**IN THE MATTER OF YUKON ENERGY CORPORATION 2017/2018 GENERAL RATE APPLICATION TO THE YUKON UTILITIES BOARD**

# FINAL ARGUMENT

# YUKON ENERGY CORPORATION

August 9, 2018

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# YUKON ENERGY 2017/2018 GENERAL RATE APPLICATION ("APPLICATION") TO THE YUKON UTILITIES BOARD ("YUB" OR "BOARD")

# YUKON ENERGY CORPORATION FINAL ARGUMENT

## PREFACE

### OVERVIEW OF YUKON ENERGY APPLICATION

The Application was submitted to the Board on June 22, 2017 (Exhibit B-1) for adjustments to Yukon Energy's ("YEC") revenue requirements, rates and other related matters as required to recover YEC's forecast costs to supply customers in 2017 and 2018 and to plan for future requirements thereafter. The Application provides for a complete and thorough review of all aspects of Yukon Energy's operations since the 2012/2013 GRA, as well for the continued development of Yukon's capability to meet ongoing growth with reliable, affordable and environmentally responsible power that is flexible to changing loads and conditions.

In summary, the Application filed in June 2017 requests approvals (Exhibit B-1, pages 4 to 7):

- To recover forecast costs to supply customers in 2017 and 2018, including provision for an allowed return on equity ("ROE") of 8.82% for both 2017 and 2018 test years;
- To implement related changes affecting reserve and deferral accounts, accounting policies for planning costs and Demand Side Management ("DSM") costs; and
- To update the Diesel Contingency Fund ("DCF") Term Sheet and the Rider F fuel rider to accommodate LNG fuel, and to approve the DCF Annual Reports for 2015, 2016 and 2017.[1]

Subsequent to the Application filing, Yukon Energy provided an updated Application forecast incorporating the wholesales forecast for 2017 as approved by Board Order 2017-01 regarding the ATCO Electric Yukon ("AEY") compliance filing for its 2017/18 General Rate Application (see Exhibit B-5 response to YUB-YEC-1-3, and Exhibit B-22, page 8).

[1] Reference to Board approval of 2015 and 2016 DCF Annual Reports as part of this proceeding is at Exhibit B-1, page 3.4-2; during this proceeding, the 2017 DCF Annual Report was also filed for Board review and approval (Exhibit B-20, UCG-YEC-2-39 Revised).

Approval is sought in the updated Application for rate adjustments through Rider J to recover the forecast revenue shortfalls for 2017 and 2018 of approximately $5.321 million and $6.571 million respectively (revenue shortfalls as set out in Table 4.1 of the Application as updated in YUB-YEC-1-3, and Rider J increases as set out in Table 4.2 of the Application as updated in YUB-YEC-1-3):

- Rider J (2017): an increase of 8.876 percentage points in Rider J applicable for all YEC and AEY retail and industrial firm rates (total Rider J of 19.89% for retail firm rates and 16.24% for industrial firm rates); and
- Rider J (2018): a further increase of 2.070 percentage points in Rider J applicable for all YEC and AEY retail and industrial firm rates (total Rider J of 21.96% for retail firm rates and 18.31% for industrial firm rates).

Since filing the Application and responding to Round 1 interrogatories in September 2017 two additional submissions have been provided for Board review:

- **Power Purchase Agreement with Victoria Gold:** The Power Purchase Agreement (PPA) with Victoria Gold Corp. and StrataGold Corporation regarding the Eagle Gold Mine (Victoria Gold PPA), was filed in November 2017 and concluded after a round of IRs, argument and Board Order 2018-04.
- **Two Part ERA Application:** The Two Part Application Regarding the Energy Reconciliation Adjustment (ERA) was filed in December 2017 as directed in Order 2017-08. The Two Part ERA Application (Exhibit B-14) addressed ERA matters prior to 2017, and how YEC proposes to deal with long-term average (LTA) hydro generation forecasts for GRA purposes, the DCF, ERA and wholesale rates for the period 2017 forward. It also provided additional information regarding the YECSIM Model [i.e., the User Manual] and a Short Term Hydro Alternative Forecast (ST Alternative GRA Forecast) for 2017 and 2018.
- **Short Term Alternative GRA Forecast:** In response to Board Order 2017-08, Yukon Energy also separately filed Exhibit B-15 in December 2017. This separate filing included the ST Alternative GRA Forecast filed in Exhibit B-14, as well as blacklined and clean versions of the Application and Round 1 IR responses showing changes to address the ST Alternative GRA Forecast. As noted in both Exhibit B-14 and B-15, Yukon Energy does not consider the ST Alternative Forecast to be appropriate for rate setting, and YEC is **not** applying for and does **not** support the ST Alternative GRA Forecast for the 2017/18 GRA.

Part 1 of the ERA proceeding concluded with Board Order 2018-05 approving final ERA amounts for 2012 to 2016, as well as an amended Rate Schedule 42 (Wholesale Rate) with an updated ERA. In relation to Part 2 of the ERA proceeding, a workshop on the YECSIM model was held in February 2018 (Exhibit B-18), and a second round of IRs completed focused on the DCF, YECSIM and the ST Alternative GRA forecast as well as the LTA forecast provided in the current GRA (Exhibit B-19, and Revised IR responses Exhibit B-20).

The three-day oral hearing (June 26 to 28, 2018) provided additional review of the Application and filings to date. Yukon Energy undertakings not addressed during the hearing were subsequently provided in correspondence dated July 3, July 13, July 20, and July 23, 2018. The July 13, 2018 correspondence also included Yukon Energy's transcript review to address any required corrections, and an updated list of undertakings from the oral hearing.

On July 23, 2018, the Board provided follow-up questions on some of the undertakings. Yukon Energy responded to these questions on July 27, 2018.

**OUTLINE OF YUKON ENERGY FINAL ARGUMENT**

Yukon Energy's Final Argument provides the support from the record for the requested Orders, focuses on the extensive evidence examined within the scope of the Board's review of the Application, and includes the following major sections:

- **Part 1 - Core Elements of Yukon Energy's Application** - Addresses core elements of the overall Application as submitted and reviewed during the hearing process to date, including matters addressed in the Application (pages 1 to 9) and Supporting Tab 1, as well as in Section 2 of the Two Part ERA Application (Exhibit B-14) and the Opening Statement (Exhibit B-22).

- **Part 2 - Response to Key Issues Raised** - Provides Yukon Energy's responses to key issues raised by the Board and intervenors in Intervenor Evidence, information requests (IRs) and the oral hearing, and provides transcript references containing more detailed information on these issues.

Responses to key issues raised regarding Exhibits B-14, B-15 and B-18 (YEC filings related to the Two Part ERA Application) are addressed in Section 5 of Part 2 of the Argument.

Total documentation and evidence in this hearing are substantial. There were two rounds of interrogatories with a total 888 information requests, 41 undertakings, follow-up questions on undertakings, and approximately 678 pages of transcript. To date, there have been over 70 exhibits, and 7 Board Orders flowing from the Application. There were 5 registered intervenors.

To the extent that the Board and intervenors examined specific issues with respect to specific parts of Yukon Energy's Application through interrogatories or cross-examination, Yukon Energy has attempted in this argument to address the apparent concerns raised. However, in the view of Yukon Energy, its filing, the answers to the many interrogatories, and other evidence submitted (including undertakings) fully address all such concerns, and fully support the reasonableness and necessity of the proposed revenue requirement. Further, no evidence-based contrary position has been tendered by any party.

Accordingly, Yukon Energy submits that all evidence necessary for the Board to address the Orders requested is in the record.

# PART 1: CORE ELEMENTS OF YUKON ENERGY'S APPLICATION

Part 1 of Yukon Energy's Final Argument addresses the following core elements of the overall Application as submitted and reviewed during the hearing process to date:

**A.** Factors Driving 2017/18 Rate Increase Requirement;

**B.** Long-Term Average (LTA) Forecast & Contingency Fund Mechanism Requirement; and

**C.** Reliance on Application Forecasts as Filed.

Due to past legacy hydro and transmission developments to meet earlier growth, Yukon continues today to offer the lowest electrical rates in Northern Canada. Yukon Energy is working to keep this advantage while meeting current and future needs.

However, Yukon Energy's Application highlights current and future challenges regarding the changing Yukon grid load profile since 2013. For example, while grid energy load declined in the period from 2014-16 (rather than continued to grow as previously expected[2]) YEC's peak winter load in 2016 was 10% higher than the approved peak forecast for 2013. This Application forecasts energy loads for 2017 and 2018 slightly higher than actual load in 2013, as well as continued peak load growth.

## A. FACTORS DRIVING 2017/2018 RATE INCREASE REQUIREMENT

The Opening Statement summarized (based on Exhibits B-1 and B-3) the key drivers for the June 2017 Application proposed total cumulative 2017 and 2018 rate increase requirement of 9.08% as follows:[3]

- **Rate Base growth (8.3% increase in rates)** – Forecast mid-year rate base increase in 2018 over approved 2013 is 28.6% ($64.9 million increase). This increase drives an 8.3% increase in overall rates to recover added depreciation and amortization ($2.5 million increase) and return on rate base ($3.5 million increase).

  Rate base growth since 2013 approved reflects $35 million net increase from two major capital projects to address capacity requirements (LNG Plant and Whistle Bend Supply/Takhini Upgrade), $25.4 million from eight major sustaining capital projects, $9.8 million from three major deferred cost projects (DSM, Resource Plan

[2] Notably, Actual 2013 YEC loads were slightly higher than the 2012/13 GRA Compliance Filing notwithstanding that the forecast Whitehorse Copper Tailings load did not materialize.

[3] The YUB-YEC-1-3 adjustment of this cumulative rate increase to 9.19% to reflect AEY's approved load forecast and related matters does not materially change this assessment of rate drivers for YEC's 2017-18 GRA.

Update, Gladstone Diversion Project), $8.3 million from other deferred projects, and $6.3 million for deferred overhauls.

Rate base growth includes additions for projects held in Work in Progress (WIP) since the 2012/13 GRA[4], including costs for deferred overhauls and deferred 2012/13 projects with costs between $0.1 and $1.0 million.

The rate changes requested in this Application are not affected by over $35 million in costs forecast in WIP at the end of 2018 for 10 major projects. These projects relate to capacity requirements, sustaining capital and other future renewable generation expected to come into service in the 2019-2024 period. Final projected costs for these 10 major projects exceed $260 million.

- **Return on rate base change (2.1% decrease in rates)** – The lower average return on rate base for 2018 compared with 2013 approved reflects interest cost savings from refinanced YDC debt[5] and other factors that more than offset higher ROE return percentage of 8.82% versus 8.25% approved in 2013.

- **Non-fuel O&M changes (5.4% increase in rates)** – The 2018 forecast non-fuel O&M is $3.9 million (22%) higher than the 2013 approved, reflecting $2.5 million increase in labour expense and $1.4 million increase in other non-fuel expense ($0.7 million for brushing). Increases in brushing costs include costs from the 2012/13 GRA that the Board directed be deferred for review at the next GRA.[6]

- **Load Growth Impacts (2.5% reduction in rates)** – Expected load growth since 2013 adds revenues at existing rates that almost match increased costs for added LTA thermal generation at 2013 forecast diesel prices. However, the Application has lower fuel prices than the approved 2013 forecast, particularly with inclusion today of LNG – as a result, the overall net impact of load growth and related thermal generation fuel costs is a 2.5% reduction in the requirement for new rates. The overall cost impact of LNG in 2018 is an approximate $1.5 million saving compared to diesel fuel.

In summary, revenue and rate requirements are driven primarily by increases in rate base growth required to meet ongoing requirements for cost-effective and reliable service, followed by non-fuel O&M increases.

The Opening Statement also documents the measures undertaken prior to this GRA by Yukon Energy and its sole shareholder, Yukon Development Corporation (YDC), to secure ongoing ratepayer savings that are reflected in the current Application. The Opening Statement indicated that Yukon ratepayers today secure savings in excess of $6 million per year from the combined impact of the following measures:

[4] Based on direction provided in Order 2013-01.
[5] YEC debt renegotiation with YDC and other factors as reviewed at the end of this section.
[6] See Tab 3, Table 3.6, Table 3.6.1, Table 3.7 and Table 3.14.2 (regarding amortization of deferred brushing costs).

- YEC debt renegotiation with YDC in late 2014 ($1.4 million saving in 2018);
- Mayo B Flexible Debt financing with YDC ($0.6 million saving in 2018);
- YDC contributions in December 2015 of $22.4 million ($2.0 million saving in 2018);
- Secondary sales revenues that have increased since 2013 ($0.642 million saving for firm rates in 2018); and
- YEC fuel costs that as of the 2012/13 GRA are adjusted based on LTA hydro at actual grid levels, and reduced due to development of the LNG Project and the use of LNG with lower costs than diesel ($1.5 million saving in 2018).

Notwithstanding these ratepayer savings measures, the Application and Opening Statement document the required rate increases for 2017 and 2018 to address Yukon Energy's forecast revenue requirements in these test years and the forecast revenue shortfalls at existing rates.

## B. LONG TERM AVERAGE FORECAST AND CONTINGENCY FUND MECHANISM

The GRA proceeding addressed issues regarding hydro generation forecasts used for GRA purposes, and contingency fund mechanisms used to address fuel costs risks related to variances from hydro forecasts. Yukon Energy has responded to all of the inquiries and issues raised both in the separate Two Part ERA Application and in two rounds of interrogatories. Core elements of YEC's Application relevant to these issues are summarized below. Detailed items are addressed in Section 5 of the Argument.

**Yukon Grid Context**

Yukon Energy supplies grid energy requirements primarily using hydro generation, with thermal generation relied on when hydro is unable to supply all requirements. Forecast thermal generation in any year depends on both the grid loads and the available water.

Aside from seasonal variability in loads and water supplies, water availability has been shown to vary a great deal over different years – with related major impacts on thermal generation requirements in each year.

- Short-term thermal generation (i.e., over 1 or 2 years) has varied materially due to changes in actual water conditions, resulting in actual thermal generation varying materially from short-term thermal forecasts.
- Long-term average (LTA) hydro generation forecasts have been developed, based on available annual water records as well as current grid conditions and generation facilities, to indicate ongoing average hydro generation capability over hydro asset lives.

A distinctive feature of the isolated Yukon grid is its degree of cost vulnerability to drought conditions.

- YEC's forecast LTA fuel cost for 2017 at GRA price assumptions ranges from $2.2 million (GRA forecast) to $4.3 million (actual per 2017 DCF Annual Report).
- Using the same load[7] and price[8] assumptions added fuel costs above the LTA adopted for the GRA are forecast at $17.0 to $18.5 million for the year of lowest recorded water; and $40 to $45 million for the worst six consecutive years of low water.[9]
- The cost impact of the worst drought year alone (with 2017 loads) equals a rate increase exceeding 20%, or an amount equal to about 15% of YEC's equity – indicating a relatively high degree of cost vulnerability to drought conditions.

**Overview of Inter-relationships: GRA Forecasts, DCF, Final Year End Costs and ERA**

In response to directions in Appendix A of Board Order 2017-08, Part 2 of the ERA Application (Exhibit B-14) provided information demonstrating the inter-relationship between the LTA hydro generation for GRAs, the Diesel Contingency Fund (DCF) and the Energy Reconciliation Adjustment (ERA).

Figure 2.1 from Exhibit B-14 (copied below) highlights the linear nature of the key inter-relationships.[10] The sequential, decision-making process required for their proper implementation is illustrated as follows:

- **Step 1 - General Rate Application Process:** General rate applications include requested approvals regarding the hydro forecast and methods. This includes selection of the following key elements:

    1. Hydro generation forecasts (LTA or ST);
    2. Forecast planning model (LTA or ST model); and
    3. Contingency fund mechanism to be used for addressing water variability from the approved GRA forecast.

    All of the above elements are reviewed as part of the GRA process and a determination is made in the final order approving the hydro forecast for test year forecast costs and the contingency fund mechanism to be used.

[7] Grid loads of 420 to 450 GW.h/yr reflect 2017 forecast and actual firm generation loads of 420 and 446 GW.h respectively.
[8] Includes the assumed 90% LNG, 10% diesel split for LTA thermal generation.
[9] Based on Application, Appendix 3.4, Attachment 3.4.4, Tables 3.4-6B and 3.4-7B. Worst six years of low water are 1996 to 2001. The worst single year is 1999.
[10] See YUB-YEC-2-9 and YUB-YEC-2-10 for IRs related to Figure 2-1, including review of other Canadian hydro jurisdiction examples (and cross reference to other IR responses elaborating on both past Yukon GRAs and Board Orders plus review of other Canadian hydro jurisdiction principles and practices).

- **Step 2 - Contingency Fund Implementation: Post GRA:** The selected contingency fund mechanism is relied on when finalizing YEC post-GRA costs for each fiscal year. Specifically, the contingency mechanism is used to address the impacts of water variability from the approved GRA forecasts in response to actual load requirements.

- **Step 3 - Final Utility Costs for Fiscal Year:** The final step is the determination of final Yukon Energy thermal generation fuel costs for each fiscal year (i.e., YEC costs after removing water variability impacts) and the determination of any ERA charge (or rebate) of YEC's wholesale net cost changes related to wholesale changes from the GRA forecast to be flowed through to AEY.

Regardless of the hydro forecast approach (i.e., short term or long-term average) adopted:

- For GRA purposes in Step 1, Yukon practice confirms that a contingency fund mechanism is required (Step 2) to address water variance impacts on YEC thermal generation costs and to determine final YEC costs for a fiscal year (Step 3).

- As part of Step 3, an ERA mechanism is also required to address wholesale variances when YEC is unable to recover fully its incremental thermal generation costs related to such variances as required by section 7 of OIC 1995/90.

