7 Residual Effects

Residual effects are those project effects that remain following the application of legislation, proponent commitments and mitigations listed in this report. The residual effects from the Project to land and resource use may include the physical presence of the transmission line. These effects will be very similar to existing baseline conditions. The Executive Committee is satisfied that residual effects resulting from the Project will not be significant.

8.8 Cumulative Effects Assessment

In relation to granular resources and property users, the Executive Committee is unaware of any activities or projects that could result in residual effects, which could act cumulatively with this project in relation to the properties and granular resources affected by this project. The only exception to this is the existing transmission line; however, effects of that transmission line in conjunction with the Project will not result in cumulative effects, as the two lines will largely follow the same alignment. Cumulative effects are considerably reduced because the two transmission lines occupy the same area. As such, the Executive Committee is satisfied that the residual effects of the Project, in combination with the effects of other projects or activities will not result in significant adverse cumulative effects to property or resource users.

In relation to harvesting, the location of the Project, largely within or along the alignment of the existing transmission line, greatly reduces residual effects of the Project such that cumulative effects are also greatly reduced. The Project involves no significant change in land use patterns or distributions over the long term and no projects in the area are known to the Executive Committee which may act cumulatively with the Project in relation to harvesting. As such, the Executive Committee is satisfied that the residual effects of the Project, in combination with the effects of other projects or activities will not result in significant adverse cumulative effects to harvesting.

9. HERITAGE RESOURCES

This section addresses potential effects of the Project on heritage resources. An understanding of the social setting for heritage resources is provided, and potential adverse effects are characterized and discussed in the context of the project proposal, stakeholder comments, relevant legislation and proposed mitigation strategies. The Executive Committee concludes that compliance with relevant legislation and the application of specific mitigative measures will effectively eliminate, reduce or control significant adverse effects on heritage resources.

9.1 OVERVIEW

YESAA defines heritage resources as:

a) A moveable work or assembly of works of people or of nature, other than a record only, that is of scientific or cultural value for its archaeological, palaeontological, prehistoric, historic, or aesthetic features,

b) A record regardless of its physical form or characteristics, that is of scientific or cultural value for its archaeological, palaeontological, ethnological, prehistoric, historic or aesthetic features; or

c) An area of land that contains a work or assembly of works referred to in paragraph (a) or an area that is of aesthetic or cultural value, including a human burial site outside a recognized cemetery.

This definition is more inclusive than that in the *Historic Resources Act* and the one that the Executive Committee will use for this assessment.

Project activities including the clearing of land may result in destruction of or damage to heritage resources where they overlap with the project footprint. The Executive Committee determined that the Project is likely to lead to significant adverse effects without the application of mitigation measures in relation to heritage resources.

The Project occurs over a large area, and the Proponent has assessed the project area for heritage resources. Based on spatial analysis and traditional knowledge, the Proponent assessed 24 likely heritage resource locations in the field. Two of these sites were found to contain prehistoric heritage resources. Historic heritage resources such as mine portals and cabins also overlap with the project area.

The Proponent is planning to conduct a follow up Heritage Resource Impact Assessment to assess potential heritage resources along the project alignment where it was changed subsequent to the July 2015 Heritage Resource Impact Assessment.

9.2 EFFECTS CHARACTERIZATION

Project activities such as the clearing of land, extraction of aggregate, or clearing of vegetation may result in destruction of or damage to heritage resources. Heritage resources provide a link between the past and present; for many, this is a vital cultural link pertinent to a society and its future. Heritage resources contribute to improving an individual's understanding of the relationship between people, the land, and other resources. The physical presence of a heritage resource helps sustain historical awareness as well as oral and traditional knowledge of an area.

The Proponent has proposed works at the location that may destroy heritage resources, "Temp Site 1", which was found to contain lithic scatter. The site, according to the Proponent, "is unlikely to contain additional information that would add significantly to the understanding of past use in the area, no further work is recommended."

The second site with prehistoric resources "consisted of a moderate sized, low to moderate density sub-surface lithic scatter." The Proponent notes this site "may contain materials that could be dated in association with cultural materials and could add data to the understanding of past use in the area." The Proponent proposes to avoid mechanical work within 30 m of the site and use clear span methods to ensure no poles are within 30 m of the site.

Historic resources including abandoned houses and mine infrastructure are proposed to be avoided and will not be affected by project activities. Not all effects to heritage resources can be known as the entire alignment has not yet been subject to a heritage resource impact assessment. The Proponent notes that there is potential for heritage resource effects in these areas.

9.3 Proponent Commitments

The Proponent will be conducting a follow up Heritage Resource Impact Assessment. In addition, the Proponent has committed to following Yukon Energy's internal policy in the event that more heritage sites are discovered. Upon discovery, the Proponent will flag heritage sites and cease activity in the proximity for further assessment.

9.4 Relevant Legislation

In addition to the Proponent's commitments, the Executive Committee has considered the requirements of the following relevant legislation:

- *Historic Resources Act*

9.5 Significance Determination

In making a significance determination, the Executive Committee considered the activities associated with the Project, the spatial extent and temporal scope of the activities, and the overlap of project activities with other potential land users. Further, the Executive Committee considered comments received during the seeking views and information period, applicable legislation and the Proponent's commitments.

Project activities may lead to the destruction of or damage to known or unknown heritage resources that overlap with project activities. The need for, and plans for, a heritage resource impact assessment for portions of the project area that have not yet been assessed for heritage resources highlights the potential for effects to currently unknown heritage resources. The scope of the project footprint also enhances the likelihood of discovering currently unknown heritage resources.

Generally destruction of or damage to heritage resources is an irreversible effect. The magnitude of any damage or destruction is dependent on the nature and context of the heritage resource. The determination of the nature and context of heritage resources may be dependent on knowledge held by First Nations.

The *Historic Resources Act* requires that a permit be obtained in order to destroy or alter "any historic object". The *Historic Resources Act* requires that historic objects found on Crown Land be reported to the Minister; however, there are no requirements that require First Nations to be notified of heritage resources discovered during project activities. As the *Historic Resources Act* defines heritage resources more narrowly than the Umbrella Final Agreement and YESAA, heritage resources may be destroyed or damaged without notification or awareness of First

Nations. The destruction of heritage resources in such a manner is likely to be significant depending on the nature of the discovery.

9.6 Terms and Conditions

The Executive Committee has determined that the Project is likely to have significant adverse socio-economic effects from the destruction of or damage to heritage resources. These effects can be eliminated, reduced or controlled by the application of the following terms and conditions:

8. If any heritage resources are discovered, the Proponent shall notify Heritage Resources Unit, Government of Yukon, as well as any First Nations whose traditional territory overlaps that heritage resource.

9.7 Residual Effects

Residual effects are those project effects that remain following the application of legislation, proponent commitments and mitigations listed in this report. The residual effects from the Project to heritage resources may include accidental destruction of previously unknown heritage resources. The Executive Committee is satisfied that residual effects resulting from the Project will not be significant.

9.8 Cumulative Effects Assessment

Cumulative effects to heritage resources can result if the body of heritage resources has been increasingly reduced and threatened such that residual effects to heritage resources are not isolated in nature but part of a pattern of adverse effects to heritage resources that threatens their overall value in providing a connection between the past and present.

The unlikely nature of residual effects of the Project suggests that it is unlikely that cumulative effects to the collective body of heritage resources will occur. This is further supported by the lack of evidence that suggests that the collective value of heritage resources in the area will be affected by the accidental and isolated chance of accidental destruction of heritage resources.

The Executive Committee is satisfied that the residual effects of the Project, in combination with the effects of other projects or activities will not result in significant adverse cumulative effects to heritage resources.

Part C ASSESSMENT RECOMMENDATION

10. RECOMMENDATION

Pursuant to paragraph 58(1)(b) of YESAA, the Executive Committee recommends to the Decision Body that the Stewart-Keno City Transmission Project be allowed to proceed without a review, subject to the terms and conditions specified below; as the Executive Committee has determined that the Project will have, or is likely to have, significant adverse environmental and/or socio-economic effects in Yukon that can be mitigated by these terms and conditions.

11. TERMS AND CONDITIONS OF RECOMMENDATIONS

1. The Proponent shall develop an Attractants Management Plan for review and approval by the Manager of Land Use, Government of Yukon, Department of Energy, Mines and Resources.

2. The Proponent shall ensure equipment is free of foreign soil and plant material before moving it to the project site.

3. The Proponent shall develop an Invasive Species Management and Monitoring Plan for review and approval by the Manager of Land Use, Government of Yukon, Department of Energy, Mines and Resources.

4. The Proponent shall report the presence of any invasive plants that are listed on the website (http://www.env.gov.yk.ca/wildlifebiodiversity/invasiveplants.php) to the Yukon Conservation Data Centre (at 867-667-5331 or Toll-free at 1-800-661-0408 local 5331), should they be encountered.

5. The Proponent shall conduct a rare plant survey at the Halfway Lakes. The survey shall be conducted during the month of July, and shall cover the right of way within two kilometres on either side of Halfway Lakes. The survey will be completed by a qualified biologist.

6. Where rare plants are found the Proponent shall:

    a. avoid disturbance of the plant and its habitat;
    b. hand clear the right of way;
    c. place poles and access trails to avoid the plant and its habitat; and
    d. reroute as necessary the transmission line within the right of way.

7. The Proponent shall coordinate with HPW to design, build, construct, and maintain the Project in a manner that does not reduce the predicted lifetime of granular resources nor restrict safe operation of granular resources operators.

8. If any heritage resources are discovered, the Proponent shall notify Heritage Resources Unit, Government of Yukon, as well as any First Nations whose traditional territory overlaps that heritage resource.

12. PROPONENT COMMITMENTS

The Executive Committee considered the following list of commitments proposed by the Proponent in its proposal (YOR 2015-0209-005-2) to mitigate potential adverse effects to the valued environmental and socio-economic components identified in this screening report.

Habitat Loss and Alteration

- To the extent feasible, vegetation removal and decommissioning activities will be undertaken in winter, and will avoid sensitive times of year such as calving and rearing (May to mid-August) and nesting season for birds (May 1 to August 15).
- Animal awareness protocols will be included in regular safety and environmental orientations performed by construction and maintenance workers. Such protocols will indicate that if caribou are encountered within 500 metres of the ROW centreline, that work will cease and the caribou will be allowed to move on.
- Long term effects on woodland caribou due to construction and operation of the Project are mitigated primarily by routing the Project, i.e. in areas south of the Stewart River, where the Project potentially intersects the seasonal range of the Ethel Lake woodland caribou herd, the Project will be located within or adjacent to the existing Carmacks-Stewart Transmission Line ROW.
- Vegetation clearing and decommissioning activities will be undertaken during the winter and hand clearing will be used for vegetation within 50 metres of any waterbody (i.e. wetland, steam, seasonal creek, lake).
- Standard water body spanning measures will also be used for any waterbody (wetland, stream, seasonal creek and lake), and pole placement will avoid wet areas and minimize removal of riparian vegetation.
- Yukon Energy will follow DFO's Measures to Avoid Causing Harm to Fish and Fish Habitat (included as Appendix 6B) for all line construction activities in the vicinity of waterways and riparian habitat.
- Clearing, maintenance brushing and decommissioning activities will be timed to occur in winter and will avoid nesting season (May 1 to August 15).
- Pre-clearing surveys for raptor nets on the ROW will be conducted, and nest deterrent structures may be used on pole structures near water to minimize osprey nests and potential line contacts/mortality.
- If clearing takes place outside of winter, pre-clearing surveys for rare plants will be conducted.

Direct Injury/ Mortality

- Animal awareness protocols will be included in regular safety and environmental orientations performed by construction and maintenance workers.
- Temporary camps will remove and manage attractants to minimize potential encounters.
- Temporary camps will remove and manage potential attractants when activities are undertaken.

- Protocols will be in place to ensure that temporary camps remove or manage attractants.
- Bird fatalities due to line strikes will be mitigated through installing the transmission line at heights similar to or below the existing forest canopy, where feasible, and by including markers on lines in open areas (e.g. Halfway Lake and Minto Creek).
- Mitigation measures to reduce potential mortality hazards due to line strikes will include installing transmission lines at heights similar to or below the existing forest canopy, where feasible, and including markers on lines in open areas, (e.g. Halfway Lake and Minto Creek).
- Pre-clearing surveys for raptor nets on the ROW will be conducted, and nest deterrent structures may be used on pole structures near water to minimize osprey nests and potential line contacts/mortality. Standard water body spanning measures will also be used for any waterbody (wetland, stream, seasonal creek and lake), and pole placement will avoid wet areas and minimize removal of riparian vegetation.
- Marking of conductors will be undertaken at Halfway Lakes and Minto Creek crossing to mitigate potential bird strikes, and checks of pole structures for nesting osprey will be undertaken when line patrols are conducted.
- Post construction surveys will be conducted at Halfway Lakes for the first two years after construction to confirm the effectiveness of marking.
- Incidents of moose, caribou and mule deer mortality near the ROW and/or highway will be documented, relying on current practices involving local conservation officer reporting, and with adaptive mitigation provided as necessary (e.g. signage, additional planting).

Increased Access

- Woody debris may also be mulched to provide insulation to permafrost sites and sensitive soil areas to minimize melting and soil loss/instability and minimize duration of disturbance to brush/forage species.
- Yukon Energy's EMS best practices for ROW access will be followed, and there will be a no-hunting policy for construction and maintenance personnel.
- Animal awareness protocols will be included in regular safety and environmental orientations performed by construction and maintenance workers. Such protocols will indicate that if caribou are encountered within 500 m of the ROW centreline, that work will cease and the caribou will be allowed to move on.
- Where possible, a vegetative buffer (nominally 30 m) will be provided between the ROW and the Silver Trail to minimize disturbance from highway traffic, act as a protective cover and to reduce opportunistic hunting.
- To mitigate the adverse effects of increased hunting pressure due to access provided along the ROW, Yukon Energy's EMS best practices for ROW access will be adhered to and there will be a no-hunting policy for construction and maintenance personnel.

Invasive Species

- Yukon Energy's EMS best practices for Transmission ROW/Distribution Corridor Vegetation Management will be followed at all times.

- Project-related vegetation removal and decommissioning activities will be timed to occur in winter under frozen conditions.
- To the extent feasible, removal of understory vegetation and disturbance of soils and ground vegetation will be minimized. Efforts to minimize the removal of understory vegetation and disturbance to the vegetative mat will mitigate the intrusion of exotic species due to soil disturbance.
- In sensitive areas, such as permafrost and riparian areas, use of heavy equipment will be minimized, and hand clearing methods may be used.
- YEC clearing and construction tenders will include a requirement for out of territory equipment to be steam cleaned, as per existing tender requirements and best management practices, prior to use on site, to minimize the likelihood of invasive species introduction. This requirement will apply during construction as well as during periodic brushing maintenance activities.
- Clearing will be undertaken in winter months whenever feasible and removal of understory vegetation and disturbance of ground vegetation and soils will be minimized to the extent possible.

Sedimentation and Erosion

- Areas of terrain stability concern (e.g., permafrost or wetlands) will be given particular attention, including non-standard spans to improve foundations, and construction will be undertaken during the winter to limit disturbance of the terrain.
- Particular care will also be applied in permafrost areas mapped with potentially moderate to high ice content (see Appendix 5A).
- Additional mitigative measures to reduce impacts on these permafrost rich areas may include: minimizing the cleared ROW, use of hand clearing, and/or light vehicle only, ensuring wood-chip piles are scattered (not thick piles that could create exothermic decomposition) and follow up visual monitoring for exposed soils and/or signs of permafrost thaw.
- Clearing on steep slopes and the approach to any watercourse will be done by hand.
- All root stock will be retained within the riparian clearing buffer areas.
- There will be no work done in streams – structures will be selected and placed so that any watercourse will be crossed with a single span.
- Any stream crossing by equipment would only be undertaken in accordance with DFO's Measures to Avoid Causing Harm to Fish and Fish Habitat (included in Appendix 6B).
- One stream crossing is required at Crooked Creek. For this crossing an ice bridge will be used for construction access in winter. All other locations will, be accessed from either side of the watercourse (avoiding any other crossings).

Land and resource use

- Consultation with landowners on construction timing
- Maintenance of a vegetative buffer between private property and the ROW
- Hand clearing within the water main easement to avoid damage to the micro hydro main.

Heritage resources

- the Proponent will flag heritage sites and cease activity in the proximity for further assessment.

Recreation areas

- Pole placement will avoid the trailhead infrastructure, walking trail and other associated infrastructure (i.e. parking lot, outhouses and garbage can)
- Yukon Energy's EMS best practices for ROW maintenance will be followed.
- Clearing and maintenance brushing activities will be conducted whenever feasible outside of peak tourist season and selective clearing will be used to remove only those trees which will cause a hazard to the transmission line.
- Clearing width and height will be minimized to the extent feasible in order to minimize any aesthetic impacts to the trailhead and parking lot area.
- The Proponent will continue to consult with YG Cultural Services Branch leading up to and following project construction activities to ensure that construction-related disturbances are minimized and remediated to the extent practicable.

13. SIGNATORY PAGE

	May 31, 2016
Wendy Randall Chair	Date
	May 31, 2016
Dave Keenan Executive Committee Member	Date
	May 31, 2016
Ken McKinnon Executive Committee Member	Date

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Yukon Government

Yukon Environmental & Socio-economic Assessment Act
Decision Document – Executive Committee Screening

This document meets the Yukon government's requirements as a Decision Body as set out in the *Yukon Environmental and Socio-economic Assessment Act* (YESAA).

Other Decision Bodies

☒Not Applicable

☐Other Decision Bodies

Consolidated Decision Document

☐No

☐Yes

☒N/A

Project

Project Name: Stewart-Keno City Transmission Project

Proponent Name: Yukon Energy Corporation **YESAB File Number:** 2015-0209

Project Description:

The Project includes construction and operation of a new 138 kV transmission line mainly within or adjacent to the existing 69 kV transmission line right-of-way (ROW) between Stewart Crossing and Keno City. The Proponent anticipates the new transmission line to be approximately 112 km in length. It includes connection of the Stewart Crossing South substation to the existing 138 kV grid, construction of a new substation adjacent to the existing Mayo substation, and development of a new substation at the South McQuesten River Road intersection with the Silver Trail to step down the voltage from 138 kV to 69 kV.

The existing 69 kV transmission line between Stewart Crossing South substation and Mayo substation will remain in place after the Project is complete and will continue to operate. The 30 m wide cleared area within the existing 60 m ROW in this segment will be widened by approximately 20 m to accommodate continued operation of both transmission lines.

The existing 69 kV transmission line between Mayo and Keno City will be removed and salvaged once the new 138 kV transmission line is in service. The cleared portion of the ROW of the new line in this segment will generally be 30 m in width throughout its operating life.

The Project also includes provision to install a new aerial fibre optic communication line on the 138 kV transmission line from Stewart Crossing South to Keno City substations.

Yukon Government

First Nations Consultation

A. Consultation under YESAA s.74(2)

☒No

☐Yes

B. First Nations Consultation – General

Yukon government Development Assessment Branch officials initiated consultation with the First Nation of Na-Cho Nyäk Dun and Selkirk First Nation upon the submission of the project proposal to the Executive Committee of the Yukon Environmental and Socio-economic Assessment Board. Yukon government encouraged both First Nations to participate in the screening under the *Yukon Environmental and Socio-economic Assessment Act* (YESAA). The First Nation of Na-Cho Nyäk Dun and Selkirk First Nation had opportunities to provide comments and views to the Executive Committee on the adequacy of the project proposal during the adequacy stage, on the complete project proposal during the seeking views and information stage, and on the draft screening report and recommendation. In addition to these opportunities provided through YESAA, Yukon government invited each First Nation to identify to Yukon government any adverse effects on treaty rights under its respective Final Agreements that may arise out of the proposed project. Yukon government officials consulted with officials from the First Nation of Na-Cho Nyäk Dun and Selkirk First Nation throughout the assessment process through a series of telephone calls and written correspondence.

The First Nation of Na-Cho Nyäk Dun did not identify specific concerns regarding adverse effects on treaty rights and did not provide comments to the Executive Committee during the assessment. On May 18, 2016, an email from Ray Sabo, Lands and Resources Manager for the First Nation of Na-Cho Nyäk Dun to Andrea Wilson, Development Assessment Process Manager with Yukon government, confirmed that the First Nation of Na-Cho Nyäk Dun had not identified any significant adverse environmental and socio-economic effects of the project during their review of the draft screening report. Following the May 31, 2016 issuance of the Executive Committee's Final Screening Report for the project, Yukon government officials contacted Na-Cho Nyäk Dun officials by letter, email and phone. An email sent June 15, 2016, from Ray Sabo, Lands and Resources Manager for the First Nation of Na-Cho Nyäk Dun to Andrea Wilson, Development Assessment Process Manager with Yukon government requested that an additional term and condition be considered by Yukon government, which would require the proponent to undertake a survey to identify existing bear dens along the proposed transmission line. As this issue was not raised during the assessment and was therefore not considered as part of the Executive Committee's recommendation, Yukon government was not able to add an additional term and condition to the decision document without referring the project back to the Executive Committee. Yukon government contacted the proponent and the proponent agreed to work directly with the First Nation of Na-Cho Nyäk Dun to address this issue. In emails received by Yukon government June 17, 2016, both the First Nation of Na-Cho Nyäk Dun and the proponent confirmed that they were satisfied with this approach.

Selkirk First Nation did not identify specific concerns regarding adverse effects on aboriginal or treaty rights and did not provide comments to the Executive Committee or Yukon government during any stage of the assessment. A June 6, 2016, conversation between Selkirk First Nation and Yukon government officials during the review of the draft screening report confirmed that Selkirk First Nation was satisfied with how the Executive Committee addressed significant adverse environmental and socio-economic effects of the project. Following the issuance of the Executive Committee Final Screening Report for the project, Yukon government officials engaged with Selkirk First Nation officials by telephone and email. On June 17, 2016 Selkirk First Nation confirmed by email correspondence that they were satisfied with the outcome of the assessment and had no concerns with the project.

Yukon Government

Throughout the assessment, NND and Selkirk First Nation did not identify any adverse effects on rights under their respective Final Agreements that may arise out of the proposed project.

YESAB Executive Committee Recommendation

Date Recommendation issued by YESAB Executive Committee: May 31, 2016

Recommendation Issued Under s.58 of YESAA:

☐ 58(1)(a) – proceed

☒ 58(1)(b) – proceed subject to terms and conditions

☐ 58(1)(c) – not be allowed to proceed

☐ 58(1)(d) – require a review

Decision

As the Decision Body, I have given full and fair consideration to the information provided with the recommendation in accordance with section 74(1) of YESAA and have decided to accept the recommendation, pursuant to s.76(1)(a) of YESAA.

This decision document is premised on the mitigation measures proposed by the proponent listed in Part C, Section 12 of the Final Screening Report being implemented along with the terms and conditions listed below.

Terms and Conditions

Term #	Term & Condition	Status
1.	The Proponent shall develop an Attractants Management Plan for review and approval by the Manager of Land Use, Government of Yukon, Department of Energy, Mines and Resources.	Agree
2.	The Proponent shall ensure equipment is free of foreign soil and plant material before moving it to the project site.	Agree
3.	The Proponent shall develop an Invasive Species Management and Monitoring Plan for review and approval by the Manager of Land Use, Government of Yukon, Department of Energy, Mines and Resources.	Agree
4.	The Proponent shall report the presence of any invasive plants that are listed on the website (http://www.env.gov.yk.ca/wildlifebiodiversity/invasiveplants.php) to the Yukon Conservation Data Centre (at 867-667-5331 or Toll-free at 1-800-661-0408 local 5331), should they be encountered.	Agree
5.	The Proponent shall conduct a rare plant survey at the Halfway Lakes. The survey shall be conducted during the month of July, and shall cover the right of way within two kilometres on either side of Halfway Lakes. The survey will be completed by a qualified biologist.	Agree

Yukon Government

6.	Where rare plants are found the Proponent shall: a. avoid disturbance of the plant and its habitat; b. hand clear the right of way; c. place poles and access trails to avoid the plant and its habitat; and d. reroute as necessary the transmission line within the right of way.	Agree
7.	The Proponent shall coordinate with HPW to design, build, construct, and maintain the Project in a manner that does not reduce the predicted lifetime of granular resources nor restrict safe operation of granular resources operators.	Agree
8.	If any heritage resources are discovered, the Proponent shall notify Heritage Resources Unit, Government of Yukon, as well as any First Nations whose traditional territory overlaps that heritage resource.	Agree

Authority

By Signing below, the Government of Yukon has exercised its authority as per YESAA s. 76 to issue a decision document on this project.

Name: Kelvin Leary

Position: Deputy Minister, Executive Council Office

Phone: (867) 667-5866

Email: Kelvin.Leary@gov.yk.ca

Signature: Kel Leary **Date:** June 29/16

Original signed by: Kelvin Leary, DM Executive Council Office

Distribution

Project Proponent	☒Yes	☐ No
Other Decision Bodies	☐Yes	☒ No
DAB, Executive Council Office	☒Yes	☐ No
YESAB Designated Office	☐Yes	☒ No
YESAB Executive Committee	☒Yes	☐ No
Minister of Environment (Canada)	☐Yes	☒ No
Yukon Surface Rights Board	☐Yes	☒ No
Yukon Water Board	☐Yes	☒ No
Land Use Planning Commission	☐Yes	☒ No
Independent Regulatory Agency	☐Yes	☒ No

Yukon Government

Other Body/Person as Required	☐Yes ☒ No

TOPIC:

REFERENCE: **November 10, 2017 Application, pages 2 and 18 and PPA Schedule 2**

PREAMBLE:

YEC states that the VGC Group is responsible for all capital costs related to the McQuesten Substation development including actual final "YEC Owners Costs" which are estimated at $483,240 (Table B-1). YEC states in a footnote that the 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 which appear to be currently estimated at $930,563 (Table B-2).

QUESTION:

a) Please identify any of the estimated "YEC Owners Costs" in Table B-1 which are currently recovered in rates as part of YEC's revenue requirement.

b) Please provide amounts and explanations of costs associated with the McQuesten Substation that the VGC Group would be entitled to recover from YEC.

c) Please identify any of the estimated "YEC McQuesten Station Costs" in Table B-2 which are currently recovered in rates as part of YEC's revenue requirement.

d) Please provide a single table showing details of all capital-related costs (including costs already incurred for permitting, etc.) associated with providing electricity to the VGC Group mine. Please identify costs that will be recovered from the VGC Group, costs to be recovered from other Yukon ratepayers, and costs to be recovered from other sources such as YDC.

e) Please explain why the VGC Group is only responsible for a portion of the required upgrade costs.

f) Please explain when and how YEC will recover the $930,563 of McQuesten Station costs.

g) Please explain how YEC will recover the costs of any new transmission facilities needed as a result of the addition of the VCG Group's operations.

ANSWER:

(a)

None of the costs outlined in Table B-1 have been or are currently being recovered in rates as part of an approved YEC revenue requirement, or are included in YEC's 2017-18 GRA revenue requirement forecasts. Specifically, these are YEC-capital related costs for a project that is not yet in service.

The costs outlined in Table B-1 are costs that YEC will recover from VGC Group regarding the McQuesten Substation development and consequently will not be recovered from ratepayers.

(b), **(e)** and **(f)**

Table B-2 of Schedule B outlines the YEC McQuesten Substation Costs that VGC Group is entitled to recover from YEC regarding the McQuesten Substation.

As outlined in the PPA Application, and in Schedule B of the PPA, YEC is responsible for the 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. These YEC McQuesten Substation Costs are set at $930,563. YEC funding of VGC Group costs for these added facilities recognizes that these facilitates are not required at the outset for delivery of Grid Electricity to the 69 kV Mine Facilities Spur line, but are required as part of any planned Transmission Facilities Development option that will include 138 kV transmission to the McQuesten Substation from either Mayo or Stewart Crossing. These costs will be retained in WIP until the Transmission Facilities Development Operation Date, after which time they will be added to rate base and included in the Transmission Facilities Fixed Cost that determine the Fixed Charge for VGC Group and any Other Industrial Customer using the Transmission Facilities (the Fixed Charge will recover 85% of YEC's annual fixed costs related to the specified items, including the YEC McQuesten Substation Costs).

Please also see response to YUB-YEC-13 (c), (d); YUB-YEC-1-5(a).

(c)

None of the costs outlined in Table B-2 have been or are currently being recovered in rates as part of a YEC revenue requirement, or are included in YEC's 2017-18 GRA revenue requirement forecasts. Specifically, these are YEC-capital related costs for a project that is not yet in service.

(d) and **(g)**

The PPA Application provides the information requested in (d), including all costs to be recovered from the VGC Group and costs to be recovered from other Yukon ratepayers and/or other sources. The 2017-18 GRA reviews in detail YEC costs incurred to date related to the SKTP, and the fact that these costs were all fully funded by contributions.

YEC is recovering costs from the VGC Group as set out in the PPA for new transmission facilities needed as a result of the addition of the VGC Group's operations. The PPA includes recovery of such costs through both the capital cost contribution provisions in Section 6 and the Fixed Charge provisions in Section 7.7.

Independent of the VGC Group Mine and the PPA, YEC has been pursuing the SKTP options as needed to replace existing end of life transmission facilities and enhance grid service capability in the region north of Mayo. Provision of continued reliable service to the Keno region, including to Alexco and the VGC Group Mine, requires replacement of the existing facilities.

As reviewed in Section 4.3 of the PPA Application, YEC is exploring options to secure funding in 2018 for the full SKTP up to 100% of full revenue requirement impact. The PPA also provides for a default option if such funding cannot to secured in a timely manner, where specific required improvements would be implemented by YEC with costs to be included in rate base and revenue requirements.

- At the time that these facilities come into service, the PPA provides for YEC to include in the Transmission Facilities Fixed Cost the YEC McQuesten Substation costs of $0.930 million as per the PPA, as well as the SVC/Statcom costs and the costs of the Transmission Facilities Development.

- The PPA provides the VGC Group and any Other Industrial Customer supplied by the Transmission Facilities will, through the Fixed Charge provisions applicable in each year that these customers are supplied under Rate Schedule 39, pay the 85% of YEC's depreciation and return (debt and equity) costs related to the Transmission Facilities Fixed Cost. The balance of these fixed costs will be recovered through rates charged to all firm customers in the Yukon (including Major Industrial Customers).

TOPIC:

REFERENCE: **November 10, 2017 Application, page 2**

PREAMBLE:

YEC states that the proposed Power Purchase Agreement provides two options for securing the required Transmission Facilities Development: (1) Subject to federal and Yukon government funding being confirmed by September 30, 2018, YEC plans to proceed with the SKTP that would include Transmission Facilities Development to provide 138 kV Transmission Facilities by March 31, 2021 connecting the McQuesten Substation with a substation at Stewart Crossing; or (2) If such external funding cannot be committed by September 30, 2018, YEC will seek approval for plans to provide the required Transmission Facilities Development by June 30, 2020 with new 138 kV Transmission Facilities connecting Mayo and the McQuesten Substation, to be operated at 69 kV until such time as 138 kV operation becomes feasible, i.e., a 138 kV line is developed to connect Mayo with Stewart Crossing.

QUESTION:

a) Please provide details of the total costs of the required Transmission Facilities Development ($90.96 million) and how much of this project needs to be funded by government in order to make the development economically feasible.

b) Please provide details of the requests for funding that YEC has submitted to various levels of government.

c) If no or limited government funding is available, please provide details on the costs that YEC would incur to provide the required Transmission Facilities Development by June 30, 2020 and how these costs would be recovered. If some or all of these costs are recovered from Yukon ratepayers, please provide details of the bill impacts to residential and commercial customers.

d) Please provide details of the approvals that YEC will seek for plans to provide the required Transmission Facilities Development.

ANSWER:

(a)

Please see response to YUB-YEC-1-14. YEC is seeking external funding of all costs for this option and has not at this time assessed any funding options.

(b)

YEC has not yet submitted any funding requests to the Territorial or Provincial government for this project.

(c)

If funding is not available for the full SKTP (or portions thereof) YEC plans (subject to receiving all approvals reasonably required) to proceed with the default development option to remove and replace deteriorated and end of life transmission infrastructure between Mayo and McQuesten Substation [i.e., construction of the new L180 Mayo to McQuesten 138 kV line, assumed to operate at 69 kV].

Please see response to YUB-YEC-1-14 for details of costs for the default option.

As outlined in Section 7.7 of the PPA, YEC costs for the default Transmission Facilities Development option will be included in the Transmission Facilities Fixed Cost that is used to determine the Fixed Charge for VGC Group and any Other Industrial Customer using the Transmission Facilities. YEC will also retain the YEC McQuesten Substation Costs in WIP until the Transmission Facilities Development Operation Date and then add these costs (as well as the SVC/Stacom costs) to rate base and include them in the Transmission Facilities Fixed Cost. The Fixed Charge will recover from VGC Group and Other Industrial Customer 85% of the Transmission Facilities Fixed Cost – the remaining 15% of these annual costs will be recovered from all ratepayers, including Major Industrial Customers.

In the event that 138 kV operation occurs, VGC Group will pay YEC's actual costs for the required Step Down Transformer at the McQuesten Substation.

(d)

YEC requires approvals from YDC and the Yukon Government to proceed with Transmission Facilities Development, including approvals for all related funding and financing.

TOPIC:

REFERENCE: **November 10, 2017 Application, page 4**

PREAMBLE:

YEC states that by 2019 its LNG generation capacity will be increased to approximately 13 MW with completion of the LNG Third Engine project.

QUESTION:

a) Please confirm that no approvals have been issued by the YUB to allow YEC to recover any costs of the proposed $6.2 million LNG Third Engine project from Yukon ratepayers.

b) Please explain how the economic feasibility of the provision of electricity to the VGC Group mine is impacted by the LNG Third Engine project.

ANSWER:

(a) and **(b)**

The YUB does not approve individual capital projects, but approves revenue requirement costs to be included in rates.

The YUB Part 3 hearing for the Whitehorse Diesel-Natural Gas Conversion Project (LNG Project) addressed development of up to 13.1 MW of additional thermal capacity as required to remove capacity shortfalls, with the first two LNG units (approximately 8.8 MW in total) to be installed in 2014-15 and the third LNG engine to be installed when new grid generation capacity was next required. Costs for the LNG Third Engine project are included in the 2017/18 General Rate Application, but are not forecast in the GRA to come into rate base during the test years.

