**YUKON ENERGY CORPORATION**

**2017/2018 GENERAL RATE APPLICATION**

**JUNE 2017**

## *2017/2018 GENERAL RATE APPLICATION*

## *TO THE YUKON UTILITIES BOARD (BOARD)*

## *YUKON ENERGY CORPORATION*

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### INTRODUCTION TO APPLICATION

Yukon Energy's 2017 and 2018 General Rate Application (the GRA or Application) addresses adjustments to Yukon Energy's approved revenue requirement and other matters as required to:

- Recover the costs to supply customers in 2017 and 2018 (the two test years);
- Implement changes to the Diesel Contingency Fund (DCF) and Rider F as of January 1, 2017; and
- Implement overall rate adjustments through implementation of an adjusted Rider J (applicable to all firm retail customer class rates and to firm major industrial customer class rates) in order to recover the revenue shortfall in each test year.

Pursuant to the Order in Council (OIC) 2014/23 direction, the Board must ensure until the end of 2018 that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers. Consequently, for both 2017 and 2018, all proposed rate adjustments for retail customers and industrial customers apply equally, as percentages.

The Application includes the following:

- Overview;
- Summary of Requested Orders; and
- Overview of Supporting Documents.

## OVERVIEW

### *Background*

Yukon Energy’s last requested rate increase was for the 2012 and 2013 test years – this was the first requested increase in Yukon Energy firm retail rates for non-industrial customers since the 1998/1999 rate review (which focused on issues arising from the closure of the Faro mine).

The 2012/13 General Rate Application noted that continued non-industrial and industrial load growth on the grid was driving forecast revenue shortfalls for Yukon Energy, leading to higher diesel generation costs as well as a range of generation and transmission cost pressures. Ongoing non-industrial growth reflected overall Yukon economic expansion and other factors such as an apparent increased use of electric heat. Industrial growth reflected the connection of Minto in 2008, Alexco in 2011 and the forecast connection of Whitehorse Copper Tailings in 2013.

Yukon Energy’s load profile today has changed from what was expected in the last GRA. Key changes include lower wholesale loads due to warmer than normal weather and slower than expected growth, increased non-industrial peak loads, reduction of industrial load to only one mine (Minto mine), and increased secondary sales loads.

### *Factors Driving the 2017 and 2018 Revenue Shortfall*

The level of rate increase required in 2017 and 2018 is driven by increased costs and changing load profiles.

Measures since the 2012/13 GRA that have helped to manage Yukon Energy's ongoing pressures and defer the requirement for the Application include debt re-negotiation with Yukon Development Corporation (YDC), the Mayo B Promissory Note's flexible debt financing provisions, YDC contributions that reduced project costs to be recovered from ratepayers, secondary sales revenues, and adjusted thermal fuel costs related to Diesel Contingency Fund operation and also to the implementation of the Whitehorse Diesel-Natural Gas Conversion Project (LNG Project or LNG Plant project).

The Application documents the full range of load profile and cost changes, including projects held in Work in Progress (WIP) from the 2012/13 GRA for review today and increases to the return on equity (ROE) from 8.25% to 8.82% to reflect current fair return requirements. Overall, the following four key factors are driving most of the 2017 and 2018 rate increase:

- **Changing load profile -** changing non-industrial loads with increasing winter peak requirements, extension of the existing industrial load through 2018, and increased secondary sales;

- **Material capital and planning expenditures -** costs added to rate base since the 2012/13 GRA for sustaining capital requirements and to address dependable capacity shortfalls, as well as for deferred costs for planning;

- **Increased non-fuel operating expenses since 2012/13 GRA -** increased costs since 2013 approved GRA for labour and other non-fuel O&M costs; and

- **Projects held in WIP from 2012/13 GRA -** costs held in WIP as directed from the 2012/13 GRA are an important cost driver for the rates proposed in the Application.

The 2017 and 2018 rate increase requirement has been reduced by ongoing cost savings from YDC debt renegotiation and contributions, and from lower liquefied natural gas (LNG) pricing compared with diesel.

***Proposed Rider J to Address Revenues Shortfalls in each of 2017 and 2018***

The current level of existing firm rates result in a $5.348 million rate revenue shortfall in 2017, and a $6.585 million rate revenue shortfall in 2018 compared to revenue requirements set out in Tab 3. These shortfalls, which are outlined in Table 1 below, form the basis for the proposed rate increases in this Application.

**Table 1:**
**Yukon Energy Revenue Required from Rates ($000s)**

| | **2017** | **2018** |
|---|---|---|
| Revenue Requirement | $48,544 | $49,864 |
| Less: Other Revenues | $ 253 | $ 253 |
| Less: Secondary Sales | $ 642 | $ 642 |
| Revenue Required from Firm Rates | $47,649 | $48,969 |
| Less: Revenues from Firm Sales at Existing Rates [includes Rider J] | $ 42,301 | $ 42,384 |
| Additional Firm Rate Revenues Required | $5,348 | $6,585 |

Firm retail non-industrial rates within each non-government retail customer class (i.e., rates for residential, general service and lighting customer classes) are required by OIC 1995/90 to be equal throughout Yukon for both Yukon Energy and AEY customers, subject to allowed variation for run-off rates to reflect incremental costs that differ for different rate zones. Pursuant to OIC 2014/23 direction, the Board must also ensure until the end of 2018 that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers.

In accordance with the above direction, the Application proposes that the Yukon Energy revenue shortfall for the test years be recovered through Rider J increases of 9.04 percentage points in 2017 and a further 2.07 percentage points in 2018, applicable to all YEC and AEY retail firm rates and all major industrial firm rates. These Rider J increases are estimated to result in an overall increase in existing rates[1] of 7.38% for 2017 and 1.58% for 2018 (cumulative increase of 9.08% over current rates). The proposed Rider J changes to recover the revenue shortfalls are reviewed in more detail below.

Further consideration of cost of service and future rate design affecting retail and industrial customer classes is deferred until expiry of the OIC 2014/23 provisions.

## SUMMARY OF REQUESTED ORDERS

In summary, approval of the Board is requested for the following:

1. **2017 and 2018 Revenue Requirement:** Approval of the forecast revenue requirement of $48.544 million for 2017 and $49.864 million for 2018, including approval, as required, of the following costs, revenues and other related provisions:

    a. **Fuel and Purchased Power Costs:** Fuel and purchase power costs forecast of $2.381 million and $2.407 million in 2017 and 2018 respectively, including approval for the following related matters:

        i. **Adjusted Fuel Prices:** Approval to adjust diesel prices and delivered LNG price used in setting average fuel costs per kW.h to be $0.2633/kW.h for diesel and $0.1467/kW.h for LNG to reflect current market conditions.

        ii. **LNG/Diesel Generation:** Approval to assume that long-term average (LTA) thermal generation requirements (separate from thermal generation maintenance activity requirements) are supplied with a combination of 90% LNG and 10% diesel generation.[2]

[1] Includes existing YEC Rider J of 11.01% for retail firm rates and 7.36% for major industrial firm rates, and the existing AEY Interim Rider R of 11.62% applicable to all retail and industrial firm rates.

[2] Based on the requested approvals, the savings from lower cost LNG compared with diesel to supply long-term average thermal generation requirements approximate $1.5 million in each test year.

iii. **Update to Rider F:** Approval to revise Rider F to include pricing related to the delivered cost of LNG, effective January 1, 2017, including the following related approvals:

- Approval to defer to the Diesel Fuel Price Variance Account (DFPVA) the variance (plus or minus) in actual delivered cost of LNG compared to the delivered cost of LNG included in the most recent General Rate Application for all thermal-electric generation.
- Approval to include deferred LNG price variances in the amounts collected (or refunded) to customers through the Rider F pursuant to the Rider F – Fuel Adjustment Rider & Deferred Fuel Price Variance Policy (Rider F Policy).
- Approval of required adjustments to the Rider F Policy to incorporate reference to LNG pricing in the Diesel Contingency Fund.

iv. **Update to the Diesel Contingency Fund (DCF)**: Approval of Yukon Energy's Revised DCF Term Sheet provided in Attachment 3.4-1 of Appendix 3.4 regarding determination of annual expected long-term average thermal generation requirements and fuel costs, including proposed updates to the DCF for the following:[3]

- Updated table for "Expected YEC Thermal; Generation with LTA YEC Hydro Generation" to reflect updated information on LTA wind and hydro generation (YEC and AEY); and
- Updates for incorporating LNG fuel and generation facilities into DCF cost determinations.

b. **Non-Fuel Operating and Maintenance Costs:** Non-fuel operating and maintenance costs forecast of $22.060 million and $22.016 million in 2017 and 2018 respectively, including approval of the following matters:

i. **Reserve for Injuries and Damages (RFID):** Approval to increase the annual appropriation to the Reserve for Injuries and Damages to $0.267 million from the current $0.190 million level starting in 2017, and approval to amortize the remaining balance of $1.059 million over a five year period (as discussed in Section 3.3.6 of Tab 3).

ii. **Vegetation Management Deferral Account:** Approval starting in 2017 to amortize the 2016 balance of the vegetation management deferral account over ten

[3] Appendix 3.4 also provides an updated information on the adequacy of the existing DCF cap in order that the Board and interveners can assess options to the current +/-$8 million cap.

years ($0.222 million per year), and to eliminate the requirement to defer brushing costs in excess of 2011 actual brushing costs.

c. **Depreciation and Amortization Expenses:** Approval of depreciation and amortization expenses forecast of $10.814 million for 2017 and $11.094 million for 2018 including the following related approvals:

   i. **Planning Cost Accounting Policy:** Approval of planning cost accounting policy provided as Appendix 5.1.

   ii. **Demand Side Management (DSM) Accounting Policy:** Approval of the DSM accounting policy provided as Appendix 5.2.

   iii. **Costs of current GRA:** As per Board Order 2013-03, Yukon Energy established a regulatory hearing reserve deferral account with a provision of $0.550 million per year. The balance of the regulatory hearing account has a 2016 year-end forecast of $0.973 million.[4] As reviewed in section 3.4 of Tab 3, Yukon Energy is seeking approval to: (1) amortize the forecast 2016 credit balance of $0.973 million over a 5 year period ($0.195 million per year); and (2) to decrease the annual provision starting in 2017 to $0.250 million.

d. **Mid-Year 2017 and 2018 Forecast Rate Base:** Approval of mid-year forecast rate base costs of $274.459 million and $291.627 million for 2017 and 2018 respectively, including costs for capital works projects brought into service (or forecast to be brought into service) since the 2012/2013 General Rate Application, as well as deferred costs. This includes the following:

   i. **Major Capital Projects:** Spending for 10 major capital projects (i.e., total costs over $1 million) forecast to be in service in the test years with a total net rate base cost of $60.4 million (after offsetting third party contributions of $18.3 million).

   ii. **Other Property, Plant and Equipment (PP&E) Capital Projects:** Other capital spending on property, plant and equipment in rate base in the test years is forecast at approximately $11.0 million for 2017 (including $6.3 million for deferred overhauls brought into rate base at the start of 2017) and $5.933 million for 2018 (before offsetting customer contributions of $0.4 million in each test year).

   iii. **Deferred Costs:** Deferred costs in rate base for feasibility, supply planning, regulatory, relicensing and dam safety are forecast at approximately $13.9 million at the end of 2017 and $15.0 million at the end of 2018, reflecting the impact of

[4] As Yukon Energy has not submitted a General Rate Application since 2013, the Corporation has had minimal hearing reserve costs since 2013.

approximately $13.9 million of deferred costs being transferred to rate base at the start of 2017 as well as rate base costs for projects closed before the end of 2018.

e. **Return on Rate Base:** Approval of $13.289 million in 2017 and $14.348 million in 2018, including an allowed rate of return on equity of 8.82% for both 2017 and 2018.

2. **2017 and 2018 Rates:** Approval of the following rates to recover the 2017 and 2018 revenue:

   a. **2017 Retail and Industrial Rates:** Approval of an increase of the current YEC Rider J by 9.04 percentage points, starting January 1, 2017, applicable to all YEC and AEY retail firm rates (all AEY recoveries from this rider would flow through to YEC), and to all major industrial firm rates, including the fixed Rider F charge of 0.211 cents/kWh.

   b. **2018 Retail and Industrial Rates:** Approval of a further increase of the current YEC Rider J by 2.07 percentage points, starting January 1, 2018, applicable to all YEC and AEY retail firm rates (all AEY recoveries from this rider would flow through to YEC), and to all major industrial firm rates, including the fixed Rider F charge of 0.221 cents/kWh.

   c. **Interim Refundable Rates effective September 1, 2017:** Approval to implement the above noted 2017 Rider J rate increase of 9.04 percentage points for retail and industrial customers via an interim refundable rate rider (Rider J) of 20.05% for retail firm rates and 16.40% for industrial firm rates effective on an interim refundable basis as at September 1, 2017 (see Tab 4, Appendix 4.1 for proposed interim Rider J rate schedule). Less than one-third of the forecast 2017 revenue shortfall will be collected by this interim Rider J over 2017.

      Following receipt of final orders in this proceeding, including a final 2017 revenue requirement, any residual shortfall or surplus for each test year will be addressed pursuant to direction of the Board.

No proposal regarding the Rate Schedule 42 Energy Reconciliation Adjustment (ERA) is provided at this time in the Application as the ERA is currently the subject of an appeal to the Court (the Appeal) from the Board's Order 2015-06 of August 18, 2015. At such time as the Court's decision is provided, Yukon Energy will review the ERA and provide the Board with a filing as required on this matter.

## OVERVIEW OF SUPPORTING DOCUMENTS

Detailed schedules, analysis and documentation in support of the Application are presented in the attached supporting documents.

The supporting documents included with the Application provide detailed information on Yukon Energy's operations and activities, focusing on actual results for 2013 to 2016, and forecasts for 2017 and 2018.

The supporting documents also provide other background information relevant to the Application, including review of past Board Orders and directives since the 2012/2013 General Rate Application, details on specific elements of the Application and copies of relevant Orders-in-Council.

The following is an outline of the specific supporting documents included with the Application as Volume 1 of Yukon Energy's filed materials:

- **Tab 1 Introduction:** Provides an introduction to the supporting documents, addressing YUB review of Yukon Energy matters since the 2012/2013 GRA.

- **Tab 2 Yukon Energy System Sales and Generation:** Provides detail on the power system operated by Yukon Energy and its forecast sales and generation for 2017 and 2018.

- **Tab 3 Revenue Requirement:** Provides detailed information on Yukon Energy's total forecast cost of providing service in 2017 and 2018, including operating and maintenance expenses, rate base, depreciation and amortization, return on rate base (including a fair return on equity) and stabilization matters.

- **Tab 4 Rates:** Reviews Yukon Energy's rates and provides an explanation of Yukon Energy's proposed rate adjustments and Riders.

- **Tab 5 Capital Projects:** Provides an overview of Yukon Energy's capital spending for the period 2013 to 2016, as well as forecast capital spending for 2017 and 2018.

- **Tab 6 Board Directives:** Provides a review of past Board Orders and responses to outstanding directives since the 2012/2013 General Rate Application.

- **Tab 7 Financial Schedules:** Provides detailed regulatory schedules for Yukon Energy supporting the Application.

- **Tab 8 Return on Equity:** Provides details with respect to Yukon Energy's fair rate of return for 2017 and 2018.

- **Tab 9 2015 Audited Financial Statements:** Provides a copy of Yukon Energy's audited financial statements.

- **Tab 10 Orders in Council:** Provides the relevant Order in Council documents which direct the Board regarding certain aspects of Yukon Energy's revenue requirement and rate design.

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

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# TAB 1
# INTRODUCTION

# 1.0 INTRODUCTION

Yukon Energy's Application includes 10 tabs of supporting documents reviewing information related to Yukon Energy's operations and the requested Board Orders.

Tab 1 provides an introduction to the supporting documents under the following headings:

- Need for 2017 and 2018 Rate Increase;
- Measures since 2013 to Defer the Need for a Rate Increase;
- Factors Driving the 2017 and 2018 Rate Increase Requirement;
- Other Regulatory Concerns Addressed in Application; and
- Yukon Energy Rates and Bills.

## 1.1 NEED FOR 2017 AND 2018 RATE INCREASE

Existing rates for Yukon Energy were established based on the 2013 revenue requirement approved by the Yukon Utilities Board (YUB) for the 2012/13 General Rate Application (GRA). The need for new rates in 2017 and 2018 is driven by changes in Yukon Energy's revenue requirements and loads since 2013.

Table 1.1 shows Yukon Energy's return on equity (ROE) since 2013. ROE's below the 2013 approved ROE of 8.25% indicate the extent that existing rates are inadequate relative to YEC's costs and sales.

Actual ROE in 2013 was only 7.42%, or about $0.75 million below the approved 8.25% ROE, despite overall rate revenues for non-secondary sales being basically as forecast and rate base being slightly lower than forecast. This outcome reflected fuel and non-fuel O&M costs (particularly O&M labour costs) being materially higher than in the approved revenue requirement. This labour cost driver has continued to affect YEC in each subsequent year, with some offset from secondary sales revenues that were not forecast in the 2013 approved revenue requirement.

The loss of the Alexco Resources industrial mine load in late 2013 plus a sharp drop in firm wholesales in 2014 adversely impacted YEC's revenues. Firm wholesale revenues continued through 2015-2016 to be below the approved 2013 forecast, offset by related reductions in fuel costs based on lower long-term average thermal generation requirements as well as (by 2016 in particular) lower cost liquefied natural gas (LNG) based thermal generation capability.

Major new capital assets came into service in 2015 and 2016 and, along with other rate base changes, this resulted in increased mid-year net rate base by $13.9 million in 2015 and by $30.9 million in 2016 above the 2013 approved mid-year net rate base. The increased rate base, combined with the other cost drivers noted since 2013, eroded YEC's ability to earn the approved ROE at existing rates. Table 1.1 highlights that the reported ROE in 2015 and 2016 would have been only 6.45% and 7.18% (versus actual of 8.10% and 8.69%) absent refinancing by Yukon Development Corporation (YDC) at the end of 2014 to reduce materially the cost of existing YEC long-term debt.

The cost drivers and reduced revenues noted since 2013 continue to affect Yukon Energy in 2017 and 2018. Notwithstanding the lower cost of the refinanced debt and other mitigation measures reviewed in Section 1.2 below, Table 1.1 shows that Yukon Energy's projected ROE at existing rates falls to 8.17% in 2017 and 7.89% in 2018. Table 1.1 also highlights that added rate base, other deferred costs, and other adjustments arising with the new GRA result in projected ROE absent rate changes at 3.96% in 2017 and 3.18% in 2018.

**Table 1.1:**
**Return on Equity (%) Earned by Yukon Energy with Existing Rates**

| Year | ROE without new GRA[1] | ROE after Other Factors |
|---|---|---|
| 2013 GRA | 8.25% GRA Compliance | |
| 2013 Actual | 7.42% | |
| 2014 Actual | 8.44% | |
| 2015 Actual | 8.10% | 6.45% ex. debt refinance[2] |
| 2016 Actual | 8.69% | 7.18% ex. debt refinance[2] |
| 2017 Forecast | 8.17% at existing rates | 3.96% after GRA impacts[3] |
| 2018 Forecast | 7.89% at existing rates | 3.18% after GRA impacts[3] |

Notes: 1. Actual or projected ROE absent a new GRA.
2. ROE in 2015 & 2016 without debt refinancing by YDC.
3. Added rate base & other adjustments resulting from the new GRA, but absent rate changes.

## 1.2 MEASURES SINCE 2013 TO DEFER THE NEED FOR A RATE INCREASE

The 2012/2013 GRA was the first increase in Yukon Energy retail rates since the 1998/1999 period.

Since the 2012/13 GRA, the following measures have helped manage ongoing cost pressures that would otherwise reduce Yukon Energy's ROE below the 8.25% approved in the 2013 forecast revenue requirement.

- **Debt Re-Negotiation with YDC:** As noted in Section 1.1, in late 2014 (effective in 2015), Yukon Energy entered into an agreement with YDC to renegotiate terms for most of its outstanding debt,[1] at a substantially lower interest rate of 2.40% (versus rates ranging from 3.69% to 4.27%) that was consistent with benchmarked market rates for debt at that time. As noted in Table 1.1, this refinancing deferred the need for rate increases in 2015 and 2016. In the test years, lower refinanced debt costs continue to lower YEC's interest costs by about $1.5 million in 2017 and $1.4 million in 2018.

- **Mayo Flexible Debt Financing:** The Mayo B Promissory Note is a mitigation measure established at the time of project capitalization to protect ratepayers against load risk impacts related to Mayo B rate base costs. The instrument contains a flexible interest provision that reduces the annual expense to YEC based on a comparison of actual grid loads versus a prescribed minimum; if the calculated interest expense is negative then YDC pays that amount to YEC in order to reduce the impact of Mayo B costs to ratepayers. In each year since 2013, YEC's annual interest expense on the Mayo B Promissory Note has been reduced by the flexible interest provisions. Lower loads in 2014 resulted in negative interest payments from YDC to YEC of $0.112 million, further reducing the impact to ratepayers in that year.

- **Yukon Development Corporation Contributions that reduce rate impacts of projects in service as well as planning costs to be recovered from ratepayers:** In December 2015, YDC made a $22.4 million capital contribution to Yukon Energy, with $18.3 million used to offset the capital costs of the Whitehorse Diesel Natural-Gas Conversion Project (LNG Project) added to rate base in 2015. The balance of the contribution ($4.2 million) was used to offset amounts for deferred projects in rates. These contributions continue to reduce ongoing annual depreciation/amortization and return costs for the affected projects.

- **Secondary Sales Revenues to mitigate impacts of loss of load:** No secondary sales were forecast in each test year for the 2012/13 GRA. Due to the fact that diesel was on the margin, secondary sales had been shut off for increasing periods of time, and YEC had proposed in the

[1] Approximately $92.5 million of debt was refinanced, excluding the $20,889,000 term note related to the Mayo Hydro Enhancement Project due December 31, 2051 and the $5,505,000 term note due December 31, 2039.

2012/13 GRA that any future secondary sales revenues be paid to the account of the reactivated Diesel Contingency Fund rather than to YEC's revenues. The Board did not approve YEC's proposal to reassign secondary sales revenues in the last GRA. Since the 2012/13 test years, industrial load (except for 2016) and firm wholesale load have both declined during a period of higher than average hydro flows, resulting in further opportunities for secondary sales over the period from 2013 to 2015. Since the last GRA, Yukon Energy has actively pursued secondary sales opportunities, including three new SCADA connections, and annual secondary sales from 2013 to 2016 have ranged between 3.9 GW.h and 7.0 GW.h with revenues as follows: $0.275 million in 2013; $0.410 million in 2014; $0.544 million in 2015; $0.371 million in 2016. Secondary sales are forecast at 11.464 GW.h/year in 2017 and 2018, with revenues forecast (at lower rates now applicable) at $0.642 million per year. All forecast revenues from secondary power in the test years go to lower the required level of retail rates for firm power. As defined by the rate schedule, the impact of quarterly rate adjustments to market are charged against the Rider F – Diesel Fuel Price Variance Account.

- **Adjusted Thermal Fuel costs:** The Diesel Contingency Fund was reactivated after the last GRA and thermal generation costs are now based on long term average requirements for actual annual generation loads. YEC's annual thermal fuel generation costs are also now adjusted automatically in each year in response to changes in firm generation loads. As a result, YEC's fuel costs in each year after 2013 were reduced well below the approved 2013 revenue requirement amount in response to the reductions in YEC's firm sales and generation requirements. Further reductions in YEC fuel costs occurred when the LNG Project was completed and in service in July 2015, resulting in an ability to use a lower cost fuel than diesel for back up generation on the integrated grid (in 2016, almost 90% of the $1.046 million fuel expense reduction relative to the approved 2013 revenue requirement amount was due to this factor). Yukon Energy continues to pursue the lowest possible LNG fuel supplies to minimize fuel costs and mitigate overall cost pressure. However, it is recognized that the LNG Project was developed to meet requirements arising from diesel unit retirements - and the capital costs for this project, even after YDC's contributions, were a major factor increasing YEC's rate base and reducing YEC's ROE below 8.25% with existing rates (prior to the YDC debt financing).

In summary, Yukon Energy has continued to pursue a range of mitigation measures to reduce costs and has also benefited in this regard from the measures adopted at the last GRA.

## 1.3 FACTORS DRIVING THE 2017 AND 2018 RATE INCREASE REQUIREMENT

The level of rate increase required in 2017 and 2018 is driven by increased costs and changing load profiles.

The Application documents the full range of cost changes, including projects held in Work in Progress (WIP) from the 2012/13 GRA for review today and increases to the return on equity (ROE) from 8.25% to 8.82% to reflect current fair return requirements. Overall, the following four key factors are driving most of the 2017 and 2018 rate increase:

- **Changing load profile** – Changing non-industrial loads, and extension of the existing industrial load through 2018;

- **Material capital and planning expenditures** – Costs added to rate base in 2017 and 2018 for sustaining capital requirements and to address the current dependable capacity shortfall, as well as for deferred costs for planning;

- **Increased operating expenses since 2012/13 GRA** – Increased costs since 2013 approved GRA for non-fuel O&M costs; and

- **Projects held in WIP from 2012/13 GRA** – Costs held in WIP as directed from the 2012/13 GRA are an important cost driver for the rates proposed in the Application.

Each of these factors is reviewed briefly below (see Tab 2 for more detail on loads, Tab 3 for more detail on O&M related costs, and Tab 5 for descriptions and costs for individual major capital and deferred cost projects).

***Changing Load Profile***

Yukon Energy's forecast load profile by the end of 2016 had changed from what was expected in YEC's last GRA and its filing in late 2013 for the LNG Project. Key changes include lower wholesale loads due to warmer than normal weather and slower than expected growth, increased non-industrial peak loads, reduction of industrial load to only one mine (Minto mine), and increased secondary sales loads. Combined, these changes in the load profile from 2014 through 2016 tended to adversely impact overall Yukon Energy revenues at existing rates, reduce long-term average thermal generation requirements, and increase dependable capacity requirements in each test year.

The approved GRA forecast for 2013 of 416.4 GW.h generation included two mine loads (Minto and Alexco) and the expected connection of a third industrial customer to be supplied by AEY (Whitehorse Copper Tailings), and no secondary sales. The Base Case load forecast filed with the Board late in 2013 for the LNG Project Part 3 Application noted some changes since the 2012/13 GRA, but expected a total firm generation of 416 GW.h in 2014 that would grow to 484 GW.h by 2022 and about 530 GW.h by 2030.

However, by the end of 2014, actual generation had dropped to 402.3 GW.h (including 5.8 GW.h for secondary sales), and firm load generation was only 396.5 GW.h; Minto was the only industrial load connected to the grid - and firm wholesales to AEY had declined from 307.9 GW.h in 2013 to 295.3 GW.h.

Since 2014, Yukon Energy's total generation for firm sales has remained below the approved forecast for 2013 and secondary sales have continued to be significant. However, in contrast to the reduced firm generation, peak winter load on the grid increased from 80 MW in the approved 2013 forecast to 88 MW in 2016.

The test year forecasts reflect continuation of these recent forecast conditions, with an improvement in overall firm energy sales and related generation requirements compared with actual 2014-16 results.

- The forecast in this Application for 2017 and 2018 includes 12.5 GW.h generation for secondary sales in each year, which help to reduce rate increase requirements.

- Generation for firm sales with continued Minto mine operations is forecast at 420.4 GW.h in 2017 and 421.2 GW.h in 2018, and are slightly above actual 2013 generation for firm sales (419.2 GW.h).

- Firm wholesales are forecast at 309.0 GW.h for 2017 and 309.5 GW.h for 2018, assuming more normalized temperature conditions rather than the warmer-than-normal weather experienced since 2013, as well as updates to AEY's forecasts for Fish Lake hydro generation.[2]

- Overall non-industrial firm sales are forecast at approximately 349 GW.h in 2018, which is only slightly higher than actual 2013 non-industrial firm sales of about 344 GW.h.

[2] As noted in Tab 2, Section 2.2.1 the LTA estimate for Fish Lake hydro was provided by AEY, based on incorporating updated planned capital work information.

- Non-industrial firm peak loads are forecast at approximately 86 MW in 2018,[3] or about 12% higher than the actual 2013 non-industrial firm peak of about 77 MW. Available evidence has indicated that this reflects continued growth in the non-industrial firm winter peak due to adoption of electric heating in almost all new residential units.

Forecasts for the Minto mine load in 2017 and 2018 have changed significantly since the start of 2017. Through early January 2017, it was understood that the mine would cease operations in late 2017. The forecast in this Application now assumes continued Minto mine operation through 2018, based on updated information provided in April 2017. The forecast of continued operation of this mine through 2018 added significantly to forecast revenues at existing rates and reduced materially the 2018 rate increase requirement for all ratepayers.[4]

Looking beyond the test years, updated load forecasts and the anticipated end of Minto mine operations within a few years highlight ongoing pressure for added dependable capacity notwithstanding limited growth opportunities for new energy requirements unless new mine connections occur. The Yukon Energy 2016 Resource Plan's updated load forecast scenario with "Very Low Industrial Activity" (i.e., no industrial loads after 2017) highlights a drop in firm energy generation load in 2019 to about 383 GW.h absent the Minto mine operation, and limited growth thereafter absent connection of industrial loads (i.e., forecast Yukon Energy firm generation at 395 GW.h in 2022, 431 GW.h in 2030, and declining to 424 GW.h in 2035). However, non-industrial peak load is expected to continue increasing more quickly than firm generation load through at least the next decade.

***Material Capital and Planning Expenditures***

Increases to rate base are a key rate increase driver in the Application, affecting increases in depreciation/amortization expense and return on rate base (particularly the increase in equity return, as cost of debt has been greatly reduced by the YDC refinancing arranged in late 2014). Overall, forecast mid-year net rate base (i.e., after contributions) in 2018 is $64 million higher than the mid-year net rate base as approved for 2013 in the last GRA.

Material capital and planning expenditure additions since the 2012/13 GRA are a key factor leading to rate base increases in 2017 and 2018, particularly with regard to investments for sustaining capital,

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[3] See Section 2.4. Excluding industrial load, the forecast peak in this Application is at 85.3 MW in 2017 and 86.4 MW in 2018. The 2016 Resource Plan forecast non-industrial peak load under the "Very Low Industrial Activity" scenario is 83.8 MW for 2017 and 85.8 MW for 2018 (excluding Minto mine peak load).

[4] As reviewed in Tab 2, more recent information indicates that the Minto mine is now expected to operate through to at least 2020.

investments to address capacity shortfalls, and deferred costs for continued planning to meet future supply requirements.

- **Sustaining Capital requirements** – The 2012/13 test year capital spending 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 and aging infrastructure.[5] Following the 2012/13 GRA Yukon Energy has continued its focus on sustaining capital requirements with spending on a number of major projects (i.e., more than $1 million) to meet ongoing sustaining capital requirements, including (as reviewed in Tab 5) Whitehorse Hydro Unit #4 Overhaul, Aishihik Electrical and Controls Upgrade, Aishihik Elevator Shaft Structural Steel Rehabilitation, Mayo A Hydro Overhaul, Wareham Spillway Gate Hoist Replacement, and T&D Breaker Replacements and T & D Line Replacement projects.

- **Investments to address capacity shortfalls** – The 2012/13 GRA identified the continuing need to meet capacity planning requirements, and Yukon Energy's 2016 Resource Plan has highlighted a current and growing need for new capacity to meet requirements under the single contingency (N-1) criterion. This Application (Tab 2, Section 2.4) forecasts the dependable capacity shortfall at 7.6 MW for 2017 and 8.7 MW for 2018,[6] based on forecast non-industrial load growth without any new diesel unit retirements. The following are major project investments completed or being carried out since 2013 to address capacity shortfalls:

    - **Completed redundancy project at Takhini Substation** – In 2011, as part of the five-year update to the 2006 Resource Plan, Yukon Energy reviewed the capability of the new system (including the integration of WAF and MD grids, and the completion of Mayo B), focusing on the question of whether the 2 hours/ year loss of load expectation planning target, continues to be appropriate for the updated and integrated grid system. This review confirmed that the previous approach used for Whitehorse-Aishihik-Faro (WAF) grid capacity planning was reasonable for the integrated system, subject to the 25 km line L172 between Takhini and Whitehorse being appropriately reinforced within the next few years so as to provide no line constraint through this line segment. Yukon

[5] Examples include the following projects reviewed in the last GRA: Aishihik Generation Station Redundancy Project (to address issues related to power cable reliability); Mayo Hydro Substation Enhancements; Mayo Head Gate Repairs and the Whitehorse Spillway Improvements.
[6] See Tab 2, Section 2.4. The 2016 Resource Plan forecasts the single contingency (N-1) dependable capacity shortfall at 6 MW for 2017 and 8 MW for 2018 (see Table 4.5 in the 2016 Resource Plan).

Energy proceeded with the Whistle Bend Subdivision Supply project in part to address this concern.

- **LNG Project** – Following the 2012/13 GRA, Yukon Energy pursued the Whitehorse Diesel-Natural Gas Conversion Project to address a capacity shortfall due to the planned retirement of two Mirrlees units at the Whitehorse Thermal Generating Station. This project was completed with 8.8 MW in service in July 2015.

- **LNG Third Engine** – To partially address the current capacity shortfall, planning is proceeding to install 4.4 MW of new LNG generation capacity at Whitehorse in Q1 2019, as reviewed and approved for the LNG Project.

- **High investment required over next five years** – The 2017/18 test years include spending on two major deferred cost planning projects (i.e., the Battery and the Thermal Plant projects) to address remaining capacity shortfall requirements by 2021.

- **Continued planning to meet other future supply requirements** – Yukon Energy's deferred costs during the test years include planning and feasibility, relicensing and rate case costs for other future supply requirements, including hydro storage enhancement projects at Mayo Lake and Marsh Lake that were reviewed in the 2012/13 GRA, other near-term supply projects (e.g., Demand Side Management), and longer term renewable generation planning (e.g., for small hydro or wind). The Mayo Lake Storage Enhancement Project was forecast in the 2012/13 GRA to be in-service by 2013; however, as noted in the LNG Project Part 3 filings, studies indicated that sediments in the Mayo Lake outlet channel from over 50 years of operation would constrain water outflows through the channel at low lake levels, and dredging of the outlet channel will be required to restore capability and enable the Mayo Lake storage enhancement to proceed.

  Closure of major feasibility study costs on potential projects that will not proceed (e.g., Gladstone Diversion Project) also affect test year net rate base costs.

  Projected costs for the Stewart Keno City Transmission Project planning do not currently affect forecast net rate base costs, as these investments have been funded by contributions.

***Increased Operating Expenses since 2012/13 GRA***

As noted in Section 1.1, material labour operating expense increases occurred in 2013 above the approved forecast and have continued to be a key cost driver since that time. The increase in labour expense reflects negotiated wage increases, changes in capital/non-capital allocations, and other increased costs without a major change in the overall number of Full Time Equivalent positions.

***Projects Held in WIP from 2012/13 GRA***

The Application addresses additional costs for projects held in WIP from the 2012/13 GRA for review at the next GRA of approximately $3.7 million, including about $1.8 million of deferred overhauls and about $1.7 million of 2012/13 GRA deferred projects with costs between $0.1 and $1.0 million, plus deferred brushing costs (increase Non Fuel O&M - other costs).

## 1.4 OTHER REGULATORY CONCERNS ADDRESSED IN APPLICATION

Aside from the need to address revenue requirement shortfalls at existing rates, the current Application considers other regulatory concerns that need to be addressed at this time (Tab 6 of the Application reviews Yukon Energy's responses to Board directives):

- **Integrated Vegetation Management Policy** – In Order 2013-01, the Board directed that YEC provide its completed transmission vegetation management policy for review in its next GRA. The Board also directed that for the period beyond 2013, distribution and transmission vegetation management costs ("brushing" related costs greater than 2011 actual brushing costs ($0.502 million) be held in a vegetation management deferral account. Yukon Energy's completed Transmission Vegetation Management Policy is provided as Appendix 3.1 of Tab 3 of this Application. Deferred transmission and distribution brushing costs are reviewed in Tab 3, Section 3.3.2 and 3.3.3.

- **Planning Costs Accounting Policy** – In Order 2013-01 following the 2012/13 GRA, the Board rejected the planning cost accounting policy as filed by YEC at that time. An updated planning cost accounting policy that reflects the Board's prior directions from Order 2013-1 is included as Appendix 5.1.

- **Demand Side Management (DSM) Accounting Policy** – In Order 2013-01 following the 2012/13 GRA, the Board deferred its findings and directions regarding YEC's DSM accounting policy until YEC and ATCO Electric Yukon (AEY) had jointly filed a DSM plan as directed in a prior section. The utilities' joint DSM Plan was filed as part of AEY's 2013-15 General Rate Application and was subject to review by the Board and intervenors. The Board's comments on the DSM Plan were provided in Order 2014-06. Yukon Energy's updated DSM Accounting Policy is provided as Appendix 5.2.

- **Update of Diesel Contingency Fund (DCF) & Related Matters** – In the 2012/13 GRA, Yukon Energy sought approval for a number of updates to the DCF and to reactivate the DCF for YEC diesel generation costs effective January 1, 2012 (these were reviewed in detail in Appendix 3.2 of the 2012/13 GRA Filing). In Order 2013-01, the Board rejected the DCF as proposed and ordered YEC to file a revised DCF proposal that incorporated the directions provided by the Board. Yukon Energy's revised DCF proposal was reviewed as part of a separate written proceeding in 2014. The Board approved the revised DCF in Order 2015-01 and Yukon Energy commenced quarterly filing in 2015 (starting with the Q3 quarterly filing). Since the last Application, LNG fuel and generation facilities have become available at Whitehorse. The current Application seeks changes to the DCF to include LNG in ongoing annual DCF determinations as well as other updates. These proposed updates are reviewed in Tab 3, Appendix 3.4.

- **Energy Reconciliation Adjustment (ERA)** – No proposal regarding the Rate Schedule 42 Energy Reconciliation Adjustment is provided at this time as the ERA is currently the subject of an appeal to the Court (the Appeal) from the Board's Order 2015-06 of August 18, 2015. At such time as the Court's decision is provided, Yukon Energy will review the ERA and provide the Board with a filing as required on this matter.

## 1.5 YUKON ENERGY RATES AND BILLS

Since Yukon Energy was established in 1987, rate matters related to Yukon Energy and AEY have been typically dealt with on a joint basis. This arrangement reflected AEY management of Yukon Energy prior to 1998 and the rate policy directives to the YUB set out since 1987 in various Orders in Council (OIC's) establishing equalized rates in Yukon (the most recent being OIC 1995/90), as well as the following more recent directives amending OIC 1995/90:

- OIC 2007/94 setting industrial rates until the end of 2012;

- OIC 2008/149 providing that, until the end of 2012, rate adjustments for all retail customers apply equally, when measured as percentages, to all classes of retail customers;

- OIC 2012/68 direction to the general effect that rate adjustments prior to the end of 2013 to retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers; and

- OIC 2014/23 direction to the general effect that rate adjustments prior to the end of 2018 to retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers.

Tab 10 provides copies of the current OIC's directing the Board on rate determinations.

The Board directly determines rates (other than Rider F for diesel fuel costs which is adjusted by the utilities in accordance with Board and OIC directives). The Yukon Government separately determines two other key factors directly affecting bills paid by most ratepayers (namely, the Income Tax Rebate related to AEY income taxes and the Interim Electrical Rebate).

The following are major changes affecting firm rates and bills generally paid by Yukon Energy's customers since the 2012/2013 GRA and prior to the changes proposed in this Application:

1. **Rider F (Diesel Fuel Price Changes and Rate Schedule 32 Changes)** – Per direction provided in Order 2009-8 quarterly updates are filed with the Board and provided on each Companies' website. Rider F adjusts all firm retail and industrial bills for changes in diesel fuel prices and Rate Schedule 32 rates since the last YEC or AEY GRA. The current Rider F is a refund of 0.560 cents per kW.h and was last changed as at February 1, 2016.

2. **Rider E (Diesel Contingency Fund [DCF])** – Order 2015-06 of the Board directed that YEC refund DCF contributions in excess of the $8.0 million cap through a rate rider applicable to all firm sales throughout the Yukon (Rider E). The current Rider E is a refund of 0.68 cents per kW.h, first established effective September 1, 2015.

3. **Interim Electrical Rebate (IER)** – The Government of Yukon provides for a 2.662 cents/kW.h rebate for up to the first 1,000 kW.h per month (first block) for residential non-government customers (since the termination of the RSF there is no longer similar rate relief for general service or municipal customers). This rebate was implemented in 2009 as an interim measure; it has continued to be extended since that time (the most recent extension being announced by the Government of Yukon on March 29, 2017, pending legislative approval).

# TAB 2
# YUKON ENERGY SYSTEM SALES AND GENERATION

# 2.0 YUKON ENERGY SYSTEM SALES AND GENERATION

Yukon Energy's rates are based on recovering the costs of owning, operating and maintaining the assets required to provide service to its customers. Tab 2 provides an overview of the Yukon Energy system forecast sales and generation for 2017 and 2018.

The following items are reviewed in this tab:

- Overview;
- Sales Forecast;
- Power Generation; and
- Peak Demand Forecast and Dependable Capacity Requirement.

## 2.1 OVERVIEW

Yukon Energy is the main generator and transmitter of electrical energy in Yukon, accounting for over 90% of annual Yukon power generation and providing 138 kV and 69 kV transmission facilities for the Integrated System.

Yukon Energy directly serves about 2,100 customers at the distribution (retail) level (about 10.5% of all electrical retail customers in Yukon), most of whom live in and around Dawson City, Mayo and Faro. Indirectly, Yukon Energy also provides power to Yukon retail customers served on the Integrated System (including those located in Whitehorse, Carcross, Carmacks, Haines Junction, Ross River and Teslin, Pelly Crossing, Keno and Stewart Crossing) through its wholesale sales to ATCO Electric Yukon (AEY).

Starting in 2014, firm load[1] supplied by Yukon Energy to non-industrial customers on the Integrated System has fallen below the actual and approved forecast load for 2013 due to a decline in firm wholesales to AEY. For example, at 339,861 MW.h, 2016 actual firm non-industrial sales were 2,608 MW.h lower than the approved 2013 forecast and 4,030 MW.h lower than the actual 2013 sales; and at 301,207 MW.h, 2016 actual firm wholesale sales to AEY were 5,940 lower than the approved 2013 forecast and 6,720 MW.h lower than the actual 2013 sales. Compared with 2016, firm wholesales to AEY

[1] Firm load is load excluding secondary or interruptible customer load.

were even lower in 2014 and 2015.

Industrial sales under Primary Industrial Rate Schedule 39 currently include only sales to the Capstone Mining Corp (Minto mine). No other industrial customer sales are forecast for the test years. Since 2013, firm grid load supplied by Yukon Energy to industrial customers has fallen below the actual and approved forecast load for 2013, except 2016, reflecting early shut down of the Alexco Resources Bellekeno mine in the last half of 2013. The Whitehorse Copper Tailings industrial load that was forecast to be supplied by AEY in the 2013 YEC Compliance Filing has not to date materialized.

Overall, firm generation load to be supplied by Yukon Energy on the Yukon Integrated System was forecast at 416.4 GW.h in the 2013 Compliance Filing. Actual total firm generation load was 419.2 GW.h in 2013, and fell thereafter to between 396.5 GW.h and 412.8 GW.h from 2014 to 2016. Forecast total firm generation load for the test years is 420.4 GW.h in 2017 and 421.2 GW.h in 2018.[2]

The 2013 Compliance Filing noted that non-firm secondary sales had been interrupted on a sustained basis since September 2010 (except for temporary resumption in September 2011 due to high water in Aishihik Lake), and as a result of this sustained interruption a number of secondary sales customers had converted to primary supply for their electric heating loads. The 2013 Compliance Filing included no forecast for secondary sales. Actual secondary sales during periods of surplus hydro generation ranged between 3.9 and 7.0 GW.h from 2013 to 2016, and are forecast to increase to approximately 11.5 GW.h in the 2017 and 2018 test years.

With new major legacy renewable generation assets in service by the end of 2011, the approved 2013 Compliance Filing forecast that over 97% of grid generation requirements in 2013 would be met with hydro generation based on annual long-term average (LTA) hydro generation capability. Due to higher than long-term average water and lower than forecast grid load, hydro generation supplied 98.4% to 99.5% of grid load from 2013 to 2016.

The 2013 Compliance Filing and subsequent Board approval of the updated Diesel Contingency Fund (DCF) have resulted in Yukon Energy's revenue requirement and annual thermal generation costs being determined based on long-term average hydro generation (rather than actual hydro generation resulting from actual water conditions). Accordingly, for the purpose of the 2017/18 GRA test years,

[2] The Application's 2017 and 2018 forecasts for firm generation and peak winter load are above the "Very Low Industrial Activity" scenario forecast in the 2016 Resource Plan (which forecast 417.8 GW.h annual energy for 2017 and 377 GW.h for 2018). Excluding the Minto load impact in 2018, the Application's 2018 forecast for firm energy generation is 377.4 GW.h, i.e., the same as the 2016 Resource Plan forecast without any industrial loads.

hydro and thermal generation forecasts are based on LTA hydro and wind generation as updated with the latest information.

The 2013 GRA highlighted increasing relevance of thermal generation on the Yukon hydro grid. As compared to the 0.95 GW.h diesel generation forecast for 2009 in the approved 2009 Compliance Filing, the 2013 Compliance Filing approved a forecast of 11.0 GW.h for LTA diesel generation requirements to supply the 2013 forecast grid load (excluding diesel requirements related to capital projects and hydro generation plant construction activities). Subsequently, in 2014, a diesel-natural gas conversion project was approved at YEC's Whitehorse facility to meet grid capacity requirements using a new liquefied natural gas (LNG) supply chain. Ongoing growth as then forecast in grid LTA annual thermal generation requirements was expected to result in fuel cost savings when supplied with LNG rather than diesel fuel. The LTA thermal generation forecast for 2018 is 14.5 GW.h as compared with 11.0 GW.h forecast for 2013 in the approved Compliance Filing.

Notwithstanding declines in firm energy generation requirements, ongoing experience is demonstrating that winter peak hour generation loads on the Yukon Integrated System have increased since the 2013 Compliance Filing, with the 2016 peak exceeding 88 MW compared to the 2013 Compliance Filing forecast of 80 MW (see Table 2.2). Peak generation load, including the Minto mine, is forecast at 91.8 MW for 2017 and 92.9 MW for 2018.[3] Based on existing dependable generation capacity available during winter on the Yukon Integrated System and the approved N-1 single contingency capacity planning criteria, a dependable capacity shortfall is forecast at 7.6 MW for 2017 and 8.7 MW for 2018 based on the non-industrial peak loads forecast in this Application. Planning is proceeding to install 4.4 MW of new LNG generation capacity at Whitehorse by Q1 of 2019 to partially address this capacity shortfall.

## 2.2 SALES FORECAST

Yukon Energy's actual sales for 2013 to 2016, and forecast sales for 2017 and 2018 are summarized in Table 2.1 at the end of this tab.

Total forecast sales are 397.9 GW.h for the 2017 test year and 398.6 GW.h for the 2018 test year, including secondary (interruptible) forecast sales of 11.5 GW.h in each of 2017 and 2018. Total firm (i.e., excluding secondary) forecast sales for 2017 include 309.0 GW.h of primary (firm) wholesale sales, 38.2

[3] See Section 2.4. These forecasts include Minto peak load of 6.5 MW in 2017 and 2018 (excluding industrial load, the forecast peak in this Application is at 85.3 MW in 2017 and 86.4 MW in 2018).

GW.h of primary major industrial sales, and 39.2 GW.h of firm retail sales (i.e., all firm sales other than wholesale or major industrial). Total firm forecast sales for 2018 include 309.5 GW.h of primary wholesale sales, 38.2 GW.h of primary industrial sales, and 39.4 GW.h of firm retail sales.

### 2.2.1 Wholesale Sales to ATCO Electric Yukon

Yukon Energy's firm sales are primarily made up of firm wholesale sales to AEY (about 80% in the test years, and 79-80% each year since 2013). Each year AEY provides Yukon Energy with its forecast power purchase estimate net of forecast generation from its Fish Lake hydro plant. YEC compares this forecast to its current year budget for wholesales and recent actual results, as well as 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 preparation for this Application, Yukon Energy also reviewed AEY's forecasts as provided in its recent 2016-2017 GRA filings. Subsequent to finalizing YEC's forecasts for this Application, Board Order 2017-01 was issued on the AEY GRA and AEY filed its Compliance Filing response for review by the Board and interveners.[4]

Firm wholesales to AEY have shown material changes since the last GRA, as summarized below:

- The 2013 approved forecast of firm wholesales at 307.1 GW.h included provision for 5.07 GW.h related to forecast AEY requirements for Whitehorse Copper Tailings (WCT) industrial load,[5] and AEY's Fish Lake hydro generation (which acts to reduce AEY wholesales) at 3.85 GW.h.

- Actual firm wholesales in 2013 of 307.9 GW.h were slightly higher than the approved forecast, notwithstanding that the WCT industrial load did not materialize. Given that actual Fish Lake hydro generation was close to forecast at approximately 3.7 GW.h, AEY's actual non-industrial load was about 5.8 GW.h higher than had been forecast in 2013.

- Firm wholesales declined sharply in 2014, falling 11.86 GW.h below the approved 2013 forecast. Over 50% of this decline (6.4 GW.h) reflected an increase in Fish Lake hydro generation to 10.25 GW.h. Before Fish Lake hydro impacts, AEY's grid firm load requirements in 2014 approximated 305.5 GW.h, and were about 6.1 GW.h lower than AEY's actual requirements in 2013.

[4] Board Order 2017-01, paragraph 40, directed AEY to refile its sales and revenue forecasts, incorporating its prior methodology using a 10-year timeframe for UPC regression and normalizing HDD. The subsequent AEY Compliance Filing provided revised firm Purchase Power forecasts of 300,363 MW.h for 2016 and 314,234 MW.h for 2017.

[5] Both YEC and AEY GRAs at that time forecast that WCT was expected to proceed with a summer-based industrial load.

- Firm wholesales in 2015 increased slightly over 2014 levels, but remained below the approved 2013 forecast and the 2013 actual. Before Fish Lake hydro impacts (which approximated 9.2 GW.h in 2015), AEY's grid firm load requirements approximated 307.1 GW.h in 2015.