Yukon Energy's current DCF contingency fund mechanism[11] ensures:

1. Water variability impacts that affect thermal generation costs continue to be assigned to ratepayers (rather than to the utility);

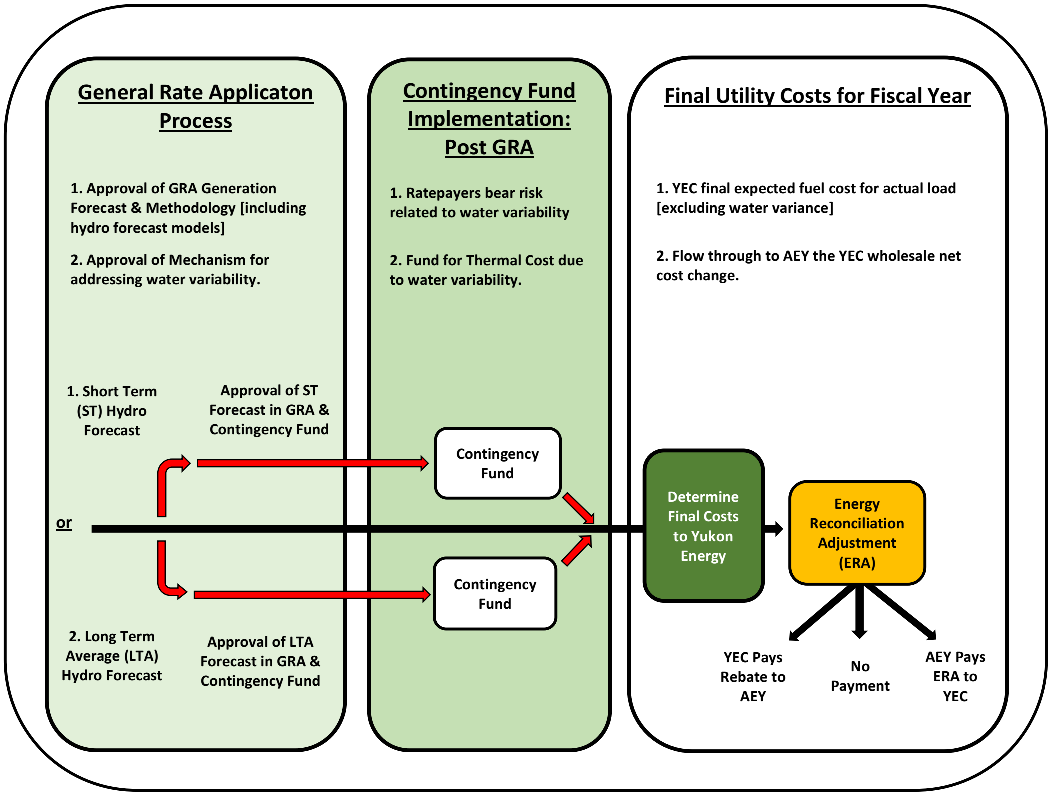
2. For years between GRAs, thermal generation cost impacts caused by load forecast fluctuations continue to be borne by the utilities; and

3. Rates are smoothed and stabilized over the range of potential different annual water conditions through the DCF fund.

These key provisions related to water risk assignment and long-term rate smoothing reflect normal principles for rate setting for hydro generation utilities in Canada[12] as well as YEC filings and Board decisions on GRA-related matters for Yukon Energy since 1989.[13]

[11] As approved to date by the Board in Order 2015-01 and Order 2015-06.
[12] The basic premise that ratepayers bear the cost risk related to hydro is applicable for all Canadian utilities reviewed with hydro generation, and in each instance measures are adopted that attempt to enhance long-term rate stability. However, each Canadian utility with hydro generation addresses ratepayer risk related to water variability differently taking into consideration the context specific to that jurisdiction. See YUB-YEC-2-9 (e) and YUB-YEC-2-31.
[13] The related history of filings and Board decisions is reviewed in YUB-YEC-2-2(c) and YUB-YEC-2-3(a, b, c, d).

**Figure 2-1: Yukon Hydro Grid Inter-relationships re: GRA Hydro Forecasts, Contingency Fund Mechanisms, Final YEC Costs, and ERA Mechanisms**




### Summary of Application – Updates to LTA and DCF

The load forecasts in this Application indicate that material thermal generation will continue to be required on the Yukon grid under long term average (LTA) hydro conditions. Consistent with Board decisions for the 2012/13 GRA when these same conditions existed, the current Application retains LTA hydro generation forecasts as the basis for thermal generation forecasts in each test year.

Also consistent with past Board decisions, the Application retains the DCF mechanism to finalize YEC's actual year-end thermal generation costs based on LTA thermal generation required at the actual annual grid load.[14]

As indicated in response to various IRs[15] and Yukon Energy's rebuttal of the City of Whitehorse (CW) Evidence (Exhibit B-21), the DCF provides a reasonable basis to separate thermal generation cost variance due to water availability outside

[14] The response to YUB-YEC-2-1(a-h) reviews the DCF as it currently exists in the context of Board Order 2015-01 and principles regarding ratepayer versus utility responsibility for variances from thermal generation fuel volume forecasts.

[15] For example: AEY-YEC-2-1, YUB-YEC-2-14(b-c) and YUB-YEC-2-16(a-b) in this proceeding, and YUB-YEC-1-5 and YUB-YEC-1-6(b) in the ERA proceeding.

management control (to be borne by ratepayers) from thermal generation cost variance due to changes in total grid load (to be borne by the utilities).

Where feasible, the DCF also addresses all potential operational risks that could affect thermal generation risks.

The DCF removes specific non-water-related thermal operation risks, e.g., risks related to Reserve for Injuries and Damages (RFID) events, capital projects, thermal unit fuel efficiencies, and (as proposed for the first time in the present Application) thermal generation maintenance and run-up requirements.

YEC is not aware of any consistent and reasonable way to isolate additional items, such as operation risks related to use of water for hydro generation to the extent that these may impact thermal generation costs.[16] Such isolation has not been attempted in either the earlier Low Water Reserve Fund (LWRF) or the DCF. Further, as noted in the response to YUB-YEC-1-6(b) (ERA Part 1 Application), YEC has well established systems to monitor its use of available water, and is not aware of any material impacts on the effectiveness of LWRF or DCF determinations related to the water management element of its systems' operation.

In this regard, the Application provides an updated DCF Term Sheet that is used for LTA thermal generation forecasts in both the Application and the DCF year-end determinations.

The DCF Term Sheet table (Table 3.4-1) sets out LTA hydro and thermal generation requirements over a range of firm grid load levels and seasonal characteristics. The 2012/13 GRA approved the use of the DCF Term Sheet table for determining LTA hydro and thermal generation requirements in the application and for determining amounts to be transferred into, or withdrawn from, the DCF fund. Yukon Energy is applying the same basic approach for the 2017/18 GRA application.

Updates to the DCF Term Sheet table reflect GRA grid loads as well as the following updates to the underlying YECSIM model:

- Added water years (35 versus 28 years in the prior GRA); and
- Updates for flow constraints at the Mayo Hydro Generation Station.[17]

As was the case for the DCF as approved after the 2012/13 GRA, the DCF Term Sheet Table 3.4-1 is subject to Board review and approval for any changes.[18]

[16] YUB-YEC-2-16(b) and YUB-YEC-2-14(b-c).
[17] General DCF updates are reviewed at section 1.2 of Appendix 3.4 of the Application (Exhibit B-1), and YUB-YEC-1-34(a-b) and YUB-YEC-1-48.
[18] Exhibit B-1, Appendix 3.4, Attachment 3.4-1, pages 3.4-13 and 3.4-14.

The DCF Term Sheet and the overall Application include updates as follows to accommodate LNG as well as diesel generation in both the GRA forecasts and in the DCF year-end determinations:[19]

- LNG generation is assumed in the Application to contribute 90% of LTA thermal generation required for firm grid loads and diesel generation 10% of LTA thermal generation;[20]
- The Application includes forecast prices for delivered LNG and diesel fuel, as well as forecast thermal unit generation efficiencies;[21] the DCF assumes the forecast GRA fuel prices;
- Rider F adjustments to reflect actual delivered fuel prices are proposed to accommodate LNG as well as diesel price adjustments from these forecasts starting January 1, 2017; and
- The year end final DCF transfer for LTA thermal based on actual grid load is to be adjusted so that the YEC's final fiscal year expense is also 90% LNG and 10% diesel, subject to the constraint that the LNG share of any transfer into or out of the DCF cannot exceed 100%. Yukon Energy bears the risk of higher costs if the final thermal generation mix for fiscal year after the DCF determinations differs from the 90:10 LNG: diesel assumed in the GRA test year forecasts.[22]

**Short-Term (ST) Hydro and Thermal Generation Forecast Alternatives**

In response to Board direction, Yukon Energy's ERA Application (Exhibit B-14) provided a ST Alternative GRA Forecast for 2017 and 2018. It also included an assessment of adopting ST versus LTA hydro forecasts for GRA purposes.

These alternatives were reviewed in round 2 of the IRs.[23] Yukon Energy once again re-iterated that its Application continues to rely only on the LTA hydro forecast approach as previously approved by the Board. Yukon Energy emphasized that discontinuing a DCF based on forecast LTA water conditions for the 2017 period forward, and instead relying on ST water condition forecasts and a related ST contingency fund mechanism (that would need to be developed) would:

- Increase rate instability;

[19] These updates are addressed in Exhibit B-1: Sections 1.3 and 1.4 of Appendix 3.4 (pages 3.4-4 to 3.4-12); and Attachment 3.4-1 (Revised DCF Term Sheet), "DCF Thermal Savings (Costs)" at pages 3.4-14 to 15 and in the attached example Table 3.4-3.

[20] Constraints on LNG unit operation were reviewed in response to YUB-YEC-1-38; the basis for adopting different percentage for DCF Annual Reports prior to 2017 is reviewed in YUB-YEC-1-40 to YUB-YEC-1-42; the basis for the proposed 90-10 LNG-Diesel split for test years is reviewed in response to YUB-YEC-1-25, and YUB-YEC-1-43. See also YUB-YEC-2-6(c), YUB-YEC-2-18(c), YUB-YEC-2-19(b), and YUB-YEC-2-22.

[21] Exhibit B-1, section 3.2 (pages 3-4 and 3-5).

[22] See YUB-YEC-2-6(a-b) and Mr. Osler: TR: 615:23 to 618:17.

[23] See for example YUB-YEC-2-11 through 25.

- Mask, rather than display, the expected long-term cost of power; and
- Frustrate, rather than facilitate, intergenerational equity and fair treatment related to the benefits provided by hydro generation over its long-term economic life.[24]

The volatility of ST hydro and thermal generation forecasts was demonstrated during this proceeding by the ST versus actual thermal generation for 2017.[25]

- Based on November 29, 2016 reservoir levels and GRA forecast loads, the 2017 ST forecast thermal generation to supply loads was 1.1 GWh with 2017 forecast fuel cost of $0.320 million (including maintenance at $0.102 million and an assumed 60/40 LNG/diesel split for the ST).[26]
- Taking into account the much higher actual grid load for 2017, the 2017 ST forecast thermal generation fuel cost forecast increased by 236% to $1.076 million (including maintenance cost and the same assumed 60/40 LNG/diesel split for the ST, indicating an updated ST forecast thermal generation slightly in excess of 5 GW.h).[27]
- Actual thermal generation in 2017 to supply grid load was slightly over 13 GW.h with a fuel cost of approximately $2.3 million[28] – well above the updated (let alone the initial) ST forecast, reflecting (among other factors) low water conditions at Mayo hydro facility, but still below the LTA thermal generation of 27.1 GW.h as updated for the final grid load.[29]
- Overall, a ST forecast for 2017 would have required a payment to YEC from the DCF - while the LTA forecast approach resulted in YEC paying into the DCF.

Review of 2018 updates highlight additional volatility for use of ST versus LTA hydro and thermal forecasts for the second GRA test year.[30]

In conclusion, the above highlights the advantages of continuing the use of LTA as a fair and balanced approach for both the utility and ratepayers, and the material disadvantages of using ST forecasts.

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[24] Several of the referenced IRs address rate instability impacts of ST versus LTA forecasts. YUB-YEC-2-13 specifically reviews issues related to price signals and intergenerational equity and fair treatment as regards ST versus LTA hydro forecast use for setting rates.

[25] See Mr. Osler TR;643:22 to 645:3 which also noted that the ST forecasts used for GRA purposes are not what YEC operators would rely upon for system operation.

[26] Exhibit B-14, page A2.2-1 and 3.

[27] Response to Undertaking #35 as filed July 20, 2018; Attachment 1, schedule 10, line 12.

[28] See DCF 2017 Annual Report as provided with Exhibit B-20, revised UCG-YEC-2-39, Attachment 1, line 17; see also CW-YEC-2-1 revised

[29] Ibid, line 16.

[30] See response to Undertaking #36 Revised as filed July 23, 2018 which shows ST forecast fuel cost for 2018 ranging from $1.8 to $3.6 million depending on the assumed load forecast for 2016 and 2017.

**DCF Cap Update**

Review of the ST versus LTA alternatives has shown that the DCF cap at the current level with Rider E impacts ends up sending a form of short-term pricing signal that can frustrate the long-term pricing objectives and rate stability sought by the LTA forecast approach.[31] This issue highlights a need to review the DCF cap, but in no way suggests any basis to replace LTA hydro forecasts with ST hydro forecasts.

Appendix 3.4 of the initial GRA Application provided an assessment of DCF Cap options. This assessment indicates the benefits of a higher cap (+/-$16 million versus current +/-$8 million cap) by increasing the number of years not needing Rider E rebates and by reducing drought year rate rider charges.

The higher grid loads experienced in 2017, and now expected in 2018 and subsequent years, further highlight the potential relevance of increasing the DCF cap at this time.[32]

Yukon Energy accordingly proposes that the DCF cap be increased at this time to +/-$16 million, and that the DCF cap be subject to ongoing review at each future GRA.[33]

## C. RELIANCE ON APPLICATION FORECASTS AS FILED

In accordance with past practice for GRA's where the utility accepts forecast risk, Yukon Energy's Application has continued to rely on the test year forecasts as filed at the outset (June 2017) except for the update required to incorporate the wholesales forecasts for 2017 as approved by Board Order 2017-01 regarding the AEY compliance filing for its GRA [response to YUB-YEC-1-3].

Regulatory principles and precedents from past GRAs reviewed by the Board highlight the importance of assessing reasonable load and cost forecasts for each test year from the timing perspective of the initial GRA filing. Utility acceptance of forecast risk is reasonable in this context, and parties avoid the range of issues that emerge when actual results beyond that time period begin to be considered.

The timing of the oral hearing for this GRA resulted in 2017 actual results being highlighted, along with certain changes affecting 2018 loads and costs for YEC. Exhibit B-22 Opening Statement and the response to Undertakings #35 and #36 filed July 20, 2018 [with revised #36 filed July 23, 2018]) highlighted the following:

- **2017 Actuals** – Based on 2017 actuals, the revenue shortfall increased slightly from the $5.3 million in the GRA as filed (and in the revised Table 4.1 per YUB-YEC-1-3)

[31] For example, see YUB-YEC-2-11(c-d).
[32] See Exhibit B-22, page 13. See also section 2.5 of Part 2 of this Argument for further review of Exhibit B-1 update of the DCF cap.
[33] See Mollard and Osler, TR. 243:23-244:15.

to $5.6 million with LTA hydro and thermal generation. Key changes from the revised GRA forecast based on AEY's compliance filing wholesales include:

- Firm sales 21.6 GW.h higher.
- Over 75% of added firm sales revenues offset by related increases in LTA fuel cost and Mayo B Flexible Debt interest increases.
- Secondary sales reduced ($0.172 million) and other revenues increased ($0.066 million).
- O&M costs excluding fuel and purchase power costs $0.418 million higher. This increase reflects higher production costs related mainly to the mobile diesel lease (which was not forecast in the GRA),[34] higher transmission and distribution costs, higher general costs, and lower administration and general costs reflecting mainly lower labour costs due to unfilled positions.
- Mid-year rate base within 0.2% of the GRA forecast.

- **2018 Updates** – The 2018 updates indicated an increase in the revenue shortfall, and highlighted the following:
  - Industrial and secondary sales 2018 load forecast adjustments would reduce 2018 forecast revenue requirement of approximately $0.712 million, while reducing sales revenues by approximately $0.8 million.[35]
  - Undertaking #36 Revised and other available evidence provide only a partial picture of ever changing conditions for 2018.

In summary, actuals for 2017 indicated a slightly greater revenue shortfall than the GRA forecast updated for the AEY compliance filing. In contrast, available updates for 2018 provide only a partial picture of changes from the GRA forecast - but this picture also implies a likely increase to the forecast revenue shortfall. In each case, there is no apparent reasonable or principled basis to move away from the forecasts as filed with the revised GRA (per YUB-YEC-1-3).

***Conclusion***

The Application's proposed 2017 and 2018 revenue requirements reflect the reasonable costs required for Yukon Energy to supply customers in 2017 and 2018 and to plan for future requirements thereafter. The proposed rate adjustments are required to recover

[34] Mr. Mollard reported that the four 2-MW units were installed for four months for a rental cost of $600,000, and that about $100,000 of other costs were incurred to connect them. TR 580:23-581:7. These rental costs were in 2017 and 2018.

[35] The Summary Update table in Undertaking #36 revised assumes LTA hydro and thermal generation based on Table 3.4-1 of the GRA (in reality, the DCF Term Sheet table would need to be updated as required to show added LTA thermal resulting from the material change in annual load shape), and indicates $0.450 million lower LTA fuel costs, $0.26 million lower Mayo B Flexible Debt interest costs, and $0.001 million reduced return on working capital. The same table showed a $0.799 million reduction in sales revenue at existing rates related to these two updates.

the forecast revenue shortfalls related to the proposed revenue requirements. The updated DCF and planning cost accounting policy as proposed are required to enhance customer rate stability.

# PART 2: RESPONSE TO KEY ISSUES RAISED

Part 2 provides Yukon Energy's responses to key issues raised by the Board and intervenors in Intervenor Evidence, IRs and at the oral hearing, and provides IR or transcript references containing more detailed information on these issues.

As reviewed in the Preface to this Final Argument, this supporting evidence follows the outline of the Application's supporting information (tabs), focusing on Tabs 2, 3, 5 and 8 and the Two Part ERA Application that address the substantive elements of the requested revenue requirement Orders.