The LNG units have been, and are being, installed to contribute towards meeting YEC minimum required capacity requirements. These units enable YEC to provide LTA thermal generation as per the 2017-18 GRA, assuming 90% LNG and 10% diesel, with the lower overall thermal energy costs than result from such access to such LNG capability.

TOPIC:

REFERENCE: **November 10, 2017 Application, page 5**

PREAMBLE:

YEC states that Minto mine load (purchases) for 2017 and 2018 were forecast at 38.2 GWh/year and that it was noted in YEC's 2017-2018 GRA that the Minto mine is currently expected to operate through to at least 2020. YEC concludes that, based on past information, the mine might continue operation until approximately 2022.

QUESTION:

a) Please provide an update on how much load the Minto mine has had / will have in 2017 and 2018.

b) Please provide documentation that confirms the claim in YEC's 2017-2018 GRA that the Minto mine was expected to operate through to at least 2020.

c) Please provide documentation that confirms that the Minto mine might continue operation until approximately 2022.

ANSWER:

(a)

The following is an update on Minto mine load for 2017 and 2018:

2017 – 36.6 GWh
2018 – 41.3 GWh

(b) and **(c)**

Please see extract below from Whitehorse Star, April 26, 2017 (emphasis added):

Minto Mine lengthens operating plan, no layoffs anticipated

By **Chuck Tobin** on **April 26, 2017**
Whitehorse Star

The Minto Mine has extended its operating plan by 2 1/2 years and possibly longer, mine manager Ron Light said this morning.

“We heard a bit of good news today,” he said from Vancouver, where he’s attending the annual general meeting of the parent company, Capstone Mining.

“At current copper prices, we are anticipating running to mid-2020.”

Light said there is also the possibility of extending the mine life out to 2022.

The mine was planning to move into temporary closure this December.

Light said the news of the company’s decision to run through to mid-2020 came today on a regular conference call to discuss the results of the first three months of mining at Minto this year.

He said the decision to extend the operating plan was made by Capstone president Darren Pylot and senior vice-president Gregg Bush.

“The decision was based on several months of reviewing our mine plan and costs,” he said.

As of the end of March, the Minto Mine had 144 of its own employees along with 162 contract employees, including 60 Pelly Construction Ltd. employees involved with the open pit mining, the underground miners and catering staff.

Open pit work for the Pelly crew was expected to run out this June.

With this morning’s announcement, the company is not anticipating layoffs, Light explained.

He said they still have to determine exactly how the mining plan will unfold from here on, but the plan to run into mid-2020 identifies additional open pit and underground targets.

Determining the sequence of how the new targets will be brought on will have a bearing on operations, but “we do not have any plans for layoffs at this time,” said the mine manager.

Copper market records show how the price of copper has taken a rough ride over the last five years.

In April 2012, the price was nosing up against $4 US per pound but then started falling.

It continued its downward spiral until it bottomed out in February 2016 at just under $2 a pound.

It began to rebound slightly but never much beyond $2.20 a pound until mid-October 2016, when it started a steady upward climb to the recent peak at $2.75 a pound in late January.

This morning, copper was trading at $2.58 a pound.

Light said they’re happy at $2.50 a pound, would take $3.50, but are happy at $2.50.

“Right now we are planning to continue without layoffs for as long as possible,” Light told the Star.

“I think the good news is we are not shutting down in December 2017.”

TOPIC:

REFERENCE: **November 10, 2017 Application, page 6**

PREAMBLE:

YEC states that the last cost of service analysis for Yukon, which was developed jointly by YEC and YECL for the 2009 GRA test year, indicated that major industrial customers were paying rates considerably in excess of allocated costs of service determined in accordance with OIC 1995/090 (including treating the whole Yukon as a single rate zone) and in accordance with normal regulatory principles applicable to similar regulated electricity utilities in Canada. YEC goes on to state in a footnote that the Compliance Filing by YEC and YECL in February 2011 included an updated cost of service estimate for 2009 indicating a revenue/cost ratio for the Industrial customer class of 111.4% per the Application and 113.7% per Order 2010-13. Board Order 2011-05 stated that the Board did not accept the cost of service as filed by YEC and YECL and "that the revenue-to-cost ratios derived from the application are without merit".

QUESTION:

a) Please confirm that, at this point, there is no cost of service-based evidence that has been accepted by the YUB that proves that the industrial customers served by YEC are currently paying more than the current costs to serve them.

b) Please confirm that the only way to determine the revenue-to-cost ratio for the industrial class of customer served by YEC is to conduct a fully allocated cost of service analysis.

c) Please provide evidence that YEC is prohibited in any way from conducting a fully allocated cost of service analysis.

ANSWER:

(a) and **(b)**

Please see response to YUB-YEC-1-8 (a-e).

As reviewed in detail in the above response, the evidence and Board determinations in the 2009 GRA Phase II proceeding provide a solid basis for determining that industrial customers served by YEC in 2009 (and today) are paying more than the current costs (as determined by a cost service consistent with the Board's directions, normal regulatory principles, and OIC 1995/90 directions) to serve them.

(c)

YEC is not specifically prohibited from conducting a fully allocated cost of service (COS) analysis, subject to securing from AEY the information needed for completing a consolidated COS for all Yukon including both YEC and AEY facilities and customers.

In practice, it is recognized that any new COS must be prepared jointly by YEC and AEY, and preferably based on a Phase 1 GRA review for YEC and AEY for a common test year.

The timing for any new COS has been affected by current OIC directions which prevent the Board from rebalancing rates for rate classes so that rates for each customer class might more closely reflect COS.

The Board in Order 2010-13 noted that OIC 2008/149 prevented the Board from adopting before December 31, 2012 rate proposals whereby rate classes would more adequately reflect their cost of service. As the 2009 COS could not be used for guiding such rate proposals, the Board directed the Companies to file a joint COS study within six months of the expiry of OIC 2008/149. Due to subsequent direction of OIC 2012/68 and OIC 2014/23 extending the earlier December 31, 2012 date to December 31, 2018, the Companies have not conducted or filed a new joint COS.

TOPIC:

REFERENCE: **November 10, 2017 Application, page 8**

PREAMBLE:

YEC states that it is pursuing the SKTP at this time to improve the electrical transmission infrastructure in central Yukon between Stewart Crossing and Keno City; reinforce and strengthen the grid between Stewart Crossing and Mayo; and replace and remove deteriorated and 'end of life' transmission infrastructure between Mayo and Keno City. The project is being planned to ensure continued safe and reliable service and to facilitate future economic development within the territory.

QUESTION:

a) Please confirm that the urgency of pursuing the Stewart Keno City Transmission project at this time is based on the proposed VGC Group mine's operations.

b) Please provide details of when the SKTP project would be brought to the YUB for approval without the proposed mine development.

ANSWER:

(a)

Not confirmed. The SKTP environmental review (YESAA), engineering and costing was pursued long before the start of PPA negotiations with VGC Group, reflecting the long-standing need to replace end of life facilities as soon as possible. Further, the PPA provides for McQuesten Substation development to connect to the existing L180 transmission.

As noted in the VGC PPA Application, YEC is pursuing SKTP to improve the electrical transmission infrastructure in central Yukon between Stewart Crossing and Keno City; reinforce and strengthen the grid between Stewart Crossing and Mayo; and replace and remove deteriorated and 'end of life' transmission infrastructure between Mayo and Keno

City. The project is being planned to ensure continued safe and reliable service and to facilitate future economic development within the territory.

YEC's decision to pursue the project at this time is also tied to the potential opportunity to secure funding of up to 100% of full revenue requirement impact.

(b)

YUB approval is not required for YEC to proceed with capital projects, including the SKTP. YUB review and report to the Minister on a capital project occurs only when the project is declared by OIC to be a "regulated project" under Part 3 of the *Public Utilities Act*. To date, SKTP has not been so designated.

YEC will make a decision on advancing the project once project costs and potential funding have been confirmed.[1]

[1] P. 5-33 in Yukon Energy Corporation's 2017/2018 General Rate Application.

TOPIC:

REFERENCE: **November 10, 2017 Application, page 15**

PREAMBLE:

YEC states that allocating 85% of annual costs of the Mayo-Keno Transmission Facilities to the industrial customer is considered reasonable based on similar treatment of Faro Mine which was based on a NEB 1985 NCPC Report finding.

QUESTION:

a) Please provide a copy of the 1985 analysis that determined that 85% is a fair allocation and explain if there were any differences in circumstances between those that existed in 1985 and those that exist now with respect to industrial customers.

b) Please provide any analysis completed by YEC since the 1985 NCPC report that confirms that the current and proposed mining operations in the Yukon should be considered responsible for the same 85% level of costs.

c) Please explain how a customer group using 99% of the capacity of a facility only be responsible for paying 85% of the cost.

d) Has YEC allocated the costs of any transmission facilities in a manner different than has been proposed for the VGC Group proposal?

ANSWER:

(a) and **(b)**

Please see response to YUB-YEC-1-7 (a - d), which reviews the analysis in 1985 (with a copy of the relevant portion of the NEB report), and subsequent analysis provided by YEC as reviewed and applied for the Alexco PPA review by the Board that confirmed the applicability of the 85% of the defined Transmission Facilities fixed cost as specified for the Alexco PPA.

(c)

See page 15 of the PPA Application and the response to YUB-YEC-1-7(a- d). The 85% is based on principles reviewed and approved by the NEB and YUB for specific cases where the mine's load on the specified transmission facilities exceeded 95% of the total load using the facilities.

As reviewed in Board Order 2010-14, although Alexco's share of the forecast load was expected to be approximately 98% of the load going through the transmission facilities as defined in the Alexco PPA (i.e., YEC's 69 kV transmission between Mayo and Keno City, or any future replacement transmission facilities at similar or higher voltage), the proposed 85% share in the Alexco PPA was based on the NEB 1985 NCPC Report finding regarding the Faro mine. The Board noted that YEC had reported at page 4 of its Alexco PPA application that, in the case of the Faro mine, Faro's share of the defined line's load (i.e., the NCPC 138 kV line between Whitehorse and Faro) was approximately 96.8%.

The approach adopted for the VGC Group PPA that assigns 85% of fixed costs for specified YEC transmission facilities is consistent with the PPA as approved by the Board for the Alexco facilities and the Alexco use of these same transmission facilities.

Similar to the approach used for the Faro mine when it was operating [and recently applied to Alexco per the Alexco PPA], VGC Group is being assigned a Fixed Charge of 85% of the annual depreciation and return costs for the relevant transmission line segment on the basis that these facilities were primarily developed to serve industrial load in the region; the remaining 15% is being rolled into pooled costs to be paid by all customer classes in the Yukon Hydro zone, including industrial customers, based on their respective demands.

(d)

As noted at page 15 of the PPA Application, YEC has allocated 85% of specific transmission facilities annual fixed costs in this manner for both the Faro Mine [for the Whitehorse to Faro line] and for Alexco [for the Mayo to Keno line as per the Alexco PPA]. This approach was not used for the Minto PPA, as a direct capital contribution towards the line was negotiated with the mine as part of the agreement.

Please also see responses to YUB-YEC-1-7 (a-d).

TOPIC:

REFERENCE: **November 10, 2017 Application, page 17**

PREAMBLE:

YEC has provided the VGC Group's power demand, consumption and related YEC generation for the initial 6 years of operation. A note to the table indicates that system losses are estimated at 8.8%.

QUESTION:

a) Please provide the calculation to support system losses of 8.8%.

b) Please explain and provide calculations why system losses would not improve with the new transmission and substation facilities.

ANSWER:

(a)

As reported in the 2016 Resource Plan (Chapter 4, page 4-17, lines 17 to 19), the forecast level of losses was defined using the average of historical levels of losses for the 2012 to 2015 period. Actual levels of losses for the years 2012 to 2016 inclusive are presented in the table below.

Table 1: Actual Levels of Losses (% of YEC Sales on Grid – 2012 to 2016)

Year	Losses
2012	8.8%
2013	9.0%
2014	7.5%
2015	10.0%
2016	8.3%

(b)

System losses are affected by a wide range of factors, including changes in loads and changes in facilities. Absent more detailed study and investigation, 8.8% as per the GRA forecast has been assumed based on the best available information at this time.

TOPIC:

REFERENCE: **November 10, 2017 Application, page 23**

PREAMBLE:

In Table 3 (YEC LTA Thermal Generation Costs and Net Revenue Impact –VCG Group Mine), YEC indicates that the thermal share of the increased generation required for the VCG Group mine load is approximately 72% in 2020, 75% in 2021 and 65% in 2025.

QUESTION:

a) Please explain why YEC would not require the VCG Group to pay an equitable share of the new thermal costs as indicated in Table 3.

b) Please explain why YEC would not require Alexco or any other industrial customer wanting to connect / reconnect to the grid to pay their fair share of increased thermal generation costs.

ANSWER:

(a) and **(b)**

The VGC Group and Alexco PPAs assign certain connection and transmission costs directly to each mine in accordance with normal regulatory principles, past Yukon practice as approved by the NEB and YUB, and Terms and Conditions as approved by the Board. Based on these same precedents and principles, generation thermal fuel costs are charged on a “fair and reasonable” basis to all customers in the Major Industrial Customer class as per Rate Schedule 39 and relevant OIC directions, without any attempt to charge new customers differently than existing customers.

The question assumes that each new mine is “responsible” for the incremental thermal generation that is expected, on a long term average basis, to be required from overall growth of the integrated grid. This ignores any similar suggestion regarding assumption that any other source of growth on this grid, e.g., other major new subdivisions to accommodate strong and ongoing non-industrial growth, is similarly “responsible” for incremental thermal generation that is expected.

Attempts to assign responsibility for new “incremental” thermal generation to specific customers or customer classes are fraught with serious issues of regulatory principle.

In principle, each customer and each customer class contributes to overall generation load on the grid, and to the current “incremental” load at any time of day or season of the year. Every kW.h consumed is a part of the load that must be served from existing and new resources, regardless as to the length of time that each customer has been on the system (e.g., old house versus new house, old industry versus new industry).

Within the current regulatory compact it would be considered unfair, inequitable and rate discrimination to make an individual customer or class of customers who receive comparable utility service pay rates for thermal generation that were designed based on fundamentally different methodologies (e.g., average cost versus incremental cost, new versus old service). Each retail and industrial customer class shares in equalized and average generation costs as forecast for the total utility service in Yukon; rates for incremental use beyond specified monthly use levels for each of these customer classes can then also include higher “run out” rate charges for incremental use by any customer that reflect a higher share of incremental thermal generation costs.

See also response to YUB-YEC-1-20(e).

TOPIC:

REFERENCE: **November 10, 2017 Application, Appendix**

PREAMBLE:

The proposed Power Purchase Agreement submitted to the YUB was executed on November 9, 2017 by YEC and November 10, 2017 by Victoria Gold and StrataGold.

QUESTION:

a) Please provide an electronic copy of the proposed Power Purchase Agreement (Appendix to the Application) which is fully searchable and accessible.

b) Please confirm whether all or parts of the proposed Power Purchase Agreement will be effective prior to it being approved by the YUB.

c) If YEC assumes that the proposed Power Purchase Agreement will be effective prior to YUB approval, please explain how and under what legislative authority the YUB's approvals related to the proposed Power Purchase Agreement can be retroactive.

d) Since other mines have discontinued their industrial power load within a few years of hooking up to the Yukon electricity grid, after considerable expense to the utility and thus other ratepayers, please explain how YEC will protect ratepayers from future risk from the VGC mine not staying connected for the anticipated 10 years or not requiring the anticipated electricity as forecast.

e) Please explain whether YEC has considered implementing a take-or-pay charge, a penalty clause or any other upfront contingency payment from the VGC Group to be held in reserve on a declining basis in case there is an early reduction in or closure of mine operations. If not, please explain why not.

f) Please explain the similarities and differences between the proposed Power Purchase Agreement with the VGC Group and the power purchase agreements that have been approved by the YUB for the Alexco and Minto mines.

ANSWER:

(a)

A fully searchable and accessible electronic copy of the proposed Power Purchase Agreement is provided as UCG-YEC-1-18(a) Attachment 1.

(b)

The PPA is effective as of November 10, 2017. The parties are proceeding based on the Agreement on the understanding that certain provisions are subject to Board approval and other conditions precedent.

Section 3 of the PPA [Conditions Precedent] outlines that the obligations of the Parties to proceed are subject to fulfilment of certain conditions, including 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 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.[1] If this condition is not fulfilled, waived, altered or the time period extended on or before the date specified, the Agreement will terminate with immediate effect and neither party will have any further right or obligation under the agreement except for the fulfilment of obligations which arose prior to the date of termination and rights or obligations which are expressly stated to survive the termination of the agreement.

(c)

The parties are proceeding based on the PPA on the understanding that certain provisions are subject to Board approval, as well as other Conditions Precedent.

It is noted that VGC Group will not be connected as an industrial customer until 2019, and any required approvals related to the Transmission Facilities Fixed Cost, as well as provisions under Section 7.7 for amending the Transmission Facilities Fixed Cost, for setting the annual amount for the Fixed Charge, and amendments to the Firm Mine Rate

[1] Section 3.1(a) of the Power Purchase Agreement.

should be addressed by that time. There is no “retroactive” element proposed for YUB approvals.

(d)

Yukon Energy disagrees with the assertion that discontinued industrial service from other mines “within a few years of hooking up to the Yukon electricity grid” has resulted in “considerable expense to the utility and thus other ratepayers”.

There are only two mines that have connected to the grid as industrial customers since the Faro mine’s closure in 1998: Minto and Alexco. Each of these mines has PPAs approved by the YUB that include provisions to protect the utility and ratepayers from “hang over” expenses when the mine discontinues industrial service

- The Minto mine has continued to operate since its connection in 2008. There have therefore been no issues to date with this mine related to discontinued service. And the Minto mine’s capital cost related obligations regarding up front connection to the grid (for the spur line, substation, and contribution to the CSTP) have all been fully discharged per the Minto PPA provisions approved by the YUB, such that there will be no hang-over expense to the utility or ratepayers when this mine does eventually discontinue industrial service.

- While Alexco discontinued industrial service in mid-2013 [after its initial connection in 2010], the Alexco PPA approved by the YUB included provisions for Alexco to pay the capital costs for connecting to the grid at the outset [meaning YEC and ratepayers were not subject to these costs]. Alexco also paid the full costs to negotiate the PPA. Discontinued industrial service to Alexco has consequently not resulted in any expense to the utility or to ratepayers.

The VGC Group PPA includes the following provisions to mitigate adverse impact risks on ratepayers related to the connection of the Eagle Gold mine:

- YEC’s actual costs to negotiation and conclude the PPA [currently estimated at $200,000] will be invoiced and paid by VGC Group well in advance of the mine’s connection to the Grid.

- 50% of the Initial YEC System Improvement capital costs related to connection of this mine must be paid by VGC Group within 15 days of YUB approval of the PPA with the balance invoiced and paid once actual costs are determined.

- 50% of YEC Owner's Costs for the McQuesten Substation will be invoiced and paid within 15 days of YUB approval of the PPA, with the balance invoiced and paid as soon as practicable after Commencement of Delivery and once final costs are determined.

Outside of the specified YEC McQuesten Substation Costs [estimated at $0.93 million and detailed in Schedule B, Table B-2], VGC Group will fund all costs, fees and expenses for the development of the McQuesten Substation.

In summary, the PPA's provisions fully protect ratepayers from future risk of incurring hang over costs and expenses related to the above costs that arise from connecting the VGC Group Mine. These costs will be fully funded by VGC Group, and therefor will not "hang over" for other ratepayers if the VGC Group Mine does not stay connected for the anticipated 10 years or does not require the anticipated electricity as forecast.

The connection of the Eagle Gold mine through the VGC Group PPA has also presented an opportunity for YEC to proceed with important additional infrastructure upgrades that will provide long term benefits to the Yukon grid and Yukon ratepayers. The VGC Group will provide payments towards these upgrades so long as it operates as an industrial customer, thereby providing near term net benefits to other ratepayers.

YEC funding of incremental McQuesten Substation costs for 138 kV service recognizes that these facilities are not required at the outset for delivery of Grid Electricity to the 69 KV Mine Facilities Spur [i.e., these costs are not required to be incurred for the connection of the Eagle Gold mine], but are required as part of either Transmission Facilities Development option that YEC expects to implement. Per the PPA YEC will retain the YEC McQuesten Substation Costs in WIP until the Transmission Facilities Development Operation Date, after which time these costs will be added to YEC's rate base and included in the annual Transmission Facilities Fixed Cost that determine the Fixed Charge. Through the Fixed Charge, VGC Group and any Other Industrial Customers using the Transmission Facilities will pay 85% of the annual Transmission Facilities Fixed Cost.

The PPA also provides that YEC's annual costs for depreciation and return on rate base related to capital costs for specific other key new infrastructure (namely, the Transmission Facilities Development and the SVC/Statcom) will be added to the annual Transmission Facilities Fixed Cost that determine the Fixed Charge recovered from VGC Group and any Other Industrial Customers using the Transmission Facilities. Accordingly, during the period when the VGC Group Mine is operating, any amounts that other ratepayers would need to pay towards this necessary infrastructure will be significantly reduced.

As shown in Table 3 of the PPA Application (and as revised in Attachment 1 to YUB-YEC-1-28), connection of VGC Group and other mine loads at this time yield the opportunity for overall net benefits to all other firm ratepayers through reductions in the revenue requirement amounts that need to be recovered from these other ratepayers. Loss of these net benefits is the one impact that the PPA cannot prevent if the VGC Group Mine does not stay connected for the anticipated 10 years or does not require the anticipated electricity as forecast.

Please also see response to JM-YEC-1-9(b).

(e)

YEC has not considered take-or-pay provisions for either Alexco or the VGC PPA.

Take-or-pay provisions would not be appropriate in these circumstances, as costs being incurred to provide service to VGC Group [PPA Negotiation Costs; YEC System Improvement capital costs; and YEC Owner's Costs for the McQuesten Substation] are to be recovered from the VGC Group prior to, or shortly after, Commencement of Delivery [see part (d) above].

VGC Group is also itself paying the costs for the Mine Facilities Spur, as well as the costs, fees and expenses for the development of the McQuesten Substation [outside of the defined YEC McQuesten Substation Costs, estimated at $0.93 million and detailed in Schedule B, Table B-2].

Unlike Minto mine PPA, where take-or-pay provisions existed, there is no provision for a loan to the mine over an extended period which would require security for the period of the loan.

Please see response to YUB-YEC-1- 26(a, b).

(f)

The Minto PPA as finally approved by the YUB was used as a template for the Alexco PPA; however, the Alexco PPA was considerably simplified compared to the Minto PPA due to different circumstances surrounding the negotiation of the respective Agreements and provisions of service to each of the mines. Similarly, the VGC Group PPA is based on the simplified approach used for the Alexco PPA, with some modifications to address issues specific to the connection of the VGC Group Mine.

As a result, the VGC Group PPA provisions are generally consistent with similar PPAs approved by the Board between YEC and Minto Explorations Ltd. (Minto) and between YEC and Alexco Resources Corp. (Alexco), and particularly with the more recent PPA with Alexco. Differences arise primarily due to VGC Group (rather than YEC) building and owning the mine facilities spur, and the resulting avoidance of the need for any decommissioning provisions, as well as the VGC Group's PPA provisions related to Initial YEC System Improvements, VGC Group Power Facilities, an Operating Agreement, and more detailed provisions related to the Fixed Charge to accommodate planned Transmission Facilities Development options as well as other considerations.

Key similarities and differences are summarized as follows:

<u>Firm Mine Rate</u>

The same firm mine rate (Rate Schedule 39) applies to all industrial customers, with the only variation being the Fixed Charge applied to Alexco and VGC Group.

Pursuant to the Minto PPA, the Minto mine paid the full cost of the Minto Spur line (constructed specifically to provide service to that mine site), the related substation facilities, as well as a contribution towards the Capital Costs of CSTP Stage 1. Given these contributions, no additional direct allocation [similar to that applied for Alexco and VGC Group] was included towards pre-existing WAF transmission infrastructure in place that was used to serve that mine.

Pursuant to the Alexco PPA, the Alexco mine and mill paid a Fixed Charge based on 85% of YEC depreciation and return on rate base for the existing Mayo to Keno City transmission facilities. This Fixed Charge provision reflected the provisions applied and approved in the past for the Faro mine, as well as the history of the Keno region transmission facilities being developed in the 1950s for the earlier United Keno Hill Mine. The Alexco PPA included provision to change the Fixed Charge when a new Major Industrial Customer connects to the same transmission facilities located north of Mayo.

The current VGC Group PPA Fixed Charge provisions reflect the Alexco PPA, and the 85% assignment of YEC's annual depreciation and return costs for the relevant portion of the transmission north of Mayo used by the VGC Group Mine. The VGC Group PPA also includes more detailed provisions (e.g., the Transmission Facilities Fixed Cost definition, and section 7.7 provisions for YUB approval of cost changes, and for Fixed Charge changes related to any Other Industrial Customer) to accommodate planned Transmission Facilities Development options as well as other considerations.

Provision for Low Grade Ore Processing Secondary Energy Rate

The Minto PPA included provision for a Low Grade Ore Processing Secondary Energy Rate that is not referenced in either the Alexco PPA or the VGC Group PPA.

It is noted that this rate schedule cannot be implemented until audit and control measures and reporting requirements are established between YEC and Minto, and filed with the YUB for approval.

Capital Cost Contribution

- **Contributions related to Facilities –** The principles underlying the Alexco and VGC Group Capital Cost Contributions are based on the principles and precedents applied with regard to the Minto PPA and endorsed by the YUB in Order 2007-05.

    - **Alexco PPA:** As was the case for the Minto Spur, Alexco paid the full Capital cost of the Mine Facilities Spur (including substation connection) built specifically by YEC to provide service to the mine. No new bulk transmission was required to be developed to serve the Alexco mine (unlike Minto which included CSTP Stage 1, for which Minto paid a contribution based on the estimated cost for 35 kV facilities). The relevant existing bulk transmission facilities for providing service to Alexco were the existing Mayo-Keno line (see above review of the Fixed Charge).

  - **VGC Group PPA:** With regard to the VGC Group PPA, VGC Group is making capital contributions as needed to pay substation connection costs (including any Step Down Transformer requirements) and, similar to the Alexco PPA, is assessed a Fixed Charge for the existing Mayo-McQuesten Transmission Facilities. Unlike either the Minto or the Alexco PPAs, VGC Group rather than YEC is developing and owning the transmission spur facilities to connect with the grid (and therefore no "capital contribution" to YEC is needed for this item). The VGC Group PPA also included provisions for capital cost contribution to enable YEC to recover its costs for Initial YEC System Improvements (reflecting the need in this instance, given the load levels and the location of the load, to provide for such system protection changes). The VGC Group PPA includes special added provisions relating to the development of the McQuesten Substation, reflecting the role that VGC Group is carrying out in the timely development of this facility.

- **Costs for Negotiation of the PPA –** The mine repays YEC for costs for negotiation of the PPA in the case of Alexco and VGC Group, but not for the Minto PPA. The requirement for this provision was added with the Alexco PPA, and was retained in the VGC Group PPA.

- **Loan Arrangement and Security Provision** – The Minto PPA included more complex arrangements for loan and security provisions based largely on the fact that pursuant to the PPA Yukon Energy was loaning Minto the funds to invest in the CSTP Stage 1 Line and Minto Spur line, and Minto was to repay these funds over a 7 year period. Yukon Energy was also incurring potential net costs for CSTP Stage 1 development in the case of the Minto mine, and sought security and minimum annual payments to offset risks related to such costs.

  The following related provisions were included in the Minto PPA, but are not included in either the Alexco PPA or the VGC Group PPA (the initial YUB review of the Minto PPA rejected ratepayers accepting any risks related to the loan to Minto, and as a result the final PPA as approved had YDC accepting all such risks as regards repayments to YEC):

- **Take or Pay Provisions -** Minto made a Minimum Take-or-Pay Amount commitment to pay at least $12 million for Grid Electricity during the first four years of YEC service, subject to certain provisions in Section 6.3 of the PPA. Similar provisions were not included in the Alexco or VGC Group PPA as there were no similar loan provisions or need for such security to offset other upfront capital costs undertaken by YEC.

- **YEC Security -** The specific risks related to the Minto PPA required that YEC ensure Minto had acceptable security for the payment of the Capital Cost Contribution, the Minto Power Bills, the Minimum Take-or-Pay Amount, the Decommissioning Cost Payment, and certain other obligations. YEC was required to conduct comprehensive due diligence with regard to the YEC Security, Minto and the Mine. The same level of risk is not present with regard to the YEC cost undertakings with regard to either the Alexco PPA or the VGC Group PPA, and therefore no specific security for YEC was required of Alexco or is required of the VGC Group.

- **Purchase of Minto Diesel Units** - Upon commencement of delivery under the Minto mine PPA, YEC was to a acquire (subject to various conditions that have not been met) four 1.6 MW trailer mounted Diesel Units from Minto which would help to provide added security and also provide opportunities to minimize WAF system costs under certain circumstances. No similar provisions are included in either the Alexco PPA or the VGC Group PPA.

In summary, there are no loan or special security provisions in either the Alexco or VGC Group PPA. In the case of Alexco, the mine paid the full capital costs for the Initial Mine Facilities Spurs shortly after commissioning. VGC Group is constructing and financing its own Mine Facilities spur required for its connection to the grid, as well as (under the MOU) constructing and funding all costs for the McQuesten Substation prior to transfer of these facilities to YEC.

<u>Decommissioning Costs</u>

The Alexco PPA included Decommissioning Cost arrangements for the mine spur and other facilities developed solely for the mine, based on the provisions provided in the Minto

PPA, with provision in each case for YEC to establish an Accrued Decommissioning Fund account. In each case the mine would make Decommissioning Cost Payments (based on the Estimated Decommissioning Costs) towards the account to be deposited into the account by YEC upon payment and invested at 6.5% interest per annum to fund YEC's regulated rate base. In each case the Board approved the establishment of the Accrued Decommissioning Fund, along with payments to be made by the mine to YEC equal to 25% of the Capital Costs incurred by YEC for the mine facilities Spur. (p. 21 of Board Order 2007-5 and p. 9 of Board Order 2010-14)

No Accrued Decommissioning Fund is established for the VGC Group PPA, as pursuant to the PPA, the VGC Group will develop and own the Mine Facilities Spur connecting the mine to the substation. The SKTP as reviewed by YESAB included provision for the McQuesten Substation as part of the full SKTP development, without the necessity for the VGC Group Mine to be connected; accordingly, the VGC Group PPA does not include any provisions for decommissioning of the McQuesten Substation.

Other Provisions

Aside from differences related to the size and number of mill sites [for Alexco], related differences in the facilities to be provided by YEC versus the mine customer (and in the VGC Group PPA case the need to provide for Transmission Facilities Development), the other provisions (beyond those specifically noted above) in the Alexco PPA and the VGC Group PPA are generally included in the Minto Mine PPA as approved by the Board. This includes provisions affecting annual load forecasts to be provided, Maximum Electric Demand increases, standards for usage of electricity, Terms and Conditions of Service [formerly ESRs], billing/ payment, metering, force majeure, representations and warranties, default, dispute resolution, indemnity, assignment, confidentiality and general provisions.

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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 11^{th} 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 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:

____
Authorized Signatory

Dated: __________________________________

VICTORIA GOLD CORP.

By:

____
Authorized Signatory

Dated: __________________________________

STRATAGOLD CORPORATION

By:

____
Authorized Signatory

Dated: __________________________________

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 <u>CREDIT:</u> 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 <u>BILL:</u> 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 <u>LOAD:</u> 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 <u>DEMAND:</u> 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 <u>LOAD:</u> 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 email 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 <u>ENERGY:</u> 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.

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

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**

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)
16	Field material and free issue equipment, control plan	VGC (construction manager)

Item	Description	Responsibility / Approval Milestones
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: ISSUED DATE	INQUIRIES TO: Review Date	TOPIC: 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.

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

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:

REFERENCE: November 10, 2017 Application, page 3

PREAMBLE:

The PPA provides for VGC Group to pay the Firm Mine Rate as approved by the Board from time to time, including a Fixed Charge that is adjusted on an ongoing basis to equal 85% of the Transmission Facilities Fixed Cost as approved by the Board from time to time to reflect changes in YEC rate base costs for the Transmission Facilities.

REFERENCE: November 10, 2017 Application, Appendix

PREAMBLE:

"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.

"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.

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.

QUESTION:

a) Please provide a detailed breakdown of the costs to be recovered by the Fixed Charge and the calculation of the initial fixed charge.

b) Please provide details of the calculation and justification of the 85% adjustment factor to be used to determine the Fixed Charge related to the specific facilities to be used to supply electricity to the VGC Group mine after the initial charge is determined.

c) Please explain the “commercially reasonable efforts” to be used by YEC to secure required YUB approvals related to Fixed Charge amounts, including amounts related to the VGC Group Share or the Transmission Facilities Fixed Cost.

ANSWER:

(a)

Please see response to YUB-YEC-1-21(b), and YUB-YEC-1-22(d).

(b)

Please see response to YUB-YEC-7(a-d) and UCG-YEC-1-15(a-d).

(c)

Please see response to YUB-YEC-1-22(c).

TOPIC:

REFERENCE: **November 10, 2017 Application, Appendix, Section 5.2**

PREAMBLE:

QUESTION:

a) Please explain why the VGC Group needs to supply YEC with its annual demand and energy requirements 8 months prior to calendar year end.

ANSWER:

(a)

These provisions in the VGC PPA reflect similar provisions in the Alexco and Minto PPAs.

Having this information sufficiently in advance of the calendar year end allows for any planned changes in demand and energy requirements to be flagged and addressed as part of Yukon Energy's annual planning processes. The PPA provisions established the annual update requirement eight months in advance of calendar year end so as to receive early notice of major changes that could affect overall YEC annual planning for the next fiscal year.

TOPIC:

REFERENCE: **November 10, 2017 Application, Appendix, Section 6.1(a)**

PREAMBLE:

QUESTION:

a) Please provide details of all costs incurred to negotiate and conclude the proposed Power Purchase Agreement.

b) Please provide details of the invoices related to these costs that YEC has submitted to the VGC Group to date and how much has been paid to date.

c) Please confirm what costs still need to be finalized before the VGC Group can be billed for all costs related to the proposed Power Purchase Agreement.