- Firm wholesales in 2016 increased slightly over 2015 levels, but remained below the approved 2013 forecast and the 2013 actual. Before Fish Lake hydro impacts (which approximated 8.0 GW.h in 2016), AEY's grid firm load requirements approximated 309.2 GW.h in 2016.

Multi-variate regression assessments by Yukon Energy of monthly wholesales change from January 2013 through September 2016, excluding Fish Lake hydro generation impacts, highlight a strong correlation ($R^2$>90%) over this period between AEY's monthly load on the grid and Whitehorse Heating Degree Days (HDD) below 13°C.[6] Whitehorse temperatures during 2014 to 2016 were warmer than normal (with the variance from normal widening over this period)[7], indicating that AEY wholesales were progressively reduced during this period by above normal temperatures. Based on AEY evidence, the magnitude of the above normal temperature impact likely reduced AEY wholesales by about 6.4 GW.h in 2015,[8] and by a higher amount in 2016.

For Yukon Energy's GRA forecast purposes, AEY's GRA forecast was compared to final actual results for 2016 and current year business plans. Table 2.1 shows firm wholesales for 2016 at 301.2 GW.h, which is 6.5 GW.h higher than the AEY original GRA forecast for 2016 but 6.7 GW.h lower than actual firm wholesales for 2013. Based on the above assessment of wholesale changes since 2013, it was concluded that the 2016 actual was at least 2 to 3 GW.h below what could be expected based on normal temperatures, i.e., a minimum firm wholesales at normal weather of about 304 GW.h. Yukon Energy's 2016 Resource Plan forecasts based on normalized weather for non-industrial loads indicated AEY firm wholesales at about 302 GW.h for 2016, 305 GW.h for 2017, and 309 GW.h for 2018.[9] In contrast, initial runs of the YEC regression model for AEY's monthly load on the grid based on 20 years of data resulted in firm wholesale forecasts for the test years well beyond acceptable estimates (i.e., approximately 320

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[6] Other factors assessed to have some significant additional impact on wholesale monthly changes over this period were indicator variables for two winter months (January and December), hours of darkness in a month, the number of stat holidays/ weekend days in a month, and the commercial customer count. The YEC analysis did not find any significant correlation for changes in this monthly wholesale load with regard to GDP.

[7] Review of Whitehorse HHD below 13°C and below 18°C from 2013 to 2016 relative to 20-year "Normal" averages (1997-2016) indicate that overall temperatures below these specified HDD temperatures were 100-102% of Normal in 2013, 95% of Normal in 2014, 90-93% of Normal in 2015, and 86-88% of Normal in 2016.

[8] The AEY GRA proceeding response to CW-YECL-24(a) Attachment 1 indicated that 2015 total AEY sales were reduced by 6.3 GW.h due to Whitehorse HDD being below 18°C 20-year normal levels in that year. Assuming that 95% of this reduction was in the Hydro Zone, and allowing 6.0% for actual AEY losses in 2015, yields a reduction in generation load of 6.36 GW.h. A higher impact would have occurred in 2016 due to growth in loads plus a still lower HDD below 18°C relative to the 20-year normal.

[9] The "Very Low Industrial Activity" scenario forecast in the 2016 Resource Plan forecast annual non-industrial sales at 338.8 GW.h for 2016, 341.9 GW.h for 2017, and 346.5 GW.h for 2018. Allowing at least 37 GW.h/year for YEC's non-industrial retail sales (see Table 2.1), the 2016 Resource Plan forecast indicates AEY firm wholesales at about 302 GW.h for 2016, 305 GW.h for 2017, and 309 GW.h for 2018.

GWh). Based on all of these comparisons, YEC settled on the 2017 firm wholesales forecast of 309 GW.h as a reasonable expectation as reviewed below.

Forecasts for test year firm wholesales focused on two key factors:

- AEY's forecast grid firm load (firm sales plus AEY losses), with reasonable expectations for normal weather temperature conditions.

- AEY's forecast long-term average Fish Lake hydro generation during each test year (which reduce wholesale purchase requirements).

Firm wholesales for 2017 are forecast in Table 2.1 at 309.0 GW.h, which is 8.7 GW.h higher than the original AEY GRA forecast for 2017 and 4.7 GW.h lower than the AEY Compliance Filing forecast in response to Board Order 2017-01. This forecast reflects forecast AEY grid firm load at 317.6 GW.h less forecast AEY long-term average generation at 8.6 GW.h:

- The Table 2.1 wholesale forecast for 2017 assumes AEY grid firm load (i.e., before considering AEY generation) at approximately 317.6 GW.h, versus 308.9 GW.h forecast in the AEY GRA. The increase of 8.7 GW.h reflects updated information and assessments as reviewed above, including the 2016 updates showing higher loads in that year than forecast by AEY, and imply an increase of slightly over 6 GW.h to allow for normal weather conditions.[10]

- The wholesale forecast reflects reductions from the AEY grid firm load for generation supplied by AEY (Fish Lake hydro and standby diesel generation), which Table 2.1 assumes at approximately 8.6 GW.h for 2017 (8.53 GW.h for LTA Fish Lake hydro and 0.04 GW.h for standby diesel generation, based on the AEY GRA).[11]

Firm wholesales for 2018 are forecast in Table 2.1 at 309.5 GW.h, which is only 0.5 GW.h higher than the forecast for 2017:

- The Table 2.1 wholesale forecast for 2018 assumes AEY grid firm load (firm sales plus losses) at approximately 318.0 GW.h.[12] YEC reviewed its forecasts with representatives from AEY; generally

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[10] Yukon Energy's 2016 Resource Plan as well as YEC's multi-variate regression model assessments and the AEY GRA response to CW-YECL-24(a) Attachment 1 [as reviewed in the previous footnote] confirm that this is a reasonable minimum adjustment for warmer than normal conditions during the 2016 and 2017 forecast years. As was noted in the AEY GRA, there is no assurance that normal weather will occur during the test years.

[11] AEY's Final Argument in its GRA noted that Fish Lake hydro forecast for 2017 is based on average output for Fish Lake Unit #2 from 1960-2015 plus the two year average for Unit #1 adjusted for capital projects.

[12] YEC modeled these results with similar assumptions to 2017, noting only small changes in minor variables.

AEY supported YEC's position that there is little evidence for higher levels of growth on the system in 2018.

- The wholesale forecast reflects reductions from the AEY grid load for generation supplied by AEY (Fish Lake hydro and standby diesel generation), which Table 2.1 assumes at approximately 8.4 GW.h for 2018 (8.39 GW.h for LTA Fish Lake hydro and 0.04 GW.h for standby diesel generation). The LTA estimate for Fish Lake hydro was provided by AEY, based on incorporating updated planned capital work information.

### 2.2.2 Major Industrial

The test years include one Major Industrial Customer (Minto Mine - Capstone Mining Corp.) with forecast sales of 38.2 GW.h each year.[13]

The Application's forecast sales for the Minto Mine load reflect updated information provided to Yukon Energy by Capstone Mining Corp. in the first week of April 2017. These forecasts have been subject to considerable change since early 2017, i.e., forecasts as at the end of 2016 assumed that the mine's operations ceased before the end of 2017. Yukon Energy will continue to monitor with Capstone Mining Corp. any updated forecasts for this mine load during the test years, as well as the potential operation of the Minto Mine after 2018.[14]

No sales are forecast under Rate Schedule 35 – Low Grade Ore Processing Secondary Energy Rate.

The GRA forecast also does not include any potential reduction in revenues related to use of the peak shaving option included in Rate Schedule 39 Industrial Primary. Electing to take service under this provision requires at least six months advance notice from the customer, and to date, such notice has not been provided.

Yukon Energy continues to monitor the situation with respect to prospects for additional connected industrial mine loads within the next few years. Aside from the potential for the Minto mine to extend and/or renew its operations, Yukon Energy is aware of two other potential near-term mines in the Mayo-

[13] Per OIC 1995/90, an industrial customer is defined as "a customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer." The 2013/13 GRA Compliance Filings forecast sales for the Minto mine and the Alexco Resources Bellekeno mine through 2013, as well as for the Whitehorse Copper Tailings (WCT) major industrial customer of AEY (forecast to begin sales in mid-2013). The Alexco Bellekeno mine was shut down in the last part of 2013. WCT has not proceeded with any development.

[14] Capstone Mining First Quarter Financial Results (April 25, 2017) note that at current copper prices Capstone anticipates the continuation of operations at Minto until mid-2020, subject to permitting and regulatory approvals. Capstone is also evaluating further deposits for re-inclusion into reserves, which may support additional mine life beyond 2020.

Keno region that may take service as industrial customers within the next few years, subject to market conditions and ability to secure financing:

- **Eagle Gold [Victoria Gold Corp.]** – The Eagle Gold mine has successfully completed environmental and Yukon Water Board reviews and permitting, and has recently renewed efforts to secure financing as required to proceed with the development of this mine within a two year time period. YEC understands that the earliest potential operation would be in late 2018 (if development was to commence by summer 2017), and that operation would likely continue for 10 years or more, with initial industrial power purchases at about 62 GW.h/yr, increasing to about 69 GW.h/yr in years 2 and 3 and to about 92 GW.h/yr by year 6 of operation. In order to proceed, a Power Purchase Agreement (PPA) would be required between Victoria Gold Corp. and Yukon Energy (with approval by the YUB), and plans confirmed to replace the existing 69 kV line between Mayo and Keno.[15]

- **Alexco Mine [Alexco Resources Corp.]** – Alexco continues to have prospects to renew mining in the Keno region, including exploration activities which, if successful, will allow the mine to optimally operate the existing mill infrastructure. Commodity and credit markets will also have influence on the possible return of this customer. Alexco recently announced that it is beginning to develop the Keno Hill project for production over at least eight years, and that achieving start of production by the summer of 2018 will largely depend on ability to secure the necessary permits.[16] Until such time as firm plans are finalized, YEC is not able to include any related load forecast for either of the test years. YEC understands that it has the necessary PPA with Alexco to accommodate any likely renewed major industrial sales.

### 2.2.3 Yukon Energy Firm Retail Sales

Yukon Energy firm retail sales are comprised of sales to residential, general service, street light and space light customer classes served directly by Yukon Energy. The 2018 forecast of 39.4 GW.h indicates a 3.417 GW.h increase in Yukon Energy's non-industrial retail sales over 2013 (actual).

Retail sales grew 1.283 GW.h (3.6%) in 2014 over 2013 (actual), 0.730 GW.h (2.0%) in 2015 over 2014, and 0.678 GW.h (1.8%) in 2016 over 2015. Retail sales are expected to grow 0.522 GW.h (1.4%) in 2017 over 2016 and 0.204 GW.h (0.5%) in 2018 over 2017.

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[15] In the past two years, using funding provided by the Yukon Government through YDC, Yukon Energy has completed the YESAB Executive Committee review process (and secured related decision documents) for development of up to 138 kV of new transmission and related facilities from Stewart Crossing to Keno City.
[16] Whitehorse Daily Star, April 19, 2017 (article by Chuck Tobin, quoting Alexco Resources Corp. president Clynton Nauman).

#### 2.2.3.1 Residential Sales

Firm residential retail sales have increased from 13,385 MW.h in 2013 (actual) to 13,390 MW.h in 2016, and are expected to grow to 13,622 MW.h in 2017 and 13,719 MW.h in 2018. The average annual growth rate is 0.5% in 2018 (forecast) compared to 2013 (actual). This reflects ongoing modest growth in the number of customers offset by a modest decline in the average use per customer.

#### 2.2.3.2 General Service Sales

Firm general service retail sales have grown from 22,283 MW.h in 2013 (actual) to 24,994 MW.h in 2016, and are forecast to grow in 2017 to 25,318 MW.h. The fluctuation in each of these years is primarily due to the Faro mine dewatering sales, which have grown from 6.462 MW.h in 2013 (actual) to 8.494 MW.h in 2017 (forecast). The general service sales are forecast to grow to 25,436 MW.h in 2018 which is about 0.5% higher compared to the 2017 sales forecast. The 2018 forecast indicates a 2.7% average annual increase in Yukon Energy's general service sales over 2013 (actual).

#### 2.2.3.3 Lighting (Street lights and Space lights)

Firm retail sales for street lights increased from 281 MW.h in 2013 (actual) to 290 MW.h in 2014 and 2015, and then declined 11.7% to 256 MW.h in 2016, and are forecast to decline 12.1% in 2017 to 225 MW.h, and another 4.9% in 2018 to 214 MW.h. The decrease in street light sales from 2015 to 2018 is primarily due to conversion to LED street lights.

Firm retail sales for space lights were 14 MW.h in 2013, 2014, 2015, and 2016, and are forecast to be 12 MW.h in 2017 and 2018.

### 2.2.4 Secondary Sales

Due to the surplus hydro generation available after the Alexco mine ceased mining operations in 2013, as well as above average water conditions, surplus hydro generation has been available for secondary sales. Secondary sales have ranged from 3,959 MW.h to 7,030 MW.h from 2013 to 2016, and are forecast at 11,464 MW.h sales in 2017 and 2018.[17]

The increase in secondary sales forecast during the test years (2017 and 2018) is due to an increase in customers from one in 2013 to three in 2017 and 2018, and the forecast of ample continuing surplus

[17] The AEY GRA forecast secondary power purchases for 2016 and 2017 at 9.4 GW.h in each year.

hydro due to the forecast firm grid sales for these years. The three key secondary customers for 2017 and 2018 are as follows:

- The Canada Games Centre represents 3,670 MW.h of sales, based on the four year average from 2013 to 2016.
- The Yukon Hospital is forecast at 3,942 MW.h, based on the average of 2009, 2010 and 2015 when it was on full-time. 2016 was not used to calculate the average as the Yukon Hospital was off for most of 2016 due to boiler issues, which were resolved in late 2016.
- The third major secondary sales customer is Yukon College, with a forecast of 3,852 MW.h. Yukon College was connected late in 2016. The limited usage in 2016 was used to forecast 2017 and 2018.

The secondary sales price as adopted in the last GRA reflected the published rate for retail secondary sales (and the related rate for wholesales secondary sales) as of April 1, 2012. Based on the secondary sales rate effective January 1, 2017 (based on the YEC's quarterly report to the YUB on November 14, 2016), the wholesales secondary sales rate for the Application is $0.056/kW.h, i.e., $0.011/kW.h lower than the retail secondary sales rate).

## 2.3 POWER GENERATION

Hydro generation remains the predominant source of generation forecast for the test period, and is expected to be supplemented by natural gas and diesel thermal generation as required. There is also a small amount of wind generation available on the system. Table 2.2 provides a summary of forecast power generation by source.

Total generation is based on the sum of total sales plus losses. Losses are forecast at 8.8% for each of the test years.

### 2.3.1 Integrated Grid Hydro Generation

The Yukon Integrated System (YIS) has 92 MW of installed YEC hydro generation, of which approximately 70.5 MW can be relied upon for the winter peak.[18]

[18] Includes 24.5 MW at Whitehorse GS, 37 MW at Aishihik GS, and 9 MW at Mayo GS.

The 2013 Compliance Filing and subsequent Board approval of the updated Diesel Contingency Fund have resulted in Yukon Energy's revenue requirement and annual thermal generation costs being determined based on long-term average hydro generation (rather than actual hydro generation resulting from actual water conditions). Accordingly, for the purpose of the 2017/18 GRA test years, hydro and thermal generation forecasts are based on LTA hydro and wind generation as updated with the latest information.

Table 2.2 shows LTA hydro generation for 2013 at 405.6 GW.h for the actual firm generation load (this was slightly higher than the 2013 approved LTA hydro at 405.1 GW.h, which was based on the lower forecast firm load).[19] LTA hydro generation for the actual firm load from 2014 to 2016 in Table 2.2 ranges between 391.0 GW.h and 402.0 GW.h, reflecting variances in actual annual firm YIS generation load. The proposed forecast LTA hydro generation in Table 2.2 for the GRA test years (assuming a GRA),[20] utilizing updates to the LTA forecast (see Section 2.3.2), is 405.7 GW.h in 2017 and 406.1 GW.h in 2018.

Table 2.2 also shows actual hydro generation for 2013 to 2016 and forecast actual hydro generation (including for secondary sales) for 2017 and 2018. Actual hydro generation indicates the extent to which favourable water conditions in each of these years enables actual hydro generation in excess of LTA plus secondary sales requirements.

The integrated system typically operates with Whitehorse Hydro as first-on generation (outside of wind and Fish Lake) as a largely run-of-river plant. Mayo is also primarily a run-of-river plant and is therefore second on. Aishihik is used to supplement this run-of-river generation to achieve required output. Aishihik is a swing plant, meaning it follows the load profile until it reaches capacity then thermal is placed onto the grid. When thermal is generating on the system, Aishihik also provides the spinning reserve which is to provide coverage for the largest thermal unit on line.

The predominance of hydro generation on the Yukon system, combined with the fact that Yukon is isolated from other grids outside the territory, creates special seasonal and multi-year conditions that vary with YIS loads. For example, other forms of backup capacity are required to supplement available hydro to meet the system's winter/spring seasonal generation constraints, to provide reliable energy generation in drought years and to otherwise provide backup generation on the YIS when hydro is

[19] LTA hydro generation expected to be used to supply firm generation loads varies with firm generation load volumes and seasonal distribution, reflecting variances in the ability to utilize the LTA hydro generation, e.g., under lower grid loads there will tend to be greater spill of water (due to inability to use the available hydro generation capability) and therefore a lower LTA hydro generation actually expected to be used to supply electricity for firm loads.

[20] Table 2.2 LTA hydro generation "existing" forecasts for 2017 and 2018 (i.e., without a GRA) retain the LTA forecast assessments as approved for the 2013 Compliance Filing. See Section 2.3.2 for review of LTA forecast assessment changes for the "proposed" LTA forecasts.

otherwise unavailable (e.g., breakdown/maintenance requirements). Conversely, on the isolated grid there is no opportunity to utilize surplus hydro (or other renewable generation) that typically occurs during summer, as well as when water conditions are higher than LTA and/or grid loads are low relative to existing hydro generation capability. The following are specifically noted:

- **Winter Constraints** – Seasonal water storage is typically needed for hydro facilities to be fully utilized in winter. In Yukon, seasonal storage exists at Aishihik and to a much lesser extent at Mayo, but is largely unavailable at Whitehorse. As grid load increases, there is an increasing need to rely on natural gas and/or diesel thermal generation to meet base load energy requirements in winter and early spring when the peak is high and/or hydro water flows are constrained.
- **Drought-Flood Year Constraints** – In addition to seasonal supply constraints, systems predominantly based on hydro generation resources such as the Yukon grid are vulnerable to drought (low water) conditions. In these circumstances, hydro generation on the YIS must be supplemented by thermal generation.

### 2.3.2 Diesel and LNG Thermal Generation

Consistent with the Board Order 2013-01 on YEC’s 2012/13 GRA, Yukon Energy's annual thermal generation costs are based on expected thermal generation required based on long-term average (LTA) annual hydro generation availability. Accordingly, for the purpose of the 2017/18 GRA test years, thermal generation forecasts are based on the forecast total firm generation requirement less LTA hydro and wind generation (as updated with the latest information) for the forecast firm generation load.

Table 2.2 shows LTA thermal generation for 2013 as approved at 11.0 GW.h, versus LTA thermal generation of 13.3 GW.h based on actual 2013 firm load (which was higher than the approved forecast) and the approved assumptions (per the 2013 Compliance Filing) for determining LTA thermal generation for actual loads. LTA thermal generation for actual 2014 to 2016 firm loads, as determined on the same approved basis, varied between 5.3 GW.h and 10.5 GW.h due to changes in firm generation loads during these years. Using the same LTA approved assumptions for determining LTA thermal generation, the "Existing Forecast" LTA thermal generation is 14.08 GW.h for 2017 and 14.38 GW.h for 2018, reflecting the higher firm grid loads forecast.

Table 2.2 also shows actual diesel and natural gas thermal generation for 2013 to 2016, highlighting the extent to which favourable water conditions (and the related higher than LTA hydro generation) resulted in actual thermal generation being well below LTA thermal in each year.

The proposed LTA thermal generation for the Application are 14.15 GW.h for 2017 and 14.48 GW.h for 2018. The "proposed" forecasts are different than the "existing forecast" for the test years based on proposed updates to the determination of LTA annual hydro and wind generation availability for the current GRA, including the following:[21]

- Yukon Energy now has more water year records compared to 2012/13 GRA [35 water years compared to 28 water years used in 2012/13 GRA]. This added information has tended to increase LTA hydro estimates.

- Updated wind generation forecast (an increase from 0.238 GW.h/year to 0.580 GW.h/year).

- Updated reservoir and generation station water flow requirements changes, including 10-year average for Aishihik Lake spring water levels, and Mayo GS winter outflow restrictions, and Mayo lake outlet channel constraints on Mayo Lake minimum outflows (due to sediment build up in this channel). These factors together have reduced LTA hydro estimates.

It is assumed in the Application that 90% of LTA thermal generation requirements as forecast for the test years will be met by natural gas generation supplied by liquefied natural gas (LNG), with the balance (10%) supplied by diesel generation.[22]

In addition to the thermal generation forecast to supply required firm loads, YEC is including in its forecast expenses in this Application (see Tab 3) forecast thermal unit operation for maintenance even when there is no firm generation load that requires thermal generation. These requirements exist separate from the LTA thermal requirements as estimated above and in Table 2.2. The most recent low load conditions show that with low demand and higher hydro generation availability the diesel and LNG units need to be run at certain times solely for maintenance purposes, especially during summer months. In these circumstances the fuel requirements for electricity generated for maintenance will be part of the operating expense requirements (but not part of the LTA generation requirements to supply customers as shown in Table 2.2) included as part of the revenue requirement. The forecast thermal unit operation for maintenance is forecast at 445.8 MW.h/year in 2017 and 329.2 MW.h/year in 2018.

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[21] See Appendix 3.4 for more detailed review of the updated LTA hydro determinations and related expected LTA thermal generation requirements at various grid loads.

[22] See Appendix 3.4 for review of the proposed DCF changes to accommodate LNG.

## 2.4 PEAK DEMAND FORECAST AND DEPENDABLE CAPACITY REQUIREMENT

As indicated in Table 2.2, the peak demand for the integrated system is forecast to be 91.8 MW in 2017 and 92.9 MW in 2018, increasing from the actual peak demand of 82.7 MW in 2013. In 2016, the grid reached a peak of 88.1 MW.

At these forecast peak levels for the test years (which exceed reliable winter hydro generating capacity of approximately 70.5 MW), thermal generation will be required to supply firm energy demand.

Yukon Energy included an extensive review of its system capacity planning criteria in the 2006 Resource Plan. New criteria were adopted in 2006 for Yukon capacity planning purposes on the Whitehorse – Aishihik – Faro (WAF) and Mayo-Dawson (MD) grids which were not connected at that time. The new criteria required that dependable winter capacity on each hydro grid be sufficient to meet both of the following requirements:

- **Loss of Load Expectation (LOLE)** – In 2006, Yukon Energy incorporated into its capacity planning criteria a probability based measure to evaluate the maximum loads that the WAF system can safely carry by identifying the potential interruption of service for any customer (forecast of the average number of system outages per year). The LOLE criterion also recognizes the role of transmission reliability, where relevant.[23] In 2006, the system-wide capacity planning criteria for WAF and MD provided that each system would be planned not to exceed a Loss of Load Expectation of 2 hours/year. The LOLE criterion includes industrial loads as part of the assessment.

- **Emergency (or "N-1") Standard** – The capacity planning review in 2006 also recognized that the LOLE function is an average that does not indicate how long any particular outage will last, or the potential severity of consequences for customers. To address the severity of a potential outage, Yukon Energy incorporated a second test – the N-1 standard which determines system capacity assuming the loss of the system's single largest generating or transmission-related generation resource. This standard does not include industrial loads as part of the assessment. It

[23] The WAF system had substantial hydro generation availability that was directly affected by certain transmission; the WAF system also had been trending to an increasing probability of longer outages as it expanded (particularly with expansion of residential and commercial loads and major reductions in industrial load). Yukon Energy therefore incorporated the LOLE approach, with recognition of transmission reliability where relevant, into its system planning criteria to better protect all of its firm customers from generation-related outages.

ensures there is sufficient grid generation installed to meet firm residential and commercial customers' loads when a failure occurs to the single largest system component.[24]

The 2006 Resource Plan noted that, absent industrial loads, the single contingency (N-1) criterion for the WAF grid was at that time setting a higher dependable capacity requirement than the LOLE criterion. It was also noted that the LOLE criterion could in future become determinative on WAF with sufficient added load (e.g., with sufficient industrial load connected to the WAF grid).

In 2011, as part of the five-year update to the 2006 Resource Plan, Yukon Energy reviewed the capability of the new system (including the integration of WAF and MD grids, and the completion of Mayo B), focusing on the question of whether the 2 hours/year loss of load expectation planning target, measured using the existing software and modeling approach,[25] continued to be appropriate for the updated and integrated grid system. This review confirmed that the previous approach used for WAF was reasonable for the integrated system, subject to the 25 km line L172 between Takhini and Whitehorse being appropriately reinforced within the next few years so as to provide no line constraint through this line segment. Yukon Energy subsequently proceeded to reinforce this segment as needed to address this concern.[26]

The 2016 Resource Plan has indicated that the existing hydro and diesel infrastructure do not meet the single contingency (N-1) capacity planning criterion in both test years at the forecast grid loads (at the forecast industrial load, the LOLE criterion is satisfied in each test year so long as the single contingency [N-1] criterion is met).[27]

The forecast dependable capacity shortfall based on the single contingency (N-1) criterion is forecast at 7.6 MW for 2017 and 8.7 MW for 2018, as outlined below:

[24] In 2006, it was noted that for WAF the single most critical system component is the Aishihik transmission line and the largest single potential loss of supply (at that time) would be 30 MW due to loss of transmission line from Aishihik to Whitehorse. Under this standard, each integrated system (WAF and MD) was planned in 2006 to be able to carry the forecast peak winter loads under the largest single contingency (known as the N-1), excluding major industrial loads which typically maintain sufficient on-site generation for their own emergency purposes.

[25] For example, the analysis included consideration of the Aishihik transmission line in overall generation adequacy assessment, but not other specific transmission lines.

[26] As part of the Whistle Bend Subdivision Supply project, a new 25 kV power line was constructed between the Takhini Substation and the Whistle Bend subdivision. This addition has the effect of providing a redundant supply into Whitehorse if the L170 should become unavailable.

[27] The 2011 Resource Plan updated the LOLE assessment, concluding that an industrial winter peak in excess of approximately 12 MW would be needed before the LOLE criterion superseded the N-1 criterion. The 2011 Resource Plan updates included integration of WAF and MD grids, completion of Mayo B and Aishihik Third Turbine, the updated CEA unavailability rate for the Aishihik line, and ongoing changes in the overall grid load factor (updates of unit ratings, change in load distribution). The estimate excluded 1 MW for Haines Junction peak load as N-1 capacity planning requirements exclude this peak load.

- Installed YEC and AEY dependable grid capacity for the winter peak in both 2017 and 2018, based on existing capacity today and any planned retirements and excluding Fish Lake hydro, is approximately 115.0 MW (70.5 MW of YEC hydro, 39.1 MW of YEC diesel, and 5.4 MW of AEY diesel).[28]

- For the single contingency (N-1) criterion assessment of the dependable capacity, excluding Fish Lake hydro, to meet the YEC load:

    - 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 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).

    - In summary, under N-1, there is shortfall of dependable capacity of approximately 7.6 MW in 2017 and 8.7 MW in 2018.

Planning is proceeding to install 4.4 MW of new LNG generation capacity at Whitehorse in Q1 2019 to partially address this capacity shortfall.

[28] YEC defines dependable capacity as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months (November to February). For hydro resources with storage, dependable capacity is based on inflows during the five driest inflow years in history. Yukon Energy's 2016 Resource Plan provides details on YEC's updated generation inventory and dependable winter capacity of 114,983 kW (see Chapter 4, Table 4.1).

## Table 2.1:

## Summary of Customers, Energy Sales and Revenues

| Line No. | Description | 2013 Approved | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Actual | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|---|---|---|---|
| 1 | **Residential** | | | | | | | |
| 2 | Customers | 1,536 | 1,559 | 1,561 | 1,588 | 1,609 | 1,624 | 1,635 |
| 3 | Sales in MWh | 12,408 | 13,385 | 13,327 | 13,121 | 13,390 | 13,622 | 13,719 |
| 4 | MWh sales per customer | 8.1 | 8.6 | 8.5 | 8.3 | 8.3 | 8.4 | 8.4 |
| 5 | Revenue ($000s) | 1,815 | 1,943 | 1,938 | 1,913 | 1,956 | 2,002 | 2,016 |
| 6 | Cents per KWh | 14.6 | 14.5 | 14.5 | 14.6 | 14.6 | 14.7 | 14.7 |
| 7 | **General Service** | | | | | | | |
| 8 | Customers | 467 | 470 | 475 | 480 | 488 | 490 | 490 |
| 9 | Sales in MWh | 22,620 | 22,283 | 23,616 | 24,551 | 24,994 | 25,318 | 25,436 |
| 10 | MWh sales per customer | 48.4 | 47.4 | 49.8 | 51.1 | 51.2 | 51.7 | 51.9 |
| 11 | Revenue ($000s) | 3,735 | 3,621 | 3,894 | 4,048 | 4,180 | 4,036 | 4,054 |
| 12 | Cents per KWh | 16.5 | 16.3 | 16.5 | 16.5 | 16.7 | 15.9 | 15.9 |
| 13 | **Industrial** | | | | | | | |
| 14 | Sales in MWh | 40,592 | 40,513 | 36,302 | 37,186 | 41,169 | 38,219 | 38,219 |
| 15 | Revenue ($000s) | 4,787 | 4,595 | 3,958 | 4,159 | 4,478 | 4,198 | 4,198 |
| 16 | Cents per KWh | 11.8 | 11.3 | 10.9 | 11.2 | 10.9 | 11.0 | 11.0 |
| 17 | **Street lights** | | | | | | | |
| 18 | Sales in MWh | 279 | 281 | 290 | 290 | 256 | 225 | 214 |
| 19 | Revenue ($000s) | 88 | 89 | 92 | 92 | 88 | 58 | 56 |
| 20 | Cents per KWh | 31.5 | 31.6 | 31.6 | 31.6 | 34.5 | 26.0 | 26.0 |
| 21 | **Space lights** | | | | | | | |
| 22 | Sales in MWh | 15 | 14 | 14 | 14 | 14 | 12 | 12 |
| 23 | Revenue ($000s) | 4 | 4 | 4 | 4 | 4 | 3 | 3 |
| 24 | Cents per KWh | 26.7 | 26.5 | 26.6 | 25.9 | 26.0 | 22.5 | 22.5 |
| 25 | **Total Company - Firm Retail & Ind.** | | | | | | | |
| 26 | Customers | 2,003 | 2,029 | 2,036 | 2,068 | 2,098 | 2,114 | 2,126 |
| 27 | Sales in MWh | 75,914 | 76,476 | 73,549 | 75,162 | 79,823 | 77,395 | 77,599 |
| 28 | Revenue ($000s) | 10,429 | 10,252 | 9,886 | 10,214 | 10,705 | 10,297 | 10,327 |
| 29 | Cents per KWh | 13.7 | 13.4 | 13.4 | 13.6 | 13.4 | 13.3 | 13.3 |
| 30 | **Wholesale sales** | | | | | | | |
| 31 | Sales in MWh | 307,147 | 307,927 | 295,284 | 297,961 | 301,207 | 309,000 | 309,519 |
| 32 | Revenue ($000s) | 25,487 | 25,546 | 24,503 | 24,725 | 24,994 | 25,641 | 25,684 |
| 33 | Cents per KWh | 8.3 | 8.3 | 8.3 | 8.3 | 8.3 | 8.3 | 8.3 |
| 34 | **Total Company - Firm** | | | | | | | |
| 35 | Sales in MWh | 383,061 | 384,403 | 368,833 | 373,122 | 381,030 | 386,395 | 387,118 |
| 36 | Revenue ($000s) | 35,916 | 35,798 | 34,388 | 34,939 | 35,700 | 35,938 | 36,011 |
| 37 | Cents per KWh | 9.4 | 9.3 | 9.3 | 9.4 | 9.4 | 9.3 | 9.3 |
| 38 | **Secondary** | | | | | | | |
| 39 | Sales in MWh | 0 | 3,959 | 5,415 | 7,030 | 4,835 | 11,464 | 11,464 |
| 40 | Revenue ($000s) | 0 | 275 | 410 | 544 | 371 | 642 | 642 |
| 41 | Cents per KWh | 0.0 | 6.9 | 7.6 | 7.7 | 7.7 | 5.6 | 5.6 |
| 42 | **Total Company** | | | | | | | |
| 43 | Sales in MWh | **383,061** | **388,363** | **374,248** | **380,152** | **385,865** | **397,859** | **398,582** |
| 44 | Revenue ($000s) | **35,916** | **36,073** | **34,798** | **35,483** | **36,071** | **36,580** | **36,653** |
| 45 | Cents per KWh | **9.4** | **9.3** | **9.3** | **9.3** | **9.3** | **9.2** | **9.2** |
| 46 | Rider J ($000s) | 6,163 | 6,288 | 6,167 | 6,172 | 6,342 | 6,363 | 6,373 |
| **47** | **Total Sales Revenues[1]** | **42,079** | **42,360** | **40,966** | **41,655** | **42,413** | **42,943** | **43,026** |
| **48** | **Total Sales Revenues excluding secondary sales** | **42,079** | **42,086** | **40,556** | **41,111** | **42,042** | **42,301** | **42,384** |

Note:
1. Excludes revenues from other sources.

## Table 2.2:

## Summary of Energy Balance, Losses, and Peak

| Line No. | Description | 2013 Approved[1] | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Actual | Existing Forecast 2017[2] | Proposed Forecast 2017[3] | Existing Forecast 2018[2] | Proposed Forecast 2018[3] |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Sales and Losses** | | | | | | | | | |
| 1 | Total Energy Sales | 383,061 | 388,363 | 374,248 | 380,152 | 385,865 | 397,859 | 397,859 | 398,582 | 398,582 |
| 2 | Losses - MWh | 33,326 | 35,127 | 28,076 | 37,883 | 32,186 | 35,012 | 35,012 | 35,075 | 35,075 |
| 3 | Losses - % | 8.7% | 9.0% | 7.5% | 10.0% | 8.3% | 8.8% | 8.8% | 8.8% | 8.8% |
| 4 | Total Generation | 416,387 | 423,490 | 402,323 | 418,035 | 418,051 | 432,871 | 432,871 | 433,658 | 433,658 |
| 5 | Secondary Sales Related Generation | 0 | 4,318 | 5,821 | 7,731 | 5,238 | 12,473 | 12,473 | 12,473 | 12,473 |
| 6 | Firm Load Generation | 416,387 | 419,172 | 396,502 | 410,304 | 412,812 | 420,398 | 420,398 | 421,185 | 421,185 |
| | **Actual Generation - MWh** | | | | | | | | | |
| | **Hydro Generation** | | | | | | | | | |
| 7 | Whitehorse | 222,299 | 221,312 | 219,243 | 234,063 | 232,820 | 228,084 | 228,084 | 228,587 | 228,587 |
| 8 | Aishihik | 124,475 | 137,991 | 112,095 | 97,330 | 100,111 | 121,755 | 121,755 | 122,024 | 122,024 |
| 9 | Mayo | 58,369 | 62,000 | 69,082 | 81,123 | 78,480 | 80,280 | 80,280 | 80,457 | 80,457 |
| 10 | Total Hydro | 405,143 | 421,303 | 400,421 | 412,517 | 411,411 | 430,119 | 430,119 | 431,068 | 431,068 |
| 11 | **Wind Turbine** | 238 | 277 | 337 | 650 | 509 | 580 | 580 | 580 | 580 |
| | **Diesel Generation[4]** | | | | | | | | | |
| 12 | Whitehorse | 5,503 | 840 | 978 | 1,672 | 1,727 | 577 | 577 | 527 | 527 |
| 13 | Faro | 1,651 | 900 | 338 | 405 | 193 | 135 | 135 | 123 | 123 |
| 14 | Dawson | 3,852 | 135 | 223 | 1,477 | 938 | 300 | 300 | 274 | 274 |
| 15 | Mayo | 0 | 34 | 26 | 20 | 22 | 10 | 10 | 9 | 9 |
| 16 | Total Diesel | 11,006 | 1,910 | 1,566 | 3,574 | 2,879 | 1,022 | 1,022 | 934 | 934 |
| 17 | **LNG Generation[4]** | 0 | 0 | 0 | 1,295 | 3,251 | 1,150 | 1,150 | 1,076 | 1,076 |
| | **Total Thermal[4]** | 11,006 | 1,910 | 1,566 | 4,868 | 6,131 | 2,172 | 2,172 | 2,010 | 2,010 |
| | **Source - %** | | | | | | | | | |
| 18 | **Hydro Generation** | 97.3% | 99.5% | 99.5% | 98.7% | 98.4% | 99.4% | 99.4% | 99.4% | 99.4% |
| 19 | **LNG Generation** | 0.0% | 0.0% | 0.0% | 0.3% | 0.8% | 0.3% | 0.3% | 0.2% | 0.2% |
| 20 | **Diesel Generation** | 2.6% | 0.5% | 0.4% | 0.9% | 0.7% | 0.2% | 0.2% | 0.2% | 0.2% |
| 21 | **Wind Generation** | 0.1% | 0.1% | 0.1% | 0.2% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% |
| | **LTA Generation - MWh** | | | | | | | | | |
| | **LTA Hydro Generation** | 405,143 | 405,643 | 390,976 | 400,056 | 402,038 | 406,076 | 405,672 | 406,567 | 406,126 |
| | **LTA Wind Generation** | 238 | 238 | 238 | 238 | 238 | 238 | 580 | 238 | 580 |
| | **LTA Thermal Generation** | 11,006 | 13,291 | 5,288 | 10,011 | 10,536 | 14,084 | 14,146 | 14,380 | 14,480 |
| | **Total LTA Generation** | 416,387 | 419,172 | 396,502 | 410,305 | 412,812 | 420,398 | 420,398 | 421,185 | 421,185 |
| | **Peak - MW[5]** | | | | | | | | | |
| 20 | **Integrated System** | 80.0 | 82.7 | 76.5 | 82.1 | 88.1 | 91.8 | 91.8 | 92.9 | 92.9 |

**Notes:**

1 2013 Approved diesel forecast assumed hydro generation at 100% of long-term average (LTA), based on assumption that WCT would be in operation.

2 "Existing Forecasts" for 2017 and 2018 LTA Generation assume 2012/13 GRA YECSIM model LTA assessments for hydro generation and 2013 approved LTA wind generation; LTA thermal assumed to be supplied 100% with LNG generation.

3 "Proposed Forecasts" for 2017 and 2018 LTA Generation assume updated YECSIM model LTA assessments for hydro generation and updated LTA wind generation; LTA thermal assumed to include peaking generation but not maintenance, and to be supplied 90% with LNG and 10% with diesel generation. The thermal generation forecast fuel costs (Table 3.2) also include forecast generation for maintenance (446 MW.h in 2017 [133 MW.h LNG, 313 MW.h diesel] and 329 MW.h in 2018 [100 MW.h LNG and 229 MW.h diesel]).

4 Actual thermal generation reflects actual generation required for maintenance, capital, RFID and all other generation, e.g., peaking. Forecast Actual Generation includes peaking, maintenance and capital (596 MW.h diesel each test year) requirements reflecting short-term hydro generation forecasts.

5 Peak load is one-hour maximum load on the grid (forecasts assume weather normalized temperature). Forecasts for 2017 and 2018 are calculated using load factors calculated in Resource Plan Load Forecast Report 2016 [hourly non-industrial peak forecast]. The load factors for non-industrial sales are expected to be lower than in the past due to higher peaks resulting from added space heat. The Load Forecast Report 2016 notes that "peak demand forecast shows a steady increase at the beginning of the period (to 2030) driven by the increase in electrical space heating in both residential and commercial buildings."

# TAB 3
# REVENUE REQUIREMENT

# 3.0 REVENUE REQUIREMENT

Yukon Energy's forecast revenue requirement is the total forecast cost of providing service in a given year, including a fair return on equity. As set out in Tab 4, this revenue requirement is recovered from the proposed firm rates charged to Yukon Energy's retail customers, industrial customers and wholesale customers, as well as other Yukon Energy revenues.

The following items are reviewed in this tab:

- Overview;
- Fuel and Purchased Power;
- Non-Fuel Operating and Maintenance Expenses;
- Rate Base, Depreciation and Amortization;
- Return on Rate Base (Interest Costs and ROE); and
- Stabilization Mechanisms.

## 3.1 OVERVIEW

This Tab summarizes the revenue requirement for Yukon Energy for test years 2017 and 2018, as well as comparative figures for 2013 to 2016 actuals.

There are three major components to Yukon Energy's 2017 and 2018 revenue requirement:

- Operating and maintenance expenses, including fuel costs, labour and cost for administering the utility;
- Depreciation and amortization of property plant and equipment and deferred costs included in rate base; and
- Return on rate base to cover the costs of the utility's sources of capital (long-term debt and equity) required to finance the rate base.

Table 3.1 compares Yukon Energy's forecast 2017 and 2018 revenue requirement to the 2013 Yukon Utilities Board (YUB) approved (compliance) revenue requirement, as well as the 2013, 2014, 2015 and 2016 actuals. Table 3.1 also shows Yukon Energy's forecast revenue requirements existing for 2017 and 2018 without this Application, highlighting areas where the Application involves changes to previous approved costs (e.g., approved fuel prices, long-term average (LTA) thermal generation requirements, and return on equity) or the inclusion of deferred costs.

Actual revenue requirement costs for 2013 were 3.9% higher than the approved compliance filing costs of $42.263 million. In the years 2014 and 2015, actual revenue requirement costs are below the approved 2013 costs ($41.247 million in 2014 and $41.855 million in 2015). Cost reductions for 2014 and 2015 mainly reflect lower fuel costs (due to lower loads and lower fuel unit costs) and lower return on rate base (due to lower average cost of debt). Actual revenue requirement in 2016 of $42.686 million was 1.0% higher than 2013 approved. Lower fuel costs, depreciation and amortization and return on rate base were offset by higher non-fuel operating and maintenance costs.

The forecast revenue requirements proposed for 2017 and 2018 in the Application are $48.544 million and $49.864 million respectively, which are higher than the 2013 approved revenue requirement by a difference of $6.281 million and $7.601 million respectively. In general, Yukon Energy's forecast 2017 and 2018 revenue requirements primarily reflect proposed adjustments to thermal generation requirements and fuel prices, changes to labour and non-labour costs, increases in rate base, as well as changes in the proposed return on equity (ROE) relative to 2013 GRA approved forecast ("2013 approved") numbers, the last test year reviewed by the Board during Yukon Energy's 2012/2013 GRA application.

**Table 3.1:**
**Yukon Energy Revenue Requirement**
**($000)**

| | 2013 GRA compliance | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|
| Fuel and Purchased Power | $ 3,200 | $ 3,878 | $ 1,569 | $ 2,756 | $ 2,159 | $ 2,214 | $ 2,381 | $ 2,229 | $ 2,407 |
| Non-Fuel Operating and Maintenance | 18,111 | 19,381 | 19,957 | 19,580 | 20,470 | 20,787 | 22,060 | 20,737 | 22,016 |
| Depreciation and Amortization | 8,604 | 9,500 | 7,783 | 8,690 | 7,816 | 8,143 | 10,814 | 8,064 | 11,094 |
| Return on Rate Base | 12,348 | 11,139 | 11,938 | 10,829 | 12,242 | 12,282 | 13,289 | 12,478 | 14,348 |
| Revenue Requirement/Revenue | $ 42,263 | $ 43,897 | $ 41,247 | $ 41,855 | $ 42,686 | $ 43,425 | $ 48,544 | $ 43,508 | $ 49,864 |

Fuel and Purchased Power consists of expected long-term average fuel costs based on forecast loads, short-term maintenance costs and power purchased from ATCO Electric Yukon (AEY). The forecast Fuel and Purchased Power cost decreases by 25% from 2013 approved to the 2018 forecast as proposed in the Application, with a $0.819 million decrease from 2013 approved to the 2017 proposed forecast and a $0.026 million increase in 2018 over 2017 forecast. This overall decrease reflects lower fuel prices (including liquefied natural gas [LNG] as a new source of thermal generation), which more than offset slightly higher long-term average thermal generation requirements (see Table 2.2).

The forecast Non-Fuel Operating and Maintenance cost increases by 22% from 2013 approved to the 2018 forecast as proposed in the Application. The forecast cost increases by $3.949 million in 2017 over 2013 approved, but decreases by $0.045 million in 2018 over 2017 forecast. The increase from 2013 to 2018 reflects higher labour and distribution costs.

Forecast Depreciation and Amortization costs increase by 29% from 2013 approved to the 2018 forecast as proposed in the Application. The forecast cost increases by $2.210 million in 2017 over 2013 approved, and by a further $0.280 million in 2018 over 2017. These increases reflect additions to net fixed asset depreciation ($2.061 million in 2018 over 2013 approved) and deferred cost amortization ($0.429 million in 2018 over 2013 approved).

The forecast Return on Rate Base increases by 16% from 2013 approved to 2018 forecast as proposed in the Application. The forecast cost increases by $0.941 million in 2017 over 2013 approved costs, and by a further $1.059 million in 2018 over 2017 forecast. These increases primarily reflect a 28% increase in mid-year rate base in 2018 over 2013 approved, as well as the increased proposed ROE of 8.82% (as compared with the 8.25% approved in 2013); the impact on Return of the increased rate base is reduced by lower interest costs (about $2.2 million lower in 2018 over 2013 approved), reflecting lower average cost of debt (2.32% in 2018 compared with 3.58% approved for 2013). Yukon Energy's capital structure continues to be financed with 60% long term debt and 40% equity.

Each of the above categories of the 2017 and 2018 revenue requirement is reviewed in detail below.

## 3.2 FUEL AND PURCHASED POWER

Fuel and Purchased Power costs as set out in Table 3.2 for 2017 and 2018 test years decrease to $2.381 million and $2.407 million respectively (from $3.200 million in 2013 approved), reflecting decreased fuel prices (including LNG as a new thermal generation source). As reviewed in Section 2.3.2, Yukon Energy's annual fuel costs continue to be based on forecast long-term average hydro and wind generation, and related long-term average thermal generation, required to supply the firm generation grid load. The test year long-term average forecasts for hydro and wind generation have been updated to reflect new information available after the 2013 GRA filings, and forecast long-term average thermal requirements for the test years are assumed to be supplied with a combination of 90% LNG and 10% diesel generation. As reviewed in Section 3.6, the Diesel Contingency Fund (DCF) is assumed to address any variance between actual thermal generation and long-term average requirements for actual firm load generation and Rider F is assumed to address any variance in diesel or LNG delivered fuel prices from the forecast prices assumed for the Application. The proposed test year fuel costs also include requirements for maintenance.

**Table 3.2:**
**Fuel and Purchased Power**
**($000)**

| | 2013 GRA compliance | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|
| Fuel | $ 3,160 | $ 3,848 | $ 1,528 | $ 2,720 | $ 2,114 | $ 2,175 | $ 2,342 | $ 2,190 | $ 2,368 |
| Purchased Power | 40 | 30 | 41 | 36 | 45 | 39 | 39 | 39 | 39 |
| Total Fuel and Purchased Power | $ 3,200 | $ 3,878 | $ 1,569 | $ 2,756 | $ 2,159 | $ 2,214 | $ 2,381 | $ 2,229 | $ 2,407 |

Note:
1. Fuel costs reflect long-term average thermal generation fuel costs at forecast firm loads, maintenance and run-up requirements, and forecast fuel prices.

As reviewed in Section 2.3.2, forecast long-term average thermal generation is 14.1 GW.h in 2017 and 14.5 GW.h in 2018 (see Table 2.2). Test year fuel cost for forecast long-term average thermal generation is $2.240 million in 2017 and $2.293 million in 2018 before considering forecast fuel costs for thermal maintenance activities.

Forecast thermal consumption for maintenance activities will require both LNG and diesel generation units. For maintenance activities, the forecast LNG unit operation required is 0.133 GW.h in 2017 and 0.100 GW.h in 2018, and the forecast diesel unit operation required is 0.313 GW.h in 2017 and 0.229 GW.h in 2018. The forecast annual maintenance cost for LNG is $0.020 million in 2017 and $0.015 million in 2018, and for diesel is $0.082 million in 2017 and $0.060 million in 2018.

Forecast LNG delivered price to Yukon Energy's Whitehorse thermal facility for the 2017/2018 test years is $0.3767 per litre.[1] Yukon Energy forecasts average efficiency for LNG generation of 2.57 kW.h/litre. The resulting forecast LNG cost is $0.1467/kW.h.

Forecast diesel prices for the 2017/2018 test years are $0.9163 per litre for Whitehorse, $0.9535 per litre for Faro, $0.9818 per litre in Dawson and $0.9616 per litre in Mayo, and reflect the most recent diesel

[1] Reflects the September to December 2016 average delivered LNG cost from the Ferus facility in Elmworth, Alberta, and the forecast that test year LNG requirements will be supplied from facilities at no greater distance from Whitehorse than Elmworth. Assumed energy content (HHV) per litre of LNG approximates 0.02369GJ.

prices for YEC as of December 2016. These diesel price forecasts are lower than the 2013 approved diesel prices of $1.0513 per litre, $1.0885 per litre, $1.168 per litre and $1.0966 per litre respectively. Yukon Energy forecast average efficiency for diesel fuel is 3.60 kW.h/litre in Whitehorse, 3.67 kW.h/litre in Faro, 3.49 kW.h/litre in Dawson and 3.46 kW.h/litre in Mayo, and is based on averages of 2015 and 2016 actuals. The overall grid efficiency of 3.58 kW.h/litre is a decrease from the 2013 GRA, where the approved average efficiency was 3.67 kW.h/litre; the decrease reflects aging assets and the assumed location of diesel generation sourcing. The average cost per kW.h of diesel for the purposes of this Application is $0.2633/kW.h.

Purchased power costs relate to power purchased by Yukon Energy from AEY at Johnson's Crossing. Forecast costs in both test years are $0.039 million compared to $0.040 million in 2013 approved.