## 1.0 TAB 2 - SALES & GENERATION

Tab 2 reviews changes in Yukon Energy grid sales and generation since 2013 relative to sales and generation forecasts for 2013 as approved by the Board for the 2012/2013 GRA, as well as the Application's forecast growth in sales and generation for the test years 2017 and 2018.

Evidence and issues regarding sales forecasts for the test years are reviewed below. The following are noted in this regard:

- No key issues were raised in IRs or the hearing regarding generation forecasts for firm and secondary sales as provided in Tab 2, Table 2.2, or regarding capacity shortfall forecasts as provided in Tab 2, section 2.4.
- Specific issues related to long-term average (LTA) thermal generation forecasts, short-term (ST) thermal generation forecasts, and LNG/diesel generation splits for these thermal generation forecasts as well as forecast fuel prices and efficiencies and DCF updates are addressed in Tab 3 (of Exhibit B-1) and Part 2 of the ERA Application (Exhibit B-14) – and in this Final Argument are addressed in Part 1 and Section 5 of this Part 2.

## 1.1 WHOLESALE SALES FORECAST

Wholesale Sales to AEY are reviewed in the Application (Exhibit B-1) in Tab 2, Section 2.2.1, pages 2-4 to 2-7.

Pages 2-5 to 2-7 explain the process and methodology used by YEC for preparing the wholesale forecast:

- Each year AEY provides YEC with its forecast power purchase estimate net of forecast generation from Fish Lake.

- YEC compares this forecast to its current year budget for wholesales, recent actual results, and regression analysis simulations.

- Based on a collective review of these comparisons, as well as management's own growth expectations, a final budget figure is selected.

As part of the preparation for the 2017-18 Application, YEC also reviewed AEY's forecasts as provided for the AEY 2016-17 GRA. Subsequent to YEC finalizing its forecasts for the 2017-18 GRA Application, Board Order 2017-01 was issued regarding the AEY GRA; and AEY also filed its Compliance Filing response for review by intervenors. However, Order 2017-03 which accepted AEY's forecast firm purchase power from YEC was not available at the time YEC's GRA was filed.

The Board requested, in YUB-YEC-1-3, that YEC provide an updated wholesales forecast based on the approved AEY Compliance Filing. The response provided the updated forecast noting that YEC did not have the information used by AEY to prepare its Compliance Filing forecast, or the details on this 2017 forecast by month as regards firm wholesales.

Updating wholesale sales per the Board's request resulted in the following changes to Yukon Energy's GRA forecast:

- 2017 wholesales increase from 309.0 to 314.2 GW.h (5.2 GW.h increase).

- Revenue requirement increase of $0.490 million for 2017, and $0.503 million for 2018; including LTA fuel cost increase of $0.407 million for 2017, and $0.415 million for 2018; and Mayo B flex term note added interest of $0.083 million for 2017, and $0.088 million for 2018.

- Revenue at existing rates increase of $0.518 million per year for both 2017 and 2018.

- The net impact of the updated wholesales forecast is a reduction in the forecast revenue shortfall of $0.027 million for 2017, and $0.014 million for 2018. This results in cumulative 2017 and 2018 rate increase required over existing rate revenues [including Rider J and Rider R revenues] at 9.19% (versus 9.08% in YEC's Application).[36]

More detailed information on specific wholesales sales forecast issues was provided in response to interrogatories and cross-examination from the Board and intervenors as summarized below:

[36] The increased Rider J requirement compared to the original Application occurred despite the reduction in the revenue shortfall. This reflects the lower revenue at existing rates due to the updated Rider R which was reduced to 8.3% in the final Board Order 2017-03 versus 11.62% assumed in Table 4.2 of the original YEC Application. See YUB-YEC-1-3.

1. YEC's Rebuttal to CW Evidence (Section 3.2 and Attachment A of Exhibit B-21), outlines AEY and YEC wholesale forecasts for 2017 (including the increase in YEC's wholesale forecast to incorporate the response to the direction provided by the Board in YUB-YEC-1-3).

    a. While YEC takes into account AEY's forecast on an annual basis, YEC prepares its own separate forecast based on professional judgment. In addition to considering information received from AEY, YEC used a multivariate linear regression model to validate the forecast.[37]

    b. There is no basis to assert that communication issues between YEC and AEY affected the accuracy of the wholesale forecast.[38] The evidence outlines the considerable communication that occurred, and that the actual results for 2017 were higher than all relevant forecasts (i.e., AEY's GRA forecast, YEC's GRA forecast or the approved AEY Compliance Filing forecast). Additional communication would not have resulted in better forecasts for 2017 and 2018.

2. YEC's Rebuttal to CW Evidence (Section 3.2 and Attachment A) outlines the history regarding Resource Plan forecasts and actuals. Attachment A of YEC's Rebuttal Evidence provides details on 2006 and 2011 Resource Plan forecasts vs. actuals, notes issues regarding the data used in tables provided in CW's Evidence, and highlights how variances between forecast and actual results reflect industrial load impacts [i.e., Alexco mine closing during 2013]. The YEC Rebuttal also addresses 2016 Resource Plan and GRA forecast variances.

3. Actual sales and generation for 2017 are reported in CW-YEC-2-1 and UCG-YEC-2-18 (sales). Impacts on LTA and actual thermal generation are reviewed in CW-YEC-2-1 and UCG-YEC-2-39 Revised which provides the 2017 DCF annual report. The following is noted regarding the actual sales for 2017 compared to the updated forecast provided in YUB-YEC-1-3[39]:

    a. Firm sales were 21.6 GW.h higher than the updated forecast (14.2 GW.h included for wholesales, 5.2 GW.h for industrial); sales revenues, including secondary and Rider J at pre-GRA levels, were $2.7 million higher than the updated forecast.

    b. Firm generation was 20.4 GW.h higher than the updated forecast (lower percentage losses than forecast at 8.1% vs 8.8%)

[37] CW-YEC-1-11 Attachment 1 provides a working excel file with the input variables and the multi-variate regression coefficients used to support the wholesales forecast of 309 GW.h and 309.5 GW.h for the 2017 and 2018 test years.

[38] CW-YEC-1-11 notes that "Senior management of AEY and YEC participated in both conference calls and email communications. Prior to filing of YEC's Application, no discussions occurred on this matter after the AEY Compliance Filing."

[39] See also Undertaking #35.

i. The non-industrial GRA forecast (378.8 GW.h generation), the updated load forecast (384.5 GW.h) and actuals (399.7 GW.h) were all higher than the 2016 Resource Plan (372.1 GW.h). The actual non-industrial sales forecast was almost the same as the LNG Part 3 forecast (at 400.9 GW.h).

ii. The actual non-industrial peak (86.2 MW) was higher than the GRA forecast (85.3 MW), the 2016 Resource Plan forecast (83.8 MW) and the LNG Part 3 forecast (80.4 MW). This highlights the increasing peak relative to energy load.

c. Fuel & Purchase Power expense was $2.1 million higher than the original GRA forecast (this reflects the LTA forecast, GRA fuel prices, inability to operate wind generator, and final DCF transfer).

4. The 2017 experience highlights non-industrial as well as industrial load forecast uncertainty, and the manner in which the DCF mechanism tends to offset the net financial impact on YEC from load variances from forecasts.

a. Load forecast uncertainty related to industrial loads is well known. However, experience since 2013 also indicates wide swings in wholesale loads that confirm uncertainties in these forecasts due to weather as well as other factors (swing from warm to cold winter weather).[40]

b. Added revenues from additional YEC sales are largely offset by added LTA fuel costs related to DCF implementation, i.e., LTA thermal costs decrease or increase as load decreases or increases.

## 1.2 MAJOR INDUSTRIAL CUSTOMER LOADS

Tab 2, Section 2.2.2 of the Application provides a summary of forecast information provided to YEC by Minto Mine management, and by the management of Alexco and Victoria Gold. This section outlines the forecast industrial sales to Major Industrial Customers in the test years based on information provided by Minto mine management. The test years include one Major Industrial customer (Minto Mine – Capstone Mining Corp.) with forecast sales of 38.2 GW.h each year. Additional information regarding expected load requirements after the test period was provided by the management of Alexco and Victoria Gold.

Overall, the Application and information provided over the course of 2017 and 2018, indicate that industrial loads continue to be subject to considerable change:

[40] YUB-YEC-1-59 (a) notes that fluctuations in firm wholesales during 2013 to 2016 were caused primarily by fluctuations in temperatures, plus impacts of changing Fish Lake hydro generation.

- Forecasts as at the end of 2016 assumed that Minto mine would cease operations before the end of 2017.
- The 2017/18 GRA Application forecasts for Minto Mine load reflected updated information provided to Yukon Energy by Capstone Mining Corp in the first week of April 2017. This indicated forecast sales of 38.2 GW.h for each test year.
- The Opening Statement [Exhibit 22] filed June 2018 provided more recent information from Minto mine which indicates the mine would significantly constrain its operations in the last half of 2018. As a result, YEC expected that 2018 electricity requirements would be well below the GRA forecast. The opening statement also confirmed that no other industrial customers were expected to connect to the grid in 2018.
- The response to Undertaking #36 provided an updated 2018 industrial sales forecast for Minto at 32.192 GW.h (versus the GRA forecast of 38.219 GW.h), based on actual January-June sales of 22.361 GW.h and a revised forecast for the balance of the year of 9.831 GW.h.

As noted in Part 1 of this Argument, based on the principle that GRA cost and sales forecasts are not to be adjusted to reflect subsequent events, Yukon Energy has not sought to adjust its Application to address any change in the industrial 2017 and 2018 test year Minto sales forecasts.

Other information provided on industrial customer loads was summarized in the following interrogatory responses:

- **Capstone Mining Corp. [Minto Mine]:** The process used by YEC to consult with Minto mine in developing test year forecasts was summarized in CW-YEC-1-12(a). Year-over-year changes in industrial load between 2015 and 2017 were explained in CW-YEC-1-12(b) and (c).[41] Updates on Minto mine load for 2017 and 2018 and documentation regarding expected operation through 2020 and potential continued operation until 2022 was provided in UCG-YEC-1-12(a).
- **Alexco Resources Corp [Alexco Mine]:** While Alexco Resources had publicly stated a desire to resume industrial mining activities by late 2018; to date, YEC has received no official notification.[42] Metered energy and demand for the last full year of Alexco's operation was provided in response to JM-YEC-1-7.
- **Eagle Gold [Victoria Gold Corp.]:** The VGC Group mine is not expected to be operational until after the test years and consequently will have no impact on test

[41] UCG-YEC-1-7(c) provides industrial sales to Minto and Alexco mines from 2013 to 2016 (Actual) and 2017 and 2018 forecasts. YUB-YEC-1-57 confirms the only industrial customer since 2013 has been Minto Mine. Minto's load for 2016 was abnormally high as it was considering a shut down and trying to produce as much as possible prior to that.

[42] CW-YEC-1-12(d).

year firm sales.[43] In November 2017 Yukon Energy finalized and filed for YUB approval an application for approval of a Power Purchase Agreement with Victoria Gold Corp. and StrataGold Corporation [jointly VCC Group]. The PPA was approved by Order 2018-04 on March 6, 2018. JM-YEC-1-21 Revised provides an assessment of Victoria Gold mine impacts with a $16 million and a $22 million DCF cap option with Victoria Gold mine on the grid.[44]

Mine loads do not currently affect the requirement for additional dependable capacity (and closure of a mine would not reduce the dependable capacity requirement).[45]

## 1.3 OTHER SALES [RETAIL; GENERAL SERVICE; SECONDARY; LIGHTING]

Retail and general service sales forecasts are reviewed in Tab 2, at page 2-9. No material issues were raised in interrogatories or in cross examination at the oral hearing regarding retail or general service sales forecasts. The response to CW-YEC-1-13 Attachment 1 provides the working papers in support of the calculation of customer forecasts for firm retail sales and general service sales. The response to CW-YEC-1-13 (b) and (c) provides the rationale for the 2017 and 2018 forecasts for retail and general service forecasts. The Victoria Gold mine will not be operational until after the test years and consequently there is no expected impact on firm retail sales for AEY or YEC during the test period.[46]

The Secondary Sales forecast for the test years was reviewed in Tab 2, page 2-9 and 2-10.[47] Secondary sales revenues over the period from 2013 through 2016 helped to mitigate the impacts of loss of load and to defer the requirement for another GRA until 2017.[48] The Opening Statement [Exhibit B-22] indicates that secondary sales in 2017 were lower than GRA forecast [8.3 GW.h], and were shut off in December 2017 due to lack of surplus hydro.[49] Secondary sales for 2018 are currently forecast at approximately 2.1 GW.h,[50] well below the GRA forecast of 11.4 GW.h.

43 JM-YEC-1-5 part (a) and (b) and JM-YEC-1-6(c).

44 The response reviewed Appendix 3.4 tables that include the new load scenario, i.e., Table 3.4-4, Figure 3-1, Table 3.4-5, Table 3.4-8A, Table 3.4-8B and Table 3.4-8C.

45 YUB-YEC-1-24; CW-YEC-10(a) notes industrial activity is not currently a driver for construction of assets to address dependable capacity deficits. Several resource options defined in the short term action plan are capacity based and intended to bridge the current dependable capacity shortfall under the Single Contingency (N-1) criterion. This criterion excludes industrial loads and construction of new assets for this purpose cannot currently be attributed to industrial activity.

46 JM-YEC-1-5(a) and (b).

47 CW-YEC-1-14 provides the detail underlying the forecasts for Canada Games Centre, the Yukon Hospital and the Yukon College; part (e) provides the explanation for the secondary sales rate used for the test years.

48 UCG-YEC-1-12(b).

49 YUB-YEC-1-23 provides secondary sales volumes (MW.h) and revenues ($000) for 2013 through 2016; while UCG-YEC-1-12(a) provides sales volumes and revenues for 2012 through 2016 (actual) and 2017 and 2018 forecasts. Preliminary actual results for 2017 (full year) were provided in CW-YEC-2-1. JM-YEC-1-6(b) provides a breakdown of forecast secondary sales in 2017 and 2018 by month.

50 Response to Undertaking #36 Revised, filed July 23, 2018.

Firm retail sales forecast for street lights and space lights in the test years is reviewed in Tab 2, page 2-9, and notes a decrease in street light sales from 2015 to 2018 primarily due to conversion to LED street lights. No material issues were raised in interrogatories or in cross examination at the oral hearing regarding retail sales forecasts for lighting. Both AEY and the YUB in interrogatories queried how LED retrofits were being undertaken; whether the lights being retrofit were at end of life; and how customer contributions for retrofits would be addressed.[51] YEC clarified that it is absorbing the existing cost of the old street lights in rate base [these have been written off to shareholder expense], and asking to be paid for the cost to purchase and install new LED street light heads.[52]

## 2.0 TAB 3 – REVENUE REQUIREMENT

Tab 3 of the Application reviews Yukon Energy's revenue requirement for the test years, including an overview, followed by more detailed consideration of key components (fuel and purchased power; non-fuel operating and maintenance expenses; rate base, depreciation and amortization; return on rate base (interest and ROE); and stabilization mechanisms (Rider F and the Diesel Contingency Fund [DCF]).

Section 2 of this Part 2 Argument focuses on the following key issues:

- Fuel and purchased power;
- Labour expense (related to new positions);
- Transmission and distribution brushing costs;
- Updated diesel contingency fund mechanism (DCF); and
- Reserve for Injuries and Damages (RFID).

Capital cost issues and planning cost policy changes are addressed Section 3 of this Part 2 Argument. Issues regarding ROE as proposed in the Application are addressed in Section 4 of this Part 2 Argument. YEC will wait to respond to any other issues raised by intervenors relating to other revenue requirement components.

## 2.1 FUEL AND PURCHASED POWER

Tab 3 of the Application reviews the forecast costs of Fuel and Purchased Power for the test years in Section 3.1 and Section 3.2 (pages 3-2 to 3-5), Table 3.1 (Yukon Energy Revenue Requirement) and Table 3.2 (Fuel and Purchased Power).

[51] AEY-YEC-1-2 (c) asks for YEC's views respecting LED retrofits in the context of Board Order 2017-01, the postage stamp rate environment and the shared investment policy with AEY; YUB-YEC-1-81 asks who should bear the costs of retrofitting streetlights in Dawson and Mayo and who should bear costs of assets removed before end of life.

[52] Transcript, page 443; and YUB-YEC-1-81.

Forecast fuel costs include the following two items:

- Forecast LTA thermal generation fuel costs for the forecast firm generation load, assuming 90% liquefied natural gas (LNG) generation and 10% diesel generation at forecast fuel prices of $0.1467/kW.h and $0.2633/kW.h respectively; and
- Forecast maintenance fuel costs for LNG and diesel units in each test year.

The 25% decrease in fuel and purchased power costs forecast in 2018 compared to 2013 approved (as described at page 3-2 and at Table 3.2) reflects lower fuel prices (including LNG as a new source of thermal generation), which more than offset slightly higher long-term average thermal generation requirements (Table 2.2).

IRs were asked regarding maintenance fuel costs[53] as well as updates on actual fuel prices.[54] No key issues were raised in the hearing as regards forecast fuel prices or forecast unit efficiencies, beyond updates noting that actual LNG delivered prices in 2017 and 2018 have been higher than the forecast price in the Application.[55] Issues regarding LTA and ST forecasts, as well as the DCF and Rider F, are addressed separately in the Application and in this Argument.

## 2.2 LABOUR EXPENSE

The increase in 2017 and 2018 forecast labour expense compared to 2013 approved costs reflects additional positions, as well as increased labour rates and changes in the capital/maintenance allocation.

The justification for labour cost increases in the test years was extensively reviewed in interrogatories and in cross examination at the oral hearing. Detailed information is provided in Tab 3, pages 3-5 to 3-8, and in Tables 3.3, 3.4, 3.5, 3.6, 3.7, 3.8 and 3.9. Further, explanation and justification and explanation for increases in labour costs was provided in response to the following interrogatories:

- **Labour cost increases:** Overall increases were discussed in YUB-YEC-1-2;[56] YUB-YEC-1-5;[57] YUB-YEC-1-28 (a)[58] and CW-YEC-1-18.[59] Interrogatory responses noted

[53] YUB-YEC-1-25(b).