ANSWER:

(a - c)

The YEC costs recorded to date to negotiate and conclude the PPA are summarized in Table 1 below.

Table 1: YEC Costs to Negotiate and Conclude the PPA (as of October 31, 2017)

Legal	57,502
Consulting	59,422
YEC Owner's Costs	1,740
Total Costs to October 31, 2017	118,664

In accordance with Section 6(a) of the PPA, YEC issued an invoice on November 27, 2017 to VGC Group in the amount of $0.100 million [i.e., 50% of the estimated costs to negotiation and conclude the PPA]. Payment is due within 15 days of issuance of the invoice.

Per the PPA, the balance of capital costs to negotiate and conclude the PPA will be invoiced to VGC Group as soon as reasonably practicable after YEC determines the actual amount of Capital Costs for negotiation and conclusion of the agreement. Negotiation of the PPA concluded in early November. YEC is awaiting November invoices from consultants and legal counsel to confirm final costs before an invoice is issued to VGC Group for the balance of costs. This is expected to occur in December.

TOPIC:

REFERENCE: **November 10, 2017 Application, Appendix, Section 6.1(b)**

PREAMBLE:

QUESTION:

a) Please provide details of all costs incurred to date and going forward related to system improvements.

b) Please provide details of the invoices related to these costs that YEC has submitted to the VGC Group to date and how much has been paid to date.

ANSWER:

(a) and **(b)**

The system improvements to connect VGC Group's Eagle Gold mine to the grid were identified through a System Impact Study (SIS) prepared by Hatch Engineering. The cost of the SIS was paid by VGC Group. The SIS was provided to YEC to prepare a cost estimate for system improvements. Only internal labour costs have been incurred by YEC to prepare the cost estimate for system improvements.

The Initial YEC System Improvements to be carried out as a result of the PPA are described in Schedule C and summarized in Table C-2 with an estimated capital cost of $1,677,883. Going forward YEC will not incur any substantial costs until the advance payment of 50% of the estimated capital costs has been received from VGC Group subsequent to YUB approval of the relevant PPA provisions. When the system improvements are completed, YEC will invoice VGC Group for the balance of the costs. As provided in the PPA, in the event the Initial YEC System Improvements exceed $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 work for the Initial System Improvements as set out in Schedule C and was an otherwise reasonably necessary increase in cost to complete the Initial YEC System Improvements.

Consistent with section 6.1(b) of the PPA, YEC has invoiced VGC Group in the amount of $838,941 for 50% of the estimated system improvements costs. Consistent with the same clause, these amounts have not yet been paid by VGC Group as payment is not due until 15 days after the YUB approval of the PPA.

TOPIC:

REFERENCE: **November 10, 2017 Application, Appendix, Section 6.1(c) and (d)**

PREAMBLE:

QUESTION:

a) Please provide details of all costs incurred to date and going forward related to the McQuesten Substation.

b) Please provide details of the invoices related to these costs that YEC has submitted to the VGC Group to date and how much has been paid to date.

ANSWER:

(a) and **(b)**

Detailed design of the McQuesten Substation was undertaken during 2017 pursuant to a contract between ATCO Power Canada Limited and VGC Group in the amount of $518,348.

- YEC paid VGC Group 50% ($259,000) of these costs to ensure the McQuesten Substation is designed to operate at the 138 kV standard required by YEC.

- Other costs incurred by YEC during 2017 equate to $120,000 for YEC Owner's Costs (labour and 3rd party engineering) to participate in and respond to the detailed design process. These costs are not considered recoverable from VGC Group as they pertain to YEC's requirement for the substation to have the ability to operate at the 138 kV standard.

During substation construction YEC is forecast to incur YEC Owner's Costs (see Schedule B, Table B-1) in the amount of $483,240 which are to be funded by VGC Group.

- Consistent with Section 6.1(c) of the PPA, YEC has invoiced VGC Group in the amount of $241,620 for 50% of the estimated YEC Owner's Costs for construction of the McQuesten Substation. Consistent with the PPA, payment is not due until within 15 days of the approval of the PPA by the YUB.

- The balance of YEC Owner's Costs will be invoiced by YEC to VGC Group after Commencement of Delivery and YEC has determined the actual owner's costs incurred and recoverable from VGC Group.

Under the terms of the PPA VGC Group will be responsible for constructing the McQuesten Substation. Please see response to YUB-YEC-1-13(a) for a review of estimated costs for the McQuesten Substation under each of the Transmission Facilities Development options.

YEC will incur only the YEC McQuesten Substation Costs related to construction for the substation to operate at 138 kV [estimated at $930,563]. Pursuant to section 6.1(d) of the PPA, YEC will pay this amount to VGC Group within 15 days after Commencement of Delivery when the substation is transferred to YEC by VGC Group. This is currently forecast to occur in 2019. As reviewed in the PPA Application (section 5.4, page 14), the above YEC McQuesten Substation Costs will be held in WIP until the Transmission Facilities Development Operation Date, and then included in the Transmission Facilities Fixed Cost per year that determine the Fixed Charge for VGC Group and any Other Industrial Customer using the Transmission Facilities.

Please see response to JM-YEC-1-2 for review of ATCO Power Canada Limited and its role in regard to the McQuesten Substation development project.

TOPIC:

REFERENCE: **November 10, 2017 Application, Appendix, Section 8.1**

PREAMBLE:

QUESTION:

a) Please explain why YEC is installing more than one revenue meter at the Point of Delivery.

b) Please explain how revenue meters having one hour integrating intervals will allow YEC to bill the VGC Group for electricity demand averaged over a rolling 15 minute period (per definition 1.1(k)).

ANSWER:

(a)

This is to ensure reliable metering. If one meter fails the backup meter can be used to record revenue.

(b)

The one hour measurement is for energy usage (kWh), the 15 minute measurement is for demand (kW). The meter is capable of measuring both.

TOPIC:

REFERENCE: **November 10, 2017 Application, Appendix**

PREAMBLE:

Table C-2 describes YEC's estimated capital costs for initial system improvements.

QUESTION:

a) Please identify which of the identified capital projects have been reviewed and approved by the YUB. Provide details of these reviews and approvals.

ANSWER:

(a)

The YUB does not "approve" capital projects.

The YUB reviews and approves in each GRA the capital project costs that can be included in rate base for the purpose of rate setting once capital projects are complete. Projects can only be included in rates once they are completed or "used and useful".

None of the Initial YEC System Improvements outlined in Table C-2 have been initiated (let alone completed), or reviewed to date by the YUB as part of a General Rate Application. The PPA provides that these costs will be fully funded by the VGC Group, and therefore will not have a net impact on YEC's future rate base.

Yukon Utilities Board

(YUB)

TOPIC: **Parties to the PPA**

REFERENCE: **Application, page 1**

PREAMBLE:

QUOTE:

"Yukon Energy Corporation ("Yukon Energy" or "YEC") is seeking an Order from the Yukon Utilities Board ("YUB" or "the Board") for required approvals related to the implementation of the Power Purchase Agreement ("PPA") that Yukon Energy has recently concluded with Victoria Gold Corp ("VGC") and StrataGold Corporation ("StrataGold") (VGC and StrataGold are collectively the "VGC Group")."

QUESTION:

a) Please explain the reason for a tripartite agreement between YEC, VGC and StrataGold.

b) Are the officers or directors of VGC and StrataGold the same persons? Please explain.

ANSWER:

(a)

StrataGold is a wholly owned subsidiary of Victoria Gold and holder of the quartz mining claims and major permits to build, operate and close the Eagle Gold project whereas Victoria Gold is the corporate parent company. Both Victoria Gold and Yukon Energy felt it was prudent to include all three parties to the agreement.

(b)

There is duplication between the directors and officers of Victoria Gold Corp. and StrataGold Corporation. Please see the list of directors and officers for Victoria Gold Corp. and StrataGold Corporation as noted in Table 1 below.

Table 1: Directors & Officers for Victoria Gold Corp. and StrataGold Corporation

Victoria Gold Corp	StrataGold Corporation
Directors:	**Directors:**
T. Sean Harvey, Chairman of the Board,	John McConnell
John McConnell, President & CEO	Marty Rendall
Mike McInnis	
Leendert Krol	
Chris Hill	
Heather White	
Patrick Downey	
Officers:	**Officers:**
John McConnell, President & CEO	John McConnell, President & CEO
Marty Rendall, CFO	Marty Rendall, CFO & Secretary
Mark Ayranto, EVP	Mark Ayranto, EVP
Anthony George, VP, Project Execution	
Paul Gray, VP, Exploration	

TOPIC: **Mine Facilities Spur**

REFERENCE: **Application, page 2**

PREAMBLE:

QUOTE:

"VGC Group's environmental permitting for the Mine includes provision for a 69 kV transmission line (the "Mine Facilities Spur") that, pursuant to the PPA, VGC Group will develop and own to connect the Mine Facilities to a substation (the "McQuesten Substation") to be located along YEC's existing 69 kV transmission line between Mayo and Keno City at approximately the junction of the South McQuesten Road and the Silver Trail Highway."

QUESTION:

a) Please confirm that VGC Group will be responsible for all future maintenance activities and the maintenance costs of the mine facilities spur.

ANSWER:

(a)

Confirmed. The Mine Facilities Spur will be owned and operated by VGC Group, and VGC Group will be responsible for all future maintenance activities and costs for this line.

TOPIC: **Stewart Keno City Transmission Project (SKTP)**

REFERENCE: **Application, page 2 and page 15**

PREAMBLE:

QUOTE:

"YEC has completed environmental review and permitting for the McQuesten Substation, as an element of the successfully completed Stewart Keno City Transmission Line Project ("SKTP") environmental review and permitting."

…

"YEC to complete Initial YEC System Improvements on YEC's existing power system to accommodate the sale of Grid Electricity for the Mine as provided for in Schedule C;"

…

"In order to accommodate VGC Group's timing for development, Grid Electricity will be supplied initially by YEC to the Mine from the existing Transmission Facilities located between Mayo and McQuesten Substation. The Parties recognize in the PPA that these existing Transmission Facilities are at, or near, their end of life and must be upgraded (the "Transmission Facilities Development") within approximately the next three years in order for YEC to reliably deliver Grid Electricity to the Mine Facilities."

…

"YEC's annual Transmission Facilities Fixed Cost forecast for the existing Transmission Facilities for 2019, including depreciation and return for YEC's transmission assets, is $118,621 as calculated in Attachment B of this Application based on forecasts for 2017."

QUESTION:

a) Upon completion in whole or in part of the SKTP, and assuming no external funding for the project, will any of the costs related to the SKTP be used in the calculation of the fixed charge to VGC Group? Please explain.

b) If the answer to (a) is yes, will any adjustments to the fixed charge occur, as work is capitalized, or will any adjustment have to wait for a subsequent YEC general rate application? Please explain.

ANSWER:

(a)

Yes, costs for the SKTP that are not otherwise externally funded will be used for the purposes of the calculation of the Fixed Charge to be paid by VCG Group or any other Industrial Customers served by the defined Transmission Facilities.

As specified in Section 7.7(b) of the PPA, potential costs that can affect the Fixed Charge include YEC depreciation and return on rate base related to the Transmission Facilities that are developed (i.e., the default Transmission Facilities Development), the SVC/Statcom at Stewart Crossing, and the YEC McQuesten Substation Costs.

Default Transmission Facilities Development

If no external funding is assumed for the SKTP, the Transmission Facilities Development will be constrained to the “default option” identified in the PPA Application (section 5.2 at page 12). Under the default option, the Transmission Facilities Development is assumed to include only the following[1]:

- New 138 kV Transmission Facilities for L180, located between the existing Mayo Substation and the new McQuesten Substation that is to be developed prior to Commencement of Delivery.

- This new line will be operated at 69 kV.

- This new line will replace the existing end-of-life L180 line, which will be removed.

[1] YEC may elect at this time, or at some future time, to proceed with additional new 69 kV or 138 kV facilities to replace the existing 69 kV line between McQuesten Substation and Keno City. Any such added development would be outside the defined Transmission Facilities relevant to the VGC Fixed Charge, as this segment of the Mayo to Keno City line is not required for providing service to the VGC Group Mine, and consequently would not have any impact on the VGC Group PPA Fixed Charge costs or provisions.

The Fixed Charge provisions are outlined in section 7.7 of the PPA and include provision to amend the Transmission Facilities Fixed Cost after the Transmission Facilities Development Operation Date based on YEC's adjusted annual costs as approved by the Board for depreciation and return on rate base related to the Transmission Facilities.

The Transmission Facilities Development Operation Date for the default option is expected in the PPA Application to occur by June 30, 2020.

YEC Potential Overall Added Rate Base Costs

YEC's potential added rate base costs, assuming no external funding for the SKTP, are assumed in the PPA Application ratepayer impact assessment (section 6.2, page 22) to approximate $25 million[2]. The following specific elements are assumed to be included in this added YEC rate base cost (totals $24.8 million per response to YUB-YEC-1-14):

- The Transmission Facilities Development default option for L180 138 kV line between Mayo Substation and McQuesten Substation (YEC estimated costs at $17.1 million, including any other related costs).

- SVC/ Statcom located at Stewart Crossing South Substation (YEC estimated costs at $6.57 million).

- The defined YEC McQuesten Substation Costs of $930,563 as per section 6.1(d) of the PPA and Schedule B of the PPA Application, plus YEC risk contingency of $0.170 million.[3]

The PPA Application reviews (section 6.2, page 22) potential impacts from an assumed $25 million added to YEC rate base for the above transmission development:

[2] Total estimated costs for the default option development, including the SVC/Statcom, are estimated at $32.20 million; excluding the portion of these estimated costs funded by VGC Group ($7.429 million), YEC's estimated costs are $24.8 million (see Table 1, response to YUB-YEC-1-14, for relevant details).

[3] See YUB-YEC-1-14, which shows total YEC McQuesten Substation Costs of $1.100 million. The PPA Application notes (section 5.4, page 14) that the YEC McQuesten Substation costs will be held in WIP until the Transmission Facilities Development Operation Date, and then included in the Transmission Facilities Fixed Cost per year that determine the Fixed Charge for VGC Group and any Other Industrial Customer using the Transmission Facilities.

- Transmission Facilities Fixed Cost impact of $1.650 million total annual costs in year 2 of asset in-service[4]; and

- Assignment of this annual cost while VGC Group mine is operating:

    - Fixed Charge (VGC Group/ Other Industrial Customers) at 85% = $1.402 million.

    - All ratepayers / general rates at 15% = $0.248 million.

(b)

The PPA specifies that any change to the Transmission Facilities Fixed Cost will need to be approved by the Board. Where feasible, this could occur as part of a General Rate Application proceeding; however, if needed to address this change on a timely basis after the work is capitalized, a limited scope proceeding would also be considered as a viable alternative in the event a full rate proceeding was not available to address this matter.

[4] Assumes 55-year average depreciation for the new rate base costs and 4.92% average return on YEC rate base per the 2017/18 GRA.

TOPIC: **Upgraded Transmission Facilities**

REFERENCE: **Application, page 2**

PREAMBLE:

QUOTE:

"In order to accommodate VGC Group's timing for development, Grid Electricity will be supplied initially by YEC to the Mine from the existing Transmission Facilities located between Mayo and McQuesten Substation. The Parties recognize in the PPA that these existing Transmission Facilities are at, or near, their end of life and must be **upgraded** (the "Transmission Facilities Development") within approximately the next three years in order for YEC to reliably deliver Grid Electricity to the Mine Facilities." [Bold font added]

QUESTION:

a) Please explain what is meant by an upgrade "to the existing Transmission Facilities located between Mayo and McQuesten Substation". Will these transmission facilities be replaced with transmission facilities to be operated at 69 KV or 138 KV? If the latter, please explain whether VGC would be responsible for incremental costs to convert the line to 138 KV and why.

ANSWER:

(a)

The referenced "upgrade" is new 138 kV transmission facilities that are to replace the existing facilities between Mayo and McQuesten Substation and to be operated at 69 kV or 138 kV.

As reviewed in section 4.3 of the PPA Application, 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 1950s.

At a minimum, the PPA recognizes the need to replace the Mayo-McQuesten portion of this line, which is at end of life and is considered the worst section of line between Mayo and Keno City. The PPA therefore specifies a default option for Transmission Facilities Development in the event that adequate external funding and approvals are not secured by September 30, 2018 to enable YEC to proceed with the full SKTP (with new 138 kV transmission facilities from Stewart Crossing to Keno City, and 138 kV operation for the line between Stewart Crossing and McQuesten Substation). The default option assumes new 138 kV Transmission Facilities for L180, located between the existing Mayo Substation and the new McQuesten Substation that is to be developed prior to Commencement of Delivery. This new line is to be operated at 69 kV under the default option (see response to YUB-YEC-1-3(a)), and will include a larger conductor than the current line, enhancing the line's ability to carry higher power loads. Rebuild of the L180 line will include brushing, adjustment and improvements in line location in many segments, replacement of end of life poles and equipment and improved access for future brushing and maintenance.

VGC Group does not require grid connection at 138 kV voltage; and as noted, while the L180 is being developed with 138 kV transmission capability, it will operate at 69 kV under the default option.

VGC Group responsibilities for any costs related to the above "upgrade" will depend on the Transmission Facilities Development option that is adopted, i.e., beyond costs that VGC Group is funding for the McQuesten Substation, VGC Group will only be exposed to specific costs for these new facilities under the default option. As reviewed in response to YUB-YEC-1-3(a), under the default option VGC Group's Fixed Charge will be increased to reflect 85% of YEC's annual fixed costs for the Transmission Facilities Development (including incremental costs to provide 138 kV capability versus only 69 kV capability). VGC Group's specific added costs will depend on whether there are any Other Industrial Customers also using the Transmission Facilities.

TOPIC: **McQuesten Substation Capital Costs**

REFERENCE: **Application, page 2; VGC PPA, Schedule B, Memorandum of Understanding, Workplan Assumptions, 1. Funding**

PREAMBLE:

QUOTE:

"Except as otherwise specified in the PPA, VGC Group is responsible for all capital costs related to the McQuesten Substation development."[1]

"The PPA provides in Section 6.1 for YEC to recover from VGC Group its reasonably incurred YEC Capital Costs for the following:

…

YEC's **capital** costs for the McQuesten Substation development ("YEC's Owners Costs") as specified in Table B-1 of Schedule B to the PPA;" [Bold font added][2]

"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." [Bold font added][3]

[1] VGC PPA Application, page 2.
[2] VGC PPA Application, page 3.
[3] VGC PPA, Schedule B, Memorandum of Understanding, Workplan Assumptions, 1. Funding.

QUESTION:

a) Please explain why YEC is responsible for incremental fees, costs and expenses associated with the McQuesten Substation being able to operate at 138 kV. Why is VGC not responsible for all substation costs?

b) Please explain why the line from Stewart Crossing to Keno City is to be converted to 138 kV.

c) Does the provision of a 69 kV transmission line provide enough Grid Electricity to the McQuesten Substation for the mine to operate with the Alexco load?

d) With respect to the McQuesten Substation, in addition to the mine spur, will the substation provide electricity for the remainder of the line from the substation to Keno City at 69 kV?

ANSWER:

(a)

The McQuesten Substation Capital Costs funded by YEC (i.e., the YEC McQuesten Substation Costs) relate to incremental fees, costs and expenses associated with the McQuesten Substation being able to operate at 138 kV voltage. This feature is not required today for VGC Group to connect to the grid, but is required with both of the identified Transmission Facilities Development options. Yukon Energy is providing the initial funding as needed to ensure that these features are cost-effectively included in the initial substation design to accommodate 138 kV transmission that is planned for the Transmission Facilities Development new 138 kV line that will connect McQuesten Substation with either the Stewart Crossing South Substation (full SKTP development option) or with the existing Mayo substation (the default development option).

As reviewed in the PPA Application (section 5.4, page 14), the above YEC McQuesten Substation costs will be held in WIP until the Transmission Facilities Development Operation Date, and then included in the Transmission Facilities Fixed Cost per year that determine the Fixed Charge for VGC Group and any Other Industrial Customer using the Transmission Facilities.

Please see also response to YUB-YEC-1-17(c).

(b)

Conversion of the line from Stewart Crossing to Keno City to 138 kV operation will only occur under one of the Transmission Facilities Development options addressed in the PPA, i.e., the full SKTP development option that is dependent on confirming necessary external funding and approvals for proceeding with the development option by September 30, 2018. This full conversion will not occur under the default Transmission Facilities Development option (see response to YUB-YEC-1-3(a)).

The SKTP as submitted for YESAB review was designed to reinforce and strengthen the grid between Stewart Crossing and Mayo, as well as between Stewart Crossing and Keno City, ensuring that future potential loads within the area can be better supplied.

- The proposed improvements to the integrated system along this line segment will extend Yukon's existing 138 kV grid capability 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.

- Proceeding to install a 69 kV transmission line between Mayo and Keno City would not provide the added capacity that could be required in future to accommodate additional industrial loads and/or renewable generation developments in the area between Mayo and Keno City.[4] In effect, proceeding to install a 69 kV transmission option 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.

[4] The SKTP Proposal to YESAB (Chapter 6 on Project Description) stated that 138 kV transmission line capability could be required to serve one or more of the potential future mine loads in pre-development in the vicinity of the Keno Hill area, e.g., VGC Group Mine was one such potential future mine load. The SKTP Proposal also noted the option to install at 138 kV capability but operate at 69 kV capability until loads warranted the added costs to convert Mayo or other existing substation facilities (as well as incur added costs for related PT site facility requirements needed with 138 kV operation).

- The SKTP as submitted to YESAB included provision for the McQuesten Substation, and the assumption that the new 138 kV McQuesten-Keno City segment would operate at 69 kV until such time as added loads in this segment justified operation at 138 kV with related requirements for Keno City substation enhancement as well as PT installation at various existing connections along this segment.

(c)

The Transmission Facilities Development, including the default option with operation at 69 kV, will be able to provide enough Grid Electricity to the McQuesten Substation for the VGC Group mine to operate with the Alexco load; however, the existing 69 kV line is not able to meet this test. Please see more detailed review below.

The existing 69 kV transmission line does not enable YEC, with Alexco in operation, to supply all of the forecast VGC Group requirements. As reviewed in section 5.3 of the PPA Application (page 12), and as addressed in Section 5.1 of the PPA, the Maximum Electric Demand that YEC is required to deliver to VGC Group with the existing 69 kV facilities is 10,100 kVA. Under these conditions, VGC Group will likely need to operate its on-site generators from time to time to meet some of its load, i.e., the peak load forecast for the VGC Group Mine is 10,400 kVA in year 1 of operation, rising to 11,900 kVA in year 2 and to 13,300 kVA in year six of operations.[5]

After the Transmission Facilities Development Operation Date, the Maximum Electric demand that YEC is to deliver to VGC Group, with Alexco in operation, is 14,300 kVA, reflecting the improved grid capabilities secured with this development (regardless as to operation at 69 kV or 138 kV) and the expectation that the new specified limit is approximately 1.0 MVA higher than the VGC Group forecast peak Electric Demand in year six of operation. (See Section 5.3 of the PPA Application, page 13, and section 5.1 of the PPA.)

(d)

Yes, the McQuesten Substation will provide electricity at 69 kV for the remainder of the line between McQuesten and Keno City under both of the Transmission Facilities

[5] See footnote 17 in the PPA Application.

Development options considered in the PPA Application. Over the long term, when loads justify such a change, the McQuesten Substation can be re-configured to provide electricity at 138 kV all the way to Keno City.

TOPIC: **New 138 kV Transmission Facilities**

REFERENCE: **Application, page 3**

PREAMBLE:

"If such external funding cannot be committed by September 30, 2018, YEC will seek approval for plans to provide the required Transmission Facilities Development by June 30, 2020 with new 138 kV Transmission Facilities connecting Mayo and the McQuesten Substation, to be operated at 69 kV until such time as 138 kV operation becomes feasible, i.e., a 138 kV line is developed to connect Mayo with Stewart Crossing."

QUESTION:

a) Please describe any impacts or effects of operating a 138 kV line at 69 kV.

b) When operating a 138 kV line at 69 kV, what is the impact on line losses? Please provide documentation in support for your response.

c) If operating a 138 kV line at 69kV results in higher line losses than operating a 69 kV line at 69 kV, then how would YEC account for those additional losses? How and to whom would those incremental losses be attributed? Specifically, would any particular rate class or customer pay for the incremental line losses?

ANSWER:

(a)

There is no positive or negative impacts to the transmission line or substations when operating a 138 kV line at 69 kV, beyond any impacts on line losses (see (b) below).

(b)

The difference in line loss for the Mayo to McQuesten Substation transmission segment between 138kV and 69kV operation with the same 138 kV capable transmission conductor required for the planned load is marginal at around 0.4%.[1] There is not a significant difference in losses in part because the distance is short, at around 35km.

In the case of the default option, added conductor capability is required on this segment to meet the planned load with VGC Group and Alexco, but 138 kV operation of this segment would require added YEC capital costs for the Mayo substation conversion to 138 kV capability (as well as requiring VGC Group to install the Step Down Transformer at McQuesten Substation). Due to the short distance for this segment and the marginal benefit gained from 138 kV operation allowing reduced line losses, it was concluded that the optimum approach for the default option was to retain 69 kV operation.

(c)

As reviewed above, operating a 138 kV line at 69 kV with the conductors as planned will not result in a material change in line losses. No assessment has been done of the extent to which line losses will change with the new facilities versus the existing facilities.

YEC does not plan to account for, or attribute to any party, any variation in line losses from operation of this line at 69 kV. Line losses for all bulk power generation and transmission are pooled for reporting and cost of service assessments related to each customer class, and therefore no particular rate class or customer will pay for these specific incremental line losses.

[1] Detailed documentation has not been developed for this estimate, which reflects review of available information. The analysis developed during the planning studies did not investigate this line loss issue in detail, given the assessment that there was no apparent prospect that 138 kV operation for the default option would be cost effective, given the anticipated minimal benefits (through reduced line losses over this short distance) versus the added capital costs need for the Mayo Substation facilities.

TOPIC: **Transmission Facilities Fixed Cost**

REFERENCE: **Application, page 3, Board Order 2010-13 Appendix A, paragraph 29**

PREAMBLE:

QUOTE:

“The PPA provides for VGC Group to pay the Firm Mine Rate as approved by the Board from time to time, including a Fixed Charge that is adjusted on an ongoing basis to equal 85% of the Transmission Facilities Fixed Cost as approved by the Board from time to time to reflect changes in YEC rate base costs for the Transmission Facilities.” (Application, page 3)

…

“29. <u>The Board notes that the last COS study approved by the Board was completed in 1997</u>. <u>The Board does not accept the COS study as filed by the Companies.</u> The Board agrees with the City of Whitehorse’s view that an updated COS study approved by the Board is essential to establishing a future rate restructuring process. 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.” (Appendix A to Board Order 2010-13, underlining added)

QUESTION:

a) Please describe how the 85% threshold was determined.

b) If the threshold was determined in the past (for example, when the Faro mine was operating), please explain why that level continues to be applicable today.

c) How does the 85% threshold level account for the development of the Carmacks-Stewart Transmission Project (CSTP) Phases 1 and II?

d) How does the 85% threshold level account for the development of the Stewart-Keno Transmission Project (SKTP).

e) When was the last Board-approved COS study?

f) Given your responses to the above, and if the last approved COS study was completed prior to 1999, please explain why the Board should accept the 85% threshold as stated in the PPA.

g) If the Board does not accept the 85% threshold and suggests a different threshold, what is the impact on the PPA?

ANSWER:

(a) and **(b)**

The 85% threshold was determined based on the Board's approved threshold for the only other major industrial customer that YEC has served from the Mayo to Keno City transmission facilities (i.e., Alexco Resources). The VGC Group mine is to be supplied by YEC using these same transmission facilities between Mayo and McQuesten, and the PPA with VGC Group retains consistency with the Alexco PPA 85% threshold as previously approved by the Board.

Yukon Energy is not aware of any change in conditions or circumstances that would justify adopting at this time a threshold for the use of these transmission facilities to supply the VGC Group mine that differs from the 85% threshold applicable to Alexco major industrial customer purchases.

The Board reviewed the basis for this 85% threshold at the time when the Alexco PPA was reviewed and approved (Board Order 2010-14).

As reviewed in Board Order 2010-14, although Alexco's share of the forecast load was expected to be approximately 98% of the load going through the transmission facilities as defined in the Alexco PPA (i.e., YEC's 69 kV transmission between Mayo and Keno City, or any future replacement transmission facilities at similar or higher voltage), the proposed 85% share in the Alexco PPA was based on the NEB 1985 NCPC Report findings regarding the Faro mine. The Board noted that YEC had reported at page 4 of its Alexco PPA application that, in the case of the Faro mine, Faro's share of the defined line's load (i.e., the NCPC 138 kV line between Whitehorse and Faro) was approximately 96.8%.

The original justification for the 85% direct cost allocation of transmission costs was provided in relation to the Faro mine [CAMC] in the 1985 NEB Report. A copy of Chapter 7 of this Report where the matter was addressed in Section 7.3.4.2 is provided as Attachment 1 to this response. This attachment outlines the NEB's rationale for the cost allocation to the CAMC mine of 85% of the Whitehorse to Faro transmission facilities' annual fixed costs. The NEB decision allocated the remaining 15% of the NCPC costs among all customers, including industrial customers, based on their respective demands.

As reviewed in the Alexco PPA proceedings, the following prior YUB decisions have accepted this precedent:

- **1992 Report on Cost of Service and Rate Design** - In the 1992 Cost of Service [COS] and Rate Design Review, the Companies relied upon the rationale provided by the NEB to determine the proportion of this asset to be assigned specifically to the industrial class (i.e., the Faro mine). It was noted during the 1992 COS and Rate Design review that "inasmuch as the Whitehorse/Faro transmission line was constructed specifically for the purpose of servicing the Faro mine operated by Cyprus Anvil, a substantial portion of the cost of the line should be allocated to the industrial class" (at page 26). At page 29 of the Report, the Board recommended that the appropriate method of allocating transmission costs is to specifically assign 85% of the costs of the Whitehorse/Faro line to Curragh, and to allocate all remaining transmission costs to all customer classes including Curragh, on the basis of demand at the time of system peak.

- **Order 1993-8** - The Board determined that there were no changes in circumstances that warrant changes to the cost of service or rate design principles from those established in the 1992 Cost of Service hearing and that that methodology and rate design proposed by the Companies was appropriate.

- **Order 1996-7** - In the 1996/97 GRA, the then current Faro mine owner (Anvil Range Mining or ARM) argued that as a new company, it should not be subject to the specific cost allocations applied in the past, noting that the transmission line was not designed specifically for ARM, is fully depreciated and the rate level should therefore reflect the current cost of the line. The Companies at that time argued that the vintage of the customer was irrelevant to the COS and that there were no changes in circumstances to justify a review or revision of the methodology from that established in the 1992 Report. The Board in 1996 agreed that this allocation conforms to similar practices in Canada and the assignment of 85% specifically to the industrial rate class was based on usage and not related to the vintage of the customer since in the absence of the mine load the line would not have been built (see page 4-5 of Order 1996/7).

- **Order 2010-14 and Order 2011-1** - In its review of the Alexco PPA Fixed Charge, the Board concluded that the precedents cited by YEC provide some support for the direct transmission allocation (85%) as applied for. The Board agreed with the submission of YEC that the Mayo-Elsa-Keno transmission line was originally constructed to serve a mining customer at what is currently known as the Alexco site. The Board noted that no other alternatives had been presented (in terms of allocation of transmission costs through fixed charges) in this proceeding; and the comparison to the Faro situation when determining fixed charges for transmission line costs is the best available evidence for this proceeding. The Board approved the fixed charge to Alexco of $7,289 per month; and concluded that the single fixed charge will apply to what is defined in the PPA as the District, that is, independent of the number of Points of Delivery.

(c)

The 85% threshold is based on industrial customer share of the load on the relevant transmission segment [i.e., for Alexco and VGC Group this relates to the Mayo to Keno Transmission line segment; for Faro this related to the Whitehorse to Faro transmission line segment].

As demonstrated by the Faro mine precedent, the relevant transmission segment for the 85% threshold relates to clear evidence of development and use specifically for industrial load purposes. The Whitehorse-Faro segment of the NCPC 138 kV transmission for which the 85% threshold applied clearly met these requirements, with the Faro mine's share of the defined line's load (i.e., the NCPC 138 kV line between Whitehorse and Faro) exceeding 95%. The Faro mine also relied on the balance of the WAF 138 kV transmission from Aishihik to Whitehorse, and these facilities had also been developed in response to the opportunities created by the Faro mine load. However, unlike the Whitehorse-Faro segment of the WAF grid, the Aishihik-Whitehorse segment was also used to supply material other loads (including the Whitehorse load) and therefore no similar fixed charge threshold for the Faro mine was applied to the Aishihik-Whitehorse transmission segment.

The Alexco PPA's 85% threshold similarly reflected the defined line's development and predominant use to supply the industrial load. Applying this same 85% threshold to the VGC Group mine load for use of the same transmission facilities ensures consistent treatment of industrial loads using these facilities (with provision for allocating the same 85% between these industrial loads when both mines are operating concurrently).

In the context of the VGC Group and Alexco mine loads, the CSTP Phase 1 and 2 developments were established to enhance overall grid capabilities rather than to supply specific mine loads. As initially established, the full CSTP enabled connection of the WAF and Mayo Dawson grids, and thereby supported the Mayo B hydro enhancement development in order that this renewable hydro could enhance supplies on the CSTP and WAF (forecast loads on the Mayo Dawson grid at that time were not sufficient to support this project's development). Accordingly, there is no basis to consider assigning any specific fixed cost share of the CSTP facilities to the VGC Group or Alexco mine loads.

(d)

The SKTP development, in whatever form it proceeds, will act to replace the end-of-life existing transmission facilities between at least Mayo and McQuesten.

The 85% threshold for the Alexco mine PPA is applicable to YEC's 69 kV transmission between Mayo and Keno City, or any future replacement transmission facilities at similar or higher voltage. Accordingly, the Alexco and VGC Group PPA provisions for the 85% threshold extend to SKTP facilities at 138kV voltage that replace the relevant Mayo to Keno City existing transmission.