## 3.3 NON-FUEL OPERATING AND MAINTENANCE EXPENSES

The total non-fuel operating and maintenance expense approved in the 2013 GRA was $18.111 million, accounting for approximately 43% of the total revenue requirement. Table 3.3 indicates a higher actual expense for 2013, 2014, 2015 and 2016 at $19.381 million, $19.957 million, $19.580 million and $20.470 million respectively. Total operating and maintenance costs are forecast in the Application to increase to $22.060 million for 2017 and $22.016 million for 2018. This is a $3.949 million increase in 2017 over 2013 approved (22% increase) but a $0.045 million decrease in 2018 over 2017 forecast (0.2% decrease). Table 3.3 labour expense is reported as a company total; subsequently in this Tab, the labour costs are broken out by function.

**Table 3.3:**
**Non-Fuel Operating and Maintenance Expenses**
**($000)**

| | 2013 GRA compliance | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|
| Labour | $ 9,348 | $ 10,604 | $ 11,172 | $ 11,068 | $ 11,739 | $ 11,770 | $ 11,770 | $ 11,823 | $ 11,823 |
| Production | 1,437 | 1,639 | 1,795 | 1,595 | 1,906 | 1,750 | 1,750 | 1,799 | 1,799 |
| Transmission | 853 | 1,266 | 594 | 680 | 709 | 661 | 1,417 | 570 | 1,419 |
| Distribution | 226 | 322 | 553 | 541 | 284 | 302 | 530 | 394 | 535 |
| General O&M | 1,154 | 1,224 | 1,321 | 1,382 | 1,156 | 1,238 | 1,238 | 1,219 | 1,219 |
| Administration | 3,646 | 2,778 | 2,947 | 2,585 | 2,726 | 3,149 | 3,149 | 3,001 | 3,001 |
| Insurance and Reserve for Injuries/Damages | 1,121 | 1,216 | 1,243 | 1,256 | 1,263 | 1,221 | 1,510 | 1,221 | 1,510 |
| Property Taxes | 326 | 331 | 331 | 473 | 686 | 696 | 696 | 708 | 708 |
| Total OM&A (Tab 7, Schedule 10) | $ 18,111 | $ 19,381 | $ 19,957 | $ 19,580 | $ 20,470 | $ 20,787 | $ 22,060 | $ 20,737 | $ 22,016 |

Non-labour costs are forecast to increase $1.527 million for 2017 over 2013 approved costs of $8.763 million, but are forecast to fall $0.098 million in 2018. The average annual compound increase in non-labour expenses is approximately 3.1% (2018 expenses over 2013 approved).

An increase in labour expense makes up $2.423 million, or 61%, of the $3.949 million increase in 2017 forecast over 2013 approved costs, and labour expense is forecast to increase further by $0.053 million in 2018 forecast over 2017 forecast. The average annual compound increase in labour expenses is approximately 4.8% (2018 expenses over 2013 approved).

Labour expense is generally a function of the following three factors:

- **Head Count** – This relates to the number of full time equivalent positions; Table 3.4 indicates that the total position count has increased by 1.7 positions since 2013; a detailed description of changes from 2013 approved to the forecast for 2018 is provided below.

- **Labour Rates** – This includes factors such as base pay, benefit cost, annual increments (performance increments, cost of living adjustments), etc. This is heavily influenced by collective bargaining agreements.

- **Capital/Maintenance Allocation** – YEC estimates the percentage of time each position will spend on capital and non-capital works. This assessment is based on past experience as well as expectations for the coming year. This allocation directly impacts the revenue requirement in any given year as maintenance charges are directly expensed while capital labour is reflected in expenses such as depreciation after the project is completed and placed into service. The 2013 approved revenue requirement forecasts included an allocation set at 23% capital and 77% maintenance. Actual results over the 2013 to 2016 period varied between 20:80 and 16:84. The allocation for the 2017 and 2018 forecasts have been adjusted to align with historical results and are set at 18:82.

The average annual negotiated increase in wages approximates 1.9% from 2013 approved to 2016, and is forecast to increase at approximately this same annual rate to 2018. Full Time Equivalent (FTE) positions are forecast to increase by 1.70 FTEs in 2018 over 2013 approved (an average annual increase of 0.4%). The Yukon Energy employee complement is shown in Table 3.4.

**Table 3.4:**
**Employee Complement History**

| | 2013 GRA compliance | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|---|---|---|
| President | 4.50 | 5.00 | 5.00 | 5.46 | 5.09 | 5.16 | 4.16 |
| Communications | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Human Resources & Info. Mgmt. | 6.25 | 6.16 | 6.12 | 6.13 | 5.20 | 5.25 | 5.25 |
| Resource Planning and Environment | 7.00 | 7.00 | 6.00 | 6.00 | 6.00 | 5.00 | 5.00 |
| Finance, Cust. Acctg. & Purchasing | 17.00 | 16.96 | 17.63 | 16.81 | 16.87 | 16.79 | 16.79 |
| Operations | 41.25 | 42.83 | 42.15 | 42.79 | 44.15 | 43.50 | 44.50 |
| Engineering Services | 13.00 | 12.00 | 13.00 | 13.00 | 13.00 | 15.00 | 15.00 |
| Health, Safety & Environment | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 |
| Total | 92.00 | 92.95 | 92.90 | 93.19 | 93.31 | 93.70 | 93.70 |

Note:
1. The employee complement numbers are net of allocation to YDC.

Yukon Energy has had minimal growth in its labour complement by filling only necessary positions. A summary of changes from 2013 approved to 2018 forecast is provided below.

- **President:** From 2013 approved to 2018 forecast the employee complement decreased by 0.34 positions. The 2013 approved complement was increased by 0.50 positions due to an allocation to Yukon Development Corporation (YDC). The President no longer provides service to YDC, resulting in an increase of 0.50 from 2013 approved. There is a decrease in 1 position in 2018 due to the elimination of the Receptionist. The remaining 0.16 positions is due to additional administrative assistance.

- **Human Resources (HR) and Information Management:** From 2013 approved to 2018 forecast the employee complement decreased by 1.00 position. The HR Director position was replaced by an HR Manager position, and the HR Advisor position was eliminated.

- **Resource Planning and Environment:** From 2013 approved to 2018 forecast the employee complement decreased by 2.00 positions. A 1.00 reduction in 2014 relates to the elimination of the Manager, Resource Planning position. A further reduction of 1.00 position in 2017 relates to an Administrative Assistant position being moved from Resource Planning to Engineering.

- **Finance:** From 2013 approved to 2018 forecast the employee complement decreased by 0.21 positions, primarily due to a reduction in casual administrative assistance.

- **Operations:** From 2013 approved to 2018 forecast the employee complement increased by 3.25 positions. In 2013, there was an increase of 0.25 positions for a Plant Operator and 1.00 position for an Administrative Assistant. A 1.00 increase in 2016 relates to the addition of an Apprentice

Maintenance Mechanic to backfill an employee on long-term disability. A 1.00 increase in 2018 is for an additional Maintenance Mechanic to reduce the amount of work contracted out.

- **Engineering Services:** From 2013 approved to 2018 forecast the employee complement increased by 2.00 positions. An increase of 1.00 position in 2017 relates to an Administrative Assistant position being moved from Resource Planning to Engineering. An additional 1.00 position increase is due to the newly created Asset Manager position.

### 3.3.1 Production

Costs for production consist of labour and non-labour components, excluding fuel and purchased power costs. As set out in Table 3.5, total production costs in 2016 are higher than 2013 approved costs by $1.545 million. Total production cost in 2017 is forecast to decrease by $0.279 million over 2016 actual and 2018 is forecast to increase by $0.148 million over 2017 forecast.

**Table 3.5:**
**Production Costs**
**($000)**

| | 2013 GRA compliance | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|
| Labour | $ 3,057 | $ 3,671 | $ 3,792 | $ 3,876 | $ 4,133 | $ 4,010 | $ 4,010 | $ 4,109 | $ 4,109 |
| Diesel | 439 | 444 | 569 | 430 | 548 | 436 | 436 | 425 | 425 |
| LNG | 0 | 0 | 0 | 61 | 224 | 155 | 155 | 196 | 196 |
| Hydro | 909 | 1,024 | 1,107 | 1,024 | 1,058 | 1,075 | 1,075 | 1,093 | 1,093 |
| Wind | 18 | 17 | 43 | 3 | 14 | 6 | 6 | 6 | 6 |
| Operation Supervision | 72 | 154 | 77 | 78 | 62 | 77 | 77 | 79 | 79 |
| Total Production | $ 4,494 | $ 5,310 | $ 5,588 | $ 5,472 | $ 6,039 | $ 5,760 | $ 5,760 | $ 5,907 | $ 5,907 |

Non-labour expenses increased $0.469 million (33%) in 2016 over 2013 approved, are forecast to decrease $0.156 million (8%) in 2017 over 2016 actual, and increase $0.049 million (3%) in 2018 over 2017 forecast. Increases in non-labour expenses are due to ongoing increases in materials, supplies and services for hydro plant, as well as maintenance of the new LNG plant.

Approximately 74% of the forecast increase in 2018 over 2013 approved for production costs is due to higher labour cost ($1.052 million increase in 2018 forecast over 2013 approved).

### 3.3.2 Transmission

As set out in Table 3.6, total transmission costs in 2017 with the Application are forecast to be $0.684 million over the approved 2013 costs of $1.293 million, and a further $0.004 million increase in 2018 over 2017 forecast. Transmission brushing costs are a key factor affecting variations in annual costs, as well as variations in 2017 and 2018 forecast costs with and without the Application. Board Order 2013-01 directed that for the period beyond 2013, distribution and transmission vegetation management ("brushing") related costs greater than 2011 actual brushing costs ($0.502 million) are to be held in the newly created vegetation management deferral account. Table 3.6 shows the impact of this direction on deferred transmission costs from 2014 to 2018. For clarity, this Application seeks recovery of these deferred balances as well as full recovery of ongoing annual brushing expenses.

**Table 3.6:**
**Transmission Costs**
**($000)**

| | 2013 GRA compliance | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|
| Labour | $ 440 | $ 577 | $ 507 | $ 562 | $ 621 | $ 560 | $ 560 | $ 562 | $ 562 |
| Brushing Cost | 639 | 948 | 1,161 | 1,069 | 1,034 | 1,182 | 1,182 | 1,161 | 1,161 |
| Deferred Brushing | 0 | 0 | -748 | -632 | -550 | -783 | 0 | -770 | 0 |
| Net Brushing Cost | 639 | 948 | 413 | 437 | 484 | 399 | 1,182 | 391 | 1,161 |
| Other Non-Labour | 214 | 318 | 180 | 243 | 225 | 261 | 235 | 180 | 258 |
| Total Transmission | $ 1,293 | $ 1,843 | $ 1,100 | $ 1,242 | $ 1,330 | $ 1,221 | $ 1,977 | $ 1,133 | $ 1,981 |

Note:
1. YUB order 2013-01 [paragraph 108] directed that for the period beyond 2013 test year, distribution and transmission vegetation management ("brushing") related costs greater than 2011 actual brushing costs are to be held in the newly created vegetation management deferral account. The total transmission and distribution brushing cost in 2011 was $0.502 million.

Forecast labour costs are expected to increase $0.122 million in 2018 over 2013 approved, with 112% of this occurring in 2013 actual over approved.

Forecast non-labour costs are expected to increase $0.565 million in 2017 over 2013 approved, and another $0.002 million in 2018 over 2017 forecast. The fluctuation results from changes in brushing deferral cost requirements and allocations between transmission and distribution lines. Table 3.6.1 provides further details on the brushing deferrals and allocations, including review of the $2.215 million of deferred brushing costs accumulated from 2014 to 2016 (see Table 3.14.2 in Section 3.4 for the proposed recovery of these deferred costs).

**Table 3.6.1:**
**Brushing Costs**
**($000)**

| | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|
| Transmission Brushing | 948 | 1,161 | 1,069 | 1,034 | 1,182 | 1,182 | 1,161 | 1,161 |
| Distribution Brushing | 113 | 262 | 160 | 39 | 304 | 304 | 331 | 331 |
| Total Brushing | 1,062 | 1,424 | 1,229 | 1,073 | 1,487 | 1,487 | 1,492 | 1,492 |
| Transmission Deferred | - | 748 | 632 | 550 | 783 | - | 770 | - |
| Distribution Deferred | - | 169 | 95 | 21 | 201 | - | 220 | - |
| Brushing Deferred | - | 917 | 727 | 571 | 985 | - | 990 | - |
| Net Transmission Brushing | 948 | 413 | 437 | 484 | 399 | 1,182 | 391 | 1,161 |
| Net Distribution Brushing | 113 | 93 | 65 | 18 | 103 | 304 | 111 | 331 |
| Net Brushing Expense | $ 1,062 | $ 507 | $ 502 | $ 502 | $ 502 | $ 1,487 | $ 502 | $ 1,492 |

Total brushing costs are forecast to increase by $0.425 million in 2017 over 2013 approved, and $0.005 million in 2018 over 2017 forecast. Brushing activities are based on Yukon Energy's brushing policy and 10 year plan (see Appendix 3.1). Yukon Energy has seen success since establishing a regular cycle as per the policy, with an overall decrease in the number of tree caused outages and an increasingly competitive bid process.[2] Tender packages offer much higher quality information and, along with an increase in contractor familiarity with the geography and conditions of YEC lines, has resulted in positive tender results. Significant work has also been done in developing brushing specifications to be followed by contractors as well as a guideline for brushing tender evaluation. There has already been a noticeable reduction in resources required to respond to vegetation management "hot spots", a trend that is expected to continue.

### 3.3.3 Distribution

Costs of operating and maintaining the distribution system since 2013 are set out in Table 3.7.

[2] See, Key Performance Indicators (KPIs) provided as Appendix 3.3, Table 2-1 which notes no tree related outages in 2016 compared to 5 in 2014 and 2015.

**Table 3.7:**
**Distribution Costs**
**($000)**

| | 2013 GRA compliance | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|
| Labour | $ 592 | $ 794 | $ 912 | $ 746 | $ 837 | $ 845 | $ 845 | $ 847 | $ 847 |
| Brushing Cost | 113 | 113 | 262 | 160 | 39 | 304 | 304 | 331 | 331 |
| Deferred Brushing | 0 | 0 | -169 | -95 | -21 | -201 | 0 | -220 | 0 |
| Net Brushing Cost | 113 | 113 | 93 | 65 | 18 | 103 | 304 | 111 | 331 |
| Other Non-Labour | 113 | 209 | 460 | 476 | 266 | 199 | 226 | 283 | 204 |
| Total Distribution | $ 819 | $ 1,117 | $ 1,465 | $ 1,288 | $ 1,121 | $ 1,147 | $ 1,375 | $ 1,242 | $ 1,382 |

Note:
1. YUB order 2013-01 [paragraph 108] directed that for the period beyond 2013 test year distribution and transmission vegetation management ("brushing") related costs greater than 2011 actual brushing costs are to be held in the newly created vegetation management deferral account. The total transmission and distribution brushing cost in 2011 was $0.502 million.

Forecast labour costs are expected to increase $0.255 million in 2018 over 2013 approved, with 79% of this occurring in 2013 actual over approved.

Forecast non-labour costs are expected to increase $0.304 million in 2017 over 2013 approved, and another $0.005 million in 2018 over 2017 forecast. The fluctuation results from changes in brushing deferral cost requirements and allocations between transmission and distribution lines. Table 3.6.1 provides further details on the brushing allocations.

### 3.3.4 General Operation and Maintenance

Yukon Energy incurs expenses categorized as "General" with respect to transportation, communications, SCADA communications, and maintenance of company owned properties, as set out in Table 3.8.

**Table 3.8:**
**General Operating and Maintenance**
**($000)**

| | 2013 GRA compliance | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|
| Labour | $ 250 | $ 261 | $ 414 | $ 368 | $ 366 | $ 394 | $ 394 | $ 394 | $ 394 |
| Transportation | 451 | 569 | 550 | 505 | 459 | 501 | 501 | 504 | 504 |
| Maintenance of Company Owned Properties | 611 | 565 | 552 | 673 | 501 | 535 | 535 | 508 | 508 |
| SCADA Communication | 93 | 90 | 219 | 203 | 197 | 202 | 202 | 207 | 207 |
| Total General O&M | $ 1,405 | $ 1,485 | $ 1,735 | $ 1,749 | $ 1,522 | $ 1,633 | $ 1,633 | $ 1,614 | $ 1,614 |

Total forecast costs in the non-labour General O&M categories in 2017 are $0.084 million higher than approved 2013 costs of $1.154 million (but only $0.015 million higher than actual 2013 costs), and in 2018 are $0.019 million lower than forecast for 2017. Transportation expenses are forecast to increase $0.051 million (11%) in 2017 over 2013 approved, and a further $0.003 million (1%) in 2018 over 2017 forecast. Maintenance of Company Owned Properties is expected to decrease $0.076 million (12%) in 2017 over 2013 approved and a further $0.027 million (5%) in 2018 over 2017 forecast. SCADA Communication expenses are forecast to increase by $0.110 million (118%) in 2017 over 2013 approved and a further $0.005 million (2%) in 2018 over 2017 forecast.

Labour costs increased $0.164 million in 2014 over 2013 approved, but are forecast to decline by $0.020 million in 2017 over 2014 actual and there is no change in 2018 over 2017 forecast.

### 3.3.5 Administration

As shown in Table 3.9, Administration expense is forecast to increase $0.456 million (5%) in 2017 over 2013 approved but decline $0.197 million (2%) in 2018 over 2017 forecast. Labour costs are forecast to increase $0.953 million (19%) in 2017 over 2013 approved but decrease $0.050 million (1%) in 2018 over 2017 forecast. Non-labour costs are forecast to decrease $0.497 million (14%) in 2017 over 2013 approved and a further $0.147 million (5%) in 2018 over 2017 forecast.

**Table 3.9:**
**Administration**
**($000)**

| | 2013 GRA compliance | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|
| Labour | $ 5,008 | $ 5,301 | $ 5,547 | $ 5,516 | $ 5,783 | $ 5,961 | $ 5,961 | $ 5,911 | $ 5,911 |
| Resource Planning | 26 | 18 | 9 | 6 | 14 | 48 | 48 | 48 | 48 |
| Communications | 105 | 155 | 100 | 144 | 129 | 130 | 130 | 130 | 130 |
| Customer Accounting | 191 | 232 | 224 | 214 | 208 | 224 | 224 | 225 | 225 |
| Environmental Mgmt | 569 | 230 | 350 | 273 | 166 | 278 | 278 | 238 | 238 |
| General | 1,099 | 590 | 741 | 438 | 613 | 705 | 705 | 662 | 662 |
| Information Systems | 607 | 481 | 488 | 557 | 576 | 631 | 631 | 645 | 645 |
| Fish Hatchery | 187 | 169 | 124 | 162 | 157 | 168 | 168 | 168 | 168 |
| Safety | 189 | 164 | 150 | 165 | 172 | 171 | 171 | 182 | 182 |
| Training | 260 | 161 | 154 | 169 | 143 | 175 | 175 | 175 | 175 |
| Recruitment | 120 | 124 | 280 | 296 | 231 | 244 | 244 | 229 | 229 |
| Board of Directors | 168 | 150 | 255 | 99 | 160 | 182 | 182 | 182 | 182 |
| Union | 23 | 117 | 0 | 0 | 0 | 95 | 95 | 20 | 20 |
| Regulatory Affairs | 34 | 113 | 0 | 39 | 99 | 33 | 33 | 33 | 33 |
| Material Management | 35 | 58 | 55 | 17 | 41 | 38 | 38 | 37 | 37 |
| Contracting | 16 | 12 | 8 | 5 | 14 | 12 | 12 | 12 | 12 |
| Professional Development | 17 | 4 | 9 | 1 | 3 | 15 | 15 | 15 | 15 |
| Total Administration | $ 8,654 | $ 8,080 | $ 8,495 | $ 8,101 | $ 8,509 | $ 9,110 | $ 9,110 | $ 8,912 | $ 8,912 |

Details of Administration categories with notable changes since the 2013 GRA are below:

- Resource Planning is forecast to increase 85% in 2017 over 2013 approved (no forecast change in 2018 over 2017 forecast) primarily due to additional maintenance for water flow monitoring station.

- Environmental Management is forecast to decrease $0.291 million (51%) in 2017 over 2013 approved and a further $0.040 million (14%) in 2018 over 2017 forecast, and is consistent with actual expenses from 2013 to 2016.

- General expenses are forecast to decrease $0.394 million (39%) in 2017 over 2013 approved and a further $0.043 million (6%) in 2018 over 2017 forecast, and is consistent with actual expenses from 2013 to 2016.

- Recruitment expenses are forecast to increase $0.124 million (103%) in 2017 over 2013 approved but are forecast to decrease $0.015 million (6%) in 2018 over 2017 forecast, and is consistent with actual expenses from 2014 to 2016.

### 3.3.6 Insurance and Reserve for Injuries and Damages

Yukon Energy's costs related to insurance and Reserve for Injuries and Damages are set out in Table 3.10.

**Table 3.10:**
**Insurance and Reserve for Injuries and Damages**
**($000)**

| | 2013 GRA compliance | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|
| Insurance | $ 895 | $ 990 | $ 1,017 | $ 1,030 | $ 1,037 | $ 1,031 | $ 1,031 | $ 1,031 | $ 1,031 |
| Reserve Appropriation (RFID) | 226 | 226 | 226 | 226 | 226 | 190 | 479 | 190 | 479 |
| Total | $ 1,121 | $ 1,216 | $ 1,243 | $ 1,256 | $ 1,263 | $ 1,221 | $ 1,510 | $ 1,221 | $ 1,510 |

Note:

1. The RFID amount for 2012-2016 years reflect annual appropriation of $0.190 million plus amortization of the balance over five year period [$0.036 million/year] to total $0.226 million per YUB Order 2013-01.

Yukon Energy's costs for insurance in 2017 and 2018 are forecast to increase by $0.136 million (15%) above approved 2013 costs of $0.895 million. These forecast costs are reasonably consistent with actual costs since 2014.

The Reserve for Injuries and Damages (RFID) is an account maintained as approved by the Board, in order to address uninsured and uninsurable losses as well as the deductible portion of insured losses. The reserve serves two purposes: (1) it allows for a balance to be struck between purchasing additional insurance vs. using a self-insurance type approach via the RFID; and (2) it allows the costs of unforeseen events to be smoothed out over a number of years to avoid rate instability for ratepayers.

Yukon Energy's Reserve for Injuries and Damages balance has grown from negative $0.330 million in 2013 to negative $1.059 million at the end of 2016 (negative amounts represent an excess of charges to the RFID compared to appropriations to the RFID). Pursuant to Board Order 2013-01, the appropriation against the RFID was set in the approved 2013 costs at $0.190 million per year.

Given the current balance in the reserve, and the desire to avoid similar negative balances in the future, Yukon Energy is seeking approval of a two-part solution to the RFID account:

1. Amortize the 2016 negative balance of $1.059 million over a 5-year period ($0.212 million per year).

2. Increase the annual appropriation to the RFID, starting in 2017, to $0.267 million per year. This is based on the 10-year average of actual expenses as shown in Table 3.11 below.

**Table 3.11:**
**RFID Annual Charges Ten Year History**
**($000)**

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 10 Year Average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Annual Charges | $633 | $63 | $101 | $159 | $415 | $302 | $204 | $404 | $196 | $193 | $267 |

Based on the above, RFID expenses for each of the test years are forecast at $0.267 million. The total RFID amount proposed for each test year, including amortization of the 2016 negative balance, is $0.479 million. Table 3.11.1 below shows the RFID continuity schedule.

**Table 3.11.1:**
**RFID Continuity Schedule**
**($000)**

| | | | | | Forecast | | Forecast | |
|---|---|---|---|---|---|---|---|---|
| | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Existing 2017 | Proposed 2017 | Existing 2018 | Proposed 2018 |
| Opening Balance | -$152 | -$330 | -$300 | -$267 | -$1,059 | -$1,059 | -$1,136 | -$847 |
| Annual Appropriation | 226 | 226 | 226 | 226 | 190 | 479 | 190 | 479 |
| Annual Costs | -404 | -196 | -193 | -1,018 | -267 | -267 | -267 | -267 |
| Closing Balance | -$330 | -$300 | -$267 | -$1,059 | -$1,136 | -$847 | -$1,213 | -$635 |

### 3.3.7 Property Taxes

Yukon Energy's property tax costs reflect payments in lieu made to the municipalities where it operates. Property taxes are forecast to increase $0.369 million in 2017 over 2013 approved (see Table 3.12) due primarily to the additional property for the LNG plant. Property taxes are forecast to increase $0.013 million in 2018 over 2017 forecast due to rate increases.

**Table 3.12:
Property Taxes
($000)**

| | 2013 GRA compliance | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|
| Property Taxes | $ 326 | $ 331 | $ 331 | $ 473 | $ 686 | $ 696 | $ 696 | $ 708 | $ 708 |

## 3.4 RATE BASE, DEPRECIATION AND AMORTIZATION

Yukon Energy's rate base includes all investment providing service to ratepayers, as well as components of necessary working capital. It comprises property, plant and equipment (net of depreciation), deferred study and other costs, reserves set aside for various regulatory purposes and working capital as indicated in Schedule 1 of Tab 7 of this submission. A detailed summary of the spending undertaken by Yukon Energy since the 2012/2013 GRA, as well as forecast capital spending for 2017 and 2018, is provided in Tab 5 of this Application. Table 3.13 provides Net Rate Base at mid-year as approved in 2013, actuals for 2013 to 2016, and forecasts for 2017 and 2018 test years.

**Table 3.13:
Mid-Year Net Rate Base
($000)**

| | 2013 GRA compliance | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|
| **Year-End:** | | | | | | | | | |
| Net plant in service[1] | $ 222,393 | $ 217,202 | $ 216,836 | $ 250,737 | $ 251,405 | $ 264,007 | $ 282,219 | $ 267,743 | $ 286,197 |
| **Mid-Year:** | | | | | | | | | |
| Net plant in service | | | | | | | | | |
| Before contributions | $ 386,941 | $ 382,576 | $ 379,478 | $ 402,204 | $ 425,340 | $ 428,459 | $ 437,638 | $ 432,912 | $ 451,390 |
| Less contributions | 166,023 | 165,732 | 162,459 | 168,417 | 174,269 | 170,753 | 170,826 | 167,037 | 167,181 |
| Net plant in service | 220,918 | 216,844 | 217,019 | 233,787 | 251,071 | 257,706 | 266,812 | 265,875 | 284,208 |
| Mid-year regulatory deferral[2] | 1,486 | 1,693 | 1,367 | 2,007 | 2,061 | 2,660 | 2,447 | 2,955 | 2,208 |
| Working capital | 4,280 | 4,521 | 4,495 | 4,791 | 4,928 | 5,137 | 5,200 | 5,152 | 5,210 |
| Net Rate Base | $ 226,684 | $ 223,058 | $ 222,881 | $ 240,585 | $ 258,060 | $ 265,504 | $ 274,459 | $ 273,982 | $ 291,627 |

Notes:
[1] Net plant in service at year end is gross property, plant and equipment plus deferred study and relicensing costs, less work in progress, depreciation, amortization, customer contributions, reserve for future removal and site restoration, deferred fire gain, and disallowed assets.
[2] This reflects the regulatory deferred costs (see Tab 5, Tables 5.3 to 5.8), excluding DSM and the balance of the hearing reserve account (see Table 3.14.1).

Yukon Energy's 2017 mid-year forecast rate base in this Application is $274.5 million (an increase of $47.8 million from 2013 approved mid-year rate base of $226.7 million, and 2018 forecast is $291.6 million (an increase of $17.1 million from 2017 mid-year forecast).

Mid-year net plant in service, which includes unamortized deferred costs, as well as physical plant net of depreciation, is forecast to increase to $437.6 million in 2017 (a $50.7 million increase over 2013 approved mid-year balance of $386.9 million), and to $451.4 million in 2018. The major increase to 2017 reflects the LNG plant, Aishihik elevator, and completion of the Takhini / Whistle Bend supply project.

Increases in net plant in service since the 2012/2013 GRA were offset partly by increased mid-year contributions for extensions ($170.8 million in 2017 and $167.2 million in 2018, as compared to $166.0 million approved in 2013).

The balance of the change in net rate base from mid-year 2013 approved to mid-year 2018 reflects increased working capital ($0.920 million increase in 2017 forecast over 2013 approved of $4.280, and $0.010 million increase in 2018 over 2017 forecast).

Yukon Energy's forecast proposed 2017 and 2018 expense related to depreciation of capital assets and amortization of deferred charges is $10.814 million and $11.094 million respectively as shown in Table 3.14.

**Table 3.14:**
**Depreciation and Amortization**
**($000)**

| | | | | | | Forecast | | Forecast | |
|---|---|---|---|---|---|---|---|---|---|
| | 2013 GRA compliance | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Existing 2017 | Proposed 2017 | Existing 2018 | Proposed 2018 |
| Fixed Asset Depreciation | $ 8,989 | $ 8,894 | $ 8,906 | $ 9,828 | $ 10,615 | $ 11,171 | $ 12,217 | $ 11,168 | $ 12,419 |
| Less: Customer contribution | -3,569 | -3,677 | -3,691 | -3,624 | -4,102 | -4,902 | -5,007 | -4,832 | -4,938 |
| Less: Amortization of fire insurance recoveries | -262 | -262 | -262 | -262 | -262 | -262 | -262 | -262 | -262 |
| Less: Disallowed Depreciation | -16 | -16 | -16 | -16 | -16 | -16 | -16 | -16 | -16 |
| Plus: Amortization of deferred charges | 3,462 | 4,561 | 2,846 | 2,764 | 1,581 | 2,152 | 3,883 | 2,006 | 3,891 |
| Total Depreciation & Amortization | $ 8,604 | $ 9,500 | $ 7,783 | $ 8,690 | $ 7,816 | $ 8,143 | $ 10,814 | $ 8,064 | $ 11,094 |

Notes:
1. Disallowed depreciation reflects fixed asset depreciation amounts for disallowed assets per YUB Orders: $0.004 million (YUB 1992-1) and $0.012 million (YUB 2013-01).

Forecast existing fixed asset depreciation expense (net of contributions) in 2017 and 2018 of $6.269 million and $6.336 million, respectively (as compared to $5.420 million in 2013 approved) reflect changes in the assets in service. Forecast proposed fixed asset depreciation expense (net of contributions) for this Application includes additional increases of $0.940 million and $1.145 million in 2017 and 2018, respectively, to include depreciation of overhauls added to rate base previously held in WIP until a prudence review as per Order 2013-01.[3]

As a component of net depreciation costs, the revenue requirement includes substantial credits related to amortization of contributions (customer contributions, and other no-cost capital such as grants from Yukon Development Corporation, Yukon Government and Federal Government). This offset has grown from $3.569 million in 2013 approved to $5.007 million forecast in 2017 but falls to $4.938 million in 2018. The largest growth in credits relate to a contribution from Yukon Development Corporation of $22.400 million in 2015.

The largest component of deferred charges relates to planning and study costs, regulatory hearing costs and licensing costs related to maintaining licenses of YEC's hydro facilities and air emission permits.

The amortization of planning costs is the largest component of deferred costs, which is primarily studies of the existing system and options for expanding the quantity of renewable generation, as well as studies related to the safety and reliability of the system, and other small projects. Forecast amortization of feasibility studies costs increase to $1.586 million in 2017 and $1.787 million in 2018 as set out in Tab 5. Amortization of feasibility studies costs increased due to studies previously held in WIP as per Order 2013-01 being added to rate base at the start of 2017 (approximately $8.5 million excluding DSM and overhauls) and completion of the 2016 Resource Plan. The following are key examples of deferred costs added to rate base in the test years:

- Gladstone Hydro Enhancement Project ($4.521 million over ten years).
- Resource Plan Update ($2.004 million over five years).
- Mount Sumanik Wind Feasibility Studies ($0.840 million over five years).
- Detailed Line Inspection on L178, 170, 171, 172, 169 ($0.728 million over five years).
- Climate Change Study ($0.599 million over five years).

[3] In 2012/13 GRA the amortization expense of overhauls was included as part of the deferred cost amortization. The actuals and 2016-2018 forecast years in Table 3.14 show deferred cost amortization under fixed asset depreciation.

Amortization of feasibility studies is net of amortization of contributions for feasibility studies. Amortization of contributions of feasibility studies is forecast at $0.786 million in 2017 and $0.705 million in 2018.

Amortization costs also increase due to Demand Side Management (DSM) costs previously held in WIP as per Order 2013-01 being added to rate base at the start of 2017 (approximately $2.694 million added in 2017, and a further $0.625 million added in 2018, with amortization over ten years).

Outside of planning costs, amortization of deferred costs is forecast to decrease due to reduced amortization of Regulatory costs. As per Order 2013-01, Yukon Energy established a hearing cost reserve account with a provision of $0.550 million per year. As Yukon Energy has not submitted a General Rate Application since 2013, the Corporation has had minimal hearing reserve costs since 2013. As a result, the balance of the hearing cost reserve account has a 2016 year-end balance of $0.973 million. Yukon Energy is seeking approval of a two-part solution to the growing hearing cost reserve account, resulting in an expense of $0.055 million per year during the test years:

1. Amortize the forecast 2016 credit balance of $0.973 million over a 5-year period ($0.195 million per year).

2. Decrease the annual provision to the hearing cost reserve account, starting 2017, to $0.250 million per year.

Table 3.14.1 shows the hearing cost reserve account continuity schedule.

**Table 3.14.1:**
**Hearing Cost Reserve Account Continuity Schedule**
**($000)**

| | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|
| Opening Balance | $0 | -$106 | -$224 | -$561 | -$973 | -$973 | -$1,523 | -$1,028 |
| Annual Appropriation | -550 | -550 | -550 | -550 | -550 | -55 | -550 | -55 |
| Annual Costs | 444 | 432 | 213 | 138 | 0 | 0 | 818 | 818 |
| Closing Balance | -$106 | -$224 | -$561 | -$973 | -$1,523 | -$1,028 | -$1,255 | -$266 |

In addition to the hearing cost reserve account, Order 2013-01 required Yukon Energy to create a vegetation management deferral account to defer brushing costs in excess of 2011 actual brushing costs. The vegetation management deferral account has a balance of $2.215 million at the end of 2016. As Yukon Energy has completed the Board requested vegetation management policy, Yukon Energy is seeking approval to amortize the 2016 balance of the vegetation management deferral account over ten years ($0.222 million per year). Furthermore, Yukon Energy is seeking approval of elimination of the requirement to defer brushing costs in excess of 2011 actual brushing costs. Brushing costs are detailed in Table 3.6.1. Table 3.14.2 shows the deferred vegetation management continuity schedule.

**Table 3.14.2:**
**Deferred Vegetation Management Continuity Schedule**
**($000)**

| | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|
| Opening Balance | $0 | $0 | $917 | $1,644 | $2,215 | $2,215 | $3,200 | $1,994 |
| Annual Deferred Costs | 0 | 917 | 727 | 571 | 985 | 0 | 990 | 0 |
| Annual Amortization | 0 | 0 | 0 | 0 | 0 | -222 | 0 | -222 |
| Closing Balance | $ - | $ 917 | $ 1,644 | $ 2,215 | $ 3,200 | $ 1,994 | $ 4,190 | $ 1,772 |

The deferred cost amortization also includes amortization of relicensing costs ($0.582 million in 2017 and $0.515 million in 2018) and amortization of dam safety reviews ($0.030 million per year).

Yukon Energy maintains a provision for future removal and site restoration related to property, plant and equipment. As a result of Order 2005-12, the provision is not to exceed the cumulative value of the provision at December 31, 2004 of $5.757 million. It also directs Yukon Energy to notify intervenors and interested parties when the balance of the provision reaches $2.000 million. Table 3.14.3 provides the continuity schedule of the reserve for site restoration.

**Table 3.14.3:**
**Reserve for Site Restoration Continuity Schedule**
**($000)**

| | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|
| Opening Balance | $4,671 | $4,671 | $4,671 | $4,367 | $4,359 | $4,359 | $4,247 | $4,247 |
| Annual Appropriation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Annual Costs | 0 | 0 | -304 | -8 | -112 | -112 | 0 | 0 |
| Closing Balance | $ 4,671 | $ 4,671 | $ 4,367 | $ 4,359 | $ 4,247 | $ 4,247 | $ 4,247 | $ 4,247 |

## 3.5 RETURN ON RATE BASE (INTEREST COSTS AND ROE)

The total forecast return on Yukon Energy's mid-year net rate base for 2017 is $13.289 million and for 2018 is $14.348 million as shown in Table 3.1 (see Section 3.1). This is comprised of average interest costs related to the Corporation's debt, and a fair return on shareholder equity (as discussed more fully in Tab 8).

As set out in Table 3.15, Yukon Energy seeks approval of a forecast average cost of capital of 4.84% for 2017 and 4.92% for 2018. This reflects changes to both the average interest rate on debt, and the level of fair return on equity, each reviewed below. There has been no change in the relative weighting of 60% debt and 40% equity in Yukon Energy's capital structure since the 2012/2013 GRA proceeding.

**Table 3.15:
Cost of Capital**

| | 2013 GRA compliance | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Existing 2017 | Forecast Proposed 2017 (no rate increase) | Proposed 2017 | Existing 2018 | Forecast Proposed 2018 (no rate increase) | Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Average Cost of Debt | 3.58% | 3.38% | 3.22% | 2.00% | 2.10% | 2.25% | 2.18% | 2.18% | 2.33% | 2.32% | 2.32% |
| Return on Equity | 8.25% | 7.42% | 8.44% | 8.10% | 8.69% | 8.17% | 3.96% | 8.82% | 7.89% | 3.18% | 8.82% |
| Average Cost of Capital | 5.45% | 4.99% | 5.36% | 4.50% | 4.74% | 4.63% | 2.89% | 4.84% | 4.55% | 2.66% | 4.92% |

Yukon Energy's forecast mid-year capital structure for 2017 with the Application is comprised of $164.7 million in long-term debt and $110.3 million in common equity, and for 2018 forecast to be $175.0 million and $116.7 million respectively (see Schedule 4B and Schedule 4C of Tab 7).

### 3.5.1 Costs of Debt

Yukon Energy's long-term debt at the end of 2016 consists of the following components (see Schedule 11 of Tab 7):

- Yukon Development Corporation Refinanced Term Note ($85.091 million): $92.458 million bearing interest at 2.40%, payable monthly with annual principal payments. In January 2015, the following long-term financings (total $92.458 million) were refinanced through new long-term debt from Yukon Development Corporation in order to reduce the interest payments (the result reduces interest payments in 2017 and 2018 by $1.5 million and $1.4 million respectively):
    - Term note ($69.891 million refinanced at 2.40% interest): $81.891 million bearing interest at 4.25%, payable monthly with annual principal payments.
    - Term note ($15.044 million refinanced at 2.40% interest): $17.095 million bearing interest at 3.69%, payable monthly with annual principal payments.
    - Unsecured advances ($7.524 million refinanced at 2.40% interest): Dividends declared to YDC in prior years and lent back to the utility, $2.053 million at 3.97% and $5.471 million at 4.27%.
- Yukon Development Corporation Mayo B Promissory Note ($20.215 million): $21.900 million bearing interest at the maximum face interest of 5.46%, payable annually with annual principal

payments, which forgives the interest expense if the Integrated Grid load is lower than Minimum Grid Load as set in Schedule 1 of the Mayo B Promissory Note; if the calculated interest expense is negative then YDC pays that amount in order to reduce the impact to ratepayers (in 2014 YDC paid $0.112 million to YEC due to the low generation load).

If the load is in the range between Maximum Grid Load and Minimum Grid Load then interest expense is calculated as follows (this situation did not occur in 2014 when interest expense was negative):

- 5.46% * (Actual Load – Minimum Grid Load) / Range for the year.

- Yukon Development Corporation Term Note ($20.145 million): $20.984 million bearing interest at 2.21%, payable annually with annual principal payments.
- Yukon Development Corporation 2016 Term Note ($12.136 million): $12.136 million bearing interest at 2.10%, payable monthly with no annual principal payments.
- TD Bank Interest Rate Swap ($9.697 million): $11.000 million bearing interest at 2.69%, payable monthly with monthly principal payments.
- Yukon Development Corporation 2014 Term Note ($5.505 million): $5.505 million bearing interest at 2.40%, payable monthly with no annual principal payments.

In order to maintain the 60% debt component of the capital structure for 2017 and 2018, Yukon Energy estimates additional long-term debt of $23.828 million and $7.004 million, respectively, bearing annual interest forecast at 2.15%. The interest rate is based on the most recent market rate for such borrowings as at May 2017.

### 3.5.2 Return on Common Equity

As reviewed in Tab 8, Yukon Energy has updated its forecast ROE based on a review of ROE methods and results in other jurisdictions to determine a reasonable low risk utility benchmark to use for the purposes of the current GRA filing.[4] As reviewed in Tab 8, and summarized below, Yukon Energy's forecast return on equity for the test years is 8.82% for both 2017 and 2018.

As in 2005 and in 2008/09, Yukon Energy proposes to use the currently available British Columbia Utilities Commission (BCUC) low risk utility benchmark and to apply a risk premium adder consistent with BCUC rulings, as an effective and simple means of setting the fair level of ROE.

In past proceedings when this information was available for an applicable BCUC low risk utility benchmark, a risk premium adder of 0.52% was determined based on the midpoint of the range of risk premium adders used for BCUC-regulated utilities considered potentially comparable with Yukon Energy.

For the current proceeding, it is proposed (see Tab 8 for details) that the recently approved BCUC low risk utility benchmark of 8.75% be adopted for the purposes of setting rates for Yukon Energy in the test years, with a risk premium adder of 0.57% (as the midpoint of risk premium adders approved for potentially comparable BCUC regulated utilities). After reduction of the 0.50% as required by Order in Council (OIC) 1995/90, this results in an overall proposed ROE for the test years of 8.82%, and would increase the ROE by 0.57% from the last approved ROE of 8.25%.[5]

## 3.6 STABILIZATION MECHANISMS

Yukon Energy maintains two mechanisms or accounts designed to stabilize rates and revenues. These are:

- Rider F; and
- Diesel Contingency Fund (DCF).

### 3.6.1 Rider F

The Deferred Fuel Price Account (Rider F) is established and maintained pursuant to Order in Council 1995/90, Section 8. This account captures all variations in fuel price per litre for each actual litre

[4] Since the late 1990s, Yukon Energy has relied upon a low risk utility benchmarking approach along with a reasonable risk premium (based on BCUC precedents for similar electric utilities) as a simplified approach that reduces overall cost to the ratepayer through eliminating the requirement of costly expert assessment and testimony.

[5] The ROE for Yukon Energy for the 2012 and 2013 test years applied the AUC-based low risk utility benchmark of 8.75%; however, as the AUC did not apply a risk premium as part of its approach, the Board did not approve a risk premium for Yukon Energy. Consequently, Yukon Energy's approved ROE for the test years was 8.25% (8.75% minus 0.50% per the direction provided in OIC 1995/90). See Tab 8 for more detailed review.

consumed, compared to the most recent GRA-approved fuel prices. Pursuant to Board Order 2005-12, Yukon Energy also credits this account with all variations (positive or negative) in the ongoing quarterly adjustment to the prices of secondary sales, compared to the most recent GRA-approved price. As with the typical situation where final rates are put in place following the start of the test year, once final approvals are received for new test year fuel prices, Yukon Energy recalculates the balances in these accounts to ensure that all charges to the accounts are precisely equal to what would have occurred had the ultimate YUB approvals been known at the start of the first test year. During 2015, LNG fuel and generation facilities (8.8 MW) became available for service and have been used to provide thermal backup generation on the integrated grid.

As part of the current GRA, Yukon Energy is proposing to revise Rider F to include pricing related to the delivered cost of LNG, effective January 1, 2017. This will result in the following required approvals:

- Approval to defer to the Diesel Fuel Price Variance Account (DFPVA) the variance (plus or minus) in the actual delivered cost of LNG compared to the delivered cost of LNG included in the most recent General Rate Application.

- Approval to include deferred LNG price variances in the amounts collected (or refunded) to customers through the Rider F pursuant to the Rider F - Fuel Adjustment Rider & Deferred Fuel Price Variance Policy (Rider F Policy).

- Approval of required adjustments to the Rider F Policy to incorporate reference to LNG pricing in the Diesel Contingency Fund.

### 3.6.2 Diesel Contingency Fund (DCF)

The Diesel Contingency Fund was established in the 1996/97 GRA Negotiated Settlement to ensure that the Fund (and utility ratepayers), rather than YEC earnings, pays for or benefits from changes to grid diesel generation due to fluctuations in grid hydro generation due to factors such as water condition changes that are beyond utility control.

With the DCF in place, the YUB can set customer rates based on long-term forecast hydro generation rather than short-term forecast hydro generation. The DCF is maintained to address ongoing fluctuations in thermal generation requirements (and related fluctuations in rates, up or down) that ratepayers would otherwise be exposed to due to annual water availability. In effect, the DCF operates to smooth rate impacts so that ratepayers are not subject to ongoing rate instability from year to year depending on whether it is a flood or drought year.

In the 2012/13 GRA, Yukon Energy sought approval for a number of updates to the DCF and to reactivate the DCF for YEC diesel generation costs effective January 1, 2012 (the proposed changes were reviewed in detail in Appendix 3.2 of the 2012/13 GRA filing). In Order 2013-01, the Board rejected the DCF as proposed, and ordered YEC to file a revised DCF proposal that incorporated the directions provided by the Board. Yukon Energy's revised DCF proposal was reviewed as part of a separate written proceeding in 2014. The Board approved the revised DCF in Order 2015-01 and Yukon Energy commenced quarterly filings in 2015 (starting with the Q3 quarterly filing). Key elements of the updated DCF as approved in Order 2015-01 include:

- The DCF applies each year going forward, without the need for new assessments as to whether diesel is "on the margin".
- It in principle addresses all YEC thermal generation requirements (i.e., includes LNG as well as diesel generation).
- The DCF assessments are approved by the Board and made final on a calendar year basis, addressing variances between actual thermal generation and expected or "long term average" (LTA) thermal generation based on (a) actual firm grid generation required in the calendar year, (b) LTA generation available from AEY's Fish Lake hydro and from YEC's wind generation (as approved in the previous GRA), and (c) LTA YEC hydro generation at the actual firm generation load (net of long-term average generation from wind and Fish Lake hydro).
- Expected thermal generation for any calendar year based on the above principles is determined using a table approved by the Board, derived from the power benefits simulation model (YECSIM model) as used in the last GRA. The table is to be adjusted (after review and approval of the Board) if there is a material change in load shape, e.g., due to the start or cessation of operations by an industrial customer.
- Any deviation between the expected thermal generation costs at LTA availability and actual thermal generation costs (at approved GRA fuel prices) are then attributed to the DCF.
- The DCF is capped at +/- $8 million with annual procedures for Board review and approval of any rider required to refund and/or collect funds when the DCF at the end of a calendar year is outside these caps.

A revised "Term Sheet" for the DCF was provided in Attachment 1 to Yukon Energy's April 7, 2015 Compliance Filing regarding the DCF approvals in Order 2015-01. An updated Term Sheet for this

Application is provided in Appendix 3.4, including a revised Table 1 based on the updated YECSIM model as used to determine the LTA thermal generation forecast for the test years in the Application.

The following DCF-related issues are addressed in this Application:

- **DCF Update - Outstanding matters raised in the 2015 Annual Filing** – LNG fuel and generation facilities (8.8 MW) became available for service in July 2015.[6] As part of the 2015 Annual DCF filing, Yukon Energy sought to include LNG in ongoing annual DCF determinations and included a proposed approach noting that annual DCF determinations need to take into account three factors related to YEC's LNG facilities: (1) capability of LNG in any year to supply the expected or long-term average thermal generation requirement;[7] (2) actual LNG use in the year (net of capital or RFID generation); and (3) the LNG fuel cost per kW.h to be assumed for DCF cost assessments.[8] The Board in correspondence dated March 7, 2016 noted that it was not prepared to make any determinations regarding including LNG in the DCF or Rider F until such time as YEC files a full rate rider application or a GRA.

  Yukon Energy's proposed approach for incorporating LNG into DCF determinations and other DCF update are provided in Appendix 3.4, including a revised DCF Term Sheet.

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

- **DCF 2016 Annual Filing** – This Application attaches the 2016 annual filing as filed in April 5, 2017 [Appendix 3.5] which provides the following updates regarding the status of DCF:

  - DCF Calculations and Balance Updates;
  - Updated Rider E Rate Schedule (at $0.14 c/kWh rebate effective May 1, 2017 and until March 31, 2018); and
  - Update on Forecast Water Conditions for 2017.

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[6] Deficiency corrections and various commissioning activities continued into Q4 2015.

[7] The Annual DCF filing assumed that LNG, as a lower cost fuel than diesel, will be fully utilized up to this capability - and diesel generation will then be assumed to be required for the balance of the LTA thermal generation requirement. Appendix 3.4 addresses changes proposed starting in 2017 to reflect the 90:10 ratio for LNG and diesel assumed for the LTA thermal generation in this Application's test years.

[8] Equivalent to the 28.7 c/kW.h diesel generation fuel cost used for the DCF based on the last approved GRA fuel price and average diesel generation efficiency.

# APPENDIX 3.1
# YUKON ENERGY VEGETATION MANAGEMENT POLICY

| YUKON ENERGY | Vegetation Management POLICY OP-001 | DEPARTMENT: | INQUIRIES TO: | TOPIC: |
|---|---|---|---|---|
| | | All | Director, Operations | Vegetation Management |
| | | ISSUED DATE: | REVIEW DATE: | APPROVED BY: |
| | | May 2017 | April 2020 | President & CEO |

## 1.0 Purpose

1.1 The purpose of this policy is to define a brushing program that ensures the organization:

- Completes brushing activities as efficiently and effectively as possible
- Remains in compliance with all relevant regulatory and legislative requirements
- Provides ratepayers with an appropriate tradeoff between the cost of electricity and system reliability
- Creates a safe environment around power lines for YEC employees and all members of the public

## 2.0 Scope

This policy includes all transmission and sub-transmission rights-of-way (ROWs) managed by YEC (approximately 1,142 km and 2,741 ha). It does not cover substations, generation facilities, or distribution lines.

## 3.0 Goals

The goal of the brushing program is to reduce reliability incidents caused by vegetation to an acceptable level at the lowest possible cost. This will be achieved through the following:

- Operate the program on a pre-determined cycle based on industry best practices
- Encourage the expansion of low-growth species that will not impede limits of approach at their maximum height
- Make use of any treatment types that comply with relevant regulation and that are widely used in other jurisdictions

## 4.0 Health & Safety

Any brushing work carried out by YEC staff or contractors will be performed in accordance with all relevant regulations, specifically sections 9.23 and 9.24 of the Yukon Occupational Health and Safety Regulations (Tree Pruning and Falling near Energized Conductors). All contractors are required to complete the online YEC Contractor Orientation before any work is performed.