[54] See for example YUB-YEC-1-26 and 27, YUB-YEC-1-46; CW-YEC-1-16.

[55] Response to Undertakings #12 and #13 as filed July 3, 2018 provides actual LNG and diesel prices for 2017 and the first four months of 2018. Mr. Mollard commented on current views on LNG price: TR 581:22-582;15.

[56] Part (a) provides term and percent increase in wages associated with the last completed collective bargaining agreement (for the period commencing January 1, 2014); (b) clarifies the non-negotiated wage increases were at same increment as specified in the collective bargaining agreement; (c) provides actual vacancy rates by operational area for 2013 through 2016; and (d) provides key labour related assumptions for the test years.

[57] Summarizes key revenue requirement increases (2016 to 2017 and 2017 to 2018).

[58] Provides the latest edition of the Yukon Economic Outlook; this forecasts Whitehorse CPI to be up 1.9% in 2017 and 1.8% in 2018.

that the specific rate for negotiated wages could not be provided as YEC was in the process of collective bargaining. In the July 13, 2018 undertaking filing,[60] it was clarified that the GRA assumed a 2% wage increase in 2017 and a 1.75% wage increase in 2018.

- **Employee Complement History:** Yukon Energy has had minimal growth in its labour complement. Specifically, FTE positions were forecast to increase by 1.70 in 2018 over 2013 approved (an average annual increase of only 0.4%). The Application at pages 3-11 to 3-17 provides a summary of changes from 2013 approved to 2018 forecast. Table 3.4 (in Tab 3, page 3-7 of the Application) reviews the Employee Complement History[61] (net of allocation to YDC).[62]

- **Capital/ Maintenance Allocation:** The response to YUB-YEC-1-7(a) through (d) provides historical results for the years 2013 through 2016 that were used to determine the 2017 and 2018 forecast capital to maintenance ratio allocation; notes the factors which may impact the variation in capital to maintenance allocation each year;[63] and indicates that based on the variability of actual results each year, 2017 and 2018 forecasts were based on the average of historical results. CW-YEC-1-19 provides the capital/ maintenance allocation calculation for 2013 through 2016 (actual) and 2017 and 2018 (forecast).[64]

- **2012/13 Additional FTE Positions:** Board Order 2013-01 regarding YEC's 2012/13 GRA directed YEC to demonstrate in its next GRA that the FTE complement levels approved in Order 2013-01 have effectively reduced the costs or use of outside consultants. FTE increases approved in Order 2013-01 in this regard included Resource Planning and Environment (6 FTE increase) and Finance, Customer Accounting & Purchasing (4.19 FTE increase). Yukon Energy provided further detail to justify positions added in 2012/13 GRA in Undertaking #27. The undertaking confirmed use of internal YEC resource planning, environment and finance positions carrying out capital activities plus administration O&M activities that would otherwise likely have been assigned to external consultants. Information also documented a material reduction in consultant costs for capital

[59] Part (a) and (b) provide clarifications regarding incentive pay; part (c) summarizes YEC benefits each year (2013 to 2016 actual and 2017 and 2018 forecast) and provides a detailed explanation of all changes in benefits, noting the main factors driving cost of benefits are wage increases, FTE counts and vacancy rates.

[60] At Transcript page 540:2-5 - Mr. Mollard was to check on general provisions in the GRA for wage increases for the test years, and confirm if this was 2% in each test year. In the Yukon Energy 2017-18 GRA: YUB Hearing June 26-28, 2018 – Transcript Review by YEC attached to the undertaking filing on July 13, 2018 it was clarified that the GRA assumed 2% wage increase in 2017 and 1.75% wage increase in 2018.

[61] Vacancies were addressed in YUB-YEC-1-2(c).

[62] YUB-YEC-1-8(a) confirms that information provided by YEC at pages 3-6 to 3-8 of the GRA Application is net of allocation to YDC; and part (b) provides the 2016 employee complement history net of allocation to YDC.

[63] Variation in capital to maintenance allocation ratios is due to a combination of factors including: variability of projects worked on in a given year; variability of labour time that is required on a specific project; variability of maintenance issues that may arise that may delay capital work; and general availability of internal resources.

[64] CW-YEC-1-19(c) Attachment 1 provides the current capitalization practice tracked against the previous version.

(including deferred) project activities since the last GRA. It was noted that the analysis only captured those aspects of this work that would otherwise have been completed by an external consultant; all positions noted have other duties that do not meet this criteria (i.e. internal employee functions).[65]

## 2.3 TRANSMISSION & DISTRIBUTION EXPENSE

Tab 3, Section 3.3.2 and Section 3.3.3 and Table 3.6, Table 3.6.1 and Table 3.7 provide a summary of transmission and distribution costs, and an explanation regarding variances in labour and non-labour costs in the test years compared to 2013 approved costs. Further detail on transmission and distribution expense and explanations regarding variances in transmission and distribution expense was provided in the following interrogatory responses: CW-YEC-1-21;[66] CW-YEC-1-22[67] and YUB-YEC-1-12.[68]

The Board and intervenors have had the opportunity to review the vegetation management policy and brushing costs as part of the current Application. Brushing costs are reasonable, and are consistent with the brushing policy and studies previously reviewed by the YUB:

- Forecast brushing costs are prepared consistent with YEC's 10-year brushing plan as discussed in section 3.3.2 of the Application.

- Variations in costs from year to year reflect site specific characteristics (such as terrain, access and vegetation composition). Distribution brushing costs in particular are more cyclical.

- Yukon Energy has fully complied with previous YUB directives related to brushing costs and vegetation management,[69] and Yukon Energy's vegetation management policy is prudent and informed by a review of industry best practice and YEC's own operating experience. Yukon Energy's Rebuttal Evidence (Exhibit B-21) reviewed in detail the history regarding the development of the vegetation management policy; and attached referenced studies

[65] Transcript page 54, lines 9-23 notes regulatory modelling work previously performed by consultants is now done in house by YEC staff. Page 55 also notes load forecasting and resource planning work has also been done internally by YEC. See also page 75, lines 16-20.

[66] Fluctuations in brushing costs result from different site specific characteristics and variations in contractor unit rates resulting from annual competitive processes. YEC continues to apply recommendations of the YUB mandated brushing study with respect to designation of areas requiring attention.

[67] Distribution brushing is more cyclical than transmission brushing due to its smaller scale. No significant lines were required to be brushed in 2016; distribution brushing costs are expected to be higher in 2017 and 2018 due to cyclical nature of requirements.

[68] YEC is seeking approval to amortize the 2016 vegetation management deferral account balance of $2.215 million over a ten year period ($0.222 million per year). The amortization period of ten years is proposed to be consistent with YEC policy of amortizing deferred costs greater than $1 million over ten years.

[69] Yukon Energy was directed in Order 2009-8 to undertake a study into brushing activities of similar utilities and report its findings to the Board, and also to include a written brushing policy to outline YEC's approach and explain the manner in which the budget for any year was derived.

undertaken by YEC prior to the 2012/13 GRA to support development of the policy. Overall, the process that resulted in the current Vegetation Management policy displayed ample and appropriate due diligence, including adequate research into other utility policies and practices with involvement of jointly funded external expertise, and there is no need for further reporting or review to compare YEC's vegetation management policy to other utilities.

## 2.4 INSURANCE AND RESERVE FOR INJURIES AND DAMAGES (RFID)

The Reserve for Injuries and Damages (RFID) allows for an appropriate balance to be maintained between self-insurance, deductibles, commercial insurance and sudden and accidental losses;[70] and allows such costs to be smoothed over a number of years to avoid rate instability for ratepayers. Section 3.3.6 and Table 3.10 provide a summary of Insurance and Reserve for Injuries and Damages costs. Table 3.11.1 provides the RFID Continuity Schedule.

The Application notes that the RFID balance has grown from negative $0.330 million in 2013 to negative $1.059 million at the end of 2016;[71] and given the current balance in the reserve and the desire to avoid similar negative balances[72] Yukon Energy is seeking the following:

(1) To amortize the 2016 negative balance of $1.059 million over a 5-year period ($0.212 million per year);[73] and

(2) To increase the annual appropriation to $0.267 million per year.

Table 3.11 provides the RFID annual charges over the past ten years and supports the $0.267 million annual appropriation amount. CW-YEC-1-25 (b) provides further detail of items charged to the RFID each year over the last 10 years. No issues regarding charges to the reserve or the annual appropriation were raised by intervenors in cross-examination at the hearing.

[70] CW-YEC-1-25 (a) notes for annual property insurance that premiums are based on the replacement cost of insured assets. As YEC expands and updates its property portfolio, there is upward pressure on the overall premium (annual premium rate stated in premium dollars/$1000 of insured assets is not subject to material changes year over year). During the 2017 property & equipment renewal, YEC reduced the deductible on mechanical breakdown from $250,000 to $100,000 without an increase in premium rate. There was no change in the liability program as YEC is in the second year of a 3-year agreement.

[71] Negative amounts represent excess of charges to the RFID compared to appropriations to the RFID.

[72] YUB-YEC-1-13 explains that the negative balances mean that the RFID is over-subscribed, i.e., costs exceed the sum of the annual appropriations. The account is in a debit balance which is due from ratepayers.

[73] YUB-YEC-1-12 provides a continuity schedule for the RFID (table 1) and notes that YEC seeking to amortizing the balance of the RFID over a five year period is consistent with Board Order 2013-01 which approved amortization of the 2011 balance over a five year period.

## 2.5 STABILIZATION MECHANISMS

The Application addressed two stabilization measures:

1. **Rider F** – Exhibit B-1, at page 3-24, includes a proposal to revise Rider F to include pricing related to the delivered cost of LNG, effective January 1, 2017, and list the related required approvals for this proposal. No issues were noted during IRs or the oral hearing on this proposal.

2. **The Diesel Contingency Fund (DCF)** – Exhibit B-1, at section 3.6-2 and Appendix 3.4, includes proposals for the following as regards the DCF:

    a. **DCF Update** – This includes an updated DCF Term Sheet and a proposed approach for incorporating LNG. Key issues related to this DCF update are reviewed in Section B of Part 1 of this Argument.

    b. **Update to DCF Cap** – Section 1.4 and Attachment 3.4.4 of Appendix 3.4 of Exhibit B-1 provides an update review of the DCF cap in the context of Board Order 2015-01 acceptance of the level of +/- $8 million "as an acceptable balance between frequency of rider applications and ability to handle material (drought) changes in hydro availability." The update concluded, based on GRA load and LTA thermal generation forecasts, that there is no reasonable basis today to consider any lower cap than the +/- $8 million last approved by the Board, and that it is timely today to review the benefits of a higher DCF cap.[74] The Exhibit B-1 analysis did not include any specific recommendation regarding a higher DCF cap.[75]

    As reviewed in Section B of Part 1 of this Argument, subsequent review of ST versus LTA alternatives indicated that the DCF cap at the current level with Rider E impacts ends up sending a form of short-term pricing signal that can frustrate the long-term pricing objectives and rate stability sought in the LTA forecast approach. The higher loads experienced in 2017, and now expected in 2018 and subsequent years, further highlight the potential relevance of increasing the DCF cap at this time. Accordingly, Yukon Energy now proposes that the DCF cap be increased at this time to +/-$16 million, and that the DCF cap be subject to ongoing review at each future GRA.[76]

    c. **DCF Annual Filings** – The Application seeks approval of the DCF Annual Reports for 2015, 2016 and 2017 which each include integration of LNG.[77]

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[74] See AEY-YEC-1-3 for questions asked regarding the original DCF cap analysis, and JM-YEC-1-21 Revised for extension of the analysis to include Victoria Gold mine loads.
[75] The reasons for this were reviewed in response to YUB-YEC-1-47.
[76] See Mollard and Osler, TR. 243:23-244:15.
[77] Reference to Board approval of 2015 and 2016 DCF Annual Reports as part of this proceeding is at Exhibit B-1, page 3.4-2; during this proceeding, the 2017 DCF Annual Report was also filed for Board review and approval

## 3.0 TAB 5 - CAPITAL PROJECTS

This section of the Final Argument focuses on the major capital projects and major deferred costs (i.e., projects with capital or deferred costs exceeding $1 million) affecting the test years as set out in Section 5.2.1 and Section 5.3.1 of the Application.

The Application and related IRs and oral hearing transcript also provide information on "other" capital and deferred projects with costs ranging from $0.1 to $1.0 million, including over $8 million of other deferred projects (including deferred project costs from the last GRA that the Board directed be deferred until the next GRA) and $6.3 million for deferred overhauls (which the Board directed in the last GRA be deferred until the next GRA, and are treated as "other capital projects" in this GRA).

- Capital projects between $0.1 to $1.0 million were reviewed in the proceeding in the Application (Appendix 5.3) as well as in IRs[78] and cross examination.[79] No specific issues were raised regarding these projects. Yukon Energy will respond to any specific issues or questions raised by intervenors in reply argument.

- Deferred projects between $0.1 to $1.0 million were reviewed in the proceeding in the Application (Appendix 5.4) and in IRs[80] and cross examination[81]. No specific issues were raised regarding these projects. Yukon Energy will respond to any specific issues or questions raised by intervenors in reply argument.

## 3.1 MAJOR CAPITAL PROJECTS

Rate base growth of $64.9 million over 2013 approved costs reflects $35 million net increase (net of contributions) from two major capital projects related to capacity planning requirements (LNG Plant and Whistle Bend Supply/Takhini Upgrades) and $25.4

(Exhibit B-20, UCG-YEC-2-39 Revised). Issues related to the 2015 and 2016 DCF Annual Reports were addressed in response to YUB-YEC-1-40, YUB-YEC-1-41, and YUB-YEC-1-42.

[78] See YUB-YEC-1-87(a) regarding Aishihik Generator Fire Protection; YUB-YEC-1-87(b) re: Whitehorse Local HMI/Historian Upgrade; YUB-YEC-1-87(d) regarding Dawson P158 T1/T2 Transformer; YUB-YEC-1-87(d) re: Transmission System Protection Upgrades; YUB-YEC-1-87(e) re: Critical Spares – System Requirement; JM-YEC-1-36 re: Whitehorse Wind 1 Decommission (site restoration); YUB-YEC-1-73 and CW-YEC-1-34(d) re:L170 Line Access; YUB-YEC-1-74 re: WAF Transmission Upgrades; UCG-YEC-1-28 re: Customer Extensions; JM-YEC-1-37 re: Building Condition Report Response; UCG-YEC-1-30 re: Dawson Derrick Digger; JM-YEC-1-38 re: Mayo B Door Installation for Crane Inspection; CW-YEC-1-34(e) re: Mayo Transient Trailer Unit; and YUB-YEC-1-87(g) and JM-YEC-1-39 re: Stewart-Minto Local SCADA.

[79] See Transcript pages 440-42 re L170 Line Access; pages 452-54 re: Dawson P158 T1/T2 transformers. See also Undertaking #21, Undertaking #22 and Undertaking #23.

[80] See YUB-YEC-1-86(a) re: Development of Asset Management Program; YUB-YEC-1-48(b) and JM-YEC-1-34(a) re: Time of Use Rate Structure and Smart Grid; JM-YEC-1-40 re: Mayo and Aishihik Hydro Climate Change Study; JM-YEC-1-41 and YUB-YEC-1-86(c) re: Mt Sumanik Wind Feasibility Study; JM-YEC-1-42 and YUB-YEC-1-86(d) re: Northern Diesel Plant Location Study; YUB-YEC-1-86(e) re: Whitehorse Hydro Uprate; and YUB-YEC-1-86(f) re: Small Hydro.

[81] See Transcript pages 444-52 re: Northern Diesel Plant; and page 495-500 for Remote Terminal Unit Replacement. See also Undertaking #25 and Undertaking #26.

million from eight sustaining capital projects.[82] Other major capital projects reviewed in the Application will not affect rate base in the test years.

### 3.1.1 COMPLETION OF LEGACY INFRASTRUCTURE PROJECTS

The 2012/13 GRA Application reviewed one legacy infrastructure project.

- **Aishihik Third Turbine (Aishihik AH3) (no impact on forecast rate base growth for test years beyond $0.290 million for wrap up activities over 2012-2016) –** Costs for this matter are reviewed in detail in Section 5.2.1.1 of the Application and in the response to YUB-YEC-1-61. Yukon Energy has incurred $2.715 million of costs after 2012 for wrap up activities,[83] including $2.574 million of costs from a dispute with a contractor on this project. Total spending in 2016 was $2.117 million, the majority being legal costs required to be expensed during the year for accounting purposes.[84] Yukon Energy is not at this time seeking to add any amount related to the legal dispute to rate base. YEC will carry these costs until the legal process is complete. YEC considers costs related to the legal dispute to be prudently incurred in order to defend the company against legal action resulting from the project. Upon final settlement of the lawsuit total project cost will be presented to the Board for review in the next GRA.[85]

### 3.1.2 SUSTAINING CAPITAL REQUIREMENTS

The Application notes that prior and current test year capital spending has focused largely on projects planned to sustain, or maintain, the capability of the existing grid system (sustaining capital projects), including a number of enhancements, repairs or improvements to existing infrastructure. Spending on sustaining capital has increased net rate base in the test years by approximately $25.379 million. The current Application has demonstrated the clear requirement for each of these projects and the prudency of costs incurred by Yukon Energy on these projects has been examined and confirmed in the Application and in subsequent IRs.

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[82] Capital costs referenced are net of contributions, but prior to any depreciation occurring during or prior to the test years. Final impacts on mid-year rate base in each test year are net of all depreciation up to the end of 2018.

[83] YUB-YEC-1-61 (c) notes AH3 wrap-up activities involved normal work required to address project deficiencies after the unit was put into service. The total for that activity of $289,830 was added to rate base at the end of 2014 and YEC is seeking approval of these costs during the current GRA.

