# YUKON ENERGY CORPORATION

YUKON UTILITIES BOARD REVIEW
IN THE MATTER OF
AN ELECTRICITY PURCHASE AGREEMENT
BETWEEN
YUKON ENERGY CORPORATION AND
TLINGET HOMELAND ENERGY LIMITED PARTNERSHIP

ROUND 2 INTERROGATORY RESPONSES FILED

June 27, 2022

**John Maissan**
**(JM)**

**REFERENCE: Page 5 Project Capabilities**

**QUESTION:**

a) How much of the increased project capacity from 8.5 MW to 8.75 MW is the result of increased water utilization efficiency in the new project configuration and how much is the result of increased projected water availability based on the now 51 years of water record vs the previous 35?

b) How much of the increased LTA energy availability in the PWP from 36.2 GWh per year to 41.5 GWh per year is the result of increased water utilization efficiency in the new project configuration and how much is the result of increased projected water availability based on the now 51 years of water record vs the previous 35?

c) Please explain the factors that contributed to the reduction to the 63.75 PWP days (85% of 75) that the full dependable capacity of 8.75 MW is available vs. the previous 70.5 days (94%) at 8.0 MW?

**ANSWER:**

**(a)**

The dependable capacity of 8.75 MW delivered at Jakes Corner is based on the revised Project configurations with the 9.3 MW hydroelectric plant. It is not tied to the modeled water availability based on 51 years of water record compared to 35 years of water record that had been previously utilized.

The capability to provide 8.75 MW of dependable capacity as required during the Peak Winter Period (PWP) is assessed based on the Project's Surprise Lake storage and modeled generations for 51 water years as reviewed on page B-3, Appendix B of the April 2022 Submission. The assessment shows that a full 8.75 MW of capacity is to be delivered to YEC at Jakes Corner for over 85% of the 75 or 76 days in the PWP.

Please also see response to c) below.

**(b)**

YEC is unable, for the reasons noted below, to provide a breakdown of the LTA Delivered Energy increase that is the result of increased water utilization efficiency in the new project configuration versus the result of the change in the number of water years and/or water inflows.

- THELP developed and provided to YEC the Delivered Energy estimates by month and water years as shown in Table A1 of the January 2022 Submission (Original EPA) and the April 2022 Submission (Amended EPA). YEC has not been provided information for any of the water years that breaks down the changes in Delivered Energy due to water utilization efficiency and/or other changes in plant configuration versus the change in water inflows.

    - Comparison of Table A1 estimates of winter Delivered Energy estimates by water year in the two Submissions is possible for 28 water years (1970-1993, 2015-2018), and indicates an increase in LTA Delivered Energy from 30.7 GWh (January 2022 Submission, ignoring partial year 2019 estimates) to 34.2 GWh (April 2022 Submission).

    - The above LTA winter Delivered Energy estimates for the same 28 water years are very close in each instance to the Table A1 LTA indicated for all water years examined in each Submission (LTA 30.8 GWh for 36 water years in the January 2022 Submission, and LTA 34.0 GWh for 51 water years in the April 2022 Submission).

- The water inflow data in the two Submissions is not directly comparable, i.e., the change is not only an increase in number of water years, but also a change in how the inflows are developed. Please see notes to Table A1 in each Submission as well as the response to YUB-YEC-2-16 b) and c) and YUB-YEC-2-29. In summary, Delivered Energy estimates in the January 2022 Submission were developed based on 32 years of recorded flows by Water Survey of Canada for the Gladys River area (1963-1993 water years in Table A1) along with Pine Creek catchment flows with data for years 2015-2019. In contrast, Delivered Energy estimates in the April 2022 Submission rely upon the hydrologic modeling studies conducted by SNC-Lavalin and Knight Piesold based on different modeling methods and data sources.

**(c)**

The referenced 94% figure in the original January Submission and the 85% figure in the April Submission each indicate the percent of PWP days that can provide full Dependable Plant Capacity at Jakes Corner with the same 14 GWh of minimum water availability. Principally, given a fixed volume of water and similar plant efficiency, the new plant design will be able to generate at higher capacity for less PWP days versus the original design with the lower capacity.

Overall, the referenced reduction in this percentage of PWP days mainly reflects the higher assumed full capacity level delivered at Jakes Corner (8.75 MW with the Amended EPA vs 8.0 MW assumed with the Original EPA) and the resulting added Delivered Energy requirement per hour required to provide 100% capacity. The impact of the higher capacity is offset to some extent by the materially lower requirement (11% versus 65% of full capacity) assumed for PWP days when full capacity is not provided. The reduction of the minimum required capacity from 65% to 11% reflects the penstock replacement of the power canal and the resulting removal of ice condition issues affecting PWP generation plant operation.

The referenced April 2022 Submission analysis is conservative. It was based on the updated Energy profile provided by THELP (Table A1). As shown in Table A2, YEC's analysis to assess LTA thermal displacement assumed a Dispatchable Option allocation of LTA Delivered Energy (see Column A in Table A2) which has slightly higher PWP deliveries (due to a higher December allocation), i.e., LTA PWP deliveries at 15.6 GWh versus 14.6 GWh. This implies that the minimum PWP deliveries are also likely to exceed the 14 GWh assumed in the referenced analysis.

**REFERENCE: Page 5 Footnote 7**

**QUESTION:**

a) Please explain what YEC knows of the (proposed?) battery installation in connection with the existing hydro plant supplying power to the community of Atlin.

**ANSWER:**

**(a)**

Yukon Energy has only been advised that THELP is proposing to install a battery with the Existing Plant in order to improve efficiency of water utilized to supply power to BC Hydro for the community at Atlin – YEC does not have further information on this battery.

**REFERENCE: Page 12 Section 3.4.1 No.4 Thermal Benchmarking Price:**

**QUESTION:**

a) What was the actual average weighted price per kWh for LNG fuel for power generation for the period January 1, 2022, to May 31, 2022?

b) What was the actual average weighted price per kWh for diesel fuel for power generation for the period January 1, 2022, to May 31, 2022?

c) What was the total thermal generation for this period and what were the actual proportions of LNG generation and diesel generation?

d) What would have been the answer to (c) above under LTA YIS water availability?

e) How would have been the answer to (d) above if the THELP project (as anticipated in this submission) had been available?

**ANSWER:**

**(a) and (b)**

The weighted average LNG cost to May 31, 2022 based on efficiency figures utilized in the 2021 GRA is $0.2141/kWh and the weighted average diesel cost is $0.3061/kWh.

**(c)**

Year-to-date thermal generation is 17.5 GWh [including 10.4 GWh LNG and 7.1 GWh diesel] and 2022 full-year-forecast thermal generation is estimated to be approximately 35.8 GWh.

**(d) and (e)**

The following assumptions are used for the LTA thermal estimates:

- The 2022 full-year load forecast is approximately 551 GWh, including year-to-date preliminary actuals to May 31, 2022 and forecasts for June-December based on the 2022 Business Plan forecast.

- Forecast IPP generation for 2022 is 2.1 GWh, including year-to-date preliminary actuals to May 31, 2022 and forecasts for June-December.
- WH2 and WH4 uprates as per Atlin EPA analysis.
- No Southern Lakes or Mayo Lake enhanced storage projects.

Based on LTA hydro availability and forecast 2022 loads, the LTA thermal generation for 2022 would be 88.6 GWh. If the Atlin Project was available in 2022 with 34 GWh delivered at Jakes Corner, then the LTA thermal generation for 2022 would be 56.6 GWh.[1]

[1] The model assessments with 2022 forecast load show a higher LTA thermal displacement percentage from Atlin winter energy deliveries (94.1%) than the 71.2% estimates for 2024 forecast load estimates in the April 2022 Submission (Table A3). The higher percentage reflects higher loads in 2022 compared to 2024 forecast used for EPA pricing [approximately 23 GWh higher load]; lower IPPs [only 2.1 GWh in 2022 compared to approximately 40 GWh under 2024 forecast]; impact of hydro storage enhancement projects [Mayo Lake or Marsh Lake hydro storage enhancement projects are not available in 2022, while 2024 forecast used for the EPA assumed benefits from both projects].

**REFERENCE: Page 15 Table 3-1**

**QUESTION:**

a) For 2024-2034 please explain why the winter energy price has increased from $0.132 per kWh for 25.2 GWh plus $0.072 per kWh for 5.6 GWh (30.8 – 25.2 GWh) to $0.135 per kWh for 34.0 GWh (all winter energy).

b) For 2035 & beyond please explain why the winter energy price has changed from $0.107 per kWh for 25.2 GWh plus $0.027 per kWh for 5.6 GWh (30.8 – 25.2 GWh) per year to $0.097 per kWh for 34.0 GWh (all winter energy).

c) Assuming LTA water availability what would have been the cost for winter energy in one winter in the 2024 to 2034 period, and for one winter in the 3035 & beyond period in the original (January 2022) submission?

d) Assuming LTA water availability what would be the cost for winter energy in one winter in the 2024 to 2034 period, and for one winter in the 3035 & beyond period in the amended (April 2022) submission?

**ANSWER:**

**(a) and (b)**

Table A3 in the April 2022 Submission provides a direct comparison of EPA price for Winter Delivered Energy (2024$/kWh) for the Original EPA and the Amended EPA for the 2024 load forecast and for the 2035 load forecast. The Table A3 comparison adopts the "one price" approach used in the Amended EPA for all Winter Period Delivered Energy and avoids the break-down of this price into separate firm and non-firm energy prices as provided for in the Original EPA.

The winter energy price increases for the 2024 and 2035 load forecasts reflect increased thermal displacement benefits as a percentage of Atlin energy purchases, as shown in line 7 of Table A3:

- For 2024 load forecast, the increase from 63.483% to 71.226%.
- For 2035 load forecast, the increase from 48.687% to 50.923%.

As shown in Table A3, the change in LTA thermal displacement as a percentage of Atlin energy purchases reflects the following:

- Higher winter energy purchases (LTA 34.0 GWh versus 30.8 GWh) provided by the amended design and the updated water availability estimates;
- Lower AEY System losses (4.5% vs. 6.2%) based on updated assessments; and
- Increased LTA thermal displacement benefits (4.618 GWh for 2024 load forecast and 2.286 GWh for 2035 load forecast), reflecting the above increases to Atlin energy plus the enhanced thermal displacement estimated due to the greatly enhanced dispatchability.

Overall, the enhanced thermal displacement due to enhanced dispatchability is the key factor explaining the higher energy prices, i.e., absent this factor, higher LTA energy deliveries would be expected to result in lower energy prices.

**(c) and (d**)

Line 9 in Table A3 in the April 2022 Submission provides the following cost for winter energy (2024$) in one winter for the Original EPA[1] and the Amended EPA for the 2024 load forecast and for the 2035 load forecast – the Amended EPA higher costs reflecting the higher displaced LTA thermal expected with the revised Project:

- 2024 Load Forecast
  - Original EPA $3.717 million
  - Amended EPA $4.594 million
- 2035 Load Forecast
  - Original EPA $2.851 million
  - Amended EPA $3.285 million

[1] Table A3-1 and A3-2 in the January 2022 Submission provide the details for the Original EPA. The LTA cost from Table A3-1 (which is also shown in Table A3 of the April 2022 Submission) was used to develop firm and non-firm prices in Table A3-2, i.e., the overall winter cost of energy remains unchanged from the amounts shown in Table A3-1.

**REFERENCE: Page B-4 and B-5 Conditions Precedent**

**QUESTION:**

a) Please provide a copy of the Interconnection Agreement between the YEC, THELP, and AEY and the budgeted costs for the AEY system upgrades.

b) Please confirm that YEC has received the Funding Plan from THELP and please provide a copy of the Plan.

c) Please confirm in providing IR answers on June 27 whether on June 14 YEC gave notice to THELP that it is satisfied that the project is viable.

d) Please confirm that THELP has the all the specified environmental authorizations and the specified TRTFN approval.

**ANSWER:**

**(a)**

The requested Agreement document and budgeted costs cannot be provided at this time. Please see the response to YUB-YEC-2-10 (with the attached correspondence provided by YEC to the Board dated June 10, 2022 regarding amended dates for satisfaction of Conditions Precedent items), and YUB-YEC-2-27.

The conditions precedent [condition 2.1(d)(i) and 2.1(d)(ii)] related to the Interconnection Agreement and the budgeted costs for AEY System Upgrades have been extended to July 29, 2022.

**(b) and (c)**

Not confirmed. Please see the response to YUB-YEC-2-10 (with the attached correspondence provided by YEC to the Board dated June 10, 2022 regarding amended dates for satisfaction of Conditions Precedent items) and YUB-YEC-2-28.

The date for satisfaction of the conditions precedent regarding providing the Funding Plan [Section 2.1(d)(iii)] has been extended to September 30, 2022. The date for Buyer to give

Notice to Seller that Buyer is satisfied with the Funding Plan has been extended to October 31, 2022.

The response to YUB-YEC-2-8(b)and(c) reviews current information regarding the sources of funding for the Atlin Hydro Expansion Project.

**(d)**

Not confirmed. Please see the response to YUB-YEC-2-10 (with the attached correspondence provided by YEC to the Board dated June 10, 2022 regarding amended dates for satisfaction of Conditions Precedent items) and YUB-YEC-2-28.

The date for satisfaction of the conditions precedent related to obtaining environmental authorizations [Section 2.1(d)(iv)] has been extended to March 31, 2023 due to a requirement (due to the change in the Project) for THELP to refile its application for the Clean Energy Development Plan authorization for the Seller's Plant located in British Columbia. The date for satisfaction of the conditions precedent related to obtaining the specified TRTFN approval [Section 2.19d)(vi)] has been extended to October 31,2022.

**REFERENCE: Page A1-7**

**QUESTION:**

a) If not already answered in JM-YEC-2-5 above, please confirm that all conditions precedent outlined in Article 2.1 (d) have been met, and, if not, what is being done to achieve compliance.

b) Please provide copies of any agreements entered into between any or all of the parties as required in the conditions precedent.

**ANSWER:**

**(a) and (b)**

Please see the response to YUB-YEC-2-10 (with the attached correspondence provided by YEC to the Board dated June 10, 2022 regarding amended dates for satisfaction of Conditions Precedent items), YUB-YEC-2-27 and YUB-YEC-2-28.

In summary, the dates contained in the EPA for satisfaction of the conditions precedent in Section 2.1(d)(i) to (ix) were extended from the dates included in the amended EPA [see table below which outlines conditions precedent provisions in Section 2.1(d) and updated deadline date for satisfaction of each conditions precedent]. The parties are continuing to work towards satisfying the conditions precedent within the updated timelines provided.

With this update to the conditions precedent deadline dates, the date for finalizing the referenced agreements has been extended beyond June 27, 2022 and final agreements are not available at this time.

| | CONDITION | Updated Due Date |
|---|---|---|
| 1 | 2.1(d)(i) | July 29, 2022 |
| 2 | 2.1(d)(ii) | July 29, 2022 |
| 3 | 2.1(d)(iii) for Seller to submit Funding Plan to Buyer | September 30, 2022 |
| 4 | 2.1(d)(iii) for Buyer to give Notice to Seller that Buyer is satisfied with Funding Plan | October 31, 2022 |
| 5 | 2.1(d)(iv) | March 31, 2023 |
| 6 | 2.1(d)(v) | 215 days after April 12, 2022 |
| 7 | 2.1(d)(vi) | October 31, 2022 |
| 8 | 2.1(d)(vii) | October 31, 2022 |
| 9 | 2.1(d)(viii) | October 31, 2022 |
| 10 | 2.1(d)(ix) | July 29, 2022 |

1

**REFERENCE:** **Page A1-19 Article 7.3 second paragraph:** "…for the new arrangements that may cause changes to the Seller's Plant, expected Delivered Energy, or Dependable Plant Capacity provided during the Peak Winter Period. …" (emphasis added)

**QUESTION:**

a) Is this a typo, should the word be except or excepted rather than expected?.