The VGC Group PPA addresses treatment of the following potentially different forms of SKTP development:

- At a minimum, replacement of the line between Mayo and McQuesten Substation (any YEC fixed costs for this new facility would be subject to the 85% threshold for VGC Group and Alexco).

- Potential development of 138kV facilities from Stewart Crossing to McQuesten Substation is also addressed, as such development would replace the then existing 69kV transmission between Mayo and McQuesten Substation; however, this expanded development is contingent on securing adequate government funding contributions such that YEC fixed costs related to these facilities would at most be minimal.

- Replacement of the 69kV line between McQuesten and Keno City, when it occurs, will not affect the 85% threshold or fixed charge applicable to the VGC Group mine (as these facilities are not used by YEC to supply power to this mine).

(e)

The last Board approved Cost of Service was filed as part of the 1996/97 GRA.

Subsequent to the 1996/97 GRA, YEC and YECL completed and filed with the Board a Cost of Service Study as part of the 2009 GRA Phase II proceeding, including a revised version as part of the Compliance Filing in that proceeding, that was not approved. Please see response to YUB-YEC-1-8 for more detailed review.

(f)

The Board in Order 2010-14 approved the 85% threshold in the Alexco PPA. This approval occurred after Board Order 2010-13 had rejected the Cost of Service study filed by YEC and YECL as part of the 2009 GRA Phase II proceeding, confirming that the 85% threshold's determination and approval for PPA purposes can be addressed on its own merits without the need for integration with a full cost of service study. On the same basis, the Board today would be consistent with Board Order 2010-13 in proceeding to approve the 85% threshold for the VGC Group PPA notwithstanding the absence of a recent approved cost of service study.

Additional supporting material on this matter is provided below.

The NEB report recommendation in 1985 regarding fixed transmission charge allocation to the Faro mine of 85% was based on the Faro mine share of the load on the relevant transmission segment (from Whitehorse to Faro) for which the fixed costs were being allocated to the Faro mine. It was not based not based on COS study results.

In the 2010 Alexco PPA proceeding the following were specifically noted in this regard:

- The 2009 Phase II hearing noted in relation to the 1996/97 COS that the Faro Mine was approximately 43% of the energy on the overall Yukon system and 29.99% of demand on the overall Yukon system. However, such shares had no bearing on the NEB report recommendation.

- The 2010 Alexco PPA proceeding noted that based on Mayo Dawson approved forecast loads for 2009 (see Tab 2 of YEC 2008/2009 GRA) and Alexco loads per the PPA, the Alexco loads were expected to approximate one third of the Mayo Dawson system energy sales and demand. Such shares had no bearing on the PPA determination of the Alexco Fixed Charge, i.e., that charge was determined as set out in Attachment B to the PPA Application, based on the Alexco share of the load on the relevant transmission segment (from Mayo to Keno) for which the fixed costs were being allocated to the Alexco facilities.

(g)

The 85% threshold is a key element of the VGC Group PPA for which Yukon Energy is seeking Board approval. Absent such approval, a key precondition to the PPA would not be met, and VGC Group and YEC would need to review and determine on what basis (if any) they might be able to continue with a revised PPA.

Removal or reduction of the 85% threshold and related Fixed Charge would reduce costs assigned to VGC Group and increase costs to be recovered from all other ratepayers, and create inconsistencies with the approved Alexco PPA and with the earlier Faro mine threshold and fixed charge.

Increase of the 85% threshold and related Fixed Charge would increase costs assigned to VGC Group and reduce costs to be recovered from all other ratepayers, and create inconsistencies with the approved Alexco PPA and with the earlier Faro mine threshold and fixed charge.

Chapter 7
Fully Distributed Cost of Service Study

7.1 Introduction

The Board, in its August 1983 report, recommended that NCPC design cost-based rates. To design cost-based rates for an electric utility it is necessary to perform a fully distributed cost of service study.

7.1.1 Fully Distributed Cost of Service Study

The purpose of a fully distributed cost of service study is to allocate the net revenue requirement of a rate zone to specific customers and to the various customer classes in the zone. The costs allocated in this manner are then used in the design of cost-based rates for each class. The cost of service study is based on the principle that all utility costs can be either directly assigned to specific customers or related to demand, energy and customer components.[1] The basic tasks to be performed in such a study consist of functionalizing, classifying and allocating costs.[1]

The general procedures followed by NCPC in developing its test year cost of service study as described in its submission are as follows:

1. Total operating costs (excluding allocated head and regional office costs) were compiled and the rate base was identified for each proposed rate zone, i.e., Yukon hydro, Yukon diesel, NWT hydro, NWT diesel and Field, B.C.
2. Head office and regional office administration revenue requirements were allocated to the rate zones and to the various electrical, heat and water & sewage utilities on the basis of forecast direct salaries and wages.
3. Costs and rate base associated with the nonelectric utilities (heat and water & sewage services) were either directly identified or allocated to the nonelectric utilities.
4. Estimates of street lighting costs and associated rate base were compiled and the costs were assigned directly to the street lighting customer classification in each rate zone.
5. After removal of nonelectric and street light related costs and rate base, all remaining electric utility costs and rate base, including the allocated head and regional office costs for a rate zone, were functionalized, where possible, into the following categories: production, transmission, distribution, support facilities, plant administration and general expenses, employee facilities, and depreciation.
6. The functionalized costs and rate base were then classified to demand, energy and customer components taking into consideration, insofar as practical, standard industry practices as outlined in the National Association of Regulatory Utility Commissioners (NARUC) "Electrical Utility Cost Allocation Manual" and the American Public Power Association (APPA) "Cost Allocation Manual" and the recommendations contained in the Price Waterhouse Associates "Report on the Review of the Cost of Service Methodology" which was commissioned by NCPC. A tabulation of the classification factors used and the rationale supporting them were included in the submission. In several instances, judgement was required on NCPC's part to derive a reasonable estimate of an appropriate classification factor.
7. Where specific assets have been provided to serve a particular customer or customer class, depreciation and rate base were assigned directly to that customer or customer class.
8. All costs classified as demand, energy and customer were then allocated to each customer class, based respectively on each customer class' noncoincident peak demand, kW.h sales plus losses and weighted number of customers. (The weighted number of customers is used so that the additional expense of serving a large industrial or wholesale customer as compared with a residential customer is recognized.)
9. The total revenue requirement for each customer class or specific customer is the sum of:

1 These terms are defined in the definition section of this report.

allocated demand costs;
allocated energy costs;
allocated customer costs;
specific charges; and
allocated return on rate base; less
allocated miscellaneous revenue credit.

The Board's findings regarding the procedures used by NCPC in its fully distributed cost of service study are provided in the succeeding sections of this chapter. The results of the Board's recommendations are summarized in Tables L-1 to L-7 in Appendix L.

7.1.2 Accounting System

The financial information required for a cost of service study is obtained from the accounting records of an electric utility. NCPC testified that there is no uniform system of accounts for electric utilities in Canada and that the Commission believed that each individual utility in Canada has devised an accounting system best suited to its own situation. The Commission stated that its accounting system is one that developed over time and, although suitable to conduct its operations under the NCPC Act, would nevertheless require some revisions in order to make it more useful for cost of service study purposes.

The Board recognizes that such revisions are complex and would require considerable resource commitments. Nevertheless, the Board encourages NCPC to make the necessary improvements so that costs can be more readily identified by functional and sub-functional categories and segmented in such a way as to be more useful for allocation purposes. Such changes should be instituted at the beginning of a fiscal year.

7.1.3 Allocation of Head and Regional Office Costs to Rate Zones

NCPC's proposed method for allocating head and regional office costs to each rate zone and the Board's recommendations thereon are discussed in Sections 6.6 and 6.7.

7.2 Functionalization Procedures

Intervenors did not express any serious objections regarding the functionalization procedures used by NCPC in its submission. Suggestions were made, however, that NCPC consider making at least the following improvements in the future. It was suggested that, in the hydro rate zones, NCPC should show separately the net plant in service of the hydro assets and the diesel assets rather than grouping them. Distribution-related assets and costs should be sub-functionalized so that assets and costs, such as meters and meter maintenance, which are related solely to serving customers, can be assigned specifically to that classification. Further, demand-related distribution assets and costs should be sub-functionalized to differentiate between services provided at primary and secondary voltage levels. In addition, customer accounting expenses including meter reading, customer service and informational expenses, and sales expenses which vary with customers should be shown separately and should be classified entirely to the customer cost component.

The Board encourages NCPC to make the necessary modifications to its accounting system to accommodate the above suggestions.

7.3 Classification Procedures

The principal issues addressed during the inquiry regarding NCPC's classification procedures were:

1. NCPC's decisions to classify:
    - production rate base in each hydro rate zone 100 percent to demand,
    - production operating costs 95 percent to demand and 5 percent to energy, and
    - distribution assets and costs 80 percent to demand and 20 percent to customer; and
2. the assignment of specific charges to specific customers.

7.3.1 Production Rate Base

On the recommendation of Price Waterhouse as set out in its report to NCPC, the Commission classified its entire production net plant in service 100 percent to demand in each rate zone. The rationale for assigning all production-related facility costs to demand is that these costs, which are incurred to meet capacity requirements, are fixed costs and do not vary with the energy produced by the facility.

Only YTG took exception to NCPC's proposal to classify production assets 100 percent to demand. An expert witness for YTG stated that most Canadian utilities recognize that generation is put in place to meet energy as well as capacity needs and that if generation were only in place to meet capacity it would be installed at minimal cost, i.e., diesel generators or gas turbines would be used. He further stated that the reason more expensive capacity such as hydro is installed is to provide lower cost energy than is possible using diesel generators or gas turbines.

In his direct evidence, the witness indicated that the significance of overemphasizing demand in cost classification is that such an approach penalizes customer classes with lower than average load factor.

He went on to cite a number of utilities in southern Canada; namely, Ontario Hydro, B.C. Hydro and Manitoba Hydro, which he indicated classify at least 50 percent of their production assets to energy. (It was noted that all of these utilities have sizeable investments in hydro assets.)

He explained that B.C. Hydro uses what he thought could be called a plant factor method to classify production rate base to demand and to energy. He indicated that this method takes the demand imposed on a particular plant at the time of the system's peak and compares that to the average load that the generating plant unit puts forth during the year. He stated that, if applied to Whitehorse No. 4, this method would assign the production rate base 100 percent to energy. He noted, however, that other methods employing plant factors might not lead to that type of result.

He concluded by stating that, at least for the first inquiry into cost-based rates for NCPC, there is merit in a simplistic approach as opposed to one in which a number of plant factors must be justified. He suggested that a simple middle of the road approach that would assign 50 percent to demand and 50 percent to energy might be appropriate.

The expert witness for CAMC stated that the objective of any cost allocation process should be to come up with a fair allocation of costs between high and low load factor customers. This witness indicated that a criticism of the plant factor method is that it causes volatility of pricing because the plant factors of each plant change over time as the system evolves. Thus, the plant factor method can yield allocation factors which vary from year to year.

NCPC testified that it saw merit in moving away from its 100 percent demand classification and assigning perhaps 20 percent of the production asset costs to energy in the hydro rate zones.

The expert witness for Cominco supported NCPC's position. He stated that, based on his experience, he would generally be more comfortable with the 80/20 split suggested by NCPC than with the 50/50 split suggested by the witness for YTG.

Based on the evidence, the Board is of the view that production-related assets in rate zones with large hydroelectric components should not be classified entirely to demand. For the test year, the Board has used the 80 percent demand 20 percent energy split suggested by NCPC in designing cost-based rates in the hydro rate zones.

With respect to the diesel rate zones, the Board notes that no intervenor objected to NCPC's classification of production plant 100 percent to demand. The Board finds this classification acceptable.

7.3.2 Production Operating Expenses

NCPC classified production operating expenditures as being 95 percent demand-related and 5 percent energy-related based on the recommendations contained in the Price Waterhouse report. The APPA Cost Allocation Manual indicates that the classification of operating expenses to cost components generally follows the same classification that is determined for the electric plant function. Production expenses can therefore be classified to demand and energy in accordance with the classification of production rate base to demand and energy.

Since the Board recommends classification of production rate base in the hydro rate zones 80 percent to demand and 20 percent to energy for the test year, the Board also finds it appropriate to similarly classify production operating expenses.

7.3.3 Distribution Rate Base and Expenses

In its submission, NCPC classified distribution assets and expenses as 80 percent demand-related and 20 percent customer-related with no differentiation between primary and secondary levels of service. The NARUC Electric Utility Cost Allocation Manual suggests that distribution costs may be split between demand and customer classifications using one of several acceptable methods, including the minimum intercept and minimum size methods.

The APPA manual describes the minimum intercept method as one which seeks to identify a common investment per customer made in a line transformer related to a no-demand situation. All additional investment costs for a transformer would be related to demand requirements. The minimum size method assumes that the current cost of installing the minimum size pole, conductor, transformer, etc., is reflective of the customer-related portion of investment in distribution plant.

NCPC did not utilize any of the methods suggested in the NARUC manual. The Commission based its customer classification percentage on an examination of NCPC's distribution facilities, with 12 percent being identified as associated with customer metering and an additional 8 percent added to cover service drops and associated equipment.

YECL, in its direct evidence, explained the method it uses to identify an appropriate customer cost. Expert witnesses for other intervenors were generally more in favour of YECL's analysis because they were of the view that this method is less arbitrary than NCPC's approach.

Cominco's expert witness, when asked if an allocation of 50 percent demand and 50 percent customer would be more reasonable than an 80/20 split in the absence of a more detailed analysis, indicated that he would prefer the 80/20 split. He felt that 50/50 would classify too great a proportion of distribution costs as customer-related. He stated that where distribution systems are fairly concentrated such as those of NCPC in the Northwest Territories, i.e., people are living in small communities and not on farm roads at intervals of a mile apart, the customer component of distribution costs is apt to be rather small.

The Board is persuaded by the evidence to accept NCPC's classification of distribution rate base and expenses for the test year, but recommends that in the future NCPC use a more systematic approach to determine classification factors for the distribution system and that direct assignment and primary/secondary cost separations be made where appropriate.

7.3.4 Specific Charges and Credits

7.3.4.1 Specific Charges

The criterion used by NCPC in assigning assets to specific customers for the purpose of levying special charges was that assets that could reasonably be determined to be for the sole use of a particular customer or particular customer class were charged directly to that customer or class. Assets that fall into this category are facilities installed for a particular customer's need (e.g., the diesel plant installed at Pine Point, NWT for Pine Point Mines Limited's 10 MW electric dragline operation) as well as substation facilities serving individual customers.

In its submission, NCPC did not assign transmission lines to specific customers or classes. Under the proposed rate zone scenario, all transmission facilities within a rate zone were assumed by NCPC to be interconnected. In light of this assumption, NCPC considered it would be inappropriate to charge specific portions of the transmission system to individual customers as this would contradict its theoretical assumption that all consumers, regardless of location in the rate zone, share the same general production and transmission facilities.

7.3.4.2 Specific Charges to Cyprus Anvil Mining Corporation

YECL questioned the reasonableness of the test year specific charges of $8,231 assigned by NCPC to CAMC. YECL filed an extract from NCPC's 1982 filing with the Yukon Electrical Public Utilities Board which identified, for the fiscal year 1982/83, some $845,000 of interest and depreciation associated with assets that appeared to have been specifically assigned by NCPC to only CAMC. A review of the evidence presented in the Board's 1983 inquiry revealed that only $491,635 of the total $845,000 had actually been assigned to CAMC, the remainder having been assigned to various locations served by YECL and to the Town of Faro.

NCPC, when asked what other assets might have been specifically assigned for the test year if it had not taken the approach of considering the two Yukon hydro systems to be interconnected, identified the following assets:

1. the 138 kV transmission line from Takhini substation, just outside of Whitehorse, to Faro would be partially assigned to Carmacks, Town of Faro, CAMC, and Ross River;
2. the 5.2 MW generating plant at Faro would be assigned as a stand-by unit for the Town of Faro and CAMC. As well, it could be partially assigned to Ross River because NCPC could energize that line with that unit; and
3. the Faro to Ross River transmission line would be fully assigned to Ross River.

NCPC stated that if it had not assumed the hydro systems to be interconnected, specific assignments also could have been made in the Mayo system. The line from the Mayo plant to Keno City and to United Keno Hill Mines would be considered a lateral supply and it would have been assigned partly to United Keno Hill Mines and partly to YECL at Keno City.

NCPC outlined further that, in the NWT hydro rate zone, the 138 kV line between Fort Smith and Pine Point could have been assigned to the Town of Pine Point and to Pine Point Mines, and the portion of the line from Pine Point to Fort Resolution could have been assigned to Fort Resolution.

The Board believes that, in the absence of contractual arrangements, established Commission policy, or regulatory decisions requiring a particular customer or group of customers to bear the cost of a new facility, be it a generating facility, transmission line or part of a distribution facility, the annual costs of such facilities should be included in the pooled costs to be allocated to all customers in the rate zone.

Nevertheless, the Board believes that, in light of the circumstances surrounding the construction of the

Whitehorse to Faro transmission line and the 5.2 MW diesel engine at Faro, a significant portion of these assets should, as was done in the past, be specifically assigned to CAMC.

With respect to the 5.2 MW diesel generating unit, the Board is of the view that the annual costs of this unit should be assigned only to CAMC and the communities of Faro and Ross River as it provides no benefits to the other customers in the Yukon hydro rate zone. However, the Board notes that this unit, constructed in 1972, was depreciated using an estimated life of 10 years and therefore was fully depreciated prior to the test year.

Turning to the Whitehorse to Faro transmission line, a review of the 1983 inquiry's transcripts indicate that Whitehorse No. 3 and the transmission line to Faro were built in 1969 as a consequence of an agreement between CAMC and the Government of Canada to build a mining facility at Faro. NCPC was designated to provide some 9.3 MW of additional capacity to supply the new mining operation and to construct a transmission line from Whitehorse to Faro. The Board is doubtful that, in the absence of instructions from the federal government to do so, NCPC would have constructed a 288-kilometre transmission line without requiring some form of guarantee to ensure that existing customers would not be burdened with the cost of this facility if the mine were to shut down.

Further, it would appear that, when the mine was operating, CAMC was assigned in excess of 95 percent of the annual costs of the transmission line with the remaining costs being assigned partly to the towns of Faro, Carmacks, and Ross River. For the fiscal year 1983/84, the annual costs assigned by NCPC to each location and to CAMC are shown in Table 7-1.

Table 7-1

Whitehorse to Faro Transmission Line
Allocation of Annual Costs by NCPC

	1983/84 Annual Cost	Percentage
CAMC	$287,943	96.8
Ross River	1,174	0.4
Carmacks	676	0.2
Faro Townsite	7,623	2.6
Total	**$297,416**	**100.0**

Source: NEB Inquiry EHR-1-83, Exhibit 41.

Because of the unusual circumstances surrounding the construction of the transmission line from Whitehorse to Faro, wherein NCPC, as a result of an agreement between CAMC and the federal government, was instructed to build the transmission line, the Board recommends that this line be treated as a specific asset. The Board further recommends that 85 percent of the annual cost be assigned specifically to CAMC and that the remaining 15 percent be rolled in with the pooled costs in the Yukon hydro rate zone to be allocated to all customer classes based on their respective demands. The 85 percent figure for CAMC reflects the fact that, under this arrangement, CAMC would also be assigned its share of the pooled costs.

Using this approach, $240,890 of the estimated test year cost of $283,401 for the Whitehorse to Faro transmission line has been specifically assigned to CAMC. The derivation of the estimated test year cost of the transmission line is shown in Table 7-2. The Board recommends that this amount be recovered from CAMC in 12 equal monthly installments.

Table 7-2

Whitehorse to Faro Transmission Line
Estimate of Specific Costs for the Test Year

Asset	In-Service Year	Asset Life	Annual Straight-line Depreciation	Average Net Book Value
Transmission Line (original cost $3,416,150)	1970	30	$113,872	$1,537,262
Right-of-Way (original cost $563,717)	1970	20	28,186	98,648
			$142,058	**$1,635,910**

Annual Straight-line Depreciation Expense	$142,058
Return (8.64% x $1,635,910)	141,343
Total Annual Costs	**$283,401**
Assigned to CAMC ($283,401 x 0.85)	**$240,890**

7.3.4.3 Specific Charges to Pine Point Mines

In 1979, NCPC installed three 2.5 MW Ruston diesels at Pine Point under an agreement between NCPC and Pine Point Mines whereby the mine agreed to pay for the capital and interest costs of these facilities.

In its submission, NCPC assigned specific charges to Pine Point Mines amounting to the payment due to NCPC in 1985/86 under the agreement. Although Pine Point Mines did not express any concern regarding the annual amount due under the agreement and assigned to it in the submission, it did, as discussed in Section 8.3.7.1, question whether the amount should be paid in monthly or annual installments.

7.3.4.4 Specific Credits

NCPC provides a specific credit to only one customer on its system: Con Mine in the NWT hydro rate zone. A credit of $9,500 has been applied to the cost of service of Con Mine to compensate for the wheeling of power on the Con transmission line. This amount has been charged back to the residential, commercial and wholesale rate groups as these groups benefit from this wheeling of power. The Board notes that no intervenor raised any objection to this credit and the Board finds the amount of the credit to be acceptable for the test year.

YECL, in final argument, argued that it ought to receive a similar credit for services supplied at Carmacks, Ross River and Haines Junction where it owns the step-down substations, whereas at other locations the transformer facilities are owned by NCPC and provide service to YECL and industrial customers at step-down voltages. The Board recommends that NCPC consider the appropriateness of granting such a credit to YECL in the future.

7.4 Allocation Procedures

Having functionalized and classified rate base and revenue requirement, the final step in the cost of service study is to allocate the classified costs to the various customer classes using appropriate demand, energy and customer allocation factors.

A number of issues were raised regarding NCPC's approach to cost allocation. These are dealt with in succeeding sections and are as follows:

1. NCPC's failure to allocate demand or customer costs to secondary industrial (interruptible) users (Section 7.4.1);
2. NCPC's incremental approach which underallocated costs to the street lighting class (Section 7.4.2);
3. NCPC's method of calculating the noncoincident peak demands of the residential and commercial classes (Section 7.4.3.1);
4. NCPC's use of an instantaneous demand meter to determine Con Mine's noncoincident peak demand (Section 7.4.3.3);
5. the inconsistency of using kilowatts and kilovolt amperes as the basis for allocating costs to customer classes (Section 7.4.3.4);
6. NCPC's exclusion of internal sales in determining energy sales for cost allocation purposes (Section 7.5);
7. the failure of NCPC to attempt to segregate distribution line losses from transmission line losses (Section 7.6); and
8. NCPC's customer weighting factors for the wholesale, and primary and secondary industrial classes (Section 7.7).

7.4.1 Industrial Secondary Class (Interruptible Service)

In the Yukon hydro rate zone, NCPC provides energy on an interruptible basis to United Keno Hill Mines and the Whitehorse Hospital for electric boiler consumption. In its submission, NCPC allocated only energy costs to the interruptible service. No demand or customer costs were allocated to this service.

Considerable concern was expressed by intervenors over the proposed rate for interruptible service. A number of intervenors were of the view that demand and customer costs should also be allocated to the class because the current excess capacity in the Yukon hydro rate zone suggests that the interruptible service will likely be without interruption and will, therefore, be virtually guaranteed the same service provided to others by NCPC. Concern was also expressed that, with a rate of 0.961¢ per kW.h and little likelihood of interruption, NCPC would be inundated with requests for interruptible service, leaving the remaining firm service customers to pick up all the demand- and customer-related costs of the system.

Based upon the Board's recommendation in Section 8.3.6 that the rates for the test year for interruptible service be set at 3.49¢ per kW.h for Whitehorse Hospital and 2.58¢ per kW.h for UKHM, the Board has estimated NCPC's test year revenue from interruptible sales to be $1,000,310 comprised of $270,900 from sales to United Keno Hill Mines and $729,410 from the Whitehorse area.[1]

Although the Board is recommending value-of-service pricing in determining the rates for customers in this class (see Section 8.3.6), the Board is of the opinion that, for cost allocation, the interruptible customer class should be assigned both energy

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1 NCPC stated it is hopeful of providing electricity for boiler purposes to other customers in the Whitehorse area during the test year. Since rates for these customers have not been established, the Board has applied the Whitehorse Hospital rate to all expected sales in the Whitehorse area.

and customer costs and where appropriate a portion of demand costs in order that proper costs for the other customer classes can be determined.

The Board believes that the allocation of costs to the interruptible class can be accomplished by first treating the interruptible class like any other class for the purpose of allocating energy and customer costs. Then, having determined beforehand the value-of-service price and therefore the projected revenue associated with providing interruptible service, the amount of the demand costs to be allocated to this class would be the remainder after deducting the allocated energy and customer costs from the forecast interruptible sales revenue. After deducting the interruptible class' share, the remaining demand-related costs in the rate zone would be allocated to the other classes based on their respective noncoincident demands.

7.4.2 Street Lighting

In its submission, NCPC proposed to treat street lighting on an incremental basis for cost allocation purposes. Using this approach, NCPC did not assign any joint rate base related to production, transmission or distribution, nor any joint costs relating to transmission, distribution or support facilities to the street lighting class. The Price Waterhouse report noted that this methodology represented a departure from NCPC's current practice of treating street lighting like any other customer class, wherein demand costs are allocated to street lighting on the basis of kW demand, energy costs are assigned on the basis of kW.h consumed plus losses, and customer costs are allocated assuming that street lighting represents one customer.

Intervenors were opposed to NCPC's proposed incremental approach for two reasons: first, street lighting contributes to the system peak in the North; and second, when using the noncoincident peak method of allocation, no class should be exempt from demand charges.

Based on the evidence, the Board recommends that NCPC's proposed incremental approach be rejected and that the Commission continue its current practice of treating street lighting like any other class for cost allocation purposes. In assigning customer costs to street lighting, the Board, for cost allocation purposes, has deemed street lighting to represent one customer in each community where NCPC provides such service. In deriving the revenue requirement for street lighting, the Board made specific assignments for direct maintenance, head and regional office administration, depreciation and return. In addition, functionalized costs, excluding head and regional office costs, were allocated to the street lighting class using demand, energy, and customer factors.

7.4.3 Demand Cost Allocation Factors

The allocation of demand-related costs to customer classes is based on the relative demand placed on the electric utility system by each customer class. NCPC has used the noncoincident peak method of determining the relative demand of each customer class.

Intervenors agreed that, for the time being, NCPC should continue to use the noncoincident peak method for allocating demand costs. However, intervenors did raise a number of concerns regarding the calculation of noncoincident peak demands for the street lighting, residential and commercial classes, and for Con Mine.

As discussed in Section 7.4.2, the Board has recommended that street lighting be treated like any other customer class. The Board, therefore, recommends that street lighting be assigned demand costs based on its noncoincident peak demand.

7.4.3.1 Residential and Commercial Demands

Since all of NCPC's industrial and wholesale customers in the hydro zones are demand-metered, NCPC had available to it the noncoincident peak demands of each of the customers in these two classes. However, none of NCPC's residential customers are demand-metered, and the proportion of NCPC's commercial customers who are demand-metered ranges from 5 to 65 percent in the various rate zones. Therefore, in its submission, NCPC resorted to a formula that applies the load factor of the customer class to the kW.h sales and losses of the class to calculate the commercial and residential noncoincident demands. The load factors of the commercial and residential classes were assumed by NCPC to be equal to the system load factor plus one percent and the system load factor minus one percent, respectively.

During cross-examination, NCPC was unable to substantiate the ± 1% formula, except to say that it had previously been recommended to the Commission.

Many intervenors took issue with NCPC's manner of calculating the residential and commercial demands, suggesting that the ± 1% factor was unrealistic and that the application of such a formula understates the demands of the two classes.

YECL was the first intervenor to address its concerns regarding the ± 1% formula. A witness for YECL stated that he had never before seen that method. In his cost of service study, he used residential and commercial load factors of 55 percent and 66 percent respectively. His judgement came from load research that Alberta Power Limited had done on communities in Alberta, which indicated that load factors for the residential class would vary from 45 percent to 55 percent and for the general service class from 50 percent to 80 percent.

An expert witness representing YTG echoed the concerns of YECL. In his study, he used load factor estimates of 34 percent for the residential and small commercial customer classes and 45 percent for large commercial customers, which he stated were based upon estimates made by Saskatchewan Power Corporation. Upon further review, he believed these load factors to be a bit low. He suggested that the load factors might be closer to 38 percent for small customer groups in Quebec and in the 50 percent range for retail class customers in Newfoundland. In B.C. and Ontario, based on coincident load factors, which he would expect to be a little higher than the class noncoincident load factors, the range was 47 percent to 50 percent.

NCPC, when asked what might be reasonable load factors for these two classes, suggested load factors ranging from 45 to 55 percent for residential customers and from 50 to 60 percent for commercial customers.

The witness for YTG considered these ranges to be acceptable and concluded his comments on this topic by stating that, in light of the evidence, he would suggest that the commercial load factor should be quite a lot higher than the residential load factor. He thought that one could adopt a ten percentage point spread in load factor, for the test year, and "move forward until somebody has some better evidence".

Cominco's expert witness also took exception to NCPC's ± 1% formula and introduced another method of determining noncoincident demands for these two classes of customers.

He stated that billing demands comprised of both estimates and, where available, meter readings provide a fair approximation of the actual noncoincident demands placed on the system by the commercial class. This witness proposed that, since such information is available, that it be used for cost allocation. However, he noted that the billing demands in NCPC's addendum to its submission are an average for the year and that the true peak demand of the customers are actually somewhat higher. Using an estimate of a peak-to-average factor of 1/.85, he adjusted the average demands upwards to represent peak demands for the test year.

Turning to residential demands, this witness, in a revised Appendix II to Cominco's direct evidence, indicated that, based on research conducted elsewhere, the average customer contribution to system coincident peak demand would be 2.6 kW, or 4 350 kW for the class in the NWT hydro rate zone.[1]

However, he noted that the residential class does not necessarily peak when the system peaks. Using a system coincidence factor of 0.84, he adjusted the residential demand in his example upwards to its class coincident peak demand of 5 179 kW. He then recognized that not all customers within the residential class peak at the same time. To adjust for this, he used a class coincidence factor of 0.81 to arrive at a noncoincident peak of 6 394 kW. He made this adjustment so that the residential customers would be treated in a manner consistent with NCPC's treatment of industrial and wholesale customers, where each individual customer's demand was summed to obtain a noncoincident peak demand of the class. In his original appendix, the witness noted that NCPC did not adjust its load factor formula by a class coincidence factor and, therefore, the results of NCPC's formula represent the coincident demand of the class; not the noncoincident demand.

The Board notes that the effect on many of the customer classes of adopting the methods proposed by the witness for Cominco in place of NCPC's ± 1% method could be dramatic. The Board also notes that the methods proposed by Cominco require that several parameters be estimated (i.e., system coincidence factor, class coincidence factor, average residential demand at system peak, and peak-to-average factor). Cominco's proposal was only introduced as evidence in the proceedings after the direct and cross-examination of NCPC and all other intervenors (except GNWT) had been completed. The Board believes that, although the methodology proposed by Cominco may have merit, there is a lack of evidence to support the adjustment factors (particularly a lack of data applicable to operations North of 60°) and further that such factors should be subject to full and proper examination by all interested parties before being recommended for implementation.

The Board, after considering the evidence, recommends that, for the test year, NCPC retain the use of a load factor approach for determining residential

1 Cominco's expert witness used the NWT hydro rate zone as an example: 1,673 customers x 2.6 kW/customer = 4 350 kW.

and commercial demands in each rate zone, but that the load factors reflect a more realistic spread of 10 percentage points as suggested by the expert witness for YTG. The Board, in determining cost-based rates for the test year, has used load factors of 45 and 55 percent for the residential and commercial classes, respectively, in each rate zone. The Board notes that these load factors are within the ranges suggested by NCPC and intervenors.

7.4.3.2 Industrial and Wholesale Demands - NWT Diesel Rate Zone

NCPC also used a formula to calculate the demands of the industrial and wholesale customers in the NWT diesel rate zone. In the formula, the load factors of the two classes were assumed by NCPC to equal the system load factor of 55.8 percent.

No intervenor raised any concern regarding NCPC's method of determining demands for the wholesale and industrial classes in the NWT diesel rate zone. Therefore, the Board accepts the load factors as determined by NCPC for the test year.

7.4.3.3 Con Mine Demand

During the inquiry, NCPC indicated that it measures Con Mine's demand using an instantaneous demand meter, whereas the Commission measures all other major customers' demands using 15-minute average demand meters.

The Board notes that the metered demands of NCPC's major customers formed the basis of the Commission's forecast of test year demands for each of these customers.

In its direct evidence, Con Mine indicated that, with its demand being metered using an instantaneous meter, it felt it was being discriminated against.

NCPC indicated that it allows Con to skip ore only during the period between 8:00 p.m. and 7:00 a.m. and explained that, when Con is skipping ore, the mine can have an instantaneous peak requirement of up to 4.7 MW in a period of approximately a minute and a half or a swing of approximately 2.7 MW. NCPC stated that, even though Con is allowed to skip ore only during the off-peak period, NCPC must nevertheless use diesel generation to meet its peak during the winter period. As a result, NCPC indicated that it must keep additional diesel generation on the system not only to provide Con with capacity, but also to take the swings.

Cominco acknowledged that Con's peak demand occurs when the mine is skipping ore or waste from the mine. However, Con argued that because the mine is allowed to skip only in the off-peak period, its demand does not contribute to the overall system peak. Further, when Con wishes to skip ore, it must get prior approval from NCPC. Cominco also pointed out that, when NCPC has a problem on its system, Con is the first load to be dropped and the last to come back on. Finally, Cominco noted that, if NCPC's system fails, NCPC draws on Con's power source for NCPC's other customers. Cominco acknowledged that under this arrangement a credit is given automatically by the meter but that there is no recognition given to the stand-by nature of Con's facilities.

In final argument, Cominco submitted that Con should not be discriminated against in terms of a different type of meter and, if anything, Con should receive preferential treatment in recognition of its stand-by function and the restrictions which are imposed on it and not on the other industrial customers. However, Cominco was also of the view that, if there were any additional facilities put in place or put in on a stand-by basis specifically to serve Con Mine, the costs of those should be recognized in Con's rates.