[84] YUB-YEC-1-61 notes YEC was forced to expense these amounts under GAAP based on the previous disallowance of costs by the YUB with respect to the Mayo-Dawson transmission project contract settlement from the 2005 Required Revenues and Related Matters proceeding. It remains YEC's position that these are valid costs for recovery from ratepayers and these costs will be applied for at the next proceeding following resolution.

[85] Exhibit B-22 notes that YEC's appeal concerning the AH3 construction project was recently allowed by the Yukon Court of Appeal, and as requested by YEC the matter has been remitted back to the Yukon Supreme Court.

Yukon Energy's asset management approach is reviewed in YUB-YEC-1-86(a) and in CW-YEC-1-24; YEC constantly monitors, measures and inspects asset condition and performance,[86] and uses a combination of internal and external reviews. Asset assessment projects have been commissioned over the last several years to build an inventory of asset conditions for key asset classes.[87] The recommendations from these reports are transferred into a checklist of prioritized actions that can then be budgeted and addressed in an orderly manner. An asset management plan is also being developed to integrate different information sources into an asset health index that would allow YEC more complete information for capital planning.

The following major capital projects were undertaken to address sustaining capital requirements to ensure ongoing safe and reliable operation of the Yukon Grid. Business cases for these projects focused on addressing the need for the project and ensuring accurate and complete estimation of costs, rather than a traditional cost benefit assessment. The evidence confirms that forecast cost for these projects were prudently incurred.

- **AH Elevator Shaft Structural Steel Rehabilitation ($10.116 million):** The project was required to meet a Yukon Workers Compensation Health and Safety Board requirement for an independent engineer to conduct a comprehensive evaluation of the installation to ensure the elevator meets all applicable codes, acts, and regulations. The engineer's review and report recommended permanent rehabilitation of the structure.[88] As regular access to the underground generator floor is required for continued operation of the plant, and as the plant is critical to the operation of the Yukon Integrated System, there was no reasonable alternative to the project. The project is complete and the elevator returned to service at the end of June 2017. YEC is seeking approval to include costs for the project in rate base in 2017.

  Tab 5, section 5.2.1.2 provides further detail on the project justification and estimated costs. Further relevant information for determining the prudence of costs incurred for this project is as follows:

  - **YUB-YEC-1-62 (d):** Provides a comparison between the GRA forecast cost of $10.116 million and the original forecast cost of $9.512 million; and an explanation of the cost variance by project sub-component.

  - **John Maissan-YEC-1-24:** Provides the estimated useful life of the asset; this was corrected at the oral hearing to be 40 years at page 19, lines 1-11.[89]

[86] CW-YEC-1-34

[87] Examples of assessment reports undertaken are provided in: CW-YEC-1-40 (Insulator and cross arms); John Maissan-YEC-1-37 (Building condition assessments); UCG-YEC-1-16 (Communication needs assessment); and YUB-YEC-1-63 (Aishihik Hydro Assessment re: electrical & control upgrades).

[88] UCG-YEC-1-14 provides the KGS report.

[89] Mr. Mollard notes, "with respect to the depreciation period on that project. It was set up when it was closed out at a 72-year life which corresponds to the approved rate for height structures. Subsequent to the IR being

- **Aishihik Electrical and Control Upgrades ($2.511 million):** A number of specific control systems and electrical upgrades are being undertaken to ensure ongoing safe and reliable operation of the Aishihik generating station. The need for the project was determined following a formal asset assessment completed by KGS as well as plant inspections undertaken in 2015. These reviews confirmed that many of the electrical and control systems in the Aishihik plant have reached end of life and need to be replaced; existing control systems lack functionality to optimize plant operations; and replacement and upgrading of these controls systems will modernize the interfaces, improve trouble shooting capability, and provide better information on the operating stage of the equipment.

  Tab 5, section 5.2.1.3 provides a review of the project elements, justification, and costs. Further relevant information for determining the prudence of costs incurred for this project is as follows:

  - **YUB-YEC-1-63:** Provides a copy of assessment report done by KGS Group, options reviewed, and other related questions.
  - **CW-YEC-1-36:** Reviews the end of life determination.

  Specific project components were reviewed in the following IR responses:

  - **YUB-YEC-1-63 (c)** reviewed the AH3 Control System Drawings Update;
  - **YUB-YEC-1-64** reviewed the AH Reactor Cable Replacement;
  - **YUB-YEC-1-65** reviewed the AH3 Lube Oil Pump Battery Installation; and
  - **YUB-YEC-1-66** reviewed the Aishihik Black Start Modifications.

- **Communications Upgrades ($1.003 million):** The project will replace end of life communications infrastructure with new technology and provide a simplified network infrastructure that will increase performance, improve reliability of the network and support future modernization projects. A Communication Needs Assessment undertaken by an independent consultant in 2016 recommended improvement of critical elements as well as network performance, reliability, redundancy and security. A proposed system design was provided with recommendations for staged implementation focusing on the most critical assets or initiatives first. The need for each planned upgrade was addressed versus the do-nothing alternatives. Each specific upgrade comes into service (and into rate base) when completed – with a total of approximately $1.003 million forecast capital costs for upgrades to be completed by the end of 2018.

answered and in connection with doing our year-end procedures, we reviewed that life cycle and reflecting on what happened with the origin install in that it lasted 40 years, we determined that that depreciation period was probably not appropriate for that asset, so we corrected that depreciation down to 40 years, and we will reflect that correction in the compliance filing."

The business case for this project, including estimated costs for work completed before the end of 2018, is provided in the Application at Section 5.2.1.4. Further relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

- **YUB-YEC-1-67:** Reviews basis for the work, inclusion of costs in rate base in test years, and any cost changes. This notes that there have been no cost changes from the estimates provided in the BBA assessment to the YEC forecasts other than the addition of YEC internal labour to support each project.
- **CW-YEC-1-37** & **YCS-YEC-1-7:** Reviews project benefits and notes that the project will increase performance[90] and improve reliability.[91]
- **UCG-YEC-1-16(d):** Provides the Executive Summary and Introduction for the referenced BBA report supporting the need for the communications upgrades.
- **JM-YEC-1-25:** Notes the proposed upgrades will not result in the retirement of the power line carrier communications system as it is still used for protection communication purposes and control redundancy.

- **Hydro Unit #WH4 Overhaul ($4.291 million):** Hydro Unit #WH4 is a critical hydro generation asset and a 10 year major overall is required as part of YEC's ongoing preventative maintenance program. During the replacement process the following additional replacement activities will also be undertaken: WH4 Rotor Spider Replacement to address stress cracks which require immediate and extensive repair; and WH4 Excitation Replacement (recommended following post-event analysis of two outages in 2014).

  The business case for the project, including estimated costs, is provided in Section 5.2.1.5 of the Application and includes a review of project elements, justification and costs. Further relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

[90] Current communications links to certain sites are barely large enough to carry essential information; the project will enable the transfer of more information allowing better analysis and decision making. Seeing grid statistics in real time allows significantly more proactive behaviors thereby extending the life of the assets. A major benefit of this increased performance is the ability of remote troubleshooting, saving staff substantial travel time.

[91] Having multiple paths to get data from site to site creates redundancy that will result in fewer outages and less travel to remote sites for troubleshooting. Having two links provides the ability to work on one link remotely with no downtime, something that would have previously taken two people (one on each end) combined with travel to the remote site. This currently occurs multiple times a year per site. This project will also allow for a full backup location for system control, so that a loss of the Whitehorse office does not result in a full loss of SCADA control of the grid. See Mr. Hall and Mr. Mollard TR: 469:9 to 472:20, and response to Undertaking #24 filed July 13, 2018.

- **YUB-YEC-1-68:** Provides an updated review of costs following substantial completion of the project as well as other related information. Part (d) details the tendering process used to award Andritz Hydro the contract to install the new rotor spider and to perform the 10-year overhaul.

- **JM-YEC-1-26:** Notes that due to the engineering and planning time required for an uprate of WH4, as well as the emergency nature of the repair, a new turbine design was not feasible for the project.

- **CW-YEC-1-38:** Notes that given the nature of the isolated Yukon grid, the reliability of generation assets is critical to providing dependable service to customers and that YEC aims to perform a major overhaul on hydro units every 10 years.[92] Major overhauls also provide an opportunity to inspect certain components that are otherwise inaccessible, offering key insights into asset health and the ability to remedy minor projects before they result in an in service failure.

- **Hydro Unit #MH2 Overhaul ($1.657 million):** The last 10-year overhaul was completed in 2002; YEC was able to defer the requirement for a major overhaul beyond the 10-year period as MH2 has not been run on a full time basis since 2011. However, certain components are now at end of life and a major overhaul is required in 2018 if the unit is to continue to be operated. A study regarding options for the future of the Mayo A facility was completed by KGS in 2016 and determined refurbishment of the facility to be the most optimal solution. Given that continued operation of the Mayo A facility was determined to be economic, the 10 year major overhaul and upgrades to MH2 are required to enable ongoing operation prior to the full Mayo refurbishment.

  The business case for this project, including estimated costs, is provided in the Application at Section 5.2.1.6. Further relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

  - **YUB-YEC-1-69:** Reviews operation of Mayo A and B, the operation of the two Mayo A units, options reviewed, and other related questions.

  - **Appendix 5.6 of the 2016 Resource Plan:** Provides the analysis showing that the continued operation of the Mayo A facility has been determined to be economic.

- **T&D Breaker Replacements ($1.350 million):** The business case for this project, including estimated costs for work to be completed by the end of 2018, is provided in the Application at Section 5.2.1.7. This provides a review of the

[92] The response notes that the 10 year timeframe could be modified depending on the actual usage of a specific unit; further, other utilities may have differing maintenance timeframes and on the nature of their assets and operating conditions which may allow for major overhauls to occur on a much less frequent basis.

project elements, justification, and costs, and notes that medium and high voltage breakers in YEC substations are required to be replaced as per the equipment manufacturer, both models of breaker are at end of life and have been phased out, making it difficult to find replacement parts. Replacement of these assets will also result in O&M savings estimated at about $30,000 every 3 to 5 years. The project will be capitalized as the breakers are replaced and put into service.

The response to CW-YEC-1-39 reviews the end of life assessment analysis conducted by YEC that demonstrates end of life; the response notes that based on the YEC condition assessment and the consequences assessment the risk to YEC is deemed unacceptable:

- The OEM assessment of the assets indicates that the existing assets are in medium to poor condition and demonstrating material reliability and performance declines from their historical condition with a low level of confidence that the equipment will perform well under normal operating conditions; and

- There are no longer ASEA parts available for these breakers and so damaged components could result in lengthy downtime.

- **T&D Line Replacements ($2.0 million for work completed in test years):** The business case for this project, including estimated costs for work completed to the end of 2018, is provided in the Application at Section 5.2.1.8. This section provides a review of the project elements, justification, and costs and notes that the project addresses replacement of key components for YEC transmission lines which are approaching the end of their economic life. YEC commissioned an external asset assessment which indicated a large number of cross arms and insulators are at end of life and have a high risk of failure. CW-YEC-1-40 provides a copy of the external assessment undertaken as well as documents and instructions provided to the entity conducting the assessment. The alternative to proceeding with the project is to respond to structure and component failures as they occur which may lead to significant reliability impacts and higher overall costs as well as employee health and safety risks related to emergency response work.

  The project will be carried out over five years to complete the required replacements beginning in 2018 and has a total cost of $11.5 million with forecast spending in the 2018 test year of $2.0 million.

- **Wareham Spillway Gate Hoist Replacement ($2.700 million):** The business case for this project, including estimated costs and options reviewed and the basis for the preferred option, is provided in the Application at Section 5.2.1.9, and notes that the hoist was determined to be at end of life through both internal review and external assessment. The project was completed in 2015 with a total cost of $2.7

million. UCG-YEC-1-21(a), (b) and (c) provides project cost information, including total project cost from conception to completion and an annual breakdown by project component. Part (d) provides the referenced International Quest Engineering study dated March 22, 2014.

### 3.1.3 INVESTMENTS TO ADDRESS CAPACITY PLANNING REQUIREMENTS

The 2012/13 GRA identified the continued need for investments to address capacity planning requirements and the 2016 Resource Plan identified a near term dependable capacity shortfall that needs to be addressed [at 6 MW in 2017 and 8 MW in 2018 and increasing to about 13 MW by 2020 and 23 to 24 MW by 2021]. The 2017-18 GRA identified a shortfall of 7.6 MW in 2017 and 8.7 MW in 2018 under the single contingency (N-1) criterion.[93]

Yukon Energy is required to provide sufficient dependable winter capacity to meet the single contingency capacity reliability criterion as well as the Loss of Load Expectation (LOLE) criterion. There is no acceptable "do nothing" option given the need to maintain reliable service, and permanent solutions are needed to address an ongoing and growing dependable capacity shortfall. There is also no basis to defer introduction of a cost effective resource to address the dependable capacity shortfall.[94]

The Application and IR responses note the following actions taken by YEC in the near term to address the capacity shortfall:

- Yukon Energy installed mobile diesel units in 2017 as a short term solution. UCG-YEC-2-19 reviews mobile diesel unit installs in 2017 and 2018, as well as the resulting change to the forecast dependable capacity shortfall [see also CW-YEC-2-8 re: mobile diesels].[95]

- Planning is proceeding to install 4.4 MW of new LNG generation capacity at Whitehorse to partially address the capacity shortfall. The response to UCG-YEC-2-19 indicates that this unit is now expected to be in-service in Q4 2018.

[93] The dependable capacity is reduced to 76.7 MW for the N-1 event (assumes 37.0 MW at Aishihik and 1.3 MW at Haines Junction are not available at Whitehorse because of an interruption to the Aishihik transmission line with the N-1 event). This remaining reliable capacity is available under the Single Contingency (N-1) criterion to meet the projected non-industrial grid winter peak load (excluding an estimated 1 MW at Haines Junction that is not supplied by the grid under N-1) of approximately 84.3 MW in 2017 and 85.4 MW in 2018 (see Table 2.2; for 2017 and 2018, the Minto mine peak load of 6.5 MW is removed for this assessment, as well as the assumed 1 MW peak load at Haines Junction).

[94] CW-YEC-1-41 (a)

[95] The response to CW-YEC-2-1 and UCG-YEC-2-18 also provide preliminary actual sales and generation for 2017.

- Other capacity-based resource options intended to bridge the current dependable capacity shortfall under the Single Contingency (N-1) criterion are defined in the Resource Plan short term action plan.[96]

The two projects that have been completed in order to address capacity planning requirements are outlined below. Each of these projects has been appropriately justified, properly managed and the related costs should be included in approved rate base. The remaining project (LNG Third Engine) is not forecast in the GRA to be completed in the test years and therefore does not impact rate base for the Application (even though recent updates suggest that this project may now be completed prior to the end of 2018).

- **Whistle Bend Supply/ Takhini Upgrade ($11.383 million):** The 2012/13 GRA identified a requirement to appropriately reinforce the 25 km line L172 between Takhini and Whitehorse; the 2012/13 GRA also noted that the development of a major new subdivision in Whitehorse (Whistle Bend Subdivision) would be connected to the Yukon grid after the test years. Yukon Energy worked with the developer and AEY to determine an approach to connecting the subdivision to the grid that would ensure adequate supply and overall system reliability and protection.

  The business case for this project, including project elements, justification and estimated costs, is provided in the Application at Section 5.2.1.10.[97] Work was completed over three years with final connection occurring in early 2015. Total project costs were approximately $11.4 million [$0.600 million less than the original budget amount]. The favourable budget variance was due to effective use of internal YEC staff as well as the installation of a substation bypass which enabled reduced diesel generation and greater schedule flexibility.

- **LNG Plant ($23.633 million net of contributions):** YEC proceeded with the Whitehorse Diesel Natural Gas Conversion Project (LNG Project) as the least cost option to address a capacity shortfall due to planned retirement of two Mirrlees units at the Whitehorse Thermal Generating Station. The project was undertaken subsequent to a period of extensive and unprecedented expansion of YEC's renewable energy capacity and project planning occurred in the context of grid energy load forecasts that were then accepted for GRA and other planning purposes.

  The project was completed and in service in July 2015 at a total project cost of $41.93 million (prior to the $18.3 million YDC contribution). The business case for the project was reviewed in detail at the LNG Part 3 Proceeding and is

[96] CW-YEC-1-10 (a) notes the N-1 criterion excludes industrial loads and construction of new assets for this purpose cannot be attributed to industrial activity.

[97] UCG-YEC-1-22 provides project cost information and notes that the cost information included in Section 5.2.1.10 did not include 2012 spending of $0.153 million; and clarifies that actual total project costs are $11.537 million as noted in the response [and not $11.383 million as noted in Tab 5].

summarized in Section 5.2.1.11 of the GRA Application, which also provides a summary of factors accounting for the $5.45 million cost increase since the 2014 Part 3 LNG proceeding (this is also summarized in the response to UCG-YEC-1-23 (a through e).

Two broad issues have been addressed during this proceeding as regards this project:

(a) The continuing economic feasibility of the project given various changes since the Part 3 proceedings; and

(b) The prudence of the capital costs incurred given the $5.45 million capital cost increase since the Part 3 proceeding.

The LNG Project was justified as providing required new capacity (to address the capacity shortfall from retirement of two Mirrlees diesel units), with forecast fuel cost savings from LNG use to displace diesel that would more than offset the added capital costs for installing new LNG (with related LNG storage, vapourization and other facilities) versus new diesel located in the existing Whitehorse diesel plant.

Ratepayer cost savings from the LNG Project are tied to savings from displaced LTA diesel generation (as used for GRA forecasts), which in turn are tied to overall grid loads (i.e., LNG Project cost savings increase with higher loads) and the extent to which other resource option development occurs (i.e., LNG Project cost savings decrease with other resource development that reduces LTA thermal generation at any given load).