**ANSWER:**

**(a)**

This is not a typo – the word "expected" is correct in the context.

**REFERENCE: Page A1-64 Exhibit B-1**

**QUESTION:**

a) The original THELP proposed plant consisted of two 3 MW generators in the upper plant and one 2.7 MW generator in the lower plant. The new configuration consists of a single 9.2 MW generator.

In practice this will mean that any trip of the generator will now have a much greater impact on the YIS grid than the trip of one of the three smaller generators would have had in the original configuration. Please discuss in detail the implications of a generator trip during the PWP when 8.75 MW is being delivered to the YIS at Jake's Corner:

i. To the AEY line and customers at Teslin,
ii. To the AEY line and customers in the Judas Creek and Marsh Lake area,
iii. To the AEY line and customers along the South Klondike Highway including Carcross and Tagish,
iv. To the AEY line from Carcross Corner to Whitehorse and S150 substation in Whitehorse, and
v. To the customers on the YIS.

**ANSWER:**

**(a)**

In order to properly respond, YEC provides the Background below on the nature of grid faults and the response (manual and automated) that is designed into the grid protection system.

**Background**

Any system disturbance such as a line fault or the trip of a generator will affect both frequency and voltage. The YIS therefore has some protection and controls in place to restore the voltage and frequency to their pre-disturbance level, either through automated controls or an operator's. Automatic protection and controls can be in the form of protection relays which isolate a faulted line or equipment during a fault, spinning reserves to respond to frequency deviations from generation loss, Underfrequency Load Shedding (UFLS) to

shed excess load if there is not enough spinning reverse, Remedial Action Scheme (RAS) to balance load and generation after a disturbance, or voltage support at generation, transmission and distribution levels. The exact prescription triggered is dependent on the nature of the fault event. As well, voltage is controlled by different methods at different points of the YIS. The key element of voltage control is the ability to inject or absorb reactive power to and from the YIS. However, reactive power cannot be transmitted over long distances; for this reason, voltage control is performed at the point of generation, at various points in the transmission system, and in the distribution network. Voltage control in the form of reactive power injection and absorption to and from the YIS is provided by synchronous generators, STATCOM, reactors, capacitor banks and voltage regulators.

The THELP hydro plant will be connected to a long radial distribution network, beginning from S150 substation in Whitehorse to Jake's Corner (~79 km) and Jake's Corner to Teslin (~92 km). The distribution system steady state voltage is maintained between 95% and 105% with no disturbance. The steady state voltage is typically maintained between 90% and 107% after a reported distribution system disturbance. From our studies, we can confirm the voltage at Teslin is at 92% pre-disturbance, this is due to voltage drop as Teslin is at the end of a long distribution network. As part of YEC's updated system impact study (SIS), reactive power requirements will be provided to AEY to maintain the voltage at Teslin within normal operating range. These requirements will be addressed as part of system upgrades to the AEY system funded by THELP.

**Effect of an Atlin Generator Trip**

A trip of the 9.2 MW Atlin generator when delivering 8.75 MW to the YIS at Jakes Corner poses minimal impact for customers on the YIS, Judas Creek and Marsh Lake area, South Klondike Highway including Carcross and Tagish, Carcross Corner to Whitehorse and S150 substation. The Battery Energy Storage System (BESS) by Q3 2023 will be providing spinning reserve and will respond to frequency deviations resulting from the generator trip. The frequency at the identified locations dips to ~59.6 Hz for a very short duration and recovers to 60 Hz as the BESS and other generation picks up the excess load. The voltages at these locations are maintained between 90% and 107% after the generator trip with the exception of Teslin which dips from a pre-disturbance voltage of 92% to 82%. This also confirms that voltage support will be required at Teslin as part of the system upgrade for the THELP interconnection.

Table 1 below show the pre-disturbance and post-disturbance voltage and frequency for each location (red highlight shows the one impact issue identified at Teslin).

**Table 1: Voltage and frequency during and after the loss of Atlin generator**

| S/N | Locations | Pre-disturbance Voltage (%) | Post-disturbance Voltage (%) | Pre-disturbance Frequency (Hz) | Post-disturbance Frequency (Hz) |
|---|---|---|---|---|---|
| 1 | Atlin Generation | 102 | 0 | 60 | 60 |
| 2 | Jake's Corner | 100 | 92 | 60 | 60 |
| 3 | Judas Creek and Marsh Lake Area | 101 | 98 | 60 | 60 |
| 3 | Macrae | 101 | 98 | 60 | 60 |
| 4 | S150 Substation and YIS | 101 | 101 | 60 | 60 |
| 5 | New Constabulary | 100 | 98 | 60 | 60 |
| 6 | Carcross and Tagish | 100 | 98 | 60 | 60 |
| 7 | Teslin | 92 | 82 | 60 | 60 |

The frequency recovers after the disturbance for all locations and throughout the YIS. The voltage for all locations and YIS stay within the acceptable limits with the exception of Teslin. The Teslin situation will be addressed by voltage support as part of the system upgrades for the THELP interconnection.

**REFERENCE: YUB-YEC-1-14 AMENDED and JM-YEC-1-5 AMENDED**

**PREAMBLE:**

**QUESTION:**

a) The original YUB-YEC-1-14 question referenced the YEC original January, 2022 submission Figure 2-4; the corresponding Figure in YEC's amended April, 2022 submission would appear to be Figure 2.2-2. Can YEC confirm that the references to Figure 2.4 in amended response to this IR both in the question and in the answer should have been changed to Figure 2.2-2?

b) JM-YEC-1-5 AMENDED provides on page 2 of 4 a graph that shows visually a distinct correlation between the Surprise Lake inflows and Marsh Lake inflows. Since the Whitehorse Rapids hydro plant provides more than half of the annual hydro energy available on the YIS, how can YEC imply in response to YUB-YEC-1-14 AMENDED (a) second paragraph, that no probability for a correlation can be provided when both 1) YEC as neither attempted a correlation and 2) a correlation is visually obvious in YEC's responses to JM-YEC-1-5 AMENDED?

**ANSWER:**

**(a)**

Confirmed. Please see the response to YUB-YEC-2-7 (c).

**(b)**

YEC did not conclude that no relationship existed, only that the data required to update the model to measure this impact is not available to YEC at this time.

The second paragraph of the response to YUB-YEC-1-14 (a) AMENDED highlighted that no model analyses were feasible with the January 2022 Submission to assess potential correlation of a YIS low water sequence with low water conditions at Atlin, i.e., the model analysis with only low water sequence for YIS and low water sequence for Atlin Hydro Expansion Project.

The April 2022 Submission provided Delivered Energy estimates for Atlin over many more water years. The response to JM-YEC-1-5 AMENDED was therefore able to show some correlation between Marsh Lake inflows and Atlin winter generation. However, the low water or drought conditions relevant to the YIS should be viewed at the YIS grid level, not by the individual storage facility as highlighted in response to YUB-YEC-2-7 a) and b). The last paragraph of response to YUB-YEC-1-14 (a) AMENDED provides the modeled winter deliveries from Atlin for water years with deliveries less than 90% of the 34 GWh/year LTA (i.e., below 30.6 GWh). However, not all of these low water year deliveries fall within the YIS low water condition at the grid level.

The Atlin Hydro Expansion Project details (i.e., water data, reservoir and generation unit operational parameters, licence requirements, other constraints) have not been integrated into the YECSIM simulation model. This integration, which is needed for a more refined assessment of this Project's impacts on LTA thermal displacement, would require amendments/modifications to the YECSIM model that are feasible only when YEC has access to such information for the final project.

A full model assessment of Atlin energy delivery impacts by water year on YIS thermal generation would include consideration of the following:

- Higher thermal generation requirements during a YIS low water year sequence would result in a higher percentage of thermal displacement from Atlin deliveries.

- As reviewed in Figure 2.2-2, the Project thermal displacement benefits include direct thermal displacement as well as thermal displacement through water storage in YEC's hydro storage facilities. Therefore, the LTA model analysis would be focused on results over all of the water years.

# Utilities Consumers' Group
# (UCG)

**REFERENCE:** **Amended Atlin Hydro Expansion Project Page 12**

> The Project will also include upgrades as required to connect the THELP's Plant to the YIS (defined in the Amended EPA as "Buyer-AEY System" and "Buyer-AEY System Upgrades"). Final scoping for these upgrades (with planning level cost estimates) is to be included in the Buyer-AEY System Interconnection Study Report that is currently being concluded as part of the Interconnection Agreement between THELP, YEC and AEY.

**QUESTION:**

a) Please provide this Interconnection Study Report.

**ANSWER:**

**(a)**

The requested document cannot be provided at this time. Please see the response to YUB-YEC-2-10 (with the attached correspondence provided by YEC to the Board dated June 10, 2022 regarding amended dates for satisfaction of Conditions Precedent items) and YUB-YEC-2-27.

The condition precedent [condition 2.1(d)(i)] related to the Interconnection Agreement (including the Buyer-AEY System Interconnection Study Report) has been extended to July 29, 2022.

**REFERENCE: Amended Atlin Hydro Expansion Project Page Footnote**

41 The $6.45.3 million/year (2024$) until the end of 2034 (and $5.0 million thereafter) assumes 8.750 MW dependable capacity($1.756 million/year) plus 34.00.8 GWh/year winter delivered energy ($4.63.7 million/year for years until the end of 2034 and $3.3 million for the years thereafter as per Appendix A, Table A3-2). The Project is capable of providing 7.55.4 GWh/year during summer, but no summer deliveries are assumed to be required from the Project given the forecast surplus of summer renewable energy. If 7.55.4 GWh of summer energy was required from the Project, and YEC's approved blended fuel cost (2024$) was $0.19/kWh, the added cost would be $0.75 million/year (price at 50% of the approved blended fuel cost).

**QUESTION:**

a) Please confirm the total capacity plus energy charge of $6.385 Million/yr?

b) How much will the negotiations and regulatory costs add to the above costs/per year (for both YEC and ATCO)?

c) How much will be the added YEC costs for operations and maintenance per year?

d) Will there be added costs for any ATCO operations and maintenance, including billing? If yes, how much?

e) How much income will the sales of 34 Gwh./year generate.

f) Please confirm there will be no rate increase to firm ratepayers on the Yukon grid resulting from the Atlin Hydro Expansion Project. If you cannot confirm please explain.

**ANSWER:**

**(a)**

In 2024$, the capacity plus winter energy charge for 2024 to 2034 is $6.340 million (capacity charge for 8.75 MW is $1.750 million per year; winter energy charge for 34.0 GWh LTA deliveries is $4.590 million), ignoring any potential impacts from Carbon Charge Saving Payment.

**(b)**

Please see the response to UCG-YEC-2-3 which provides YEC costs to date for EPA preparation and negotiations as well as for the regulatory review process. The costs related to the regulatory review process will be added into the Hearing Reserve deferral account as per YUB approval of costs and amortized as part of that account.

The cost to date for EPA preparation and negotiations is approximately $1.182 million. If this cost is amortized over 40 years, based on the Term of the Amended EPA, then the average annual cost reflected in the revenue requirement would be approximately $60,000 [higher in the initial years due to the higher rate base and reduced over time due to annual amortization].

The costs related to YEC and AEY system upgrades will be part of the Interconnection Agreement and recovered from THELP. Any AEY costs related to the regulatory review process will be added into the Hearing Reserve deferral account as per YUB approval of costs and amortized as part of that account.

**(c) and (d)**

There will be some added activities related to operations for YEC and billing work for both YEC and AEY; however, YEC does not expect that the cost would be significant [e.g., any change to operations and billing related work can be managed within the existing labour complement without any added new positions].

Based on the EPA, THELP is responsible for the cost of design, construction, and maintenance of transmission and substation assets at Atlin, from Atlin to Jakes Corner

and at the Interconnection Substation at Jakes Corner, and of any additional metering requirements.

There will be maintenance costs in the future due to YIS system upgrades and to maintain the new and existing transmission assets due to added Atlin load; however, YEC does not have estimates for such costs, and they are likely to be lower than would have otherwise been required to maintain equipment that was in place prior to the upgrades.

**(e) and (f)**

YEC cannot provide useful estimates at this time for overall revenue requirements and rates for test years during the Atlin EPA Term, and therefore cannot estimate future YEC income from sales of 34 GWh/year during this period or whether there will be rate increase requirements associated with the EPA during this period. YEC is not aware of, nor is it appropriate to associate revenues with, a given customer sales mix, i.e., there is no basis for discrimination regarding which customers receive the electricity generated by the project. The EPA pricing provisions, however, have been determined based on current estimates of related thermal fuel and dependable capacity fixed costs that would otherwise be forecast to be required during this period. Section 4.2 of the Submission review EPA effects on customer rates, and Section 4.3 reviews risks associated with the EPA.

**REFERENCE: Atlin Hydro Expansion Project, YEC Response IR YUB 1-42(b)**

The table below captures the costs incurred by YEC to date related to planning, analysis and negotiations for this EPA.
Contractor costs relate to system impact and operational 3 studies that YEC expects to recover from the seller. The remaining costs are related to EPA negotiations and are expected to be recovered through rates.
These costs will increase as YEC will incur costs as part of finalization of Conditions Precedent under the EPA. YEC estimates approximately $0.175million will be recoverable from THELP, subject to final reconciliation and invoicing. YEC is separately tracking the costs of this proceeding and will apply for recovery in accordance with YUB rules.

| Expense Type | |
|---|---|
| Legal | 507,949 |
| Consultants | 311,056 |
| Contractors | 172,830 |
| Internal Labour | 18,867 |
| AFUDC | 10,150 |
| Travel & Miscelaneous | 5,311 |
| Total | 1,026,163 |

**QUESTION:**

a) Please update these costs, showing breakdown for each of these costs giving legal, consultant, and contractors' names and work done.

b) Update and explain work completed for: internal labour costs; AFDUC costs; and travel/miscellaneous costs.

**ANSWER:**

**(a) and (b)**

Please see the updated table below that shows costs to date broken down by consultant and contractors as well as internal YEC costs. The table also includes a column for costs to date for the YUB review process, including costs associated with EPA application preparation and the first round IR process.

| | Atlin EPA Preparation & Negotiations | Atlin EPA YUB Review |
|---|---|---|
| DLA Piper (Canada) LLP | 585,889 | |
| InterGroup Consultants Ltd. | 337,045 | 69,670 |
| Hatch Ltd. | 178,846 | |
| Sussex Strategy Group | 39,600 | |
| KPMG LLP (Vancouver) | 4,441 | 3,700 |
| Orbis Engineering Field Service Ltd. | 2,915 | |
| Aasman Brand Communications Inc. | | 3,406 |
| Arctic Star Printing Inc. | | 1,714 |
| Internal Labour | 25,478 | 6,864 |
| AFUDC | 2,206 | 149 |
| Travel and Miscelaneous | 5,423 | |
| **Total** | **1,181,844** | **85,503** |

Internal Labour reflects the labour cost charged to the project by YEC employees based on time spent on work related to the project [such as project management, EPA negotiations, review and discussions, the EPA application, and the IR process], AFUDC reflects the estimated interest cost applied to project costs while the project is in WIP [the AFUDC cost was revised since the time when the information was provided in response to YUB-YEC-1-43 b)], and travel cost reflects the cost incurred for travel during EPA negotiations, review, and discussions.