With respect to brushing activities during Yukon fire season, YEC will assess the risk of fire based on daily review of the daily fire danger rating published by Yukon Government. Where appropriate, brushing activities will be suspended when the rating is unacceptably high.

## 5.0 Environment

Yukon Energy, through its mandate to provide safe and reliable electricity, commits to act in an environmentally responsible manner while developing and maintaining energy infrastructure in the Yukon. Assessments of all proposed vegetation management methods will include an analysis of the impact on the air, soil and water. Brushing activities will be carried out in compliance with all relevant regulation and guided by YEC's environmental management system. YEC's Environmental Work Practice EMS-EWP-013 contains information regarding relevant permits, seasonal timing of brushing activities, working near water, and applicable legislation.

## 6.0 Methods

The following mechanical brushing methods will be considered for use by YEC:

- Slashing
- Mowing
- Girdling
- Grooming
- Pruning

If approved for use, the following herbicide application methods will be considered for use by YEC (refer to section 9.0 for further commentary on herbicide use):

- Cut Surface
- Basal Bark
- Backpack Foliar
- Mechanized Foliar
- Injection Techniques

The following assessment criteria will be used for selecting a specific method (or combination of methods) for a given area:

- First Nations concerns/benefits
- Land owner concerns
- Environmental impact
- Concerns of the general public
- Health & safety considerations
- Site characteristics (terrain, species, other land uses)
- Aesthetics
- Effectiveness (long and short term)
- Cost
- Contractor or equipment availability

## 7.0 Annual Area Selection

YEC has been following the recommended work priority 10-year cycle based on the ECI transmission vegetation condition assessment and their aerial/ground survey of 2010. A summary of the 10 year cycle is attached as Appendix A. In addition, visual inspections are performed by air or ground for all lines at least twice per year and any "hot spot" areas discovered are dealt with on a priority basis.

The cyclical plan will continue to be followed, although as YEC completes a full cycle of the entire system it will be re-evaluated to ensure that the chosen cycle is the most cost effective and efficient way to maintain the Yukon transmission grid.

## 8.0 Contracting Process

The contracting of brushing services will follow standard YEC procurement procedures, including First Nation Procurement PP-002.

## 9.0 Herbicide Use

Yukon Energy has not historically used herbicides as a component of its vegetation management plan. The ECI transmission vegetation condition assessment recommended that YEC consider the use of herbicides for vegetation management as a component of IVM to maximize both cost benefits and program effectiveness. As of the current version of this policy, YEC is in the process of studying the use of herbicides for transmission vegetation management in the Yukon.

## 10-Year Cycle Option and Estimated Cost

**10 Year Cycle- BY LINE BASED ON WORK PRIORITY 2013 Forward Work Schedule- 1st Cycle** (COST IN 2010 DOLLARS- APPROXIMATELY 283 ha/yr)

| Cycle Year | Recommended Maintenance Year | Line Number | Voltage | Width Meters (KM) | Span Length (KM) | Square KM per span | Line Length (KM) | SPANS (#) | Total Square KM | Total Hectres | Total Hectres Requiring Work | 163 HA / YR<br>Cost Estimate: Priority & Critical=$4,000/HA | COMMENTS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 2010-2011 | *Critical* work from ECI Survey 2010 | | 0.03 | 0.23 | 0.0069 | | Critical<br>66 | 0.4554 | 45.54 | 45.00 | **$180,000** | * **PRODUCTION:** Priority & Critical = 2 hectres / day (current rate of production); Scheduled $/H = 4 hectres / day **WORK SCOPE**- asume 80% of total spans require work |
| | | | | 0.03 | 0.23 | 0.0069 | | Priority<br>150 | 1.0350 | 103.5 | 104.00 | **$416,000** | **66 total critical spans - from ECI survey 2010**<br>**311 total priority spans - from ECI survey 2010** |
| | | **TOTAL 2010 - 2011** | | | | | | 216 | | | **149.00** | **$596,000** | |
| 0 | 2011-2012 | *Priority* work from ECI Survey 2010 | | 0.03 | 0.23 | 0.0069 | | Priority<br>211 | 1.4559 | 145.59 | 146.00 | **$584,000** | * **COST**: Critical & Priority: $4,000/H-based on current actual; Scheduled: $2,800/H - based on 30% production improvement (reduced work scope + use of herbicides + change in contract type) |
| | | **TOTAL 2011-2012** | | | | | | 211 | | | **146.00** | **$584,000** | **66 total critical spans - from ECI survey 2010**<br>**311 total priority spans - from ECI survey 2010** |
| CYCLE # 1<br>1A | 2012 - 2013 | L 356 | 25 KV | 0.015 | 0.12 | 0.0018 | 60 | 501 | 0.1080 | 10.8 | 8.64 | **$24,192** | * COST: Scheduled: $2,800/H - based on 30% production improvement (reduced work scope + use of herbicides + change in contract type) |
| 1A | 2012 - 2013 | L 355 | 25 KV | 0.015 | 0.12 | 0.0018 | 55 | 310 | 0.5580 | 55.8 | 44.64 | **$124,992** | |
| 1A | 2012 - 2013 | L 171 | 138 KV | 0.03 | 0.23 | 0.0069 | 50 | 230 | 1.5870 | 158.7 | 126.96 | **$355,488** | L 171: Total KM=131, Total spans= 606 |
| | **TOTAL** | **CYCLE1-YR 1** | | | | | | | | | **180.24** | **$504,672** | |
| CYCLE # 1<br>2A | 2013 - 2014 | L 171 | 138 KV | 0.03 | 0.23 | 0.0069 | 82 | 376 | 2.5944 | 259.44 | 207.55 | **$581,146** | L 171: Total KM=131, Total spans= 606 |
| | **TOTAL** | **CYCLE 1-YR 2** | | | | | | | | | **207.55** | **$581,146** | |
| 3A | 2014-2015 | L 169 | 138 KV | 0.03 | 0.23 | 0.0069 | 7 | 31 | 0.2139 | 21.39 | 17.11 | **$47,914** | |
| 3A | 2014-2015 | L 172 | 138 KV | 0.03 | 0.23 | 0.0069 | 25 | 116 | 0.8004 | 80.04 | 64.03 | **$179,290** | |
| 3A | 2014-2015 | L 250 | 69 KV | 0.02 | 0.01 | 0.0002 | 52 | 531 | 0.1062 | 10.62 | 8.50 | **$23,789** | |
| 3A | 2014-2015 | L 453 | 25 KV | 0.015 | 0.14 | 0.0021 | 8 | 57 | 0.1197 | 11.97 | 9.58 | **$26,813** | * COST: Scheduled: $2,800/H - based on 30% production improvement (reduced work scope + use of herbicides + change in contract type) |
| 3A | 2014-2015 | L 170A | 138 KV | 0.03 | 0.23 | 0.0069 | 35 | 150 | 1.0350 | 103.5 | 82.80 | **$231,840** | |
| | **TOTAL** | **CYCLE 1-YR 3** | | | | | | | | | **182.02** | **$509,645** | |
| CYCLE # 1<br>4A | 2015-2016 | L 170A | 138 KV | 0.03 | 0.23 | 0.0069 | 76 | 325 | 2.2425 | 224.25 | 179.40 | **$502,320** | |
| | **TOTAL** | **CYCLE 1-YR 4** | | | | | | | | | **179.40** | **$502,320** | |
| CYCLE # 1<br>5A | 2016-2017 | L 170 A | 138 KV | 0.03 | 0.23 | 0.0069 | 57 | 247 | 1.7043 | 170.43 | 136.34 | **$381,763** | L 170A: Total KM=166; Total spans= 722 |
| | 2016-2017 | L 170B | 138 KV | 0.03 | 0.23 | 0.0069 | 18 | 80 | 0.5520 | 55.2 | 44.16 | **$123,648** | L 170B: Total KM= 191; Total Spans= 834 |
| | **TOTAL** | **CYCLE 1-YR 5** | | | | | | | | | **180.50** | **$505,411** | |
| CYCLE # 1<br>6A | 2017-2018 | L 170B | 138 KV | 0.03 | 0.23 | 0.0069 | 80 | 350 | 2.4150 | 241.5 | 193.20 | **$540,960** | L 170B: Total KM= 191; Total Spans= 834 |
| | **TOTAL** | **CYCLE 1-YR 6** | | | | | | | | | **193.20** | **$540,960** | |
| 7A | 2018 - 2019 | L 170B | 138 KV | 0.03 | 0.23 | 0.0069 | 92 | 404 | 2.7876 | 278.76 | 223.01 | **$624,422** | * COST: Scheduled: $2,800/H - based on 30% production improvement (reduced work scope + use of herbicides + change in contract type) |
| | **TOTAL** | **CYCLE 1-YR 7** | | | | | | | | | **223.01** | **$624,422** | |
| CYCLE # 1<br>8A | 2019 - 2020 | L 174 | 66 KV | 0.02 | 0.14 | 0.0028 | 101 | 750 | 2.1000 | 210 | 168.00 | **$470,400** | * COST: Scheduled: $2,800/H - based on 30% production improvement (reduced work scope + use of herbicides + change in contract type) |
| 8A | 2019 - 2020 | L 173A | 138 KV | 0.03 | 0.2 | 0.006 | 30 | 150 | 0.9000 | 90 | 72.00 | **$201,600** | |
| | **TOTAL** | **CYCLE 1-YR 8** | | | | | | | | **181** | **240.00** | **$672,000** | |
| CYCLE # 1<br>9A | 2020 - 2021 | L 173A | 138 KV | 0.03 | 0.2 | 0.006 | 80 | 402 | 2.4120 | 241.2 | 192.96 | **$540,288** | * COST: Scheduled: $2,800/H - based on 30% production improvement (reduced work scope + use of herbicides + change in contract type) |
| | **TOTAL** | **CYCLE 1 YR 9** | | | | | | | | **181** | **192.96** | **$540,288** | |
| CYCLE # 1 | | L 355 | 25 KV | 0.015 | 0.09 | 0.00135 | 55 | 1976 | 2.6676 | 266.76 | 133.38 | **$293,436** | SECOND TIME IN 10 YEAR- $2,200 / Ha and 50% work. |
| 10A | | S253-25F2 | 25 KV | 0.015 | 0.09 | 0.00135 | 29 | 336 | 0.4536 | 45.36 | 36.29 | **$101,606** | |
| | **TOTAL** | **CYCLE 1 YR 10** | | | | | | | | **181** | **169.67** | **$395,042** | |

CYCLE # 2 **10-year Cycle**

| Year of cycle | Cycle year | *First Cycle Cost Estimate | **Cost Estimate Second Cycle | Cost Assumptions |
|---|---|---|---|---|
| 1B | 2022 - 2023 | $504,672 | $403,738 | * **Assumption First Cycle**: scheduled cost=$2,800 / HA based on 30% production improvement + use of herbicides + change in contract type. ****Assumptions Second Cycle**: reduced scope of w ork (low er brush height and stems per acre and few er critical & priority locations) + incorporating the use of herbicides as a major part of VM program + change in contracting streategy = cost reduction of 20% over cycle 1. |
| 2B | 2023 - 2024 | $581,146 | $464,916 | |
| 3B | 2024 - 2025 | $509,645 | $407,716 | |
| 4B | 2025 - 2026 | $502,320 | $401,856 | |
| 5B | 2026 - 2027 | $505,411 | $404,329 | |
| 6B | 2027 - 2028 | $540,960 | $432,768 | |
| 7B | 2028 - 2029 | $624,422 | $499,538 | |
| 8B | 2029 - 2030 | $672,000 | $537,600 | |
| 9B | 2030 - 2031 | $540,288 | $432,230 | |
| 10B | 2031 - 2032 | $395,042 | $316,034 | |

# APPENDIX 3.2
# RESERVE FOR INJURIES AND DAMAGES (RFID) POLICY

| YUKON ENERGY | FINANCE POLICY FA-014 | DEPARTMENT: | INQUIRIES TO: | TOPIC: |
|---|---|---|---|---|
| | | All | Chief Financial Officer | Reserve for Injuries and Damages |
| | | ISSUED: | REVIEW DATE: | APPROVED BY: |
| | | March 2012 | February 2015 | President & CEO |

**1.0 Purpose**

1.1 The Reserve for Injuries and Damages ("RFID") is utilized to address uninsured and uninsurable losses, and associated costs, as well as the deductible portion of insured losses.

1.2 The reserve serves two purposes: (1) it allows for an appropriate balance to be maintained between self-insurance, deductibles, commercial insurance and sudden and accidental losses; and, (2) it allows the costs in question to be smoothed over a number of years to avoid rate instability for ratepayers.

**2.0 Background**

2.1 An RFID account is a risk management tool commonly used by regulated utilities to address uninsured and uninsurable losses in a manner that allows for smoothing of rate impacts over time[1]. If an uninsured or uninsurable loss occurs, and it meets defined criteria, then the value of the loss is charged against the balance in the RFID[2].

2.2 Prior to the 2012/13 GRA, the Corporation's RFID had been approved by the Yukon Utilities Board ("Board") and funded through an annual appropriation as approved by the Board. Historically, this amount fluctuated between $50,000 and $150,000 per year.

2.3 A 2010 study commissioned by the Corporation concluded that an annual appropriation of $195,000 per year was appropriate. Pursuant to Board Order 2013-01, the appropriation against the RFID was set to an approved 2013 amount of $0.190 million per year.

**3.0 Annual appropriation to the RFID**

3.1 Subject to the approval of any increase in the annual appropriation to the RFID by the Board as part of future Yukon Energy General Rate Applications, the RFID will be funded and raised through an approved annual appropriation of $190,000 with no specific limits on surpluses or deficits.

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[1] Due to the nature of these losses, the timing and quantum of the loss cannot be forecast accurately. Consequently, an annual appropriate to the reserve is approved in rates. This amount is charged to the reserve and effectively "builds up" the account over time.

[2] This expectation would be that the accumulation of annual appropriations will net out against losses incurred. However, historically, the account tends to go negative (losses exceed accumulated appropriation); at the next GRA, the utility will ask to be made whole for this amount.

## 4.0 Criteria

4.1 Uninsured and uninsurable losses and associated costs will be charged to the RFID if they meet the following criteria:

(a) The loss exceeds $10,000;
(b) The loss was sudden and accidental and not the result of normal wear and tear;
(c) The incident was of significance to the operation of the unit; and
(d) The loss was one of low probability, not normally expected to occur in a typical operating year.

4.2 The deductible portion of insured losses and any portion of a loss not covered by insurance and not related to betterment of the asset, and any extra expense related to an uninsurable or uninsurable unplanned plant outages[3] will also be charged to the RFID.

[3] For example, the loss of a hydro generating unit may require the utility to burn diesel to meet demand. Unless the utility specifically purchases Extra Expense coverage for this loss, these amounts are uninsured.

# APPENDIX 3.3
# KEY PERFORMANCE INDICATORS (KPIs)

# KEY PERFORMANCE INDICATORS

# YUKON ENERGY CORPORATION

# 2016 ANNUAL REPORT

# TABLE OF CONTENTS

## EXECUTIVE SUMMARY

Yukon Energy directly serves approximately 2,100 customers (10% of all electrical customers in Yukon) at the distribution (retail) level, most of who live in Dawson City, Mayo and Faro. Through its wholesale sales to ATCO Electric Yukon ("AEY"), it also provides power indirectly to approximately 16,600 retail customers served on the inter-connected system. During 2016 the only customer served under Rate Schedule 39 - Primary Industrial was Capstone Mining Corp ("Minto mine") which operated for the whole year.

As shown in Table 1 (following page), the number of retail customers increased modestly during 2016. Total firm sales increased by 2.1% as Industrial sales to Minto were 10.7% higher than in 2015 and Wholesale sales to AEY were 1.1% higher.

As the LNG generation project was commissioned in 2015, both LNG and diesel generation are now combined and reported herein as thermal generation for KPI reporting purposes. The addition of the two LNG generation units was offset by a corresponding reduction of diesel generation units as both the WD1 and WD2 Mirrlees units were retired during 2015. The Bonus wind turbine (0.150 MW) was also retired during 2015 as it had reached the end of its useful life. Wind generation is now comprised of only one Vestas 0.66 MW unit (WD2).

Hydro generation remains the predominant source of generation supplemented by thermal generation as required. Thermal generation was higher the past 2 years due to the Aishihik Elevator Steel Replacement project which caused the Aishihik units to be out of service from June to early October. Winter peak generation was minimal at 2 GWh for winter months in 2015 and 3 GWh for 2016.

As is typical, the Yukon Energy system experienced more outages than the CEA average (YEC 5-year average SAIFI index of 10.23 compared to 2.81 for CEA); however, they were of a shorter duration (YEC 5-year average SAIDI index of 4.66 compared to 7.40 for CEA); and customers experienced a shorter overall duration without power (YEC 5-year average CAIDI index of 0.45 compared to 2.63 for CEA).

During 2016, YEC experienced 1 Lost Time Injury of 4 days duration (same as 2015), compared to 1 Lost Time Injury of 1 day duration in 2014.

**Table 1: Summary of Customers, Energy Sales and Generation**

| Line No. | Description | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Actual | Proposed Forecast 2017 | Proposed Forecast 2018 |
|---|---|---|---|---|---|---|---|
| | **Residential** | | | | | | |
| 1 | Customers | 1,559 | 1,561 | 1,588 | 1,609 | 1,624 | 1,635 |
| 2 | Sales in MWh | 13,385 | 13,327 | 13,121 | 13,390 | 13,622 | 13,719 |
| 3 | MWh sales per customer | 8.6 | 8.5 | 8.3 | 8.3 | 8.4 | 8.4 |
| | **General Service** | | | | | | |
| 4 | Customers | 470 | 475 | 480 | 488 | 490 | 490 |
| 5 | Sales in MWh | 22,283 | 23,616 | 24,551 | 24,994 | 25,318 | 25,436 |
| 6 | MWh sales per customer | 47.4 | 49.3 | 51.8 | 51.2 | 51.7 | 51.9 |
| | **Industrial** | | | | | | |
| 7 | Sales in MWh | 40,513 | 36,302 | 37,186 | 41,169 | 38,219 | 38,219 |
| | **Street lights** | | | | | | |
| 8 | Sales in MWh | 281 | 290 | 290 | 256 | 225 | 214 |
| | **Space lights** | | | | | | |
| 9 | Sales in MWh | 14 | 14 | 14 | 14 | 12 | 12 |
| | **Total - Firm Retail & Ind.** | | | | | | |
| 10 | Customers | 2,029 | 2,036 | 2,068 | 2,098 | 2,114 | 2,126 |
| 11 | Sales in MWh | 76,476 | 73,549 | 75,162 | 79,823 | 77,395 | 77,599 |
| | **Wholesale sales** | | | | | | |
| 12 | Sales in MWh | 307,927 | 295,284 | 297,961 | 301,207 | 309,000 | 309,519 |
| | **Total - Firm** | | | | | | |
| 13 | Sales in MWh | 384,403 | 368,833 | 373,122 | 381,030 | 386,395 | 387,118 |
| | **Secondary** | | | | | | |
| 14 | Sales in MWh | 3,959 | 5,415 | 7,030 | 4,835 | 11,464 | 11,464 |
| | | | | | | | |
| | **Total** | | | | | | |
| 15 | Sales in MWh | 388,362 | 374,248 | 380,152 | 385,865 | 397,859 | 398,582 |
| 16 | Losses - MWh | 35,127 | 28,076 | 37,883 | 32,186 | 35,012 | 35,075 |
| 17 | Losses - % | 9.0% | 7.5% | 10.0% | 8.3% | 8.8% | 8.8% |
| 18 | Total Generation | 423,490 | 402,323 | 418,035 | 418,051 | 432,871 | 433,658 |
| | | | | | | | |
| | **Source** | | | | | | |
| 19 | Hydro Generation | 421,303 | 400,421 | 412,517 | 411,411 | 430,119 | 431,068 |
| 20 | *% of total* | *99.484%* | *99.5%* | *98.7%* | *98.4%* | *99.4%* | *99.4%* |
| 21 | Thermal Generation | 1,910 | 1,566 | 4,868 | 6,131 | 2,172 | 2,010 |
| 22 | *% of total* | *0.451%* | *0.4%* | *1.2%* | *1.5%* | *0.5%* | *0.5%* |
| 23 | Wind Generation | 277 | 337 | 650 | 509 | 580 | 580 |
| 24 | *% of total* | *0.065%* | *0.1%* | *0.2%* | *0.1%* | *0.1%* | *0.1%* |

## 1.0 GENERATION KPIs

***Operational Performance Indicators***

The operational performance of generation units is gauged on the basis of Capacity Factor, Unit Availability, Operating Factor and Forced and Planned Outage Rates.

Detailed definitions are as provided below:

- ***Capacity Factor*** – Defined as the actual energy produced by the generators, divided by the maximum possible energy production in a year. This indicator ignores the fact that there may not be sufficient fuel (e.g., water or wind) to run the generation unit at its maximum for 365 days. It is useful as an indication of the utilization of the generators as useful assets, especially in terms of providing energy (kWhs). The higher the percentage the more the units are being run at closer to their maximum capacity.
- ***Unit Availability*** – Defined as the actual number of hours the generators were available for use in the year, divided by the total number of hours in the years (8,760 except in a leap year). This number, expressed as a percentage, is useful in monitoring the overall reliability of the generators but does not consider whether the units were available when they were needed the most, (i.e., hydro in the summer and diesel in the winter).
- ***Operating Factor*** – Defined as the hours that the generators were on-line and generating power, divided by the total number of hours in the year. It is useful in assessing the value of the generation required on the grid.
- ***Forced Outage*** – Defined as the occurrence of a component failure or other condition which requires that the generation unit be removed from service immediately or up to and including the very next weekend. It represents the percentage of time that a unit is not available for operation due to an unscheduled removal from service.
- ***Planned Outage*** – Defined as the removal of a generating unit from service for inspection and/or general overhaul usually scheduled well in advance. It is the overall percentage of hours less Unit Availability and Forced Outage rates.

The tables and graphs on the pages following provide the Capacity Factor, Unit Availability, Operating Factor, and Forced & Planned Outage rates for Yukon Energy owned hydro and diesel generators.

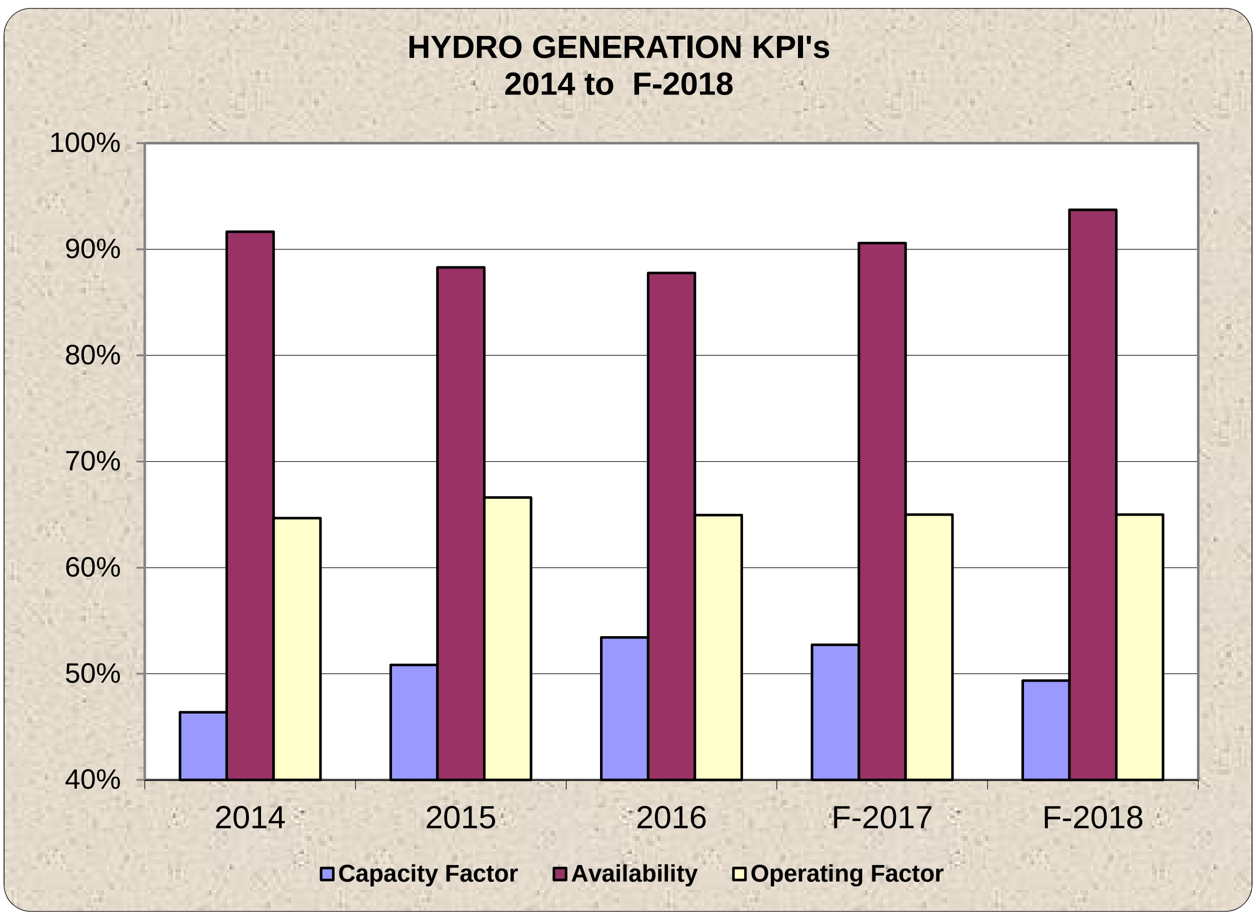
***Summary of Results for Hydro Generation KPIs***

A summary of Hydro generation KPIs is provided in Table 1-1 and Figure 1-1 below:

**Table 1-1: Hydro Generation KPI's**

| Year | Capacity Factor | Unit Availability | Operating Factor | Forced Outage Rate | Planned Outage Rate |
|---|---|---|---|---|---|
| 2014 | 46.37% | 91.65% | 64.67% | 1.10% | 7.25% |
| 2015 | 50.84% | 88.29% | 66.61% | 0.25% | 11.46% |
| 2016 | 53.42% | 87.76% | 64.95% | 0.80% | 11.44% |
| F-2017 | 52.74% | 90.59% | 65.00% | - | 9.41% |
| F-2018 | 49.35% | 93.72% | 65.00% | - | 6.28% |

**Figure 1-1: Hydro Generation KPIs**



The hydro generation Capacity and Operating Factors for 2014 generally reflect normal operations with the increased capacity from the newly installed hydro generation units (AH3 and MBH 1&2) that went into service in 2011 and 2012. The lower Availability rate during 2015 and 2016 is due to the Aishihik hydro units being out of service for June through to early October while the structural steel in the elevator shaft was being replaced.

The Forced Outage Rates for 2014 through 2016 are the result of multiple minor incidents all of relatively short duration; there was no event which incapacitated any hydro unit for an extended period of time. The Planned Outage Rate for 2014 is indicative of standard annual planned maintenance programs and unit overhauls. The higher Planned Outage Rate for 2015 and 2016 is due to the Aishihik units being out of service for June to early October for the elevator structural steel replacement project. The forecast rate for 2017 (F-2017) of 9.41% is higher than average due to the WH4 10 Year Overhaul scheduled for April through June 2017.

***Summary of Results for Thermal Generation KPIs***

A summary of thermal generation KPIs is provided in Table 1-2 below:

**Table 1-2: Thermal Generation KPI's**

| Year | Capacity Factor | Unit Availability | Operating Factor | Forced Outage Rate | Planned Outage Rate |
|---|---|---|---|---|---|
| 2014 | 0.45% | 93.29% | 1.06% | 1.06% | 5.65% |
| 2015 | 1.29% | 94.67% | 1.93% | 0.54% | 4.79% |
| 2016 | 1.75% | 96.95% | 1.92% | 1.53% | 1.52% |
| F-2017 | 0.63% | 97.22% | 1.00% | - | 2.78% |
| F-2018 | 0.49% | 97.22% | 1.00% | - | 2.78% |

Thermal generation (diesel & LNG units combined) remains minimal as it continues to fulfill the role of peaking and back-up generation. Both the Capacity and Operating Factors for 2015 and 2016 were slightly higher as thermal generation was required while the Aishihik hydro units were out of service from early June to early October. Peaking generation during winter months was approximately 2 GWh for 2015 and 3 GWh for 2016. The Unit Availability rate increased as there were fewer forced outages, and planned outage hours were reduced due to less maintenance work. The LNG project was commissioned at mid-year 2015 but was offset by the planned retirement of the WD1 and WD2 Mirrlees units.

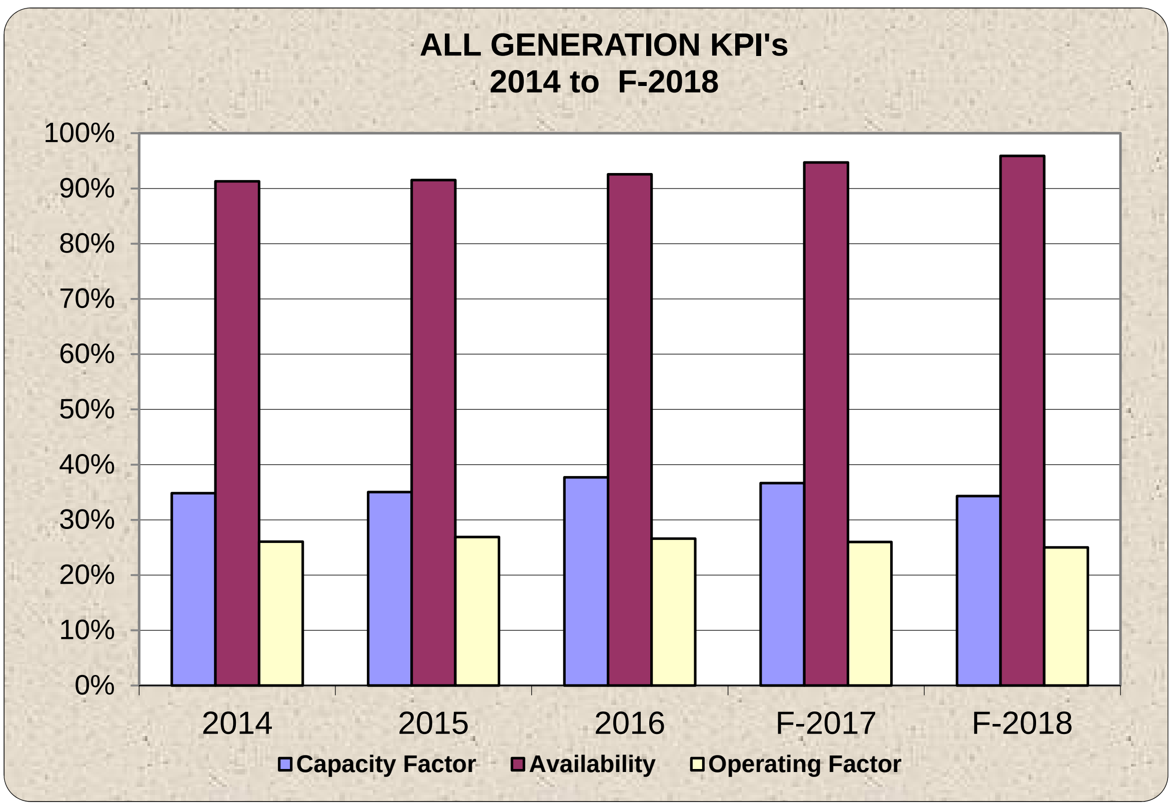
***Wind Turbine***

During 2016 the Vestus wind turbine achieved a Capacity Factor of 8.9% versus 11.24% in 2015 with a Unit Availability rate of 66.55% versus 67.36% in 2015. The unit Forced Outage status for 2016 was 33.45% (or 122 days) versus 31.83% (or 110 days) in 2015. The forced outages are mainly due to icing incidents rendering the unit unavailable for service. The Bonus wind turbine was officially retired during 2015 as it had reached the end of its useful life.

***Summary of Results for All Generation KPIs***

A summary of all generation KPIs for the period from 2014 to 2016 with forecast numbers for 2017 and 2018 are as provided in Figure 1-2 below:

**Figure 1-2: All Generation KPIs: 2014 to F-2018**




Forecast Availability for 2017 and 2018 reflects only planned maintenance for generation units but does not include any provision for forced outages. This results in a higher forecast availability rate compared to actual rates reported for prior years. As maintenance and forced outages are responsive to the operation of units, the actual rate achieved for 2017 and 2018 will likely be lower than the forecast rate.

## 2.0 DISTRIBUTION KPIs

The reliability indices on the following pages report distribution performance for Yukon Energy service areas and include all outages of any duration that affect greater than 50 customers, a complete YEC or AEY service area or result in an interruption in service to an industrial customer.

### *Reliability Performance Indicators*

Reliability of the distribution system is assessed based on the following indicators that define distribution performance:

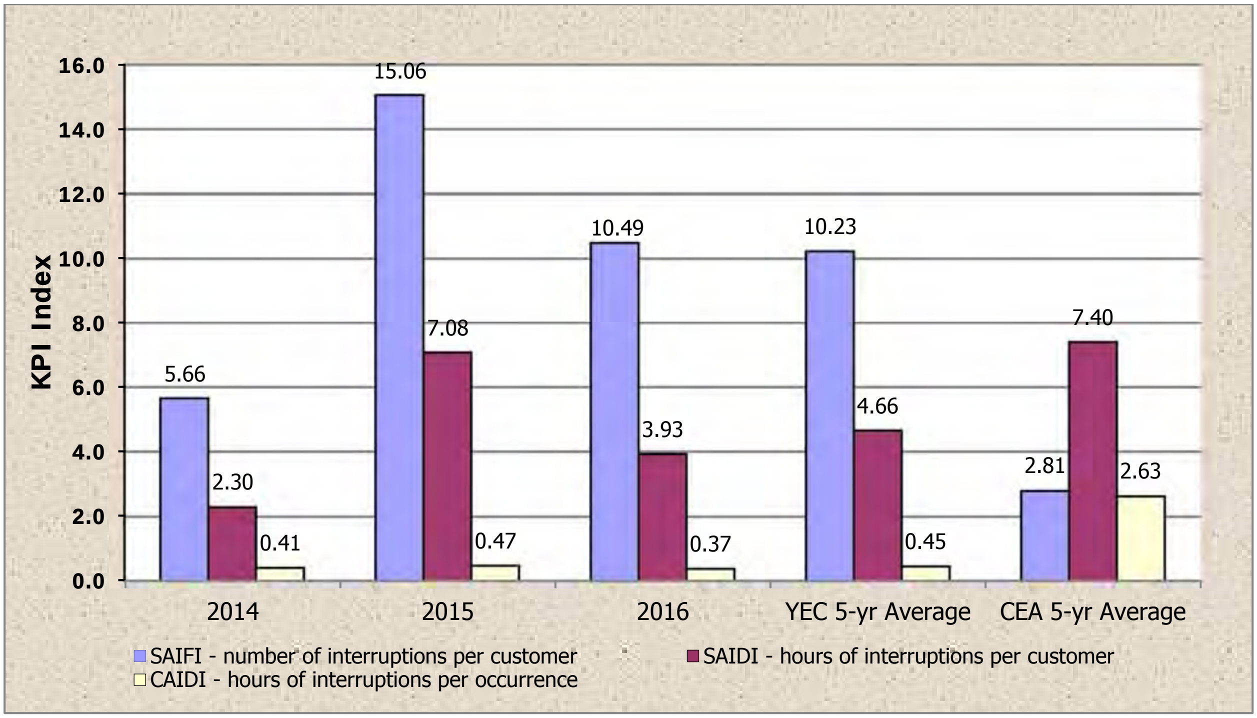
- ***System Average Interruption Frequency Index (SAIFI) -*** SAIFI is the average number of interruptions per customer for the period (a year in this case). It is a measure of how many outages an "average" customer experienced throughout the year. SAIFI is calculated by taking the total number of customer interruptions divided by the total number of customers served.
- ***System Average Interruption Duration Index (SAIDI) -*** SAIDI is the system average interruption duration for customers served for the period (a year in this case). It is a measure of how long all customers were affected (i.e., the last customer to be restored power). SAIDI is calculated by totalling the customer hour interruptions and dividing by the total number of customers served.
- ***Customer Average Interruption Duration Index (CAIDI) -*** CAIDI is the average customer interruption duration for customers interrupted. It is a measure of how long the "average" outage lasted for the customers affected. CAIDI is the total number of customer hour interruptions divided by the total number of customer interruptions.

### *Summary of Results for Distribution KPIs*

Figure 2-1 (following page) illustrates the reliability indicators using YEC data for 2014 through 2016 along with a 5-year average for YEC compared to the most current 5-year CEA average[1].

[1] The Canadian Electrical Association (CEA) compiles data from member utilities across the country which differentiates urban utilities (Region 1) from urban/rural (Region 2) utilities. For comparative purposes, Yukon Energy is more similar to Region 2 utilities. 5-year CEA averages are calculated based on 2011-2015 numbers.

**Figure 2-1: Yukon Energy Distribution KPIs: 2014 to 2016**




The SAIFI index is a function of the number of customers affected by outages that occur each year. Refer to the Classification of Distribution Outages section (below) for analysis and comment regarding causation of outages. As a small grid, YEC typically experiences a higher frequency rate than the CEA index. Part of this increased frequency is due to the YEC reporting standard which includes any outage that affects a whole YEC service area, or a community served by AEY which receives power from YEC, or an industrial customer, even though there may be fewer than 50 customers affected by the outage. The graph above illustrates a spike in outage incidents during 2015 due to lightning and weather incidents being greater than normal with many occurring on the L250 line between Mayo and Elsa.

The SAIDI index is a function of the duration of the outages. The nature of an outage often affects the duration as localized outages are usually quicker to restore power to customers, while outages originating on a transmission line usually take longer to determine the cause and location, then resolve. Outage incidents caused by trees, lightning or snow affecting transmission lines contribute most to the customer hour interruptions because they affect a larger segment of the grid for a longer duration than smaller more localized outages. Typically, YEC customers experience fewer customer hour interruptions than the CEA average. This is due to having back-up generation in communities which is readily available when an outage occurs that impacts transmission infrastructure. During 2015, the increase in SAIDI correlates to the increased number of outages affecting the customer base and thereby increasing the customer hours of interruptions. However, there were no outages of a notably longer duration during 2015 than in prior years. During 2016 the index returns closer to normal with the reduced number of outages.

The CAIDI index indicates the average duration of outages experienced by customers. It is typically lower than the CEA average which reflects YEC's ability to restore power on its grid more quickly than southern grids resulting in shorter outage durations being experienced by its customers. As illustrated within the graph, CAIDI is generally consistent as localized back-up generation is typically available to restore service to customers.

***Classification of Distribution Outages***

Yukon Energy classifies the primary cause of its customer interruptions to match the following CEA classification codes and descriptions:

> ***0 – Unknown/Other -*** Customer interruptions with no apparent cause or reason which could have contributed to the outage.
>
> ***1 - Scheduled Outage -*** Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.
>
> ***2 – Loss of Supply -*** Customer interruptions due to problems in the bulk electricity supply system such as under frequency load shedding, transmission system transients, or system frequency excursions.
>
> ***3 – Tree Contacts -*** Customer interruptions caused by faults due to trees or tree limbs contacting energized circuits.
>
> ***4 – Lightning -*** Customer interruptions due to lightning striking the Electrical System, resulting in an insulation breakdown and/or flashover.
>
> ***5 – Defective Equipment -*** Customer interruptions resulting from equipment failure due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.
>
> ***6 – Adverse Weather -*** Customer interruptions resulting from rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost and other extreme conditions.

***7 – Adverse Environment -*** Customer interruptions due to equipment being subjected to abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.

***8 – Human Element -*** Customer interruptions due to the interface of the utility staff with the system such as incorrect records, incorrect use of equipment, incorrect construction or installation, incorrect protection settings, switching errors, commissioning errors, deliberate damage.

***9 – Foreign Interference -*** Customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins, vandalism, sabotage (by others) and foreign objects.

***YEC Outages for 2016***

Yukon Energy reports all outages of any duration that affects greater than 50 customers, or interrupts service to a complete YEC or AEY service area, or results in an interruption in service to an industrial customer. Table 2-1 lists the number of interruptions by cause from 2014 to 2016:

**Table 2-1: Cause of Interruption: 2014 to 2016**

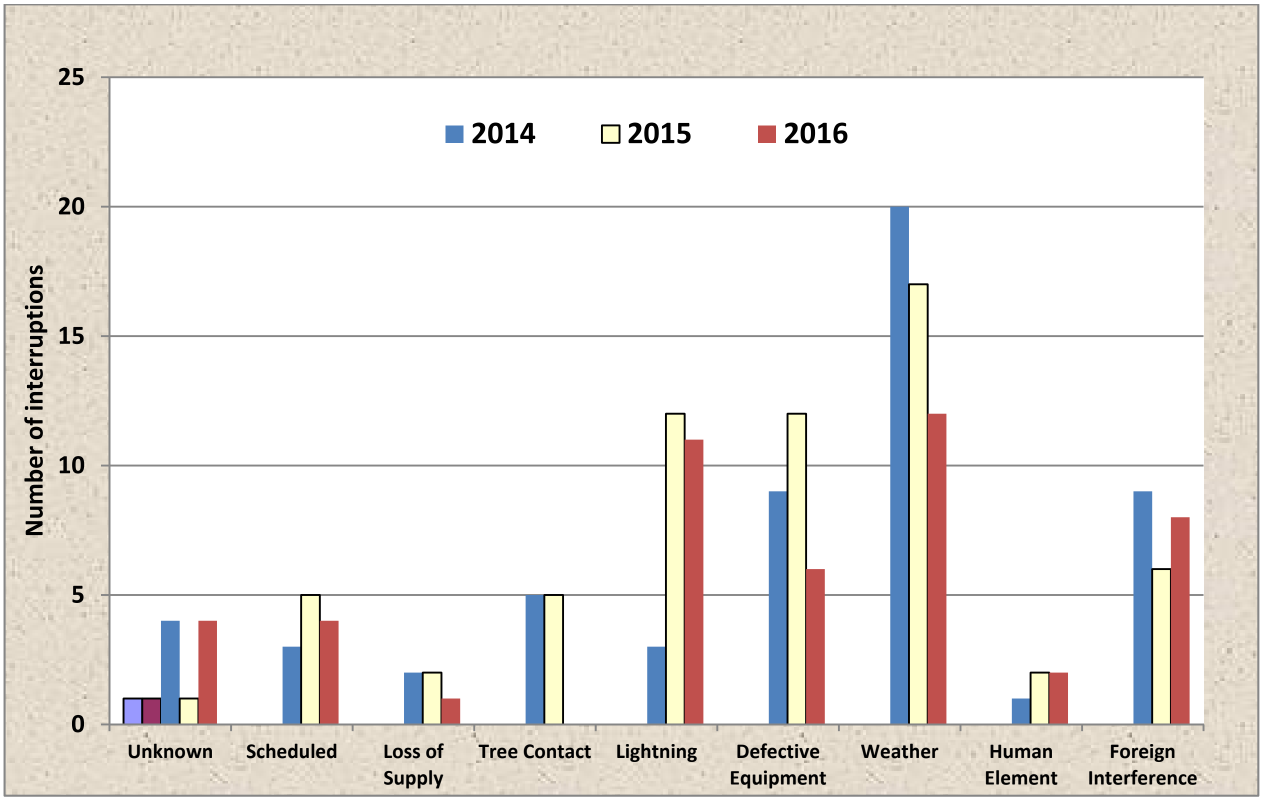
| Cause of Interruption | 2014 | 2015 | 2016 |
|---|---|---|---|
| Unknown | 4 | 1 | 4 |
| Scheduled | 3 | 5 | 4 |
| Loss of Supply | 2 | 2 | 1 |
| Tree Contact | 5 | 5 | 0 |
| Lightning | 3 | 12 | 11 |
| Defective Equipment | 9 | 12 | 6 |
| Weather | 20 | 17 | 12 |
| Human Element | 1 | 2 | 2 |
| Foreign Interference | 9 | 6 | 8 |
| Total | **56** | **62** | **48** |

During 2016 there were:

- 33 Transmission outages caused by Weather (12), Lightning (11), Unknown or Scheduled (6), Defective Equipment (2), Other Causes (2). There were no Tree Contacts during 2016.
- 9 Distribution outages caused by Foreign Interference (7), Defective Equipment (1), Scheduled (1).
- 6 Generation outages caused by Defective Equipment (3), Unknown (1), Loss of Supply (1), and Foreign Interference (1).

Figure 2-2 (next page) illustrates the number of interruptions by cause from 2014 to 2016.

**Figure 2-2: Causes of Interruptions: 2014 to 2016**




Unknown, Scheduled, Tree Contacts, Lightning, Weather and Foreign Interference contribute towards the majority of outages each year and are often due to events beyond the immediate control of the utility. An unusually high number of Tree Contacts in 2013 caused the company to adopt a 10 year brushing cycle program which addresses problem areas on rights-of-way first, then manages brushing on a more proactive basis later – thus the reduction in 2014 and 2015 and no Tree incidents reported for 2016. Weather incidents includes 11 Snow and Wind events on the L250 (Elsa) line during 2015 and 7 during 2016. Lightning incidents have increased the past 2 years and resulted in the greatest number of customer interruptions by cause. Most of the Foreign Interference incidents involve ravens.

Loss of Supply, Defective Equipment, and Human Element are categories where YEC attempts to reduce outages through preventative maintenance, improved procedures, and training activities. Of the 9 incidents that occurred during 2016 in these three categories, 4 incidents were due to failure of alarms, PLCs or equipment controlling the operation of hydro units; 4 incidents required replacement or adjustment of transmission equipment; and 1 short outage was due to a commissioning error. Of the 16 incidents that occurred during 2015 in these three categories, 8 incidents were due to failure of alarms or PLCs controlling the operation of hydro units; 7 incidents required replacement of insulators, fuses or pole structural components; and 1 incident was due to the failure of ancillary generation equipment.

### Environmental Performance

As part of its Environmental Management System and in compliance with various regulations, YEC reports spill incidents involving release of new unused petroleum hydrocarbon materials of 5 litres or more; used materials of .5 litres or more; any release of natural gas to atmosphere; or any release of petroleum or coolants to water. During 2016, there were 3 incidents of release of a small volume of natural gas to atmosphere while unloading. During 2015, there were 2 incidents of release of a small volume of natural gas to atmosphere while unloading; and one incident where approximately 16 litres of lubricant was released from a spillway gearbox of which approximately 6-8 litres was not recoverable due to safety reasons.

### Health and Safety Performance

The following definitions are used in describing Health and Safety Performance. All the definitions are based on the exposure hours or hours worked adjusted to a 100 employee company that averages 200,000 person-hours of work per year with a vehicle fleet that averages 1,000,000 km per year. During both 2015 and 2016 there were 93 employees, or full time equivalents, at Yukon Energy. Vehicle fleet mileage was 900,245 km in 2016 versus 990,614 km in 2015.

***All Injury Frequency*** includes any work related injury or illness suffered by an employee. An injury is work related if any event or exposure in the work environment either caused or contributed to the resulting condition or aggravated a pre-existing condition. It is based on the total number of Lost Time injuries combined with the total number of Medical Aid injuries.

$$\text{All Injury Frequency Rate} = \frac{(\#\text{ of Lost Time Injuries} + \#\text{ of Medical Aid Injuries})\text{ x }200{,}000}{\text{Exposure Hours (Hours Worked)}}$$

***Medical Aid injury*** is a classification for any medical care or treatment beyond first aid but does not include a Lost Time Injury as defined below.

***Lost Time Injury*** is a work injury that results in a fatality, permanent total disability, permanent partial disability, or temporary total disability. In the case of temporary partial disability, a day of disability is any day on which an employee is unable, because of injury and with medical authorization, to perform effectively through a full shift. The day on which the injury occurs is not counted as a day of disability.

$$\text{Lost Time Injury Frequency} = \frac{(\#\text{ of Lost Time Injuries/Illnesses})\text{ x }200{,}000}{\text{Exposure Hours (Hours Worked)}}$$

***Lost Time Injury Severity Rate*** is calculated by combining the calendar days of disability lost and days charged for fatalities and permanent (total and partial) disabilities.

$$\text{Lost Time Injury Severity Rate} = \frac{(\#\text{ of Days Lost}) \times 200{,}000}{\text{Exposure Hours (Hours Worked)}}$$

***Recordable Motor Vehicle Incident*** is any incident involving a motor vehicle being operated by an employee that would meet the Recordable Injury criteria or costing more than $5,000 in total property damage. This includes any motor vehicle operating but stationary in traffic when the incident occurs.

$$\text{Motor Vehicle Incident Freq Rate} = \frac{\text{Number of Recordable Accidents} \times 1{,}000{,}000}{\text{Kilometers driven}}$$

The table below is a record of Yukon Energy's safety performance for 2014 through 2016 according to the CEA injury and accident definitions, and comparing them against the 2015 CEA utility statistics for the Group III – Under 300 Employees category.

| CATEGORY | 2014 | 2015 | 2016 | CEA |
|---|---|---|---|---|
| All Injury Frequency Rate | 2.54 | 2.47 | 6.11 | 2.14 |
| Lost Time Injury Frequency Rate | 1.27 | 1.23 | 1.22 | 1.38 |
| Lost Time Injury Severity Rate | 1.27 | 4.94 | 4.89 | 9.73 |
| Motor Vehicle Frequency Rate | 5.06 | 0.00 | 0.00 | .33 |

During 2016 there were 5 reportable injuries: 4 Medical Aid and 1 Lost Time injury of 4 days duration resulting in an All-Injury Frequency Rate of 6.11; a Lost Time Injury Frequency Rate of 1.22; and a Lost Time Severity Rate of 4.89. During 2015 there were 2 reportable injuries: 1 Medical Aid and 1 Lost Time injury of 4 days duration resulting in an All-Injury Frequency Rate of 2.47; a Lost Time Injury Frequency Rate of 1.23; and a Lost Time Severity Rate of 4.94. During 2014 there were 2 reportable injuries: 1 Medical Aid and 1 Lost Time injury of 1 day duration resulting in an All-Injury Frequency Rate of 2.54 and the Lost Time Injury Frequency Rate and Lost time Severity Rate being 1.27.