Since the project's development, the requirements for new capacity have been confirmed and currently constitute a major ongoing challenge for the Yukon grid. Delivered fuel costs for LNG have also been confirmed to provide fuel cost savings relative to diesel generation, with improvements in this regard as LNG supply has been developed in northern Alberta (Elmworth) and northern B.C. (Dawson Creek). In addition, no other new generation resource development has occurred to adversely affect the economics of this project.

Subsequent to the Part 3 proceeding, several material changes occurred to affect the project economics including:

- Regulatory delays and change requirements that delayed proceeding on the planned schedule and design, and resulted in major increases in capital costs relative to prior forecasts;

- Reductions in grid energy loads (and therefore in long-term average thermal requirements) which acted to reduce the opportunity for fuel cost savings with LNG versus diesel generation;

- Delays in securing lower haul cost options for LNG supply to YEC, which increased LNG delivered costs and reduced savings from LNG use versus diesel;

- Decreases in diesel fuel prices for YEC, which acted to reduce savings from use of LNG versus diesel; and

- YDC capital contribution that in effect removed any capital cost penalty for this initial LNG project relative to the new diesel alternative that would otherwise have been implemented.

The capital cost contribution has reduced the final rate base cost for the LNG Project to a level where there is no incremental capital cost penalty relative to the original new diesel alternative. On this basis, ratepayer savings are assured from this project so long as LNG fuel costs continue to be lower than diesel fuel costs – and the project's overall benefits to ratepayers are confirmed.

The evidence also confirms that the capital costs incurred, including the $5.45 million increase over the prior estimate, were prudently incurred to address regulatory delays and changes that YEC could not reasonably foresee, which YEC was required to address, and which YEC addressed in a prudent and reasonable manner to control costs and complete the project as required.

Finally, the evidence confirms the continuing financial feasibility of the overall LNG Project with the Third LNG Engine (as it is currently expected to cost), taking into account actual grid loads and fuel prices (which reduce LNG cost savings compared to the Part 3 hearing forecasts) as well as actual project costs excluding the YDC $18.3 million contribution (see response to Undertakings #12 and #13).

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

- **YUB-YEC-1-70:** Reviews the final costs for the LNG project, and factors accounting for the cost increase (as well as any other relevant considerations). Table 1 addresses demolition costs, transportation and FN benefit costs. Updated cost estimates for the 3rd engine are provided in response to YUB-YEC-1-71.

- **YCS-YEC-1-8:** Reviews the prudence of proceeding with the LNG project, changes since the Part 3 hearing that have affected project economics. The response also reviews the regulatory risks related to undertaking the project and notes that regulatory risks were clearly identified in the Part 3 Application for the project and discussed in detail in interrogatory responses and at the oral hearing; the draft YESAB Screening Report issued prior to the Part 3 hearing did not indicate any major environmental issues that threatened proceeding with the project and subsequent issues relating to the final report and decision body approval delays were not foreshadowed in the draft report; and in contrast to the YESAB process, YOGA's requirements were being newly developed as the project proceeded and directions that created requirements for last minute material and costly changes in the project could not reasonably have been forecast based on established Canadian criteria applicable to similar projects.

- **JM-YEC-1-27:** Reviews Part 3 Proceeding forecasts and subsequent outcomes relating to capital costs, delivered costs and grid load requirements through the 2017 and 2018 test years, including updates to the table and figure used in the Part 3 proceeding to review the project's overall economic costs and benefits. Based on all changes since the Part 3 proceeding, including the YDC capital contribution, all fuel cost savings from the project now represent growing net economic benefit to ratepayers.

- **Undertakings #12 and #13:** As filed July 3, 2018 update both Figures 1 and 2 from JM-YEC-1-27 in order to include the third LNG engine as at January 1, 2019 (at the updated capital cost of $8.9 million), and provide an assessment of full 2015-2019 year operations based on actual LNG Project capital costs without the YDC grant, actual grid loads (with updated forecast for 2018 plus forecast for 2019), and actual LNG and diesel delivered prices (through to April 2018). Looking at overall financial feasibility over the 40-year life of the LNG assets, the analysis shows the following:

    - With the YDC contribution specifically and only for the LNG Project, the added capital cost for LNG (with the Third LNG Engine) of approximately $0.4 compared to New Diesel is fully recovered by 2017; and

    - Removing the LNG advantage as regards the YDC contribution and leaving an added capex with LNG compared to New Diesel of $18.7 million, approximately $3.9 million of this added cost is recovered by the end of 2019 in the analysis. Based only on the $2.1 million net ratepayer cost saving (after provision for depreciation and return) forecast in the last year shown (2019), and assuming that at least this much saving per year will be earned over the decade after the Eagle Gold mine connects in 2019, the balance of the added capex with LNG will be recovered within the next 7.2 years, i.e., within the expected life of the Eagle Gold mine, and well within the 40 year expected life of the LNG assets.

- **LNG Third Engine (no impact on forecast test year rate base):** The LNG Third Engine project is required to meet ongoing capacity requirements and the dependable capacity shortfall forecast in Yukon Energy's 2016 Resource Plan and the GRA's Tab 2 forecasts. There is no acceptable "do nothing" option given the need to maintain reliable service, and permanent solutions are needed to address an ongoing and growing dependable capacity shortfall. There is no basis to defer introduction of a cost effective resource to address the current dependable capacity shortfall. The LNG Third Engine is the first new resource identified for in service that can address a portion (4.4 MW) of the dependable capacity gap. Regulatory reviews have been concluded for the project,[98] with an additional option review in late 2016. As indicated in the 2016 Resource Plan, the project is a cost effective addition to dependable capacity and is able to be in service sooner than other identified options.[99]

  The business case for this project, including project elements, justification, and estimated costs, is provided in the Application at Section 5.2.1.12. The project was originally forecast to be completed in 2019, however, this has been updated to Q4 2018.[100] However, this project continues to have no impact of forecast test year rate base costs.

  Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

  - **YUB-YEC-1-71:** Provides updated costs for the project, including the initial forecast cost, updated forecast cost, variance and explanation for changes from the initial forecast.

  - **CW-YEC-1-41:** The 2016 Resource Plan justification for the project, review of options, and related information.

  - **John Maissan-YEC-1-28**: Provides the basis for the option review, preliminary engineering and development equipment specifications, grid impact and detailed engineering studies. Notes dependable energy and capacity that would be provided from the LNG plant with the project.

  - **UCG-YEC-1-24:** Provides key references relevant for determining the prudence of costs incurred for the project.

[98] UCG-YEC-1-24(d) notes YESAB and Public Utilities Act Part 3 regulatory reviews were completed; permit amendments will be required under the Environment Act (air emissions permit) and the Yukon Oil and Gas Act (LNG Facilities Licence).

[99] CW-YEC-1-41. See also Portfolio Analysis (Chapter 8) and Action Plan (Chapter 9) of the 2016 Resource Plan for details on the methodology and alternatives examined that led to the recommendation of the LNG Third Engine as part of the Short Term Action Plan.

[100] UCG-YEC-2-18.

## 3.2 MAJOR DEFERRED COST PROJECTS

As set out in Section 5.3.1 of the Application, nine major deferred cost projects are identified that reflect sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance), investments to ensure sufficient dependable capacity for the integrated grid, and continued planning expenditures to meet other potential future generation and transmission requirements.

Rate base growth of $64.9 million over 2013 approved costs includes $9.8 million from three major deferred cost projects (DSM, Resource Plan Update, and Gladstone Diversion Project).[101] Ten other major deferred projects reviewed in the Application with costs forecast in WIP at the end of 2018 of over $35 million will not affect rate base in the test years.

Yukon Energy has described the planning approach, or stagegate project development framework, used to advance major projects from early planning to commissioning.[102] A summary of the stagegate framework is also provided in the Planning Cost Accounting policy included in the Application, in Appendix 5.1, page 5.1-3. This approach requires a review of the project by the Board of Directors at each decision point referred to as "Stagegate". "Stagegate 3" is a Board of Directors review and go/no go decision based on preliminary engineering, socio-economic and environmental assessments, First Nation engagement and public engagement, and defining of a procurement strategy.

### 3.2.1 SPENDING ON SUSTAINING CAPITAL

Deferred cost spending on Sustaining Capital projects >$1 million has no net rate base impact in the test years, with net deferred costs in WIP by end of 2018 forecast at approximately $2.899 million. Spending relates to the following major projects:

- **Stewart-Keno City Transmission Project (no net impact on forecast test year rate base)**: $2.807 million in rate base by the end of 2016 for planning and permitting is fully offset by contributions. The project will improve electrical transmission infrastructure in central Yukon between Stewart Crossing and Keno City; reinforce and strengthen the grid between Stewart Crossing and Mayo and replace and remove deteriorated and end of life transmission infrastructure between Mayo and Keno City. The project is being planned to ensure continued safe and reliable service and to facilitate future economic development within the territory.

[101] Deferred costs referenced are net of contributions, but prior to any amortization occurring during or prior to the test years. Final impacts on mid-year rate base in each test year are net of all amortization up to the end of 2018.
[102] YUB-YEC-1-78(f).

Section 5.3.1.1 of the Application reviews the project concept, risks, costs and benefits and reviews work undertaken to date. Costs incurred to date relate to work required to get the project to a shovel ready state and costs to date are fully covered by government contribution. Further information is provided in YUB-YEC-1-76 and YCS-YEC-1-7.

- **Aishihik Generating Station Water Use Licence Renewal (no impact on forecast test year rate base):** Total deferred costs of $2.899 million to end of 2018, remains in WIP with projected completion in 2019. The Aishihik Generating Station water use licence was last renewed in 2022 for a 17 year period and will expire at the end of 2019. A licence renewal is required for the continued operation of the 37 MW hydro facility, which provides the only multi-year hydro storage and largest winter peak hydro generation capacity on the Yukon Integrated System.

  Section 5.3.1.2 of the Application reviews the project concept, risks, costs and benefits and reviews work undertaken to date. Further information is provided in the response to YUB-YEC-1-77 and UCG-YEC-1-32.

### 3.2.2 SPENDING TO ADDRESS CAPACITY PLANNING REQUIREMENTS

The 2016 Resource Plan identified a dependable capacity shortfall for the Yukon Integrated System under its single contingency (N-1) capacity reliability criteria that approximates 6 MW in 2017 and increases to about 13 MW by 2020. Yukon Energy is required to provide sufficient dependable capacity to meet the single contingency reliability criterion and there is no acceptable "do nothing" option given the need to maintain reliable service. Permanent solutions, rather than temporary options, are needed to address this ongoing and growing issue.

Deferred cost spending on projects >$1 million to address capacity planning requirements has no net rate base impact in the test years, with net deferred costs in WIP by end of 2018 forecast at approximately $13.067 million. Spending relates to the following major projects:

- **Battery Project (no impact on forecast test year rate base):** Forecast WIP cost of approximately $8.856 million by the end of 2018 for planning, engineering, permitting, long-lead equipment procurement, and civil work. The project will provide a Battery Energy Storage System (BESS) to assist in addressing the current dependable capacity shortfall in a cost-effective manner over the near term. The 2016 Resource Plan identified construction of the BESS as one of the preferred options for addressing a portion of the dependable capacity gap. Section 5.3.1.3 of the Application reviews the project concept, risks, costs and benefits and reviews work undertaken to date. Further information is provided in the response to YUB-YEC-1-78; CW-YEC-1-42(c); JM-YEC-1-31; and YCS-YEC-1-9.

- **Thermal Plant Project (no impact on forecast test year rate base):** Forecast WIP cost of approximately $4.211 million by end of 2018 for planning, engineering, permitting, and long-lead equipment procurement, with project planned for completion in 2020. The thermal plant will provide up to 20 MW of new diesel or natural gas thermal generation capacity to assist in addressing the current dependable capacity shortfall in a cost-effective manner. Forecast spending during 2017 and 2018 includes planning, preliminary engineering, environmental permitting and the start of detailed design for the project. Section 5.3.1.4 of the Application reviews the project concept, risks, costs and benefits and reviews work undertaken to date. Further information is provided in the response to YUB-YEC-1-79; CW-YEC-1-42(d); JM-YEC-1-32; and YCS-YEC-1-13.

### 3.2.3 SPENDING ON PLANNING TO MEET OTHER POTENTIAL FUTURE GENERATION AND TRANSMISSION REQUIREMENTS

The 2012/13 GRA identified deferred capital expenditures for planning and feasibility, relicensing and regulatory costs, including near term generation projects (such as DSM and hydro storage enhancement projects at Mayo Lake and Marsh Lake) and longer term renewable generation projects (e.g., hydro and wind).

Deferred cost spending on projects >$1 million related to planning to meet other potential future generation and transmission requirements has a net rate base impact increase of approximately $9.845 million by the end of 2018, excluding reductions due to amortization in the test years. Net deferred costs in WIP by the end of 2018 is forecast at approximately $11.512 million. Spending relates to the following major projects:

- **Demand Side Management (DSM) ($3.319 million):** DSM accounts for a $3.319 million net increase in rate base costs by end of 2018, excluding reductions due to amortization. Tab 5, Section 5.3.1.5 of the Application reviews the DSM program elements, costs and benefits of implementation. Further information regarding the DSM program is also provided in YUB-YEC-1-80, YCS-YEC-1-14 and JM-YEC-1-3. Specifically, the DSM program planning process is outlined in response to YUB-YEC-1-80(g); and YUB-YEC-1-80(f) provides annual DSM expenditures by program by year from 2011 to 2016 (actual) and 2017 and 2018 (forecast). In summary, DSM costs are prudently incurred and it remains a relatively low cost supply option compared to other available near term supply options being reviewed.

    - The Five Year DSM plan for the Yukon developed by YEC and AEY was presented for review as part of AEY's 2013-15 GRA. Order 2014-06 approved the 2014 and 2015 program elements of the residential non-government DSM portfolio that pass all of the four cost-effectiveness measures.[103] The Application, page 5-40 provides a summary of energy savings and costs updated to the end of 2016 and reviewed by a third party evaluation advisor. Evaluation reports by the third party evaluator for 2015 and 2016 are attached to UCG-YEC-1-40(a). The evaluations demonstrate that the DSM programs have been well received and key performance indicators have been met or exceeded. Yukon Energy plans to continue delivery of the approved inCharge program for the test years.[104] Section 5.2.1.5 reviews programs included in the Application.[105]

- The 2016 Resource Plan recommends that additional DSM programs provide a cost effective way to meet energy and capacity demand and should be included in the proposed future portfolio and energy supply projects. Starting in 2018 YEC plans to start the development of new DSM programs including peak load reduction programs.[106] Further explanation of the current and future DSM programs is provided in Section 5.3.1.5 of the Application, as well as in the response to YUB-YEC-1-80. Additional DSM programs must be designed prior to submission to YUB for approval. Consequently, the Application includes $0.190 million for new program development in 2018. As noted, all new DSM programs will be filed with the YUB for review in advance of delivery.

  DSM programs, costs and related issues are reviewed in the following IR responses: YUB-YEC-1-80; YCS-YEC-1-14; UCG-YEC-1-10,[107] UCG-YEC-1-40; JM-YEC-1-3 and JM-YEC-1-3.[108]

  YUB-YEC-1-82 and YUB-YEC-1-75 review the DSM accounting policy. These note that the policy is essentially unchanged from the version reviewed as part of the 2012/13 GRA; and confirm that the policy addresses only the

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[103] Per Application page 5-39, this included LED and Block Heater Timer rebate program; the Low Cost Energy Efficient Products program; and Education, Engagement and Communications activities to make customers aware of DSM program opportunities and conservation in general.

[104] YCS-YEC-1-14(a)

[105] This includes Industrial DSM (net cost to 2016 of $0.082 million); Pilot DSM Projects (net cost to 2016 of $0.051 million, including a contribution of $0.500 million from YDC, with costs to contribute to Yukon Government's commercial lighting program of $0.020 million in 2018); LED Streetlight retrofits (net cost to 2016 is $0.142 million and cost for retrofitting the streetlights in Dawson and Mayo in 2016 of $0.168 million and cost to complete retrofits of $0.080 million in 2018); Internal Energy Conservation (cost up to 2016 of $0.353 million and cost for 2018 of $0.025 million); and administration ($0.397 at the end of 2016 and $0.020 in both 2017 and 2018).

[106] Per section 5.3.1.5, this process will include residential and commercial customer end use surveys, update to the Conservation Potential Review (CPR) model to inform DSM program design, development of in-house capacity to use the CPR model to extract data for resource planning and program design purposes and undertaking a capacity DSM feasibility study to quantify the potential achievable uptake for capacity-focused DSM.

[107] Confirms that all DSM costs will be subject to a prudence review by the YUB prior to being recovered in rates and provides details of DSM-related expenditures from 2013 to 2016 and 2017 and 2018 forecast and their corresponding percentage of total revenue requirement for those years.

[108] Notes YEC is planning to conduct the capacity DSM feasibility study in 2018 to help design a suite of new peak load reduction aimed DSM programs to compliment the existing in Charge program. YEC is also involved in the electric thermal storage (ETS) pilot project with the Energy Solutions centre.

accounting treatment of DSM costs. For deferred costs to be included in rates these costs must first be reviewed by the Board as part of a GRA process. YEC is required to file an application with the YUB any time it seeks to adjust rates due to changes in revenue requirement.

- **Resource Plan Update 2016 ($2.004 million):** The 2016 Resource Plan accounts for a $2.004 million net increase in rate base costs by end of 2017, excluding reductions due to amortization. Tab 5, Section 5.3.1.6 reviews the history of the resource planning process [dating back to the 2006 20-Year Resource Plan; and the 5-Year Update undertaken in 2011], as well as the key activities underlying the costs for the 2016 Resource Plan. The 2016 Resource Plan document was provided as Volume 2 of the GRA Application (absent the appendices). The Appendices were filed as response to YUB-YEC-2-29.