**REFERENCE:** **YEC Submission Re: Yukon Utilities Board Review of the Electricity Purchase** Agreement between YEC and THELP April January 2022 Appendix B: Summary of Key EPA Terms and Conditions Page B-5 of the Amended EPA Conditions Precedent specifies that, on or before May January 31, 2022, the three parties (Seller, Buyer and AEY) will have entered into the Interconnection Agreement. Section 2.1(d)(ii) of the Amended EPA Conditions Precedent specifies that, on or before May 31 February 15, 2022, these same parties will have agreed on the budgeted costs for the AEY System Upgrades.

 Funding Plan: Section 2.1(d)(iii) of the Amended EPA Conditions Precedent specifies that:

1. On or before May 31, 2022, Seller will have provided Buyer a detailed funding plan (the “Funding Plan”) setting out Seller’s sources of grant funding together with independent third party estimates of Seller’s costs to develop Seller’s Plant and Buyer-AEY System Upgrade Costs; and
2. On or before June 14, 2022, Buyer will have given Seller notice (based on the Funding Plan) that Buyer is satisfied, acting reasonably, as to the financial viability of Seller’s Plant.

 Environmental Authorizations: Section 2.1(d)(iv) of the Amended EPA Conditions Precedent specifies that, on or before May 31, 2022, Seller will have received satisfactory terms and conditions for the Clean Energy Development Plan authorizations for Seller’s Plant located in British Columbia and for the YESAA Decision Documents for Seller’s Plant located in Yukon.

 TRTFN Approval: Section 2.1(d)(vi) of the Amended EPA Conditions Precedent specifies that, on or before May 31, 2022, Seller will have obtained approval of the Amended EPA by the TRTFN by way of Clan Directive or a Joint Clan Meeting Mandate.

 Yukon Government Approval: Section 2.1(d)(v) of the Amended EPA Conditions Precedent specifies that, on or before 215 days after the Execution Date (which is April 12 January 14, 2022 for the Amended EPA), Buyer will have received such approvals of this Amended EPA as may be required by Buyer to perform Buyer’s.

**QUESTION:**

a) For each of the five bullets above please identify and explain if each of these terms and conditions have now been met.

b) For Funding Plan please give details of Seller's sources and amounts of grant funding as well as the independent third party name and estimate of Seller's cost to develop plant and AEY system upgrade cost.

**ANSWER:**

**(a)**

Please see the response to YUB-YEC-2-10 (with the attached correspondence provided by YEC to the Board dated June 10, 2022 regarding amended dates for satisfaction of Conditions Precedent items), YUB-YEC-2-27 and YUB-YEC-2-28.

In summary, the dates contained in the amended EPA for satisfaction of the conditions precedent in Section 2.1(d)(i) to (ix) have been extended from the dates included in the amended EPA. As such, the date for completing the conditions precedent for each of the items identified in the preamble above has not been met. The following is specifically noted regarding the conditions precedent specified in the preamble above:

- Interconnection Agreement [Section 2.1(d)(i)] – the date for satisfaction of this condition has been extended to July 29, 2022.

- Funding Plan [Section 2.1(d)(iii)] – the date for Seller to submit the Funding Plan has been extended to September 30, 2022, and the date for Buyer to give Notice to Seller that Buyer is satisfied with the Funding Plan has been extended to October 31, 2022.

- Environmental Authorizations [Section 2.1(d)(iv)] – the date for satisfaction of this condition has been extended to March 31, 2023.

- TRTFN Approval [Section 2.1(d)(vi)] – the date for satisfaction of this condition has been extended to October 31, 2022.

- Yukon Government Approval [Section 2.1(d)(v)] – the date for satisfaction of this condition is 215 days after April 12, 2022 (the date the Amended EPA was provided to the YUB), and is the same as provided in the Amended EPA.

**(b)**

See response to part (a) above. The dates for satisfaction of the condition regarding the funding plan [Section 2.1(d)(iii)] have been extended to September 30, 2022 and October 31, 2022.

Please see response to YUB-YEC-2-8(b) and (c) which reviews current information regarding the sources of funding for the Atlin Hydro Expansion Project.

Please see response to YUB-YEC-1-15 AMENDED which reviews information regarding the $240 million estimate (2024$) for Project capital costs including Buyer-AEY System Upgrade Costs. Yukon Energy understands that THELP is currently estimating total Project cost at $254 million, including $35 million contingency.

# Yukon Utilities Board
# (YUB)

**ISSUE:** **Dependable winter capacity**

**REFERENCE:** **Updated application, black-lined version, page 1, PDF page 5**

**QUOTE:** The Project expands TRTFN's existing 2.1 MW hydro facility that has operated since 2009 to displace BC Hydro diesel generation otherwise needed to supply the Atlin community. It can provide the Yukon Integrated System ("YIS") at Jakes Corner with 8.75 MW of winter dependable capacity and 42 GWh/year of long-term average renewable hydro energy if operated throughout the year. The Project will be dedicated to supplying the YIS during the term of the Amended EPA.

**QUESTION:**

a) Please explain what changes occurred to increase the winter dependable capacity from 8.0 to 8.75 MW.

b) YEC notes that "42 GWh of long-term average renewable capacity is available if operated throughout the year." Please confirm that YEC's intention to obtain summer energy is on a limited basis only, e.g., to meet peak demand.

**ANSWER:**

**(a)**

The increase in winter dependable capacity is due to the increased generation capacity and new design for the Project proposed by the Seller. More specifically, the following summarize generation capacity changes related to the increased dependable capacity provided at Jakes Corner by the Project:

1. Schedule B of the EPA specifies an installed capacity increase at Atlin from 8.7 MW to 9.3 MW, as well as the penstock replacement for the power canal (which enhances dependable capacity capability during the Peak Winter Period [PWP]); and

2. Section 4.4 of the EPA specifies the following increases in minimum and maximum Dependable Plant Capacity for deliveries at the POI at Jakes Corner (various factors have affected the capacities adopted for the specified minimum and maximum delivered capacity):

    a. Minimum Dependable Plant Capacity increases from 8.0 MW to 8.5 MW (the minimum originally selected was conservative relative to the expected installed capacity - the increase from this conservative capacity generally reflects the increase in installed capacity at Atlin); and

    b. Maximum Dependable Plant Capacity increases from 8.5 MW to 8.75 MW (the amended 8.75 MW reflects Seller advice as to the maximum that is expected with the amended plant design – the earlier 8.5 MW was an amount specified to limit any increases in the earlier plant capacity given the water and operation constraints associated with PWP dependable capacity deliveries reliant on the power canal).

**(b)**

Confirm that YEC's intention is to obtain summer energy (i.e., deliveries made between June 1 and August 31) on a limited basis only.

- Section 6.4 of the EPA specifies that Summer Delivered Energy will be provided only upon YEC's written request on 48 hours' Notice up to a maximum combined period of two weeks every Summer Period. (The parties will collaborate on getting any required approvals if YEC requests Summer Delivered Energy beyond the combined period of two weeks per Summer Period).

- No Summer Delivered Energy is planned at this time because YEC's substantial forecast energy surpluses during the Summer Period result in no long-term average (LTA) thermal displacement benefits being currently forecast from the Project for energy deliveries during this period. (See YEC Submission, Appendix B page B-9, footnote 12).

**ISSUE:** **Early contractor involvement**

**REFERENCE:** **Updated application, black-lined version, page 1, PDF page 5**

**QUOTE:** On April 8, 2022, Yukon Energy sent a letter to the Board noting that "as a result of recent changes to the design of the Atlin Project arising from an early contractor involvement process initiated by THELP, the EPA signed on January 14, 2022 needs to be amended. Although the amended EPA will not change the basic impacts on YEC and ratepayers beyond improving the expected ratepayer benefits, the Board and intervenors will need time to review the changes to the project and the amended EPA."

**QUESTION:**

a) Why was the EPA agreed to and signed before THELP confirmed the design?

b) Will the contractor from the early involvement process be the same contractor going forward?

**ANSWER:**

**(a)**

The Original EPA as signed in January 2022 specified an agreed design in Schedule B. An amended EPA was therefore required to change the agreed Schedule B design.

THELP proposed an amended EPA in response to results from its early contractor involvement process.

**(b)**

YEC understands that THELP's early involvement process was intended, subject to finalizing satisfactory final contract arrangements, to select the contractor that would be retained going forward. YEC is not aware of any changes in this regard.

**ISSUE:** **Transmission line to YEC's S-150 substation**

**REFERENCE:** **Updated application, black-lined version, page 4, PDF page 8**

**QUOTE:** A 92 km 69 kV new transmission line from a new substation at the new hydro facilities to a new interconnection substation at Jakes Corner, YK with interconnection to the YIS at the existing 34.5 kV ATCO Electric Yukon ["AEY'] facilities ["AEY System"] for transmission to YEC's S-150 substation in Whitehorse. [footnote removed]

**QUESTION:**

a) Please provide the outage history for the transmission line from substation S-150 to Teslin.

b) What consideration did YEC give to transmission line outages in respect to increased power flows from Atlin?

**ANSWER:**

**(a)**

Historical outage information related to the AEY 6L11 (S150 to Teslin designation) power line is provided in response to JM-YEC-1-1 for 2016 to 2020.

Please note that YEC does not own the 6L11 power line, only the distribution at Johnson Crossing. However, many events on this line are related to other YEC system events. S150-Teslin line is part of the system load shedding scheme, where the loss of generation could result in an outage on this line. When Atlin generation is added to the YEC system this line will be removed from the under-frequency protection and therefore is expected to see less outage events.

**(b)**

The quoted paragraph was not changed in the revised Submission. The Buyer-AEY System Interconnection Study Report addresses Buyer-AEY System Upgrades required to facilitate the Interconnection and to allow the Buyer-AEY System to support the

integration of the Energy produced by Seller's Plant under the EPA and Buyer-AEY System Interconnection Standards. Accordingly, the increased power flows are not expected to increase transmission line outages on the YIS.

Transmission line outages on the YIS that could disrupt EPA deliveries and require Monthly Constraint Energy payments to THELP are addressed in Section 6.5 of the EPA with the provisions regarding a Non-Permitted System Constraint. Transmission line outages on the THELP line to Jakes Corner will reduce THELP deliveries and earnings. YEC did not adjust its financial assessments of the EPA based on any specific assumptions as to potential future outages on either of these transmission line systems.

**ISSUE:** **Project capabilities**

**REFERENCE:** **Updated application, black-lined version, page 6, PDF page 10**

**QUOTE:** Expected LTA energy deliveries during each PWP, based on the Project's Surprise Lake storage and its 51 modeled water years of record, will enable a full 8.75 MW of capacity to be delivered to YEC at Jakes Corner for over 85% of the 75 or 76 days in the PWP, which is more than enough days to cover the 20 or less days of the PWP period when minus 30ºC or lower temperature has been recorded at Whitehorse.

**QUESTION:**

a) The availability percentage has dropped from 94% in the original EPA to 85% in the amended EPA. Please discuss the significance of the change and the drivers for the change.

b) Footnote 7 at the end of the paragraph includes two changes, one where "and battery" is added after "Existing Plant", and the second changes the Atlin community load from 6.93 GW.h/yr to 7.11 GW.h/yr. Explain why the addition of "and battery" was required and how the addition is relevant to the amended EPA. Further, explain why the Atlin community load was increased in the amended application.

**ANSWER:**

**(a)**

The referenced change assumes that the same minimum PWP energy deliveries of 14 GWh are allocated to provide 8.75 MW at the updated full capacity versus only 8.0 MW at the prior full capacity. The higher capacity requires more delivered energy per day – which results in the lower percentage of PWP days than can be provided with the minimum 14 GWh.

Please see response to YUB-YEC-2-25(b) for a more detailed review of this change.

**(b)**

As reviewed in notes to Table A1 in the April 2022 Submission, the referenced 7.11 GWh/yr load included 6.93 GWh/yr unchanged town load and 0.18 GWh/yr for the battery. The January 2022 Table A1 referenced an Atlin load bank for the Existing Plant (without reference to its equivalent energy load). YEC does not have details on this Existing Plant change, but understands that THELP is now planning to include a new battery for its Existing Plant to improve water use efficiency, and that overall water availability for hydro generation is forecast to be improved by this change.

**ISSUE:** **Firm energy**

**REFERENCE:** **Updated application, black-lined version, page 7, PDF page 11**

**PREAMBLE:** The amended EPA reduces the firm energy during the lowest water year from 25.2 GWh to 23.5 GWh.

**QUESTION:**

a) Please discuss the rationale and significance of the above noted reduction.

b) Please provide a definition for “firm energy”.

**ANSWER:**

**(a) and (b)**

The Original EPA identified firm winter energy as the Delivered Energy during the Winter Period for the lowest water year conditions in Table A1 of the January 2022 Submission, i.e., the 25.2 GWh shown for the 1978 Winter Period. “Firm energy” during winter in this context is the minimum Delivered Energy expected to occur during winter, based on the available water record and modelling assessments.

The Amended EPA no longer defines firm energy. Based on the earlier definition, firm winter energy for the lowest water year during the Winter Period is shown in Table A1 in the April 2022 Submission which shows 23.5 GWh for 1985 as the lowest Winter Period water year conditions. This change reflects the impact of the amended Project and the updated modeled water flow assessments developed by SNC Lavalin and Knight Piesold for a longer number of water years. (See Table A1 for the updated Delivered Energy estimates by month and water year for 51 years through 2020 inclusive as provided by SNC for the redesigned Project.)

In the context of the overall Amended EPA, which no longer includes separate firm and non-firm winter energy prices, the change in lowest water year conditions has no significant impact on YEC net benefits or risks related to the EPA.

**ISSUE:** **Firm energy**

**REFERENCE:** **Updated application, black-lined version, page 17, PDF page 21**

**QUOTE:** Winter Delivered Energy – the basis for 2024-2034 and 2035 to end of Term Delivered Energy prices paid by YEC to THELP.

**QUESTION:**

a) Please explain why the terms “firm” and “non-firm” were removed from the original application.

b) Firm and non-firm winter rates have been replaced with one winter energy rate. How will the elimination of the lower winter rate affect ratepayers?

**ANSWER:**

**(a)**

The enhanced dispatchability with the revised Project enabled removal of separate firm and non-firm winter energy tariffs included in the Original EPA. One Winter Energy Price (2024$) was therefore adopted in the Amended EPA for each of the two load forecast periods (2024 to 2034, and 2035 to end of Term).

Absent the need for defining “firm” and “non-firm” winter energy prices, there was no longer any need to retain these terms in the EPA and they were therefore removed.

**(b)**

Adoption of one winter energy rate will not affect the long-term average (LTA) costs charged to ratepayers based on LTA winter energy deliveries. As shown in the January 2022 Submission, the firm and non-firm rates were determined to yield the LTA thermal benefits (2024$million) related to the LTA winter energy deliveries. Adoption of one winter energy rate related to the January 2022 Submission would be determined to yield the same LTA thermal benefits related to LTA winter energy deliveries.