The City of Yellowknife and ICG indicated that, in the past, the NWT Public Utilities Board had approved NCPC's use of an instantaneous demand meter for Con. These two intervenors argued that, in the absence of any compelling new evidence to the contrary, NCPC should continue to use an instantaneous demand meter for Con Mine.

The Board is of the view that, in determining the appropriate demand for Con Mine for cost allocation, all factors must be taken into consideration including the restrictions placed on the mine's utilization of its hoist and the stand-by nature of Con's power facility. Accordingly, the Board recommends that Con's non-coincident peak demand for cost allocation be determined on the basis of a 15-minute interval.

During the inquiry, Cominco indicated that it believed that an appropriate 15-minute demand for the mine could be arrived at by subtracting 900 kV.A from the demand measured by the instantaneous demand meter. Cominco indicated that this figure was based on the results of a report done by Thomas Associates in which the figure of 900 kV.A was determined by actual measurement.

The Board accepts this adjustment as reasonable and, accordingly, has decreased Con Mine's non-coincident demand for the test year by 900 kV.A. However, in recommending that Con's demand in the future be determined on the basis of a 15-minute interval, the Board also recommends that Con's future rates should reflect any incremental costs that can be directly attributed to the demands placed on NCPC's system in providing power to accommodate Con's ore-skipping operation.

7.4.3.4 kW vs. kV.A

NCPC testified that the demands of its major wholesale customers, industrial customers with the exception of Pine Point Mines and Dome Petroleum Limited (Dome), and some of its commercial customers are measured and expressed in kV.A. The demands of all other customers are either estimated or measured and expressed in kWs.[1] NCPC acknowledged that, in the cost allocation and rate design sections of its submission, it had used kWs and kV.As interchangeably. As such, NCPC had implicitly assumed a one-to-one relationship between kWs and kV.As. The Board notes that the true relationship is that kWs equal kV.As times power factor. Therefore, kWs equal kV.As only when the power factor of the customer or class is unity.

Intervenors and NCPC agreed that, ideally, to avoid inter-class inequities, the demands of all classes for cost allocation purposes should be expressed in a common unit of measurement.

The Board agrees that, ideally, the demands of all customer classes should be expressed in the same units of measurement for cost allocation purposes (be it kWs or kV.As) and therefore, recommends that NCPC consider using only one or the other in future submissions. However, for the test yèar, the Board, in determining the demands for each customer class, has not converted NCPC's kWs to kV.As or vice versa, with the exception of Pine Point Mines' demand.

NCPC indicated during the inquiry that the demands of two of its three industrial class customers in the NWT hydro rate zone; namely, Con Mine and Giant Yellowknife Mines Ltd., were expressed in kV.As, whereas the demand of the third customer, Pine Point Mines, was expressed in kWs.

The Board believes that, where a class is comprised of so few customers, expressing the demands of all but one customer in kV.As creates an obvious intra-class inequity.

During cross-examination, NCPC indicated that it believed the power factor of Pine Point Mines to be roughly .95. The Board notes that Pine Point Mines did not challenge this figure and further that Cominco's expert witness believed that demand costs should be allocated to customer classes on the basis of kV.A demand.

The Board believes that, where administratively practicable, intra-class inequities should be eliminated and therefore, recommends that, for cost allocation and rate design purposes, Pine Point Mines' demand in the test year be expressed in kV.A. Accordingly, the Board has divided Pine Point Mines' kW demand by .95 to arrive at an equivalent demand expressed in kV.As.

7.4.3.5 Determination of Demands in Future

Having reviewed specific concerns as outlined in Sections 7.4.3 to 7.4.3.4, the Board recommends that NCPC should examine various methods of determining demands for the residential and commercial customers in all zones and for the wholesale and industrial customers in the NWT diesel rate zone with a view to coming up with more appropriate demands for these classes in the future, and further, that NCPC be able to justify whatever method it incorporates in future submissions.

7.5 Internal Sales

In determining energy sales for residential customers in each rate zone for the test year, NCPC excluded energy sales to its own employees. Intervenors took the position that these sales, referred to as internal sales by NCPC, should have been included in residential energy sales for cost allocation and rate design purposes.

NCPC testified that, in light of its current utility benefit package with its employees, it considers internal sales to be similar to energy consumed in its plants in that it is effectively a cost of doing business. Presently, NCPC charges each employee, excluding those in head office, a flat amount of $70 per month for utilities, with NCPC picking up the total cost of each employee's utilities.

In NCPC's opinion, this is an untenable situation for it to be in. NCPC, in effect, has no control over the amount of assistance it provides to each employee because at a flat rate of $70 per month regardless of consumption, the employees have no incentive to conserve energy. NCPC, therefore, is taking steps to alleviate this situation. During cross-examination, NCPC indicated that it proposes to implement a utility user-pay program for employees in the Yukon and NWT hydro rate zones in the test year. Such a plan would roll into the employee wage package an acceptable level of offset of remuneration that would

1 kV.As recognize the reactive power drawn from the system by the customer whereas kWs do not. Depending upon the customer's power factor, kV.As equal or exceed kWs.

compensate for the current utility package, but would require the employee to pay his own utility bills.

Because NCPC included, in its submission, a utility offset amount in wages and salaries in both hydro rate zones, NCPC agreed that employees in these two zones should be considered as normal bill-paying electric utility residential customers in the test year, and that, therefore, it would be appropriate to include energy sales to the employees (i.e., internal sales) in determining total residential energy sales. However, since NCPC is not proposing to implement the new benefit package in the diesel rate zones, NCPC was of the view that it should continue to exclude internal sales in estimating energy sales for residential customers in those rate zones.

The Board concurs with NCPC's position regarding the treatment of internal sales for cost allocation and rate design purposes in the diesel rate zones, and with NCPC's views on including internal sales in residential sales in the hydro rate zones. The Board, therefore, has adjusted upwards only NCPC's estimate of the residential energy sales in the hydro rate zones to include internal sales in the test year.

7.6 Allocation of Line Losses

Energy costs are allocated to customer classes in a cost of service analysis according to their respective kilowatt-hour sales including system losses. When allocating system losses to customer classes in its submission, NCPC made no attempt to differentiate between losses on transmission lines and losses on distribution lines. Total line losses in each rate zone were simply allocated to all classes based on the ratio of each class' energy consumption to total sales.

A number of intervenors took exception to NCPC's approach because it effectively assigned a portion of distribution losses to the wholesale and industrial classes which do not use the distribution facilities. They argued that distribution losses should be allocated only to the residential, general service and street lighting categories.

NCPC agreed with this approach, but indicated that it does not have metering that would identify separately distribution and transmission losses, nor had it attempted to estimate such losses.

A witness for YECL suggested that NCPC use a loss factor of ten percent of sales to determine distribution losses. This factor was based on his company's experience of supplying electricity in Yukon. Witnesses for other intervenors supported the reasonablensss of this factor and a witness for NCPC thought that a distribution loss factor of 10 to 12 percent of sales would be reasonable.

While in due course one could look to better estimates from NCPC upon which to base distribution line losses in each rate zone, the Board recommends that, for the test year, NCPC use a loss factor of 10 percent of sales to the residential, general service and street lighting classes to determine distribution losses attributable to those classes. Further, the resulting transmission losses in each rate zone (total losses minus distribution losses) should be apportioned to each class in the rate zone based upon its ratio of energy sales plus distribution losses (if any) to total energy sales plus distribution losses in the zone.

7.7 Customer Weighting Factors

The allocation of customer costs to customer classes is based on the number of customers in each class multiplied by appropriate weighting factors to reflect differences in the costs of providing service to the various classes. For example, the NARUC manual indicates that the capital cost of meters is a cost requiring weighting for different classes because the metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for a single residential customer.

7.7.1 Wholesale and Industrial (Primary) Classes

As a guide to determining appropriate weighting factors for assigning customer-related costs to the industrial (primary) and wholesale classes in the hydro rate zones and the industrial (primary) class in the NWT diesel rate zone, NCPC used a method which considered the installed capital cost of metering. This method yielded a ratio of 115 to 1 for wholesale and industrial (primary) customers compared to residential and commercial customers. NCPC did not, however, believe that a factor based solely on metering costs was a reasonable basis for allocating all customer costs to these classes and, therefore, chose a weighting of 80 which NCPC believed to be comparable to the upper limit of the 20 to 80 range suggested in the NARUC manual.

In response to an information request, NCPC indicated that customer-related expenses for industrial (primary) and wholesale customers exceed those for residential and general service customers by an approximate factor of 22 for metering-related costs and by a factor of 50 to 60 for other customer-related costs.

NCPC agreed that, if the weighted average of meter-related and other customer-related costs were calculated, the customer costs for industrial (primary) and wholesale customers would exceed those for residential and general service customers by a factor of only 45 to 55.

Intervenors also questioned the reasonableness of the weighting factor used by NCPC. Cominco's expert witness performed his own analysis, the results of which suggested to him a range of 38 to 50.

Based on the evidence, the Board recommends that, for the test year, a weighting factor of 50 be used for assigning customer-related costs to the wholesale and industrial (primary) classes in each hydro rate zone and to the industrial (primary) class in the NWT diesel rate zone.

It was also noted that, in the NWT diesel rate zone, NCPC has classified some 50 customers as being "wholesale" for cost allocation purposes, but has assigned them a class weighting factor of only one. NCPC explained that the "wholesale" designation was used simply to distinguish these customers (Transport Canada and GNWT), which are supplied at primary voltage and provide their own secondary transformation and distribution, from other commercial customers using NCPC's distribution system. The Board finds NCPC's weighting factor for the "wholesale" class in the NWT diesel rate zone to be acceptable.

7.7.2 Industrial (Secondary) Class

In the Yukon hydro rate zone, NCPC did not allocate any customer-related costs to industrial (secondary) customers. NCPC indicated that, if it were deemed appropriate to allocate such costs to the secondary class, a weighting factor of 10 might be more appropriate than a factor of 80 because the customers in this class are not demand-metered as are primary industrial customers and the customer bill for one such customer is calculated by hand.

The Board recommends that a weighting factor of 10 be used for the test year for assigning customer-related costs to this class.

7.7.3 Number of Customers

NCPC stated that the number of customers projected for the test year as presented in the submission was the actual number of customers serviced as at 31 March 1984. During cross-examination, NCPC indicated that the number of customers in certain communities, particularly Dawson, Yukon, varies from summer to winter. NCPC agreed that, for cost allocation purposes, it would have been more appropriate to weight the number of customers during the year rather than taking the count at one point in time.

The Board recommends that, in the future, NCPC use a 12-month average to determine the number of customers in each class in each rate zone for cost allocation purposes.

7.7.3.1 NWT Diesel Rate Zone

In its submission, NCPC used seven as the number of industrial customers for cost allocation purposes, but used five in the design of rates for this class.

NCPC acknowledged that it had assumed that two services at Norman Wells for Esso Resources Canada Limited would have no consumption in the test year but would remain connected. However, these two services were subsequently disconnected in the fall of 1984.

Accordingly, the Board has used five as the number of customers for both cost allocation and rate design purposes.

7.8 NWT Heat and Water & Sewerage Rate Zones

In addition to providing electric utility service, NCPC provides a heat service at Inuvik and Frobisher Bay, and a water & sewage service at Inuvik. NCPC distributes the heat at Inuvik. At Frobisher Bay, the Commission provides heat on a wholesale basis to GNWT for subsequent distribution by the government.

NCPC's plant at Inuvik houses facilities for all three utility services while the plant at Frobisher Bay supports the electricity and heat services.

In its submission, NCPC assigned specific water & sewerage and heat-related equipment directly to each utility service. The powerhouse and equipment common to all services were allocated on the basis of the relative floor area occupied by each utility service in the powerhouse. A further allocation of production fuel costs at Inuvik was then made between heat and water & sewerage on the basis of the BTUs utilized by each service.

The fuel tanks and fuel handling equipment common to the services were allocated on the basis of the relative fuel consumption of each service. Having determined the total rate base for each service, NCPC allocated an appropriate return on rate base.

NCPC allocated head and regional office costs to the heat and water & sewerage rate zones on the basis of direct salaries and wages. Specific operating costs were identified and assigned directly to the heat and water & sewerage rate zones. Common operating costs were allocated between services using factors estimated by the superintendent at each plant.

The Board accepts as reasonable the allocation methodology used in the submission for the heat and water & sewerage rate zones with the exception of the head and regional office allocations. The recommended method of allocating these costs is outlined in Sections 6.6 and 6.7.

TOPIC: **Allocated Costs**

REFERENCE: **Application, page 6**

PREAMBLE:

QUOTE:

"The last cost of service analysis for Yukon, which was developed jointly by YEC and YECL for the 2009 GRA test year, indicated that major industrial customers were paying rates considerably in excess of allocated costs of service determined in accordance with OIC 1995/090 (including treating the whole Yukon as a single rate zone) and in accordance with normal regulatory principles applicable to similar regulated electricity utilities in Canada."

QUESTION:

a) Did the Board reject the Phase II portion of the 2009 GRA for the reasons set out in Appendix A to Board Order 2010-13?

b) In light of your response to (a), how can the statement that "major industrial customers were paying rates considerably in excess of allocated costs of service" be verified?

c) If a cost of service study was rejected by the Board, how can the Board rely on a statement that revenues exceed costs for any given rate class?

d) Given that the Phase II portion of the 2009 GRA was completed before the CSTP (both phases), SKTP currently being contemplated, the Mayo B Project and the Aishihik Third Turbine Project, please explain how YEC can rely on the 2009 cost of service study and rate design.

e) With respect to the rates that VGC will pay for electricity, please provide support for the statement that rates to be charged will be in excess of allocated costs of service.

ANSWER:

(a)

Board Order 2010-13 did not accept the Cost of Service (COS) study as filed by YEC and YECL (the "Companies"). This Board Order also did not require a COS study to be finalized as part of the Phase II Compliance Filing of the Companies.

Section 3.3 of Appendix A to the Order, at paragraphs 108 to 111, provided the following guidance on reasons for the Board's decision in this regard related to its review of allocation methods (Section 3.3.3) and concerns raised regarding the applicability to Yukon of the customer class load factor estimates adopted in the COS study and derived from recent ATCO Electric customers in Alberta:

- The Board noted the significant increase in General Service load factors, that YEC could not identify a reasonable Yukon-based explanation of ATCO's calculations for these increased load factors, and that cross checks done in earlier COS studies had not been done in this instance to confirm that this reflected Yukon customer conditions.

- The Board was concerned that, if the current COS was approved and rates were to be based on it, the General Service class of customers may be allocated too low a share of costs, while the other customer classes may be allocated too high a share of costs.

- As a result, the Board found the validity of data underpinning the Energy Demand and Loss Analysis (EDLA) currently available in the proceeding to be questionable in determining the load factors of Yukon customers. Accordingly, the Board did not accept the Companies' proposed 2009 COS demand load metrics (CP and NCP load factors).

- In order to resolve the above data issues relating to customer class load factors, the Board directed the Companies in the next COS study to collaborate and select appropriate and cost-effective measures that will effectively measure actual Yukon-specific loads (proxy study) so that the ATCO Alberta models can be calibrated to provide reliable Yukon-specific load information, and to confirm the appropriateness of using the demand tables from the REA Bulletin 45-2 and that the document has not been updated.

No specific concerns were raised in Appendix A to Order 2010-13 regarding the load factors adopted for the industrial customer class in the COS study.

In short, Appendix A to Board Order 2010-13 identified the above concerns related to General Service load factors, and the validity of data underpinning CP and NCP load factors for non-industrial customer classes. The Board's concerns in this regard led to its non-acceptance of the proposed 2009 load factors for these customer classes, the direction for added analysis in the next COS study by the Companies.

The Board in Appendix A to Order 2010-13 also noted views that OIC 2008/149 prevented the Board from adopting, before December 31, 2012, rate proposals whereby rate classes would more adequately reflect the costs of servicing them. In this regard, the 2009 GRA COS study could not at that time be used for guiding such rate proposals.

Appendix A to Board Order 2010-13 directed the Companies to file a joint COS study within six months of the expiry of OIC 2008/149, and to incorporate in that COS study all findings and directions of this Decision. (paragraph 29) A key feature of Appendix A to Board Order 2010-13 was the findings and directions provided in this regard for completion of the next COS study.

Due to the subsequent direction of OIC 2012/68 and OIC 2014/23, the Companies to date have not filed a new joint COS study, beyond what was provided in the February 2011 Compliance Filing response to Board Order 2012-13.

(b) and **(c)**

The PPA Application focuses only on the industrial customer class COS assessments from the 2009 COS study, on the basis that these assessments continue to provide guidance related to the OIC 1995/90 requirement for industrial rates to at least recover costs of service for this customer class.

As reviewed in response to (a) above, the Board's reasons for rejecting the 2009 COS as filed in the original 2009 GRA Phase II application of YEC and YECL (the Companies) related to load factors for the non-industrial classes and (potentially) to the impact of OIC 2008/149 rendering no specific need for approval of a COS study at that time.

In contrast, Appendix A to Board Order 2010-13 did not identify any specific issues in the 2009 COS study relating to load factor estimates for the industrial class COS assessment. Distribution cost allocation, and related NCP load factor estimates, are not relevant to the COS assessments for Industrial customers.

The key elements of a COS study relevant to the industrial customer class served at transmission voltage relate to bulk power (generation and transmission) costs, i.e., bulk power costs account for over 95% of industrial costs of service in 2009.[1] Appendix A to Order 2010-13 provided the following clear directions on COS methods to be used for the bulk power determinations to assess the extent that major industrial customers were paying rates in excess of allocated costs of service:

1. Aishihik Hydro Plant – The Companies are to classify this plant 60% energy and 40% demand in the next COS study (Section 3.3.1.1 of Appendix A).

2. Mayo Hydro Plant – The Companies are to classify this plant 60% energy and 40% demand in the next COS study (Section 3.3.1.2 of Appendix A).

3. Transmission – The Companies are to classify this plant 60% energy and 40% demand in the next COS study (Section 3.3.1.3 of Appendix A).

4. Distribution – The Board agrees with the Companies that costs functionalized as distribution that are purely related to the distribution system, i.e., are not beneficial to the overall system and to all customers, should not be allocated to customers connected to the grid via transmission assets (Section 3.3.1.4 of Appendix A).

[1] The 2009 COS as originally filed by the Companies estimated (Schedule 4-T-31 in Appendix 3.1) that 94.8% of the $2.946 million cost of service for Industrial customer class in 2009 related to production and transmission functions; with this class revenue of $3.203 million, the R/C ratio was estimated at 109%. After a subsequent correction removed approximately $79,000 of distribution costs that had been incorrectly allocated to Industrial, the application COS for Industrial was revised to $2.867 million (97.4% related to production and transmission, and R/C ratio of 111%). The 2009 GRA Phase II Compliance Filing with changes to bulk power cost classification per Appendix A, Board Order 2010-13, reduced the Industrial cost of service for 2009 to $2.817 million (97.3% bulk power costs, R/C ratio of 113.7%).

5. Secondary Sales - The Board finds the Companies' proposal to be reasonable and directs the Companies in the next COS to use these secondary sales revenues to reduce the firm rate revenues required to be collected from all distribution connected rate classes. (Section 3.3.1.5 of Appendix A).

Accordingly, adoption of these Board's bulk power method directions in Appendix A of Board Order 2010-13 and the 2009 COS study information provide a clear basis for assessing the extent that major industrial customers were paying rates more than sufficient to cover costs of service as required by the OIC 1995/90 Section 6(1) direction. The statement in the PPA Application as quoted in this question, which referenced the last COS study developed jointly by the Companies for the 2009 test year, summarized accurately the results of the last COS analysis for Yukon, i.e., the COS update provided in the Compliance Filing by the Companies in February 2011 in response to Board Order 2010-13. The updated COS estimate for 2009 (Table 1) provided in the February 2011 Compliance Filing based on the bulk power COS methodology directions of the Board in Order 2010-13 as reviewed above indicated a Revenue/Cost ratio for Industrial in 2009 of 113.7% per the Order (versus 111% for 2009 per the Application as revised prior to the Board's directions, and 100% as per the 1997 COS approved by the Board).[2]

Board Order 2011-05 stated that the Board does not accept the 2009 Cost of Service as filed by the Companies in the February 2011 Compliance Filing. However, the issue relevant to the current PPA Application is much narrower than acceptance of the full 2009 COS and its revenue-to-cost (R/C) ratios for each customer class. The current issue relates only to the determination that the R/C ratio for one class (the industrial customer class) in the 2009 test year equaled or exceeded 1.0. On this specific issue, the Board has the following evidence to confirm that major industrial customers in 2009 were paying rate revenues considerably in excess of allocated costs of service determined in accordance with OIC 1995/90 (including the whole Yukon as a single rate zone) and the findings and directions of the Board in Appendix A of Board Order 2010-13:[3]

- The COS provided by the Companies in 2009, and as updated in the February 2011 Compliance Filing, complied in general with OIC 1995/90 as regard including the whole Yukon as a single rate zone.

[2] Ibid.

[3] Ibid. for related details and sources of information.

- There are no issues as regards the estimates for Industrial class revenues for 2009 as estimated in the above COS study and its update.

- The costs of service applicable to the Industrial class in the 2009 COS as updated for the February 2011 filing were based almost entirely on bulk power (generation and transmission) costs, classified as per the directions in Board Order 2010-13, and allocated to the industrial class as per the loads and load factors for this class (which were not an issue in the Board's review).

- Based on the 2009 information and the Board's Order 2010-13 directions, the updated 2009 R/C ratio for the Industrial class was increased from 111% in the application as revised to 113.7% in the compliance filing.

- In summary, the evidence clearly showed throughout the 2009 GRA Phase II review that revenues for industrial customers in 2009 were more than 10% higher than the applicable and relevant allocated cost of service for this class. The Board's directions in Appendix A to Board Order 2010-13 resulted in this "excess" percentage increasing from 11.4% to 13.7%.

- Adjustments to R/C ratios for other customer classes due to adjustment of load factors for these other classes cannot in this instance result in any challenge to the conclusion that the industrial customer class R/C ratio in the 2009 test year was well above 1.0.

- The Board's noted concern in Appendix A of Order 2010-13 regarding General Service customer load factors in the 2009 COS study was that the R/C ratio may be too low for this customer class. If this concern was to be supported by future review, it would only serve potentially to raise (rather than lower) the R/C ratio for Industrial, and thereby indicate a higher "excess" over the OIC 1995/90 requirement.

- In summary, there is no available evidence from the 2009 GRA Phase II proceedings to suggest any basis on which the industrial class R/C ratio for 2009 could possibly be estimated at close to 1.0, let alone to be less than 1.0.

(d)

The 2009 COS study as it related to industrial customer costs of service provides a solid basis for assessing subsequent events after 2009 to discern if there is any reasonable basis for concern that the R/C ratio for industrial customers might have deteriorated to the extent needed to fall below 1.0 (and thereby raise concern that industrial customer rates were not sufficient to at least recover costs of service as required by OIC 1995/90).

As reviewed in response to (b) and (c) above, the 2009 COS study as revised for the Companies' February 2011 Compliance Filing provided reliable evidence that industrial customer rate revenues were more than 10% higher (i.e., about 13.7% higher) than applicable and appropriate cost of service estimates for this customer class based on findings and directions in Board Order 2010-13 relevant to bulk power costs. This evidence related specifically to the Minto mine load with a coincident load factor estimated at 77.4%.

The following changes since 2009 could potentially affect the R/C ratio for the industrial customer class under a new COS study:

1. Changes in rates for Industrial versus Retail customer classes;

2. Changes in Industrial customer load shape (especially annual coincident load factor); and

3. Changes in overall bulk power costs of service.

Each of these factors is reviewed separately below.

Rate Changes

Since the COS study for 2009 reviewed by Board Order 2010-13, the percentage rate increases for each firm customer class have been required by successive OICs to be identical - with the one exception of the 2.8% increase specifically applicable only to industrial customers as at January 1, 2011 (per Board Order 2011-4, and the prior direction in OIC 2007/94).[4] OIC 2014/23 retains this direction until December 31, 2018. Subject to no new OIC direction, the Board will be able after December 31, 2018 to adjust rates by customer class (including Rate Schedule 39) as required to comply with OIC 1995/90.

Based on this evidence, basic rates applicable to industrial customers have increased slightly more (in percentage terms) than for other firm retail customers since 2009. On its own, this factor would tend to increase the R/C ratio for industrials above the 113.7% estimated for 2009.

Industrial Customer Coincident Load Factor

During the period after 2009, an Alexco industrial load was added and then removed, and the Minto mine load has continued. Future scenarios examined in the current PPA Application assume up to three mine loads, namely Minto and Alexco (at least until 2022) and the VGC Group Eagle Gold mine load.

A potential future scenario with only the VGC Group Eagle Gold mine load would be expected to display a material overall increase in industrial customer coincident load factor from what was estimated for the 2009 COS study (see below). Including loads for Minto and Alexco would still leave an overall increase in coincident load factor compared to 2009 (see below):

- The VGC Group load, which would likely constitute over half the mine load connected to the grid if both Minto and Alexco were connected (see Table 3 in PPA Application), would have a much higher coincident load factor than the 77.4% estimated for 2009 with only the Minto mine load.

    - As reviewed in Table 1 of the PPA Application, peak load for the VGC Group mine from early December to early March is less than the average load through the year – highlighting the impact of this mine's load being concentrated outside the typical winter peak period.

[4] The existing differential in Rider J applicable to Industrial versus retail rate customer classes is fully offset by the 3.4% increases approved only for Industrial customers as at January 1, 2012 (per Board Order 2011-14, and the prior directions in OIC 2007/94).

  - o Even if the annual load is compared to the annual peak load, the annual load factor after the first year is in the range of 86% to 90%, confirming a load factor well above 77%.

- The Minto and Alexco mine loads are not expected to display coincident peak load shapes much different than displayed by Minto for 2009, let alone materially lower that 77%.

In summary, the load shape and coincident load factor for the VGC Group mine on their own (i.e., not considering any other factors) are likely to increase the overall industrial R/C ratio for industrials above the 113.7% estimated for 2009.

The VGC Group mine will pay a minimum demand charge (ratchet based on maximum demand from October 1 to March 31) through the year notwithstanding much lower loads (and cost of service impacts) during an approximate 90-day period between December 1 and March 31. Aside from the specifics related to winter period loads, the higher annual load factor will also tend to increase the industrial R/C ratio above the 2009 estimate.

Changes in Bulk Power Costs of Service

The 2009 COS addressed costs for the first phase of the CSTP. Since that time, the second phase of CSTP and Mayo B hydro enhancement have been completed, along with Aishihik Third Turbine, the initial LNG Project, and various other bulk power projects.

Overall, there is no basis to assume that the cumulative impact of these bulk power cost additions on their own since 2009 would have a material impact towards reducing the industrial R/C ratio below the 113.7% estimated for 2009. Key considerations in this regard include the following:

- Rates overall have been increasing since 2009 as needed to cover all updated costs, and industrial rates are being increased by at least the same percentage as firm retail rates.

- Government and/or YDC contributions offset a material share of capital cost requirements for many of the bulk power developments since 2009, including CSTP Stage 2, Mayo B, Aishihik Third Turbine, and the LNG Project.

- The bulk power net capital cost expansion on YEC's rate base since 2009 will be largely allocated based on 60% to energy and 40% to demand (per directions in Appendix A to Board Order 2010-13), and will therefore not adversely impact overall COS impacts for industrial with the VGC Group load and its high coincident load factor.

    - The energy portion of these added capital costs will affect each customer class based on energy use;

    - However, the demand portion of these added capital costs will tend to be less of a burden per kW.h in overall COS assessment for customer classes with high versus low coincident load factors.

- Fuel costs are the other major factor affecting bulk power cost of service, and these costs are allocated in a COS study to customer classes based on energy use. Overall, this factor has tended to decline in recent years within the total bulk power cost of consolidated Yukon COS for the Companies due to increased hydro capability (Mayo and Aishihik), lower cost LNG displacement of diesel, and lower diesel fuel prices.

Adding the SKTP development to this picture will not have any adverse impact on industrial R/C ratio with VGC Group load. Under some funding scenarios, the entire SKTP would be developed with government contributions and thus no ratepayer impacts. If ratepayer funding is to be relied upon, the scaled back project costs for the Mayo to McQuesten segment (plus a few other elements) will be 85% directly assigned (by the Fixed Charge) to the industrial customers served by this segment. Absent industrial loads such as the VGC Group mine load, replacement of this end-of-life transmission would increase costs allocated to all other ratepayer customer classes.

Overall Assessment

In summary, review of rate changes, industrial load factor changes, and bulk power cost of service changes since 2009 all indicate that there is no reasonable basis for concern that the R/C ratio for industrial customers might today, or in the period when VGC Group mine is connected, deteriorate to the extent needed to fall below 1.0 (and thereby raise concern that industrial customer rates are not sufficient to at least recover costs of service as required by OIC 1995/90).

If anything, the above review suggests that the industrial R/C ratio with VGC Group mine connected may rise above the 113.7% estimated for 2009 due to the following factors:

- Higher overall rate increase percentage for industrials than retail firm customers since 2009, with overall rate increases sufficient to cover the Companies' consolidated cost changes since 2009;

- Higher coincident load factor, and annual load factor, for VGC Group mine than for the Minto mine industrial load in 2009; and

- Bulk power cost changes since 2009 with increased element of capital costs (from new projects) classified to demand, as well as lower unit average fuel costs and enhanced hydro displacement of thermal generation.

(e)

The analysis provided in response to (d) above supports the statement that rates to be charged to VGC Group, and any other currently expected potential major industrial customer over the expected life of the VGC Group mine, will be in excess of the allocated cost of service for this customer class as required by OIC 1995/90.

The statement takes into consideration the 2009 COS study, Board Order 2010-13 directions and finding on bulk power COS determination, and review of material changes to rates, industrial customer loads and bulk power costs of service since 2009. Together, all of this evidence confirms that industrial COS with VGC Group mine connection will continue to exceed the allocated cost of service for the customer class as required by OIC 1995/90.

Table 3 and related analysis in the PPA Application for the VGC Group mine provides added support to the above statement. Table 3 looks only at the basic incremental cost and revenue impacts of adding the VGC Group load, highlighting that increased revenues are expected to exceed increased YEC costs. Based on this evidence, and the evidence reviewed for 2009 and subsequent time periods, it is clear that the VGC Group mine load will be paying rates that are in excess of allocated cost of service estimated in accordance with directions in Board Order 2010-13 and OIC 1995/90.

TOPIC: **Mayo-Dawson Transmission Line**

REFERENCE: **Application, page 7 and footnote 12**

PREAMBLE:

To test the base numbers used for the calculation of the fixed charge to VGC.

QUOTE:

“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;”

…

“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.” (footnote 12)

QUESTION:

a) Please provide the annual costs for maintaining the Keno City transmission line from 1992 to 2017. Identify and categorize the annual amounts into capital and O&M expense.

ANSWER:

(a)

Please see Table 1 below (data are not available prior to 1998).

Table 1: Annual costs for the Mayo - Keno line: 1992 to 2017

Year	Capital	O&M
2017	$0.00	$10,248.18
2016	$49,766.02	$9,635.05
2015	$57,019.33	$38,411.69
2014	$60,668.64	$52,496.42
2013	$48,195.44	$2,934.80
2012	$407,079.10	$28,082.07
2011	$145,714.95	$74,221.64
2010	$104,086.45	$32,002.79
2009	$80,335.46	$52,116.11
2008	$136,071.14	$48,243.11
2007	$0.00	$19,904.93
2006	$75,024.60	$33,765.71
2005	$0.00	$15,296.08
2004	$123,673.73	$42,932.93
2003	$0.00	$42,167.86
2002	$209,170.07	$74,436.01
2001	$389,948.14	$99,967.24
2000	$0.00	$28,556.91
1999	$0.00	$13,156.80
1998	$0.00	$0.00

TOPIC: **SKTP**

REFERENCE: **Application, page 8**

PREAMBLE:

QUOTE:

"Substation development at McQuesten (S258) as well as at Stewart Crossing South (S251) to accommodate the new line and an SVC/Statcom; and at Mayo (S249) for fibre tie in.

"Other elements including PT sites and structures and First Nation benefits." (bullet points omitted)

QUESTION:

a) Please identify who is responsible for carrying out the work for the Stewart Crossing South substation (S251) and Mayo substation (S249) and its costs, as well as, explain the need for this work.

b) Please explain how a fibre tie in relates to the proposed PPA.

c) Do the other elements, including PT sites and structures and First Nation benefits of the SKTP, relate to any of the initial work to meet the requirements of the PPA?

ANSWER:

(a)

The referenced section of the PPA Application describes the SKTP proposal as defined for environmental review and permitting, and/or engineering/costing work. As reviewed in the PPA Application, the extent to which all of the SKTP elements will be developed as Transmission Facilities Development per the PPA will depend on securing the necessary external funding and approvals to enable development to commence by September 30, 2018.

In the event that development per the SKTP proposal proceeds at Stewart Crossing South substation (S251) and/or at the Mayo substation (249), Yukon Energy will be responsible for carrying out and funding the work.

- Under the SKTP proposal, the Stewart Crossing South substation work is required to provide the new 138 kV line terminal and related MVAR reactors. Design modifications included expansion of the existing substation footprint.

- Under the SKTP proposal, a new substation within the existing Mayo Hydro station property, adjacent to the existing substation, was included to accommodate future connection of the 138 kV transmission line infrastructure to the Mayo Hydro facility.

The above work, however, will only be advanced if YEC receives external funding and approvals in time to allow development to proceed by September 30, 2018.

The SVC/Statcom to be located at Stewart Crossing South substation was added recently for system stability, and was not part of the SKTP proposal to YESAB. The SVC/Statcom would be included in the Transmission Facilities Development under all of the VGC Group PPA options, and its costs will impact the Fixed Charge to be applied to VGC Group and any Other Industrial Customers using the Transmission Facilities as defined in the PPA.

(b)

The SKTP project proposal as submitted to YESAB made provision to install a new aerial fibre optic communication link on the 138 kV transmission line from S251 to S257 (Stewart Crossing South and Keno City substations) to enable communications between S251, S258, S249 and S257 for protection systems relaying, SCADA, data and voice communications between substations on this line. This will also include drops/taps at S249, S258, S257 and S251 (other commercial and industrial taps are not intended to be tied to the fibre optic network at this time).