Applying the CEA criteria for Recordable Vehicle Incidents, (where an incident results in a Recordable Injury or exceeds $5,000 in property damages), there were no recordable motor vehicle incidents during 2016 or 2015 resulting in a Motor Vehicle Incident Frequency Rate of 0.00; compared to 5 incidents during 2014 for a Motor Vehicle Incident Frequency Rate of 5.06.

# APPENDIX 3.4
# DIESEL CONTINGENCY FUND (DCF) AND LTA UPDATES

# APPENDIX 3.4: DIESEL CONTINGENCY FUND (DCF) AND LTA UPDATES

Appendix 3.4 provides updates on the Diesel Contingency Fund (DCF) and the process for determining long-term average (LTA) hydro and thermal generation forecasts adopted in this Application, and includes the following attachments:

- **Attachment 3.4.1 – Revised DCF Term Sheet: YEC Grid and AEY Fish Lake**
- **Attachment 3.4.2 – Potential Thermal Generation Variability (GW.h/year) Depending on Water Conditions (35 years) - Range of Grid Loads from 380 to 450 GW.h/year;**
- **Attachment 3.4.3 – Information on YECSIM Model; and**
- **Attachment 3.4.4 – DCF Cap Option Assessment.**

## 1.1 BACKGROUND

Tab 2, Section 2.3 of this Application reviews the Yukon Energy hydro and thermal generation forecasts for the test years, based on forecast firm sales requirements. Tab 3, Section 3.6.2 of this Application provides background on the DCF.

Based on the Board's approval of the 2012/13 GRA and the then updated DCF, Yukon Energy's annual thermal generation expense for revenue requirement purposes is determined based on long-term average hydro generation (rather than actual hydro generation resulting from actual water conditions).

Subsequent to Order 2015-06, quarterly DCF reporting has been provided (starting with Q3 2015). Total thermal generation expense for each year is determined at year-end based on the LTA thermal generation requirement for that level of actual firm generation as determined by the rules established in the DCF Term Sheet as approved by the Board. The LTA estimate for any specific level of firm generation is determined by reference to the relevant table in the approved DCF Term Sheet.

In accordance with the approach approved by the Board for the 2012/13 GRA, hydro and thermal generation forecasts for the purpose of the 2017/18 GRA test years are also based on LTA hydro and wind generation as updated with the latest information (see Sections 1.2 and 1.3 below).

Rider E rebates have been provided pursuant to Order 2015-06 since September 1, 2015, due to the total DCF funds exceeding the Board approved cap of $8 million. The initial Rider E was set at a rebate of 0.68

cents/kW.h, effective September 1, 2015, and continuing until March 31, 2016. As directed in the DCF Term Sheet, Rider E amounts are reviewed annually, based on the year-end annual DCF filings.

The DCF Term Sheet as approved in Order 2015-06 reflects reliance on diesel generation as the only thermal generation source, as Liquefied Natural Gas (LNG) generation only commenced in July 2015. As part of the DCF 2015 Annual Report, Yukon Energy sought to include LNG in ongoing annual DCF determinations and included a proposed approach for LNG inclusion. The Board in correspondence dated March 7, 2016 noted that it was not prepared to make any determinations regarding including LNG in the DCF, or Rider F, until such time as YEC files a full rate rider application or a GRA. On April 6, 2016, the Board approved the reinstatement of the prior Rider E (of 0.68 cents/kW.h) on an interim basis, effective May 1, 2016, and until such time as the final DCF amounts for the years 2015 and forward can be finalized. Yukon Energy's proposed approach for incorporating LNG into DCF determinations is provided in the current GRA Application (see below), and Yukon Energy is seeking final Board approval for the final DCF amounts for the years 2015 and 2016 as part of this Application.

DCF reporting to the end of 2016[1] is provided in Appendix 3.5, based on the DCF Term Sheet as approved in Order 2015-06.

Updates to the LTA determinations and to the DCF for this Application are outlined below and reflect the latest information regarding factors affecting LTA hydro and wind generation, the implementation of LNG fuel and generation facilities as at July 2015, and the DCF cap. The revised DCF Term Sheet (see Attachment 3.4.1) provides an updated table for subsequent LTA determinations for the DCF (starting in 2017) based on the proposed DCF updates reviewed below. This updated table has also been used for LTA determinations for the test years in the 2017/18 General Rate Application.

## 1.2 GENERAL UPDATES FOR EXPECTED YEC THERMAL GENERATION AT LTA

Yukon Energy LTA thermal generation in any calendar year continues to be the thermal generation expected to be required to supply firm grid generation requirements net of LTA generation available from AEY's Fish Lake hydro, YEC's wind generation, and YEC's hydro generation.

[1] This refers to the DCF 2016 Annual Report, which includes reporting for each year since 2012.

The following are the related updates for LTA determinations adopted for this Application:

- AEY's LTA Fish Lake hydro generation is as provided by AEY for each test year (8.53 GW.h for 2017 and 8.39 GW.h for 2018), based on incorporating updated planned capital work information for this facility. Absent specific information related to impacts from capital work or related issues in a given year, the default LTA for Fish Lake hydro generation remains 8.73 GW.h/year as per Board Order 2009-02, Appendix A (page 11).[2]

- YEC's LTA wind generation is updated from 0.238 GW.h/year in the 2012/13 GRA to 0.580 GW.h/year for each test year (2017 and 2018).

- YEC's LTA hydro generation continues to be based on the power benefits system simulation model as used in the last GRA (i.e., the YECSIM model),[3] updated to reflect the load shape for the test years (with basically the same Minto mine loads being forecast in each of these years) and the following information related to Yukon Integrated System hydro operations:

    - Additional water year records compared to the 2012/13 GRA [35 water years, from 1981 to 2015, compared to 28 water years used in the 2012/13 GRA]. This added information has tended to increase LTA expected hydro generation.

    - Updated reservoir and generation station water flow requirement changes, including 10-year average for Aishihik Lake spring water levels, Mayo GS winter outflow restrictions, and Mayo Lake outlet channel constraints on Mayo Lake outflows (due to sediment build up in this channel). These factors together have reduced LTA expected hydro generation.

Previous YECSIM-related LTA submissions (e.g., the LNG Part 3 Application, Appendix C) have broken out the LTA assessment to show the estimated thermal generation requirement for each of the separate water years used to determine the overall LTA for each load forecast scenario. Attachment 3.4.2 provides an update to this analysis, based on the updated YECSIM model, showing the estimated thermal generation requirement for each of the 35 water years for a range of potential load scenarios.

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[2] Board Order 2017-01 (section 3, paragraphs 41-43 and 47-49) reviews current information on Fish Lake hydro generation. AEY has retained the average output for Fish Lake Unit #2 from 1960-2015 as per Order 2009-02. LTA generation for the new Unit #1 in AEY's last GRA was based on the two year average for this Unit adjusted for planned decrease in generation for capital rebuilds (resulting in 8.536 GW.h forecast Fish Lake generation for the 2017 test year). AEY's response in its last GRA to YUB-YECL-9(b) estimated that without the capital rebuilds, the Fish Lake LTA generation would be 9.576 GW.h/year; however, the Board has not to date provided any new direction as to the LTA for Fish Lake absent the capital rebuild impacts.

[3] Yukon Energy continues at this time to use the YECSIM model for the LTA assessments for this Application and the 2016 Resource Plan (see Attachment 3.4.3 for information on the YECSIM model). YEC is currently examining another system planning model (VISTA) for potential future use in assessing LTA hydro and thermal requirements.

Table 3.4-1 in Attachment 3.4.1 utilizes the updated YECSIM model, as described above, to update the DCF Term Sheet table for determining annual expected YEC thermal generation based on long-term average YEC hydro generation at YEC grid loads (net of expected wind and expected Fish Lake generation) ranging from 370 to 485 GW.h/year, assuming mine loads connected as forecast in the GRA for 2017 and 2018. Table 3.4-1 is used in this Application to determine annual expected YEC thermal generation for each test year. As specified in the prior approved DCF Term Sheet, Yukon Energy will provide the Board, for review and approval, an update to Table 3.4-1 when required in future to address material changes in LTA hydro system capability due to changes in loads, installed capacity, licensing/permits or other factors.

The LTA thermal generation as determined pursuant to the YECSIM model and Table 3.4-1 addresses thermal generation requirements for firm grid loads, i.e., thermal generation needed for capital projects, emergencies/grid interruptions, or other Reserve for Injuries and Damages (RFID) requirements are not included in the DCF assessments or in the LTA expected thermal generation determinations. As part of the current update, ongoing maintenance-related thermal generation (i.e., run-ups needed on a regular basis to maintain each unit, even when there is no firm load requirement for operation of the thermal unit) are also specifically excluded from the DCF assessments (and provision for such maintenance costs are separately included in this Application's forecast fuel costs for each test year). Other thermal generation requirements (i.e., expected generation not addressed by the LTA assessments) that may occur under higher-than-median water conditions will be assessed as required in future GRAs.

### 1.3 LNG RELATED UPDATES

In July 2015, LNG fuel and generation facilities (8.8 MW) became available for service, although deficiency corrections and various commissioning activities continued in Q4 2015 and testing and optimization activities continued through the first half of 2016.

As noted in the DCF Term Sheet as approved in Order 2015-06 (footnote 10), YEC committed to report to the Board when LNG generation is in service, and to provide for Board review and approval a proposed approach for inclusion of LNG in ongoing DCF determinations.

As part of the DCF 2015 Annual Report, Yukon Energy sought to include LNG in ongoing annual DCF determinations and included a proposed approach for LNG inclusion. The Board in correspondence dated March 7, 2016 noted that it was not prepared to make any determinations regarding including LNG in the DCF or Rider F until such time as YEC files a full rate rider application or a GRA.

The following addresses the proposed approach for including LNG in ongoing annual DCF determinations as well as the 2017/18 GRA fuel cost forecasts.

### Overview of LNG Factors Affecting Annual DCF Determinations

The DCF Term Sheet notes that the DCF table determinations for LTA expected thermal generation are based on annual calendar year loads. LNG inclusion in DCF and other LTA determinations (i.e., for GRA test years) must therefore also ultimately relate to the annual DCF and other LTA determinations.

The DCF Term Sheet Annual DCF determinations need to take into account the following three factors related to YEC's LNG facilities:

1. Capability of LNG in any year to supply the expected or LTA thermal generation requirement (assuming that LNG, as a lower cost fuel than diesel, will be fully utilized up to this capability - and diesel generation will then be assumed to be required for the balance of the LTA thermal generation requirement);

2. Actual LNG use in the year (net of capital, RFID generation, or maintenance run-ups of thermal units); and

3. The LNG fuel cost per kW.h to be assumed for DCF cost assessments (equivalent to the 28.7 c/kW.h diesel generation fuel cost used to date for the DCF based on the last approved GRA fuel price and average diesel generation efficiency for the 2012/13 GRA).

Determinations as proposed for including LNG are reviewed below, taking into account the Board's 2014 review of the YEC's Part 3 Application for the Whitehorse Diesel-Natural Gas Conversion Project (LNG Part 3 Application).

### Proposed LNG treatment for the Annual DCF Filing Determinations

Each of the above three factors is reviewed below as regards proposed LNG treatment in the annual DCF filing determinations for 2015 and 2016 and the 2017/18 GRA test years:

1. **Capability to supply LTA thermal generation:** Based on YEC's LNG Part 3 Application, the two initial LNG units (8.8 MW) over a full year were expected to displace all LTA diesel generation at LTA thermal requirements of up to at least 17 GW.h/year. This assessment assumed operation of the LNG units as required during low water conditions (i.e., during the water years accounting

for the vast majority of the LTA thermal generation requirement at grid loads then forecast) to enhance hydro storage for use in wintertime (so that enhanced hydro operation can help to displace diesel generation during periods of peak diesel requirements).[4] LTA thermal generation requirements on the grid remained below 17 GW.h/year in 2015 and 2016, and remain below 17 GW.h/year in each of the 2017/18 GRA test years, indicating that (subject to LNG unit availability) an assumption of 100% LNG displacement of LTA diesel generation during these years would be consistent with the LNG Part 3 submissions.[5]

The key reality affecting LNG capability in 2015 was that LNG generation was available only during the last six months of the year, and even then continued to have some constraints until Q4 of 2015. Taking into account that LNG capability was available only after mid-year, with some added constraints during that period, it has been assumed in the DCF Annual Filing that in 2015 LNG could only displace 15% of the LTA thermal generation requirement (or about 1.502 GW.h). This assumption is consistent with evidence provided in the Part 3 Hearing and with YEC's assessments of the limited portion of LTA thermal generation accounted for by grid loads after mid-year.[6]

The two LNG generation units were available throughout 2016, and are forecast to be available throughout the 2017 and 2018 test years. A third LNG unit is forecast to come into service in 2019, expanding considerably the overall LNG capability to displace diesel generation on the grid.

Actual LNG unit operation has been constrained by unit size at 4.4 MW, i.e., smaller existing diesel units are relied upon for thermal loads less than 2.6 MW, thermal loads between 4.4 and 5.2 MW, and thermal loads of short duration (less than a few hours). These constraints are not considered to have a material impact on the ability of LNG (with operation during low water conditions to enhance hydro storage) to supply overall LTA thermal generation at the grid loads relevant for this Application, based on the following considerations:

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[4] For example, see LNG Part 3 Application starting at bottom of page 29 and pages 30 and 31, and related information in Appendix D of the Part 3 Application. This matter was also addressed in various IRs in the Part 3 proceeding. The 17 GW.h/year LTA was the forecast in the Part 3 Application for 2015, when the assessment assumed LNG unit ability to supply 100% of the LTA thermal requirement.

[5] LTA thermal generation requirement was 10.0 GW.h in 2015 and 10.5 GW.h in 2016 (see Appendix 3.5, 2016 DCF Annual Report); the forecast LTA thermal generation requirement for 2017 and 2018 remains below 14 GW.h/year (see Table 2.2).

[6] See LNG Part 3 Application at page 7, footnote 7 and response to YUB-YEC-1-12(b) where it was noted that January to June 30 accounted for over 82% (14 of the then forecast 17 GW.h) of the LTA thermal generation then forecast for 2015. Based on available information, an assumption of 15% is considered to reflect a reasonable upper limit on actual LNG capability to displace LTA thermal generation requirement in 2015.

- Emergency thermal loads, which typically require quick response and may continue for only a short duration, are excluded from LTA assessments; and

- Other small or short duration loads of the type affecting actual current LNG use are not important factors affecting LNG unit ability to supply overall LTA thermal generation at the grid loads relevant for this review.

However, the following are noted regarding the implications of the current limitation on LNG unit operation:

- **DCF Annual Reporting** - Actual LNG and diesel unit operation during above average water conditions (i.e., when a contribution to the DCF must be made by YEC, as occurred in 2016 and is currently expected in the test years) directly affects YEC expenses, e.g., see 2016 DCF Annual Report in Appendix 3.5 where diesel generation (and its related fuel cost) accounted for 2.293 GW.h of actual generation. The DCF determinations in this instance do not offset actual diesel generation costs incurred by YEC, and YEC is not at this time proposing any change to this approach.

- **GRA Test Year for Revenue Requirement determinations** - This Application proposes that LTA thermal requirements be assumed, for revenue requirement purposes at this time, to be supplied 90% by LNG-supplied natural gas generation and 10% by diesel generation. This approach is proposed to ensure that revenue requirement costs used to set rates provide some recognition of the current limits on actual LNG ability to displace all diesel generation.

2. **Actual LNG use in the year and year-end DCF determinations related to LNG:** The 2016 DCF Annual Report (Appendix 3.5) shows the actual LNG generation in 2015 and 2016, net of capital and RFID generation (based on this Application, future DCF Annual Filing years will also exclude maintenance run-up generation). In each of these years, expected thermal generation exceeded actual thermal generation, and the balance (approximately 7.2 GW.h in 2015 and 5.1 GW.h in 2016) was thermal generation for which YEC transferred fuel cost into the DCF. Due to limits in LNG unit availability, only 15% of the 2015 thermal generation included in the DCF transfer by YEC was assumed to be supplied by LNG - however, in 2016, 100% of the thermal generation included in the DCF transfer by YEC was assumed to be supplied by LNG.

As noted under item #1 above, actual diesel generation in 2015 and 2016 was charged to YEC at the approved fuel cost per kW.h for diesel generation, i.e., actual diesel generation directly affected YEC's actual expenses in each year. Based on the proposals in this Application, this will continue at this time for future actual diesel generation. Actual LNG generation is also charged to YEC at specified fuel costs per KW.h (see item 3 below).

YEC's final fuel expense for annual expected thermal generation after DCF transfers is affected by the LNG/diesel mix for actual thermal generation as well as by the LNG/diesel mix adopted for transfers into or out of the DCF. In 2016, due to the actual generation mix being 45% diesel, YEC's final expense for all expected (LTA) thermal generation showed 21.8% being supplied by diesel (2.293 GW.h out of 10.536 GW.h), notwithstanding that 100% of the thermal generation included in the DCF transfer by YEC (to address the difference between LTA thermal generation and actual thermal generation) was assumed to be supplied by LNG.

As noted under item #1 above, this Application proposes that test year thermal generation be assumed to be supplied 90% by LNG generation and 10% by diesel generation. In order to enable final year-end YEC LTA fuel expense to reflect this same LNG/diesel mix to the extent possible, it is proposed in this Application that subsequent DCF Annual Filings (for 2017 and 2018, and subsequent years until changed by approval of the Board) adjust YEC's year-end DCF payment into (or receipt from) the DCF as required so that YEC's final fiscal year expense for the total expected thermal generation (i.e., YEC expense after all transfers) is 90% LNG and 10% diesel, subject to the constraint that the LNG share of any transfer into or out of the DCF cannot exceed 100%. This proposed approach is reflected in the DCF example in Appendix 3.4-1 (Table 3.4-3).

3. **Diesel and LNG fuel cost per kW.h:** Diesel fuel costs in 2015 and 2016 were set at the Board's approved diesel fuel cost from the 2012/13 GRA of 28.71 cents per kW.h. However, due to the absence of any Board-approved fuel cost for LNG, fuel costs for LNG in the 2015 and 2016 DCF Annual Filings were set at actual average LNG fuel costs for LNG generation in each year:

   - 2015 average delivered LNG fuel cost of 18.83 cents/kW.h assumed 40% energy conversion efficiency as per the LNG Part 3 Application. This delivered fuel cost reflected deliveries from the FortisBC LNG facility at Tilbury in Delta BC, using a combination of Tandem and Tridem haul units with smaller LNG payloads than were assumed in the LNG Part 3 Application.

- 2016 average delivered LNG fuel cost of 18.17 cents per kW.h was actual costs of LNG used from inventory divided by kW.h of actual LNG generation in 2016 of 3.251 GW.h (reflected actual energy conversion efficiency of about 39.21%, as well as weighted average costs that continued to reflect deliveries from the FortisBC LNG facility at Tilbury).

Yukon Energy has continued to focus on measures to optimize the transportation supply chain in order to reduce the total delivered cost of LNG to Whitehorse. This has included continuing to pursue licencing and development of larger configurations of LNG haul units that would materially reduce the per unit costs for delivery, as well as opportunities to secure LNG from potential new or enhanced LNG facilities that are much closer to Whitehorse. In September 2016, YEC had its first LNG deliveries from the Ferus facility at Elmworth, Alberta, which offered the opportunity to reduce LNG delivered costs due to the much shorter haul distance to Whitehorse.

This Application assumes a forecast delivered fuel cost of LNG for the 2017 and 2018 test years of $0.1467 per kW.h, based on a delivered average fuel cost of $0.3767 per litre and average efficiency for LNG generation of 2.57 kW.h/litre (assumes 0.02369 GJ/litre of LNG [HHV]). This LNG fuel cost reflects the average delivered LNG cost from September to December 2016 from the Ferus facility in Elmworth, and the forecast that test year LNG requirements will be generally supplied from facilities at no greater distance from Whitehorse than Elmworth.

This Application assumes that LTA generation for the test years is supplied 90% by LNG generation and 10% by diesel generation. Given the average LNG fuel cost at 14.67 cents per kW.h, and average diesel fuel cost at 26.33 cents/kW.h, the average blended fuel price of 15.83 cents per kW.h is assumed for test year LTA thermal generation.[7]

## 1.4 DCF CAP UPDATE

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

Board Order 2015-01 (Appendix, page 15) provided the following direction on the matter of the DCF cap as proposed in the last GRA:

[7] The blended fuel price reflects more detailed LNG and diesel price determinations, e.g., 14.668 cents/kW.h for LNG and 26.333 cents/kW.h for diesel.

> Thus, the Board accepts the level of +/- $8 million as proposed by YEC as an acceptable balance between frequency of rider applications and ability to handle material (drought) changes in hydro availability.

Throughout past discussion of the DCF, the basic starting premise has been that thermal cost variance from forecast due to water availability is a ratepayer risk rather than a utility risk.[8] The Board noted in Order 2015-01 (Appendix, page 11) that all Parties to that proceeding agreed that there is a need for a mechanism that effectively protects ratepayers from diesel generation cost impacts caused by fluctuation of hydro generation due to water conditions or changes in wind conditions.

The DCF has been established to provide stability for rates, and to reflect the underlying long-term valuation of renewable hydro and wind resources (where economic feasibility typically is assessed based on long-term average energy supply). Rate stability is achieved, as noted above by the Board in Order 2015-01, by limiting the requirement for separate rider collections/refunds to ratepayers, and by enabling ratepayers (to the extent practical) to pay the same LTA cost during droughts as during floods.

To achieve its objectives, the DCF needs robust threshold limits, i.e., maximum and minimum levels allowed before funds are dispersed (for overages) or replenished (when fund falls below minimum). This differs from Rider F, where the object is to regularly collect and/or refund amounts to/from ratepayers through regular riders.

Evidence and argument in the previous DCF proceeding arising from YEC's last GRA included the following highlights:

- YEC initially forecast (in the last GRA) 2013 firm load at 430 GW.h and LTA thermal at 18.2 GW.h. Based on this information, the worst drought year was expected to require over 100 GW.h of diesel, implying a one-year cost (with diesel at $0.287/kW.h) of slightly over $30 million. The evidence also showed that a drought would likely last for several years, with severe cumulative effects.

- The final 2013 firm load forecast approved by the Board was 416 GW.h with an approved LTA thermal generation of 11.0 GW.h, i.e., the Board's final decision reduced the firm load forecast (see Table 2.2 in this 2017/18 GRA).

[8] Response to AEY-YEC-1-10 in the DCF/ERA proceeding reviewed basic issues in this regard (including relevant price signal impact issues raised by the Board), and referenced other related IRs from that proceeding.

- Discussion in the last GRA and the subsequent DCF proceeding focused on whether the DCF cap should be materially lower than the +/-$8 million that YEC had proposed. No proposal was advanced at that time for a higher cap – however, intervener submissions were made for lower caps at +/-$2 million and at +/-$5 million.

- Evidence in the DCF proceeding indicated (UCG-YEC-1-6(b)) that the DCF would already have accumulated over $8 million as at the end of 2013 due to highly favourable water conditions since the start of 2012.

- The Board was aware of the above highlights when it subsequently approved the current DCF cap, and concurrently a Rider E rebate of 0.68 cents per kW.h for all firm customers in Yukon (to address DCF fund collections that exceeded the $8 million cap).

The current 2017/18 GRA forecast indicates a slightly higher forecast load (419 GW.h in 2018) and LTA thermal generation (13.6 GW.h in 2018) than was approved for 2013. This alone suggests that there is no reasonable basis today to consider any lower cap than the +/-$8 million last approved by the Board.

The following additional update information indicates that it is timely today to review the benefits of a higher DCF cap than the current +/-$8 million amount:

- Contrary to stated objectives for the DCF as approved by Board Order 2015-01, rider applications related to the DCF have remained "very frequent", i.e., Rider E rebates at $0.68/kW.h have continued in every year since the fund's terms were last approved in the fall of 2015 (due to the DCF continuing to exceed the $8 million cap as a result of extended favourable water conditions), reducing effective rates below the LTA thermal generation costs as approved by the Board (the overall reduction in 2016 approximated $2.4 million).

- Short-term forecasts of favourable water conditions and loads indicate that Rider E rebates are likely to continue during the test years if the DCF cap remains at $8 million.

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

- The current +/- $8 million cap limits the robustness of the DCF in dealing with severe drought, implying the need for major and extended Rider E charges when material low water conditions occur. Table 3.4-4 shows that, at the GRA loads forecast for 2018, low water conditions (i.e., less than LTA hydro generation) are expected in 10 of the 35 updated water years of record. Absent future changes to renewable generation capability, the frequency of low water conditions will increase if future loads exceed the 2018 forecast of just under 420 GW.h/year.

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

The following summary highlights impacts with a $16 million DCF cap option:

1. At the GRA load range of 420 GW.h and LNG assumptions, a DCF cap increased to $16 million from the current $8 million would have the following key positive impacts:

    a. Increased years not needing rate riders, from 16 to 21 (out of 35) water years. This change mainly relates to reducing the number of years with rebates.

    b. Major reduction in drought year rate rider charges - reduces the peak drought year charge from $13.6 million to $4.7 million, and the average charge year amount (for years with rate rider charges) from $4.2 million to $2.2 million.

2. At the GRA load range of 450 GW.h and LNG assumptions, a DCF cap increased to $16 million from the current $8 million would have the following key positive impacts:

    a. Increased years not needing rate riders, from 20 to 26 (out of 35) water years. This change relates to reducing the number of years with charges as well as rebates.

    b. Major reduction in drought year rate rider charges - reduces the peak drought year charge from $14.0 million to $8.2 million, and the average charge year amount (for years with rate rider charges) from $4.8 million to $3.5 million.

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

## ATTACHMENT 3.4.1: REVISED DCF TERM SHEET: YEC GRID & AEY FISH LAKE

The DCF Term Sheet as approved in Appendix A to Board Order 2015-01 is hereby updated and revised as part of the Yukon Energy 2017/2018 General Rate Application.

**PURPOSE & FUNCTION:**

The Diesel Contingency Fund ("DCF") operates to smooth customer rate changes from thermal (diesel, LNG and other thermal) generation cost impacts caused by fluctuation of hydro generation due to water conditions or changes in wind conditions.[9]

Yukon Energy Corporation (YEC) manages the DCF as a ratepayer "trust fund". The Fund is only to be used for variations from long-term average (LTA) water and wind availability.[10]

**LONG-TERM AVERAGE:**

Board Order 2013-01 directed YEC to base its hydro and diesel energy requirements for YEC's GRA forecasts on 100 percent of long-term average (LTA) hydro generation.

The annual expected thermal generation requirements are determined based on the formulaic approach as provided below and takes into account variability from LTA in ATCO Electric Yukon's (AEY's) Fish Lake hydro generation and YEC hydro and wind generation.[11]

[9] Appendix A to Board Order 2015-01, section 2.1.1.4, page 11.

[10] Appendix A to Board Order 2015-01, section 2.1.1.4, page 14. The Board directed as follows: "Any application to utilize the fund in some other fashion will require the closing of the fund, the refunding of any balances to customers, and the direction for YEC to use short-term forecasts for its hydro generation in future GRAs."

[11] Unless otherwise noted, AEY Fish Lake generation based on long-term average as approved by the Board Order 2014-06 at 8.73 GW.h and the last approved YEC wind generation (238 MW.h/year in the 2012/13.GRA). The Fish Lake long-term average generation for 2012 and 2013 was at 4.38 GW.h due to unavailability of Unit #1. YEC's 2017/2018 GRA assumes Fish Lake hydro long term average generation of 8.53 GW.h for 2017 and 8.39 GW.h for 2018, based on information provided by AEY, and updated YEC LTA wind generation of 580 MW.h/year.

Formulaic approach – determine expected YEC thermal generation based on LTA water-based YEC hydro generation that is forecast using a formulaic relationship to load in each year (including non-test years):[12]

a. Table 3.4-1 is adopted to determine annual expected YEC thermal generation based on long-term average YEC hydro generation at YEC grid loads (net of expected wind and expected Fish Lake generation) ranging from 370 to 485 GW.h/year, assuming mine loads connected as forecast in the GRA for 2017 and 2018.

b. Table 3.4-1 provides (below) an example of the determination of expected YEC diesel generation at a grid load of 417 GW.h (net of expected wind and expected Fish Lake generation).

c. YEC will provide the Board, for review and approval, an update to Table 3.4-1 when required in future to address material changes in LTA hydro system capability due to changes in loads, installed capacity, licensing/permits or other factors.

**DCF THERMAL SAVINGS (COSTS):**

YEC thermal generation savings (excess) are calculated on an annual basis for the DCF based on expected thermal generation less actual thermal generation[13]. Starting with YEC fiscal year 2017, costs for YEC thermal generation savings (excess) are calculated so that YEC's final fiscal year expense for the total expected thermal generation (i.e., YEC expense after all transfers) is 90% LNG and 10% diesel, subject to the constraint that the LNG share of any transfer into or out of the DCF cannot exceed 100%. Fuel costs for this calculation are based on the last approved average cost of LNG and diesel fuel for YEC per kWh based

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

[13] Actual thermal generation excludes thermal generation charged to capital projects, RFID, or maintenance. Costs for actual thermal generation are charged separately for diesel and LNG generation based on the last approved average cost of fuel for YEC per kW.h based on the most recent YEC GRA.

on the most recent YEC GRA.[14] The DCF example in Table 3.4-3 reflects these requirements based on fuel prices in the 2017/18 GRA.

Non-fuel O&M costs related to YEC thermal generation are not included in the DCF calculations at this time. YEC will review and report on this at its next GRA.

**DIESEL ON THE MARGIN:** The Board in Order 2015-01 noted that it does not consider diesel being "on the margin" part of the criteria for invoking the DCF. Based on current loads, expected load growth and LTA hydro generation, the Board determined that there is a reasonable expectation that under these conditions that diesel or "thermal" generation will form part of baseload generation thus making the question of diesel being either "on the margin" or "off the margin" moot.

**QUANTUM & CAP:** The Board in Order 2015-01 approved a "cap" for the DCF of +/- $8 million as an acceptable balance between frequency of rider applications and ability to handle material (drought) changes in hydro availability.

In any year when the balance in the DCF falls outside of the approved DCF cap range at fiscal year end, YEC shall apply to the Board for approval of a rate rider to dispense with the balance that is outside of that range within 60 days of the fiscal year end.

The refund (when DCF balance exceeds the approved maximum cap level) or collection (when DCF balance is below the approved minimum cap level) is to be made by way of a rate-rider to customers over next 12 month period. YEC may apply and the Board may approve the longer/shorter refund/collections period depending of the amount of refund/collections required. The rider is applicable for all retail and industrial firm sales in Yukon for both YEC and AEY.

**INTEREST:** The Fund is to attract interest based upon the short/intermediate term bond rates in which YEC may invest the Fund and any negative balances would only

[14] YEC's 2017/2018 GRA includes average LNG fuel cost at 14.668 cents per kW.h and average diesel fuel cost at 26.333 cents/kW.h, and assumes that 90% of LTA thermal is supplied by LNG and 10% by diesel (average blended price of 15.058 cents per kW.h).

attract interest at the lowest short-term borrowing rate available to YEC through a line of credit.

**QUARTERLY & ANNUAL REPORTING:** An annual report is required to be filed with the Board detailing additions and deletions to the Fund and a forecast of water conditions for the next year. The annual report to the Board is also to include a proposed rate rider to refund/collect any amount that exceeds the approved cap. The Board will direct YEC on the additions and deletions to the Fund, and on any proposed rate rider.

Quarterly reports regarding the DCF calculations and DCF balance updates will be provided to the Board based on interim determinations prior to a fiscal year end. The quarterly DCF calculations will be based on forecast loads for the year at the time of calculation as the DCF table calculates the expected diesel amount based on annual load, not quarterly.

Any interim determinations prior to a fiscal year end will only be placeholders; only the year end determinations will in fact have ongoing relevance for accounting and rate riders.

Examples of DCF calculations for 5 years are provided in Tables 3.4-2 and 3.4-3 below.

## Table 3.4-1: Expected YEC Thermal Generation with LTA YEC Hydro Generation

| Line Number | YEC Grid Load Net of Wind (GWh) | YEC Hydro Generation (GWh) | YEC Thermal Generation (GWh) | Increase in Load (GWh) | Increase in Thermal Generation (GWh) | Thermal as % of Increased Load |
|---|---|---|---|---|---|---|
| | Column A | Column B | Column C | Column D | Column E | Column F = E/D |
| **1** | 370.0 | 369.337 | 0.663 | | | |
| **2** | 375.0 | 373.626 | 1.374 | 5.0 | 0.710 | 14% |
| **3** | 380.0 | 377.800 | 2.200 | 5.0 | 0.826 | 17% |
| **4** | 385.0 | 381.845 | 3.155 | 5.0 | 0.955 | 19% |
| **5** | 390.0 | 385.750 | 4.250 | 5.0 | 1.096 | 22% |
| **6** | 395.0 | 389.503 | 5.497 | 5.0 | 1.246 | 25% |
| **7** | 400.0 | 393.098 | 6.902 | 5.0 | 1.405 | 28% |
| **8** | 405.0 | 396.528 | 8.472 | 5.0 | 1.570 | 31% |
| **9** | 410.0 | 399.789 | 10.211 | 5.0 | 1.739 | 35% |
| **10** | 415.0 | 402.877 | 12.123 | 5.0 | 1.911 | 38% |
| **11** | 420.0 | 405.793 | 14.207 | 5.0 | 2.084 | 42% |
| **12** | 425.0 | 408.537 | 16.463 | 5.0 | 2.256 | 45% |
| **13** | 430.0 | 411.111 | 18.889 | 5.0 | 2.426 | 49% |
| **14** | 435.0 | 413.521 | 21.479 | 5.0 | 2.590 | 52% |
| **15** | 440.0 | 415.772 | 24.228 | 5.0 | 2.748 | 55% |
| **16** | 445.0 | 417.874 | 27.126 | 5.0 | 2.898 | 58% |
| **17** | 450.0 | 419.836 | 30.164 | 5.0 | 3.038 | 61% |
| **18** | 455.0 | 421.669 | 33.331 | 5.0 | 3.167 | 63% |
| **19** | 460.0 | 423.388 | 36.612 | 5.0 | 3.281 | 66% |
| **20** | 465.0 | 425.007 | 39.993 | 5.0 | 3.380 | 68% |
| **21** | 470.0 | 426.545 | 43.455 | 5.0 | 3.462 | 69% |
| **22** | 475.0 | 428.019 | 46.981 | 5.0 | 3.525 | 71% |
| **23** | 480.0 | 429.452 | 50.548 | 5.0 | 3.567 | 71% |
| **24** | 485.0 | 430.865 | 54.135 | 5.0 | 3.587 | 72% |

Notes:

1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid, excluding actual less expected Fish Lake hydro generation.
2. The thermal generation and increase for the added load are based on a polynomial equation derived from "YECSIM" - the simulation model developed for the Integrated Grid by KGS Group.
3. The model calculates expected hydro plant generation for each load scenario. It incorporates, on a weekly time step, 35 "water years" on record (1981-2015) and 20 "load years" (each examines a different hypothetical scenario to evaluate generation under different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this removes results distorted by starting or ending year volumes). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.
4. The simulation model results used for this table assume the current operation rule in effect at Aishihik Lake (i.e., 10-year rolling average spring elevation no lower than 913.7 m), current Mayo Lake operation rule (no additional storage, impact of sedimentation at the outlet of Mayo Lake) and restricted Mayo GS winter flows.
5. The simulation model results are based on the 2018 forecast load distributions, and requires modifications when new mines or industrial loads are connected [or disconncted from] to the grid.
6. This table assumes max load at 485 GW.h and minimum load at 370 GW.h. If the load exceeds these limits then the table needs to be updated.
7. Numbers are subject to rounding.

**Example**

**Expected YEC Thermal Generation for the YEC generation at 417 GW.h (net of expected (GRA) Wind)**

Step 1. Find the closest load from Column A that is less than 417 GW.h = 415 GW.h (Line 10).

Step 2. Find the thermal generation from Column C = 12.123 GW.h (Line 10).

Step 3. Find the difference between the given load (417 GW.h) and load from Step 1 (415 GW.h) = 2 GW.h

Step 4. Apply the percentage from Column F (Line 11, 42%) to the difference from Step 3 (2 GW.h) = 0.840 GW.h

Step 5. Add numbers from Step 2 (12.123 GW.h) and Step 4 (0.840 GW.h) = 12.963 GW.h

The expected thermal generation at 417 GW.h load is 12.963 GW.h.

Notes:
The load assumed the maximum load at 485 GW.h and the minimum load at 370 GW.h.

## Table 3.4-2: DCF Operation Example for 5 Forecast Years

**Assumed DCF cap (+/- million) $8**

| Line | Activity | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|---|
| **A** | **DCF Opening Balance[1] ($000s)** | **$9,485** | **$8,000** | **$8,000** | **$8,000** | **($183)** |
| B | **Yukon Grid Generation[2]** | 423,730 | 433,730 | 445,500 | 455,600 | 469,730 |
| C | **AEY Fish Lake[2]** | 8,730 | 8,730 | 8,900 | 7,000 | 8,730 |
| | **YEC Grid Generation[2]** | | | | | |
| D | Assumed actual YEC Hydro (MW.h) | 412,420 | 420,420 | 433,000 | 378,400 | 355,420 |
| E | Assumed actual YEC Thermal [net of capital, insurance, maintenace] (MW.h) | 2,000 | 4,000 | 3,100 | 70,000 | 105,000 |
| F | Assumed actual actual Wind (MW.h) | 580 | 580 | 500 | 200 | 580 |
| G=D+E+F | Total YEC Generation (MW.h) | 415,000 | 425,000 | 436,600 | 448,600 | 461,000 |
| H | Expected YEC Thermal Generation in Rates[3] (MW.h) | 11,891 | 18,446 | 22,134 | 27,913 | 36,898 |
| I=E-H | YEC Thermal Generation to be Included in DCF (MW.h) | -9,891 | -14,446 | -19,034 | 42,087 | 68,102 |
| J=I*Fuel cost | Incremental Thermal Generation Cost to Charge[4] (Refund) DCF ($000s) | ($1,473) | ($2,119) | ($3,038) | $8,181 | $14,225 |
| K=J | Total DCF operation for YEC | | | | | |
| | YEC pays to DCF Fund | $1,473 | $2,119 | $3,038 | | |
| | YEC withdraws from DCF Fund | | | | ($8,181) | ($14,225) |
| **L=A+K** | **DCF Ending Balance ($000s)** | **$10,958** | **$10,119** | **$11,038** | **($181)** | **($14,408)** |
| **M** | **Interest on DCF Balance[5] ($000s)** | **$137** | **$126** | **$138** | **($2)** | **($180)** |
| **N=L+M** | **DCF Ending Balance[6] after Interest charge ($000s)** | **$11,095** | **$10,245** | **$11,176** | **($183)** | **($14,588)** |
| **O** | **Required Collections/(Refund)[7] ($000s)** | **$3,095** | **$2,245** | **$3,176** | **$0** | **($6,588)** |
| **P=N-O** | **DCF Ending Balance[8] after Required Collections/(Refund) ($000s)** | **$8,000** | **$8,000** | **$8,000** | **($183)** | **($8,000)** |

Notes:
1. DCF opening balance for Year 1 is 2016 preliminary actual ending balance of DCF account.
2. Assumed actual generation. Please see detailed calculations in Table 3.4-3.
3. Expected YEC thermal generation is calculated based on Updated Table 3.4-1 in Appendix 3.4. Please see detailed calculations in Table 3.4-3.
4. LNG generation cost assumed at 14.668 cents per kW.h and diesel generation cost assumed at 26.333 cents/kW.h (based on 2017/18 GRA average fuel costs).
5. Per the March 11, 1996 letter recording the settlements [provided as Exhibit B-16 in the 2008/2009 GRA] the DCF fund is to attract interest based upon the short/intermediate term bond rates in which the Companies may invest the fund and any negative balances would only attract interest at the lowest short-term borrowing rate available to the Companies through a line of credit. For this example used 1.25% based on Government of Canada Bond Yields for 3-year and 5-year issues.
6. Positive balances represent amounts to the benefit of ratepayers; negative balances are amounts owing to YEC.
7. YUB in its Order 2015-01 approved the current DCF balance cap at +/- $8 million. In any year when the balance in the DCF falls outside of the approved DCF cap range at fiscal year end, YEC shall apply to the Board for approval of a rate rider to dispense with the balance that is outside of that range within 60 days of the fiscal year end.
8. Notional ending balance for illustration purposes only. Any excess amount of approved +/- DCF cap balance range at fiscal year end would be dispensed within the next 12 months [April through March of following year], unless YUB approves a different period for a charge to mitigate adverse rate impacts.

## Table 3.4-3: DCF Formulaic Approach Operation Examples for 5 Load Forecast Cases

| Line No | | | | | Notes |
|---|---|---|---|---|---|
| *L1a* | Diesel Fuel Cost per kW.h | | 26.333 | cents/kW.h | GRA Application Average Fuel cost (2017/18 GRA Application) |
| *L1b* | LNG Fuel Cost per kW.h | | 14.668 | cents/kW.h | |
| | **Calculation of Thermal Cost to Charge (Refund) DCF** | | | | |
| | **Year 1 - Actual Wind and Fish Lake at Forecast; Actual Thermal Generation Below Expected** | | | | |
| | *Assumptions* | | | | |
| *L2* | YEC Grid load | | 415,000 | MW.h | assumed actual |
| *L3* | Fish Lake | | 8,730 | MW.h | assumed actual |
| *L4=L2+L3* | Total Grid load | | 423,730 | MW.h | |
| | Assumed Actual Generation Sources | | | | |
| *L5* | YECL Fish Lake | | 8,730 | MW.h | assumed actual |
| *L6* | YEC Hydro | | 412,420 | MW.h | assumed actual |
| *L7* | YEC Thermal (net of capital, insurance and maintenance) | | 2,000 | MW.h | assumed actual |
| *L7a* | *YEC Diesel (net of capital, insurance and maintenance)* | | *1,000* | *MW.h* | *assumed actual* |
| *L7b* | *YEC LNG (net of capital, insurance and maintenance)* | | *1,000* | *MW.h* | *assumed actual* |
| *L8* | YEC Wind | | 580 | MW.h | assumed actual |
| *L9* | Total Grid load | | 423,730 | MW.h | |
| | Expected Generation Sources | | | | |
| *L10* | YECL Fish Lake (expected) | | 8,730 | MW.h | YECL Fish Lake long term average hydro generation based on YUB Order 2014-06. |
| *L11* | YEC Wind (expected) | | 580 | MW.h | YEC 2017/18 GRA |
| *L12=L9-L10-L11* | YEC Grid load net of expected Fish Lake and Wind | | 414,420 | MW.h | |
| *L13* | Expected Base Thermal Generation at 410 GW.h | | 10,211 | MW.h | Derived from updated Table 3.4-1, Appendix 3.4 |
| *L14=(L12-400 GW.h)x31%* | Expected Incremental Thermal Generation at 4,420 MW.h above 410 GW.h | | 1,680 | MW.h | 38% of Grid Load between 415 GW.h and 420 GW.h is thermal - Derived from updated Table 3.4-1, Appendix 3.4 |
| *L15=L13+L14* | Total Expected YEC Thermal Generation | | 11,891 | MW.h | |
| *L16=L15* | Expected YEC Thermal Generation in Rates | | 11,891 | MW.h | 100% of long-term average |
| *L17=L7* | Actual YEC Net Thermal Generation | | 2,000 | MW.h | assumed net actual |
| *L18=L17-L16* | YEC Thermal Generation to be included in DCF | - | 9,891 | MW.h | |
| *L18a [see Notes]* | YEC Diesel Generation to be included in DCF | - | 189 | MW.h | IF L18<0, Maximize (0.1xL16-L7a and 0) - - Otherwise, IF L18>0, Minimize (0.1xL16-L7a and 0) - -result shown as negative |
| *L18b=L18-L18a* | YEC LNG Generation to be included in DCF | - | 9,702 | MW.h | |
| *L19=L1axL18a+L1bxL18b* | Incremental YEC Thermal Generation Cost to Charge (Refund) DCF ($000s) | | ($1,473) | | |
| | **Year 2 - Actual Wind and Fish Lake at Forecast; Actual Thermal Generation Below Expected** | | | | |
| | *Assumptions* | | | | |
| *L2* | YEC Grid load | | 425,000 | MW.h | assumed actual |
| *L3* | Fish Lake | | 8,730 | MW.h | assumed actual |
| *L4=L2+L3* | Total Grid load | | 433,730 | MW.h | |
| | Assumed Actual Generation Sources | | | | |
| *L5* | YECL Fish Lake | | 8,730 | MW.h | assumed actual |
| *L6* | YEC Hydro | | 420,420 | MW.h | assumed actual |
| *L7* | YEC Thermal (net of capital, insurance and maintenance) | | 4,000 | MW.h | assumed actual |
| *L7a* | *YEC Diesel (net of capital, insurance and maintenance)* | | *3,000* | *MW.h* | *assumed actual* |
| *L7b* | *YEC LNG (net of capital, insurance and maintenance)* | | *1,000* | *MW.h* | *assumed actual* |
| *L8* | YEC Wind | | 580 | MW.h | assumed actual |
| *L9* | Total Grid load | | 433,730 | MW.h | |
| | Expected Generation Sources | | | | |
| *L10* | YECL Fish Lake (expected) | | 8,730 | MW.h | YECL Fish Lake long term average hydro generation based on YUB Order 2014-06. |
| *L11* | YEC Wind (expected) | | 580 | MW.h | YEC 2017/18 GRA |
| *L12=L9-L10-L11* | YEC Grid load net of expected Fish Lake and Wind | | 424,420 | MW.h | |
| *L13* | Expected Base Thermal Generation at 420 GW.h | | 14,207 | MW.h | Derived from updated Table 3.4-1, Appendix 3.4 |
| *L14=(L12-415 GW.h)x42%* | Expected Incremental Thermal Generation at 4,420 MW.h above 420 GW.h | | 4,239 | MW.h | 45% of Grid Load between 420 GW.h and 425 GW.h is thermal |
| *L15=L13+L14* | Total Expected YEC Thermal Generation | | 18,446 | MW.h | |
| *L16=L15* | Expected YEC Thermal Generation in Rates | | 18,446 | MW.h | 100% of long-term average |
| *L17=L7* | Actual YEC Net Thermal Generation | | 4,000 | MW.h | assumed net actual |
| *L18=L17-L16* | YEC Thermal Generation to be included in DCF | - | 14,446 | MW.h | |
| *L18a [see Notes]* | YEC Diesel Generation to be included in DCF | | - | MW.h | IF L18<0, Maximize (0.1xL16-L7a and 0) - - Otherwise, IF L18>0, Minimize (0.1xL16-L7a and 0) - -result shown as negative |
| *L18b=L18-L18a* | YEC LNG Generation to be included in DCF | - | 14,446 | MW.h | |
| *L19=L1axL18a+L1bxL18b* | Incremental YEC Thermal Generation Cost to Charge (Refund) DCF ($000s) | | ($2,119) | | |

## Table 3.4-3: DCF Formulaic Approach Operation Examples for 5 Load Forecast Cases (cont.)

**Year 3 - Actual Wind and Fish Lake Higher than Forecast; Actual Thermal Generation Below Expected**

| | | | | |
|---|---|---|---|---|
| | *Assumptions* | | | |
| *L2* | YEC Grid load | 436,600 | MW.h | assumed actual |
| *L3* | Fish Lake | 8,900 | MW.h | assumed actual |
| *L4=L2+L3* | Total Grid load | 445,500 | MW.h | |
| | Assumed Actual Generation Sources | | | |
| *L5* | YECL Fish Lake | 8,900 | MW.h | assumed actual |
| *L6* | YEC Hydro | 433,000 | MW.h | assumed actual |
| *L7* | YEC Thermal (net of capital, insurance and maintenance) | 3,100 | MW.h | assumed actual |
| *L7a* | *YEC Diesel (net of capital, insurance and maintenance)* | *100* | *MW.h* | *assumed actual* |
| *L7b* | *YEC LNG (net of capital, insurance and maintenance)* | *3,000* | *MW.h* | *assumed actual* |
| *L8* | YEC Wind | 500 | MW.h | assumed actual |
| *L9* | Total Grid load | 445,500 | MW.h | |
| | Expected Generation Sources | | | |
| *L10* | YECL Fish Lake (expected) | 8,730 | MW.h | YECL Fish Lake long term average hydro generation based on YUB Order 2014-06. |
| *L11* | YEC Wind (expected) | 580 | MW.h | YEC 2017/18 GRA |
| *L12=L9-L10-L11* | YEC Grid load net of expected Fish Lake and Wind | 436,190 | MW.h | |
| *L13* | Expected Base Thermal Generation at 435 GW.h | 21,479 | MW.h | Derived from updated Table 3.4-1, Appendix 3.4 |
| *L14=(L12-435 GW.h)x55%* | Expected Incremental Thermal Generation at 1,190 MW.h above 435 GW.h | 655 | MW.h | 55% of Load between 435 GW.h and 440 GW.h is thermal |
| *L15=L13+L14* | Total Expected YEC Thermal Generation | 22,134 | MW.h | |
| *L16=L15* | Expected YEC Thermal Generation in Rates | 22,134 | MW.h | 100% of long-term average |
| *L17=L7* | Actual YEC Net Thermal Generation | 3,100 | MW.h | assumed net actual |
| *L18=L17-L16* | YEC Thermal Generation to be included in DCF | - 19,034 | MW.h | |
| *L18a [see Notes]* | YEC Diesel Generation to be included in DCF | - 2,113 | MW.h | IF L18<0, Maximize (0.1xL16-L7a and 0) - - Otherwise, IF L18>0, Minimize (0.1xL16-L7a and 0) - -result shown as negative |
| *L18b=L18-L18a* | YEC LNG Generation to be included in DCF | - 16,920 | MW.h | |
| *L19=L1axL18a+L1bxL18b* | Incremental YEC Thermal Generation Cost to Charge (Refund) DCF ($000s) | ($3,038) | | |

**Year 4 - Actual Wind and Fish Lake below Forecast; Actual Thermal Generation Above Expected**

| | | | | |
|---|---|---|---|---|
| | *Assumptions* | | | |
| *L2* | YEC Grid load | 448,600 | MW.h | assumed actual |
| *L3* | Fish Lake | 7,000 | MW.h | assumed actual |
| *L4=L2+L3* | Total Grid load | 455,600 | MW.h | |
| | Assumed Actual Generation Sources | | | |
| *L5* | YECL Fish Lake | 7,000 | MW.h | assumed actual |
| *L6* | YEC Hydro | 378,400 | MW.h | assumed actual |
| *L7* | YEC Thermal (net of capital, insurance and maintenance) | 70,000 | MW.h | assumed actual |
| *L7a* | *YEC Diesel (net of capital, insurance and maintenance)* | *20,000* | *MW.h* | *assumed actual* |
| *L7b* | *YEC LNG (net of capital, insurance and maintenance)* | *50,000* | *MW.h* | *assumed actual* |
| *L8* | YEC Wind | 200 | MW.h | assumed actual |
| *L9* | Total Grid load | 455,600 | MW.h | |
| | Expected Generation Sources | | | |
| *L10* | YECL Fish Lake (expected) | 8,730 | MW.h | YECL Fish Lake long term average hydro generation based on YUB Order 2014-06. |
| *L11* | YEC Wind (expected) | 580 | MW.h | YEC 2017/18 GRA |
| *L12=L9-L10-L11* | YEC Grid load net of expected Fish Lake and Wind | 446,290 | MW.h | |
| *L13* | Expected Base Thermal Generation at 445 GW.h | 27,126 | MW.h | Derived from updated Table 3.4-1, Appendix 3.4 |
| *L14=(L12-445 GW.h)x61%* | Expected Incremental Thermal Generation at 1,290 MW.h above 445 GW.h | 787 | MW.h | 61% of Load between 445 GW.h and 450 GW.h is thermal |
| *L15=L13+L14* | Total Expected YEC Thermal Generation | 27,913 | MW.h | |
| *L16=L15* | Expected YEC Thermal Generation in Rates | 27,913 | MW.h | 100% of long-term average |
| *L17=L7* | Actual YEC Net Thermal Generation | 70,000 | MW.h | assumed net actual |
| *L18=L17-L16* | YEC Thermal Generation to be included in DCF | 42,087 | MW.h | |
| *L18a [see Notes]* | YEC Diesel Generation to be included in DCF | 17,209 | MW.h | IF L18<0, Maximize (0.1xL16-L7a and 0) - - Otherwise, IF L18>0, Minimize (0.1xL16-L7a and 0) - -result shown as negative |
| *L18b=L18-L18a* | YEC LNG Generation to be included in DCF | 24,878 | MW.h | |
| *L19=L1axL18a+L1bxL18b* | Incremental YEC Thermal Generation Cost to Charge (Refund) DCF ($000s) | $8,181 | | |

**Year 5 - Actual Wind and Fish Lake at Forecast; Actual Thermal Generation Above Expected**

| | | | | |
|---|---|---|---|---|
| | *Assumptions* | | | |
| *L2* | YEC Grid load | 461,000 | MW.h | assumed actual |
| *L3* | Fish Lake | 8,730 | MW.h | assumed actual |
| *L4=L2+L3* | Total Grid load | 469,730 | MW.h | |
| | Assumed Actual Generation Sources | | | |
| *L5* | YECL Fish Lake | 8,730 | MW.h | assumed actual |
| *L6* | YEC Hydro | 355,420 | MW.h | assumed actual |
| *L7* | YEC Thermal (net of capital, insurance and maintenance) | 105,000 | MW.h | assumed actual |
| *L7a* | *YEC Diesel (net of capital, insurance and maintenance)* | *40,000* | *MW.h* | *assumed actual* |
| *L7b* | *YEC LNG (net of capital, insurance and maintenance)* | *65,000* | *MW.h* | *assumed actual* |
| *L8* | YEC Wind | 580 | MW.h | assumed actual |
| *L9* | Total Grid load | 469,730 | MW.h | |
| | Expected Generation Sources | | | |
| *L10* | YECL Fish Lake (expected) | 8,730 | MW.h | YECL Fish Lake long term average hydro generation based on YUB Order 2014-06. |
| *L11* | YEC Wind (expected) | 580 | MW.h | YEC 2017/18 GRA |
| *L12=L9-L10-L11* | YEC Grid load net of expected Fish Lake and Wind | 460,420 | MW.h | |
| *L13* | Expected Base Thermal Generation at 460 GW.h | 36,612 | MW.h | Derived from updated Table 3.4-1, Appendix 3.4 |
| *L14=(L12-460 GW.h)x68%* | Expected Incremental Thermal Generation at 420 MW.h above 460 GW.h | 286 | MW.h | 68% of Load between 460 GW.h and 465 GW.h is thermal |
| *L15=L13+L14* | Total Expected YEC Thermal Generation | 36,898 | MW.h | |
| *L16=L15* | Expected YEC Thermal Generation in Rates | 36,898 | MW.h | 100% of long-term average |
| *L17=L7* | Actual YEC Net Thermal Generation | 105,000 | MW.h | assumed net actual |
| *L18=L17-L16* | YEC Thermal Generation to be included in DCF | 68,102 | MW.h | |
| *L18a [see Notes]* | YEC Diesel Generation to be included in DCF | 36,310 | MW.h | IF L18<0, Maximize (0.1xL16-L7a and 0) - - Otherwise, IF L18>0, Minimize (0.1xL16-L7a and 0) - -result shown as negative |
| *L18b=L18-L18a* | YEC LNG Generation to be included in DCF | 31,792 | MW.h | |
| *L19=L1axL18a+L1bxL18b* | Incremental YEC Thermal Generation Cost to Charge (Refund) DCF ($000s) | $14,225 | | |

## ATTACHMENT 3.4.2 – POTENTIAL THERMAL GENERATION VARIABILITY (GW.H/YEAR) DEPENDING ON WATER CONDITIONS (35 YEARS) – RANGE OF GRID LOADS FROM 380 TO 450 GW.H/YEAR

Previous YECSIM-related LTA submissions (e.g., the LNG Part 3 Application, Appendix C) have broken out the LTA assessment to show the estimated thermal generation requirement for each of the separate water years used to determine the overall LTA for each load forecast scenario. This break out allows the Board and participants to see, for any given load scenario, the underlying range of annual thermal generation for each of the 35 water years associated with the long-term average determination.