**ISSUE:** **Low water years**

**REFERENCE:** **Updated application, black-lined version, page 9, PDF page 13**

**QUOTE:** Forecast LTA thermal displacement benefits on the YIS resulting from the Project are based on the average of forecast thermal displacement under varying YIS water conditions over 38 water years. Figure 2.2-4 highlights the wide variance in forecast thermal displacement using 2024 forecasts over the 38 water years - ranging from 1.6 GWh/yr average for the 2013-2018 high water sequence to 41.1 GWh/yr average for the 1994-1999 low water sequence.

**QUESTION:**

a) When YEC was experiencing low water years 1994-1999, were the same low water conditions occurring at Surprise Lake/Atlin? Please explain.

b) Please provide the evidentiary support for part (a) of the response, including any water records.

c) Why is Figure 2.2-4 not included in the clean version of the application?

**ANSWER:**

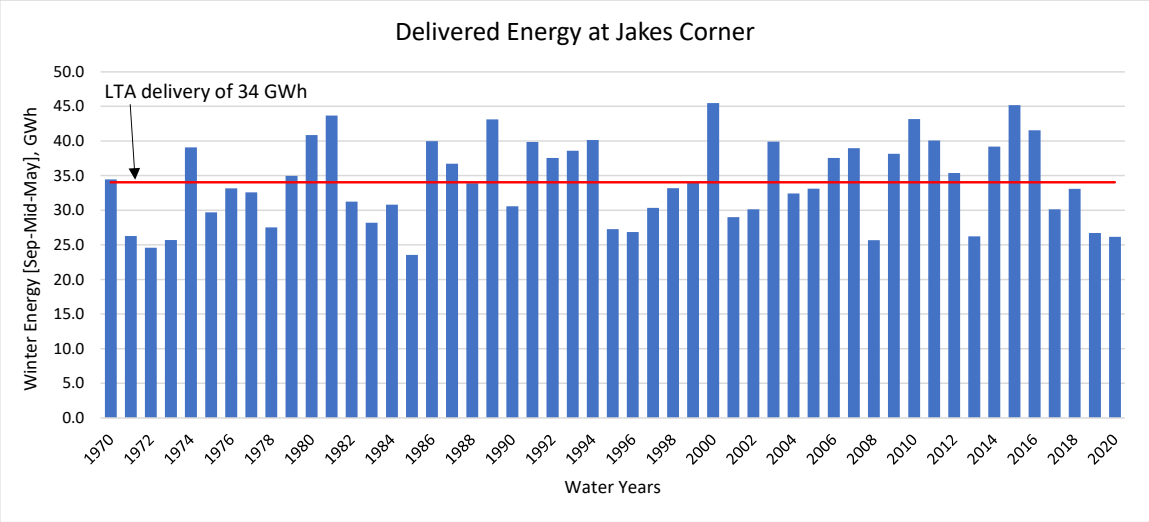
**(a) and (b)**

The April 2022 Submission provides information showing Atlin low winter generation from 1995 through 1997, overlappling with a portion of the YIS 1994-1999 annual low water years.

Table A1 in Appendix A of the Amended EPA application shows Atlin Hydro Expansion Project modeled generations for 51 water years [1970-2020]. The table shows the water years of 1971 through 1973, 1982 through 1985, and 1995 through 1997 as series of years with lower winter generation; with the lowest winter generation in 1985 water year. This also was illustrated in the figure provided in response to JM-YEC-1-5 AMENDED that compares Marsh Lake inflows to Atlin winter generation for 1981-2018 water years.

It should be noted, however, that the low water or drought conditions should be viewed at the YIS grid level, not by the individual storage facility. For example, in some water years Marsh Lake inflows are low, but it is somewhat offset by higher inflows in Aishihik Lake and/or Mayo Lake. In this sense, the 1994-1999 water years are low water year sequence for the YEC grid when the inflows in all three storage facilities were much lower compared to the LTA impacting overall generation on the YEC grid. Therefore, when looked at the YIS grid level the modeled Atlin generation for 1995-1997 would fall within a portion of the YIS 1994-1999 drought or low water year conditions.

Please see figure below that shows modeled delivered winter energy at Jakes Corner by water years based on Table A1 in Appendix A of the Amended EPA.




Please also see response to JM-YEC-2-9(b).

**(c)**

The clean version of the April Submission includes Figure 2.2-2 at page 7, which is the figure referenced in the text at page 6. There is no Figure 2.2-4 in the EPA Submission. The above quote is not correct.

**ISSUE:** **Grant funding**

**REFERENCE:** **Updated application, black-lined version, page 11, PDF page 15**

**PREAMBLE:** British Columbia has been removed as a funding source

**QUOTE:** Grant funding of approximately $150 million has been committed from the governments of the Yukon Territory and Canada to support the economics of the Project. Such funding would allow Yukon Energy to purchase energy and capacity from the Project at prices comparable with the lowest cost thermal alternatives, and deliver a reasonable return to THELP.

**QUESTION:**

a) Why has British Columbia been removed in the application as a funding source?

b) Please provide the expected amount of funding from each of the governments of Canada and of the Yukon Territory.

c) How will the originally expected funding from BC be covered? Will Canada's or Yukon's portions increase, or will THELP provide funding through another source (e.g., financial institution)?

**ANSWER:**

**(a)**

British Columbia has not been removed in the submission as a funding source. The original Submission (which included BC) referenced governments from whom funding "is being sought" and the revised Submission (which did not include BC) references governments from whom funding "has been committed" as at the Submission date.

As reviewed in YUB-YEC-1-16 AMENDED, THELP has continued to seek funding from British Columbia.

**(b) and (c)**

As reviewed in YUB-YEC-1-16 AMENDED, the Yukon government has committed $50 million to the Atlin Hydro Expansion Project and Canada has committed $100 million to the development phase (other funds are being provided during the planning phase). Yukon Energy is not aware of any potential for changes to these commitments.

The Canadian Infrastructure Bank on June 1, 2022 announced that it has committed up to $80 million to the Atlin Hydroelectricity Expansion Project.

Yukon Energy understands that THELP is seeking $20 million from the government of British Columbia.

**ISSUE:** **Delivery of dependable capacity**

**REFERENCE:** **Updated application, black-lined version, page 12, PDF page 16**

**QUOTE:** The additional terms related to the delivery of dependable capacity went beyond the IPP template document.

**QUESTION:**

a) Is Atlin considered an isolated system?

b) Does the Standing Offer Program contain a dependable capacity element? If the response is yes, please provide details.

c) Does the BC Hydro IPP Large Project EPA contain a capacity element?

d) What components of the YEC (Standard Offer Program) EPA and BC Hydro IPP Large Project EPA were used to develop the Atlin EPA? In your response, please explain any similarities and differences between each of the two EPAs and the amended Atlin EPA.

e) Why is a capacity element required for this agreement? Based on the agreed energy deliveries and the time period where those deliveries are to occur, is there already an implied capacity in the pricing? Please explain.

f) Are the energy and capacity charges payable under the revised EPA agreement equal to the costs of a new thermal plant? If not, please explain from a rates perspective why the EPA is the preferred option.

g) Can the EPA go forward without a capacity component? Please explain.

h) What evidence can YEC provide that a capacity payment component is required for the EPA to go forward? Please provide that evidence and explain.

**ANSWER:**

**(a)**

Yes

**(b), (c) and (d)**

The Standing Offer Program (SOP) in Yukon and the BC Hydro IPP Large Project EPA each do not contain a dependable capacity element. See YUB-YEC-1-19(a) attachments for the two referenced EPA templates.

As referenced in the January 2022 Submission, the Parties used these EPA documents only as a starting template for the initial negotiations and have not referenced these documents thereafter, due in part to the need to extensively edit the BC document to suit the Yukon environment. Accordingly YEC did not consider it prudent to track these differences and such an analysis cannot be provided in the timelines available to fully document similarities or differences between each of these two EPAs and the amended Atlin EPA.

**(e)**

The dependable capacity element is a key feature of the EPA, distinguishing the Atlin Project from other renewable IPPs that do not provide dependable capacity during the Peak Winter Period (PWP) relevant to the Yukon Integrated System. Without this element and the related capacity payment the Project would not be of interest to YEC, and would not be financially viable for THELP.

The provision of dependable capacity during the PWP enables Yukon Energy to displace fixed cost requirements for equivalent thermal generation capacity (assumed to be new diesel generation), and is an added benefit beyond the Project's ability to displace thermal generation fuel costs as provided for in the EPA energy prices. There is no implied fixed cost saving capacity benefit included in the thermal fuel cost savings used to determine the winter energy price in the EPA.

**(f)**

The energy and capacity charges payable under the amended EPA are based on displacement of thermal generation costs, i.e., the energy charges are based on estimated thermal fuel cost savings and the capacity charges are based on fixed cost savings for equivalent new diesel plant dependable capacity.

The Submission and responses to other IRs review in detail the specific methods used to determine these charges based on the above principles. Analysis at page 27 of the April Submission shows that the Amended EPA effect on customer rates is materially lower than equivalent SOP IPP renewable supplies.

**(g) and (h)**

The EPA cannot go forward without the capacity component. Exclusion of the capacity payment would not comply with the EPA as amended and would therefore prevent it from proceeding.

The capacity payment component is an integral and material part of the revenue relied upon by THELP under the amended EPA, given that the energy prices in the EPA are adjusted to reflect the extent to which expected thermal displacement equals only a portion of the Delivered Energy provided by the Project. Accordingly, THELP's financing is dependent on the pricing terms of the EPA, including the capacity charges. In other words, deletion of the capacity component without adjusting other financial terms would render the agreement not viable financially from THELP's perspective.

The capacity payment component also reflects benefits to Yukon Energy resulting from dependable capacity provided through the amended EPA, and as such there is no reasonable basis for excluding this component.

**ISSUE:** **Conditions precedent**

**REFERENCE:** **Updated application, black-lined version, page 13, PDF page 17 and footnote 11**

**QUOTE:** The Amended EPA has no legal force until the various Conditions Precedent provisions in Section 2.1(d) are completed to the mutual satisfaction of YEC and THELP, with the last deadline for such condition completion in the Original EPA being prior to approximately mid-August 2022.

**PREAMBLE:** The above quote notes a mid-August 2022 date for completion. Footnote 11 on the same page states in part: "All other Condition Precedents are to be completed by no later than June 14, 2022."

**QUESTION:**

a) Please provide the revised date for last condition completion changed with the amended EPA and clarify whether there are multiple condition dates that apply to Section 2.1(d).

**ANSWER:**

**(a)**

The last Conditions Precedent completion date today with the latest amendment is March 31, 2023 for completion of Section 2.1(d)(iv) regarding receipt of Clean Energy Development Plan authorization for Seller's Plant in British Columbia and receipt of YESAA Decision Documents for the Seller's Plant in Yukon. Multiple other Conditions Precedent completion dates are now applicable:

- November 13, 2022 continues to apply for Section 2.1(d)(v), the 215 days after April 12, 2022 for Buyer receipt of approvals of the EPA from Governmental Authorities on terms and conditions satisfactory to all Parties.

- October 31, 2022 applies for the following parts of Sections 2.1(d):
    - (iii) [Buyer Notice to Seller that Buyer is satisfied with Funding Plan]

- (vi) [Seller receipt of TRTFN approval of EPA]
- (vii) [Seller receipt of consents from BC Hydro and Canada Life Assurance Company of Canada to enter into the EPA]
- (viii) [Parties agree on allocation of Environmental Attributes based on requirements of funding contributed to Seller's Plant by Yukon, BC, and Canada governments]

- September 30, 2022 applies for Section 2.1(d)(iii) wherein Seller submits to Buyer a Funding Plan.

- July 29, 2022 applies for the following parts of Section 2.1(d):
  - (i) [Parties sign Interconnection Agreement]
  - (ii) [Parties agree on costs for AEY System Upgrade costs after AEY received bids for labour costs through a competitive bidding process]
  - (ix) [YEC and AEY sign Implementation Agreement].

To clarify the above quote and the referenced Footnote 11 from the April 2022 Submission:

- The referenced "mid-August 2022" date for the last deadline for Conditions Precedent completion was from the Original EPA.

- Footnote 11 compared Section 2.1(d)(v) of the Original EPA and the Amended EPA, which each provide 215 days from the Execution Date to YEC's receipt of approvals by any Government Authority – and then noted that the Original EPA Execution Date was January 14, 2022 and the Amended EPA Execution Date is April 12, 2022, i.e., whereas a mid-August completion date was applicable in the Original EPA, the latest completion date with the Amended EPA is November 13, 2022.

- The Footnote 11 quote in the above Preamble then followed the above review with a statement applicable to both the Original EPA and the Amended EPA, i.e., "All other Condition Precedents are to be completed by no later than June 14, 2022." This quote may be misleading in that only one of the other Conditions Precedent (Section 2.1(d)(iii) for Buyer notification to THELP of satisfaction re: the financial viability) has a date of June 14, 2022 for completion.

- Review of Section 2.1(d) in the Amended EPA confirms a May 31, 2022 completion date for all Conditions Precedent other than those referenced in the above quotes.

Since filing of the Amended and Restated EPA, THELP has continued its review of dates for satisfaction of Conditions Precedent and has advised YEC of the need for extensions of these dates, including the requirement to refile its application for Clean Energy Development Plan authorization for Seller's Plant in B.C. and the resulting need for the related Conditions Precedent to be extended to March 31, 2023.

Yukon Energy and THELP have subsequently mutually agreed to extend the dates for satisfaction of the Conditions Precedent as required by THELP. Attachment 1 provides a copy of Yukon Energy's June 10, 2022 letter to the Board regarding amended dates for satisfaction of Conditions Precedent items, and including a copy of the amendment agreement between YEC and THELP that extends the dates for satisfaction of Conditions Precedent for the Amended and Restated EPA. The Seller's Target COD for commercial operation of the Seller's Plant remains at December 1, 2024 as provided in the Amended EPA.

Please see responses to YUB-YEC-2-27 and YUB-YEC-2-28 for review of status for specific Conditions Precedent elements and consequences for the Amended EPA of the updated dates and any potential future new delays in the dates for satisfaction or waiving of Conditions Precedent.

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Box 5920, Whitehorse
Yukon Y1A 6S7
yukonenergy.ca

June 10, 2022

Mr. Richard Buchan, Chair
Yukon Utilities Board
Box 31728
Whitehorse, Yukon Y1A 6L3

Dear Mr. Buchan:

**Re: Yukon Energy Corporation (Yukon Energy or YEC) Submission for the referral of the Electricity Purchase Agreement (EPA) with Tlingit Homeland Energy LP (THELP) to the Yukon Utilities Board (Board) for review under s. 18(1) of the *Public Utilities Act* – Amended and Restated EPA**

The Amended and Restated EPA includes a number of Conditions Precedent under section 2.1(d). Since filing of the Amended and Restated EPA, THELP has continued its review of dates for satisfaction of Conditions Precedent and has advised YEC of the need for extensions of these dates.

Yukon Energy and THELP have subsequently mutually agreed to extend the dates for satisfaction of the Conditions Precedent as required by THELP. The Target COD for completion remains at December 1, 2024.

The amendment agreement between YEC and THELP that extends the dates for satisfaction of Conditions Precedent for the Amended EPA is attached with this correspondence.