  YUB-YEC-1-83 notes that in comparing the cost of the 2016 Resource Plan update with the 2011 Resource Plan update, the 2011 update costs do not reflect the extensive separate and concurrent consultant assessments then carried out for a range of specific resource options (these separate study costs were reviewed during the 2012/13 GRA). In contrast, scaled down versions of similar assessments were addressed in the costs directly reported for the 2016 update. The 2016 resource plan also include added features as reviewed in detail in the response to YUB-YEC-1-83(c).[109]

  A detailed comparison of the 2011 and 2016 Resource Plans in terms of planning principles, methodology, assumptions and conclusions and recommendations is provided in Section 1.6 of the 2016 Resource Plan and summarized in the response to YUB-YEC-1-83(d). In summary, findings were influenced by the added features (noted in YUB-YEC-1-83(c)) as well as other factors such as updates to existing unit capabilities and expected retirement dates, load forecast updates and updated information regarding each of the resource options/ technologies considered.

  A number of specific questions were asked regarding information included in the Resource Plan and responses were provided as follows: CW-YEC-1-1; CW-YEC-1-2; CW-YEC-1-3 to CW-YEC-1-10; YCS-YEC-1-1; YCS-YEC-1-3; YCS-YEC-1-5; and UCG-YEC-1-6.

- **Gladstone Diversion Project ($4.521 million):** Closure of the Gladstone Diversion Project accounted for $4.521 million net increase in rate base costs by start of 2017 (as a result of proceeding with this GRA). This project was extensively reviewed in the 2012/13 GRA review process and commented on by the Board in Order 2013-01. Section 5.3.1.2 of the 2012/13 GRA Application reviewed the

[109] Established models were specifically applied to the Yukon for assessing load forecast scenarios; examination of a wide range of resource options; industry standard capacity expansion optimization model for portfolio analysis; social cost of carbon applied to economics; environment, social and economics evaluation; and more extensive public engagement process.

project concept, risks, costs and benefits, and review work undertaken to that point. The 2017/18 GRA Application, Tab 5 section 5.3.1.7 provides an update regarding project costs incurred since the 2012/13 GRA, the decision making process, and factors underlying the decision not to proceed with the project. Expenditures since the 2012/13 GRA were prudently incurred and YEC immediately ceased work on the project once it was clear that local First Nations did not support the project.

Further information for determining the prudence of costs incurred for this project is available in the following interrogatory responses for this proceeding:

- **YCS-YEC-1-12 –** Discusses the identification of permitting issues for the project. YEC was aware of the permitting challenges at the time of project initiation. Notwithstanding this risk, the forecast cost to execute the project would have resulted in very affordable energy for the grid (particularly in winter).

- **UCG-YEC-1-34 –** Provides references to relevant information for determining the prudence of costs incurred for this project on the record of this proceeding, or other public proceedings. The response provides updated costs; and outlines references for relevant information available to determine prudence of costs for the project on the record of current and prior proceedings.

- **YUB-YEC-2-30 –** Provides the dates and documentation indicating when YEC became aware that the Gladstone project would not receive DFO and First Nations support.

The YUB has previously reviewed the justification for this project and concurred that pursuit of this extra water made sense as long as there is economic benefit to ratepayers [YUB 2013-01, Reasons for Decision, p.344].[110] YEC during the 2012/13 GRA proceeding stipulated that ongoing work would be conditional on securing First Nation support for the project.[111] As both affected First Nations have indicated that they will not support the project, YEC has concluded there is very low probability that the regulator will approve this project and has determined not to proceed with the project.

[110] In Order 2013-1 the Board noted, "The Board finds that this project has potential to be viable and directs that all project expenditures be held in WIP until the project is completed. Moreover, YEC is to cease work on this project if and when YEC concludes that there is no net economic benefit of the project to ratepayers". Yukon Energy has proceeded as outlined to the Board in the 2012/13 proceeding - this reflects a prudent risk management approach for the project.

[111] In the 2012/13 proceeding, YEC noted that risk and uncertainties respecting this project relate to regulatory risks and the need to resolve arrangements with the First Nation groups. 2012 activities were directed at addressing and resolving these risks, and future expenditures beyond 2012 were dependent on the success of these activities.

- **Marsh Lake Storage Enhancement Project (no impact on forecast test year rate base):** Forecast WIP of approximately $8.156 million by end of 2018, with project subject to ongoing review and potential in service by 2022. This project remains in WIP through the 2018 test year and has no impact on test year rates or rate base.

  This project was extensively reviewed in the 2012/13 GRA review process and commented on by the Board in Order 2013-01. Section 5.3.1.1 of the 2012/13 GRA Application reviews the project concept, risks, costs and benefits, and review work undertaken to that point. The 2017/18 GRA Application, Tab 5 section 5.3.1.8 provides an update regarding project costs incurred since the 2012/13 GRA, and the decision making process.

  Further information is available in the following interrogatory responses for this proceeding:

  - **YUB-YEC-1-84:** Provides a detailed breakdown and explanation of the actual costs and forecast costs for the Marsh Lake Storage project (renamed Southern Lakes Enhanced Storage Project).

  - **YCS-YEC-1-10:** review of mitigation measures and costs. Notes that to date, the estimated costs (and technical feasibility) of project mitigation have not resulted in rendering the Project non-viable.

  - **YUB-YEC-2-32:** Notes the project is still in planning stages with earliest in service in 2022 and will not affect lake levels or storage in the test years.

  To date, the estimated costs (and technical feasibility) of project mitigation have not resulted in rendering the Project non-viable. The project is subject to regular review via a stagegate decision process – as part of this process, the project will not be advanced unless it continues to be considered economically feasible taking into account all related risks regarding monitoring, mitigation, adaptive management, and the Whitehorse hydro facility relicensing requirements in 2025.

- **Mayo Lake Storage Enhancement Project (no impact on forecast test year rate base):** Forecast WIP cost of approximately $3.356 million by end of 2018, with project subject to ongoing review and potential in service by 2022.

  This project was extensively reviewed in the 2012/13 GRA review process and commented on by the Board in Order 2013-01. Section 5.3.1.4 of the 2012/13 GRA Application reviews the project concept, risks, costs and benefits, and review work undertaken to that point.[112] The 2017/18 GRA Application, Tab 5 section

[112] YEC determined after the 2012/13 proceeding that the silted outlet of Mayo Lake imposes constraints on flows out of Mayo Lake to the Mayo hydro facility during periods when Mayo Lake levels approach current license low supply levels. Updated information regarding delayed timing of the YESAB Project proposal filing was provided in the 2014 LNG Part 3 proceeding.

5.3.1.9 provides an update regarding project costs incurred since the 2012/13 GRA, and the decision making process.

Further information is available in the following interrogatory responses for this proceeding:

- **YUB-YEC-1-85:** Part (a) notes that the project proposal submission has not been re-filed at this time; part (b) notes the Mayo Lake Enhanced Storage Project (MLESP) proposal includes a detailed monitoring and adaptive management plan (MAMP) co-developed with the First Nation of Na-Cho Nyak Dun. The required environmental monitoring has been minimized to only those key data necessary to maintain a suitable pre-project baseline for future use under the MAMP should the project proceed. Part (c) summarizes work undertaken and planned regarding the Mayo Lake Outlet Channel Erosion, Sedimentation, and Dredging Study, including costs for each phase. Part (d) summarizes NND involvement in work undertaken to date. Part (e) reviews actual and forecast costs (2016 to 2018 Forecast).

- **UCG-YEC-1-36:** References relevant information for determining the prudence of costs incurred for the project available for review on the record of the current proceeding, or other public proceedings.

The Stagegate Project Development Framework approach will be continue to be applied. Studies are planned for 2018 – following this work YEC will develop a suitable engineering design to remove the sediment and minimize the frequency of future re-dredging. At the end of 2018, once the business case information has been developed, YEC Board of Directors will review the information as part of a Stagegate and provide a go/no go decision. At this time the project continues to show potential benefits.

This project remains in WIP through the 2018 test year and has no impact on test year rates or rate base.

### 3.2.4 PLANNING COST ACCOUNTING POLICY

The changes to the Planning Cost Accounting Policy provided in Appendix 5.1 of the 2017/18 GRA compared to the Planning Cost Accounting Policy provided in the 2012/13 GRA were reviewed in the response to YUB-YEC-1-75 and again in Undertaking #29. In order to facilitate review of changes, a blackline of the new Planning Cost Account Policy compared to the 2012/13 version was provided as Undertaking #29 Attachment 1.

The Board in Order 2013-01 noted that it did not accept the planning cost accounting policy [see paragraph 405 of Order 2013-01]. Order 2013-01 notes the Board and interveners must be given the opportunity to test the prudence of all costs incurred by

YEC in respect of deferred costs "… and considered that "the policy as proposed would allow the inclusion of these costs without any prior scrutiny by the Board and interveners."

Yukon Energy is not seeking to, and has never intended to, include in rates any deferred or other costs that had not been subject to review and approval by the Board. Given there was significant confusion regarding this issue during the 2012/13 GRA, Yukon Energy made amendments to the policy to clarify this point.

The version of the policy provided as Appendix 5.1 of the 2017/18 GRA was revised to take into consideration the concerns raised by the Board in Order 2013-01; and wording was changed/ added to provide greater clarity compared to the provisions included in the 2012/13 GRA version of the policy [this applies in particular to section 2.1 and new section 2.2].

- **Section 4** was added to provide greater clarity that while YEC will close out and begin amortization of studies as prescribed by the policy, all deferred costs will be subject to a prudency review by the YUB prior to any change in customer rates.
- **Insertion of new Section 2.3:** Addresses how viability of planning cost projects will be assessed on an ongoing basis.
- **New Section 2.5:** Added to clarify how planning costs will be amortized in the event a project does not proceed. The 2012/13 version of the policy included provision for a "transition policy for 2012 & 2013 Test Years". This was considered a "one-time" transition approach for costs in WIP at that time and intended to mitigate rate impacts from 5-year amortization of existing WIP costs for projects incurred that exceeded $1 million. The new section 2.5 seeks to continue with this approach in order to continue to mitigate rate impacts from projects in WIP that are being closed out and that have costs in excess of $1 million.

## 4.0 RETURN ON EQUITY (ROE)

The basis for determining the return on equity (ROE) for Yukon Energy in 2017 and 2018 is reviewed in Tab 8 of the Application. This provides background regarding how ROE has historically been determined for YEC in this jurisdiction [section 8.1]; and a summary of the rationale for determining fair ROE for YEC of 8.82% in the test years.

**Yukon Precedent for Using BCUC Low Risk Utility Benchmark & Risk Premium**

Reference to a benchmark ROE for a low risk utility, with adjustments to reflect any specific added risks related to Yukon Energy, provides for continuity with prior Yukon proceedings and practice, and offers a simple, transparent and cost effective method to determine a consistent and fair return for Yukon utilities. The following is specifically noted in this regard:

1. Over the past decade the Board has confirmed its strong preference for using a simplified approach for determining ROE for Yukon utilities in order to ensure regulatory efficiency and reduce costs in a jurisdiction with a relatively small customer base.[113]

2. Board Order 2017-01 recently established use of the BCUC low risk benchmark ROE of 8.75% in Yukon, and confirmed that a risk premium should be applied to Yukon utilities relative to the BCUC low risk utility benchmark.[114]

    a. The relevant BCUC Orders were provided in response to YUB-YEC-1-52; these confirm the ROE for the benchmark utility of 8.75%,[115] and also provide the most recent BCUC determination for the equity risk premium over the benchmark utility for utilities more comparable to Yukon Energy: FortisBC Electric (FBC or FortisBC) and PNG-West.[116]

    b. Yukon Energy clarified in its review of the YUB hearing transcript [comments filed July 13, 2018] that review of the BCUC website has failed to identify any current or ongoing Stage 2 BCUC process. Consequently, the outcomes of Order G-47-14 which established a common equity component and equity risk premium over the benchmark utility for FBC and PNG-West remain relevant for determining the equity risk premium for Yukon Energy.

3. Order 2017-01 also established a risk premium of 0.25% for AEY noting that "in determining relative risk for AEY, the Board should look at size and generation risk".[117]

    a. With regard to **size** the Board noted that, "based on the evidence, the Board has determined that small size is the most significant factor to be considered in determining a risk premium for AEY," and "the evidence on

[113] See Order 2009-02 at page 28-29 notes as follows:

"The Board strongly agrees with the part of the YECL argument that states:

> The proposal to rely on the generic ROE as a point of departure was intended to be the most efficient means of addressing what is inherently a complex and costly matter, given the current state of ROE determination throughout Canadian regulatory jurisdictions.
>
> YECL covers a geographically dispersed area with a relatively small customer base. It is incumbent upon the Board to explore ways that yield regulatory efficiency and yet provide fairness to all interested parties. In this regard, the Board supports a formula based approach to determining ROE issues."

[114] YUB-YEC-1-52 provides copies of BCUC decisions and Orders G-158-09, G-75-13; G-47-14; and G-129-16.

[115] BCUC Order B-75-13 established a common equity component and a ROE for the benchmark utility (FEI or FortisBC Energy) of 40% and 8.75% respectively, effective January 1, 2013. BCUC Order G-129-16 confirmed no change in the common equity component or ROE for the low risk utility, effective January 1, 2016.

[116] BCUC Order G-47-14 established a common equity component and equity risk premium over the Benchmark utility, effective January 1, 2013 for FortisBC Electric (FBC or FortisBC) (40% common equity and 40% risk premium) and for PNG-West (46.5% common equity and 75% risk premium).

[117] Order 2017-01, page 41, para 211.

this record shows that BCUC has set a premium for a small size utility at 25 basis points."

b. With regard to **generation risk** the Board noted that, "although FortisBC Electric is larger than AEY, its generation assets are a quantum level higher than the generation assets of AEY" and "the Board does not find generation to be a significant risk for AEY in relation to the risk of FortisBC."

As outlined in further detail below, similar to AEY, Yukon Energy is a small utility compared to FEI or FBC, and warrants a risk premium over the benchmark on that basis. Generation risk also is a key risk for YEC which differentiates it from comparable BC utilities as well as AEY; YEC has significantly higher generation (100% of supply requirements) than FortisBC Electric (45% of supply requirements) and AEY (9% of supply requirements).

**Basis for Yukon Energy Equity Risk Premium**

Yukon Energy's Application has relied on the simplified approach for determining the appropriate risk premium for Yukon utilities that has been approved by the Board in 2005 (Order 2005-12) and in 2008 (Order 2009-2 and Order 2009-8).[118] These prior reviews have considered FBC and PNG-West to be comparable utilities for determining Yukon Energy's risk premium; and the risk premium for YEC was determined based on the mid-point of the range between FBC and PNG-West. The range was considered reasonable as Yukon Energy was considered more risky than FBC (at the lower end of the range) and less risky than PNG-West (at the top end of the range). This simplified approach would result in a risk premium of 57.5 basis points and an ROE for YEC of 8.82%.

Evidence to support the risk premium sought by YEC and its level of risk relative to the benchmark utility, FBC, PNG-West and AEY was reviewed in detail in the Application, IRs, in testimony at the oral hearing, undertakings and interrogatories on undertakings. The following is specifically noted:

1. Evidence filed for prior Yukon Energy applications as well as for the current Application has supported that Yukon Energy has a higher risk relative to FBC based on utility size of operations (revenues, rate base, customers) and financial structure (capital structure), and nature of business (e.g., exposure to generation-related risks, including hydroelectric generation, and industrial customer loads). Yukon Energy provided updated information regarding these factors for FBC and PNG-West in Table 8.1 and 8.2 of the Application. This information confirms the continuing applicability of the current approach.

2. YUB-YEC-1-53 provides further detail supporting the rationale for using FBC and PNG-West as comparable utilities for determining Yukon Energy's risk premium above the low risk utility ROE, noting that Yukon Energy is less comparable to the

[118] Order 2005-12 and Order 2009-8 approved a risk premium of 52% for Yukon Energy based on being at the mid-point of the range between FBC (40%) and PNG West (65%).

low risk benchmark utility (FEI) and in certain cases more comparable to FBC and PNG-West. The information provided demonstrates that YEC is much smaller compared to FEI (the low risk benchmark). YEC's customer count and rate base are also smaller than FBC; while, the financial structure for both YEC and FBC is the same (40% equity).

3. YUB-YEC-1-56 (b) reviews key factors that have been considered in prior reviews to determine YEC's risk relative to comparable BC utilities [FBC and PNG-West] and that remain applicable for determining the risk premium for YEC at this time. This includes the following factors:

   a. **The isolated nature of the Yukon Grid –** Unlike BC utilities, YEC operates on an isolated grid and cannot purchase power from other electrical systems or sell surplus power into such systems. This is a critical risk for YEC that sets it apart from other southern utilities as well as AEY.

      Follow up questions on YEC Undertakings [YUB-YEC-3-5] provides additional detail related to FBC's power supply context and arrangements with BC Hydro and notes that the context for FBC is very different and less risky than YEC. The power supply context for FBC was also reviewed in Undertaking #38 and Undertaking #39 as well as the following follow-up questions on YEC Undertakings: YUB-YEC-3-3,[119] YUB-YEC-3-4,[120] and YUB-YEC-3-6.[121]

      - **FBC is insulated from hydrology risk under the Canal Plant Agreement (CPA):** FBC's resource stack includes four existing hydro plants operated under the CPA with BC Hydro directly dispatching and FBC receiving guaranteed entitlement to energy and capacity provided that the generating plants are available to be dispatched. FBC has a long-term contract to purchase the whole output of the four hydro generating units of the Brilliant Plant, which is also a CPA entitlement plant.

      - **FBC has other supply arrangements not available to Yukon Energy:** This includes a Power Purchase Agreement with BC Hydro, capacity blocks from the hydro Waneta Expansion project, and

[119] Reviews the Power Purchase Expense Variance Deferral Account [PPEVDA] and clarifies that the relevant provisions continue to operate in non-test years. The response notes that the account was discontinued by Decision G-138-14, but that per the Decision, the expenses and revenues related to the PPEVDA would continue to be flowed through to ratepayers each year through the annual flow-through mechanism.
[120] In addressing variances due to water variability for FBC, it is necessary to understand the context of FBC's hydro power supply arrangements with BC Hydro, the BCUC-approved cost flow through mechanisms and the extent that these arrangements collectively remove risk from FBC related to water variability cost impacts.
[121] Notes that FBC is not exposed to water risks that would merit or require a specific and separate deferral or contingency account mechanism similar to the DCF. Accordingly, the absence of a specific FBC deferral account similar to the DCF is of no importance when comparing risks for FBC relative to YEC.

the ability to import electricity from the Mid-C market via existing transmission connections.