Attachment 3.4.2 provides an update to this analysis, based on the updated YECSIM model, showing the estimated thermal generation requirement for each of the 35 water years for a range of potential load scenarios.

Table 3.4-4 and Figure 3.4-1 updates review potential thermal generation variability for each of the 35 water years for a range of potential grid firm loads, based on the updated YECSIM model and load forecasts potentially relevant within the next few years.

Table 3.4-4 and Figure 3.4-1 address three potential grid firm load scenarios:

- Load at 420 GW.h/year [approximates 2018 GRA grid load with Minto mine];
- Load at 380 GW.h/year [approximates 2018 GRA grid load with no mines]; and
- Load at 450 GW.h/year [approximates 2018 GRA grid load plus 30 GW.h/year new mine load].

The following summarizes the information in Table 3.4-4 and Figure 3.4-1:

- The left side of Table 3.4-4 shows, for each grid load scenario, the annual variability of average thermal generation for each of the 35 water years of record (1981-2015); in each scenario with 420 GW.h or higher load 1996-2001 is a string of six consecutive notable drought condition years. At the bottom of each load scenario the long-term average (LTA) thermal generation is shown, based on the overall average for the 35 water years, and the median water year generation is shown for the 35 water years.

- The right side of Table 3.4-4 shows, for each grid load scenario, the percent of the 35 water years (i.e., how many years in the 35 water years) when the annual average thermal generation required is not less than the specified level.

- Figure 3.4-1 shows the annual load duration curve for thermal generation over the 35 water years for each of the three load scenarios (reflects the right side of Table 3.4-4).

### Table 3.4-4: Average Annual Thermal Generation (Averaged Load Years for 35 Water Years)

| Water Year | Load at 420 GW.h [approx. 2018 GRA load level] | Load at 380 GW.h [approx. 2018 GRA load level no mines] | Load at 450 GW.h [approx. 2018 GRA load level plus 30 GW.h new mine load] | | % of Years not less than | Load at 420 GW.h [approx. 2018 GRA load level] | Load at 380 GW.h [approx. 2018 GRA load level no mines] | Load at 450 GW.h [approx. 2018 GRA load level plus 30 GW.h new mine load] |
|---|---|---|---|---|---|---|---|---|
| 1981 | 0.2 | 0.0 | 0.7 | 1 | 3% | 107.5 | 55.2 | 117.0 |
| 1982 | 0.2 | 0.0 | 0.7 | 2 | 6% | 58.3 | 18.7 | 76.8 |
| 1983 | 0.2 | 0.0 | 0.7 | 3 | 9% | 53.8 | 6.1 | 71.2 |
| 1984 | 0.4 | 0.0 | 31.0 | 4 | 11% | 50.1 | 0.6 | 70.8 |
| 1985 | 0.3 | 0.0 | 43.9 | 5 | 14% | 35.4 | 0.0 | 61.2 |
| 1986 | 0.4 | 0.0 | 48.0 | 6 | 17% | 33.2 | 0.0 | 58.6 |
| 1987 | 0.2 | 0.0 | 27.7 | 7 | 20% | 31.2 | 0.0 | 54.2 |
| 1988 | 0.2 | 0.0 | 32.4 | 8 | 23% | 24.0 | 0.0 | 48.0 |
| 1989 | 0.2 | 0.0 | 12.9 | 9 | 26% | 16.7 | 0.0 | 43.9 |
| 1990 | 0.2 | 0.0 | 14.9 | 10 | 29% | 14.2 | 0.0 | 35.3 |
| 1991 | 0.2 | 0.0 | 3.3 | 11 | 31% | 13.8 | 0.0 | 32.4 |
| 1992 | 0.2 | 0.0 | 1.6 | 12 | 34% | 12.6 | 0.0 | 31.4 |
| 1993 | 0.2 | 0.0 | 2.8 | 13 | 37% | 11.4 | 0.0 | 31.2 |
| 1994 | 0.2 | 0.0 | 2.5 | 14 | 40% | 6.5 | 0.0 | 31.0 |
| 1995 | 6.5 | 0.0 | 61.2 | 15 | 43% | 5.1 | 0.0 | 30.1 |
| 1996 | 50.1 | 0.0 | 71.2 | 16 | 46% | 3.7 | 0.0 | 27.7 |
| 1997 | 53.8 | 18.7 | 76.8 | 17 | 49% | 1.9 | 0.0 | 26.5 |
| 1998 | 31.2 | 0.6 | 70.8 | 18 | 51% | 1.6 | 0.0 | 25.5 |
| 1999 | 107.5 | 55.2 | 117.0 | 19 | 54% | 0.4 | 0.0 | 24.4 |
| 2000 | 58.3 | 0.0 | 58.6 | 20 | 57% | 0.4 | 0.0 | 22.7 |
| 2001 | 35.4 | 0.0 | 24.4 | 21 | 60% | 0.3 | 0.0 | 21.2 |
| 2002 | 24.0 | 0.0 | 31.4 | 22 | 63% | 0.2 | 0.0 | 14.9 |
| 2003 | 14.2 | 0.0 | 30.1 | 23 | 66% | 0.2 | 0.0 | 12.9 |
| 2004 | 33.2 | 6.1 | 54.2 | 24 | 69% | 0.2 | 0.0 | 10.3 |
| 2005 | 16.7 | 0.0 | 21.2 | 25 | 71% | 0.2 | 0.0 | 4.1 |
| 2006 | 12.6 | 0.0 | 25.5 | 26 | 74% | 0.2 | 0.0 | 3.3 |
| 2007 | 13.8 | 0.0 | 35.3 | 27 | 77% | 0.2 | 0.0 | 2.8 |
| 2008 | 11.4 | 0.0 | 22.7 | 28 | 80% | 0.2 | 0.0 | 2.5 |
| 2009 | 1.9 | 0.0 | 10.3 | 29 | 83% | 0.2 | 0.0 | 1.9 |
| 2010 | 5.1 | 0.0 | 31.2 | 30 | 86% | 0.2 | 0.0 | 1.6 |
| 2011 | 3.7 | 0.0 | 26.5 | 31 | 89% | 0.2 | 0.0 | 1.6 |
| 2012 | 1.6 | 0.0 | 4.1 | 32 | 91% | 0.2 | 0.0 | 1.0 |
| 2013 | 0.2 | 0.0 | 1.6 | 33 | 94% | 0.2 | 0.0 | 0.7 |
| 2014 | 0.2 | 0.0 | 1.0 | 34 | 97% | 0.2 | 0.0 | 0.7 |
| 2015 | 0.2 | 0.0 | 1.9 | 35 | 100% | 0.2 | 0.0 | 0.7 |
| LTA (Average) | 13.9 | 2.3 | 28.6 | | | 13.9 | 2.3 | 28.6 |
| Median | 1.6 | 0.0 | 25.5 | | | 1.6 | 0.0 | 25.5 |

**Figure 3.4-1: Duration Curve – Grid Thermal Generation Variability over 35 Water Years**

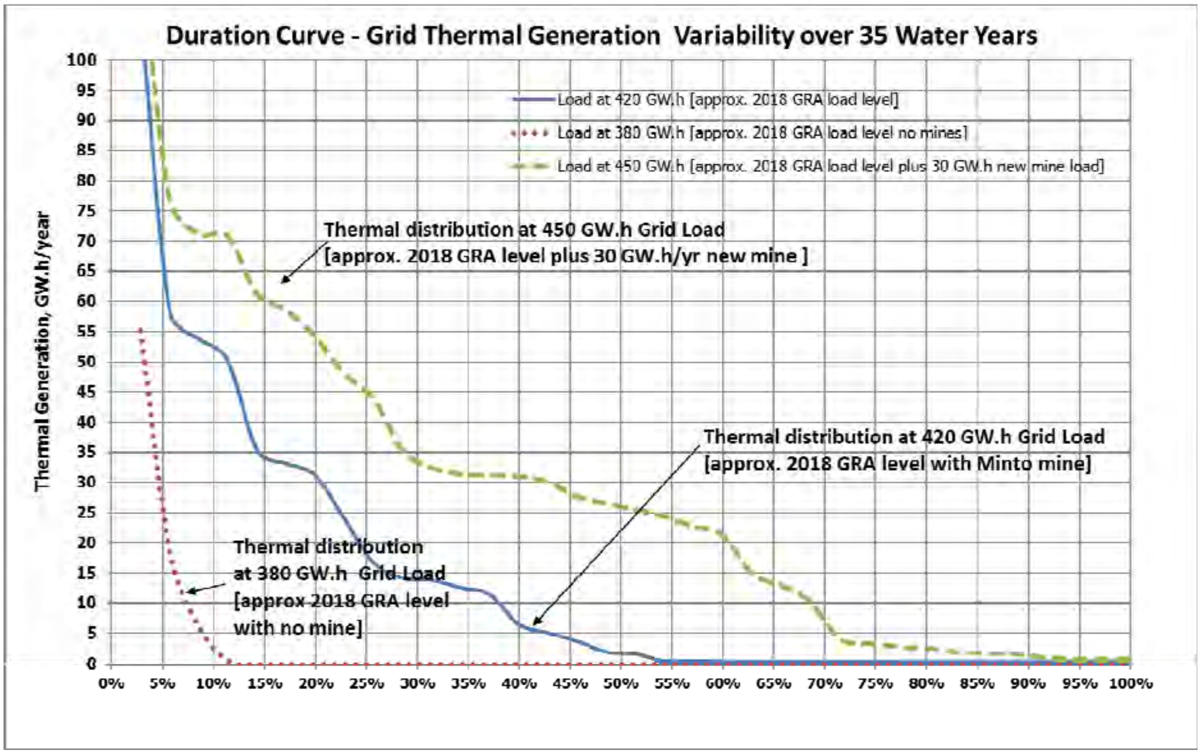


Figure 3.4-1 highlights the sensitivity of the current LTA thermal generation assessments as firm grid load varies from -40 GW.h to + 30 GW.h from the 420 GW.h/year level that approximates this Application's 2018 load forecast. In summary, Figure 3.4-1 and Table 3.4-4 show the following:

- At 420 GW.h per year load with the Minto mine, LTA thermal generation is 13.9 GW.h with 75% of this thermal generation occurring in the 20% of the 35 water years with the worst drought conditions, and less than 1% of this thermal generation occurring in the 46% of the 35 water years with the best water conditions.

- At 450 GW.h per year load with the Minto mine, LTA thermal generation is 28.6 GW.h with 51% of this thermal generation occurring in the 20% of the 35 water years with the worst drought conditions, and 10% of this thermal generation occurring in the 46% of the 35 water years with the best water conditions.

- At 380 GW.h per year load without the Minto mine, LTA thermal generation is 2.3 GW.h with 99% of this thermal generation occurring in the 20% of the 35 water years with the worst drought conditions, and about 0.5% of this thermal generation occurring in the 46% of the 35 water years with the best water conditions.

## ATTACHMENT 3.4.3 – INFORMATION ON YECSIM MODEL

The YECSIM model was developed by the KGS Consulting Group (KGS) for Yukon Energy in 2007, and has been used by YEC since that time for estimating power generation requirements. It is a planning model that is designed to simulate YEC system energy generation under a variety of hydrological and load conditions, and in summary has the following key elements:[15]

- The major model inputs are:
  - The load (energy) forecast and its distribution throughout the year; and
  - The resource technical attributes (installed capacity, unit efficiencies, reservoir storages vs. elevation curves, non-power water release rating curves, transmission losses).
- The major model operational criteria are:
  - Water use license requirements;
  - Minimum and maximum flows;
  - Minimum and maximum reservoir elevations; and
  - Priority of water releases between power generation and environmental releases.
- The major model output is expected energy generation by each resource.

YEC has consistently used YECSIM for its recent assessments of planning and revenue requirement applications that the Board has ultimately recommended or approved (as appropriate for the proceeding), including recent Part 3 Project applications that the Board has reviewed (namely, Mayo B Project Application and Whitehorse Natural Gas Conversion Project Application), as well as for forecasts of long-term average hydro generation and diesel generation requirements as approved by the Board in Order 2013-01 for the YEC 2012-13 GRA and Order 2015-01 and 2015-06 for the DCF.

[15] YEC 2016 Resource Plan, Section 4.3.1.

More detailed information is provided below on YECSIM's development and approach, as well as its specific features.[16]

### *YECSIM Development and Approach*

In 2007, YEC approached KGS to prepare a plan for preparation of a numerical model that could be used for analysis of the operation and future expansion of the YEC electrical generating system.[17] KGS prepared the structure of the model to follow other well established precedents in this field.[18] YECSIM was custom-made to acknowledge all significant factors that affect the operation of the YEC power system, including the complex rules of operation and the regulatory demands on YEC. Key features of the YECSIM model as noted in past submissions are noted below:

- YECSIM is a composite of many sub-models that combine to provide an accurate representation of the YEC power system under a variety of hydrological conditions. The accuracy of individual components of the model, such as energy generation for given flows and heads, have been verified individually, and are known to be accurate representations of the real phenomenon. Model inputs such as spillway discharge rating curves have been based on, and verified with, actual data.

- The model uses the recorded sequences of river flows (termed "water years") and superimposes it over the projected years being analyzed (termed "load years").[19] Each combination of a sequence of "water years" and "load years" constitutes a "cycle". The "water years" are then shifted by one year and superimposed on the "load years" again, and this process is repeated until all possible sequence combinations ("cycles") have been applied. This provides the hypothetical scenario of energy generation capability that would occur if the recorded series of "water years" would repeat itself.[20]

- Typical uses of the model for system planning and/or revenue requirement assessments focus on assessing long-term average changes to hydro generation (i.e., based on an average of "water years" and "cycles") under different assumed grid load conditions. The model's assessment is on a weekly time step basis.

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[16] Includes summary of information provided in August 19, 2014 response to YUB-YEC-1-3 in the DCF-ERA Proceeding.
[17] From 1992 up to 2006 Yukon Energy had continued to use Acres (now Hatch-Energy) MULRES model for its hydro resource planning for the purposes of assessing various supply option scenarios.
[18] KGS staff have been actively involved in understanding and applying similar models used for similar purposes in other hydro-thermal electric power systems. Specific examples were provided in DCF-ERA Proceeding IR response YUB-YEC-1-3(a)(i).
[19] The YECSIM model does not apply Monte Carlo simulations. See response to YUB-YEC-1-3(a)(ii) in DCF-ERA Proceeding.
[20] In this respect, YECSIM is no different from Manitoba Hydro's SPLASH planning model. KGS Group consulted with Manitoba Hydro on SPLASH and how their modeling strategy could be applied to YECSIM.

- Being a planning model, YECSIM is not structured in a way that lends itself to retrospective verification per se.[21] Detailed test year verifications are not typically undertaken as such a verification or "test" would not normally be seen as a verification that is required or appropriate for this type of a planning model. If the model was to be reviewed for an historic test year it would be necessary to use the actual loads and inflows as input, and consider as well any special conditions that could have occurred during the test year.

- Expected thermal generation as provided by YECSIM output does not reflect the impact of risk events not related to water conditions (e.g., diesel generation due to transmission outages, or diesel generation funded by RFID or insurance events), thermal generation due to capital project restriction of hydro generation, or thermal generation required solely for maintenance run-ups.

- Expected thermal generation as provided by YECSIM reflects the extent to which LTA thermal generation (as a percent of total incremental generation) changes as grid load changes, thereby reflecting the fact that under current load conditions (unlike when the Faro mine was operating) LTA thermal generation accounts for less than 100% of any variance in grid generation requirements.

- Expected thermal generation as provided by YECSIM is based on LTA hydro and wind generation for the specified grid load and all water years of record (currently 35 years). As such, YECSIM does not forecast thermal generation for any specific week, month or year (i.e., the test years). The difference between LTA and short term thermal generation forecasts was fully reflected in YEC's 2012-2013 GRA. The ultimate determination of LTA in any year generally depends on the full year assessments and not on individual month assessments, i.e., DCF quarterly reports provide month-by-month assessments as placeholders and model assessments are intended to be provided on a full annual basis.

- Expected thermal generation as provided by YECSIM based on LTA hydro and wind generation for specified grid loads assumes that thermal generation is dispatched only as required to meet energy load requirements, i.e., it does not include or assess options for thermal generation to enhance hydro storage for wintertime use. The LNG Part 3 Application (Appendix D) stipulated specific scenarios for LNG operation in order to assess such potential storage opportunities and impacts.

[21] This is similar to other planning models such as Manitoba Hydro's SPLASH model.

***YECSIM Considerations & Operational Rules***

The YECSIM model incorporates the operation rules and license requirements that specifically apply to each site. This includes minimum flow requirements for each river, and each segment of the river when the requirements change along the same water course, as well as the maximum and minimum levels of operation of each lake in the system, in accordance to the licence. The model also includes seasonal changes, when these apply, as well as the necessary provisions to adjust during a simulation (for instance, in the operation of Aishihik Lake for which minimum levels are based on the 10-year rolling average of minimum spring levels).

The model also includes conditions that derive from YEC's operation, such as the priority sequence for drawing water from the lakes in the system. These were initially based on discussions with YEC, and have been derived from experience and knowledge of the sites. YEC has continued to update these conditions based on currently available information.

Other conditions that relate to the physical characteristics of the stations and reservoirs, such as tailwater rating curves and discharge rating curves, storage capacity were included in the model based on the data that YEC provided. The characteristics of each plant (flow capacity, head, head losses, efficiencies) are also consistent with records.

As an example of the model reflecting the condition and historical water levels and outflows for each generating station and/or reservoir, the power generated at the Whitehorse Rapids Generating Station is calculated for the differential water levels (reservoir level minus tailwater level) that exist at that structure. It requires an accurate algorithm that computes the tailwater level as a function of the river flow, and acknowledges the fact that in winter there can be some increases in tailwater due to ice. The algorithms that are built into the model have been based on surveyed water levels and known plant outflows.

The YECSIM model has the capability of making changes to the elements listed above. This allows adjusting the model to potential changes on these conditions or to evaluate alternatives.

The historical operation of the system was revised at the developing stages to obtain a general understanding of YEC's operation. At those stages, simulations were carried out to verify in general that the model results properly corresponded to the operation of the WAF system. Model results were discussed with YEC at that stage. However, the YECSIM model is not set to replicate the past; but to simulate the system operation within the conditions imposed by physics, regulation and operational priorities, in order to supply the estimated loads with the available hydrologic inputs.

***Data, Calculations & assumptions***

The calculations in the model are based on general rules of physics (such as energy derived from flow and head, head loss calculations) or in available data (rating curves, storage curves).

The data that constitutes the input to the YECSIM model includes:

- Hydrologic Inputs:
    - Inflows Available for Outflows (total inflows minus ground water outflows and evaporation) to all the reservoirs in the system.
- Reservoirs:
    - Elevation-Storage Volume Curves;
    - Minimum and maximum water levels as per operation license;
    - Initial water levels;
    - Minimum riparian outflows at each structure;
    - Discharge rating curves (water elevation vs. flow) for spillways and control structures;
    - Priorities for drawdown of reservoir levels; and
    - Limits to maximum winter draw-down if applicable.
- Generating Stations:
    - Efficiency curves (efficiency vs flow); and
    - Station service loss.

- Energy Inputs:
  - Total load for each simulated year;
  - Weekly factors to estimate weekly loads;
  - Load duration curve to estimate hourly peaks within each week;
  - Maximum diesel capacity;
  - Other energy sources (optional); and
  - System configuration to be used in the simulation: WAF, MD, individual stations, interconnected.

The user can define the inputs to the model, including the following:

- Rules of operation and the regulatory demands for each lake/ reservoir, including minimum and maximum allowed water levels, minimum and maximum outflows;
- Minimum and maximum outflows for each generating station, flow rates and generation unit efficiencies, tailwater and head loss coefficients.
- Load data, including weekly distribution and load duration curve for the week; and
- Inflows Available for Outflows, the inflows estimated based on historical water levels and outflows.

The input parameters allow including forced outages in the estimate of energy from each plant. The values normally used in simulations are derived from YEC's experience and can be modified by the user of the model.

## ATTACHMENT 3.4.4 – DCF CAP OPTION ASSESSMENT

### Approach

The DCF cap option impact assessment examines, for the 420 and 450 GW.h/year loads, the average annual GW.h/year thermal generation in each of the 35 water years used to determine the LTA thermal average of 13.9 GW.h for 420 GW.h load and 28.6 GW.h/year for 450 GW.h load (sourced from Appendix 3.4, Attachment 3.4.2, Table 3.4-4). The two grid loads examined reflect potential near-term loads with Minto and Alexco (i.e., Victoria Gold would be higher load than the ones examined here), and help to show the extent to which a 20 GW.h load increase (above the 420 GW.h load range forecast for 2018 in the GRA) could change the DCF cap assessments.

This information is used to examine potential annual DCF transfers (in and out of DCF) without and with a specified DCF cap, based on two LTA price scenarios (one with only Diesel generation assumed, and one assuming 90% LNG and 10% diesel generation as per current GRA).

The "no cap" assessments highlight the basic features of each load scenario and how annual thermal requirements vary relative to LTA over the 35 water years. Examining diesel as well as the current GRA costs with LNG/diesel highlights the savings and related impacts provided with LNG.

Comparative assessments of the DCF cap options are summarized in Table 3.4-5 based on changes in the number of water years with a rate rider requirement, and the magnitude of the rate rider impacts, i.e., fewer years with rider impacts and lower rider impacts are assumed to be preferred options.

The analysis assumes the average load assessment by water year sequence derived from the YECSIM analysis of various load years, i.e., there is no assurance that water years in future would proceed in this specific sequence. It excludes any interest impacts for the DCF, as well as the extent that LNG generation would need to be operated beyond levels assumed here in order to secure added hydro storage (this latter factor is expected to become less material to the extent that more LNG capacity is added to the grid). It is noted that the third LNG engine to be added by 2019 will enhance LNG capability in this regard to a level consistent with a full scope LNG option for the 450 GW.h load scenario.

Detailed tables for each option are attached:

- 420 GW.h load - Table 3.4-6A and Table 3.4-6B cover DCF cap options of $8 million and $16 million.

- 450 GW.h load - Table 3.4-7A and Table 3.4-7B cover DCF cap options of $8 million and $16 million.

### No Cap Scenario

The "No Cap" scenario shows annual DCF transfers, based on the LTA and the annual water year thermal generation "actual" requirement, and the assumed diesel and LNG prices per the current GRA. The results are specific to the assumed grid load (and do not vary for different "with cap" options), with notable changes as load grows from 420 to 450 GW.h.

- **Water Years <LTA:** In most of the 35 water years, actual thermal is less than LTA and transfers are paid into the DCF by YEC. This situation changes as grid load increases (and the LTA comes closer to the median).
    - 420 GW.h load (LTA at 13.9 GW.h, median water year at 1.6 GW.h):[22] 25 water years < LTA, and in 17 years actual thermal at this grid load is less than 0.4 GW.h/yr.
    - 450 GW.h load (LTA at 28.6 GW.h, median water year at 25.5 GW.h): 20 water years < LTA, and in 3 years actual thermal at this grid load is less than 1.0 GW.h/yr. (less than 5 GW.h in 11 years).
- **Water Years >LTA:** In years when actual thermal is more than LTA, transfers are paid out of the DCF to YEC.
    - 420 GW.h load: Transfers paid to YEC in 10 consecutive water years (1996-2005).
    - 450 GW.h load: Transfers paid to YEC in 15 water years, over six separate time periods (1996-2000; 2002-2004; 1984-1986; 1988; 2007; 2010).
- **Peak drought year thermal requirement:** Peak year thermal generation is 7.7 times LTA at 420 GW.h load, and 4.1 times LTA at 450 GW.h load. Related thermal generation costs for this peak requirement are much higher with diesel only versus the current LNG option.

[22] The median year value indicates the mid-point of the 35 water years, i.e., half of these 35 years the value is above this level, and half of these 35 years it is below this level. In contrast, the LTA value is the simple average equal to total thermal generation required over 35 water years (at the stated load) divided by 35 water years.

  - 420 GW.h load: peak drought year thermal requirement is 107.5 GW.h (vs. LTA thermal of 13.9 GW.h), costing $17.0 million for 90% LNG/10% diesel generation, and $28.3 million if 100% diesel is assumed.
  - 450 GW.h load: peak drought year thermal requirement is 117.0 GW.h (vs. LTA thermal of 28.6 GW.h), costing $18.5 million for 90% LNG/10% diesel generation, and $30.8 million if 100% diesel is assumed.

- **Range of Annual DCF Year End Amounts:** Ignoring any cap (which means rates remain stable through all water year conditions), the DCF is assumed to balance out over the full 35 water years. Annual year end DCF amounts fluctuate as follows (the range is increased slightly, but becomes more balanced on each side of LTA, as load increases and median water year amounts approach LTA):
  - 420 GW.h load:
    - at 90% LNG and 10% diesel, from +$31.3 million to -$13.9 million
    - at 100% Diesel, from +$52.1 million to -$23.1 million
  - 450 GW.h load:
    - at 90% LNG and 10% diesel, from +$26.6 million to -$20.0 million
    - at 100% Diesel, from +$44.7 million to -$33.6 million

### DCF Cap Option Assessments

Detailed assessments in Tables 3.4-6A and 3.4-6B and 3.4-7A and 3.4-7B show the impact of each assumed DCF cap option (for each load scenario) in limiting the amount in the DCF fund, and in requiring new Rider E rebates or charges to all firm ratepayers in various water years. Table 3.4-5 provides a summary comparison of the DCF cap options examined.

General observations of DCF option impacts are summarized below (focused on DCF with 90% LNG and 10% diesel):

- **420 GW.h load:**

- **Reduction in need for rate riders** - Increasing the DCF cap from $8 to $16 million increases number of water years with no rate rider impact from 16 to 21 (out of 35). This change mainly relates to reducing the number of years with rebates.

- **Reduction in drought year rate rider charges** - Increasing the DCF cap from $8 to $16 million reduces the peak drought year charge from $13.6 million to $4.7 million, and the average charge year amount (for years with rate rider charges) from $4.2 million to $2.2 million.

- **450 GW.h load:**

  - **Reduction in need for rate riders** - Increasing the DCF cap from $8 to $16 million increases number of water years with no rate rider impact from 20 to 26 (out of 35). This change relates to reducing the number of years with rider charges as well as rider rebates.

  - **Reduction in drought year rate rider charges** - Increasing the DCF cap from $8 to $16 million reduces the peak drought year charge from $14.0 million to $8.2 million, and the average charge year amount (for years with rate rider charges) from $4.8 million to $3.5 million.

  - **Overall impact of higher load** - The higher grid load appears to help in reducing the frequency of rate riders for any given DCF cap level; however, a modest added increase in the DCF cap appears likely to be needed to reduce peak year charges to similar levels.

Table 3.4-5 shows that relying only on diesel rather than LNG would result, at any given DCF cap examined in the table, in more frequent rate rider requirements as well as much higher peak drought year charges, e.g., peak drought year charges at the 420 GW.h load equal $24.7 million with the $8 million DCF cap and $17.3 million with a $16 million DCF cap, while at the 450 GW.h load this charge is $23.3 million for all DCF cap levels examined in Table 3.4-5.

**Table 3.4-5: Summary - DCF Cap Option Impacts - 420 & 450 GW.h/yr. Loads with Minto Mine**

| | 420 GW.h/year load (13.9 GW.h/yr LTA thermal) | | 450 GW.h/yr load (28.6 GW.h/yr LTA thermal) | |
|---|---|---|---|---|
| | "+/-" DCF Cap ($million) | | "+/-" DCF Cap ($million) | |
| | 8 | 16 | 8 | 16 |
| | Table 3.4-6A | Table 3.4-6B | Table 3.4-7A | Table 3.4-7B |
| **DCF at 90% LNG and 10% Diesel** | | | | |
| **Number of water years (out of 35) with** | | | | |
| No rate rider impact | 16 | 21 | 20 | 26 |
| Rider rebates | 12 | 8 | 8 | 4 |
| Max rebate | 8 | 6 | 1 | 1 |
| Rider charges | 7 | 6 | 7 | 5 |
| **Rider Impact ($M/yr)** | | | | |
| Max Rebate | -2.16 | -2.16 | -5.06 | -4.14 |
| Peak Charge | 13.63 | 4.67 | 14.00 | 8.24 |
| Average charge year | 4.18 | 2.20 | 4.82 | 3.54 |
| Net impact after 35 yrs | 5.90 | -2.10 | 8.00 | 5.06 |
| **DCF at 100% Diesel** | | | | |
| **Number of water years (out of 35) with** | | | | |
| No rate rider impact | 11 | 17 | 17 | 22 |
| Rider rebates | 15 | 11 | 10 | 7 |
| Max rebate | 9 | 8 | 1 | 1 |
| Rider charges | 9 | 7 | 8 | 6 |
| **Rider Impact ($M/yr)** | | | | |
| Max Rebate | -3.59 | -3.59 | -7.34 | -7.09 |
| Peak Charge | 24.66 | 17.27 | 23.28 | 23.28 |
| Average charge year | 6.58 | 6.17 | 8.34 | 8.45 |
| Net impact after 35 yrs | 8.00 | 7.12 | 8.00 | 16.00 |

## Table 3.4-6A: + / - $8 Million DCF Cap with 420 GW.h Load

**Impact of DCF at Cap - 2018 Example - Load at 420 GWH**

| | | | | | | |
|---|---|---|---|---|---|---|
| **Cap assumed :** | **$8.00** | **million** | | | | |
| LTA | 13.87 | GW.h | | | | |
| LNG cost | 0.1467 | $/kWh | Blend cost | 0.1583 | 90% | LNG (balance diesel) |
| Diesel cost | 0.2633 | $/kWh | | | | |

| | | **DCF at 100% Diesel** | | | | **DCF at 90% LNG, 10% Diesel** | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | **DCF start in 1981 - No Cap ($ Million)** | | **DCF - With Cap ($ million)** | | **DCF start in 1981 - No Cap ($ Million)** | | **DCF - With Cap ($ million)** | |
| **Water Year** | **Thermal GW.h** | **Annual** | **Total** | **Charge or (Rebate)** | **Total** | **Annual** | **Total** | **Charge or** | **Total** |
| 1981 | 0.24 | 3.59 | 3.59 | | 3.59 | 2.16 | 2.16 | | 2.16 |
| 1982 | 0.24 | 3.59 | 7.18 | | 7.18 | 2.16 | 4.31 | | 4.31 |
| 1983 | 0.24 | 3.59 | 10.76 | -$2.76 | 8.00 | 2.16 | 6.47 | | 6.47 |
| 1984 | 0.38 | 3.55 | 14.31 | -$3.55 | 8.00 | 2.14 | 8.61 | -$0.61 | 8.00 |
| 1985 | 0.26 | 3.58 | 17.90 | -$3.58 | 8.00 | 2.15 | 10.76 | -$2.15 | 8.00 |
| 1986 | 0.35 | 3.56 | 21.46 | -$3.56 | 8.00 | 2.14 | 12.90 | -$2.14 | 8.00 |
| 1987 | 0.24 | 3.59 | 25.04 | -$3.59 | 8.00 | 2.16 | 15.06 | -$2.16 | 8.00 |
| 1988 | 0.24 | 3.59 | 28.63 | -$3.59 | 8.00 | 2.16 | 17.22 | -$2.16 | 8.00 |
| 1989 | 0.24 | 3.59 | 32.22 | -$3.59 | 8.00 | 2.16 | 19.37 | -$2.16 | 8.00 |
| 1990 | 0.24 | 3.59 | 35.81 | -$3.59 | 8.00 | 2.16 | 21.53 | -$2.16 | 8.00 |
| 1991 | 0.24 | 3.59 | 39.39 | -$3.59 | 8.00 | 2.16 | 23.69 | -$2.16 | 8.00 |
| 1992 | 0.24 | 3.59 | 42.98 | -$3.59 | 8.00 | 2.16 | 25.85 | -$2.16 | 8.00 |
| 1993 | 0.24 | 3.59 | 46.57 | -$3.59 | 8.00 | 2.16 | 28.00 | -$2.16 | 8.00 |
| 1994 | 0.24 | 3.59 | 50.16 | -$3.59 | 8.00 | 2.16 | 30.16 | -$2.16 | 8.00 |
| 1995 | 6.48 | 1.95 | 52.10 | -$1.95 | 8.00 | 1.17 | 31.33 | -$1.17 | 8.00 |
| 1996 | 50.07 | -9.53 | 42.57 | | -1.53 | -5.73 | 25.60 | | 2.27 |
| 1997 | 53.82 | -10.52 | 32.05 | $4.06 | -8.00 | -6.33 | 19.27 | | -4.06 |
| 1998 | 31.16 | -4.55 | 27.49 | $4.55 | -8.00 | -2.74 | 16.53 | | -6.80 |
| 1999 | 107.50 | -24.66 | 2.84 | $24.66 | -8.00 | -14.83 | 1.71 | $13.63 | -8.00 |
| 2000 | 58.34 | -11.71 | -8.88 | 11.71 | -8.00 | -7.04 | -5.34 | 7.04 | -8.00 |
| 2001 | 35.40 | -5.67 | -14.55 | 5.67 | -8.00 | -3.41 | -8.75 | 3.41 | -8.00 |
| 2002 | 23.98 | -2.66 | -17.21 | $2.66 | -8.00 | -1.60 | -10.35 | 1.60 | -8.00 |
| 2003 | 14.19 | -0.09 | -17.30 | $0.09 | -8.00 | -0.05 | -10.40 | 0.05 | -8.00 |
| 2004 | 33.15 | -5.08 | -22.37 | $5.08 | -8.00 | -3.05 | -13.45 | 3.05 | -8.00 |
| 2005 | 16.68 | -0.74 | -23.12 | $0.74 | -8.00 | -0.45 | -13.90 | 0.45 | -8.00 |
| 2006 | 12.58 | 0.34 | -22.78 | | -7.66 | 0.20 | -13.70 | | -7.80 |
| 2007 | 13.84 | 0.01 | -22.77 | | -7.65 | 0.00 | -13.69 | | -7.79 |
| 2008 | 11.40 | 0.65 | -22.12 | | -7.00 | 0.39 | -13.30 | | -7.40 |
| 2009 | 1.91 | 3.15 | -18.97 | | -3.86 | 1.89 | -11.41 | | -5.51 |
| 2010 | 5.08 | 2.31 | -16.66 | | -1.54 | 1.39 | -10.02 | | -4.12 |
| 2011 | 3.71 | 2.67 | -13.99 | | 1.13 | 1.61 | -8.41 | | -2.51 |
| 2012 | 1.63 | 3.22 | -10.76 | | 4.35 | 1.94 | -6.47 | | -0.57 |
| 2013 | 0.24 | 3.59 | -7.18 | | 7.94 | 2.16 | -4.31 | | 1.59 |
| 2014 | 0.24 | 3.59 | -3.59 | -$3.53 | 8.00 | 2.16 | -2.16 | | 3.74 |
| 2015 | 0.24 | 3.59 | 0.00 | -$3.59 | 8.00 | 2.16 | 0.00 | | 5.90 |
| Average | 13.87 | | | | | | | | |
| | | | Net | 8.00 | | | Net | 5.90 | |

## Table 3.4-6B: + / - $16 Million DCF Cap with 420 GW.h Load

**Impact of DCF at Cap - 2018 Example - Load at 420 GWH**

| | | | | | |
|---|---|---|---|---|---|
| **Cap assumed :** | **$16.00 million** | | | | |
| LTA | 13.87 GW.h | | | | |
| LNG cost | 0.1467 $/kWh | Blend cost | 0.1583 | 90% | LNG (balance diesel) |
| Diesel cost | 0.2633 $/kWh | | | | |

| | | **DCF at 100% Diesel** | | | | **DCF at 90% LNG, 10% Diesel** | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | **DCF start in 1981 - No Cap ($ Million)** | | **DCF - With Cap ($ million)** | | **DCF start in 1981 - No Cap ($ Million)** | | **DCF - With Cap ($ million)** | |
| **Water Year** | **Thermal GW.h** | **Annual** | **Total** | **Charge or (Rebate)** | **Total** | **Annual** | **Total** | **Charge or** | **Total** |
| 1981 | 0.24 | 3.59 | 3.59 | | 3.59 | 2.16 | 2.16 | | 2.16 |
| 1982 | 0.24 | 3.59 | 7.18 | | 7.18 | 2.16 | 4.31 | | 4.31 |
| 1983 | 0.24 | 3.59 | 10.76 | | 10.76 | 2.16 | 6.47 | | 6.47 |
| 1984 | 0.38 | 3.55 | 14.31 | | 14.31 | 2.14 | 8.61 | | 8.61 |
| 1985 | 0.26 | 3.58 | 17.90 | -$1.90 | 16.00 | 2.15 | 10.76 | | 10.76 |
| 1986 | 0.35 | 3.56 | 21.46 | -$3.56 | 16.00 | 2.14 | 12.90 | | 12.90 |
| 1987 | 0.24 | 3.59 | 25.04 | -$3.59 | 16.00 | 2.16 | 15.06 | | 15.06 |
| 1988 | 0.24 | 3.59 | 28.63 | -$3.59 | 16.00 | 2.16 | 17.22 | -$1.22 | 16.00 |
| 1989 | 0.24 | 3.59 | 32.22 | -$3.59 | 16.00 | 2.16 | 19.37 | -$2.16 | 16.00 |
| 1990 | 0.24 | 3.59 | 35.81 | -$3.59 | 16.00 | 2.16 | 21.53 | -$2.16 | 16.00 |
| 1991 | 0.24 | 3.59 | 39.39 | -$3.59 | 16.00 | 2.16 | 23.69 | -$2.16 | 16.00 |
| 1992 | 0.24 | 3.59 | 42.98 | -$3.59 | 16.00 | 2.16 | 25.85 | -$2.16 | 16.00 |
| 1993 | 0.24 | 3.59 | 46.57 | -$3.59 | 16.00 | 2.16 | 28.00 | -$2.16 | 16.00 |
| 1994 | 0.24 | 3.59 | 50.16 | -$3.59 | 16.00 | 2.16 | 30.16 | -$2.16 | 16.00 |
| 1995 | 6.48 | 1.95 | 52.10 | -$1.95 | 16.00 | 1.17 | 31.33 | -$1.17 | 16.00 |
| 1996 | 50.07 | -9.53 | 42.57 | | 6.47 | -5.73 | 25.60 | | 10.27 |
| 1997 | 53.82 | -10.52 | 32.05 | | -4.06 | -6.33 | 19.27 | | 3.94 |
| 1998 | 31.16 | -4.55 | 27.49 | | -8.61 | -2.74 | 16.53 | | 1.20 |
| 1999 | 107.50 | -24.66 | 2.84 | $17.27 | -16.00 | -14.83 | 1.71 | | -13.63 |
| 2000 | 58.34 | -11.71 | -8.88 | 11.71 | -16.00 | -7.04 | -5.34 | $4.67 | -16.00 |
| 2001 | 35.40 | -5.67 | -14.55 | 5.67 | -16.00 | -3.41 | -8.75 | 3.41 | -16.00 |
| 2002 | 23.98 | -2.66 | -17.21 | 2.66 | -16.00 | -1.60 | -10.35 | 1.60 | -16.00 |
| 2003 | 14.19 | -0.09 | -17.30 | 0.09 | -16.00 | -0.05 | -10.40 | 0.05 | -16.00 |
| 2004 | 33.15 | -5.08 | -22.37 | 5.08 | -16.00 | -3.05 | -13.45 | 3.05 | -16.00 |
| 2005 | 16.68 | -0.74 | -23.12 | 0.74 | -16.00 | -0.45 | -13.90 | 0.45 | -16.00 |
| 2006 | 12.58 | 0.34 | -22.78 | | -15.66 | 0.20 | -13.70 | | -15.80 |
| 2007 | 13.84 | 0.01 | -22.77 | | -15.65 | 0.00 | -13.69 | | -15.79 |
| 2008 | 11.40 | 0.65 | -22.12 | | -15.00 | 0.39 | -13.30 | | -15.40 |
| 2009 | 1.91 | 3.15 | -18.97 | | -11.86 | 1.89 | -11.41 | | -13.51 |
| 2010 | 5.08 | 2.31 | -16.66 | | -9.54 | 1.39 | -10.02 | | -12.12 |
| 2011 | 3.71 | 2.67 | -13.99 | | -6.87 | 1.61 | -8.41 | | -10.51 |
| 2012 | 1.63 | 3.22 | -10.76 | | -3.65 | 1.94 | -6.47 | | -8.57 |
| 2013 | 0.24 | 3.59 | -7.18 | | -0.06 | 2.16 | -4.31 | | -6.41 |
| 2014 | 0.24 | 3.59 | -3.59 | | 3.53 | 2.16 | -2.16 | | -4.26 |
| 2015 | 0.24 | 3.59 | 0.00 | | 7.12 | 2.16 | 0.00 | | -2.10 |
| Average | 13.87 | | | | | | | | |
| | | | | Net | 7.12 | | | Net | -2.10 |

## Table 3.4-7A: + / - $8 Million DCF Cap with 450 GW.h Load

**Impact of DCF at Cap - 2018 Example - Load at 450 GWH**

| | | | | |
|---|---|---|---|---|
| **Cap assumed at** | **$8.00** | **million** | | |
| LTA | 28.58 | GW.h | | |
| LNG cost | 0.1467 | $/kWh | Blend cost 0.1583 | 90% LNG (balance diesel) |
| Diesel cost | 0.2633 | $/kWh | | |

| | | **DCF at 100% Diesel** | | | | **DCF at 90% LNG, 10% Diesel** | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | **DCF start in 1981 - No Cap ($ Million)** | | **DCF - With Cap ($ million)** | | **DCF start in 1981 - No Cap ($ Million)** | | **DCF - With Cap ($ million)** | |
| **Water Year** | **Thermal GW.h** | **Annual** | **Total** | **Charge or (Rebate)** | **Total** | **Annual** | **Total** | **Charge or** | **Total** |
| 1981 | 0.71 | 7.34 | 7.34 | | 7.34 | 4.41 | 4.41 | | 4.41 |
| 1982 | 0.71 | 7.34 | 14.68 | -$6.68 | 8.00 | 4.41 | 8.83 | -$0.83 | 8.00 |
| 1983 | 0.71 | 7.34 | 22.02 | -$7.34 | 8.00 | 4.41 | 13.24 | -$4.41 | 8.00 |
| 1984 | 31.00 | -0.64 | 21.38 | | 7.36 | -0.38 | 12.86 | | 7.62 |
| 1985 | 43.93 | -4.04 | 17.34 | | 3.32 | -2.43 | 10.43 | | 5.19 |
| 1986 | 48.03 | -5.12 | 12.22 | | -1.80 | -3.08 | 7.35 | | 2.11 |
| 1987 | 27.66 | 0.24 | 12.46 | | -1.56 | 0.15 | 7.49 | | 2.25 |
| 1988 | 32.44 | -1.02 | 11.44 | | -2.58 | -0.61 | 6.88 | | 1.64 |
| 1989 | 12.93 | 4.12 | 15.57 | | 1.55 | 2.48 | 9.36 | | 4.12 |
| 1990 | 14.95 | 3.59 | 19.16 | | 5.14 | 2.16 | 11.52 | | 6.28 |
| 1991 | 3.32 | 6.65 | 25.81 | -$3.79 | 8.00 | 4.00 | 15.52 | -$2.28 | 8.00 |
| 1992 | 1.64 | 7.09 | 32.90 | -$7.09 | 8.00 | 4.27 | 19.78 | -$4.27 | 8.00 |
| 1993 | 2.81 | 6.79 | 39.69 | -$6.79 | 8.00 | 4.08 | 23.86 | -$4.08 | 8.00 |
| 1994 | 2.45 | 6.88 | 46.57 | -$6.88 | 8.00 | 4.14 | 28.00 | -$4.14 | 8.00 |
| 1995 | 61.24 | -8.60 | 37.97 | | -0.60 | -5.17 | 22.83 | | 2.83 |
| 1996 | 71.23 | -11.23 | 26.74 | $3.83 | -8.00 | -6.75 | 16.08 | | -3.92 |
| 1997 | 76.79 | -12.69 | 14.04 | $12.69 | -8.00 | -7.63 | 8.44 | $3.56 | -8.00 |
| 1998 | 70.79 | -11.12 | 2.93 | $11.12 | -8.00 | -6.68 | 1.76 | $6.68 | -8.00 |
| 1999 | 116.98 | -23.28 | -20.35 | $23.28 | -8.00 | -14.00 | -12.24 | $14.00 | -8.00 |
| 2000 | 58.57 | -7.90 | -28.25 | 7.90 | -8.00 | -4.75 | -16.99 | 4.75 | -8.00 |
| 2001 | 24.38 | 1.11 | -27.14 | -1.11 | -8.00 | 0.66 | -16.32 | -0.66 | -8.00 |
| 2002 | 31.36 | -0.73 | -27.88 | $0.73 | -8.00 | -0.44 | -16.76 | 0.44 | -8.00 |
| 2003 | 30.10 | -0.40 | -28.28 | $0.40 | -8.00 | -0.24 | -17.00 | 0.24 | -8.00 |
| 2004 | 54.19 | -6.74 | -35.02 | $6.74 | -8.00 | -4.05 | -21.06 | 4.05 | -8.00 |
| 2005 | 21.24 | 1.93 | -33.09 | | -6.07 | 1.16 | -19.89 | | -6.84 |
| 2006 | 25.49 | 0.81 | -32.27 | | -5.25 | 0.49 | -19.41 | | -6.35 |
| 2007 | 35.32 | -1.77 | -34.05 | | -7.03 | -1.07 | -20.47 | | -7.41 |
| 2008 | 22.71 | 1.55 | -32.50 | | -5.48 | 0.93 | -19.54 | | -6.49 |
| 2009 | 10.26 | 4.82 | -27.68 | | -0.66 | 2.90 | -16.64 | | -3.58 |
| 2010 | 31.22 | -0.69 | -28.37 | | -1.35 | -0.42 | -17.06 | | -4.00 |
| 2011 | 26.53 | 0.54 | -27.83 | | -0.81 | 0.33 | -16.73 | | -3.68 |
| 2012 | 4.12 | 6.44 | -21.39 | | 5.63 | 3.87 | -12.86 | | 0.20 |
| 2013 | 1.63 | 7.10 | -14.29 | -$4.73 | 8.00 | 4.27 | -8.59 | | 4.46 |
| 2014 | 1.02 | 7.26 | -7.03 | -$7.26 | 8.00 | 4.36 | -4.23 | | 8.83 |
| 2015 | 1.88 | 7.03 | 0.00 | -$7.03 | 8.00 | 4.23 | 0.00 | -$5.06 | 8.00 |
| Average | 28.58 | | | | | | | | |
| | | | Net | 8.00 | | | Net | 8.00 | |