The fibre optic tie would be included in the full SKTP project if external funding and approvals as required to allow development to proceed by September 30, 2018. As this option assumes full external funding, the fibre optic tie would not affect PPA related costs, including the Fixed Charge.

The fibre optic tie would not be included in the default option as defined on page 9 of the PPA Application, where only the line between Mayo and McQuesten Substation is replaced.

(c)

Other elements noted in the referenced quote will vary depending on the Transmission Facilities Development that is carried out. Under the default option, where only the line between Mayo and McQuesten Substation is replaced and the line operates at 69 kV, there will be no requirement for PT sites and structures (which are otherwise needed to accommodate 138 kV connections at locations where there currently is a 69 kV connection). Provisions for First Nation benefits are adjusted as required depending on the actual development that is carried out.

TOPIC: **YESAB**

REFERENCE: **Application, page 8**

PREAMBLE:

The Board notes the following submission respecting the Stewart Keno City Transmission Line Project in YEC's GRA, page 5-32, line 24 to page 5-33, line 2: "Initial engineering, planning and assessment activities required to prepare and submit a Yukon Environmental and Socio-economic Assessment Act (YESAA) project proposal to YESAB were undertaken in Q3 and Q4 2015. A YESAA Project Proposal **for a 138 kV transmission line (with related substation infrastructure) between Stewart and Keno City** was submitted to YESAB before the end of 2015, with the YESAB screening completed in May of 2016. A Land Use application was submitted to the Yukon government and authorizations required to proceed with geo-technical and survey work to complete detailed engineering were obtained in September 2016." [Bold font added]

QUOTE:

"Initial engineering, planning and assessment activities required to prepare and submit a Yukon Environmental and Socio-economic Assessment Act (YESAA) project proposal to YESAB were undertaken in Q3 and Q4 2015. A YESAA Project Proposal was filed before the end of 2015, with a YESAA Screening Report issued May 31, 2016. A Land Use application was submitted to the Yukon government and authorizations required to proceed with geo-technical and survey work to complete detailed engineering were obtained in September 2016."

QUESTION:

a) Has a final approval been received for the above-noted YESAA project proposal from YESAB?

b) If not, when does YEC expect a final approval?

c) Please confirm that the line (between Stewart Crossing and Keno City) is to be converted from 69kv and to be operated at 138 kV (as stated in the above quote), while the line to Dawson City from Stewart Crossing is to remain operating at 69 kV.

d) Please explain what the term “(with related substation infrastructure) between Stewart and Keno City” is referring to.

ANSWER:

(a) and **(b)**

Yes, final recommended approval has been received from YESAB for the above-noted YESAA project proposal, and the Government of Yukon has accepted the YESAB recommendation.

YESAB issued the Screening Report on May 31, 2016 recommending that the Government of Yukon allow the project to proceed without a review subject to specified terms and conditions. The Government of Yukon issued its decision document on June 29, 2016 allowing the project to proceed subject to terms and conditions.

(c)

Under the SKTP proposal reviewed by YESAB, a new 138 kV transmission line (with related infrastructure) was to be developed between Stewart Crossing and Keno City; however, under the SKTP proposal the following additional provisions were noted:

- The existing relatively new 69 kV line between Stewart Crossing and Mayo would remain in place;

- The end of life 69 kV line between Mayo and Keno City would be replaced by the new 138 kV line;

- The McQuesten Substation would be developed as part of the SKTP proposal; and

- The new 138 kV line between the McQuesten Substation and Keno City would be operated at 69 kV (and thereby avoid the need, until higher loads justified a change, to convert the existing Keno City substation and to provide PTs at various existing points of connection to the current 69 kV line along this segment).

The line to Dawson City from Stewart Crossing will not be affected by the SKTP development under any of the options considered in the PPA and will continue operating at 69 kV.

(d)

"Related substation infrastructure" refers in the SKTP proposal to the required expansion and upgrades to existing substations to accommodate the new 138 kV transmission line and the new substation to be built at McQuesten to step down power from 138 kV to 69 kV north of Mayo.[1] The SKTP proposal also included PTs as required for the new 138 kV operation.

[1] Stewart-Keno City Transmission Project: YESSA Project Proposal Executive Committee Submission, pp. 6-17 – 6-18.

TOPIC: **SKTP Components**

REFERENCE: **Application, Section 4.3, page 8**

PREAMBLE:

QUOTE:

"Yukon Energy is pursuing the SKTP at this time to improve the electrical transmission infrastructure in central Yukon between Stewart Crossing and Keno City; reinforce and strengthen the grid between Stewart Crossing and Mayo; and replace and remove deteriorated and 'end of life' transmission infrastructure between Mayo and Keno City. The project is being planned to ensure continued safe and reliable service and to facilitate future economic development within the territory.

- The SKTP as **defined for environmental review and permitting**, and/or for the **engineering/costing work**, included the following components:
  - o 138 kV H-frame transmission line development involving the following segments:
    - L179 Stewart to Mayo (58 km) [the existing new 69 kV line would remain as well for this segment];
    - L180 Mayo to McQuesten (31 km) [to be operated at 138 kV]; and
    - L250 McQuesten to Keno City (20 km) [this segment would initially be operated at 69 kV].
  - o Substation development at McQuesten (S258) as well as at Stewart Crossing South (S251) to accommodate the new line and an SVC/Statcom;13 and at Mayo (S249) for fibre tie in.
  - o Other elements including PT sites and structures and First Nation benefits." [Bold font added]

QUESTION:

a) Please explain why the above description of the SKTP project development from Stewart to Keno City was not included in YEC's current General Rate Application.

b) Please explain why it is necessary to operate L180 (Mayo to McQuesten) at 138 kV, when McQuesten to Keno City would be operated at 69 kV.

c) Please explain why the line from Stewart to Keno City is not to operate at 138 kV, as noted in the previous IR?

d) With respect to the above quote, why is YEC proposing that the line from Mayo to McQuesten operate at 138 kV instead of from Stewart to McQuesten? Please explain.

e) Please explain what PT sites are. Who would be responsible for PT sites and structure costs?

f) Please specify what First Nation benefits were provided in relation to the above-noted project?

g) Please provide single line diagrams in respect of the existing line and proposed alternatives.

h) Please explain why a project for future economic development is the responsibility of YEC and a cost that should be borne by ratepayers.

ANSWER:

(a)

The description of the SKTP provided in the 2017/2018 General Rate Application is a summary description based on the more detailed project description submitted as part of the YESAA Project Proposal.

The brevity of the GRA summary reflected the stage of development, the fact that all costs to date had been funded by contributions, and that decisions to advance the project had yet to be made.

The description included in the GRA provided a summary of the project status and costs incurred to date, noting that a decision to advance the project would be undertaken once Yukon Energy had confirmed the project costs and potential funding availability; and indicating that options for a staged project development were being considered in the event that third party funding is not available.

(b), (c), and (d)

The SKTP proposal assumed new 138 kV line development from Stewart Crossing to Keno City (to allow for increased potential future loads and/ or renewable generation throughout this region), but assumed 138 kV operation only from Stewart Crossing to McQuesten. The project proposal included the new McQuesten Substation for step down from 138 kV to 69 kV, and considered new substation facilities at Mayo as an option.

The SKTP proposal assumed retention of the relatively new 69 kV line from Mayo to Stewart Crossing, and replacement of the end of life 69 kV line from Mayo to Keno City.

The proposal provided for extending the 138 kV grid to McQuesten in order to secure added ability to supply or move power loads. Specifically, the 138 kV line will reinforce and strengthen the grid and allow further increases to the Eagle Gold maximum load limit, the Mayo Dawson import limit as well as mitigate contingencies.

Development of these new facilities and the McQuesten substation was seen to be facilitating future connection at 69 kV of the relatively large potential new Eagle Gold mine load (which had received YESAB review and other permitting approvals).

The SKTP proposal assumed operation at 69 kV of the new 138 kV line from McQuesten to Keno City in order to defer, until load conditions justified 138 kV operation, new substation facilities at Keno City and various PT (potential transformer) sites and structures required with 138 kV operation along this segment.

(e)

PT (potential transformer) site is a term for small substations on the transmission system that feed small loads or very few customers. Existing small load step down taps that serve specific customers along the existing 69 kV transmission would need to be replaced and re-designed to operate at 138 kV. YEC would be responsible for these facilities and costs.

(f)

With respect to the planning project completely funded by YG for planning and permitting, YEC contracted directly with an NNDFN joint venture for survey and brushing work on the right of way. The value of contract was $166,000. No other First Nation benefits have been provided to date for the SKTP proposal.

(g)

Please see Attachment 1 to this response.

(h)

The full SKTP would facilitate future economic development in the territory through improving electrical transmission infrastructure in central Yukon and reinforcing and strengthening the grid between Stewart Crossing and Mayo. However, the justification for undertaking this project at this time also relates to the need to replace and remove deteriorated and 'end of life' transmission infrastructure between Mayo and Keno City in order to ensure continued safe and reliable service from the grid in this region.

In this respect the following are specifically noted:

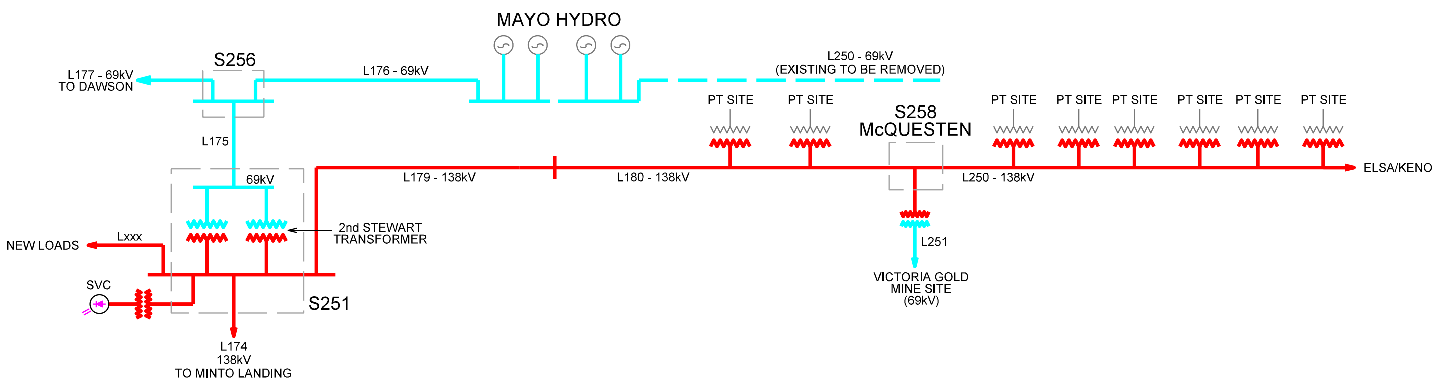
- Yukon Energy is exploring options to secure funding for the full SKTP (or portions thereof) up to 100% of the full revenue requirement impact.

- In the event that government funding cannot be secured for the full SKTP, Yukon Energy is evaluating options for proceeding, including options for staged project development.

    - The default development option would focus on to removal and replacement of deteriorated and 'end of life' transmission infrastructure between Mayo and the McQuesten Substation (assuming VGC Group mine development proceeds and that this substation is developed for connection of this mine to the existing L180 69 kV transmission line).

    - This default development option is required at this time to maintain the existing grid and ensure continued, reliable grid service to both industrial and non-industrial customers in this region.

- In this respect, this default option is being undertaken to address current requirements, and is not being undertaken for future economic development.



YUKON ENERGY CORPORATION

REV.	DESCRIPTION:	DATE:	SKETCH SHOWING:
1	IFT - Detailed Eng.	1-Mar-2016	FUTURE DEVELOPMENT
2	ADD L251 INFO	7-Dec-2017	SINGLE LINE DIAGRAM

DRAWN BY: Tara	29-Feb-2016	SCALE: nts	DRWG. # SKETCH 3.dgn	REV. 2

TOPIC: **McQuesten Substation All-in Costs**

REFERENCE: **Application, footnote 15, page 9; Application, Section 5.4, YEC Capital Costs Recovered from VGC Group, pages 13-14**

PREAMBLE:

QUOTE:

"The all in-costs estimated for the McQuesten Substation in this option is $9.869 million, with $8.939 million estimated to be funded by VGC Group under the PPA (includes $6.715 million estimate for initial substation, $0.884 million risk contingency, and future Step Down transformer cost estimate of $1.34 million); the balance of the McQuesten Substation costs of **$0.930 million are to be funded by** YEC under the PPA to facilitate initial development prior to the Transmission Facilities Development."[1] [Bold font added]

"Section 6.1(d) of the PPA identifies YEC McQuesten Substation Costs of $930,563, as set out under Section B.4 of Schedule B, associated with the McQuesten Substation as initially developed being able to operate in future (if and when so required) at 138 kV. YEC funding of VGC Group costs for these added facilities for 138 kV service recognizes that these facilities are not required at the outset for delivery of Grid Electricity to the 69 kV Mine Facilities Spur line, **but are required as part of any planned Transmission Facilities Development option**. YEC will retain these costs in WIP until the Transmission Facilities Development Operation Date, after which time these costs will be added to rate base and included in the Transmission Facilities Fixed Cost that determine the Fixed Charge for VGC Group and any Other Industrial Customer using the Transmission Facilities. **In the event that 138 kV operation occurs**, VGC Group will pay YEC's actual costs for the required Step Down Transformer at the McQuesten Substation."[2] [Bold font added]

[1] VGC PPA Application, footnote 15, page 9.
[2] VGC PPA Application, Section 5.4, YEC Capital Costs Recovered from VGC Group, pages 13-14.

QUESTION:

a) Please provide a table with items that make up the McQuesten Substation all-in costs totalling $9.869 million. The table should include costs for the items as well as an explanation for each. Also in the table, please provide who is responsible for funding each cost item and the reasoning underpinning who is responsible.

b) Please confirm that the $0.930 million referred to in the above-noted quote, are the McQuesten Substation costs noted in Table B-2 of Schedule B, in the VCG PPA. If not confirmed, please provide the costs making up $0.930 million.

c) Please confirm that “planned Transmission Facilities Development option” is related to VGC Group mine development.

d) If part (c) is confirmed, please explain the difference between the phrases “but are required as part of any planned Transmission Facilities Development option” and “In the event that 138 kV operation occurs”, i.e. it appears that the first phrase stipulates that future mine operation will require 138 kV operation, while the phrase “in the event that 138 kV operation occurs” appears to suggests that operation at 138 kV is not necessary.

ANSWER:

(a)

The all-in costs estimated for the McQuesten Substation of $9.869 million are for full SKTP development with 138 kV transmission line development from Stewart Crossing to Keno City. The PPA Application notes that costs estimated for the McQuesten Substation are lower, at $8.529 million, under the default development option with new 138 kV transmission facilities limited to L180 from Mayo to McQuesten (and with the new line operated at 69 kV).

Table 1 below provides the all-in McQuesten Substation costs totaling $9.869 million, as well as the McQuesten Substation costs for the default development option totaling $8.529 million. All costs shown are funded by VGC Group, except for the YEC McQuesten

Substation Costs (which are funded by YEC paying this to VGC Group as per Section 6.1(d) of the PPA).

- The YEC McQuesten Substation Costs in Table 1 of $1.1 million include a YEC risk contingency for the amount in excess of $0.930 million as estimated in Section B.4 of Schedule B of the PPA. As reviewed in the PPA Application (section 5.4, page 14), the YEC McQuesten Substation costs will be held in WIP until the Transmission Facilities Development Operation Date, and then included in the Transmission Facilities Fixed Cost per year that determine the Fixed Charge for VGC Group and any Other Industrial Customer using the Transmission Facilities.

- The Step Down Transformer is only required if the full SKTP development occurs, with 138 kV transmission operated from Stewart Crossing South Substation to McQuesten Substation. This work (for the Step Down Transformer) would be done by YEC, and funded by VGC Group.

Table 1: McQuesten Substation Costs ($000)

	Default Option Development ($000)	Full SKTP Development ($000)	Difference ($000)
McQuesten Substation			
VGC Group Costs & Funding	6,946	6,946	-
YEC Owners Costs (funded by VGC Group)	483	483	-
YEC McQuesten Substation Costs*	1,100	1,100	-
Step Down Transformer funded by VGC Group		1,340	1,340
Sub total	8,529	9,869	1,340

Notes:
* Provision for 138 KV operation. Includes $0.930 million estimate plus risk contingency.

(b)

Confirmed.

(c) and (d)

The reference in the quote from Section 5.4 of the PPA Application is to "<u>any</u> planned Transmission Facilities Development option" (emphasis added), and addresses both the full SKTP option and the default option for Transmission Facilities Development. Each of these Transmission Facilities Development options will include installation of 138 kV transmission capability to the McQuesten Substation from either Mayo or Stewart Crossing. Accordingly, it is necessary to ensure that the McQuesten Substation development also includes full 138 kV capability.

Although each of the two Transmission Facilities Development options will include 138 kV transmission capability to the McQuesten Substation from either Mayo or Stewart Crossing, these options differ as regards planned initial operation.

- Under the full SKTP development option, 138 kV transmission is extended from Stewart Crossing to McQuesten Substation and this new line is then operated at 138 kV.[3]

- Under the default option, where only the Mayo to McQuesten Substation transmission is developed (built at 138 kV), the new facility will initially be operated at 69 kV (thereby avoiding the need for additional substation facilities at Mayo, as well as PT or other structure developments along this line).

The statement “In the event that 138 kV operation occurs” in the same above quote references the full SKTP development option, when 138 kV operation is required. As noted, the default Transmission Facilities Development option would not require 138 kV operation (i.e., it would operate at 69 kV).

As evidenced by the default Transmission Facilities Development option, the VGC Group Mine development does not require the full SKTP development option and does not require 138 kV operation. Further, the existing 69 kV line between Mayo and Keno City is end of life and in need of replacement, regardless of the VGC Group Mine development.

In summary, the costs incurred at McQuesten Substation to ensure the future ability to operate at 138 kV voltage are incremental to VGC Group’s requirements at this time, and do not specifically relate to any requirements imposed by VGC Group. Ensuring the future ability to operate the line at 138 kV will increase the total transmission capacity of the line to facilitate additional (future) industrial load and/or local renewable resource supply

[3] The full SKTP development option also replaces the line between McQuesten and Keno City with 138 kV capability, but assumes initial operation of this segment at only 69 kV.

development [which may not relate directly to providing service to the Eagle Gold Mine site].

Please also see response to JM-YEC-1-9(b).

TOPIC: **SKTP Development Costs**

REFERENCE: **Application, page 9**

PREAMBLE:

QUOTE:

"Class 2 cost estimates (+15%, -10%) are as follows for the two options relevant to the PPA (each option includes $6.6 million estimate for SVC/Statcom at Stewart Crossing South substation):

1. Full SKTP development: $90.96 million, including costs that VGC Group and/or YEC will fund for the McQuesten Substation pursuant to the PPA.

2. L180 Mayo to McQuesten 138 kV line (assumed to be operated at 69 kV): $32.2 million, including costs that VGC Group and/or YEC will have funded for the McQuesten Substation pursuant to the PPA."

QUESTION:

a) Please provide an explanation regarding the difference of close to $60 million for the two options regarding SKTP development project. In your explanation, provide a table with underpinning costs items and explanations regarding the differential of $60 million.

ANSWER:

(a)

Please see Table 1 below. The difference in costs of $58.8 million for the two options relates to exclusion from the default option of elements included in the full SKTP development option, including added transmission lines and fibre cable ($40.7 million), added Stewart Crossing South Substation elements ($11.0 million), added McQuesten Substation elements ($1.3 million), and Other ($5.7 million).

1 **Table 1: Costs for Transmission Facilities Development Options ($000)**

2

	Default Option Development ($000)	Full SKTP Development ($000)	Difference ($000)
McQuesten Substation			
VGC Group Costs & Funding	6,946	6,946	-
YEC Owners Costs (funded by VGC Group)	483	483	-
YEC McQuesten Substation Costs*	1,100	1,100	-
Step Down Transformer funded by VGC Group		1,340	1,340
Sub total	8,529	9,869	1,340
Transmission Lines			
L180 Mayo to McQuesten 138 kV H-frame (31 km)**	16,687	17,809	1,122
L179 & L250 (Stewart-Mayo, McQuesten-Keno 138 kV (78 km)		39,589	39,589
Sub total	16,687	57,397	40,711
Stewart Crossing South Substation		10,958	10,958
SVC/Statcom at Stewart Crossing South Substation	6,570	6,570	-
Other* **	417	6,165	5,748
Total Cost Estimate	**32,203**	**90,960**	**58,757**

Notes:
* Provision for 138 KV operation. Includes $0.930 million estimate plus risk contingency.
** Full SKTP includes fibre tie in (this not included with default option).
3 *** Other includes FN Benefits and PT sites and structures

TOPIC: **Conditions Precedent to the Agreement**

REFERENCE: **Application, page 10**

QUOTE:

"VGC Group Demonstrates to YEC ability to Proceed by February 15, 2018."

QUESTION:

a) YEC has requested that the Board issue a decision on this matter before February 28, 2018. If the Board does not issue a decision on the PPA Application by February 15, 2018, will YEC place on the record of this proceeding a letter by February 16, 2018 stating whether or not the VGC has provided evidence satisfactory to YEC, that this condition has or has not been met?

ANSWER:

(a)

If a decision on the PPA Application is not issued by February 15, 2018, YEC will, by February 16, 2018 place a letter on the record of this proceeding stating whether or not the condition precedent provided in Section 3.1(b) of the VGC PPA has been met.

TOPIC: **Requirements for Achieving Commencement of Delivery by March 2019.**

REFERENCE: **Application, page 11**

PREAMBLE:

QUOTE:

"Yukon Energy and VGC Group are working together to design, engineer, procure, construct and commission the McQuesten Substation [as set out in Schedule B of the PPA]. Yukon Energy and VGC Group have entered into the McQuesten Substation MOU provided in Schedule B to the PPA (the "MOU") to establish the formal relationship between the Parties and the commitments to enable the Parties to work together on tendering, procurement, construction, commissioning and eventual turnover of the McQuesten Substation to YEC."

QUESTION:

a) Please confirm that YEC will recover all costs identified in the above quote from VGC Group. If not confirmed, please explain.

b) When does YEC anticipate that the MOU is to be finalized?

ANSWER:

(a)

Not confirmed.

There are no specific costs identified in the above quote. However, pursuant to the McQuesten Substation MOU and the PPA, and unless otherwise specified, VGC Group will itself fund all of the costs, fees and expenses for the development of the McQuesten substation, including actual final YEC Owner's Costs as outlined in Table B-1 of Schedule B of the PPA (currently estimated to be $483,240). VGC Group will also fund YEC's actual costs for the Step Down Transformer to be located at the McQuesten Substation and designed to step down 138 kV to 69 kV, if it is determined to be required.

YEC is responsible for the defined YEC McQuesten Substation Costs for incremental fees, costs and expenses associated with the McQuesten Substation being able to operate in future (if and when so required) at 138 kV voltage. Section 6.1(d) of the PPA identifies YEC McQuesten Substation Costs of $930,563, as set out under Section B.4 of Schedule B. YEC funding of VGC Group costs for these added facilities for 138 kV service recognizes that these facilities are not required at the outset for delivery of Grid Electricity to the 69 kV Mine Facilities Spur line, but are required as part of the full SKTP Transmission Facilities Development option. As reviewed in the PPA Application (section 5.4, page 14), the above YEC McQuesten Substation costs will be held in WIP until the Transmission Facilities Development Operation Date, and then included in the Transmission Facilities Fixed Cost per year that determine the Fixed Charge for VGC Group and any Other Industrial Customer using the Transmission Facilities. (Please also see response to YUB-YEC-1-5(a)).

(b)

The final McQuesten Substation MOU is provided as Schedule B to the VGC Group PPA.

TOPIC: **Transmission Facilities Development, default option**

REFERENCE: **Application, Section 5.2, page 12**

PREAMBLE:

QUOTE:

"**Transmission Facilities Development expected to be completed by June 30, 2020** – This development option, which is the default option, assumes completion of Transmission Facilities Development that includes only new Transmission Facilities located between McQuesten Substation and the existing Mayo Substation (L180) that are to be operated at 69 kV. Costs for this option are assumed to be funded by Yukon Energy and to be recovered through rates as approved by the Board."

QUESTION:

a) Respecting the above quote, please explain what facilities make up the "new Transmission Facilities located between McQuesten Substation and the existing Mayo Substation (L180) that are to be operated at 69 kV". Are the facilities only transmission-line related ones?

b) Does line L180, referred to above, parallel the existing line between Mayo and Keno City? Please explain.

c) Considering the need for the McQuesten Substation is triggered by VGC mine development, please explain why the costs for the above-noted option are "to be funded by Yukon Energy and to be recovered through rates as approved by the Board."

ANSWER:

(a) and **(b)**

The new Transmission Facilities referenced between McQuesten Substation and the existing Mayo Substation are essentially only new 138 kV transmission line facilities.

Under the default option as referenced, these new facilities will be operated at 69 kV and therefore there is no concurrent requirement for added substation or PT facilities. (See response to YUB-YEC-1-3(a) for added information on the default option.)

The new transmission facilities between Mayo and McQuesten Substation will replace the existing 69 kV line. It will not always parallel the location of the existing line, but will be located mainly within or adjacent to the existing 69 kV transmission line ROW. There are a small number of minor deviations from the existing 69 kV ROW in order to avoid potential land use conflicts, and to improve line routing by improving access and reducing exposure to wet ground, difficult terrain and permafrost. The new 138 kV line north of Mayo will be located closer to the Silver Trail in areas where it would reduce future maintenance costs or in areas where permafrost concerns need to be addressed.[1]

(c)

The McQuesten Substation was included in the SKTP proposal as reviewed by YESAB, prior to development of the VGC Group PPA. This facility is assumed to be a key element of the SKTP proposal, with or without the VGC Group mine. The McQuesten Substation development timing (i.e., prior to funding decisions related to the full SKTP, as well as prior to other new transmission facility development) is the one thing triggered by the VGC Group mine development, reflecting the need for a connection of this mine to the existing grid prior to any new transmission facilities development such as the SKTP proposal.

Pursuant to the VGC Group PPA, except for certain specified costs, VGC Group is responsible for funding all of the costs, fees and expenses for the development of the McQuesten Substation, including actual final YEC's Owners Costs as outlined in Table B-1 of Schedule B of the VGC Group PPA.

The McQuesten Substation Capital Costs funded by YEC relate to incremental fees, costs and expenses associated with the McQuesten Substation being able to operate at 138 kV voltage. This feature is not required today for VGC Group to connect to the grid. Yukon Energy is providing the initial funding as needed to ensure that these features are cost-effectively included in the initial substation design to accommodate 138 kV transmission

[1] See description provided in Stewart-Keno Transmission Line YESAA Project Proposal, Chapter 6, page 6-1.

at such time as this may be implemented in future, i.e., in the event that external funding is provided for the full SKTP development with new 138 kV transmission from Stewart Crossing South Substation to McQuesten Substation.

As reviewed in the PPA Application (Section 5.4, page 14), the above YEC McQuesten Substation costs will be held in WIP until the Transmission Facilities Development Operation Date, and then included in the Transmission Facilities Fixed Cost per year that determine the Fixed Charge for VGC Group and any Other Industrial Customer using the Transmission Facilities.

TOPIC: **Power Factor Requirement**

REFERENCE: **Application, page 12**

PREAMBLE:

QUOTE:

"Section 5.1 of the PPA provides for the Grid Electricity to be delivered by YEC to VGC Group, subject to the Maximum Electric Demand amounts specified before and after the Transmission Facilities Development, and a load Power Factor requirement of 96% leading."

QUESTION:

a) Please explain what is meant by a load Power Factor requirement of <u>96% leading.</u>

ANSWER:

(a)

This is a power quality requirement. It ensures VGC does not cause detrimental voltage to the system or other customers.

"96% leading Power Factor" means that VGC Group is required, at the Point of Delivery, to accept charges for 1.0 kVA for each 0.96 kW, i.e., Power Factor of 96%. This requirement is contributing to support of the grid voltage by producing "reactive power" or vars, to maintain the voltage as needed to deliver active power (watts). This requirement was undertaken to avoid the expense of installing other equipment at the McQuesten substation to produce reactive power.

TOPIC: **Firm Mine Rate & Fixed Charge**

REFERENCE: **Application, page 14**

PREAMBLE:

QUOTE:

"The existing Industrial Primary Rate (Rate Schedule 39) is set out in Schedule A of the PPA for approval of the Board (the Firm Mine Rate). The Firm Mine Rate is amended: (1) to revise the wording for the Fixed Charge to be applied to Alexco mine; (2) to provide a new Fixed Charge applicable to the VGC Group; and (3) to edit the "Available" section as needed to reflect todays Yukon Integrated Grid. The determination of the Fixed Charge for the VGC Group is outlined in Section 7.7 of the PPA and summarized below."

QUESTION:

a) Would any changes to a rate schedule, including a change to a fixed charge, be compliant with the existing OIC that govern changes to existing rates? Please explain.

ANSWER:

(a)

The Board last made a change to the Rate Schedule 39 fixed charge in Board Order 2010-14, when it approved the Alexco PPA. At that time, the Board was subject to OIC 2008/149, which in effect provided the same basic rate direction as the current OIC 2014-23 governing changes to existing rates. At that time, no issue of compliance with OIC 2010-14 was raised regarding the change to the Rate Schedule 39 fixed charge. Similarly, no issue was raised at that time regarding the extent to which OIC 2008/149 provisions overrode the need to confirm compliance of Rate Schedule 39 charges with OIC 1995/90 directions under Section 6(1) (i.e., that rates to major industrial customers are sufficient to recover the costs of service).

OIC 2014-23 directs that the Board must ensure that, up to December 31, 2018, rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and the class of major industrial customers. As demonstrated in the 2009 GRA Phase II approved changes to rate design for various retail customer classes, the Board retains the ability under this OIC direction to change rates so long as the overall percentage rate adjustment remains the same for each of the specified customer classes.

The amendments to the Firm Mine Rate, including the Fixed Charge, in Schedule A of the PPA do not require any change to Fixed Charge amounts to be charged to any customer prior to the December 31, 2018 expiry date for OIC 2014-23. The amendments to the Fixed Charge (Rate Schedule 39) sought in the PPA Application are as follows:

1. Revised wording for Fixed Charge to be applied to Alexco mine:

    a. The Revised wording simply references the existing Alexco PPA, which set the current Fixed Charge at $7,289 per month, which amount was approved in Board Order 2010-14.

    b. Under the revised wording, this Fixed Charge in effect continues to apply to Alexco "until such time as this amount is amended by the YUB based on the VGC Group PPA." No such amendment is required until the earlier of (i) the VGC Group mine being connected to the grid (earliest such date being March 2019), and (ii) the Alexco facilities resuming operation as a major industrial customer.

2. Wording to provide a new Fixed Charge applicable to the VGC Group:

    a. The proposed wording references the PPA provisions rather than any specific dollar amounts.

    b. The earliest date that any Fixed Charge could be applied to the VGC Group per the PPA is March 2019, in the event that Commencement of Delivery occurs in that month.

c. Based on section 7.7 of the PPA, 85% of the proposed Transmission Facilities Fixed Cost of $118,621 equals $100,828 per year or $8,402 per month, which (due to updates in the YEC annual transmission facilities fixed costs) differs slightly ($1,113 more per month) from the existing Alexco Fixed Charge. In the context of expected annual VGC Group Rate Schedule 39 charges of $8.75 million in 2020 excluding the Fixed Charge as per Table 3 in the PPA Application, the added Fixed Charge amount of about $13,000 per year due to the updated YEC costs would equal less than 0.2% impact.

d. The Fixed Charge provisions in Section 7.7 provide for YEC to apply to the Board to change to the Transmission Facilities Fixed Cost (and therefore to the Fixed Charge) after the Transmission Facilities Development Operation Date (the earlies potential date for such application being after June 30, 2020). The potential amendment requirement in this regard remains very uncertain today.

3. Edit of the “Available” section as needed to reflect today’s Yukon Integrated Grid – this amendment has no impact on any rate amounts.

In the event that the OIC 2014-23 provisions expire on December 31, 2018, the Board will clearly not be constrained by these provisions in addressing the above changes to the Fixed Charge in 2019 and beyond.

In the event that a new OIC extends beyond the end of 2018, the OIC 2014-23 directions governing changes to existing rates, the Board can then assess whether the Fixed Charge changes required by the VGC Group PPA are sufficient to raise any compliance concerns. If such compliance concerns are found to exist, the Board will have the flexibility to adjust other provisions of Rate Schedule 39 as required to ensure compliance.

TOPIC: **Fixed Charge Applicable to Industrial Customers**

REFERENCE: **Application, page 14.**

QUOTE:

"Yukon precedent for industrial grid connections establishes that industrial customers are required to make contributions towards existing and new transmission infrastructure built specifically to provide them with industrial service."

…

"In 2010, prior to Alexco receiving grid service as an industrial customer, a Fixed Charge was established and included in the YUB-approved Alexco PPA. This ensured that Alexco paid its share of costs for transmission facilities maintained in service to serve future industrial customers after the closure of the UKHM mine. This also established a precedent that industrial customers connecting to the existing Mayo-Keno transmission facilities would collectively be assigned, through a fixed charge included in Rate Schedule 39, an 85% share of annual depreciation and return costs related to these transmission facilities."

QUESTION:

a) Please explain how the contributions from VGC Group contribute towards existing transmission infrastructure, including the WAF, Carmacks-Stewart and Mayo-Dawson transmission lines.

b) Did the Alexco PPA precede the second phase of the CSTP?

c) If the answer to (b) is yes please explain how the 85% of annual depreciation and return costs related to the transmission facilities was determined.

d) Should the 85% only relate to transmission facilities related to the Mayo-Dawson line? Please explain.

e) Should a portion of fixed generation costs be included in the fixed charge? Please explain.

f) What other alternatives did YEC consider in setting the 85% threshold? Please explain.

ANSWER:

(a)

Fixed Charge contributions from either the VGC Group or Alexco, pursuant to PPAs with each of these major industrial customers, provide no direct contribution towards the costs of existing transmission infrastructure beyond the 69 kV Mayo to Keno City transmission facilities, i.e., there are no Fixed Charge direct contributions by either of these major industrial customers towards the costs of existing WAF, CSTP or Mayo Dawson transmission facilities. As reviewed in response to YUB-YEC-1-7(a-c), the assignment of direct costs to any mine is based on clear evidence of development and/or dominant use specifically for the identified mine.