Yours truly,

Ed Mollard
Vice President, Finance & CFO

1

the power of yukon

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May 25, 2022

Tlingit Homeland Energy Limited Partnership
By Its General Partner
Tlingit Homeland Energy Limited
P.O. Box 408
Atlin, BC, V0W 1A0

**Re: Electricity Purchase Agreement Dated January 14, 2022 as amended and restated on April 12, 2022 (collectively, the "EPA") Between Yukon Energy Corporation ("YEC") and Tlingit Homeland Energy Limited Partnership By Its General Partner Tlingit Homeland Energy Limited ("THELP")**

YEC is writing to confirm its agreement with THELP that the dates contained in the EPA for satisfaction of the conditions precedent in Sections 2.1(d)(i) to (ix) are extended from their current dates until the dates set out below. Capitalized terms used and not defined in this letter have the meanings in the EPA.

| | CONDITION | Updated Due Date |
|---|---|---|
| 1 | 2.1(d)(i) | July 29, 2022 |
| 2 | 2.1(d)(ii) | July 29, 2022 |
| 3 | 2.1(d)(iii) for Seller to submit Funding Plan to Buyer | September 30, 2022 |
| 4 | 2.1(d)(iii) for Buyer to give Notice to Seller that Buyer is satisfied with Funding Plan | October 31, 2022 |
| 5 | 2.1(d)(iv) | March 31, 2023 |
| 6 | 2.1(d)(v) | 215 days after April 12, 2022 |
| 7 | 2.1(d)(vi) | October 31, 2022 |
| 8 | 2.1(d)(vii) | October 31, 2022 |
| 9 | 2.1(d)(viii) | October 31, 2022 |
| 10 | 2.1(d)(ix) | July 29, 2022 |

Except as amended by this letter the EPA remains in full force and effect, unamended.

Yukon Energy Corporation

Per: _____

Agreed on May 25, 2022

Tlingit Homeland Energy Limited Partnership
By Its General Partner
Tlingit Homeland Energy Limited

Per: _____

the power of yukon

**ISSUE:** **Delivery of all winter energy available**

**REFERENCE:** **Updated application, black-lined version, page 15, PDF page 19**

**QUOTE:** … while YEC will only pay for winter energy that is expected to displace LTA forecast thermal generation, YEC will take delivery each winter season (Sep-May) of all available energy that the Project is able to generate.

**QUESTION:**

a) To clarify what is meant by "expected to displace LTA forecast thermal generation", if 8.75 MWs are available to be delivered at Jakes Corner in a given hour but for that hour the LTA expected thermal displacement is only 1 MWh, will YEC only pay for 1 MWh of energy (not including capacity charges)? Please explain.

b) If the assumption in part (a) is correct, is it probable that YEC may have to spill water on the YIS (assuming LTA conditions exist for that hour) due to the deliveries at Jakes Corner? Please explain.

c) If the assumption to part (b) is correct, is there an opportunity cost to YEC due to the spilled water? Please explain.

**ANSWER:**

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

Please see response to YUB-YEC-1-24 AMENDED, and its references to YUB-YEC-1-11 AMENDED and YUB-YEC-1-12 AMENDED, which address these same basic questions regarding the quote (the only change for the above quote in the April 2022 Submission being the words "is expected to displace" versus "displaces").

YEC will pay for all energy delivered as defined by the EPA but the price paid will reflect that not all energy deliveries from this project will offset thermal (see YUB-YEC-1-11 AMENDED for the determination of this lower rate). The quoted principles were adopted to guide the determination of the Winter Energy Price. The Winter Energy Price is determined based on long-term average (LTA) expected or forecast thermal generation

displacement over the entire Winter Period, and is applied without reference to actual or expected thermal displacement in any specific hour or other segment of the Winter Period. Subject to these constraints, the following are reviewed in the previous IR responses:

- The EPA Winter Energy Price is based on forecast LTA thermal displacement, e.g., if forecast LTA thermal displacement over the Winter Period equals only about 11% of purchased EPA deliveries (as per “a’ in the above question), this EPA energy price equals only about 11% of the assumed thermal fuel cost per kWh.

- Determination of the EPA Winter Energy Price takes into account the extent to which there is an expected need to spill water on the YIS due to the deliveries at Jakes Corner (i.e., the extent to which there is no LTA benefits from EPA deliveries) and the extent to which there is an expected opportunity to secure added hydro water storage on the YIS due to the deliveries at Jakes Corner (i.e., the extent to which there are deferred thermal displacement benefits from EPA deliveries enabling additional hydro storage that is subsequently used to displace thermal generation).

- Overall, spilled water resulting from the EPA energy deliveries signifies the absence of ability to secure additional water storage, and the absence of any YEC opportunity cost impact related to this water. The EPA Winter Energy Price reflects the thermal generation alternative use for any addition to spilled water on the YIS.

**ISSUE:** **Payment for capacity**

**REFERENCE:** **Updated application, black-lined version, page 15, PDF page 19**

**QUOTE:** … rather than paying for actual dependable capacity provided by the Project, YEC will pay for Dependable Plant Capacity Committed over each Peak Winter Period, based on the outcome of a capacity test completed each December at the beginning of each winter period.

**QUESTION:**

a) Why wasn't actual dependable capacity used? Would it not simplify the agreement? Please explain.

b) By using dependable forecast capacity, is YEC and therefore ratepayers assuming risk or losing the time-value of money? Please explain.

**ANSWER:**

**(a)**

The response to YUB-YEC-1-24 AMENDED, pages 6 and 7, addressed the same basic question regarding the quote (the quote remains unchanged from the January 2022 Submission). In summary, the use of committed capacity was required to enable all parties to proceed with work to advance the Project in order to secure the forecast benefits for both YEC (and ratepayers) and THELP.

After extensive discussion, the parties were not able to agree on an approach where capacity payments made each Peak Winter Period would be based on actual dependable capacity provided to YEC during that period. THELP required a firm capacity revenue amount for each year to assist in securing its financing, and was not prepared to proceed with these annual payments being subject to variance based on actual performance. THELP did agree, however, to the December capacity test for each year to confirm Dependable Plant Capacity Committed for each PWP based on this test – and for annual capacity payments to be dependent on this test. This measure addressed basic risks related to Seller Plant conditions over time, confirming actual dependable capacity available for each Peak Winter Period.

The Dependable Capacity Excess Payment (DCEP) mechanism was also included to address actual dependable capacity shortfalls from committed. THELP agreed to enable YEC to recover excess capacity payments related to any such shortfall from other potential future payments to THELP. Recoveries are contingent on THELP being eligible for additional payments in future years beyond the EPA prices – but YEC recoveries are to occur before any THELP additional payments would be made for higher-than-forecast loads after 2034 or any carbon tax charges applicable to YEC.

**(b)**

The EPA provisions regarding payments for dependable capacity result in YEC and therefore ratepayers assuming some risk or losing the time value of money to the extent that DCEP amounts occur.

The December capacity test for each year to confirm Dependable Plant Capacity Committed for each PWP addresses basic risks related to Seller Plant conditions over time. Analysis provided in the Submission confirms that water availability is also not an expected risk affecting Project ability to provide dependable plant capacity required during the PWP. Any disruptions affecting THELP's Plant after a December test are expected to be brief and are not expected to occur on any frequent basis.

The risk of not recovering DCEP amounts, as well as any losses of time value of money due to delays in such recoveries, will be reduced to the extent that a carbon tax becomes applicable to YEC fuel costs, i.e., any such carbon tax change will establish a Carbon Charge Saving Payment with the potential ability for DCEP amount recoveries to occur without material delay. Absent a Carbon Charge Saving Payment or a Summer Delivered Energy Payment, DCEP recoveries related to any Additional Payments (linked to Added Load on the grid) cannot occur before 2035 - however, starting in 2035 any Added Load would also provide the potential ability for DCEP amount recoveries to occur without material delay.

**ISSUE:** **New arrangements affecting enhancement of the existing plant**

**REFERENCE:** **Updated application, black-lined version, page 17, PDF page 21, and Section 7.3, Enhancement of Existing Plant Using Seller's Plant, page A1-20, PDF page 108**

**PREAMBLE:** The following was deleted on page 17 (PDF page 21) in the amended EPA: "new arrangements affecting enhancement of the Existing Plant using the THELP's Plant under certain conditions that would provide enhanced capability to supply YEC as well as for Atlin Community Customer loads."

The new paragraph reads: "… provisions for the enhancement of the Existing Plant using the Seller's Plant, including current plans to tap the Penstock to supply the Existing Plant and provisions for YEC to review and consider for approval prior to 2034 any changes proposed by THELP to the configuration of the Existing Plant when the Existing EPA with B.C. Hydro regarding the Existing Plant terminates."

Section 7.3 of the amended EPA includes the following:

"If Seller uses the Penstock also to provide water to the Existing Plant, Seller will ensure that operation of the Penstock will not have a material adverse effect on Seller's ability to deliver and Buyer's ability to receive during each Peak Winter Period.

…

Buyer will review and approve such changes, acting reasonably, provided that such changes comply with all other provisions of this EPA and also provided that such changes do not cause a decrease in the average expected Delivered Energy, or the expected Dependable Plant Capacity to be provided during the Peak Winter Period."

**QUESTION:**

a) Please fully explain the changes to the section titled “Enhancements of Existing Plant Using THELP’s Plant” from the original submission to the revised.

b) Please explain how “material adverse effect” will be determined under Section 7.3 of the amended EPA.

c) How will it be determined that “changes do not cause a decrease in the average expected Delivered Energy, or the expected Dependable Plant Capacity to be provided during the Peak Winter Period”?

**ANSWER:**

**(a)**

Changes to Section 7.3 of the EPA address THELP plans to use the new penstock element of Seller’s Plant with the Amended EPA in order (via a tap) to supply water to its Existing Plant. Under the Original EPA, this was only a possible future option when the Existing EPA regarding the Existing Plant terminates in 2034 and if there is a plan to be implemented to enhance the Existing Plant with a new EPA with BC Hydro.

Updated wording was also adopted to clarify the process for review of any future proposal by Seller outlining any changes to the configuration of the Existing Plant and all related terms and conditions for the new arrangements that may cause changes to the Seller’s Plant, expected Delivered Energy (i.e., LTA Delivered Energy provided to Yukon Energy) or Dependable Plant Capacity (i.e., Dependable Plant Capacity provided to Yukon Energy) during the Peak Winter Period (PWP). As with the Original EPA Section 7.3, YEC approval, acting reasonably, is required for any such Seller proposal – the updated wording specifies that such approval is contingent upon such changes not causing a decrease in average expected Delivered Energy or the expected Dependable Plant Capacity to be provided during the PWP.

**(b)**

The term “material adverse effect” has been used in Original EPA and Amended EPA Section 7.2(a) as well as the Amended EPA Section 7.3. Assessment of any such effect

related to Section 7.3 will be based on evidence of a reduction, due to the Penstock tap to the Existing Plant, in Seller's ability to operate Seller's Plant at full capacity during the PWP. As reviewed in the April 2022 Submission, Table A1 provides evidence of Delivered Energy capabilities during the PWP under varying water year conditions – and Seller will be able to justify constraints on full capacity operation during the PWP to the extent that Surprise Lake level and water availability constraints are consistent with Table A1 modeled assessments.

**(c)**

THELP will be required to confirm, to YEC's satisfaction (acting reasonably), that any proposal it makes under Section 7.3 would not result in the LTA decreases noted.

The specific methods for this assessment may vary depending on the proposal under consideration – but it is likely that modeled water use assessments over a range of water year conditions similar to analysis in the April 2022 Submission would be required, with comparison made of scenarios with and without the proposal under consideration. Engineering reviews may also be required to confirm assumptions related to any proposed new facilities.

**ISSUE:** **Moon Lake**

**REFERENCE:** **Updated application, black-lined version, page 26, PDF page 30**

**QUOTE:** Figure 4-1 and Table 4-1 indicate a forecast YIS N-1 capacity shortfall for winter 2024/25 without the Project of 17.2 MW related to non-industrial YIS load. Without the Atlin Project and the Moon Lake Pumped Storage Project, this capacity shortfall increases to 27.6 MW by 2027/28 (requiring 16 of 1.8 MW diesel rental units, plus any spares needed to support these units), and then to 41.5 MW by 2030/31 (requiring 24 rented diesel units). [footnotes removed]

**QUESTION:**

a) Please explain why it was necessary to add the words “Atlin” and “and the Moon Lake Pumped Storage Project” to this paragraph.

b) If the words identified in part (a) were not included, would the capacity shortfall numbers change?

**ANSWER:**

**(a)**

“Atlin” was added for clarity as to the specific “Project” being referenced. “Moon Lake Pumped Storage Project” was added to correct an error in the original Submission (without this clarification as to the exclusion of the Moon Lake Pumped Storage Project, the subsequent numbers would not be as shown in the last row of Table 4-1).

**(b)**

The word “Atlin” inclusion has no impact on the capacity shortfall numbers so long as “Project” is assumed to be the Atlin Project. Inclusion of “Moon Lake Pumped Storage Project” would reduce the capacity shortfall numbers after 2027/28.

**ISSUE:** **Steady state operation**

**REFERENCE:** **Updated application, black-lined version, page 30, PDF page 34**

**QUOTE:** The Project's capability to displace LTA thermal energy generation is enhanced by its hydro storage which enables the 8.75 MW of dependable capacity during the PWP and by the amended Project design that enables materially enhanced dispatch capability for the Project during the Winter Period. The amended Operating Rules required for the Project (see Section 2.3.2 of this Submission) no longer require reasonably steady state operation at full capacity to the extent practicable during the PWP when LTA thermal energy generation is forecast to be required. [underlining added]

**QUESTION:**

a) In the original EPA, there was a requirement for steady state operation at full capacity. Please explain why that steady state operation at full capacity is no longer required under the amended EPA.

**ANSWER:**

**(a)**

The requirements in the Original EPA for "reasonably steady state operation at full capacity to the extent practicable during the PWP" reflected requirements related to the 7.8 km power canal, including risks related to destabilizing ice conditions in the power canal as well as delays and challenges in frequently changing flows in the power canal (see footnote 33 in January 2022 Submission – the same points are also made throughout that Submission).

This earlier requirement is not needed with the Amended EPA due to the Penstock being used to move all water from Surprise Lake to the Powerhouse.

As reviewed in detail in the April 2022 Submission (and the April 12, 2022 letter providing that Submission), this Penstock removes the need to form and maintain ice conditions in a power canal and enables greatly enhanced dispatchability for Delivered Energy, including:

- 1 hour vs 3 days for YEC direction to change dispatch;
- Ability in all seasons to change dispatch between 100% of capacity and 1 MW at the generation plant versus prior winter requirement for minimum water flow at 65% of capacity;
- Ability for YEC to schedule 4 changes per day (2 up and 2 down);
- Ability for YEC to change next day and following planned weekly dispatch in response to changes in forecast weather or YIS system conditions; and
- Ability to more effectively use available water for thermal generation displacement.

**ISSUE:** **Modeled water years**

**REFERENCE:** **Updated application, black-lined version, page 30, PDF page 34, footnote 34**

**QUOTE:** See Section 2.1.3 of this Submission. The LTA energy generation estimate for the Project deliveries to YEC was prepared by SNC Lavalin, retained by THELP, based on modeled water year flows as reviewed in Appendix A, Table A1. The Project LTA energy generation in Appendix A, Tables A1 and A3 for winter deliveries to YEC at Jakes Corner reflects the average Atlin Project hydro generation during the Winter Period (Jan. 1 to May 31, Sept. 1 to Dec. 31) for all modeled water years [Although the Winter Period includes period to May 31, the LTA energy delivery at 34.0 GWh was modeled to May 15 to exclude energy from freshet,] [sic]The transmission losses between the Atlin generation location and delivery point at Jakes Corner is estimated to be at around 2.7%. Additional losses of 4.5% are added that reflect losses on the YIS system for estimated energy delivered from Jakes Corner to YEC's substation S150 at Whitehorse (these added losses take into account the material portion of the Delivered Energy expected to be used to supply customer loads on the southern Yukon AEY System and assume that AEY System Upgrades will result in continuation of past average losses on this AEY System despite the material increases in energy being transmitted on this system).