## Table 3.4-7B: + / - $16 Million DCF Cap with 450 GW.h Load

**Impact of DCF at Cap - 2018 Example - Load at 450 GWH**

| | | | |
|---|---|---|---|
| **Cap assumed at** | **$16.00** | **million** | |
| LTA | 28.58 | GW.h | |
| LNG cost | 0.1467 | $/kWh | Blend cost 0.1583 90% LNG (balance diesel) |
| Diesel cost | 0.2633 | $/kWh | |

| | | **DCF at 100% Diesel** | | | | **DCF at 90% LNG, 10% Diesel** | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | **DCF start in 1981 - No Cap ($ Million)** | | **DCF - With Cap ($ million)** | | **DCF start in 1981 - No Cap ($ Million)** | | **DCF - With Cap ($ million)** | |
| **Water Year** | **Thermal GW.h** | **Annual** | **Total** | **Charge or (Rebate)** | **Total** | **Annual** | **Total** | **Charge or** | **Total** |
| 1981 | 0.71 | 7.34 | 7.34 | | 7.34 | 4.41 | 4.41 | | 4.41 |
| 1982 | 0.71 | 7.34 | 14.68 | | 14.68 | 4.41 | 8.83 | | 8.83 |
| 1983 | 0.71 | 7.34 | 22.02 | -$6.02 | 16.00 | 4.41 | 13.24 | | 13.24 |
| 1984 | 31.00 | -0.64 | 21.38 | | 15.36 | -0.38 | 12.86 | | 12.86 |
| 1985 | 43.93 | -4.04 | 17.34 | | 11.32 | -2.43 | 10.43 | | 10.43 |
| 1986 | 48.03 | -5.12 | 12.22 | | 6.20 | -3.08 | 7.35 | | 7.35 |
| 1987 | 27.66 | 0.24 | 12.46 | | 6.44 | 0.15 | 7.49 | | 7.49 |
| 1988 | 32.44 | -1.02 | 11.44 | | 5.42 | -0.61 | 6.88 | | 6.88 |
| 1989 | 12.93 | 4.12 | 15.57 | | 9.55 | 2.48 | 9.36 | | 9.36 |
| 1990 | 14.95 | 3.59 | 19.16 | | 13.14 | 2.16 | 11.52 | | 11.52 |
| 1991 | 3.32 | 6.65 | 25.81 | -$3.79 | 16.00 | 4.00 | 15.52 | | 15.52 |
| 1992 | 1.64 | 7.09 | 32.90 | -$7.09 | 16.00 | 4.27 | 19.78 | -$3.78 | 16.00 |
| 1993 | 2.81 | 6.79 | 39.69 | -$6.79 | 16.00 | 4.08 | 23.86 | -$4.08 | 16.00 |
| 1994 | 2.45 | 6.88 | 46.57 | -$6.88 | 16.00 | 4.14 | 28.00 | -$4.14 | 16.00 |
| 1995 | 61.24 | -8.60 | 37.97 | | 7.40 | -5.17 | 22.83 | | 10.83 |
| 1996 | 71.23 | -11.23 | 26.74 | | -3.83 | -6.75 | 16.08 | | 4.08 |
| 1997 | 76.79 | -12.69 | 14.04 | | -16.53 | -7.63 | 8.44 | | -3.56 |
| 1998 | 70.79 | -11.12 | 2.93 | $11.64 | -16.00 | -6.68 | 1.76 | | -10.24 |
| 1999 | 116.98 | -23.28 | -20.35 | $23.28 | -16.00 | -14.00 | -12.24 | $8.24 | -16.00 |
| 2000 | 58.57 | -7.90 | -28.25 | 7.90 | -16.00 | -4.75 | -16.99 | 4.75 | -16.00 |
| 2001 | 24.38 | 1.11 | -27.14 | -1.11 | -16.00 | 0.66 | -16.32 | -0.66 | -16.00 |
| 2002 | 31.36 | -0.73 | -27.88 | $0.73 | -16.00 | -0.44 | -16.76 | 0.44 | -16.00 |
| 2003 | 30.10 | -0.40 | -28.28 | $0.40 | -16.00 | -0.24 | -17.00 | 0.24 | -16.00 |
| 2004 | 54.19 | -6.74 | -35.02 | $6.74 | -16.00 | -4.05 | -21.06 | 4.05 | -16.00 |
| 2005 | 21.24 | 1.93 | -33.09 | | -14.07 | 1.16 | -19.89 | | -14.84 |
| 2006 | 25.49 | 0.81 | -32.27 | | -13.25 | 0.49 | -19.41 | | -14.35 |
| 2007 | 35.32 | -1.77 | -34.05 | | -15.03 | -1.07 | -20.47 | | -15.41 |
| 2008 | 22.71 | 1.55 | -32.50 | | -13.48 | 0.93 | -19.54 | | -14.49 |
| 2009 | 10.26 | 4.82 | -27.68 | | -8.66 | 2.90 | -16.64 | | -11.58 |
| 2010 | 31.22 | -0.69 | -28.37 | | -9.35 | -0.42 | -17.06 | | -12.00 |
| 2011 | 26.53 | 0.54 | -27.83 | | -8.81 | 0.33 | -16.73 | | -11.68 |
| 2012 | 4.12 | 6.44 | -21.39 | | -2.37 | 3.87 | -12.86 | | -7.80 |
| 2013 | 1.63 | 7.10 | -14.29 | | 4.73 | 4.27 | -8.59 | | -3.54 |
| 2014 | 1.02 | 7.26 | -7.03 | | 11.99 | 4.36 | -4.23 | | 0.83 |
| 2015 | 1.88 | 7.03 | 0.00 | -$3.02 | 16.00 | 4.23 | 0.00 | | 5.06 |
| Average | 28.58 | | | | | | | | |
| | | | Net | 16.00 | | | Net | 5.06 | |

# APPENDIX 3.5
# DIESEL CONTINGENCY FUND (“DCF”) 2016 ANNUAL REPORT

Yukon Energy Corporation
Box 5920
Whitehorse, Yukon Y1A 6S7

April 5, 2017

Mr. Robert Laking, Chair
Yukon Utilities Board
Box 31728
Whitehorse, Yukon Y1A 6L3

Dear Mr. Laking:

**Re: Diesel Contingency Fund ("DCF") 2016 Annual Report**

Pursuant to Yukon Utilities Board ("YUB" or the "Board") direction provided in Order 2015-01 and 2015-06, this correspondence provides Yukon Energy Corporation's ("Yukon Energy" or "YEC") Annual Report summarizing DCF activities up to December 31, 2016 based on preliminary actuals, and includes the following information:

- **Attachment 1 -** DCF Calculations and Balance Updates.
- **Attachment 2 -** Updated Rider E Rate Schedule (at $0.14 c/kWh rebate effective May 1, 2017 and until March 31, 2018).
- **Attachment 3 -** Update on Forecast Water Conditions for 2017.

A summary of each of the above documents follows.

**DCF Calculations and Balance as of December 31, 2016**

Attachment 1, Table 1 in this filing provides DCF calculations and balance as of December 31, 2016, and Attachment 1, Table 2 provides a DCF Continuity Schedule for the years 2012 to 2016. Attachment 1, Table 3 provides Rider E calculation. Monthly calculations for 2016 are provided in Table 4 of Attachment 1.

In summary, these attachments indicate as follows regarding the annual DCF calculations and balance for 2016:

- Based on actual annual load for 2016 and the approved DCF Term Sheet, the "expected" (i.e., based on long term average water conditions) thermal requirement for 2016 is 10.536 GW.h (Table 1, L15);
  - LNG is assumed to displace 100% of the 2016 expected long-term average thermal requirements.
- Actual annual thermal generation requirement for 2016 (net of LNG and diesel charged to capital and RFID) was 5.087 GW.h, including 2.293 GW.h diesel and 2.794 GW.h LNG.
- The resulting overall gap between expected and actual thermal generation for 2016 equals 5.449 GW.h.
- The resulting payment required from YEC into the DCF for 2016 is $0.990 million.[1]
- Based on the above, and the DCF balance at the end of the previous year net of the forecast impact of the current Rider E rebate applicable until April 30, 2017, the forecast DCF balance at 2016 year-end that affects determination of a new Rider E is $8.520 million.[2]

**Updated Rider E**

In Order 2015-06, the Board directed that YEC refund DCF contributions in excess of the $8.0 million cap through a rate rider applicable to all firm sales throughout the Yukon (Rider E). Based on the 2015 Annual filing, the Board's letter of April 6, 2016 reinstated the earlier DCF rebate at 0.68 cents/kWh on an interim basis, effective May 1, 2016.

The DCF calculations and balance update for 2016 (Attachment 1, Tables 1 and 2) forecast DCF contributions at $0.520 million in excess of the $8.0 million cap as of April 30, 2017,[3] and indicate that retention of the current Rider E at 0.68 cents per kW.h beyond April 2017 would reduce the DCF below the $8.0 million cap within a few months. Based on this forecast, a new Rider E refund to ratepayers is therefore proposed of 0.14 cents/kW.h is estimated for implementation from May 1, 2017 to March 31, 2018. For further detail regarding the Rider E calculation see Attachment 1, Table 3.

The updated Rider E Rate Schedule (based on Table 3) is provided as Attachment 2.

[1] Calculation assumes 100% LNG. The LNG price of $0.1817 per kW.h is actual LNG cost from inventory for LNG generation in 2016 divided by kW.h of actual LNG generation in 2016 of 3.251 GW.h.
[2] See Attachment 1, Table 2. The DCF balance at December 31, 2016 net of refunds is $9.485 million. Forecast refunds in 2017 for January through April equal $0.965 million. The forecast DCF balance as at April 30, 2017 is therefore $8.520 million.
[3] Considering the implementation effective April 1, 2017 is not achievable, the new rates proposed to be effective May 1, 2017. The current Rider E at 0.68 cents/kW.h is assumed to continue until April 30, 2017.

**Update on Forecast Water Conditions for 2017**

An update on forecast water conditions for 2017 is provided as Attachment 3, including the complete preliminary March 1 snow survey results. Unofficial snow surveys indicate an overall below average snow water equivalent in all three of YEC's water basins.

The forecast notes that Marsh Lake is forecast to be at or near full supply by October 2017 if summer temperatures and precipitation are at or above normal, while Aishihik and Mayo are not forecast to reach operational full supply level by October 2017.

The refill for Aishihik and for Mayo by the fall is impacted by having to generate higher amounts in April, May and June due to the Whitehorse Unit #4 being out of service for a major overhaul, as well as by expected low snow pack.

As Aishihik Lake is a multi-year reservoir, not reaching full supply does not impact energy capability during the winter of 2017/18 but energy from Mayo GS will likely be constrained by spring of 2018.

If you have any questions regarding the above please contact the undersigned.

Yours truly,

Ed Mollard, CGA
Chief Financial Officer
Yukon Energy Corporation

# ATTACHMENT 1: DCF CALCULATIONS AND BALANCE UPDATES – 2016

## Table 1: DCF Calculations for 2012-2016

| Line No | | 2012 Actuals | 2013 Actuals | 2014 Actuals | 2015 Actuals | 2016 Preliminary Actuals | | Notes |
|---|---|---|---|---|---|---|---|---|
| *L1* | Fuel Cost per kW.h, Diesel | 28.71 | 28.71 | 28.71 | 28.71 | 28.71 | cents/kW.h | 2012/13 GRA Compliance Filing Average Fuel cost |
| | Fuel Cost per kW.h, LNG | | | | 18.83 | 18.17 | cents/kW.h | |
| | **Calculation of Diesel or LNG Cost to Charge (Refund) DCF** | | | | | | | |
| | *Assumptions* | | | | | | | |
| *L2* | YEC Grid load | 424,541 | 419,173 | 396,498 | 410,316 | 412,776 | MW.h | Actual net of secondary sales (with losses) |
| *L3* | Fish Lake | 3,388 | 3,687 | 10,247 | 9,180 | 8,033 | MW.h | Fish Lake generation |
| *L4=L2+L3* | Total Grid load | 427,929 | 422,860 | 406,745 | 419,495 | 420,809 | MW.h | |
| | Assumed Actual Generation Sources | | | | | | | |
| *L5=L3* | YECL Fish Lake | 3,388 | 3,687 | 10,247 | 9,180 | 8,033 | MW.h | Fish Lake generation |
| *L6* | YEC Hydro | 421,039 | 416,987 | 394,595 | 404,797 | 406,136 | MW.h | Residual as total generation less diesel and wind |
| *L7* | YEC Thermal | 3,057 | 1,910 | 1,566 | 4,868 | 6,131 | MW.h | Diesel and LNG |
| | *Diesel* | *3,057* | *1,910* | *1,566* | *3,574* | *2,879* | | |
| | *LNG* | | | | *1,295* | *3,251* | | |
| *L7a* | *YEC Diesel/LNG charged to capital* | *373* | *872* | *951* | *2,047* | *1,043* | | Includes charged to RFID |
| | *Diesel* | *373* | *872* | *951* | *1,345* | *586* | | |
| | *LNG* | | | | *702* | *457* | | |
| *L7b=L7-L7a* | *YEC Net Diesel/LNG* | *2,683* | *1,037* | *615* | *2,822* | *5,087* | | |
| | *Diesel* | *2,683* | *1,037* | *615* | *2,229* | *2,293* | | |
| | *LNG* | *-* | *-* | *-* | *593* | *2,794* | | |
| *L8* | YEC Wind | 445 | 277 | 337 | 650 | 509 | MW.h | Wind generation |
| *L9=L5+L6+L7+L8* | Total Grid load | 427,929 | 422,860 | 406,745 | 419,495 | 420,809 | MW.h | |
| | Expected Generation Sources | | | | | | | |
| *L10* | YECL Fish Lake (expected) | 4,380 | 4,380 | 8,730 | 8,730 | 8,730 | MW.h | Unit #2 at 4.380 GW.h - no Unit #1 generation in 2012 and 2013. |
| *L11* | YEC Wind (expected) | 239 | 238 | 238 | 238 | 238 | MW.h | |
| *L12=L9-L10-L11* | YEC Grid load net of expected Fish Lake and Wind | 423,310 | 418,242 | 397,777 | 410,527 | 411,841 | MW.h | |
| *L13a* | YEC Grid Load amount per Column A of Approved DCF Term Sheet Table | 420,000 | 415,000 | 395,000 | 410,000 | 410,000 | GW.h | Table 1.1, Approved DCF Term Sheet (Order 2015-06) |
| *L13b* | Expected Base Thermal Generation at YEC Grid Load amount in row L13a | 14,100 | 11,800 | 4,400 | 9,800 | 9,800 | MW.h | Derived from Table 1.1, Approved DCF Term Sheet (Order 2015-06) |
| *L14a* | Incremental Expected Thermal Generation as percent of load above L13a (%) | *46%* | *46%* | *32%* | *40%* | *40%* | % | Table 1.1, Approved DCF Term Sheet (Order 2015-06) |
| *L14b=(L12-L13a)xL14a* | Expected Incremental Thermal Generation above amount in L13b | 1,522 | 1,491 | 889 | 211 | 736 | MW.h | Derived from Table 1.1, Approved DCF Term Sheet (Order 2015-06) |
| *L15=L13b+L14b* | Total Expected YEC Thermal Generation | 15,622 | 13,291 | 5,289 | 10,011 | 10,536 | MW.h | |
| *L16=L15* | Expected YEC Thermal Generation in Rates | 15,622 | 13,291 | 5,289 | 10,011 | 10,536 | MW.h | 100% of long-term average |
| | *Diesel* | 15,622 | 13,291 | 5,289 | *8,509* | *-* | *MW.h* | |
| | *LNG* | | | | *1,502* | *10,536* | *MW.h* | At 15% LNG displacement of expected diesel in 2015; 100% in 2016. |
| *L17=L7b* | YEC Thermal Generation | 2,683 | 1,037 | 615 | 2,822 | 5,087 | MW.h | Net of capital diesel (L7b) |
| | *Diesel* | 2,683 | 1,037 | 615 | *2,229* | *2,293* | *MW.h* | |
| | *LNG* | | | | *593* | *2,794* | *MW.h* | |
| *L18=L17-L16* | YEC Thermal Generation to be Included in DCF | - 12,939 | - 12,254 | - 4,674 | - 7,189 | - 5,449 | MW.h | |
| | *Diesel* | - 12,939 | - 12,254 | - 4,674 | - *6,281* | *-* | *MW.h* | |
| | *LNG* | | | - | - *909* | - *5,449* | *MW.h* | |
| *L19=L1xL18* | Incremental YEC Thermal Generation Cost to Charge (Refund) DCF ($000s) | ($3,715) | ($3,518) | ($1,342) | ($1,974) | ($990) | | |

## Table 2: DCF Continuity Schedule

| Line | Activity | 2012 ($000s) | 2013 ($000s) | 2014 ($000s) | 2015 ($000s) | 2016 Preliminary ($000s) |
|---|---|---|---|---|---|---|
| **A** | **DCF Opening Balance[1]** | **$902** | **$4,628** | **$8,198** | **$9,627** | **$10,895** |
| B | Incremental Diesel Generation Cost to Charge/(Refund)[2] to DCF | ($3,715) | ($3,518) | ($1,342) | ($1,974) | ($990) |
| C=B | Total DCF operation for YEC | | | | | |
| | YEC pays to DCF Fund | $3,715 | $3,518 | $1,342 | $1,974 | $990 |
| | YEC withdraws from DCF Fund | $0 | $0 | $0 | $0 | $0 |
| **D=A+C** | **DCF Balance after Total DCF Operation** | **$4,617** | **$8,146** | **$9,540** | **$11,601** | **$11,885** |
| **E** | **Interest on DCF Balance[3]** | **$11** | **$52** | **$87** | **$53** | **$54** |
| **F=D+E** | **DCF Balance after Interest charge** | **$4,628** | **$8,198** | **$9,627** | **$11,654** | **$11,939** |
| **G** | **DCF (Rebate)/Collections [January - December]** | **$0** | **$0** | **$0** | **($759)** | **($2,454)** |
| **H=F+G** | **DCF Ending Balance** | **$4,628** | **$8,198** | **$9,627** | **$10,895** | **$9,485** |
| **I** | **DCF (Rebate)/Collections January - April 2017 (forecast)** | | | | | **($965)** |
| **J=H+I** | **Forecast DCF Balance, After (Rebate)/Collections to April 30** | | | | | **$8,520** |
| **K** | **DCF Cap Approved by Board[4]** | | | | | **`+/-8000** |
| **L=J-K** | **DCF Rebate/(Collections) Required** | | | | | **$520** |

Notes:
1. 2012 DCF Opening Balance is 2011 actual ending balance of DCF.
2. Based on calculations in Table 1. 2016 DCF charge estimate is based on preliminary actuals.
3. Per the March 11, 1996 letter recording the settlements [provided as Exhibit B-16 in the 2008/2009 GRA] the DCF fund is to attract interest based upon the short/intermediate term bond rates in which the Companies may invest the fund and any negative balances would only attract interest at the lowest short-term borrowing rate available to the Companies through a line of credit.
4. Approved DCF Cap based on YUB Order 2015-01.

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**Table 3: Rider E Calculations**

| Line | Activity | Rider Estimate |
|---|---|---|
| **A** | **DCF Rebate/(Collections) Required ($000s)** | **$520** |
| B | Retail Sales for the previous 11 months (MW.h) [1] | **360,562** |
| C=A/B | **DCF Rebate/(Collection) Rider (cents/kW.h)** | **0.14** |

Notes:

1. The total retail sales include YEC and AEY retail and industrial sales based on 2016 preliminary actuals. The rider expected to be effective May 1, 2017. Therefore, the sales information is for 11 months.

# Table 4: DCF Quarterly Report (2016 Q4)

| | | Jan Actual | Feb Actual | Mar Actual | Apr Actual | May Actual | Jun Actual | Jul Actual | Aug Actual | Sep Actual | Oct Preliminary Actual | Nov Preliminary Actual | Dec Preliminary Actual | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Generation Report** | | | | | | | | | | | | | |
| *L1* | YEC Grid Load (MW.h) | 40,444 | 38,781 | 37,251 | 28,995 | 28,229 | 28,053 | 27,318 | 30,647 | 30,731 | 38,000 | 40,541 | 49,061 | 418,051 |
| *L2* | Less Secondary Sales with Losses (MW.h) | -418 | -426 | -490 | -400 | -268 | -323 | -273 | -473 | -234 | -132 | -829 | -1,008 | -5,275 |
| *L3* | YECL Fish Lake (MW.h) | 835 | 796 | 851 | 821 | 924 | 858 | 697 | 355 | 238 | 427 | 576 | 655 | 8,033 |
| *L4=Sum(L1:L3)* | Total Grid Load excluding secondary sales (MW.h) | 40,861 | 39,150 | 37,612 | 29,417 | 28,884 | 28,587 | 27,741 | 30,529 | 30,735 | 38,296 | 40,289 | 48,708 | 420,809 |
| | **Actual Generation Sources** | | | | | | | | | | | | | |
| *L5* | YECL Fish Lake (MW.h) | 835 | 796 | 851 | 821 | 924 | 858 | 697 | 355 | 238 | 427 | 576 | 655 | 8,033 |
| L6 | YEC Hydro (MW.h) [residual: YEC Grid firm load less thermal and wind] | 39,823 | 38,263 | 36,631 | 28,464 | 27,694 | 27,551 | 26,462 | 29,965 | 28,564 | 37,618 | 39,641 | 45,459 | 406,136 |
| *L7* | YEC Diesel (MW.h) | 65 | 24 | 29 | 27 | 133 | 94 | 507 | 126 | 638 | 51 | 71 | 1,114 | 2,879 |
| *L7a* | *YEC Diesel Charged to Capital and RFID* | - | - | - | - | 118 | - | 187 | - | 220 | - | 62 | - | 586 |
| *L7b=L7-L7a* | *YEC Net Diesel* | 65 | 24 | 29 | 27 | 16 | 94 | 320 | 126 | 418 | 51 | 10 | 1,114 | 2,293 |
| *L8* | YEC LNG (MW.h) | 135 | 68 | 48 | 36 | 11 | 10 | 24 | 7 | 1,234 | 198 | - | 1,480 | 3,251 |
| *L8a* | *YEC LNG Charged to Capital and RFID* | - | - | - | - | - | - | - | - | 457 | - | - | - | 457 |
| *L8b=L8-L8a* | *YEC Net LNG* | 135 | 68 | 48 | 36 | 11 | 10 | 24 | 7 | 777 | 198 | - | 1,480 | 2,794 |
| *L9* | YEC Wind (MW.h) | 2 | - | 54 | 68 | 122 | 74 | 51 | 76 | 60 | 1 | - | - | 509 |
| *L10=L5+L6+L7+L8+L9* | Total Grid Load excluding secondary sales (MW.h) | 40,861 | 39,150 | 37,612 | 29,417 | 28,884 | 28,587 | 27,741 | 30,529 | 30,735 | 38,296 | 40,289 | 48,708 | 420,809 |
| | **Expected Generation Sources** | | | | | | | | | | | | | |
| *L11* | YECL Fish Lake (expected ) (MW.h) | | | | | | | | | | | | | 8,730 |
| *L12* | YEC Wind (expected ) (MW.h) | | | | | | | | | | | | | 238 |
| *L13=L10-L11-L12* | YEC Grid Load net of expected Fish Lake and Wind (MW.h) | | | | | | | | | | | | | 411,841 |
| *L14* | Grid Load Benchmark (MW.h) (Col A of Table 1-1, Approved DCF Term Sheet) | | | | | | | | | | | | | 410,000 |
| *L15* | Diesel as % of incremental Grid Load above line 14 (%) | | | | | | | | | | | | | 40% |
| *L16* | Expected Base Thermal Generation at Benchmark (MW.h) | | | | | | | | | | | | | 9,800 |
| *L17=(L13-L14)xL15* | Expected Incremental Thermal Generation (MW.h) | | | | | | | | | | | | | 736 |
| *L18=L16+L17* | Total Expected Thermal Generation (MW.h) | | | | | | | | | | | | | 10,536 |
| *L19=L18* | Expected Thermal Generation in Rates (MW.h) | | | | | | | | | | | | | 10,536 |
| | *Diesel* | | | | | | | | | | | | | - |
| | *LNG* | | | | | | | | | | | | | *10,536.50* |
| *L20=L7b+L8b* | Actual YEC Thermal Generation (net of capital & RFID Thermal) (MW.h) | | | | | | | | | | | | | 5,087 |
| | *Diesel* | | | | | | | | | | | | | *2,293* |
| | *LNG* | | | | | | | | | | | | | *2,794* |
| *L21=L20-L19* | Thermal Generation to be Included in DCF (MW.h) | | | | | | | | | | | | | -5,449 |
| | *Diesel* | | | | | | | | | | | | | - |
| | *LNG* | | | | | | | | | | | | | *- 5,449* |
| *L22* | Thermal Fuel Cost per kW.h ($/kW.h) | | | | | | | | | | | | | |
| | *Diesel* | | | | | | | | | | | | | 0.2871 |
| | *LNG* | | | | | | | | | | | | | 0.1817 |
| *L23=L21xL22* | Incremental YEC Thermal Generation Cost to Charge (Refund) DCF ($000s) | | | | | | | | | | | | | ($990) |
| *L24* | DCF Balance at 2015 Year End ($000) | | | | | | | | | | | | | 10,895 |
| *L25* | Rider E (Rebate) forecast by March 31, 2017 | | | | | | | | | | | | | (2,454) |
| *L26* | Interest | | | | | | | | | | | | | 54 |
| *L27=L24+L25+L26-L23* | DCF Balance at 2016 Year End ($000) | | | | | | | | | | | | | 9,485 |

# ATTACHMENT 2: UPDATED RIDER E RATE SCHEDULE

**Page 1 of 1**

**Effective: 2017 05 01**
**Supercedes: 2016 05 01**

## RIDER E

## DIESEL CONTINGENCY FUND RIDER

**AVAILABLE:** To all retail and major industrial electric services throughout the Yukon Territory.

**APPLICABLE:** To all retail and major industrial classes of service [not applicable to secondary sales].

**RATE:** Service will be rendered at the applicable rates with the following surcharge/(refund):

A refund of -0.14 ¢ per kW.h will be applied to all firm kWh consumed.

**NOTE:** Rider E will be applied to all firm kWh consumed for the period from May 1, 2017 to March 31, 2018.

Rider E does not apply to Rate Schedule 32 Secondary Energy.

## ATTACHMENT 3: UPDATE ON FORECAST WATER CONDITIONS FOR 2017

YUKON
ENERGY

Yukon Energy Corporation
Box 5920
Whitehorse, Yukon YlA 6S7

# Memo

To: Ed Mallard

From: Ronald Gee

Date: March 7, 2017

Re: 2017 Water Availability Forecast

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The present generation forecast for 2017 on the total Yukon Energy grid is approximately 430.729 GW.h. The complete preliminary March 1 snow survey results are attached. Unofficial snow surveys indicate an overall below average snow water equivalent in all three of Yukon Energy's water basins. Snow survey station results specific to each basin are listed below:

Aishihik:

| Station | March 2017 Snow Water Equiv (mm) | %of Normal | March 2016 SWE(mm) | 5YrAvg SWE(mm) |
|---|---|---|---|---|
| Canyon Lake | 76 | 94 | 50 | 75 |
| Aishihik Lake | 60 | 81 | 42 | 68 |

Whitehorse:

| Station | March 2017 Snow Water Equiv (mm) | %of Normal | March 2016 SWE(mm) | 5 Yr Avg SWE(mm) |
|---|---|---|---|---|
| Tagish | 100 | 78 | 81 | 114 |
| Montana Mt | 110 | 84 | 76 | 125 |
| Log Cabin | 368 | 111 | 332 | 343 |
| Atlin | 85 | 77 | 87 | 87 |
| Mt McIntyre | 128 | 94 | 82 | 130 |
| Whse Airport | 52 | 56 | 63 | 83 |

Mayo:

| Station | March 2017 Snow Water Equiv (mm) | %of Normal | March 2016 SWE(mm) | 5Yr Avg SWE(mm) |
|---|---|---|---|---|
| MayoAirp | 38 | 42 | 113 | 92 |
| Calumet | 150 | 86 | 202 | 177 |

The current level of Aishihik: Lake is 914.13m. The spring low in May is expected to be approximately 913.8m or 1.35m below full supply level. Spring low levels as forecasted have not been experienced since the start of the decade. With the expected low snow pack the lake is not expected to fully refill by fall. The refill will also be impacted by having to generate higher amounts in April, May, and June with the Whitehorse Unit #4 out of service for new rotor and overhaul. The fall peak level for Aishihik Lake is forecast to be in the range of 914.8m.

Marsh Lake reservoir is presently 654.54m. The spring low in May is expected to be near low supply level. A major shut down and repair program for the Unit #4 hydro plant is scheduled to begin in April 2017 but will have no impact on refill as all gates at Marsh Lake Control Structure need to be open by May 15. The loss of generation from Unit #4 in April, May, and June will have to be made up by Aishihik: and Mayo Generating Stations. The level of Marsh Lake is expected to be at full supply level by October 2017 if summer temperatures and precipitation are at or above normal.
Winter drawdown of Marsh Lake will begin in November and continue through to May 2018. Energy and capacity at Whitehorse Rapids will be constrained by the decreasing flow in the Yukon River as the winter progresses. This decrease in generating capability is the normal operating situation for Whitehorse Rapids. Scheduled hydro maintenance is not expected to impact the 2017/18 winter generating capability of Whitehorse Rapids Generating Station.

Mayo Lake is currently 663.92m. The spring low in May is expected to be approximately 663.25m or near the low supply level. With the low snowpack and having to generate higher levels in early summer with Whitehorse Unit #4 out of service, Mayo Lake is not expected to fully refill by fall unless significant summer precipitation occurs. The lake level will fall short of full supply by approximately 0.45m.

In summary, Marsh Lake is forecast to be at or near full supply by October 2017 while Aishihik and Mayo do not reach operational full supply level. Water level graphs for the three reservoirs are attached. As Aishihik Lake is a multi-year reservoir, not reaching full supply does not impact the energy capability during the winter of 2017/18 but energy from Mayo GS will likely be constrained by spring of 2018.

# TAB 4
# RATES

# 4.0 RATES

This tab reviews Yukon Energy's existing rates and sets out the changes to those rates proposed in this Application.

This tab consists of the following items:

- Summary of Proposed Rate Changes;
- Overview;
- Secondary Energy Rate Design;
- Major Industrial Firm Rates;
- Non-Industrial Firm Retail Rates; and
- Wholesale Rates.

## 4.1 SUMMARY OF PROPOSED RATE CHANGES

The key rate changes sought in this Application are:

- **Rider J – Yukon Energy Revenue Shortfall Rider** – Applicable to all YEC and ATCO Electric Yukon (AEY) firm retail rates (all AEY recoveries from this rider would flow through to YEC) and industrial rates. The existing Rider J is 11.01% for non-industrial rates and 7.36% for industrial rates. The Rider J increase to each existing Rider J to recover the Application revenue shortfalls is 9.04% for 2017 and 2.07% for 2018. As noted below, interim refundable rates at the Rider J rate levels for retail and industrial customers are sought effective September 1, 2017.
- **Rider J – 2017/2018 Yukon Energy Interim Revenue Shortfall Rider** – An interim refundable increase to Rider J of 9.04% starting September 1, 2017 and applicable to all YEC and AEY firm retail rates (all AEY recoveries from this rider would flow through to YEC) and industrial rates. These interim rates will be replaced with final approved rates as described above. Appendix 4.1 provides the proposed rider.

The rates arising from the final order in this GRA will not be in place until sometime in 2018, given current timing estimates. As outlined in Section 4.5, interim refundable rates at the Rider J rate level are sought effective September 1, 2017. This approach will mean that any required "true up" for 2017 and 2018 will be part of the YUB's final order setting rates arising from this Application.

No proposal regarding the Rate Schedule 42 Energy Reconciliation Adjustment (ERA) is provided at this time in the Application as the ERA is currently the subject of an appeal to the Court (the "Appeal") from the Board's Order 2015-06 of August 18, 2015. At such time as the Court's decision is provided, Yukon Energy will review the ERA and provide the Board with a filing as required on this matter.

## 4.2 OVERVIEW

Yukon Energy's revenue earned from rates is collected from charges for firm power and for secondary (interruptible or surplus) sales. All revenues from secondary power, as an opportunity use of hydro power that would otherwise be wasted, go to lower the required level of retail rates for firm power.

The rates charged to Yukon Energy's customers for firm sales are designed to yield the revenue requirements set out in Tab 3, net of a small amount of non-rate revenues[1] ($0.253 million in each test year) received by Yukon Energy and secondary sales ($0.642 million in each test year).

In 2017, the revenue required from firm rates is $47.649 million, and in 2018 is $48.969 million. Yukon Energy's forecast revenues from existing firm electrical rates (including the existing Rider J) is $42.301 million in 2017 and $42.384 in 2018.

As set out in Table 4.1, assuming the sales forecasts set out in Tab 2, the current level of existing firm rates would result in a $5.348 million rate revenue shortfall in 2017, and a $6.585 million rate revenue shortfall in 2018 compared to revenue requirements set out in Tab 3. These shortfalls form the basis for the proposed rate increases in this Application.

[1] Including items such as pole rentals, connection charges, and other facility rentals.

**Table 4.1:**
**Yukon Energy Revenue Required from Rates**
**($000s)**

| | 2017 | 2018 |
|---|---|---|
| Revenue Requirement | $48,544 | $49,864 |
| Less: Other Revenues | $ 253 | $ 253 |
| Less: Secondary Sales | $ 642 | $ 642 |
| Revenue Required from Firm Rates | $47,649 | $48,969 |
| Less: Revenues from Firm Sales at Existing Rates [includes Rider J] | $ 42,301 | $ 42,384 |
| Additional Firm Rate Revenues Required | $5,348 | $6,585 |

## 4.3 SECONDARY ENERGY RATE DESIGN

Yukon Energy's secondary rate offering provides interruptible power to customers of Yukon Energy or AEY who qualify under Rate Schedule 32. In order to qualify, the power must be "in excess of normal consumption and represent incremental electric usage displacing an alternative fuel source in order to provide space or process heating." The customer must have a viable alternative fuel source available to provide backup in the event of power interruptions.

The bulk of secondary sales in Yukon are made by AEY as retailer, with Yukon Energy selling the equivalent quantity of power on a wholesale secondary basis to AEY at the then current retail secondary power rate less 1.1 cents/kWh (per approved Wholesale Secondary Rate Schedule 32). Yukon Energy does not propose to change this relationship between wholesale and retail secondary energy rates.

### 4.3.1 Retail Secondary Sales Rates (Rate Schedule 32)

In 2005, the Yukon Utilities Board (YUB or the Board) approved an increase in the secondary sales rate and established an ongoing adjustment mechanism to maintain a reasonable correlation between the secondary sales rate and fuel oil prices. The secondary sales rate was set effective January 1, 2005 at 66.7% of the equivalent costs of heating with oil.[2] Yukon Energy also proposed, and the Board approved

[2] For measuring the costs of heating with oil, the calculation uses the price for oil based on the lowest of the three values cited in the biweekly Yukon bureau of Statistics measurement for Furnace Oil in Whitehorse. The efficiency assumed for the alternate heating source was 90%.

in Order 2005-12, an automatic adjustment mechanism that would adjust the rate on a quarterly basis, based on the lowest of the three most recent Yukon Bureau of Statistics bi-weekly furnace oil prices for Whitehorse. In order to address fuel price related variance in income, the Rider F Deferred Fuel Price mechanism was used to normalize the secondary sales revenues and act as a natural hedge to the Rider F account, reducing variability that would otherwise be charged through the joint Yukon Energy/Yukon Electrical rate rider.

In the 2008/2009 GRA, Yukon Energy noted that with the increased utilization of surplus hydro generation in coming years, the existing opportunity to sell secondary energy on an interruptible basis would be basically eliminated; however, limited quantities of secondary energy may remain available in summer months during off-peak hours over the following years. At the time it was noted that in the test years secondary sales were forecast to be maintained through most hours of the year, but during cold winter periods there would be increased use of diesel generation for firm load peaking requirements and consequently greater forecast interruptions of secondary sales than in previous years.

After the 2008/2009 test years, secondary sales were suspended for a prolonged period of time due to low water.[3] As a result of this suspension of service a number of secondary sales customers converted to primary supply for their electric heating loads. The 2013 Compliance Filing included no forecast secondary sales. As reviewed in Section 2.2.4, surplus hydro generation (reflecting favourable water conditions as well as reductions in firm grid loads) resulted in actual secondary sales between 3.9 to 7.0 GW.h per year from 2013 to 2016.

Secondary sales are forecast at 11,464 MW.h/year in 2017 and 2018 (see Section 2.2.4). Secondary sales revenues are forecast at $0.642 million in each year, assuming a wholesale rate of 5.6 cents per kW.h (retail rate of 6.7 cents per kW.h).[4] The existing Rider F adjustment mechanism will continue to be applied on a quarterly basis to adjust the rate based on the lowest of the three most recent Yukon Bureau of Statistics bi-weekly furnace oil prices for Whitehorse.

### 4.3.2 Low Grade Ore Processing Secondary Energy (Rate Schedule 35)

The Power Purchase Agreement (PPA) with Minto Explorations included as Schedule D, Rate Schedule 35, Low Grade Ore Processing Secondary Energy Rate. As discussed during the PPA hearing process, this was

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[3] Except for the period from September 1, 2010 until September 1, 2011 when they were temporarily resumed due to high water in Aishihik Lake.

[4] See Secondary Sales Advisor for January 1, 2017 Rate Determination which notes an Oil Price Index for the January 1, 2017 rate is 95.33 cents/litre and equals a Secondary Energy price of 6.7 cents/kWh and results in a Rate Schedule 43 Wholesale Secondary energy price of 5.6 cents/kWh. http://yukonutilitiesboard.yk.ca/pdf/Reports/SS_Quarterly_Rate_Advisory_-_Jan_2017.pdf

a negotiated rate specific to the circumstances of the Minto mine (i.e., it may only be used for processing low grade copper ore as defined under Rate Schedule 35), interruptible and available only from surplus hydroelectricity not otherwise required by Rate Schedule 32 customers.

This rate was reviewed by the Board and intervenors during the PPA hearing process, and was approved by the Board on an interim basis. The Board also noted that audit and control measures and reporting requirements must be developed between YEC and Minto, and once developed these are to be filed with the Board for approval.[5] This requirement was included in the PPA as amended May 14, 2007, which was approved by Board Order 2007-6. Accordingly, YEC cannot implement this rate until such audit and control measures and reporting requirements have been proposed by Minto, reviewed and agreed upon by Yukon Energy, and approved by the Board.

To date, the Yukon Utilities Board prerequisites for Rate Schedule 35 have not been met.

## 4.4 MAJOR INDUSTRIAL FIRM RATES

Major industrial customers are defined in Order in Council (OIC) 1995/90 as being those customers "engaged in manufacturing, processing, or mining and whose peak demand for electricity exceeds 1 MW". This classification applies to the Minto mine for 2017 and 2018, which is the only forecast major industrial customer in the test years. No other major industrial customers are forecast to require service under Rate Schedule 39 in the test years.

Rates for major industrial customers have been set in recent GRAs pursuant to Section 6 of OIC 1995/90, as amended by subsequent OICs.

- OIC 2007/94 amended OIC 1995/90 to add subsection 6(3) immediately after subsection 6(2). Subsection 6(3) at that time provided that "despite subsection (1), the Board must ensure that the rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to Rate Schedule 39, Industrial Primary" attached as Schedule A to the OIC. Board Orders 2011-04 and 2011-14 approved increases in Rate Schedule 39 demand and energy rates as provided for in OIC 2007/94.

- OIC 2012/68 amended Section 6(3) in OIC 2007/94, and also amended Section 2.1 of OIC 1995/90. Excluding directions affecting rates only in 2012, OIC 2012/68 required that Rate

[5] See Board Order 2007-5.

Schedule 39, as approved in Board Order 2011-14, continue until December 31, 2013,[6] subject to the following direction in the amended Section 2.1:

- The Board must otherwise ensure until December 31, 2013 that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers.

OIC 2014/23 subsequently extended the provisions of 2.1(3) and 6(3) of OIC 1995/90 (as amended by OIC 2012/68) to December 31, 2018. Specifically, the OIC requires that until December 31, 2018 rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers (with Rate Schedule 39, as approved in Order 2011-14, otherwise continuing until December 31, 2018).

The existing Rider J rate applicable for major industrial customer rates (Rate Schedule 39) is 7.36%. In conformance with OIC 2014/23 and the Rider J increases reviewed below in Table 4.2, the existing Rider J applicable to Rate Schedule 39 is to be increased by 9.04% for 2017 and 2.07% for 2018 (applicable total Rider J rate for major industrial customers rates of 16.40% for 2017 and 18.47% for 2018). The interim refundable Rider J increase of 9.04% effective September 1, 2017 would apply to Rate Schedule 39.

## 4.5 NON-INDUSTRIAL FIRM RETAIL RATES

Firm retail non-industrial rates within each non-government retail customer class (i.e., rates for residential, general service and lighting customer classes) are required by OIC 1995/90 to be equal throughout Yukon for both Yukon Energy and Yukon Electrical customers, subject to allowed variation for run-off rates to reflect incremental costs that differ for different rate zones.

On October 3, 2008, the Yukon Government enacted OIC 2008/149 amending OIC 1995/90 to add immediately after Section 2 the following direction to be in effect until December 31, 2012:

> 2.1(1) the Board must ensure that rate adjustments for all retail customers apply equally, when measured as percentages, to all classes of retail customers.

[6] OIC 2012/68 retains Schedule A from OIC 2007/94, which set out Rate Schedule 39, Industrial Primary. The rate schedule approved in Board Order 2011-14 conformed to Schedule A of OIC 2007/94.

Section 2.1 provided in OIC 2008/149 was replaced in April 2012 with OIC 2012/68. Insofar as it affects all classes of retail customers, this new direction in effect extended the earlier Section 2.1(1) direction until December 31, 2013, and ensured that the same percentage rate adjustments will also apply to the class of major industrial customers (subject to provisions noted in Section 4.4 of this Application). OIC 2014-23 has subsequently extended this OIC direction to December 31, 2018.

In accordance with OIC 2014/23, the Application proposes that the Yukon Energy revenue shortfall for 2017 and 2018 as shown in Table 4.1 be recovered through Revenue Shortfall Riders applied across the board to all firm retail and industrial rates of YEC and AEY in 2017 and in 2018 as follows (see Section 4.4 of this Application for details regarding how these riders also apply to industrial rates):

- **2017:** An across the board increase is required of 7.38% applied, on an ongoing basis, to all firm retail and industrial customer rates, including YEC Rider J and AEY Rider R (i.e., excludes customers served under Rate Schedule 32 and Rate Schedule 35, as well as Rider F and Rider E), assumed to have started as of January 1, 2017 as provided in Table 4.2.
    - Considering that the current YEC Rider J is applied only to base rates, the required new Rider J as of January 1, 2017 would increase from the current 11.01% for non-industrial to 20.05%, and from the current 7.36% for industrial to 16.40%. The calculation of Rider J is provided in Table 4.2.
- **2018:** An across the board increase is required of 1.58% applied, on an ongoing basis, to all firm retail and industrial customer rates, including YEC Rider J and AEY Rider R, (i.e., excludes customers served under Rate Schedule 32 and Rate Schedule 35, as well as Rider F and Rider E), assumed to start January 1, 2018 as provided in Table 4.2.
    - As indicated above, YEC Rider J is applied to base rates and therefore the new Rider J effective January 1, 2018 will be 22.12% for non-industrial, and 18.47% for industrial as provided in Table 4.2.

## Table 4.2: Calculation of Required 2017 and 2018 Rate Increases and Rider J[7]

| Line # | | | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| 1a | Consolidated Firm Retail Sales Revenues - Base Rates | $000 | 54,990 | 55,074 |
| 1b | Consolidated Firm Industrial Sales Revenues - Base Rates | $000 | 4,198 | 4,198 |
| 2a | Consolidated Rider J Revenues | $000 | 6,363 | 6,373 |
| 2b | AEY Rider R Revenues | $000 | 6,878 | 6,887 |
| 3=1+2 | **Total Consolidated Firm Sales Revenues at existing rates** | $000 | 72,429 | 72,532 |
| 4=Table 1 | Retail Revenue increase required in 2017 | $000 | 5,348 | |
| 5=4/3 | Required Rate Increase | % | 7.38% | |
| 6=3+4 | **Total Consolidated Firm Sales Revenues with 2017 Increase** | $000 | 77,777 | 77,888 |
| 7=Table 1 | Total Revenue increase required in 2018 | $000 | | 6,585 |
| 8=6-3 | To Be Recovered from 2017 Increase | $000 | | 5,355 |
| 9=7-8 | Total net increase required in 2018 | $000 | | 1,230 |
| 10=9/6 | Required Rate Increase in 2018 | % | | 1.58% |
| 11=9+6 | **Total Consolidated Firm Sales Revenues with 2018 Increase** | $000 | | 79,118 |
| 12 | Total Cumulative 2017 and 2018 Rate Increases (compounded) | | | 9.08% |
| | **Rider J Required** | | | |
| 13a=4/(1a+1b) | Rider J Increase Required | % | 9.04% | |
| 13b=4/(1a+1b) | Rider J Increase Required | % | | 2.08% |
| 14 | Existing Rider J - non-industrial | % | 11.01% | |
| 15 | Existing Rider J - industrial | % | 7.36% | |
| 16=13+14 | Total Rider J with increases - non-industrial | % | 20.05% | 22.12% |
| 17=13+15 | Total Rider J with increases - industrial | % | 16.40% | 18.47% |
| 18 | **Total Consolidated Firm Sales Revenues with increases** | $000 | $77,777 | $79,118 |

Notes:
1. Total Consolidated Retail Revenues at existing rates include revenues from YEC and AEY's residential, general service and streetlight sales.
2. Consolidated Rider J revenues at existing rates include YEC Rider J at 11.01% for YEC and AEY firm retail sales and at 7.36% for firm industrial sales.
3. AEY Rider R revenues at existing rates include AEY's interim Rider R at 11.62%R for firm retail and industrial base rate sales of YEC and AEY.

It is proposed that Rider J for 2017 of 20.05% for all firm non-industrial, and 16.40% for all firm industrial, be applied initially as of September 1, 2017 as an interim refundable rate rider, equal to a 9.04 percentage point increase in the existing Rider J rates for non-industrial and industrial rates.[8]

This interim refundable rate rider proposal also recognizes that rates arising from the final order in this GRA will not be in place until sometime in 2018 given current timing estimates, and that any required

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[7] Total Consolidated Retail Revenues at existing rates include revenues from YEC and AEY's residential, general service and streetlight sales. AEY revenues at existing rates are based on AEY 2016-17 GRA Schedule 2.1. Rider J increases at line 13 are rounded (the calculations to three decimal places are 9.035% for 2017 and 2.075% for 2018. In order to address rounding impact and derive the total Rider J as shown at lines 16 and 17, the Application references a Rider J increase of 9.04% in 2017 and an increase of 2.07% in 2018.

[8] Assuming that September 1 to December 31 accounts for one-third of forecast annual Consolidated Base Rate revenues (which is likely excessive), an interim Rider J increase at 9.04 percentage points can secure only about 33.3% of the forecast 2017 revenue shortfall of $5.348 million.

"true-up" for 2017 and 2018 will be part of the YUB's final order setting rates arising from this Application.

Appendix 4.2 includes bill comparisons related to non-government residential and commercial customers, indicating how Yukon rates compare with those in other jurisdictions and impacts of the Application on monthly rate charges and bills for a residential customer using 1,000 kW.h/month and a general service customer using 2,000 kW.h/month.

## 4.6 WHOLESALE RATES

Yukon Energy's firm rate revenues today primarily arise from the wholesale rate charged to AEY (Rate Schedule 42) plus the provision for all AEY recoveries from YEC's rate riders to flow through to YEC. Rate Schedule 42 includes a fixed Energy Charge of 8.298 cents per kW.h that applies to all wholesale primary supply to AEY by YEC, and an Energy Reconciliation Adjustment provision which is intended to adjust charges to AEY that are attributable to AEY's wholesale purchases that vary from the wholesale forecast approved for YEC's last GRA in years when AEY's variance from this approved forecast is in the same direction as YEC's variance of actual thermal generation costs from the last approved forecast.[9]

No change in the Energy Charge is proposed as a result of this Application.