Established Yukon precedent for industrial grid connections is for industrial customers to make contributions towards existing and new transmission infrastructure built specifically to provide them with industrial service. In practice, this relates to the mine facilities spur and any substation costs required to connect a mine to the grid and to step down the power from the grid to the mine site; as well as contributions towards the cost of specific new or existing bulk transmission infrastructure that is used almost exclusively for the mine.[1]

There is no established Yukon precedent for an industrial customer to make similar Fixed Charge assigned cost contributions towards all grid transmission infrastructure (see also response to YUB-YEC-1-7 (a to c)):

[1] For example, the Minto mine paid an agreed-upon contribution towards Stage 1 of the Carmacks-Stewart Transmission line based on estimated costs for 35 kV service; and Alexco mine paid a Fixed Charge based on 85% of the existing costs of the Mayo-Keno line that was originally constructed and maintained to ensure industrial service to the region, where Alexco's share of the line's load was expected to approximate 98%.

- The Faro mine Fixed Charge applied only to the Whitehorse-Faro segment of the WAF transmission facilities, notwithstanding that other segments of the WAF were also used to supply power to this mine;

- The Minto mine made capital contributions towards the CSTP Stage 1; but was not required to pay a fixed charge or make any other specific contributions for the WAF transmission line; and

- The Alexco Fixed Charge was based on costs for the Mayo to Keno Transmission line, but did not include any costs for the portion of the line between Stewart and Mayo, or for any other portion of the Mayo Dawson line.

VGC Group is directly paying for the Mine Facilities Spur required to connect the Mine facilities to the Yukon Integrated Grid, and has agreed to a Fixed Charge for existing and future costs for the defined Transmission Facilities [includes the existing transmission between Mayo and McQuesten]. VGC Group is also making capital contributions pursuant to Section 6.1 of the PPA for the following:

- YEC's actual costs to negotiate and conclude the PPA, estimated at $200,000;

- YEC's actual Initial YEC System Improvements capital costs as set out in Schedule C of the PPA, currently estimated at $1,677,883;

- YEC’s actual capital costs for the McQuesten Substation development ("YEC's Owners Costs") as specified in Table B-1 of Schedule B to the PPA, currently estimated at $443,240 (VGC Group is responsible for all capital costs for the McQuesten Substation development, other than the YEC McQuesten Substation Costs under Section B.4 of Schedule B of the PPA); and

- YEC's actual costs for the Step Down Transformer to be located at the McQuesten Substation and designed to step down from 138 kV to 69 kV, if it is determined to be required.

(b) and **(c)**

Yes, the Alexco PPA preceded the in service of Carmacks-Stewart Transmission Project – Stage 2.[2]

The basis for the 85% of annual depreciation and return costs related to the Transmission Facilities Fixed Charge for Alexco was reviewed during the 2010 Alexco PPA proceeding. The following are noted in this regard (see also response to YUB-YEC-1-7(a to c)):

- The Alexco Fixed Charge of $7,289/month assigned to Alexco 85% of YEC 2010 annual owner costs (depreciation and return) related only to the existing costs for the Mayo to Keno line; it was noted that this line segment was primarily developed in the past to serve industrial customers in the District (i.e., UKHM).

- The calculation for YEC's 2010 annual owner costs for the Mayo-Keno line that was used to determine the Alexco Fixed Charge was provided in Attachment B of the Alexco PPA [the electronic excel file for Attachment B from the Alexco PPA Application is provided as Attachment 1 to this response].

- The source data for the YEC Annual Transmission Facilities was provided in the response to YUB-YEC-1-14 (a) and (b) from the 2010 Alexco PPA Proceeding. The relevant data is provided as Attachment 2 to this response.

The response to YUB-YEC-1-14 from the Alexco PPA proceeding noted that Alexco was not deriving direct benefits from the completion of CSTP Stage 2. Alexco was commencing service as an industrial customer prior to the completion of this line and interconnection of the grids, and would be served through the existing 69 kV Mayo-Keno line via a Mine Facilities Spur that the mine was fully funding. The CSTP Stage 2 line was fully funded by Federal and YDC contribution payments and any benefits from the line would occur for ratepayers through reduction in YEC diesel generation cost otherwise required without connection of the two existing grids.

[2] The Alexco PPA was concluded by the parties to the agreement on September 1, 2010 and approved by the Board January 26, 2011 [Order 2011-01]. Carmacks-Stewart Transmission Project – Stage 2 was completed in June 2011.

(d)

There is no basis at this time for considering the Mayo-Dawson line for an 85% threshold Fixed Charge assignment of transmission costs to any mine.

As reviewed in response to YUB-YEC-1-7(a to c), the basis for this VGC Group Fixed Charge follows the principle applied for the Alexco Fixed Charge and is based on accepted precedent that extends back to the mid-1980s and the National Energy Board [NEB] report into Matters Relating to the Northern Canada Power Commission (1985). The NEB proceeding specifically addressed the issue of allocating costs for transmission facilities to specific customers [i.e., the Faro mine]. Notably, the Faro mine was allocated 85% of costs for the Whitehorse to Faro portion of the WAF [and not the entire WAF grid].

Section 7.3.4.1 of the NEB report addresses “specific charges and credits” and notes as follows at page 41:

> The criterion used by NCPC in assigning assets to specific customers for the purpose of levying special charges was that assets that could reasonably be determined to be for the sole use of a particular customer or particular customer class were charged directly to that customer or class. Assets that fall into this category are facilities installed for a particular customer’s need (i.e., diesel plant installed at Pine Point, NWT for Pine Point Mines Limited’s 10 MW electric dragline operation) as well as substation facilities serving individual customers.

The following was specifically noted re: the treatment of transmission lines:

> In its submission, NCPC did not assign transmission lines to specific customers or classes. Under the proposed rate zone scenario, all transmission facilities within a rate zone were assumed by NCPC to be interconnected. In light of this assumption, NCPC considered it would be inappropriate to charge specific portions of the transmission system to individual customers as this would contradict its theoretical assumption that all consumers, regardless of location in the rate zone, share the same general production and transmission facilities.

The Board provided its conclusions on this issue at page 42 to 43:

> …in the absence of contractual arrangement, established Commission policy, or regulatory decision requiring a particular customer or group of customers to bear the cost of a new facility, be it a generating facility, transmission line or part of a distribution facility, the annual costs of such facilities should be included in the pooled costs to be allocation to all customers in the rate zone.
>
> Nevertheless, the Board believes that, in light of the circumstances surrounding the construction of the Whitehorse to Faro transmission line and the 5.2 MW diesel engine at Faro, a significant portion of these assets should, as was done in the past, be specifically assigned to CAMC.

(e)

There is not a principled basis for a portion of YEC fixed generation costs to be included in the VGC Group fixed charge.

Under the existing Yukon regulatory framework new/ incremental industrial customers have not been required to make any direct contributions (outside of rate changes established for the Industrial class through normal cost of service principles) to the cost of new generation and/or the added costs of existing thermal generation.

Requiring such a charge may be considered rate discrimination, as other classes of customers do not pay a similar charge for fixed generation costs; and other industrial customers such as Faro mine, the Minto mine and the Alexco mine have not [and do not] pay a fixed charge based on fixed generation costs (beyond the one case of fixed diesel generation costs for specific units at Faro for the Faro mine, related to local operational spinning reserve).

The existing approach is consistent with Yukon Energy's understanding of practice in other similar jurisdictions. Specifically, while there is ample precedent in other jurisdictions for requiring contributions by customers for transmission costs to connect such loads to the grid, Yukon Energy is not aware of any precedents in any other similar hydro-based rate regulated jurisdictions where such customers are required to pay specific fixed cost contributions towards generation.[3]

Aside from the above basic principles as applied in Yukon and other jurisdictions, it can also be noted that Yukon Energy is not planning to develop any new renewable or thermal generation facilities specifically related to connection of the VGC Group load. Under the current capacity planning criteria, the single contingency (N-1) criterion is expected to continue to set dependable capacity planning requirements – and this criterion is not affected by any industrial loads.

(f)

For the VGC Group PPA Yukon Energy did not consider any other alternatives in setting the 85% threshold for the Fixed Charge determination.

The 85% threshold for VGC Group Fixed Charge is based on well-established Yukon precedent dating back to the mid-1980s, and the specific PPA related provisions approved by the Board for Alexco with regard to industrial use of the same specific transmission facilities.

The reasonableness of this threshold was reviewed during the 2010 Alexco PPA proceeding and approved by the Board as a result of the proceeding [see Order 2010-14 and Order 2011-01]. As the Victoria Gold mine is planned to operate in the same region as Alexco, using the same infrastructure, it was not considered appropriate to consider alternatives to the 85% threshold at this time.

[3] During the Alexco PPA proceeding the response to YUB-YEC-1-3 noted that contributions to “generation” in this regard are differentiated from contributions towards added facilities specifically installed to maintain power quality related to impacts of a customer’s load (e.g., local operational spinning reserve that was required during Faro mine operation). Similarly, Yukon Energy is aware of a BC Hydro related policy (Tariff Supplement #6) whereby capital cost contributions to generation may be required from industrial customers with very large new loads (150 MVa or larger) coming on to the grid system if new local generation resources may be required (in addition to new transmission facilities) to ensure system stability and power quality.

Attachment B – YEC Annual Transmission Facilities Costs

Line #	Description	Cost ($)
	Transmission Facilities costs as of end of 2008:	
1	Total assets at cost	1,455,125
2	Accumulated depreciation	294,939
3=1-2	Net book value at yr end	1,160,186
4	Annual depreciation	29,723
	Estimated Transmission Facilities costs at end of 2009 and end of 2010, assuming no new assets:	
5=3-4	Projected Net Book value at end of 2009	1,130,463
6=5-4	Projected Net Book value at end of 2010	1,100,740
7=(5+6)/2	Projected Net Value at mid yr 2010	1,115,602
	Based on YUB approved return (debt and equity cost at 6.56% blended) on rate base for 2009, plus depreciation, the annual owner costs for this	
8=4	Depreciation	29,723
9=7*6.56%	Return at 6.56%	73,183
10=8+9	Total Annual Cost	102,906
11=10/12months	**Cost per month**	**8,576**
8,576*0.85	**Alexco Fixed Charge**	**7,289**

Asset #	GL Code	Gl Desripton	Amount Dec 31, 2008	Ending Accum. Dep 2008	rate	Annual Deprec	
290	20.140006.300	Poles and fixtures	328,856.38	94,189.86	2.00	6,577.13	
803	20.140006.300	Poles and fixtures	24,028.74	4,182.51	2.00	480.57	
1074	20.140006.300	Poles and fixtures	28,519.52	4,162.32	2.00	570.39	
1165	20.140006.300	Poles and fixtures	209,170.07	29,074.76	2.00	4,183.40	
1674	20.140006.300	Poles and fixtures	123,673.73	11,724.79	2.00	2,473.47	
4461	20.140006.300	Poles and fixtures	75,021.60	3,376.09	2.00	1,500.43	
7399	20.140006.300	Poles and fixtures	43,044.24	-	2.00	860.88	Asset was added at 12/31/2008
7430	20.140006.300	Poles and fixtures	19,754.56	-	2.00	395.09	Asset was added at 12/31/2008
7370	20.140009.605	Communication Equipment	20,677.62	-	5.00	1,033.88	Asset was added at 12/31/2008
291	20.140006.402	Overhead Conductors/Poles	241,985.37	88,814.62	2.00	4,839.71	
804	20.140006.402	Overhead Conductors/Poles	287,160.90	50,920.60	2.00	5,743.22	
879	20.140006.402	Overhead Conductors/Poles	53,231.89	8,493.21	2.00	1,064.64	
Total Plant In Service			1,455,124.62	294,938.76		29,722.82	
			net y/e 2008	1,160,185.86			

TOPIC: **Fixed Charge**

REFERENCE: **Application, page 15, Footnote 22 and Appendix A to Board Order 2010-14.**

QUOTE:

"The basis for the fixed charge applicable for the Mayo-Keno Transmission Facilities was initially reviewed and approved by the YUB in 2010 as part of the Alexco PPA;"

…

"Allocating 85% of annual costs of the line to the industrial customer is considered reasonable based on similar treatment of Faro Mine in the past".

…

"[22] The 85% share of fixed costs included in the approved Alexco PPA is based on the NEB 1985 NCPC Report finding regarding the Faro Mine which was subsequently retained by the YUB to set the fixed charge for the Faro Mine under Rate Schedule 39." (footnote 22)

…

"YEC cited several decisions allowing that 85% of transmission line costs to be directly allocated to an industrial customer. Board Order 2007-5 was also cited as support for the 85% allocation of transmission line costs to industrial customers. In Appendix A to YUB Board Order 2007-5, the Board said:

> The Board agrees with intervenor concerns regarding the lack of a complete COS study. The Board is of the view that due to the articulating nature of a COS study; rates cannot be developed in isolation. Therefore, the Board reiterates its earlier direction that YEC and YECL must provide a complete COS study and rate design with their next GRA. The COS is to include updated studies on allocators, and will look at the feasibility of direct assigning assets, where applicable to certain rate classes. Further, the Board expects to see justification on the allocation of transmission assets.

> The Board later said that it accepted Rate Schedule 39 on an interim basis and that it had concerns about the sufficiency of the current COS presented by YEC.
>
> The Board concludes that the precedents cited by YEC provide some support for the direct transmission allocation (85%) as applied for. Most of the cases cited refer to cost of service and not the fundamental basis or appropriateness for the establishment of fixed charges to industrial customers. The Board notes that no other alternatives have been presented (in terms of allocation of transmission costs through fixed charges) in this proceeding. The comparison to the Faro situation when determining fixed charges for transmission line costs is the best available evidence for this proceeding. Furthermore, the Board accepts the information with respect to calculations provided by YEC in Attachment B to YUB-YEC-1-3(b) and approves the fixed charge to Alexco of $7,289 per month." (Appendix A to Board Order 2010-14, page 5 of 11)

QUESTION:

a) If the Board were to direct a direct transmission allocation other than 85%, would this have any impact on existing PPAs such as for Minto and Alexco?

b) Please provide the detailed calculation of how the fixed charge of $8,402/month (for VGC Group) is determined (include a version in electronic format stating all assumptions).

ANSWER:

(a)

The existing PPA with Alexco would be impacted if the Board was to direct a direct transmission allocation other than 85%; the only other existing PPA (i.e., the one with Minto) would not be impacted by such a change.

VGC Group and Alexco [should it resume service while VGC Group is in operation] would receive service from the same grid transmission infrastructure [the Mayo to McQuesten portion of the Mayo to Keno line segment].

The Alexco PPA Fixed Charge assigns to Alexco 85% [$87,468 per annum] of YEC 2010 annual owner costs (depreciation and return) related to the defined Transmission Facilities, as approved by the Board when approving the Alexco PPA (Order 2010-14). A change to the basis for the fixed charge [i.e., the principle for charging industrial customers direct costs in relation to defined Transmission Facilities] would change one of the fundamental features of the Alexco PPA, and would likely require YEC to re-open the PPA with Alexco prior to Alexco resuming grid service. See response to YUB-YEC-1-7(a-c) and YUB-YEC-1-20(b-d).

A change to the 85% direct transmission allocation would not impact the Minto PPA.

- The Minto PPA provides for Minto to pay the full cost of the Minto Spur line (constructed specifically to provide service to that mine site). Minto also paid a contribution towards the Capital Costs of CSTP Stage 1 pursuant to the Agreement (as approved by the Board in Order 2007-5).

- Given these required contributions, no additional direct allocation was made to Minto regarding annual fixed costs for any pre-existing transmission infrastructure in place to provide service to the mine.

(b)

The detailed calculation for the Fixed Charge of $8,402/month (for VGC Group) can be derived from Attachment B of the Application.

Attachment B provides the updated determination of YEC’s annual Transmission Facilities Fixed Cost for 2019 of $118,621 [$9,885/month].

The VGC Group Fixed Charge equals 85% of the Transmission Facilities Fixed Cost [i.e., $9,885 *0.85 = $8,402/month], assuming no Other Industrial Customer. [If there is an Other Industrial Customer, e.g., Alexco or another industrial customer also supplied by the specified Transmission Facilities, the above Fixed Charge is multiplied by the VGC Group

Share.] See Attachment 1 to this response which provides an excel sheet with the calculations in electronic format for the Fixed Charge of $8,402 per month.

YEC - Annual L250 (Mayo-Elsa-Keno City) 69 kV Transmission Costs

Transmission Facilities costs as of		2017		2018
Total assets at cost	$	2,244,721	$	2,244,721
Accumulated depreciation	$	534,434	$	571,656
Net book value	**$**	**1,710,287**	**$**	**1,673,065**
Annual depreciation	**$**	**37,222**	**$**	**37,222**

Projected Net Book Value:		
At end of 2018	$	1,673,065
At end of 2019:	$	1,635,843
2019 Mid-Yr Rate Base	**$**	**1,654,454**

Transmission Facilities Fixed Cost		2019
Average Cost of Capital (per GRA)		4.92%
Return on Rate Base	$	81,399
Depreciation	$	37,222
Total Annual Cost	**$**	**118,621**
Cost per month	**$**	**9,885**

Fixed Charge		
Percent of Transmission Facilities Fixed Cost		85%
VGC Group Share (assumes no Other Industrial Customer)		100%
Fixed Charge per month for VGC Group	**$**	**8,402**

Asset ID	Asset Description	Place in Service Date	Cost Basis	Periodic Depreciation Rate	Yearly Depreciation Rate	YTD Depreciation Amount	LTD Depreciation Amount	Depr to 2017 YE	2017 NBV	Depr to 2018 YE
000290	MAYO ELSA 69/KV	1/1/1999	$ 263,351.42	$ 337.63	$ 4,051.56	$ 3,038.67	$ 70,402.48	$ 71,415.37	$ 191,936.05	$ 75,466.93
000291	MAYO ELSA 69/KV	1/1/1999	$ 241,985.37	$ 403.31	$ 4,839.71	$ 3,629.79	$ 131,158.09	$ 132,368.02	$ 109,617.35	$ 137,207.72
000749	ELSA RE-POLE	6/1/2001	$ 25,526.63	$ 32.73	$ 392.72	$ 294.57	$ 9,071.11	$ 9,169.29	$ 16,357.34	$ 9,562.01
000803	C01062LIGHTNING PROT-ELSA FEED	9/1/2001	$ 24,028.74	$ 30.81	$ 369.67	$ 277.29	$ 7,749.30	$ 7,841.72	$ 16,187.02	$ 8,211.39
000804	C98072 REPOLE ELSA FEEDER	4/1/2001	$ 287,160.88	$ 478.60	$ 5,743.22	$ 4,307.40	$ 101,178.90	$ 102,614.70	$ 184,546.18	$ 108,357.92
000879	C01070 Elsa Feeder-Chq Poles	12/31/2001	$ 53,231.89	$ 88.72	$ 1,064.64	$ 798.48	$ 17,812.45	$ 18,078.61	$ 35,153.28	$ 19,143.25
001165	Pole & Insulator Change out	12/1/2002	$ 209,170.07	$ 268.17	$ 3,218.00	$ 2,413.53	$ 60,133.55	$ 60,938.05	$ 148,232.02	$ 64,156.05
001674	Change Poles Elsa Feeder	7/1/2004	$ 123,673.73	$ 158.56	$ 1,902.67	$ 1,427.04	$ 30,083.94	$ 30,559.61	$ 93,114.12	$ 32,462.28
004461	Elsa Line Upgrades	2/1/2007	$ 75,024.60	$ 96.19	$ 1,154.22	$ 865.71	$ 14,513.82	$ 14,802.38	$ 60,222.22	$ 15,956.60
007399	L-250 Transmission upgrade	2/1/2009	$ 43,044.24	$ 55.18	$ 662.22	$ 496.62	$ 6,393.74	$ 6,559.29	$ 36,484.95	$ 7,221.51
007401	L250 Keno Gang Switch	12/31/2008	$ 74,179.37	$ 95.10	$ 1,141.22	$ 855.90	$ 11,017.49	$ 11,302.80	$ 62,876.57	$ 12,444.02
007430	Elsa Transmission Upgrade	12/31/2008	$ 19,754.56	$ 25.33	$ 303.92	$ 227.97	$ 2,933.73	$ 3,009.71	$ 16,744.85	$ 3,313.63
007549	L250 Elsa Transmission Upgrade	12/31/2009	$ 74,804.63	$ 95.90	$ 1,150.84	$ 863.10	$ 9,613.67	$ 9,901.38	$ 64,903.25	$ 11,052.22
007729	L250 Elsa Trans Line Upgrade	8/26/2010	$ 104,086.45	$ 133.44	$ 1,601.33	$ 1,200.96	$ 12,011.48	$ 12,411.81	$ 91,674.64	$ 14,013.14
008051	L250 Transmission Upgrade-Mayo	12/31/2011	$ 145,714.95	$ 186.81	$ 2,241.77	$ 1,681.29	$ 12,896.28	$ 13,456.72	$ 132,258.23	$ 15,698.49
008155	L250 Transmission Upgrade	12/14/2012	$ 190,138.07	$ 243.77	$ 2,925.20	$ 2,193.93	$ 14,038.59	$ 14,769.89	$ 175,368.18	$ 17,695.09
008391	L250 Transmission Line upgrade	12/31/2013	$ 48,195.44	$ 61.79	$ 741.47	$ 556.11	$ 2,782.55	$ 2,967.92	$ 45,227.52	$ 3,709.39
008439	L250 Transmission 2014 Lines Upgrades	9/15/2014	$ 60,668.64	$ 77.78	$ 933.36	$ 700.02	$ 2,842.91	$ 3,076.25	$ 57,592.39	$ 4,009.61
008555	L250 Transmission Line upgrades	9/1/2015	$ 57,019.33	$ 73.10	$ 877.22	$ 657.90	$ 1,828.33	$ 2,047.64	$ 54,971.69	$ 2,924.86
008690	L250 Transmission Upgrade - 2016 - Mayo	8/17/2016	$ 49,766.02	$ 63.80	$ 765.63	$ 574.20	$ 860.79	$ 1,052.20	$ 48,713.82	$ 1,817.83
008157	Test & Treat L250, L356, L170	8/31/2012	$ 74,196.30	$ 95.12	$ 1,141.48	$ 856.11	$ 5,805.65	$ 6,091.02	$ 68,105.28	$ 7,232.50
Total			2,244,721.33	3,101.84	37,222.07	27,916.59	525,128.85	534,434.37	1,710,286.96	571,656.44

TOPIC: **Alexco Fixed Charge**

REFERENCE: **Application, page 16.**

QUOTE:

"The PPA provisions will require amendment to the Alexco fixed charge at such time as the VGC Group receives Grid Electricity from YEC."

…

"With regard to securing any required YUB approvals related to Fixed Charge amounts, including amounts related to the VGC Group Share or the Transmission Facilities Fixed Cost, YEC will provide the YUB pursuant to Section 7.7 (c)(iii) with such supporting documentation as required by the YUB, and will use <u>commercially reasonable efforts to obtain the approval of the YUB."</u> (underlining added)

QUESTION:

a) Does the Alexco PPA allow for such changes? Please explain.

b) Do any changes to fixed charge amounts require YUB approval?

c) Please explain what is meant by "commercially reasonable efforts to obtain the approval of the YUB"? Why has this limitation been added to the VGC Group PPA?

d) Please provide your estimate, in terms of order of magnitude, as to what the amendment to the Alexco fixed charge will be.

ANSWER:

(a)

Yes, the Alexco PPA allows for changes to the Fixed Charge.

Section 6.7 of the Alexco PPA provides that each time a Major Industrial Customer proposes to commence for the first time to receive Grid Electricity from the Transmission

Facilities (defined in the Alexco PPA as: "YEC's 69 kV Mayo-Keno transmission facilities located north of Mayo, Yukon Territory, or any future replacement transmission facilities at similar or higher voltage"), YEC will determine on a reasonable basis a proposed amended Fixed Charge applicable to Alexco reflecting an allocation of costs relating to the Transmission Facilities among the new Major Industrial Customer, Alexco and all other Major Industrial Customers receiving Grid Electricity from the Transmission Facilities at the time. YEC will then on a timely basis make application to the YUB seeking YUB approval of such proposed amended Fixed Charge for Alexco.

In summary, Section 6.7 of the Alexco PPA provides that when VGC Group proposes for the first time to receive Grid Electricity from YEC from the Mayo to McQuesten transmission facilities, YEC will determine on a reasonable basis a proposed amended Fixed Charge applicable to Alexco reflecting an allocation of costs relating to the Transmission Facilities among VGC Group and Alexco. Section 7.7(c) of the VGC Group PPA sets out the provisions to address such allocation of costs among VGC Group and Alexco (and any Other Industrial Customer) based on the portion of the Major Industrial Customer MW.h load on the Transmission Facilities during the calendar year.

(b)

Both the Alexco PPA and the VGC Group PPA specify that changes to the Fixed Charge for each mine require YUB approval. This requirement reflects the fact that the Fixed Charge is an element of Rate Schedule 39 and therefore would require YUB approval prior to any changes.

(c)

"Commercially reasonable efforts to obtain approval of the YUB" means that the efforts made to obtain YUB approval will be reasonable based on commercial standards, recognizing that a party cannot commit to succeed in seeking such regulatory approval.

The provisions relating to "commercially reasonable efforts" in seeking such YUB approval were also in the Alexco PPA. Section 6.7 of the Alexco PPA relating to amendment of the Fixed Charge includes provision that "YEC will provide the YUB with such supporting documentation as required by the YUB for such application, and will use commercially reasonable efforts to obtain the approval of the YUB for such proposed amended Fixed

Charge for Alexco, and Alexco will use commercially reasonable efforts to support such application by YEC."

(d)

Amendments to the Alexco Fixed Charge in response to the VGC Group PPA will be dependent at the outset on VGC Group connection to the grid and Commencement of Delivery of Grid Electricity to VGC Group by YEC. The following example provides an order of magnitude estimate of the adjusted Alexco Fixed Charge in 2020 under assumptions consistent with the VGC Group PPA Application.

Section 7.7(c) of the VGC Group PPA provides that the Fixed Charge applicable to VGC Group and each Other Industrial Customer receiving service from the Transmission Facilities will be determined based on each such industrial customer's share of the Major Industrial Customer MWh load on the Transmission Facilities during the calendar year. As such, any required amendment to the Alexco Fixed charge in the future [should Alexco resume service as an industrial customer of YEC at a time when the VGC Group is also an industrial customer of YEC] will depend on the following factors:

- The Transmission Facilities Fixed Costs as determined at that time per the VGC Group PPA; and

- Alexco's share of the Major Industrial Customer MWh load on the Transmission Facilities at that time.

Using 2020 as an example, the following are noted regarding the potential Fixed Charge for Alexco should the VGC Group Eagle Gold mine also be in operation and connected to the grid as an industrial customer:

- Assume that the 2020 YEC annual Transmission Facilities Fixed Cost for the existing Transmission Facilities, including deprecation and return on YEC's assets, is $118,621 (as per the VGC Group PPA estimates for 2019 - see the calculation provided in Attachment B of the VGC Group PPA Application, and the response to YUB-YEC-1-21(b)). In effect, this assumes no change in 2020 to the Transmission Facilities Fixed Cost due to Transmission Facilities Development activities.

- The VGC Group PPA Application notes that assuming no Other Industrial Customer is using the Transmission Facilities, the VGC Group PPA initial Fixed Charge based on the Attachment B Transmission Facilities Fixed Cost is $8,402/month [$100,828 per annum], equal to 85% of the $118,621 Transmission Facilities Fixed Cost for the existing Transmission Facilities. See the response to YUB-YEC-1-21(b).

- Assuming that Alexco has resumed service as an industrial customer at this time, the Alexco Fixed Charge would be revised per the VGC Group PPA based Alexco's share of the Major Industrial MWh load on the Transmission Facilities.

    - For this example, it is assumed in 2020 that Alexco's load equals 19 GW.h and VGC Group's load equals 63 GW.h. These are the approximate Alexco mine and VGC Group mine loads assumed for 2020 in Table 3 of the VGC Group PPA Application, indicating an assumed total load of 82 GW.h in 2020 for Major Industrial Customers using the Transmission Facilities (as defined in the VGC Group PPA).

    - Based on these assumed loads, the Alexco mine accounts for a 23.17% share of the 2020 annual load for Major Industrial Customers on the Transmission Facilities.

    - Accordingly, based on these assumptions, the final Alexco Fixed Charge for 2020 equals $1,947 per month [or 23.17% of $8,402/month]. [This $1,947/month adjusted Alexco Fixed Charge compares with the current Alexco Fixed Charge of $7,298/month – see response to YUB-YEC-1-20(c).]

    - Under this example, the final VGC Group Fixed Charge for 2020 would equal the balance of $6,455/month.

- Table 1 below summarizes the above calculations (see also Attachment 1 to this response for excel file version).

Table 1: Calculation of 2020 example Alexco Fixed Charge revised based on Alexco's share of the Major Industrial MWh load on the Transmission Facilities with VGC Group mine load

Assumptions		Notes
VGC Group Fixed Charge without Alexco		
Transmission Facilities Fixed Cost for existing Transmission Facilities	118,621	VGC Group PPA Application - Attachment B
85% of Transmission Facilities Fixed Cost	100,828	85% Transmission Facilities cost for Existing Facilities in 2019
Fixed Charge ($/month)	**8,402**	
Assumed 2020 Major Industrial Customer Loads on the Transmission Facilities		
VGC Group Load (GWh/yr)	63	VGC Group PPA Application, Table 3
Alexco Load (GWh/yr)	19	VGC Group PPA Application, Table 3
Total Transmission Facilities Industrial Load	**82**	
VGC Group Share of Major Industrial Customer MWh load on the Transmission Facilities (2020)	76.83%	
Alexco Share of Major Industrial Customer MWh load on the Transmission Facilities (2020)	23.17%	
VGC Group Fixed Charge in 2020 ($/month)	**6,455**	76.83% of VGC Group Fixed Charge without Alexco
Alexco Fixed Charge in 2020 ($/month)	**1,947**	23.17% of VGC Group Fixed Charge without Alexco

TOPIC: **Total Assets at Cost**

REFERENCE: **Application, Attachment B, Page B-1**

PREAMBLE:

QUESTION:

a) Please describe what is included in the total assets at cost (for example, what transmission lines, substations, etc.).

b) For incremental transmission developments, when would the annual transmission fixed cost be updated? Would it be the year following capitalization or following a YUB decision on a YEC general rate application?

c) Would total assets at cost include any capital replacements and upgrades to the identified assets?

ANSWER:

(a) and **(c)**

Please see Table 1 at the end of this response (an excel version is provided as Attachment 1 to this response) for a description of what is included in the total assets at cost of $2,244,721. In essence, these assets are L250 transmission facilities between Mayo and Keno City through to the end of 2016. Total assets at cost include any capital replacements and upgrades to these assets.

(b)

The PPA provides for these costs to be updated after the Transmission Facilities Development Operation Date. The PPA also specifies that any change to the Transmission Facilities Fixed Cost will need to be approved by the Board.

Where feasible, Board review and approval of any change could occur as part of a YEC General Rate Application proceeding; however, if needed to address this change on a more timely basis after the work is capitalized, a limited scope proceeding would also be considered as a viable alternative in the event a full rate proceeding was not available to address this matter.

Table 1: Transmission Facilities Fixed Costs – Assets Forecast as at Year End 2017 and 2018

Asset ID	Asset Description	Place in Service Date	Cost Basis	Periodic Depreciation Rate	Yearly Depreciation Rate	YTD Depreciation Amount	LTD Depreciation Amount	Depr to 2017 YE	2017 NBV	Depr to 2018 YE
000290	MAYO ELSA 69/KV	1/1/1999	$ 263,351.42	$ 337.63	$ 4,051.56	$ 3,038.67	$ 70,402.48	$ 71,415.37	$ 191,936.05	$ 75,466.93
000291	MAYO ELSA 69/KV	1/1/1999	$ 241,985.37	$ 403.31	$ 4,839.71	$ 3,629.79	$ 131,158.09	$ 132,368.02	$ 109,617.35	$ 137,207.72
000749	ELSA RE-POLE	6/1/2001	$ 25,526.63	$ 32.73	$ 392.72	$ 294.57	$ 9,071.11	$ 9,169.29	$ 16,357.34	$ 9,562.01
000803	C01062LIGHTNING PROT-ELSA FEED	9/1/2001	$ 24,028.74	$ 30.81	$ 369.67	$ 277.29	$ 7,749.30	$ 7,841.72	$ 16,187.02	$ 8,211.39
000804	C98072 REPOLE ELSA FEEDER	4/1/2001	$ 287,160.88	$ 478.60	$ 5,743.22	$ 4,307.40	$ 101,178.90	$ 102,614.70	$ 184,546.18	$ 108,357.92
000879	C01070 Elsa Feeder-Chq Poles	12/31/2001	$ 53,231.89	$ 88.72	$ 1,064.64	$ 798.48	$ 17,812.45	$ 18,078.61	$ 35,153.28	$ 19,143.25
001165	Pole & Insulator Change out	12/1/2002	$ 209,170.07	$ 268.17	$ 3,218.00	$ 2,413.53	$ 60,133.55	$ 60,938.05	$ 148,232.02	$ 64,156.05
001674	Change Poles Elsa Feeder	7/1/2004	$ 123,673.73	$ 158.56	$ 1,902.67	$ 1,427.04	$ 30,083.94	$ 30,559.61	$ 93,114.12	$ 32,462.28
004461	Elsa Line Upgrades	2/1/2007	$ 75,024.60	$ 96.19	$ 1,154.22	$ 865.71	$ 14,513.82	$ 14,802.38	$ 60,222.22	$ 15,956.60
007399	L-250 Transmission upgrade	2/1/2009	$ 43,044.24	$ 55.18	$ 662.22	$ 496.62	$ 6,393.74	$ 6,559.29	$ 36,484.95	$ 7,221.51
007401	L250 Keno Gang Switch	12/31/2008	$ 74,179.37	$ 95.10	$ 1,141.22	$ 855.90	$ 11,017.49	$ 11,302.80	$ 62,876.57	$ 12,444.02
007430	Elsa Transmission Upgrade	12/31/2008	$ 19,754.56	$ 25.33	$ 303.92	$ 227.97	$ 2,933.73	$ 3,009.71	$ 16,744.85	$ 3,313.63
007549	L250 Elsa Transmission Upgrade	12/31/2009	$ 74,804.63	$ 95.90	$ 1,150.84	$ 863.10	$ 9,613.67	$ 9,901.38	$ 64,903.25	$ 11,052.22
007729	L250 Elsa Trans Line Upgrade	8/26/2010	$ 104,086.45	$ 133.44	$ 1,601.33	$ 1,200.96	$ 12,011.48	$ 12,411.81	$ 91,674.64	$ 14,013.14
008051	L250 Transmission Upgrade-Mayo	12/31/2011	$ 145,714.95	$ 186.81	$ 2,241.77	$ 1,681.29	$ 12,896.28	$ 13,456.72	$ 132,258.23	$ 15,698.49
008155	L250 Transmission Upgrade	12/14/2012	$ 190,138.07	$ 243.77	$ 2,925.20	$ 2,193.93	$ 14,038.59	$ 14,769.89	$ 175,368.18	$ 17,695.09
008391	L250 Transmission Line upgrade	12/31/2013	$ 48,195.44	$ 61.79	$ 741.47	$ 556.11	$ 2,782.55	$ 2,967.92	$ 45,227.52	$ 3,709.39
008439	L250 Transmission 2014 Lines Upgrades	9/15/2014	$ 60,668.64	$ 77.78	$ 933.36	$ 700.02	$ 2,842.91	$ 3,076.25	$ 57,592.39	$ 4,009.61
008555	L250 Transmission Line upgrades	9/1/2015	$ 57,019.33	$ 73.10	$ 877.22	$ 657.90	$ 1,828.33	$ 2,047.64	$ 54,971.69	$ 2,924.86
008690	L250 Transmission Upgrade - 2016 - Mayo	8/17/2016	$ 49,766.02	$ 63.80	$ 765.63	$ 574.20	$ 860.79	$ 1,052.20	$ 48,713.82	$ 1,817.83
008157	Test & Treat L250, L356, L170	8/31/2012	$ 74,196.30	$ 95.12	$ 1,141.48	$ 856.11	$ 5,805.65	$ 6,091.02	$ 68,105.28	$ 7,232.50
Total			2,244,721.33	3,101.84	37,222.07	27,916.59	525,128.85	534,434.37	1,710,286.96	571,656.44

TOPIC: **YEC Inspections**

REFERENCE: **Power Purchase Agreement, Schedule D, (h)**

PREAMBLE:

QUOTE:

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

QUESTION:

a) How will the costs of YEC inspections be recorded, and which party is responsible for those costs as incurred?