**QUESTION:**

a) Please describe what review and testing YEC has undertaken with respect to SNC Lavalin's modeled water year flows.

b) Do the modeled results include all the years 1994 to 1999 inclusive? Please explain.

c) If the years 1994-1999 are included, how were the modeled water year flows calculated given that YEC has previously stated that information for those years was not available?

**ANSWER:**

**(a)**

YEC reviewed information provided by SNC-Lavalin describing modeled water year data and methods. Please see YUB-YEC-2-29(a-b) review of the hydrologic modeling studies conducted separately by SNC-Lavalin and Knight Piesold.

YEC did not attempt to verify or validate the modeled flows developed by SNC-Lavalin and/or Knight Piesold, however, the SNC-Lavalin information shows that two experienced engineering firms used industry accepted methods to develop simulated water flows, reviewed the results and combined two separate results to come up with reasonable inflow estimates. The results were also within the range of prior estimates developed first by Morrison Hershfield and then SNC-Lavalin (for the January 2020 Submission).

Please also see response to YUB-YEC-2-21 (a).

**(b) and (c)**

Yes, the modeled results in the referenced SNC-Lavalin report include all years from 1970 to 2020 as illustrated in Table A1 of Appendix A of the April 2022 Submission. As reviewed below, the April 2022 Submission utilized new modeled estimates developed for THELP that were not provided to YEC for the January 2022 Submission.

In the original January 2022 Submission, Table A1 in Appendix A included Atlin generation estimates for 1963-1993 and 2015-2019 water years which was used for the LTA thermal displacement benefits calculations. In response to YUB-YEC-1-34 a) YEC had noted that the initial feasibility studies on this Project prepared for THELP by Morrison Hershfield and KGS Group were able to develop a flow and power hydrological simulation model for Pine Creek flows based on comparison to Gladys River area's nearly complete 32 years of recorded flows by Water Survey of Canada from 1964 to 1993. It was concluded that the 30 year synthetic flow series from the Gladys River provides a reasonable estimate for long-term flows in Pine Creek. The earlier feasibility study was also able to utilize monitoring initiated in September 2014 of Pine Creek catchment flows with data for 2015-2019 years. Therefore, generation estimates for 1994 through 2014 were not included in the January 2022 Submission Table A1.

As indicated in response to a), the generation estimates for Atlin Expansion Project for the April 2022 Submission are based on the hydrologic modeling studies conducted by SNC-Lavalin and Knight Piesold (KP). The response to YUB-YEC-2-29 (a) and (b) details the SNC-Lavalin and KP methodology used to develop modeled inflows to Surprise Lake. These are modeled long-term inflow series simulated based on reconstituted inflow series into Surprise Lake calibrated with overlapping climate data and historical daily climate data from 1964 to 2020. Therefore, the modeled inflows to Surprise Lake include all years.

Please also see response to YUB-YEC-2-21 (b) - (e).

**ISSUE:** **Operating rules**

**REFERENCE:** **Updated application, black-lined version, page 30, PDF page 34, footnote 33 and page A1-79, PDF page 167**

**QUOTE:** See Schedule D of the Amended EPA. The Operating Rules as amended enable one hour dispatch (versus three days required with the Original EPA), provide ability in all seasons to change dispatch between 100% of capacity and 1MW at the generation plant (versus the prior winter requirement for minimum flow at 65% of capacity to protect ice conditions), enable YEC to schedule four changes per day, and enable YEC one day in advance to adjust its dispatch schedule in response to changes in weather forecasts or YIS system conditions.

**QUESTION:**

a) Is the change to the penstock from a power canal the only factor that changed the operating rules? Please explain.

b) The new operating rules include frequent and regular communications between Whitehorse and Atlin that was not present in the original EPA. How will this affect operations?

c) Please explain Exhibit D-1.

**ANSWER:**

**(a)**

The change to a penstock from a power canal is the only factor that changed the operating rules outlined in the referenced footnote 33. Please see response to YUB-YEC-2-15 for review of the factors enabling greatly enhanced dispatchability compared to required operations in the Original EPA for “reasonably steady state operation at full capacity to the extent practicable during the PWP” due to prior requirements related to the 7.8 km power canal, including risks related to destabilizing ice conditions in the power canal as well as delays and challenges in frequently changing flows in the power canal.

**(b)**

The new operating rules enable more frequent and regular communications between YEC and THELP than was feasible with the Original EPA. This will provide YEC with enhanced opportunity to adjust its operations in coordination with adjusted EPA Delivered Energy so as to enhance thermal generation displacement and utilization of Atlin's renewable dependable capacity.

**(c)**

Exhibit D-1 shows Surprise Lake operating constraints that affect dispatch of Delivered Energy within the allowed operating range for the lake, based on water available in the lake at a specified time (ignoring potential new inflows) and the factors noted below:

- **Minimum lake level requirement** - Delivered Energy must be shut down if Surprise Lake levels fall below the lower dashed line at any time during the Winter Period – the line represents (at any time shown) the Surprise Lake level required prior to the next freshet refill in order to supply the Existing Plant for the town of Atlin plus instream flow requirements (per licence conditions).

- **Maximum lake level requirement** - Delivered Energy must run at full load and Buyer must take and pay for all Delivered Energy if Surprise Lake levels rise above the upper dashed line at any time during the Winter Period (subject to other provisions of the Operating Rules or of the EPA that relieve Buyer of an obligation to receive Delivered Energy) – the line represents (at any time shown) the Surprise Lake level that will result in spilled water requirements if the water is not utilized for energy generation at the Existing Plant and for Delivered Energy provided to YEC.

YEC is able to direct Delivered Energy dispatch during the Winter Period (per the Operating Rules) within the above ranges specified in Exhibit D-1. THELP is required to provide YEC with an updated Exhibit D-1 on a regular basis as set out in the Operating Rules (item 1(a)).

**TOPIC:**

**ISSUE:** **Operating lease**

**REFERENCE:** **Updated application, black-lined version, page 34, PDF page 38**

**QUOTE:** There is some uncertainty with respect to what, if any impact the Amended EPA may have on YECs balance sheet (i.e., rate base). Based on preliminary assessments of the Agreement, YEC has concluded that this transaction does not contain a capital lease and therefore there is no balance sheet or rate base impact. This conclusion, however, is not final. The ultimate impact can only be known when the Project is complete and YECs auditors (the Auditor General of Canada) have reviewed the transaction.

**QUESTION:**

a) Please provide an analysis showing the financial impact to rate base if YEC were to record the amended EPA as a capital lease.

b) If YEC's auditors determine the amended EPA is best recorded as a capital lease, would that be a force majeure event or circumstance?

c) If the auditors determined that the amended EPA should be recorded as a capital lease, when would YEC apply for approval of the capital leasing costs in rates? Please explain.

**ANSWER:**

**(a)**

YEC understands and acknowledges the importance of the rate impact of the EPA to Yukon rate payers. In light of the long duration of the EPA, the fact that its accounting treatment is subjective and subject to determination and audit in the year of commencement, and that the IFRS accounting may be subject to change over the life of the project, YEC proposes that the impact on rates be neutral to whether the EPA is on or off balance sheet.

Since the previous filing, YEC has reached out BC Hydro (BCH), an industry peer with greater experience with IPP transactions and a similar regulatory environment. In note 12 to BCH's consolidated financial statements in their most recently available annual report (for the years ended March 31, 2021 and 2020), BCH discloses right-of-use assets arising from long-term energy purchase agreements in the amount of $1.281 billion as of March 31, 2021. BCH revenue requirement includes cost of energy, amortization and finance charges and these amounts are structured to match the total payments under the IPP contract.

Contacts confirmed BCH return on rate base calculations specifically exclude the balance sheet value of these right-of-use assets such that the rate impact of these leases is the same as if they were not accounted for on the statement of financial position. Yukon Energy's business case for this transaction does not include a return on any asset value: the project is justified on its own. Therefore, Yukon Energy proposes that in the event YEC's auditors conclude that the amended EPA contains a lease and a right-of-use asset should be recorded under IFRS (the measurement of which is described further below), YEC will adopt a similar approach to BCH and will not apply to earn a return on this asset.

**Potential Impact of Lease Accounting under IFRS**

As described in YUB-YEC-1-42, YEC management believes there will not be an impact to YEC's statement of financial position from this transaction, but that assessment requires validation by external auditors. This validation cannot be completed until such time as the plant is complete, final values are known and provided to the Office of the Auditor General for review. Determinations made at the time of commencement are also subject to possible future changes in accounting standards throughout the term of the arrangement.

Notwithstanding the above, YEC provides the following additional context to provide a better understanding of potential balance sheet impact if the amended EPA were considered to contain a lease under International Financial Reporting Standards ("IFRS") with respect to some or all of the underlying assets. In this event, on the lease commencement date, YEC would record a right-of-use asset and lease liability on the statement of financial position, using information as of that date. The lease commencement date is expected to be the date the plant and transmission lines becomes operational and able to generate electricity for YEC's benefit, which is currently expected to be December 2024.

The right-of-use asset would be measured on initial recognition up to an amount equal to the present value of the dependable capacity payments for the term of the amended EPA plus initial direct costs incurred by YEC. The right-of-use asset would be adjusted annually for changes in Canadian CPI, and reduced over time by a constant annual depreciation charge. A corresponding liability would be recorded for unpaid amounts.

The following inputs are needed as of the lease commencement date in order to measure the right-of-use asset and lease liability, and cannot be determined by YEC until that date:

(a) YEC's incremental borrowing rate (will vary depending on market interest rates and YEC's credit risk at the time of the assessment);
(b) The plant's dependable capacity upon completion of construction;
(c) Consumer Price Index for Canada value as of the assessment date (the dependable capacity payments are increased each year by half the increase in Canadian CPI); and
(d) Initial direct costs incurred by YEC up to the date of lease commencement.

**(b)**

Under the terms of the amended EPA, the outcome of YEC's final accounting assessment (including the determination that it should be accounted for as a lease on the statement of financial position under IFRS) would not be considered a force majeure event.

**(c)**

YEC would seek inclusion in rates for costs associated with the amended EPA at the first GRA after in-service (or earlier if project in service is in the test year period for a given GRA). Based on the response to "a" above, YEC is not expecting the impact on rates to vary if YEC auditors conclude that the transaction should be recorded as a capital lease under IFRS accounting standards.

As further noted in response to "a", any determination by YEC auditors cannot be completed until such time as the Seller's Plant is completed, final values are known and provided to the Office of the Auditor General for review.

**ISSUE:** **Fuel prices**

**REFERENCE:** **Updated application, black-lined version, page 37, PDF page 41**

**QUOTE:** Fuel prices for the Amended EPA are reasonably consistent with prices mandated for SOP IPP renewable energy supplies on the YIS, i.e., based on fuel prices at the outset of the Amended EPA with annual escalation at 50% of CPI.

**QUESTION:**

a) Why are fuel prices set at the beginning of the EPA with a 50% CPI escalator as opposed to a reset of fuel prices after every GRA with an escalator used between GRAs? Please explain.

b) What statistical analysis has YEC undertaken regarding trending fuel prices compared to the application of a 50% CPI escalator over a 40-year period?

c) For this particular EPA, was YEC's position that it was bound by the SOP IPP term to escalate at 50% of CPI? Please explain.

**ANSWER:**

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

The referenced quote addresses implied fuel price assumptions adopted for setting the Winter Energy Price for Delivered Energy, i.e., the Winter Energy Price is set in the EPA based on forecast blend fuel price for 2024, and the specified Winter Energy Price in 2024$ is then escalated each year after 2024 at 50% of CPI. These provisions (and the essence of the referenced quote) remained unchanged in the Amended EPA and the April 2022 Submission.

The EPA negotiation noted and adopted the Yukon SOP IPP approach regarding energy price determination based on an initial blend fuel price (known at the time the EPA is finalized) with escalation thereafter at 50% of CPI. Aside from providing consistency with existing Yukon IPP pricing policy, this approach recognizes the IPP proponent's need for reasonable price certainty over the EPA Term. Financing requirements for a capital

intensive hydro project such as the Atlin Project cannot generally accept the risk of material reductions in future thermal fuel prices, and therefore the option of resetting energy prices during the Term based on changes in actual thermal fuel prices was not considered. The approach adopted also retains for ratepayers the benefit of added fuel cost savings if fuel priced in fact escalate faster than 50% of CPI.

YEC has not done any statistical analysis regarding trending fuel prices compared to the application of a 50% CPI escalator over a 40-year period.

**ISSUE:** **Monthly constrained energy**

**REFERENCE:** **Updated application, black-lined version, page 38, PDF page 42**

**QUOTE:** The revised Project design's materially enhanced dispatchability has also materially reduced the ratepayer cost risks for Monthly Constraint Energy by enabling curtailment of wasted water flows quickly (no longer than one hour) and to no more than a requirement for 1MW/hour at the Powerhouse.[45]

**QUESTION:**

a) Please provide a further explanation of how this is advantageous to YEC and Yukon ratepayers.

**ANSWER:**

**(a)**

The EPA requires YEC to pay for Monthly Constraint Energy, which is energy that THELP could not provide due to a Non-Permitted System Constraint on the Buyer-AEY System. Yukon ratepayers are therefore exposed to costs incurred by YEC for Monthly Constraint Energy (in the event that the Non-Permitted System Constraint is on the AEY System, this ratepayer exposure would occur through related costs ultimately incurred by AEY – but through the Yukon rate setting processes, all Yukon ratepayers are ultimately impacted by revenue requirement changes for either YEC or AEY).

Monthly Constraint Energy as defined in Schedule "F" of the Amended EPA includes provision to reduce the related Constraint Shortfall Energy to reflect Seller actions taken consistent with the Operating Rules to reduce or shut down water deliveries to the Powerhouse. Section 1(d) of the Operating Rules in Schedule "D" of the Amended EPA requires the Seller within one hour of Notice to reduce the flow to the Penstock either by shutting down or by reducing the flow required for 1 MWh/hour generation at Seller's Plant. These requirements and measures, which are a direct result of the materially enhanced dispatchability referenced in the above quote, in effect severely constrain the extent to which Monthly Constraint Energy can accumulate after a Non-Permitted System

Constraint event. As such, YEC and ratepayer cost risks for Monthly Constraint Energy are reduced, to the advantage of YEC and Yukon ratepayers.

In contrast, under the Original EPA with the power canal, there was a requirement to maintain reasonably steady state operation at full capacity during the Winter Period when ice conditions existed (see response to YUB-YEC-2-15). Accordingly, in response to a Non-Permitted System Constraint event the Seller had a very limited ability to reduce water deliveries during most of the Winter Period - and therefore YEC and ratepayers were exposed to much greater cost risks for Monthly Constraint Energy amounts related to such events.