In summary, FBC is not on an isolated grid, and is not exposed to the same thermal cost risks that YEC is exposed to given that FBC has access to renewable generation resource options available on BC's integrated grid system.

b. **Yukon Energy is the main generator and transmission utility for Yukon –** Generation risk is a key risk for YEC that differentiates it from comparable BC utilities; YEC has significantly higher generation (100% of supply requirements) than FBC (45% of supply requirements) and AEY (9% of supply requirements).

   i. Yukon Energy is a vertically integrated utility with generation, transmission and distribution functions and must plan and generate the power required to serve the Yukon Integrated System (i.e., it cannot purchase additional power from outside the grid, and cannot sell surplus power to other jurisdictions).[122]

   ii. FortisBC Energy (FEI, the low risk benchmark) is a distribution gas utility with no generation. FBC [a vertically integrated electric utility that meets 45% of its load requirements with its own generation] is more comparable to Yukon Energy. However, Yukon Energy carries relatively more risk as it meets 100% of its load requirements with its own generation on an isolated grid.

   iii. Material difference in generation risk between YEC and FBC was reviewed at the oral hearing and in undertakings [see also response to YUB-YEC-3-5]:

      1. **Undertaking #38** notes that "FBC's existing resource stack offers a lot of options and protections not available to YEC, given FBC's location adjacent to BC Hydro and other power supply sources."

      2. **Undertaking #39** notes "FBC's existing resource stack includes four existing hydro plants operated under the CPA with BC Hydro directly dispatching and FBC receiving guaranteed entitlement energy and capacity provided that the generating plants are available to be dispatched. FBC's usage of its plants to meet system requirements is therefore insulated under the CPA from hydrology risk, but is still subject to plant outages. FBC also has a long-term

[122] YUB-YEC-1-55 notes YEC's hydro-based generation with new as well as old assets on an isolated grid displays a high level of generation risk.

> contract to purchase the whole output of the four hydro generating units of the Brilliant Plant, which is also a CPA entitlement plant. Other FBC supply arrangements that further reduce risk to FBC include a Power Purchase Agreement with BC Hydro, capacity blocks from the hydro Waneta Expansion project, and ability to import electricity from the Mid-C market via existing transmission connections."

The generation risk faced by YEC was addressed in detail in the oral hearing. The Panel was asked at page 461-62 whether the long term nature of the assets owned by a generator such as YEC (i.e., hydro assets), the cost of building these types of facilities, and the customer base (i.e., industrials) impact risk for the utility.

> A. MR. OSLER: Yes. And it ends up, in the Yukon Territory in particular, with isolated grid and variable industrial loads. Since Yukon Energy's been created, we've seen the degree of extra stress and variability that occurs for the generating utility, which is the Crown utility. It's capital intensive, it gets to have aged assets that are expensive to deal with, it has requirements to keep trying to develop new renewables rather than just settling back and accepting thermal because it's low risk to the utility compared to investing in things. So from my point of view, it certainly demonstrates why the simple assessment of extra risk from having generating assets and generating responsibilities would be recognized by the BCUC. Mr. Mollard can probably talk at more length and more specificity as to the nature of the risk from a financial chief executive officer point of view.
>
> A. MR. MOLLARD: Yeah, so just to add to that, I mean, particularly with hydro assets, they have an exceedingly long life, anywhere to 70 to a hundred years, depending on the configuration, and the utility needs to demonstrate that those assets are used and useful at every -- every proceeding along the way. And I would contrast that with a distribution utility. You know, they could -- distribution utility's going to have their poles and wires and they may be used to a greater or lesser degree, but they're always going to be useful in their configuration. There is a scenario in generation situation, especially when you're isolated and you can't sell your surplus, we're a commodity based economic, we have a very cyclical activity, and we actually had this situation occur in the '80s when the federal government started building wheel number 4, the day they put the shovel in the ground, the Faro mine closed and that asset had no value. And it very much affected the transaction of

our acquisition of it, but it goes to highlight that aspect of it where the variations in load can basically wipe out the usefulness of a key expensive asset.

c. **Business risks related to industrial loads –** YEC has historically been the utility supplying industrial load that connects to the Yukon grid. The business risk related to industrial customers has fluctuated with the connection of new industrial customers in 2008 (Minto) and 2011 (Alexco) and the loss of Alexco after the 2012/13 GRA. In preparing the 2017/18 GRA the load for Minto changed significantly [see discussion in section 1.1.2 of Argument regarding the industrial load forecast].

d. **Size relative to larger, southern utilities –** YEC is relatively small in terms of customers, rate base and revenues compared to larger utilities such as FortisBC Energy (FEI) and FBC. Yukon Energy also operates in a relatively small market with limited diversity, which carries more risk than a utility serving a large southern Canadian market with greater economic diversity and strength.[123]

4. It is also well accepted that YEC is more risky than AEY and as such should have a higher risk premium.[124] This was reviewed in detail in the response to CW-YEC-1-28 where it was noted that Board Orders, Yukon Energy, AEY (and experts retained by AEY) have all accepted that YEC faces higher risk levels than AEY.[125] The following is specifically noted regarding the level of risk that Yukon Energy has relative to AEY:

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

b. AEY has a retail customer base of about 17,600 retail customers across Yukon (and has no industrial customers); Yukon Energy's load is

123 YUB-YEC-1-54 reviews YEC's risk profile and notes that it has been influenced by the same factors that have been discussed since the 2005 GRA, with the most notable risk factors being the lack of interconnection with external electricity grids, YEC's reliance on its own generation, and industrial loads.

124 Order 2009-02 notes at page 29:

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

125 Mr. Osler TR: 643, lines 14-21: "…relative to the distribution utility in the territory -- it's been said over and over again in various proceedings -- this utility [Yukon Energy] has more risk, and trying to quantify that is what we're trying to do. But the fact that it's more than the distribution utility I haven't seen disputed by anybody that's ever appeared before this Board working for either one of the two utilities."

dominated by one wholesale customer (AEY) and an industrial customer (Minto Mine) with other potential industrial connections in the near future (Alexco and Victoria Gold).

5. The absence of a specific FBC deferral account similar to the DCF is of no importance when comparing risks for FBC relative to YEC. The central point is that FBC, unlike YEC, Is not exposed to any of the risks that would lead to a need for such a specific deferral account. Undertaking #38 and follow up questions on undertakings [YUB-YEC-3-3, YUB-YEC-3-4, YUB-YEC-3-5 and YUB-YEC-3-6] clarify that FBC is not exposed to water risk that would merit or require a specific and separate deferral or contingency account mechanism similar to the DCF. FBC has a general flow through deferral account mechanism to capture power supply and other cost variances from forecast. In addition, prior to any such deferral account being established, FBC does not have the same thermal cost or water variance risk exposure as YEC due to its CPA with BC Hydro. As a result of these two factors, a specific and separate DCF type deferral contingency account model is not required or appropriate.

   Looking beyond impacts of water variability from forecast, the FBC deferral account shifts other risk from the utility to customer beyond what is approved for YEC with the DCF.

6. The approval of the DCF in this proceeding also does not affect YEC's risk profile - As noted in YUB-YEC-2-9 and YEC's Rebuttal Evidence, the regulatory principles that resulted in the development of the DCF (or earlier LWRF), DFPVA and Rider F, and the ERA mechanism included in Rate Schedule 42 have been in place since the early 1990's. The ROE for Yukon Energy has been established since that time with consideration of these factors; and Yukon Energy's risk profile would be increased and the ROE would need to be increased accordingly if the Board were to determine that YEC should bear risks related to water variability. Such a determination would break with established regulatory precedent in Yukon and elsewhere.

**Conclusion**

The simplified approach adopted by Yukon Energy is consistent with past practice in Yukon and prior Board orders and directions. The Application, response to IRs, oral testimony and response to undertakings and follow-up questions on undertakings provides support for using FBC and PNG West as comparable utilities for the purpose of determining the risk premium. The evidence filed or presented during the proceeding also clearly supports Yukon Energy's level of risk relative to FEI and to FBC (i.e., Yukon Energy has materially more risk than both utilities).

In this proceeding there was extensive investigation regarding YEC's level of risk relative to FBC. The response to IRs, cross-examination, undertakings and follow-up questions on undertakings confirms the following:

- YEC is smaller than FBC and, similar to AEY, must be provided a risk premium in this regard.
- YEC has more generation (as a share of load served) than FBC or AEY and must also be provided a risk premium to address the added generation risk related to its isolated grid context (and related less extensive deferral account protections) as well as the much higher share of load supplied by its own generation.
- Before considering deferral accounts, YEC has much greater water-related risk than FBC. The record has clarified that YEC intrinsically has more water-related risk than FBC, as FBC is insulated from hydrology risk under the Canal Plant Agreement (CPA) and has other supply arrangements available that YEC does not have. Given this context for FBC, it does not require a contingency mechanism similar to the DCF to address smoothing of rates over the range of annual water conditions.
- After considering deferral accounts, YEC does not have the same degree of protections through deferral accounts that FBC has (e.g., YEC has load-related risk whereas FBC has deferral mechanisms to address this risk as well as other risks). To re-iterate the prior point, FBC does not need a specific DCF account – its deferral account covers any residual water risk along with other variances from approved forecasts.
- With regard to capacity planning, Yukon's isolated grid intrinsically has more risk than FBC's grid which is interconnected with BC Hydro as well as other jurisdictions. The fact that Yukon's capacity planning criteria addresses this risk specific to isolated grids does not change the fact that these risks for YEC are greater than for southern jurisdictions such as FBC.

Based on the above, Yukon Energy is clearly entitled to a risk premium (relative to the BCUC benchmark ROE) greater than the FBC risk premium of 40%. The best available determination of the applicable YEC risk premium remains the half way point between FBC and PNG West risk premiums of 40% and 75% respectively (each as determined by BCUC).

In summary, the BCUC benchmark ROE of 8.75% should be used for determining the benchmark for Yukon Energy for the test years and an equity risk premium of 57.5% should be applied to address the additional risk Yukon Energy faces compared to FEI and FBC.

## 5.0 TWO PART ERA APPLICATION

Section B of Part 1 of this Argument addresses the core issues regarding LTA forecast and contingency fund mechanism requirements, including the basic requirements for use of the LTA forecast approach for this GRA and adoption of the DCF as proposed in the

Application, review of the ST hydro forecast alternative and why it should not be adopted for this GRA, and a proposed increase in the DCF cap to +/-$16 million. Section B of Part 1 also addresses relevant evidence from Exhibits B-14, B-15 and B-18 and related interrogatory responses and hearing transcript on Yukon and other jurisdiction precedents for customers bearing water risks and approaches to related contingency or deferral accounts, and the history of the DCF/ LWRF and ST versus LTA forecasts in Yukon.

Responses to the following other key issues raised regarding Exhibits B-14, B-15 and B-18 are addressed below (YEC will wait to respond to any other issues raised by intervenors):

- YECSIM Model;
- Accuracy of LTA versus ST hydro and thermal forecasts; and
- LNG/ Diesel Split.

## 5.1 YECSIM MODEL

The YECSIM model has received extensive review and testing in this proceeding.

In response to Board concerns about Yukon Energy's water forecasting model used for LTA hydro and thermal generation forecasts,[126] Appendix 2.4 of Exhibit B-14 provides a description of the YECSIM forecasting model and a copy of the YECSIM Model User Manual to enable the Board and intervenors to review the constraints, processes and operational rules of this model for testing and assessment.

A workshop was held with Board staff and intervenors (Exhibit B-18 for power point presentation) to review and discuss this material. Subsequently, Yukon Energy provided responses to IRs specifically related to YECSIM model assumptions, methods and capabilities, including:

- AEY-YEC-2-4 (YECSIM uses weekly load duration curves to calculate peak loads within a week; it does not consider load location, and it is not considered that adding the load location would materially improve the results).
- UCG-YEC-2-6 through 9, and JM-YEC-2-6 (various specific questions regarding YECSIM).

The history of YECSIM and earlier hydro generation models, as well as comparison with similar long-term simulation models used by Manitoba Hydro, was reviewed in the oral hearing.[127]

[126] See Board Order 2017-08. See also responses to YUB-YEC-1-49 (regarding testing and verification of YECSIM) and YUB-YEC-1-51 (regarding whether YECSIM mirrors day-to-day operation of the hydro system). Questions related to YECSIM model updates for the GRA DCF filings are addressed in Section B of Part 1 of this Argument.
[127] YEC responses to Mr. Rondeau, TR 86:20 to 108:21.

## 5.2 ACCURACY OF LTA VERSUS ST HYDRO AND THERMAL FORECASTS

Questions have been raised regarding the relative "accuracy" of LTA versus ST hydro and thermal generation forecasts for revenue requirement forecasts for the two test years.[128]

In addressing this issue, a key distinction to be noted is the purpose of a LTA versus a ST forecast for hydro and thermal generation for the test years.[129]

- **Short-term forecasts:** A ST forecast used for a GRA would aim to forecast actual hydro and diesel generation for the two test years (which would ultimately involve review of actual reservoir levels just prior to the test years and forecast water conditions specific to these two years assuming long-term average water inflows).[130] Actual results compared to ST forecasts used in the GRA are subject to very high variability[131] and Yukon Energy did not intend that these forecasts could be relied upon for revenue requirement forecasts in the current Application.[132]

- **Long-term average forecasts:** A LTA forecast aims to establish a consistent long-term average (i.e., applicable over the hydro asset lives) for application in the two test years based on historic water records, current hydro system facilities and capabilities, and forecast grid loads for the test years. The LTA forecast does not attempt to forecast actual hydro and diesel generation that will occur in these test years based on forecast water conditions specific to these two years, and its "accuracy" cannot therefore be assessed based on the actual water conditions that occur during these two years. The LTA forecast is adopted to provide smoothing of revenue requirement impacts over varying short-term annual water conditions – and its "accuracy" needs to be assessed relative to its objective.

Overall, the concept of LTA forecasts does not imply that actual hydro and thermal generation in "typical" years will necessarily conform to a LTA.[133] The LTA can be heavily affected by drought conditions in a small percentage of the recorded water years. The LTA is used to figure out what could happen in the long-term on average, for the purpose of business investment decisions and for creating funds (such as the DCF) for the "non-rainy-day" conditions.

A contingency or deferral account fund is required in any event for both ST and LTA forecasts to address the variances from forecast due to water availability (so that

[128] See for example Board counsel question at TR. 561, lines 18-23.

[129] See Osler, TR. 562:5 to 565:22; also TR. 566:19-568:4. Also Osler and Mollard, TR: 569:3 -571:15, and TR. 575:16-576:19.

[130] In contrast, ST forecasts used for hydro system operation do not rely on a two-year out forecast of water conditions, and are updated on a regular basis throughout each year in response to new water condition and other information.

[131] See Section b of Part 1 of this Argument for review of ST forecasts versus actual results for 2017, as well as indications of the potential volatility for such forecasts for 2018.

[132] See Osler TR. 282:23-283:12.

[133] See Osler and Sreckovic, TR: 577:1-23.

ratepayers rather than the utility bear the risks for such variances). However, a contingency fund such as the DCF is also designed to enhance long term rate stability and is therefore directly compatible with the LTA forecast purpose.

## 5.3 LNG / DIESEL SPLIT

Questions were raised about the basis for the 90/10 LNG/diesel split for the LTA thermal generation forecast, the 60/40 LNG/ diesel split for the ST thermal forecast, and why these two forecasts differ.

The LNG/ diesel split for the LTA forecast used in the GRA is applied after the LTA thermal generation forecast is estimated for a test year based on the DCF Term Sheet Table 3.4-1 and the forecast of actual grid load. The YECSIM model is not used to estimate this split.[134]

Section B of Part 1 of this Argument reviews evidence from the Application and IR responses on the basis for the 90/10 LNG/diesel split adopted in the GRA forecast and for the DCF year-end determinations, and how Yukon Energy bears the risk of higher costs if the final thermal generation mix for a fiscal year after the DCF determinations differs from the 90:10 LNG: diesel assumed in the GRA test year forecasts. As reviewed during the oral proceeding, Yukon Energy did not have any specific “statistical” basis for deriving this 90/10 forecast split,[135] beyond reference to the LTA thermal generation being driven by a small share of the 35 water years with low water conditions.[136]

In contrast, the ST forecast 60:40 LNG: diesel mix was intended to reflect actual fuel mix that is forecast in the test years under forecast load and (ST) water conditions.[137] YEC noted that there is considerable risk that the LNG/diesel split is each test year could be very different from this forecast, and that YEC is not using the ST forecasts for rate requirement purposes.[138]

As reviewed above for overall thermal generation forecasts, the LTA and ST forecasts serve very different purposes. Accordingly, the ST forecast LNG/diesel mix (as well as actual LNG/diesel mix) for the test years has no relevance to the forecast of the LTA mix.[139]

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[134] See Osler and Sreckovic, TR: 108:3-20.

[135] See Osler TR; 280:21 to 281:15 where it was also suggested that the 90/10 split be reviewed in each GRA.

[136] At forecast conditions representing forecast and actual 2017 grid loads (i.e., grid loads of 420 to 450 GW.h/year as reviewed in Appendix 3.4 of Exhibit B-1 at page 3.4-23), 51% to 75% of the LTA thermal generation occurs in the 20% of the 35 water years with the worst drought conditions. On this basis, it was concluded that 90% LNG share of LTA was reasonable as a forecast.

[137] See Exhibit B-14, Appendix 2.2 (page A2.2-2 to A2.2-3) and responses to YUB-YEC-2-6; YUB-YEC-2-19; JM-YEC-2-4.

[138] Exhibit B-14, Appendix 2.2, page A2.2-3; YUB-YEC-2-14. See Mollard and Osler, TR; 281:17 to 283:13.

[139] See also response to YUB-YEC-2-21.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

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