ANSWER:

(a)

YEC is responsible for the costs of its inspections and will retain records of any relevant costs.

TOPIC: **YEC Capital Costs**

REFERENCE: **Power Purchase Agreement, Table C-2**

PREAMBLE:

Table C-2 does not identify any costs for pole replacement or reconductoring of transmission line between Mayo and Keno.

QUESTION:

a) Should any of the line improvement, replacement costs of the Mayo-Dawson transmission line be attributed to VGC Group? Please explain.

ANSWER:

(a)

Table C-2 addresses costs for Initial YEC System Improvements other than those related to the Transmission Facilities Development options (i.e., the full SKTP development option or the default option, related to transmission facilities between Stewart Crossing and Keno City) or the McQuesten Substation. The Initial YEC System Improvements outlined in Schedule C [with costs detailed in Table C-2] are required to be undertaken in order to provide safe and reliable grid service to the Eagle Gold mine.

Aside from the new costs addressed in the VGC Group PPA, there is no basis to attribute to VGC Group any improvement or replacement costs of the Mayo-Dawson transmission line.

TOPIC: **Minimum Take-or-Pay Contract**

REFERENCE: **Minto PPA Section 6.2, Minto PPA Application page 15**

PREAMBLE:

QUOTE:

"Section 6.2 provides that, within the first eight years of YEC service and subject to Sections 3.5 and 6.3, Minto will pay YEC a minimum aggregate amount of $24 million for Grid Electricity regardless of the amount of Grid Electricity actually delivered by YEC or consumed by Minto; provisions are also included during this eight year period for minimum cumulative annual payments averaging $3 million per year. Section 6.4 enables Minto, prior to the 9th Annual Payment Date, to apply any Take-or-Pay payments made (in excess of Minto Power Bills for Grid Electricity) as a credit against payments in any following year for Grid Electricity purchases in excess of $3 million."

QUESTION:

a) Does the VGC Group PPA have a similar take-or-pay provision?

b) Would a similar take-or-pay provision expose YEC and YEC ratepayers to lower risk? Please explain.

ANSWER:

(a) and **(b)**

There is no similar take-or-pay provision in the VGC Group PPA.

The context for VGC Group PPA is very different than the context for the Minto mine PPA. Specifically, unlike the Minto PPA, there is no provision for a loan to the mine over an extended period to fund capital costs for transmission connection (including related substation costs) as was the case for the Minto PPA (which required security in the form of a take-or-pay arrangement over the period of the loan). The VGC Group PPA, as was the case with the Alexco PPA, requires the mine to pay up-front for capital costs required for transmission connection (including substation costs). Accordingly, there is no basis for requiring VGC Group to make take-or pay payments to YEC.

TOPIC: **Memorandum of Understanding (MOU)**

REFERENCE: **VGC Group PPA, PDF page 38 of 58**

PREAMBLE:

Parts 3, 4 and 5 of the MOU refer to ATCO and VGC.

QUESTION:

a) Please explain the role of ATCO in the MOU and in regards to this PPA.

ANSWER:

(a)

ATCO Power Canada Limited was selected through an RFP process and retained by VGC Group to undertake detailed design of the substation and to provide Issued for Construction (IFC) drawings and technical specifications for a construction RFP document for tendering this work. As noted in the response to UCG-YEC-1-23 (a-b), Yukon Energy funded 50% of these costs to ensure the McQuesten Substation was designed to operate at the 138 KV standard required by YEC.

Pursuant to the MOU provided in Schedule B of the PPA, ATCO Power Canada Limited and Yukon Energy have worked together to complete the required substation design in order to advance the project towards the construction stage.

See also response to JM-YEC-1-2(b).

TOPIC: **Ratepayer Impact Analysis**

REFERENCE: **Application, page 19.**

PREAMBLE:

QUOTE:

The following analysis is intended to provide a reasonable indication of likely ratepayer impacts from the PPA and YEC delivery of Grid Electricity to the Mine. For simplicity, the analysis focuses on three years (calendar 2020, 2021 and 2025) to provide an indication of potential utility revenue and cost impacts after the initial year of power delivery and in year six of power delivery.

QUESTION:

a) Please update the analysis to show all six years of operations based on VGC forecasts plus the five years of closure activities.

ANSWER:

(a)

Attachment 1 to this response provides a revised Table 3 for the PPA Application that adjusts the incremental LTA thermal estimates for changes in weekly load shapes related to adding mine loads. The revised Table 3, and related changes to Section 6.2 text in the PPA Application, result in an increase in the estimated net ratepayer surplus expected with the addition of the VGC Group Mine load.

Yukon Energy is not able to provide useful additional analysis that shows how ratepayer impacts are likely to vary separately for each of the six years of operation and/or the five years of closure activities.

- Although YEC has received forecast VGC Group loads for each of the first six years of operation, the overall ratepayer impacts will be driven by the extent of other industrial mine loads on the grid in each of these years – and YEC does not have useful information today as to likely forecasts for each year for Minto or Alexco.

- With regard to years of closure activity, YEC does not have useful current forecast information from VGC Group for this period. As noted on pages 1 and 17 of the PPA Application, VGC Group Mine operation based on existing reserves is forecast for ten years. When these Mine operations end, rinsing the Heap Leach Pad will occur for one to two years, followed by active closure activities for approximately three years. YEC understands that Mine Site power requirements during these rinsing and closure years are expected to be much lower than any annual amounts forecast during the operating years – however, at this time VGC Group has not provided YEC with updated forecasts of these power requirements by year during this period, i.e., any earlier forecasts that YEC has previously received are understood to be out of date and not useful for current planning.

Table 3 in the PPA Application focused on three years in order to provide an indication of ratepayer impacts over a range of relatively high potential grid load conditions that could occur in the initial six years of VGC Group Mine operation, and absent any new renewable generation capability. The analysis was not intended to provide a forecast of what load is likely in each year, i.e., the loads in 2020 and 2021 in this analysis assumed material industrial mine requirements at both Minto and Alexco, neither of which has been committed at this time.

In summary, the 2021 case in Table 3 as revised demonstrates ratepayer impacts with a high potential industrial load (assumed at approximately 127 GW.h sales) where incremental LTA thermal generation accounts for 64% of the incremental generation needed for the VGC Group Mine. For each of the other two cases examined in Table 3 (2020 and 2025, each with lower overall grid load due mainly to lower industrial load levels), incremental LTA thermal generation accounts for a lower share of the incremental generation needed for the VGC Group Mine – highlighting the extent to which overall industrial load levels and timing are determinative of material changes in LTA thermal generation impacts among each of the first six years of VGC Group Mine operation. As noted above, YEC does not have useful information today as to likely forecasts for each year for Minto or Alexco, and therefore cannot provide useful analysis that shows how ratepayer impacts are likely to vary separately for each of the six years of operation.

REVISED Table 3 in Section 6.2 of PPA Application

The attached provides a revised Table 3 for the PPA Application, along with edits as needed to Section 6.2 text of the PPA Application to reflect the revisions to Table 3. To facilitate review, all of Section 6 of the PPA Application is attached – however, no numbers or analysis are changed in other parts of Section 6.

The changes to Table 3 relate to revised YEC long term average ("LTA") thermal generation estimates, and resulting changes to YEC incremental fuel costs and estimated VGC Group Mine net impact on YEC net costs (i.e., added costs less added revenues).

Previous LTA YECSIM Thermal Generation Estimates

Table 3 LTA thermal generation estimates as provided in the PPA Application as filed essentially used YECSIM model results as per the YEC 2017/18 GRA, involving an extension of the DCF Term Sheet Table 3.4-1 (to address higher loads), without any changes to the YECSIM assessments to reflect changes in load shape over the 52 weeks of the year due to the assumed added mine loads.

In short, the YECSIM analysis used in the initial Table 3 took the added annual load and allocated it over the year for the YECSIM assessments as per the 2018 GRA load (which only included the Minto mine load).

Revised LTA YECSIM Thermal Generation Estimates

As shown in the 2012-2013 YEC GRA, applicable YECSIM assessments of LTA thermal generation for different grid loads will change when an industrial load is added to the grid, i.e., in the 2012-13 GRA, the DCF Term Sheet table for 2013 differed from the Table for 2012 so long as the Whitehorse Copper Tailings industrial load was assumed to be added in 2013.[1]

The revised Table 3 thermal generation estimates as attached are based on YECSIM runs with adapted weekly load shapes to reflect the assumed added mine loads (relative to 2018 GRA forecast with only the Minto mine load). Each added mine load tends to flatten the grid load shape over the year (i.e., more load in summer vs winter, compared to GRA 2018 load shape) and thus reduce the thermal generation LTA requirement compared to what is estimated assuming the 2018 load shape. In the case of the VGC Group Mine load, this shift is even more pronounced than for Alexco mine loads (due to the VGC Group Mine load's major reduction for an approximate 90-day winter period between December 1 and March 31).

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[1] Initial 2012-13 GRA filing, DCF Term Sheet tables (Table 3.2-2 for 2013 differed from Table 3.2-1, due to the assumed connection of WHCT industrial load in 2013).

The Table 3 revisions in estimated LTA thermal generation result in reductions in the estimated incremental thermal generation each year due to the VGC Group Mine load, with resulting reductions in incremental fuel costs and increases in the estimated rate revenue surplus due to the VGC Group Mine load:

- **2020:**
  - Thermal share of added load due to VGC Group = 62% now (vs. 72% as originally filed).
  - YEC added thermal generation cost = $6.79 million now (vs. $7.88 million as originally filed).
  - Rate revenue shortfall (Surplus) = ($1.96) million now (vs. ($0.87) million as originally filed).
  - Average per kW.h VGC Group Sales = ($0.031/kW.h) now vs. (($0.014/kW.h) as originally filed).

- **2021:**
  - Thermal share of added load due to VGC Group = 64% now (vs. 75% as originally filed).
  - YEC added thermal generation cost = $7.39 million now (vs. $8.63 million as originally filed).
  - Rate revenue shortfall (Surplus) = ($1.93) million now (vs. ($0.69) million as originally filed).
  - Average per kW.h VGC Group Sales = ($0.029/kW.h) now vs. (($0.010/kW.h) as originally filed).

- **2025:**
  - Thermal share of added load due to VGC Group = 54% now (vs. 65% as originally filed).
  - YEC added thermal generation cost = $6.92 million now (vs. $8.24 million as originally filed).
  - Rate revenue shortfall (Surplus) = ($3.33) million now (vs. ($2.02) million as originally filed).
  - Average per kW.h VGC Group Sales = ($0.045/kW.h) now vs. (($0.027/kW.h) as originally filed).

- VGC Group will have a Fixed Charge set at 85% of the amended Transmission Facilities Fixed Cost.

Fixed Charge Applicable to Alexco Mine and Other Industrial Customers

The Bellekeno mine and related mill were connected to the grid and received grid electricity as industrial customers in 2010 but have not operated since mid-2013. However, Alexco continues to have prospects to renew mining in the Keno region, including exploration activities which, if successful, will allow the mine to optimally operate the existing mill infrastructure.

The PPA provisions will require amendment to the Alexco fixed charge at such time as the VGC Group receives Grid Electricity from YEC.

Section 7.7(c) provides that in years where 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.

With regard to securing any required YUB approvals related to Fixed Charge amounts, including amounts related to the VGC Group Share or the Transmission Facilities Fixed Cost, YEC will provide the YUB pursuant to Section 7.7 (c)(iii) with such supporting documentation as required by the YUB, and will use commercially reasonable efforts to obtain the approval of the YUB.

6.0 IMPACTS ON GRID AND RATEPAYERS

The PPA enables a new major industrial customer load to be connected at the northern extreme of the existing Yukon integrated grid, in close proximity to where the initial United Keno Hill Mine (UKHM) load provided the economic base for development in the 1950s of Mayo hydro generation and Mayo-Keno City transmission. The Mine's environmental permitting and development is based on being connected to the Yukon integrated grid, rather than relying on its electricity to be supplied from on-site fossil fuel thermal generation.

Table 1 summarizes forecast VGC Group power demand and electricity consumption at the Mine for each of the Mine's first six operating years based on the expected schedule in the PPA. Table 1 also indicates the related YEC generation requirements that will impact YEC's revenue requirements and overall rates. The forecast highlights the material reduction in peak power demand and energy requirements during the approximate 90-day period each year between December 1 and March 31 when stockpiling will occur at the Mine. The forecast also shows increases each year in the Mine power requirements.

Mine operation based on existing reserves is forecast for ten years; however, forecasts for power requirements after year 6 are to be developed by VGC Group during the first years of operation and are not included in Table 1. When Mine operations end, rinsing of the Heap Leach Pad will occur for one to two years followed by active closure activities for approximately three years, and during this period the Mine Site power requirements are expected to be much lower than any annual amounts forecast in Table 1.

Table 1: VGC Group Power Demand & Consumption, and Related YEC Generation (Initial 6 years)

		Forecast VGC Power Demand & Consumption					YEC Generation	
		90 day winter period between Dec 1 & Mar 31		Balance of Year		Total Year	Annual Total*	
Iniital 6 Years	PPA Expected Schedule (Mar-Feb)	Energy MW.h	Peak Demand MW	Energy MW.h	Peak Demand MW	Energy MW.h	Losses** MW.h	Generation MW.h
1	2019-20	7,892	5.11	43,910	10.04	51,802	4,559	56,360
2	2020-21	8,404	5.38	55,166	11.41	63,571	5,594	69,165
3	2021-22	8,696	5.52	58,656	11.87	67,351	5,927	73,278
4	2022-23	8,987	5.66	61,188	12.29	70,175	6,175	76,350
5	2023-24	9,298	5.81	63,332	12.60	72,630	6,391	79,021
6	2024-25	9,369	5.84	64,729	12.72	74,098	6,521	80,619

* Prior to the Transmission Facilities Development Date, the PPA limits Maximum Electric Demand delivered by YEC to VGC at 10,100 kVA (equivalent to 9.70 MW at 96% power factor lead required by PPA); thereafter, the Maximum Electric Demand is 14,300 kVA (equivalent to 13.73 MW at 96% power factor lead required by PPA). YEC generation shown in table has not been reduced in the initial years to reflect the Maximum Electric Demand constraint as estimates of the impact from this constraint currently are not available.

** System losses estimated at 8.8% (system average).

6.1 IMPACTS ON YUKON INTEGRATED GRID

The PPA enables the Mine to be connected to the Yukon grid. This development will have impacts on the Yukon grid development and operation.

The Mine being developed by VGC Group will increase utility electrical sales in the Keno region well above earlier levels even when UKHM was operating. This new load will utilize available Mayo hydro generation resources, and require import to the northern grid of available WAF renewable and thermal generation.

Initial Yukon Grid Improvements

Prior to Commencement of Delivery to the Mine in 2019, the 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 PPA.

These Yukon grid enhancements and facilities are required to connect the Mine to the existing transmission, 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.

These initial new facilities and enhancements are to be funded by VGC Group, with the exception of YEC McQuesten Substation Costs of approximately $0.93 million as described in Schedule B, Table B-2.

The PPA recognizes that, with these initial measures, the Yukon grid likely can only deliver to the Mine up to 10,100 kVA until further Yukon grid improvements (i.e., the Transmission Facilities Development) are implemented[23] – and the Mine will likely need to utilize its on-site diesel generation to supply some of its peak load from approximately March through to December in years before the Transmission Facilities Development Operation Date.

Near-term Transmission Facilities Development

The PPA and the Mine's development provide the basis for moving as quickly as possible to replace the end of life existing Mayo to Keno City transmission facilities.

As reviewed in section 4.3 of this Application, YEC is exploring options to secure funding in 2018 for the full SKTP up to 100% of full revenue requirement impact to replace and greatly improve the existing Yukon grid facilities in this region. The PPA is expected to enhance initiatives to secure this funding.

The PPA also provides for a default option if such funding cannot be secured in a timely manner, where specific required improvements would be implemented by YEC with costs to be included in rate base and revenue requirements.

In summary, after Commencement of Delivery to the Mine and during 2020 or early 2021 under the expected schedules in the PPA, the PPA provides that the Transmission Facilities Development will at a minimum replace the existing end-of-life transmission between Mayo and McQuesten Substation (L180) with new 138 kV facilities[24] and install an SVC/Statcom at Stewart Crossing Substation.[25]

These two basic enhancements will enable the Maximum Electric Demand limits in the PPA to be increased to supply all of the Mine's forecast requirements, and also to enhance significantly Yukon grid long-term capability to supply customers on the northern grid.[26] As reviewed in Section 4.3 of this Application, estimated YEC capital costs for these two enhancements are $24.8 million. At the time that these facilities come into service, the PPA also provides for YEC to include in the Transmission Facilities costs the YEC McQuesten Substation Costs ($0.93 million as per the PPA).

[23] This limit allows for existing Keno region power loads plus some renewed Alexco loads.
[24] The existing conductor on this line is replaced with larger conductor, enhancing this line's ability to carry higher power loads; until the full SKTP is developed with 138 kV transmission from Stewart Crossing to McQuesten Substation, the new L180 line will operate at 69 kV. Rebuild of the line will carry out brushing of the line, adjust and improve line location in many segments, replace end of life poles and equipment, and improve access for future brushing and line maintenance.
[25] The SVC/Stacom will provide voltage support equipment (a Static-Var Compensator or a Statcom) that enhances the MD import ability from WAF following contingencies.
[26] By way of example, these two enhancements are estimated to increase the L180 (Mayo to McQuesten Substation) capability to supply the Mine from 9.7 MW to 16.7 MW and increase the MD import limit from WAF from 11 MW to 19 MW. The forecast Mine peak load in year six of operation is approximately 12.7 MW (see Table 1).

The PPA provides that VGC Group and any Other Industrial Customer supplied by the Transmission Facilities will, through the Fixed Charge provisions applicable in each year that these customers are supplied under Rate Schedule 39, pay for 85% of YEC's depreciation and return (debt and equity) costs related to these Transmission Facilities improvements. The balance of these fixed costs will be recovered through rates charged to all firm customers in the Yukon (including Major Industrial Customers).

These facility improvements will continue to provide benefits for the Yukon grid and its customers long after the Mine ceases to receive Grid Electricity from YEC.

6.2 RATEPAYER IMPACTS

Rates for utility delivery of firm electricity in Yukon are generally set (as directed by OIC 1995/90) to be the same for all regions and for each customer class served by both YEC and Atco Electric Yukon ("AEY"). Accordingly, impacts on YEC revenue requirement costs and rate requirements resulting from the PPA and connection of the Mine to the Yukon grid will affect all Yukon ratepayers using firm electricity supplied by YEC and AEY.

In general, the expected overall rate impact on Yukon ratepayers will reflect the extent to which supplying Grid Electricity to the Mine is expected to increase YEC and AEY revenues more than it increases YEC annual costs to supply electricity (i.e., YEC's annual revenue requirement). Any change to rates as a result of YEC supplying the Mine, however, will require future YUB review and approval following a new general rate application by YEC.

The following analysis is intended to provide a reasonable indication of likely ratepayer impacts from the PPA and YEC delivery of Grid Electricity to the Mine. For simplicity, the analysis focuses on three years (calendar 2020, 2021 and 2025) to provide an indication of potential utility revenue and cost impacts after the initial year of power delivery and in year six of power delivery.

Incremental Rate Revenue Impacts

The PPA confirms (subject to Board approval) the Firm Mine Rate applicable to VGC Group and the Mine, including the provisions for the Fixed Charge whereby VGC Group and any Other Industrial Customer together pay for 85% of the ongoing annual Transmission Facilities Fixed Cost of YEC.

Major industrial customers such as VGC Group are charged an existing Rate Schedule 39, which is subject to general rate riders approved for both YEC and AEY (see Schedule A to the PPA). Table 2 provides forecast incremental YEC and AEY rate revenues from the Mine, excluding the Fixed Charge, based on the PPA and the Mine forecast loads in Table 1 (adjusted to calendar basis for each year, to reflect YEC fiscal years). Table 2 includes Rider J as applied for in YEC's current GRA, and the Rider R approved recently for AEY (applicable by 2018). To the extent that the Board approved different riders in future for either utility, the estimates in Table 2 would need to be adjusted accordingly.

Overall, the average YEC rate revenues per kW.h of sales to the Mine forecast in Table 2 over 2020, 2021 and 2025 remain reasonably stable, ranging from $0.1384 to $0.1388 per kW.h. Total incremental annual YEC revenues excluding Fixed Charge increases from $8.8 million in 2020 to $10.3 million in 2025.

Incremental forecast rate rider revenue to AEY in Table 2 equals $0.0097/kW.h sales in each year, and in total increases from $0.6 million in 2020 to $0.7 million in 2021.

Table 2: Forecast Utility Rate Revenues from the VGC Group Mine (excluding Fixed Charge)

	Assumed rates		Billing Determinants			Rate Revenues ($000)		
			2020	2021	2025	2020	2021	2025
YEC revenues (ex. Fixed Charge)								
Demand $/kVA per month	$15.94	MVA	11.21	12.03	13.17	$2,144	$2,300	$2,518
Energy $/kW.h	$0.0808	MW.h	63,245	67,157	74,051	$5,110	$5,426	$5,983
Fixed Rider F $/kW.h	$0.00211					$133	$142	$156
Rider J % [GRA]	$0.1847					$1,364	$1,453	$1,599
Total YEC						$8,752	$9,322	$10,257
Average $ per kW.h						***0.1384***	***0.1388***	***0.1385***
AEY revenues								
Rider R %	8.30%					$613	$653	$719
Total YEC and AEY (ex. Fixed Charge)						$9,365	$9,975	$10,976
Average $ per kW.h						***0.1481***	***0.1485***	***0.1482***

YEC will also receive Fixed Charge rate revenues from the Mine under the PPA.

- Prior to the Transmission Facilities Development Date, these revenues per the PPA would at most be $100,828,[27] or about $0.0016 per kW.h for the year 2020.
- After the Transmission Facilities Development Date, the PPA allows for the Fixed Charge to VGC Group (and any other Industrial Customer) to be adjusted to equal 85% of any adjusted YEC Transmission Facilities Fixed Cost that may result from bringing the new facilities into service.

Incremental YEC Costs and Net Rate Revenue Impacts

New sales to the Mine will require added YEC generation, as indicated in Table 1.

The main incremental cost impact for YEC from this added generation will be incremental long-term average (LTA) thermal generation costs.[28]

LTA thermal generation requirements for YEC are sensitive to the overall YEC grid load without the VGC Group Mine (i.e., higher grid loads typically lead to higher incremental LTA thermal for new added loads)

[27] Equals 85% of the specified Transmission Facilities Fixed Cost of $118,621. If Alexco is also connected at that time as a major industrial customer, this charge would be allocated between VGC Group and Alexco.
[28] Working capital increases related to incremental thermal generation fuel requirements will result in a small added YEC revenue requirement (potentially in the range of $0.025 million per year increases in return costs).

as well as to any new renewable resource generation developments that reduce LTA thermal generation required at each grid load level.

Table 3 provides a conservative assessment of LTA thermal generation impacts for 2020 and 2021, assuming grid sales to both the Minto mine and the Alexco mine as well as no new renewable generation resources or enhancements. In contrast, the 2025 assessment in Table 3 removes the Minto mine (which has to date never been discussed as extending beyond 2022) as well as the Alexco mine in order to highlight the VGC Group Mine incremental LTA generation sensitivity to overall grid loads (this scenario continues to assume no new renewable generation resources or enhancements).[29]

- The 2020 assessment, with Minto and Alexco assumed loads, shows 42.9 GW.h incremental LTA thermal for 68.8 GW.h incremental generation with the VGC Group Mine, i.e., incremental LTA thermal accounts for 62% of the incremental generation needed for the VGC Group Mine.
- The 2021 assessment, also with Minto and Alexco assumed loads, shows 46.7 GW.h incremental LTA thermal for 73.1 GW.h incremental generation with the VGC Group Mine, i.e., incremental LTA thermal accounts for 64% of the incremental generation needed for the VGC Group Mine. The high grid load assumed in this scenario results in LTA thermal being a higher share of new generation in 2021 versus 2020.
- The 2025 assessment without any assumed other mine loads shows 43.7 GW.h incremental LTA thermal for 80.6 GW.h incremental generation with the VGC Group Mine, i.e., incremental LTA thermal accounts for only 54% of the incremental generation needed for the VGC Group Mine. LTA thermal accounts for a lower share of the new generation in 2025 versus 2020 or 2021 due to the lower overall level of the grid load in 2025, highlighting the sensitivity of LTA thermal generation impacts to the overall level of the grid load.

For each of the years examined in Table 3, the LTA thermal will decline when new renewable resources or enhancements are developed. YEC's 2016 Resource Plan identifies several potential short-term action recommendations for potential in-service prior to 2023, including two hydro storage enhancement projects (Southern Lakes, and Mayo Lake [which includes dredging of the Mayo Lake Outlet Channel]), an IPP Standing Offer Program project, uprates at the Aishihik and Whitehorse hydro stations, and Mayo A refurbishment.

Overall, Table 3 with its conservative assumptions shows average YEC incremental LTA thermal generation cost per kW.h of sales to the Mine forecast in 2020 and 2021 that range from $0.107 to $0.110 per kW.h VGC Group sales; in 2025 these costs are lower, at $0.094 per KW.h VGC Group sales, reflecting the impact of the assumed lower grid load. Total incremental annual YEC thermal generation costs in Table 3 increase from $6.8 million in 2020 to $7.4 million in 2021, and decline to $6.9 million in 2025.

Table 3 also shows the VGC Group impact on YEC net costs to be recovered from all ratepayers beyond direct revenues from VGC Group, based on Table 2 rate revenues (which exclude Fixed Charge revenues)

[29] Table 3 LTA thermal generation estimates based on YECSIM as per YEC 2017/18 GRA, with model runs adjusted as needed to reflect the respective grid loads assumed in Table 3 and weekly load shapes over the year that reflect these loads.

and Table 3 LTA thermal generation costs. Based on this assessment, the overall net impact of the Mine under the assumption adopted is to reduce future rate increase pressures. YEC net revenue requirement amounts that need to be recovered from all ratepayers are reduced as follows with the VGC Mine load:

- $1.96 million reduction in 2020, when assume total grid load includes Minto and Alexco mines;
- $1.93 million reduction in 2021, when assume three mines in operation (shows scenario where the increase in LTA thermal cost more than offsets the increase in revenues from higher VGC Group load); and
- $3.33 million reduction in 2025, when assume VGC Group Mine is the only mine on the grid (shows impact of higher revenues due to higher VGC Group load, combined with lower LTA thermal cost per kW.h VGC Group sales due to lower overall grid load without Minto or Alexco mine loads).

The Table 3 assessment does not address potential impacts from any Transmission Facilities Development costs that YEC may need to be included in rate base. The following high level assessment reviews potential impacts from an assumed $25 million added to YEC rate base for such transmission development[30]:

- Transmission Facilities Fixed Cost impact, assuming 55-year average depreciation[31] and 4.92% average return on YEC rate base per 2017/18 GRA[32]:
  - Depreciation — $0.454 million per year
  - Return on rate base (mid year in year 2) — $1.196 million
  - Total Annual Cost — $1.650 million in year 2 of assets
- Allocation of Annual Cost
  - Fixed Charge: VGC Group/ Others (85%) — $1.402 million
  - All ratepayers / general rates (15%) — $0.248 million

In summary, based on the assumptions in Table 3, even if the Transmission Facilities Development results in an addition of $25 million to YEC's rate base the overall impact on all ratepayers from the PPA, the VGC Group Mine load and the new facilities development would still be a reduction in YEC net revenue requirement amounts to be recovered from other ratepayers.

[30] Section 4.3 of this Application estimated costs for the default option (no government funding, new L180 transmission connection from Mayo to McQuesten Substation plus SVC/Statcom at Stewart Crossing Substation and other related costs) at $23.8 million, excluding McQuesten Substation costs funded by VGC Group and/or YEC. The cost added to YEC's rate base for McQuesten Substation ($0.93 million) increases this amount to $24.8 million.
[31] Assumes transmission assets at 65 year life (about 67% of total cost); YEC McQuesten Substation Costs per the PPA assumed at 54 year life; balance assumed conservatively at 40 year life.
[32] See Table 3.15 of YEC 2017/18 GRA (2.32% average cost of debt, and 8.82% return on equity, with 60/40 debt/equity ratio).

Table 3: YEC LTA Thermal Generation Costs & Net Rate Revenue Impact - VGC Group Mine

	2020	2021	2025
Assumed YEC Grid Sales[1] (GW.h)			
Non Industrial	359.7	364.2	386.6
Minto Mine	38.2	38.2	-
Alexco Mine	19.0	21.9	-
VGC Group Mine	63.2	67.2	74.1
Total YEC (firm)	480.1	491.5	460.7
YEC Grid Generation	***522.4***	***534.7***	***501.2***
Incremental Generation due to VGC Group Mine	*68.8*	*73.1*	*80.6*
YEC LTA Thermal Generation (GW.h)			
With VGC Mine Load	79.1	88.9	66.5
Without VGC Group Mine Load	36.2	42.2	22.8
YEC Incremental thermal generation	42.9	46.7	43.7
Thermal share of increased generation	62%	64%	54%
YEC added thermal generation cost[2] ($million)	***$6.79***	***$7.39***	***$6.92***
Average $ per kW.h VGC Group Sales	***0.1074***	***0.1100***	***0.0935***
YEC Added Revenues ex. Fixed Charge ($million)	***$8.75***	***$9.32***	***$10.26***
Average $ per kW.h VGC Group Sales	***0.138379***	***0.1388***	***0.1385***
VGC Group Mine Net Impact on YEC Net Costs (Added Costs less Added Revenues)			
Rate Revenue Shortfall (Surplus) ($million)	***-$1.96***	***-$1.93***	***-$3.33***
Average $ per kW.h VGC Group Sales	***-$0.031***	***-$0.029***	***-$0.045***

1. Non-industrial sales per YEC 2016 Resource Plan, Medium Industrial forecast. Minto and Alexco loads are assmuptions for scenario assessment. VGC Mine load based on Table 2.

2. Assumed average cost per 2017/18 GRA at $0.1583/kW.h (90% LNG, 10% diesel).

TOPIC: **Summer Storage**

REFERENCE: **Application, Section 4.1, page 4**

QUOTE:

The YIS has 92 MW of installed YEC hydro generation, of which approximately 70.5 MW can be relied upon for the winter peak.

QUESTION:

a) Will VGC Group be a summer or winter peaking load customer? Please explain.

b) If VGC is a summer peaking load customer, please explain the impact on YEC's ability to store water over the summer months to produce a reliable winter peak capacity of 70.5 MW with the addition of VGC Group as a customer.

ANSWER:

(a) and **(b)**

The VGC Group peak load is expected to occur between April 1 and November 30, and will be reduced by 50 to 55% during a 90 day winter period between December 1 and March 31. In this context, VGC Group would likely not be considered as a winter peaking load customer, although its annual peak load may occur in November.

Yukon Energy does not anticipate that VGC Group's summer load will have any material impact on YEC's ability to store water over the summer months to produce a reliable winter peak capacity of 70.5 MW with the addition of VGC Group as a customer. Aishihik Hydro, which accounts for 37 MW of the 70.5 MW, is designed and operated to provide reliable winter peaking capacity, i.e., summer generation at this facility is constrained as required to enable this winter generating capability. The next largest component of the 70.5 MW is Whitehorse Hydro, which has very limited ability to store water on a seasonal basis and is operated to ensure that 24.5 of the 40 MW installed can provide reliable peaking capability during the winter peak period. The 9 MW of reliable winter peaking capacity at Mayo Hydro will similarly not be impacted by the VGC Group operation.