**ISSUE:** **Modeled deliveries**

**REFERENCE:** **Updated application, black-lined version, page A-3, PDF page 49**

**QUOTE:** Assumes 9.3 MW at Turbine, 9.2 MW after all losses at Atlin plant, approximately 8.7 MW delivered at Jakes Corner at full capacity. Daily generation estimates based on 70% flow being taken from SNC modeled series (using hydrologic model with daily climate data at Atlin from 1964 to 2020) and 30% from Knight Piesold modeled series (using a different hydrologic model to simulate the hydrology of the Pine Creek watershed).

**QUESTION:**

a) The quote includes modeled climate data for 1964 to 2020 at Atlin and Pine Creek. What evidence can YEC provide that the hydrologic data for Pine Creek watershed is applicable to that for Atlin?

b) Does the Pine Creek data include any data points for low water years? If so, what years are considered low water years and what is the threshold for what is considered low water?

c) Was there a low water event at Atlin during the years 1993-1999? Please explain.

d) If there was a low water event in 1993-1999 at Atlin and that is not included in the data, what impact does that have on the LTA?

e) If YEC were to remove water values for the years 1993-1999 for its LTA determinations, what effect would that have on LTA?

**ANSWER:**

**(a)**

The applicability of the Pine Creek Watershed data to Atlin is analyzed in the model information provided by THELP. Specifically, the referenced modeled data was developed by THELP's consultant (SNC-Lavalin), working with Knight Piesold (KP) who was retained by THELP's contractor Dent Construction.

The information provided to YEC by SNC-Lavalin shows the setup of the model showing Pine Creek watershed which confirms that this catchment area is applicable to Surprise Lake. Surprise Lake is a large lake on Pine Creek with a water spread of nearly 32 $km^2$ and provides storage for hydropower generation for the existing plant and the catchment area of Pine Creek at the outlet of Surprise Lake is 478 $km^2$.

For additional information, please see YUB-YEC-2-29 (a-b) review of the hydrologic modeling studies conducted separately by SNC-Lavalin and Knight Piesold.

**(b) to (e)**

There is no specific threshold that has been adopted for what is considered a low water per se. The Delivered Energy estimates indicate long-term average (LTA) estimates for all water years examined, the years when deliveries are estimated to be below LTA, and the year or years with the lowest deliveries. Please see response to ”a” above for information on development of data for Pine Creek inflows.

In response to YUB-YEC-2-7 a) and b), YEC provided a figure that compares winter Delivered Energy estimated for the Project over 51 water years. The response also highlighted that Table A1 in Appendix A of the April 2022 Submission shows that the water years of 1971 through 1973, 1982 through 1985 and 1995 through 1997 have lower winter Delivered Energy estimated compared to the long-term average; with the lowest winter Delivered Energy estimate in the 1985 water year.

In that response YEC also noted that the low water or drought conditions should be viewed at the YIS grid level, not by the individual storage facility. Therefore, when looked at the YIS grid level, the Atlin Delivered Energy estimates for 1995-1997 would fall under drought or low water year conditions for the YEC grid. The modeled Delivered Energy estimates for these and other low water years identified in response to b) are included in determination of LTA thermal displacement benefits as they are part of the 34.0 GWh long-term average winter deliveries from the Project.

If YEC were to remove Delivered Energy estimates for all low water years [1971 through 1973, 1982 through 1985 and 1995 through 1997] then the LTA deliveries from Atlin would change from 34 GWh to 35.6 GWh. If YEC were to remove Delivered Energy estimates for low water years 1995 through 1997 then the LTA deliveries from Atlin would change from 34.0 GWh to 34.4 GWh.

**ISSUE:** **Table A2 - updated energy profile**

**REFERENCE:** **Updated application, black-lined version, page A-6, PDF page 52**

**PREAMBLE:** Updated Table A2 reduces the dispatchable energy during the prime winter peak (November/December) and provides more on the shoulder winter peak (April and September).

**QUOTE:**

**QUESTION:**

a) Please fully discuss the effect of the change noted in the preamble.

**ANSWER:**

**(a)**

Contrary to the preamble, Table A2 increases the dispatchable energy during November/December compared to the Table A1 modeled estimates, and reduces dispatchable energy during April/September/October compared to the Table A1 modeled estimates. The effect of this change is to increase estimated long-term average (LTA) displacement of thermal generation.

A more detailed review is provided below.

Table A2 is included only in the April 2022 Submission – it does not update any earlier Table A2.

Table A2 compares the following two different monthly allocations of the updated LTA Winter Period Delivered Energy of 34.0 GWh as determined in Table A1:

- Column B – Updated monthly energy profile provided by THELP, April 11, 2022 (see Table A1) per SNC Lavalin modeled results; and

- Column A – Dispatchable Option at Jakes Corner – YEC's assumed LTA Delivered Energy dispatch by month to maximize thermal generation displaced on the YIS (as prepared by YEC staff). This allocation was used for the Amended EPA YECSIM assessments of LTA thermal displacement in Table A3.

In summary, the new Table A2 analysis introduced the Column A allocation used for subsequent YECSIM assessments. Compared with Column B from the Table A1 allocation, Column A increased the dispatchable energy during March, November and the first PWP month of December; the offsetting reductions were in shoulder Winter Period months (April, May, September and October). The effect of this change was to increase LTA thermal displacement estimated from the Winter Period LTA Delivered Energy.

**ISSUE:** **Energy profile and dispatchable option**

**REFERENCE:** **Updated application, black-lined version, page A-8, PDF page 54, figure A1**

**QUOTE:**

**QUESTION:**

a) Please provide definitions of “Dispatchable Option at Jakes Corner” and “Updated Energy Profile”.

b) What is the difference between Dispatchable Option at Jakes Corner and Updated Energy Profile?

**ANSWER:**

**(a) and (b)**

The “Updated Energy Profile” numbers in Table A2 and Figure A1 in Appendix A of the Amended EPA reflect an updated monthly winter energy profile which is the update from the energy profile that was used in the original EPA. It is based on long-term average generation over 51 water years as per Table A1 of Appendix A of the Amended EPA application [the second last row in the table].

The “Dispatchable Option at Jakes Corner” numbers in Table A2 and Figure A1 in Appendix A of the Amended EPA reflect adjusted monthly energy use allocation by Yukon Energy; it uses the same total LTA winter energy at 34.0 GWh from Table A1 but adjusts the monthly allocation values. The penstock option gives a greater flexibility compared to the canal option and YEC can dispatch the Project and use the stored water more efficiently, i.e., whenever it is best to displace the thermal generation on the grid. It should be noted that the Dispatchable Option was developed based on LTA thermal and assumes annual variations based on energy demand and water conditions.

Compared with the Updated Energy Profile from the Table A1 allocation, the Dispatchable Option at Jakes Corner increased the dispatchable energy during March, November and the first PWP month of December; the offsetting reductions were in shoulder Winter Period months (mainly in April, September and October). The effect of this change was to increase LTA thermal displacement estimated from the Winter Period LTA Delivered Energy.

It is noted that the values for May in Table A2 and Figure A1 reflect the generation for the first half of the month and remained unchanged under both “Updated Energy Profile” and “Dispatchable Option at Jakes Corner” [with small variance due to month-to-week conversion for the model purposes] as the generation in May was deemed non-dispatchable for the purpose of LTA thermal displacement benefits [i.e., it cannot be stored and/or used later].

It is also noted that the Amended EPA includes the Annual Operating Plan, in the form of Schedule C attached to the Amended EPA, which requires Seller to confirm if the Surprise Lake reservoir level is expected to be at full storage level before the end of the coming October. In addition, the Operating Rules in Schedule D of the Amended EPA require Seller to provide regular updates on the level of Surprise Lake from mid-November to the start of the following June. Based on this information and the Operating Rules provisions facilitating ongoing YEC winter dispatch, YEC will have the opportunity to develop appropriate dispatch options each year for the Project.

**ISSUE:** **Dependable plant capacity**

**REFERENCE:** **Updated application, black-lined version, page B-3, PDF page 73**

**QUOTE:** Project capability to provide Dependable Plant Capacity to Yukon Energy at Jakes Corner has been estimated for the Peak Winter Period ("PWP") from December 16 to the end of February based on expected Delivered Energy provided to Yukon Energy estimated on the basis of modeled water availability to Seller's Plant during 51 modeled water years (see Appendix A, Table A1) and assumed Seller's Plant operation each day at either 100% or approximately 11% of full capacity (assumes minimum 1 MW generation at the plant per Operating Rules).

**QUESTION:**

a) Explain the significance and impact of moving from actual water years to modeled water years.

b) Please explain the significance of the change from 65% of full capacity to 11% of full capacity.

**ANSWER:**

**(a)**

Project capability has always been based on modelled results. For both the Original EPA and the Amended EPA (and the related Submissions), Project capability to provide Dependable Plant Capacity for the PWP has been consistently based on expected Delivered Energy, and expected Delivered Energy has been consistently derived from modeled estimates for water years shown in Table A1 of each Submission. As reviewed in the April 2022 Submission, the number of water years and water data used for the models changed between the Submissions.

**(b)**

The reduction noted in the quote for the PWP minimum level of Seller's Plant operation (from 65% of full capacity to approximately 11% of full capacity) reflects the greatly enhanced PWP dispatchability for Seller's Plant due to the Penstock replacing the power canal. When the power canal was required, the higher minimum operation level was needed to maintain stable ice cover. With the Penstock, there is no longer a need to form or maintain ice cover – the only requirement during winter is to maintain some water movement sufficient to prevent freezing of water in the Penstock.

The significance of this change is the material reduction in water wastage when minimum operation is requested during the PWP – and the resulting enhancement in water availability: (a) for providing Dependable Plant Capacity when requested during the PWP; and (b) for otherwise providing Delivered Energy at optimum times to displace thermal generation.

**ISSUE:** **December deliveries**

**REFERENCE:** **Updated application, black-lined version, page B-3, PDF page 73**

**QUOTE:** Based on the referenced LTA delivered energy estimates and assuming approximately 52% of December deliveries are in the PWP, expected LTA energy deliveries during each PWP over the 51 modeled water years would equal at least 14 GWh and be sufficient to enable a full 8.75 MW of capacity to be delivered to YEC at Jakes Corner for more than 85% of the 75 or 76 days in the PWP, which is more than enough days to cover all of the PWP period when minus 30ºC or lower temperature has been recorded at Whitehorse during the PWP period. [underlining added]

**QUESTION:**

a) Why is only approximately 52% of December deliveries in the PMP rather than 100%?

b) The second underlined passage changes the coverage (original application to amended application) from 94% to 85%. Does this imply a lower reliability? Please explain why or why not.

**ANSWER:**

**(a)**

The PWP is defined to start December 16th and therefore to include only approximately 52% of the hours (rather than 100% of the hours) during December.

Table A1 shows modeled Delivered Energy per month for each water year as estimated by SNC Lavalin – estimates in the April 2022 Submission range from 3.35 GWh to 6.50 GWh for the full month. Assuming approximately 0.209 GWh/day at maximum delivered capacity (see January modeled estimates in Table A1), the maximum Delivered Energy during the December PWP (starting December 16th) approximates 3.3 GWh, confirming that in most water years it would not be possible during the PWP to deliver 100% of the estimated Delivered Energy for the total month.

YEC is able, under the amended Operating Rules, to direct different levels of delivery at different days throughout December. To be conservative, the April 2022 Submission analysis assumes the same average deliveries per day during December before and after the start of the PWP.

In contrast, the January 2022 Submission analysis assumed deliveries starting December 16 at maximum capacity (assumed per January month average from January 2022 Submission Table A1 at 0.188 GWh/day). Under this approach, the allocation during the PWP in December averaged approximately 67% of the month total rather than 52% (and was always less than 100%). The updated estimates adopted a more conservative approach for estimated use of water throughout the month.

**(b)**

The change from 94% to 85% (percent of PWP days that can provide full Dependable Plant Capacity at Jakes Corner with 14 GWh minimum water availability) does not imply a lower reliability. It mainly reflects the impact of the increase in plant capacity, i.e., a higher hydro capacity can only be provided for less time than a lower hydro capacity, assuming a fixed volume of available water and similar plant efficiency.

On the matter of reliability, the April 2022 Submission outlines enhanced reliability to deliver Dependable Plant Capacity during the PWP due to the penstock replacement of the power canal and the resulting removal of ice condition issues and risks affecting PWP generation plant operation.

The change in days mainly reflects the higher assumed full capacity level delivered at Jakes Corner (8.75 MW vs 8.0 MW) and the resulting 11% added Delivered Energy requirement per hour assumed required to provide 100% capacity. The impact of the higher capacity is offset to some extent by the materially lower requirement (11% versus 65% of full capacity) assumed for PWP days when full capacity is not provided. The reduction of the minimum required capacity from 65% to 11% reflects the penstock replacement of the power canal and the resulting removal of ice condition issues affecting PWP generation plant operation.

The referenced April 2022 Submission analysis is conservative. It was based on the updated Energy profile provided by THELP (Table A1). As shown in Table A2, YEC's analysis to assess LTA thermal displacement assumed a Dispatchable Option allocation of LTA Delivered Energy (see Column A in Table A2) which has slightly higher PWP deliveries (due to a higher December allocation), i.e., LTA PWP deliveries at 15.6 GWh versus 14.6 GWh. This implies that the minimum PWP deliveries are also likely to exceed the 14 GWh assumed in the referenced analysis.

**ISSUE:** **Surprise Lake**

**REFERENCE:** **Updated application, black-lined version, page B-4, PDF page 74**

**QUOTE:** If Surprise Lake is not full in the prior October, it has been confirmed that so long as the Existing Plant and battery load does not exceed 9 GWh/year, water availability is expected to be adequate for LTA delivered energy to YEC during the PWP to be at least 12 GWh, which is sufficient to enable a full 8.75 MW of capacity to be delivered at POI for over 54 full days (assuming the balance of PWP days at approximately 11% of 8.75 MW), i.e., confirmed ability to accommodate at full capacity at least one two-week cold temperature period plus at least 40 additional days if needed.

**QUESTION:**

a) Please provide a full explanation for the statement in the above quote.

b) If, in the scenario described in the above quote, only 11% of the capacity is available, does that mean all contracted energy deliveries cannot be met and that YEC would receive less capacity than contracted for in the EPA?

**ANSWER:**

**(a)**

The above quote examines a scenario (per Section 7.2(a) of the EPA) with 12 GWh PWP Delivered Energy when Surprise Lake reservoir is not full before the end of the prior October and load for Existing Plant and its battery is 9 GWh/yr or less (this scenario provides for an Existing Plant load higher than the 7.11 GWh/yr assumed in Table A1 – at the Table A1 load, over 14 GWh Delivered Energy is available for YEC).[1]

- The quote indicates expected Delivered Energy under this scenario of at least 12 GWh per PWP is sufficient to deliver a full 8.75 GWh MW capacity at POI for over

[1] Table A1 in the April 2022 Submission shows at least 14.1 GWh during the PWP for all water years, including years when Surprise Lake reservoir is not full before the end of the prior October. Section 7.2(a) of the EPA (which was not changed) also confirms at least 14 GWh per PWP is expected when Surprise Lake reservoir is full before the end of the prior October, without any caveats re: the load at the Existing Plant and its battery.

54 full days during the PWP, assuming that during the remaining 21 to 22 days of the PWP the minimum generation as required per the Operating Rules (approximately 11% of full capacity) is maintained.[2]

- The quote confirms ability with the Amended EPA under this scenario during PWP to accommodate full capacity for YEC during at least one two-week cold temperature plus at least an additional 40 days if needed.

**(b)**

No, the reference to 11% does not mean that all contracted energy deliveries cannot be met and that YEC would receive less capacity than contracted for in the EPA.

Section 7.2(a) specifies minimum Delivered Energy to be provided per PWP, subject to the specified assumptions. The quote confirms the Dependable Plant Capacity that can be provided with these minimum levels of Delivered Energy.

The Operating Rules as amended specifiy the minimum level of operation required during PWP unless Seller elects to shut down operation when YEC specified minimum level operation.

[2] The January 2022 Submission indicated capability during PWP to provide YEC at least 37 full days of 8.0 MW full capacity, assuming that during the remaining days of the PWP the minimum generation as required per the Operating Rules (which in the Original EPA was 65% of full capacity) is maintained.

**ISSUE:** **Interconnection Agreement**

**REFERENCE:** **Updated application, black-lined version, page B-5, PDF page 75**

**PREAMBLE:** The original application stated that the interconnection agreement would be completed by January 31, 2022. In the Round 1 IR responses, that date moved to March 31, 2022. The date in the amended EPA application is May 31, 2022.

**QUOTE:** Interconnection Agreement: Section 2.1(d)(i) of the Amended EPA Conditions Precedent specifies that, on or before May 31, 2022, the three parties (Seller, Buyer and AEY) will have entered into the Interconnection Agreement. Section 2.1(d)(ii) of the Amended EPA Conditions Precedent specifies that, on or before May 31, 2022, these same parties will have agreed on the budgeted costs for the AEY System Upgrades.

**QUESTION:**

a) Please confirm that if the interconnection agreement is signed by May 31, 2022, that the agreement will be filed on the record of the proceeding.

b) If the agreement is not signed by May 31, 2022, what is the impact to the amended EPA? In your response, please comment on any delays or other expected consequences to the delivery of energy under the amended EPA.

**ANSWER:**

**(a)**

Please see the response to YUB-YEC-2-10 with the attached correspondence provided by YEC to the Board dated June 10, 2022 regarding amended dates for satisfaction of Conditions Precedent items.

The amended date for satisfaction of Section 2.1(d)(i) is July 29, 2022. The Interconnection Agreement is not currently completed. If the Interconnection Agreement is signed prior to the hearing for this proceeding it will be filed on the record of the proceeding.

**(b)**

Failure to sign the Interconnection Agreement by May 31, 2022 has had no impact to the Amended EPA.

Pursuant to the provisions of the Amended EPA, the Parties agreed to extend the date for signing of the Interconnection Agreement to July 29, 2022. This extension was required to enable completion of updates to the Buyer-AEY System Interconnection Study Report to reflect the changes to the Seller's Plant under the Amended EPA. This remains the earliest completion date for Section 2.1(d) Conditions Precedent elements and does not affect critical schedules for the Project or the Amended EPA. There are no expected consequences to the delivery of energy under the Amended EPA.

Based on current information, Yukon Energy is not aware of any potential future delays to this Conditions Precedent that are likely to have expected consequences to the delivery of energy under the amended EPA.

**ISSUE:** **Conditions precedent**

**REFERENCE:** **Updated application, black-lined version, pages B-4 – B-5, PDF pages 74-75**

**PREAMBLE:** **Section 2 of Appendix B lists several conditions precedent that are due May 31, 2022.**

**QUESTION:**

a) The budgeted costs of AEY, the funding plan, environmental authorizations, government approvals, TRTFN approval, and other consents (e.g., BC Hydro and The Canada Life Insurance Company of Canada) are due by May 31, 2022. Please provide the funding plan, environmental authorizations and TRTFN approval in your IR responses.

b) Explain the consequences if any of the requested conditions precedent are not completed by the May 31, 2022 deadline.

**ANSWER:**

**(a)**

The requested information is not currently available. Please see the response to YUB-YEC-2-10 with the attached correspondence provided by YEC to the Board dated June 10, 2022 regarding amended dates for satisfaction of Conditions Precedent items.

The amended dates for satisfaction of the above referenced documents and Conditions Precedent are now all after May 31, 2022, and none of these documents or Conditions Precedent are currently completed or available to provide to the Board. The amended dates for satisfaction of the above referenced Conditions Precedent are:

- July 29, 2022 for signing of the Interconnection Agreement and approval of budgeted costs of AEY System Upgrades;
- September 30, 2022 for Seller submitting the Funding Plan;
- October 31, 2022 for Buyer notification to Seller that Buyer is satisfied with the Funding Plan, for TRTFN approval, and for other referenced consents; and
- March 31, 2023 for environmental authorizations.

**(b)**

YEC does not believe the changes to Conditions Precedent due dates will have a material impact on the project. Pursuant to the provisions of the Amended EPA, and as evidenced in the response to YUB-YEC-2-10, the Parties agreed to extend the dates for satisfaction or waiving of the referenced Conditions Precedent that were previously to be satisfied or waived on or before May 31, 2022. All other terms and conditions in the Amended EPA continue to apply.

As noted in the response to YUB-YEC-2-10, the Seller's Target COD for commercial operation of Seller's Plant remains at December 1, 2024 as provided in the Amended EPA notwithstanding that the requested conditions precedent to be completed by May 31, 2022 in the Amended EPA were not completed by that date. Yukon Energy understands the following as regards THELP's critical milestones affecting the Seller's Target COD date:

- Deferral of environmental authorizations to March 31, 2023 does not affect this schedule; in order to protect this schedule, work that requires these authorizations must begin in the 2023 summer construction season.

- THELP is assessing the timing and requirements for any long lead equipment orders that must be placed before March 31, 2023 in order to protect the December 1, 2024 Target COD date; THELP's ability to proceed with such orders is understood to be conditional mainly on securing required final funding arrangements.

The last Conditions Precedent completion date today with the latest amendment is March 31, 2023 for completion of Section 2.1(d)(iv) regarding receipt of Clean Energy Development Plan authorization for Seller's Plant in British Columbia and receipt of YESAA Decision Documents for the Seller's Plant in Yukon.[1] This change resulted from the requirement, due to the changes in the Project, for THELP to refile its application for Clean Energy Development Plan authorization for Seller's Plant in B.C. THELP has advised Yukon Energy that the change to a penstock to replace the power canal addressed (among other considerations) concerns with the power canal raised by

[1] Section 2.3 of the April 2022 Submission notes that the YESAB Teslin Designated Office issued its Evaluation Report on September 10, 2021 recommending that the project in Yukon proceed subject to four recommended terms and conditions. The Decision Document has not yet been issued by the Yukon Government.

regulators in BC, that receipt of the required authorization is expected on or before March 31, 2023, and that this delay does not affect THELP's ability to complete COD of Seller's Plant by December 1, 2024.

The dates for satisfaction of the Conditions Precedent regarding the Funding Plan [Section 2.1(d)(iii)] have been extended to September 30, 2022 and October 31, 2022. Considerable information is already known regarding key elements of the Funding Plan and its expected feasibility – the outstanding matters relate mainly to finalizing existing funding commitments and contracts related to the construction and procurement components.

- Please see the response to YUB-YEC-2-8(b) and (c) which reviews current information regarding the sources of funding for the Atlin Hydro Expansion Project.

- Please see the response to YUB-YEC-1-15 AMENDED which reviews information regarding the $240 million estimate (2024$) for Project capital costs including Buyer-AEY System Upgrade Costs. Yukon Energy understands that THELP is currently estimating the total Project cost at $254 million, including a $35 million contingency.

- Please see the response to YUB-YEC-2-27 which reviews information and implications regarding the extended date for signing of the Interconnection Agreement and approval of budgeted costs for AEY System Upgrades.

**ISSUE:** **Modeled water years**

**REFERENCE:** **Amended IR responses, black-lined version, YUB-YEC-1-34, PDF page 112**

**QUOTE:** Appendix A, Table A1 in the Amended Submission includes 51 modeled water years from 1970 to 2020. Therefore 1994-2014 is now included.

**QUESTION:**

a) Please explain what is included in the modeled data.

b) Are there any historical water years from which the modeled data is based? If so, what years of actual data are included?

c) In the part (b) response to the information request, losses have changed from 6.2% (original response) to 4.5%. Please explain why this change was made. What confidence interval does YEC apply to the lower loss figure?

**ANSWER:**

**(a) and (b)**

The referenced modeled data was developed by THELP's consultant (SNC-Lavalin), working with Knight Piesold who was retained by THELP's contractor Dent Construction.

Prior to finalizing the Amended EPA, YEC was provided on April 11, 2022 with the Delivered Energy results by month and water year as shown in Table A1 of the April 2022 Submission. YEC was informed that both SNC-Lavalin and Knight Piesold (KP) undertook separate hydrologic modeling studies and that both studies were used in the SNC-Lavalin's Delivered Energy estimates provided to YEC. Information is provided below on what YEC understand to have been included in the modeled data developed by SNC-Lavalin and KP.

SNC-Lavalin provided YEC with the following regarding the hydrologic modeling carried out by them in 2021:

> Modeling was carried out using Soil and Water Assessment Tool (SWAT) which is a semi-distributed continuous watershed scale simulation model that operates on daily and sub-daily time steps. The model takes into account different topography, land uses and soil types that impacts the hydrology and it works through a QGIS interface. The hydrologic simulation of a watershed is carried through two phases, a) the land phase and b) the routing phase. The hydrologic cycle as simulated by SWAT is based on the water balance equation. Daily climate data from 1964 to 2020 at Atlin was used as of the model inputs.
>
> In order to calibrate the model, an inflow series into Surprise Lake was reconstituted based on the available lake level data (2015 to 2018) and the hydraulic properties of the outflow structures. The reconstituted inflow series was verified based on the lake level data and the intermittent downstream flow data. The model is calibrated on this reconstituted inflow series at the lake. Since the flow data is available only for a four-year period, the model is simulated for this period wherein overlapping climate data is also available. The model output, in terms of streamflow, from 2015 to 2018 is compared with the reconstituted lake inflow. The model parameters are then suitably tuned to match with simulated streamflow with the reconstituted flows. The SWAT hydrologic model produced very good calibration results which was verified based on various quantitative metrices and is therefore representative of the hydrological behavior of the Pine Creek watershed.
>
> The calibrated model was then used to simulate the inflows for the entire series of available precipitation and temperature data between 1964 and 2020. …The mean annual flow is estimated as 4.03 $m^3/s$. The computed natural inflows are judged reliable and could be used in the various assessments of the project requiring natural inflow input.

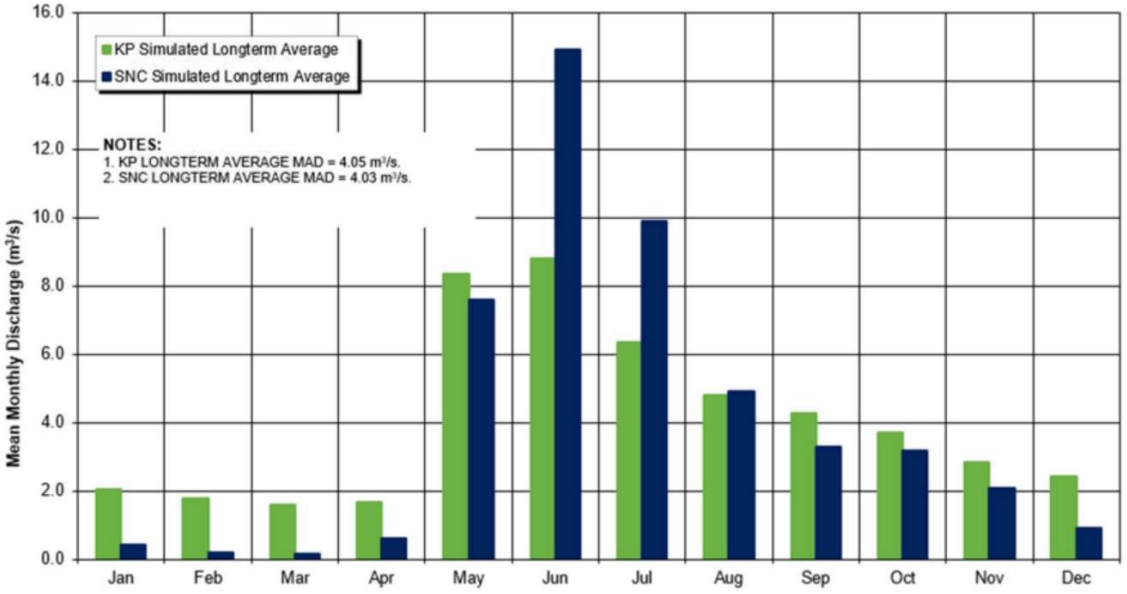
SNC-Lavalin also provided the following regarding the hydrologic modeling carried out by Knight Piesold in 2022:

> Hydrologic modeling was also carried out by KP in 2022. Raven hydrologic model with UBCWM sub-routine was applied to simulate the hydrology of Pine Creek watershed. The model is based on parameter values that were determined by the development of a Spruce Creek watershed model, which was calibrated to measured Spruce Creek flows over a four-year period. Based on the similar

physiography of the various sub-watersheds, it is reasonable to conclude that the hydrologic characteristics, and therefore the model structure and parameters, are reasonably consistent within the entire Pine Creek watershed area.

Applying the same parameters to the entire Pine Creek water shed a long-term flow series is generated. The mean annual flow is estimated as 4.05 $m^3/s$.

SNC-Lavalin noted that although the mean annual flow under both modeling provides similar results [4.03 $m^3/s$ based on SNC modeling compared to 4.05 $m^3/s$ in KP simulation results], certain differences were found in the monthly distribution of flows (see figure below as provided by SNC-Lavalin). The SNC model simulates lower winter flow (the baseflow) as compared to the KP simulations, and higher spring peak flow (primarily snowmelt driven) compared to the KP simulations. SNC-Lavalin concluded that the difference in results is not unacceptable given the differences in the models, the parameters and the calibration approach. It was decided to consider a flow series that has a blend of both the modeling results.




SNC-Lavalin developed the adopted inflow series at Surprise Lake, noting the following conclusion:

Since the observed flow along the Pine Creek and winter flow at some of the creeks were found to be close to the results from the SNC model, a higher proportion of the flow has been attributed to the results from SNC model. The adopted series

for energy generation is generated with a 70:30 ratio, with 70% flow being taken from the SNC series and 30% from the KP series.

SNC-Lavalin reported that the average mean annual flow for 51 years of analysis with the final 70:30 ratio use of SNC series and KP series is 4.04 $m^3/s$, and it varies from 2.8 $m^3/s$ in 2019 to 6.9 $m^3/s$ in 2007.

**(c)**

YEC still retained 6.2% line losses for the power delivered from Jakes Corner to Whitehorse. However, as reviewed in the table below, YEC has determined since the original filing that most of the 8.75 MW delivered by the Project at Jakes Corner is not supplied to Whitehorse, i.e., most of the Delivered Energy supplied by the EPA is used to supply AEY and YEC customers located on the grid south of Whitehorse. Therefore, the line losses were adjusted based on estimated power deliveries as per the table below. YEC is confident that the updated line losses are more reasonable than the 6.2% used previously which was based on total line losses approved for AEY.

| | MW | Losses | MW less losses |
|---|---|---|---|
| Jakes Corner to Whitehorse | 2.25 | 6.20% | 2.11 |
| Jakes Corner to along line | 4.00 | 4.10% | 3.84 |
| Jakes Corner to Teslin | 2.50 | 3.10% | 2.42 |
| **Total** | **8.75** | 4.35% | **8.37** |

Overall losses [rounded] 4.5%