No proposal regarding the ERA is provided at this time in the Application as the ERA is currently the subject of an appeal to the Court from the Board's Order 2015-06 of August 18, 2015.[10] In summary, Yukon Energy's Appeal states that the effect of Order 2015-06 is to deny Yukon Energy its costs of thermal generation when two factors, both beyond Yukon Energy's control, coincide: the demand by AEY for wholesale electricity is higher than forecast, and hydro generation is (because of water availability) different from the forecast as approved by the Board for thermal costs charged to Yukon Energy. At such time as the Court's decision is provided, Yukon Energy will review the ERA and provide the Board with a filing as required on this matter.

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[9] As noted in YEC's April 7, 2015 submission to the Board, Order 2015-01 directions with regard to the ERA are understood by YEC to require an ERA that achieves this overall objective.

[10] Yukon Energy requested a review and variance of Order 2015-06, which the Board dismissed on December 31, 2015. Leave to Appeal was granted by the Court of Appeal of Yukon on March 9, 2016. The Appeal was heard in the Court on December 7, 2016.

# APPENDIX 4.1
# RATE SCHEDULES

**Effective:** 2017/0~~7~~9/01
Supersedes: 2013/07/01
Page 1

## RIDER J

## NEW INTERIM RIDER J TO INCLUDE RECOVERY OF PORTION OF 2017 YUKON ENERGY REVENUE SHORTFALL

**AVAILABLE:** To all electric service throughout the Yukon Territory.

**APPLICABLE:** To all electric service retail rates except Rate Schedule 32, Rate Schedule 35, Rate Schedule 42 and Rate Schedule 43.

**RATE:** Rider J at ~~11.01~~20.05% applicable to the base rates of the following rate classes to recover/refund the 2017 revenue shortfall with all Yukon Electrical Company Limited recoveries from this rider to flow through to the Yukon Energy Corporation:

Residential Non Gov.
Residential Gov
General Service Non Gov.
General Service Municipal Gov.
General Service Gov. Fed. and Terr.
Street and Sentinel Lighting

Rider J for Industrial customers at ~~7.36~~16.40% applicable all firm sales revenues, including fixed Rider F revenues.

**NOTE:** Rider J does not apply to Rate Schedule 32, Rate Schedule 35, Rate Schedule 42 and Rate Schedule 43.

# APPENDIX 4.2
# BILL IMPACTS FOR YUKON RESIDENTIAL NON-GOVERNMENT AND GENERAL SERVICE NON-GOVERNMENT CUSTOMERS

# APPENDIX 4.2: BILL IMPACTS FOR YUKON RESIDENTIAL NON-GOVERNMENT AND GENERAL SERVICE NON-GOVERNMENT CUSTOMERS

The tables and figures below show bill impacts for the Yukon Residential Non-Government and General Service Non-Government customers.

- **Table 4.2A-1** compares Yukon Residential electricity bills (excluding rate relief and taxes) at 1,000 kW.h monthly consumption to other cities across Canada. The Yukon Residential bills, which at this level of consumption are equalized for all rate zones in Yukon, are less than all other northern city customers, and less than Residential bills reviewed for cities in Ontario, PEI and Nova Scotia.
  - **Note:** Table 4.2A-1 does not review current rate increase proposals for non-Yukon jurisdictions. For example, this table does not reflect the current NTPC GRA for additional rate increases in 2017/18 and 2018/19.
- **Figure 4.2A-1** compares northern residential bills to Yukon residential bills - Yukon is lowest.
- **Figure 4.2A-2** compares Yukon residential bills to residential bills in 16 cities across Canada.
- **Table 4.2A-2** compares Yukon small General Service bills (excluding rate relief and taxes) at 2,000 kW.h monthly consumption to other northern cities. The Yukon General Service bills, which at this level of consumption are equalized for all rate zones in Yukon, are less than all other northern city customers.
- **Figure 4.2A-3** compares northern small commercial bills.
- **Table 4.2A-3** compares existing Yukon Residential Non-Government rates and bills to the proposed rate changes for 2017 and 2018 prior to consideration of subsidies, rebates and taxes. Due to concurrent changes to rates for AEY and YEC during 2017 and 2018, the table shows AEY rate changes first and then shows the added changes with YEC's proposed rates.
- **Table 4.2A-4** compares existing General Service Non-Government rates and bills to the proposed rate changes for 2017 and 2018 prior to consideration of subsidies, rebates and taxes. Due to concurrent changes to rates for AEY and YEC during 2017 and 2018, the table shows AEY rate changes first and then shows the added changes with YEC's proposed rates.

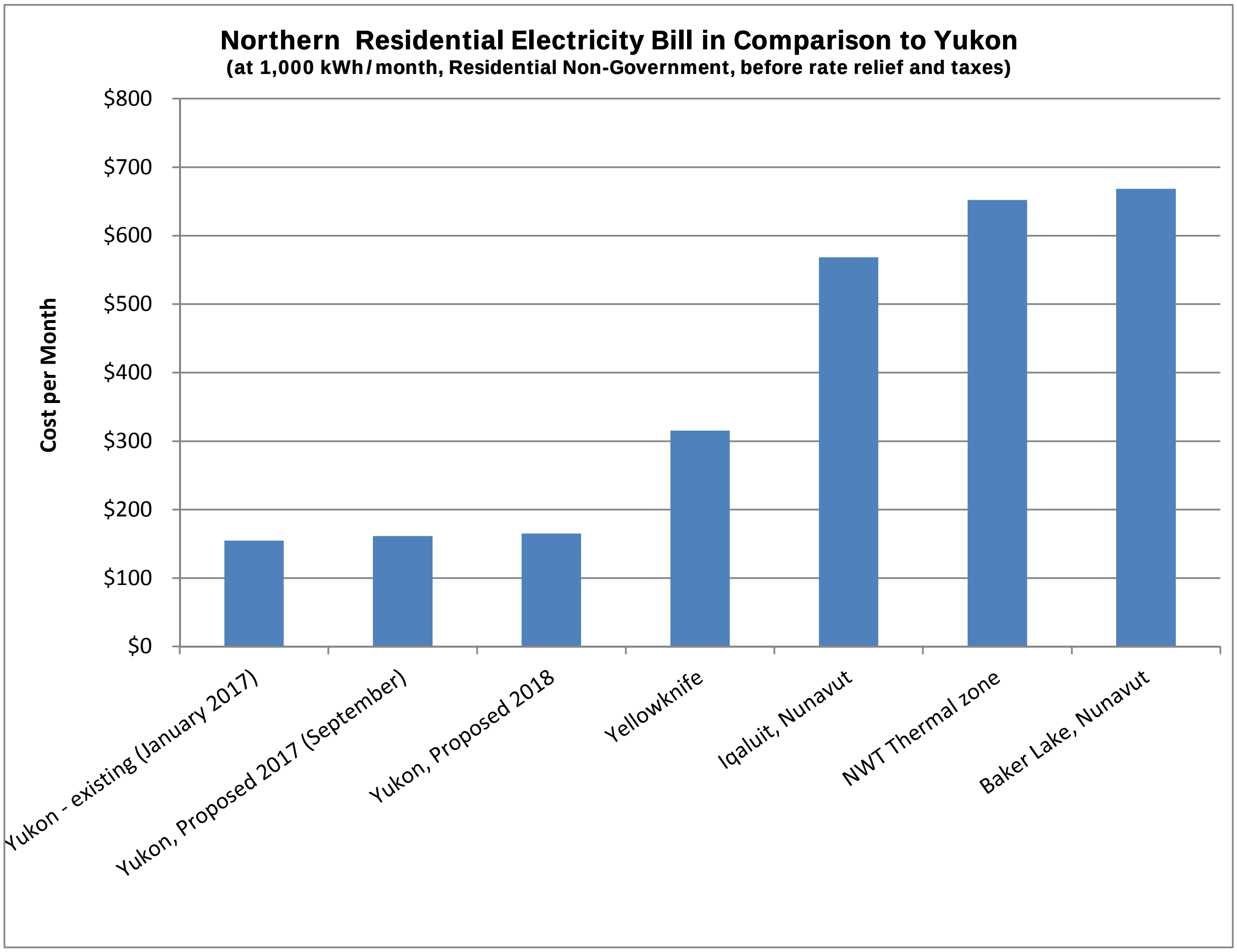
**Table 4.2A-1:**
**Residential Electricity Bills in Comparison to Yukon**
**(1000 kWh/month consumption, Residential Non-Government, $)**

| | | Monthly Bills before rate relief and taxes |
|---|---|---|
| 1 | Yukon - existing (January 2017) | $154.44 |
| 2 | Yukon, Proposed 2017 (September) | $161.36 |
| 3 | Yukon, Proposed 2018 | $165.04 |
| 4 | Yellowknife | $315.18 |
| 5 | Iqaluit, Nunavut | $568.30 |
| 6 | NWT Thermal zone | $651.90 |
| 7 | Baker Lake, Nunavut | $668.50 |
| 8 | Montreal, QB | $72.26 |
| 9 | Winnipeg, MB | $84.29 |
| 10 | Edmonton, AB | $103.69 |
| 11 | Calgary, AB | $104.00 |
| 12 | Vancouver, BC | $107.03 |
| 13 | St. John's, NL | $119.64 |
| 14 | Moncton, NB | $124.98 |
| 15 | Regina, SK | $146.45 |
| 16 | Halifax, NS | $158.83 |
| 17 | Charlottetown, PEI | $160.17 |
| 18 | Ottawa, ON | $161.52 |
| 19 | Toronto, ON | $178.08 |

Notes:

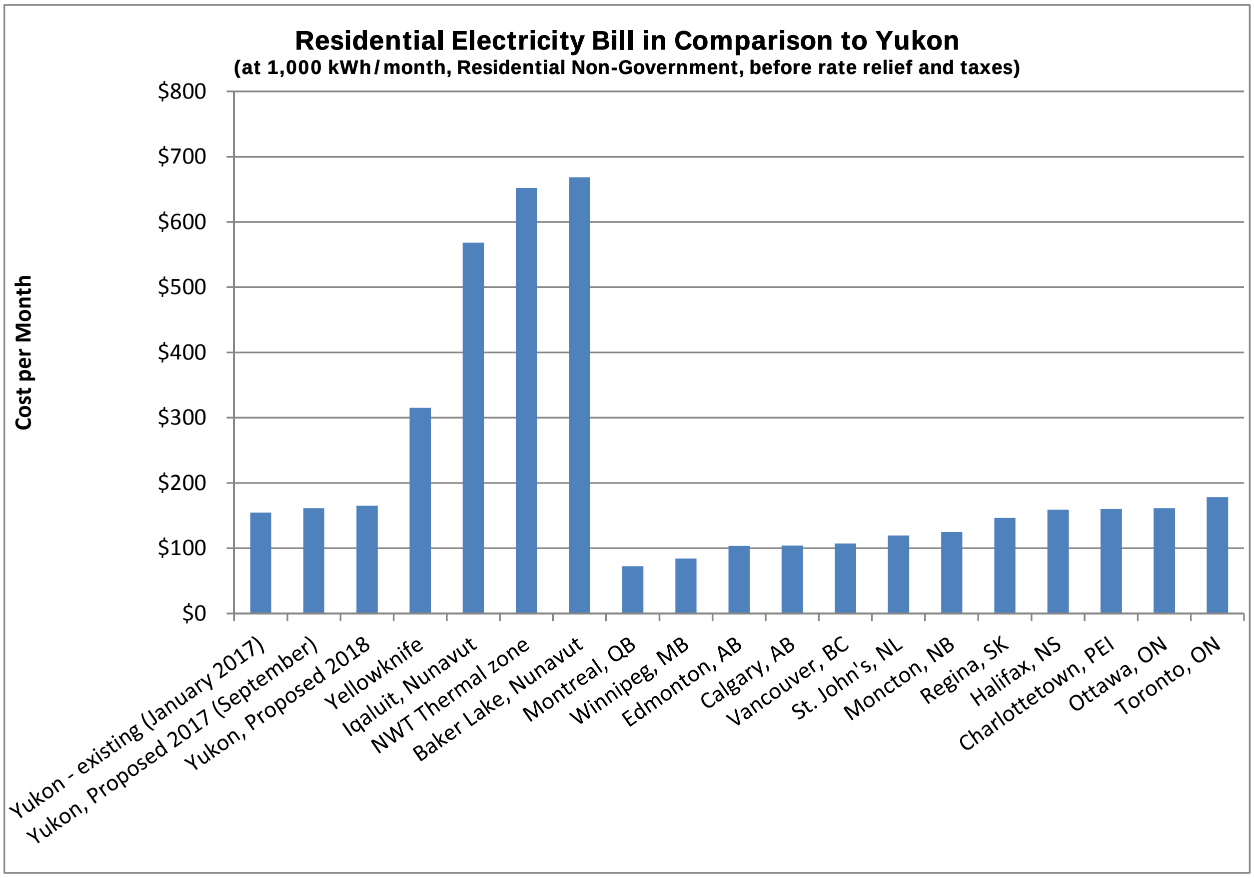
1. Monthly Bills are before Rate Relief and taxes.
2. Yukon existing bills include YEC Rider J [11.01%], AEY Rider R [11.62%] and Rider F and Rider E. See Table 4.2A-3.
3. Yukon proposed bills assume YEC's 9.04% Rider J rate increase starting September 1, 2017 and 2.08% Rider J increase starting January 1, 2018. This also includes proposed change of AEY's Rider R effective July 1, 2017 to 7.67% and 8.30% effective January 1, 2018 [based on AEY's May 26, 2017 Compliance Filing]. Please see notes to Table 4.2A-3.
4. Rates for NWT include interim increase of 4.8% effective August 1, 2016; thermal zone bills exclude GNWT subsidy to remove some or all of the difference from Yellowknife bills. [NWT rates do not reflect NTPC's filing for a GRA with PUB which proposes additional increase of 4% for 2017/18 and further 4% for 2018/19].
5. Nunavut community bills based on rates approved as of May 1, 2014, and do not reflect Nunavut government subsidy to reduce residential bills.
6. Rates for the other cities as of April 2016 (Source: Hydro Quebec).

**Figure 4.2A-1**
**Northern Residential Electricity Bill in Comparison to Yukon**




Source: See Table 4.2A-1.

**Figure 4.2A-2**
**Residential Electricity Bill in Comparison to Yukon**




Source: See Table 4.2A-1.

**Table 4.2A-2**
**Small Commercial Electricity Bills in Comparison to Yukon**
**(2000 kWh/month consumption, Commercial Non-Government, $)**

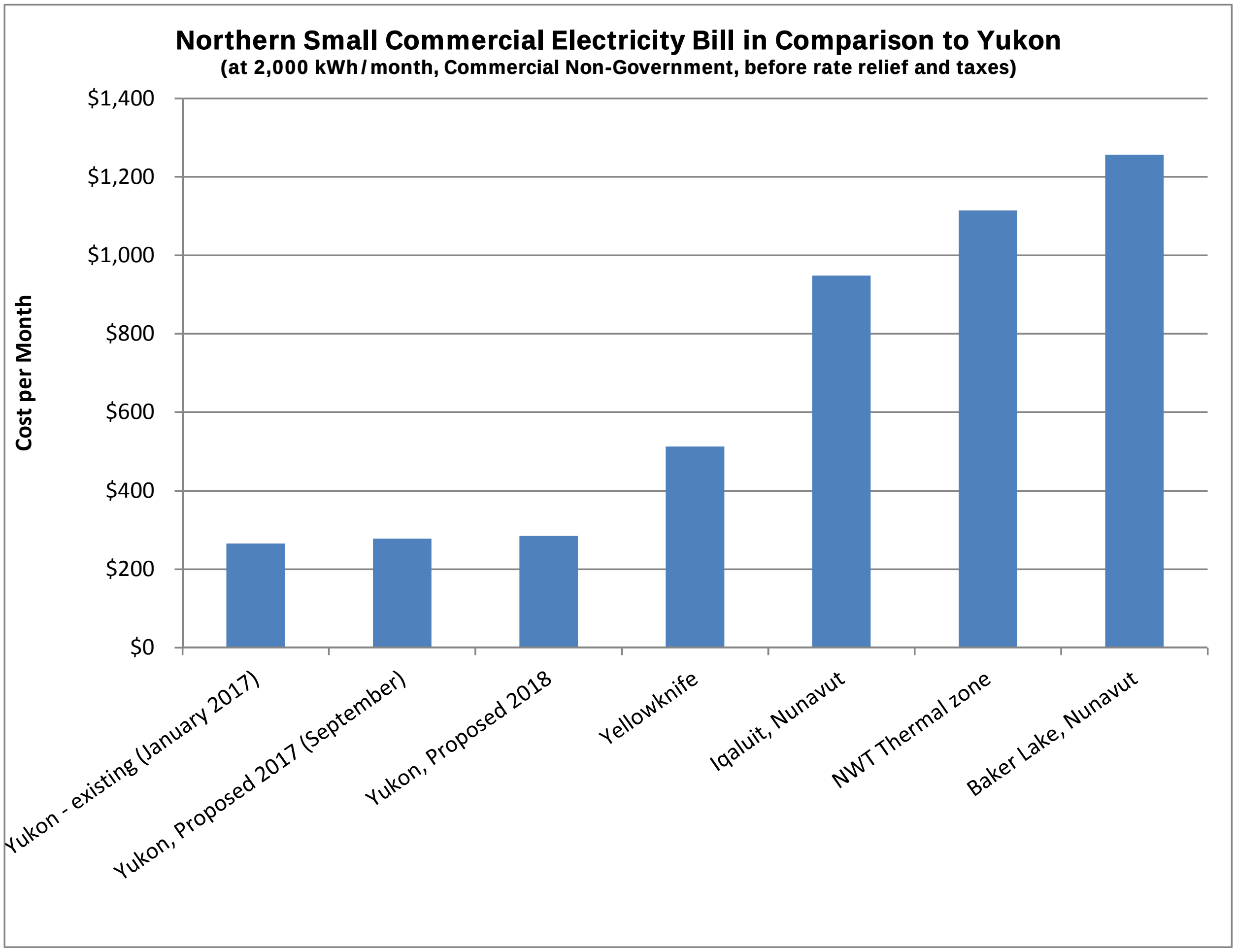
| | | Monthly Bills before rate relief and taxes |
|---|---|---|
| 1 | Yukon - existing (January 2017) | $265.77 |
| 2 | Yukon, Proposed 2017 (September) | $277.82 |
| 3 | Yukon, Proposed 2018 | $284.23 |
| 4 | Yellowknife | $512.34 |
| 5 | Iqaluit, Nunavut | $948.40 |
| 6 | NWT Thermal zone | $1,114.40 |
| 7 | Baker Lake, Nunavut | $1,256.60 |

**Notes:**

1. Monthly Bills are before Rate Relief and taxes.
2. Yukon existing bills include YEC Rider J [11.01%], AEY Rider R [11.62%] and Rider F and Rider E. See Table 4.2A-4.
3. Yukon proposed bills assume YEC's 9.04% Rider J rate increase starting September 1, 2017 and 2.08% Rider J increase starting January 1, 2018. This also includes proposed change of AEY's Rider R effective July 1, 2017 to 7.67% and 8.30% effective January 1, 2018 [based on AEY's May 26, 2017 Compliance Filing]. Please see notes to Table 4.2A-4.
4. Rates for NWT include interim increase of 4.8% effective August 1, 2016 [NWT rates do not reflect NTPC's filing a GRA with PUB which proposes additional increase of 4% for 2017/18 and further 4% for 2018/19].
5. Nunavut community bills based on rates approved as of May 1, 2014.
6. Under Nunavut Subsidy program the small commercial enterprises with annual gross revenues less than $2 million are eligible for subsidy. This rebate is not included in the table above.
7. Rates for the other cities as of April 2016 (Source: Hydro Quebec).

**Figure 4.2A-3**

**Northern Small Commercial Electricity Bill in Comparison to Yukon**




Source: See Table 4.2A-2.

## Table 4.2A-3
## Yukon Bills– Existing vs. Proposed - Non-Government Residential
## (prior to consideration of subsidies, rebates and taxes)

| Line # | Customer Use per month: | 1,000 kWh | Jan-16 | | Jan-17 | | AEY 2016/17 GRA May 26, 2017 Compliance Filing: Jul-17 | | AEY 2016/17 GRA May 26, 2017 Compliance Filing: Jan-18 | | Proposed Rates in YEC's 2017/18 GRA: Sep-17 | | Proposed Rates in YEC's 2017/18 GRA: Jan-18 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Rates | Bill | Rates | Bill | Rates | Bill | Rates | Bill | Rates | Bill | Rates | Bill |
| | Base Rates | | | | | | | | | | | | | |
| 1 | Customer Charge (per month) | | $14.65 | $14.65 | $14.65 | $14.65 | $14.65 | $14.65 | $14.65 | $14.65 | $14.65 | $14.65 | $14.65 | $14.65 |
| 2=KWh*Base rate | First Block Energy (kWh) | 1,000 | $0.1214 | $121.40 | $0.1214 | $121.40 | $0.1214 | $121.40 | $0.1214 | $121.40 | $0.1214 | $121.40 | $0.1214 | $121.40 |
| 3=KWh*Base rate | Second Block Energy (kWh) | - | | | | | | | | | | | | |
| 4=KWh*Rider F rate | Rider F (kW.h)[Fuel Price Rider] | | -$0.004870 | -$4.87 | -$0.005600 | -$5.60 | -$0.005600 | -$5.60 | -$0.005600 | -$5.60 | -$0.005600 | -$5.60 | -$0.005600 | -$5.60 |
| 5=(1+2+3)*Rider J rate | YEC Rider J (%) | | 11.01% | $14.98 | 11.01% | $14.98 | 11.01% | $14.98 | 11.01% | $14.98 | 20.05% | $27.27 | 22.12% | $30.09 |
| 6=KWh*Rider E rate | Rider E (kW.h) [DCF Rider] | | -$0.006800 | -$6.80 | -$0.006800 | -$6.80 | -$0.006800 | -$6.80 | -$0.006800 | -$6.80 | -$0.006800 | -$6.80 | -$0.006800 | -$6.80 |
| 7=(1+2+3)*Rider R rate | AEY Rider R (%) | | 7.20% | $9.80 | 11.62% | $15.81 | 7.67% | $10.44 | 8.30% | $11.29 | 7.67% | $10.44 | 8.30% | $11.29 |
| 8=Sum(1:7) | Total Before Tax Rebate, IER, GST | | | $149.15 | | $154.44 | | $149.06 | | $149.92 | | $161.36 | | $165.04 |
| 8A=8-4-6 | Total Before Tax Rebate, GST (excl. Rider F and Rider E) | | | $160.82 | | $166.84 | | $161.46 | | $162.32 | | $173.76 | | $177.44 |
| | *Change from last rate* | | | *$0.00* | | *$6.01* | | *-$5.37* | | *$0.86* | | *$12.29* | | *$3.68* |
| | Change from Jan 2018 AEY Rider Change | | | | | | | | | | | | | *$15.12* |

Notes:

1. AEY Rider R for July 2017 and January 2018 based on AEY May 26, 2017 Compliance Filing (not yet approved).
2. The table excludes adjustments to Rider F after January 2017 (adjustments will reduce Rider F portion for AEY to zero starting July 2017, and Rider F portion for YEC to zero when final YEC rates approved in 2018).

## Table 4.2A-4
## Yukon Bills– Existing vs. Proposed - Non-Government General Service
## (prior to consideration of subsidies, rebates and taxes)

| Line # | First Block Energy Use - Customer Use per month: | | | | | AEY 2016/17 GRA May 26, 2017 Compliance Filing | | | | Proposed Rates in YEC's 2017/18 GRA | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2,000 kWh | Jan-16 | | Jan-17 | | Jul-17 | | Jan-18 | | Sep-17 | | Jan-18 | |
| | 5 kW | | | | | | | | | | | | |
| | | Rates | Bill | Rates | Bill | Rates | Bill | Rates | Bill | Rates | Bill | Rates | Bill |
| | Base Rates | | | | | | | | | | | | |
| 1 | Demand Charge (per kW per month) | $7.39 | $36.95 | $7.39 | $36.95 | $7.39 | $36.95 | $7.39 | $36.95 | $7.39 | $36.95 | $7.39 | $36.95 |
| 2=KWh*Base rate | First Block Energy (kWh) | $0.1000 | $200.00 | $0.1000 | $200.00 | $0.1000 | $200.00 | $0.1000 | $200.00 | $0.1000 | $200.00 | $0.1000 | $200.00 |
| 3=KWh*Rider F rate | Rider F (kW.h) | -$0.00487 | -$9.74 | -$0.00560 | -$11.20 | -$0.00560 | -$11.20 | -$0.00560 | -$11.20 | -$0.00560 | -$11.20 | -$0.00560 | -$11.20 |
| 4=(1+2)*Rider J rate | YEC Rider J (%) | 11.01% | $26.09 | 11.01% | $26.09 | 11.01% | $26.09 | 11.01% | $26.09 | 20.05% | $47.50 | 22.12% | $52.41 |
| 5=KWh*Rider E rate | Rider E (kW.h) [DCF Rider] | -$0.00680 | -$13.60 | -$0.00680 | -$13.60 | -$0.00680 | -$13.60 | -$0.00680 | -$13.60 | -$0.00680 | -$13.60 | -$0.00680 | -$13.60 |
| 6=(1+2)*Rider R rate | AEY Rider R (%) | 7.20% | $17.06 | 11.62% | $27.53 | 7.67% | $18.17 | 8.30% | $19.67 | 7.67% | $18.17 | 8.30% | $19.67 |
| 7=Sum(1:6) | Total Before Tax Rebate, GST | | $256.76 | | $265.77 | | $256.41 | | $257.91 | | $277.82 | | $284.23 |
| 7a=7-3-5 | Total Before Tax Rebate, GST (excl. Rider F and Rider E) | | $280.10 | | $290.57 | | $281.21 | | $282.71 | | $302.62 | | $309.03 |
| | *Change from last rate* | | *$0.00* | | *$10.47* | | *$9.36* | | *$1.49* | | *$21.41* | | *$6.41* |
| | Change from Jan 2018 AEY Rider Change | | | | | | | | | | | | $26.33 |

Notes:

1. AEY Rider R for July 2017 and January 2018 based on AEY May 26, 2017 Compliance Filing (not yet approved).
2. The table excludes adjustments to Rider F after January 2017 (adjustments will reduce Rider F portion for AEY to zero starting July 2017, and Rider F portion for YEC to zero when final YEC rates approved in 2018).

# TAB 5
# CAPITAL PROJECTS

# 5.0 CAPITAL PROJECTS

Capital project investments in rate base are generally grouped in one of two categories: capital works on property, plant and equipment or deferred cost studies (including new supply and other feasibility studies, studies required by regulation or relicensing and dam safety works). This section provides an overview of Yukon Energy's actual capital spending since the 2012/2013 General Rate Application, as well as forecast capital spending for 2017 and 2018.

- **Overview of Capital Spending:** Provides a summary of Yukon Energy capital spending from 2013 through 2018.
- **Capital Works:** Reviews the capital spending on property, plant and equipment (PP&E), including a detailed discussion of the major projects over $1 million (undertaken from 2013 to 2016, and forecast to be undertaken in 2017 and 2018). General descriptions for projects in excess of $100,000 and up to $1 million forecast to occur in 2017 and 2018 are also provided.
- **Spending on Deferred Costs:** Reviews the capital spending on deferred cost projects (i.e., planning and study costs, regulatory and licensing activities, and dam safety reviews) for major initiatives from 2013 to 2018. Detailed descriptions of projects greater than $1 million are provided along with general descriptions of projects between $100,000 and up to $1 million forecast to occur in 2017 and 2018.

Tables 5.2 to 5.8 at the end of this Tab provide details of capital projects constructed since 2013 and including forecasts for test years 2017 and 2018. More specifically, Table 5.2 describes investment in property plant and equipment while Tables 5.3-5.8 describe the various deferred capital projects (i.e. feasibility studies, regulatory, relicensing, dam safety). The 2016 Resource Plan document is provided for reference as Volume 2 of this filing (absent the Appendices, which are available on Yukon Energy's web site under the following link: http://resourceplan.yukonenergy.ca/more/).

## 5.1 OVERVIEW OF CAPITAL SPENDING

Yukon Energy's capital spending from 2013 through 2018 reflects investments to complete legacy infrastructure projects previously reviewed by the Board, spending on sustaining capital requirements, investments specifically to ensure sufficient dependable capacity for the integrated grid, and continued planning expenditures to meet other potential future generation and transmission requirements.

- **Completion of Legacy Infrastructure Projects:** Significant investment in new infrastructure has been undertaken since 2006 based on specific opportunities and to ensure that Yukon Energy continues to meet Yukon load growth in a safe and reliable matter. The 2012/13 General Rate Application reviewed major legacy initiatives largely completed and in service in 2011 that resulted in the connection of the Whitehorse-Aishihik-Faro (WAF) and Mayo-Dawson (MD) grids and enhanced the renewable hydro capability on the new integrated grid. This included review of three major legacy projects: Carmacks-Stewart Transmission Project (CSTP) – Stage 2; Aishihik Third Turbine; and the Mayo Hydro Enhancement Project (Mayo B). While the projects were complete and in service in 2011, costs were incurred after 2012 (and not included in the 2012/13 GRA forecasts) to address outstanding issues for each project.[1] In each case no further spending is anticipated in the 2017/18 test years.

- **Focus on Sustaining Capital Requirements:** The 2012/13 test year spending 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. This included the Aishihik Redundancy Project, Mayo Hydro Substation Enhancements, Mayo Head Gate Repairs and the Whitehorse Spillway Improvements.

  Following the 2012/13 GRA Yukon Energy continued its focus on sustaining capital requirements, and the 2017/18 test year forecasts include spending on a number of major sustaining capital projects.

- **Investments to address Capacity Planning Requirements:** The 2012/13 GRA identified the continuing 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.

  - A requirement to appropriately reinforce the 25 km line L172 between Takhini and Whitehorse so as to provide no line constraint through this line segment was addressed as part of the Whistle Bend Subdivision Supply project completed in 2015.[2]

[1] Additional costs related to Aishihik Third Turbine are reviewed in Section 5.2. Between 2013 and 2016, additional costs of $0.757 million were incurred for CSTP – Stage 2, related to a contractor dispute and payments to trapping concession holders and First Nations that were required in order to complete undertakings made to obtain the necessary permits for the project; and between 2013 and 2014 additional costs of $0.589 million were incurred for Mayo B related to correction of deficiencies, and land purchase.
[2] The Whistle Bend Project was undertaken to ensure that Whistle Bend could be connected to the system in a manner that ensured adequate supply and overall system reliability and protection.

- The Whitehorse Diesel-Natural Gas Conversion Project, which addressed a capacity shortfall due to the planned retirement of two Mirrlees units at the Whitehorse Thermal Generating Station was completed in 2014-15 and in service in July 2015.

- The 2017/18 test years include a major capital works project for the third LNG engine as well as major deferred cost projects currently being planned to meet ongoing capacity requirements and the dependable capacity shortfall forecast in Yukon Energy's 2016 Resource Plan and this Application's Tab 2 forecasts.

- **Continued 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 Demand Side Management (DSM) and hydro storage enhancement projects at Mayo Lake and Marsh Lake [Southern Lakes]) and longer term renewable generation projects (e.g., hydro and wind). The Mayo Lake Storage Enhancement Project was forecast in the 2012/13 GRA to be in-service by 2013. However, studies indicated that sediments in the Mayo Lake outlet channel from over 50 years of operation would constrain water outflows through the channel at low lake levels, and that dredging of the outlet channel will be required to restore capability and enable the opportunity to expand long-term average hydro energy through the extra storage proposed by the Mayo Lake Storage Enhancement Project. The 2012/13 GRA also included forecast spending of $10 million (fully offset by customer contributions) towards mine grid connections for Victoria Gold and Western Copper. In each case, the mine grid connection has not proceeded to date, and this Application does not forecast that any new major industrial Rate Schedule 39 customer will connect to the grid in the test years.

  The 2017/18 test years include closure of feasibility study costs on potential projects that will not proceed, as well as forecast costs for longer term renewable generation planning. Forecast costs for the Stewart Keno City Transmission Project planning do not currently affect forecast net rate base costs as these investments have been fully funded by contributions.

Total spending on PP&E projects in the test year as shown in Table 5.2 totals $14.605 million and $14.633 million respectively, with 64% of this spending on major projects over $1 million ($18.6 million). This reflects a lower average annual spending level than occurred between 2013 and 2016 (about $24.6 million per year, including overhauls but excluding costs expensed for the Aishihik Third Turbine project).

- From 2013 to 2016, 67% of Yukon Energy's spending on capital works prior to any contributions ($98.6 million, including overhauls) was on major projects over $1 million ($65.9 million), with

92% of this major project spending on three projects (LNG Plant $40.9 million,[3] AH Elevator $8.5 million, and Whistle Bend Supply/Takhini Upgrade $11.4 million).

- Annual spending on capital works peaked in 2010/11 (average over $85 million/year), dropping to an average of $24.6 million/year from 2013 to 2016, and forecast at a still lower average of $14.6 million/year for 2017/18.
- Contributions reduced rate base impacts from capital works over the past decade, including approximately $128.5 million of government/Yukon Development Corporation (YDC) contributions noted in the 2012/13 GRA (CSTP, Mayo B and Aishihik Third Turbine projects) and an $18.3 million YDC contribution in 2015 for the LNG Plant project.

Deferred cost capital spending (including Work in Progress [WIP] and before contributions) averaged $4.9 million per year from 2013 to 2016 (contributions that offset these costs averaged $1.9 million per year). Deferred cost capital spending (including projects that remain in WIP) is projected at $5.6 million in 2017 and $17.6 million in 2018 (no contributions forecast for the test years).[4] The current GRA also results in approximately $13.9 million of deferred costs for feasibility studies, 2016 Resource Plan, DSM and other projects being brought into rate base as at January 1, 2017.

This Application also results in approximately $6.3 million of earlier deferred overhaul, both hydro and diesel, costs being brought into the PP&E capital works rate base as of January 1, 2017.

The Application includes, for approval of the Board, policies related to accounting for particular capital expenditures, including Yukon Energy's Planning Cost Accounting Policy (Appendix 5.1) and the DSM Accounting Policy (Appendix 5.2).

## 5.2 CAPITAL WORKS

This section reviews (a) major capital works projects (projects over $1 million) undertaken by Yukon Energy since the 2012/2013 GRA hearing and planned for 2017 and 2018; and (b) ongoing capital projects costing between $100,000 and $1 million forecast to occur in the 2017 and 2018 period.

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[3] Total spending of $41.9 million includes approximately $1.1 million in 2012.

[4] The $17.6 million in 2018 includes approximately $15.5 million in WIP, with three projects that each exceed $1 million (Battery, Thermal Plant, Marsh Lake Storage) accounting for approximately $12.8 million of this WIP. It is expected that most of the spending forecast for these projects will be on PP&E Major Projects once construction commences.

### 5.2.1 Major Projects over $1 Million

With the completion of major legacy infrastructure projects, test year spending on major capital works projects is focused on projects required to address sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance), and investments to ensure sufficient dependable capacity for the integrated grid. Total cost forecast to be added to net rate base for major projects by the end of 2018 is approximately $60.4 million (net of contributions of $18.3 million). An additional cost slightly in excess of $6 million is forecast for assets to come into service in Q1 2019.

Each major project is reviewed separately below (see also Tables 5.1 and 5.2 at the end of Tab 5):

- **Completion of Legacy Infrastructure Projects:** No impact on Net Rate Base, spending of approximately $0.665 million for work prior to December 31, 2016:
    - **Aishihik Third Turbine (Aishihik AH3) –** (cost of approximately $0.665 million in Table 5.2 plus $2.050 million expensed to the end of 2016, retained for Yukon Utilities Board (YUB) review pending appeal of court decision, with no spending forecast in test years). See discussion in Section 5.2.1.1.
- **Spending on Sustaining Capital:** Net Rate Base increase of approximately $25.379 million:
    - **AH Elevator Shaft Structural Steel Rehabilitation –** (forecast cost of approximately $10.116 million, to be completed in 2017).
    - **Aishihik Electrical and Control Upgrades –** (forecast cost of approximately $2.511 million, to be completed in 2018).
    - **Communications Upgrades –** (forecast cost of approximately $1.003 million for work completed before December 31, 2018).
    - **Hydro Unit #WH4 Overhaul –** (forecast cost of approximately $4.291 million, to be completed in 2017).
    - **Hydro Unit #MH2 Overhaul –** (forecast cost of approximately $1.657 million, to be completed in 2018).

- **T&D - Breaker Replacements –** (forecast cost of approximately $1.350 million for work completed before December 31, 2018).

- **T&D - Line Replacement –** (forecast cost of approximately $1.750 million for work completed before December 31, 2018, $0.250 not forecast in-service until 2019 [and therefore not affect rate base in test years]).

- **Wareham Spillway Gate Hoist Replacements –** (forecast cost of approximately $2.700 million, work completed in 2015 and no spending forecast in test years).

- **Spending to address Capacity Planning Requirements:** Net Rate Base increase in test years of approximately $35.016 million after no cost contributions of $18.3 million (an additional $5.950 million spending in test years for projects coming into service in 2019).

  - **Whistle Bend Supply/Takhini Upgrade –** (forecast cost of approximately $11.383 million, work completed in 2015 and no spending forecast in test years).

  - **LNG Plant –** (forecast cost of approximately $41.933 million for spending to the end of 2016 and no spending forecast in test years; offset by no cost contribution of $18.3 million).

  - **LNG Third Engine –** (forecast cost of approximately $5.950 million by December 31, 2018, not forecast in-service until Q1 2019 [and therefore not affect rate base in test years]).

#### 5.2.1.1 Aishihik AH3 ($0.665 million capital costs plus $2.050 million expensed as at the end of 2016, mainly related to contract dispute costs - costs held for review pending appeal of court decision)

The Aishihik hydro facility 7 MW third turbine (AH3) came into service in December 2011. Yukon Energy has incurred $2.715 million of costs after 2012 for wrap up activities related to this project, including $2.574 million of costs from a dispute with a contractor on this project. Total spending in 2016 was $2.117 million, the majority being legal costs required to be expensed during the year for accounting purposes. YEC considers these costs to be prudently incurred in order to defend the company against legal action resulting from the project. Upon final settlement of the lawsuit (under appeal as of this Application), total project costs will be presented to the Board for review in the next GRA.

In 2012, a contractor on the AH3 hydro enhancement project served YEC with a notice of claim that alleged that YEC owed the contractor outstanding amounts for work completed on the project.

YEC filed a statement of defense and counterclaim and the matter proceeded to trial. The option of negotiation and settlement was explored, and ultimately resulted in an agreement by both parties to discontinue certain of the claims against each other. However, as the parties were in significant disagreement regarding the nature of the balance of the claims and on monetary terms, the matter could not entirely be settled outside of the court proceeding.

A decision on the dispute was provided in August 2016 by the Yukon Supreme Court, awarding the contractor a net amount of $1,623,565 plus interest and costs. The amount awarded by the Court included $1,308,462 that consisted of holdbacks and extra works done where the price had been agreed upon, but not yet paid due to YEC's claims for set-off rights. The final cost of the claim dispute includes YEC legal fees of $0.962 million. Based on the advice of legal counsel, YEC has filed the necessary documentation to appeal the court decision.

#### 5.2.1.2 Aishihik Elevator Shaft Structural Steel Rehabilitation - ($3.937 million to end of 2015, plus $4.587 million in 2016 and $1.593 million projected in 2017)

Following the addition in 2011 of a second feeder cable in the Aishihik elevator shaft, the Yukon Workers Compensation Health and Safety Board required YEC to have an independent engineer[5] conduct a comprehensive evaluation of the installation to ensure the elevator meets all applicable codes, acts, and regulations. The engineering firm reviewed the elevator structural frames and support system in 2013 and observed degradation of the steel integrity. The report recommended permanent rehabilitation of the structure and a list of conditions imposed on the use of the elevator to provide a reasonable margin of safety until the work is completed. Since regular elevator access to the underground generator floor is required for continued operation of the plant, and the plant is critical to the operation of the Yukon Integrated System, there was no reasonable alternative to completing this project.

The project was executed over two summers during the window when the facility can be taken off-line for major maintenance work. The work performed included the removal and re-installation of the elevator shaft cladding, drilling of rock anchors to support the new steel, installation of new steel columns and beams, and the removal of the old steel.

[5] KGS Group, January 2014.

The project is forecast to be completed in 2017 with a forecast cost of $10.116 million. These costs will be depreciated over 72 years and are broken down as follows:

- Engineering and Design - $0.487 million;
- Construction Field Costs - $8.036 million;
- Construction Management - $1.280 million; and
- YEC Owners and Financing Costs - $0.313 million.

#### 5.2.1.3 Aishihik Electrical and Control Upgrades – ($0.887 million by end of 2016, $1.284 million in 2017 and $0.340 million in 2018)

The Aishihik Control Systems and Electrical Upgrades project includes a number of specific control systems and electrical upgrades that are being undertaken to ensure ongoing safe and reliable operation of the Aishihik Generating Station. Approximately $2.511 million of upgrades are planned to be completed before the end of 2018.[6]

In 2014, a formal asset assessment was completed by KGS. The asset assessment as well as recent plant inspections in 2015 confirmed the need for this project as follows:

- Many of the electrical and control systems in the Aishihik plant have reached end of life and need to be replaced; and
- Existing control systems lack the functionality to optimize plant operations (e.g., the original controls feature analog gauges that lack the accuracy to run optimally). The replacement and upgrading of these control systems will modernize the interfaces, improve trouble-shooting capability and provide better information on the operating state of the equipment.

A project to replace equipment and complete a number of specific associated plant control system upgrades and electrical upgrades was developed for execution over multiple years, with most of the upgrades planned to be completed in 2017 and 2018. The need for each planned upgrade (based on currently available upgrade options) was addressed versus the do-nothing alternative. Given the current

[6] The AH3 Control System Replacement upgrade will complete certain upgrades in 2017, and include some additional work after 2018.

importance of reliability for this plant (i.e., the Aishihik plant and transmission constitute the N-1 single contingency event for the Yukon Integrated System, and this system currently has a shortfall of dependable capacity based on the N-1 capacity planning criterion), Yukon Energy has placed priority on ensuring these upgrades are completed in the near term. Each specific upgrade comes into service (and into rate base) when it is completed.

**Control system upgrades:** The project includes the following five specific control system upgrades, with a total of approximately $1.904 million forecast capital costs for upgrades to be completed in 2017 and 2018:

- ***AH1 & AH2 Control System Replacement ($1.489 million)*** – AH1 and AH2 control systems are at end of life and need to be replaced. Equipment failure could result in extended unit outages as the existing equipment is outdated and replacement parts and technical support are difficult to procure. The units also operate at different levels of visibility with different operating procedures, making troubleshooting difficult and creating operational and reliability risks. System replacement will modernize the AH1 and AH2 control systems to the same standard. Spending to date approximates $0.350 million on AH1 and $0.359 million on AH2. Forecast spending in 2017 of $0.390 million on each of AH1 and AH2 will complete the work at a final total cost of $0.740 million for AH1 and $0.749 for AH2.

- ***AH3 Control System Drawings Update*** **($0.025 million)** – This project will review operator interfaces and correct the existing drawings to safely operate the equipment in anticipation of a full control system replacement in future years.[7]

- ***AH0 – Turbine Inlet Valves (TIV) Automation*** **($0.190 million)** – This project entails the installation of an electrical control system to enable remote operation of the AH hydro generator TIVs. At present, the valve of the Aishihik hydro plant cannot be closed automatically,[8] and in the event of an emergency, the plant operator must manually operate the valve directly adjacent to the turbine. This places the operator at risk in the event of flooding or a catastrophic mechanical failure of the unit. Automation of the TIV valve will improve response time and allow for remote control without putting personnel at risk. The TIV automation system is planned to be installed at the same time as the AH1 & AH2 control system upgrades to take advantage of a single plant

[7] While the AH3 control system was installed in 2011, and is a modern system that is still in good condition, numerous deficiencies documented during installation need to be corrected. The full control system replacement upgrade, planned in conjunction with the next scheduled overhaul in 2021 at a forecast cost of $0.550 million, will also bring the unit in line with AH1 and AH2 in terms of functionality and interface.

shut-down and to minimize down-time. Work is forecast to be completed in in 2017 at a cost of $0.190 million.

- ***Aishihik Human Machine Interface (HMI) Installation ($0.175 million)*** – HMI is a software application with associated field displays that provides information to plant operators regarding the state of a process, and allows operators to enter instructions in the field. Forecast spending in 2018 of $0.175 million is intended to tie the new AH1 and AH2 control systems installed during 2017 into an HMI system, including a data historian for the entire AH plant. This will provide better visibility of plant operating conditions and improve the ability to investigate and troubleshoot plant operating issues.

- ***Aishihik Remote Terminal Unit (RTU) Replacement[9] ($0.025 million)*** – The RTU that serves the AH1 & AH2 control systems was installed in 1975 and lacks the features and functionality of newer systems. Forecast spending of $0.025 million for 2017 will transfer controls for the AH1 & AH2 units to the more modern RTU for AH3 (installed in 2011) and remove the original RTU serving AH1 and AH2. This will reduce resources required to monitor and control all three Aishihik units.

**Electrical Upgrades:** The project includes the following six specific electrical upgrades, with a total of approximately $0.607 million forecast capital costs for upgrades to be completed in 2017 and 2018:

- ***Motor Control Centre (MCC) Equipment for AH0 Station Service*** **($0.243 million)** – The MCC controls key auxiliary systems (e.g., pumps, governors, etc.) at the Aishihik hydroelectric plant. The existing MCC is at end of life and has had operational issues. A new MCC was purchased in 2015 and will be installed in 2017. As failure of this equipment could result in a plant shutdown, installation of a new MCC will increase operational reliability and safety for maintenance personnel. Approximately $0.150 million has been spent to date. Forecast spending of $0.093 million in 2017 will complete the work at a final total cost of $0.243 million.

- ***Aishihik Grounding Refurbishment*** **($0.045 million)** – Improper grounding is a critical safety risk for personnel. The Asset Assessment Study completed in 2014 identified that some grounding is missing in the Aishihik substation; other grounding in the substation is broken after

[8] This issue was identified in the 2014 Asset Assessment Study.
[9] A remote terminal unit (RTU) is a microprocessor-controlled electronic device that interfaces the AH units with YEC centralized SCADA control system. Data is transmitted to SCADA and electronic directions from SCADA are translated to operate the generation equipment.

years of wear or corrosion. Work undertaken in 2017 will verify and improve grounding to address these safety or equipment hazards. Work is forecast to be completed in 2017 at a cost of $0.045 million.

- ***S167 Porcelain Insulator Change Out*** **($0.079 million)** – The existing 138 kV porcelain insulators in S-167 (AH0) substation (48 units) are of an older vintage and show signs of cracking and failing. The failure of a single insulator has the potential to cause a plant-wide outage. New insulators were purchased in 2016 at a cost of approximately $0.031 million and are planned to be installed in 2017. Work is forecast to be completed in 2017 at a final total cost of $0.079 million.

- ***AH Reactor Cable Replacement*** **($0.075 million)** – During the AH3 project in 2011 the cables between the breakers and reactors within the S-167 (AH0) substation were replaced. However, the new cables are undersized and need to be replaced. There is a risk that constant heavy load between the reactors and breakers will eventually result in a cable failure which could damage equipment and cause an unscheduled outage of the Aishihik hydro plant. This work is scheduled to be undertaken at the same time as the S167 Porcelain Insulator Change Out project when the substation will be taken out of service. Work is forecast to be completed in 2017 at a cost of $0.075 million.

- ***AH3 Lube Oil Pump Battery Installation*** **($0.090 million)** – A battery bank needs to be installed to serve the lubricating oil pump for the AH3 hydro unit. The lube oil pump is critical for operation of the hydro unit, and must be operational for the AH3 unit to operate. Isolating this pump onto its own backup power supply would enable AH3 to operate independently from the main AH0 backup battery bank, reduce the drawdown and extend the life of the main AH0 backup battery bank during a station service outage. Failure to install this backup increases the risk of the AH0 backup battery bank being drawn down too quickly, which could compromise the ability to recover the AH plant following an extended outage. Work is forecast to be completed in 2018 at a cost of $0.090 million.

- ***Aishihik Black Start Modifications*** **($0.075 million)** – The black start generator of the Aishihik plant can be improved in order to take on additional loading to run more efficiently when it is called into service. It would also be beneficial to increase the number of Aishihik station services served by the black start generator. This project will involve first determining the optimal underground station services that could be shifted to the black start diesel, then performing the work to physically relocate them to the centralized underground station service points supported by the black start diesel. Work is forecast to be completed in 2018 at a cost of $0.075 million.

#### 5.2.1.4 Communications Upgrades – ($0.113 million by end of 2015, $0.135 million in 2017, and $0.755 million in 2018)

The Communications upgrades project includes a number of specific communications network upgrades that will replace end of life communication network infrastructure with new technology and implement a simplified network infrastructure which will increase performance and improve reliability of the network. The new network environment will also support other modernization projects that may be undertaken in the future (e.g., Smart Grid Technology). Approximately $1.003 million of upgrades are planned to be completed by the end of 2018.

Communication systems allow YEC to monitor and control generation and substation equipment from the System Control Centre (SCC) in Whitehorse.[10] Loss of communications with YEC operating facilities increases the risk to the overall operation of these assets and the electrical system as a whole, and a failure of part or all of YEC's communications network can result in:

- Inefficient operation of the system and increased costs to ensure adequate system security;[11]
- Employee fatigue and related safety concerns associated with extended working hours;
- An increase in outage restoration times and potential impacts on public safety;
- Increased risk of equipment failure and/or damage due to the inability to properly monitor the generation facilities; and
- Environmental risks linked to the loss of communications to the facilities (e.g., ramping protocols (fish stranding), flooding and release or oil-based lubricants).

In 2016, an independent consultant completed a Communications Needs Assessment[12] and made recommendations to improve critical elements such as Supervisory Control and Data Acquisition (SCADA) system features, and improve network performance, reliability, redundancy and security. A proposed

[10] YEC operates three hydro facilities, four thermal generation sites, and numerous substations and switching stations that are remotely monitored and controlled from the SCC. While these facilities can be operated locally by YEC operations staff, YEC does not have the necessary personnel required to deliver sustained 24/7 coverage that can be provided by SCC and the associated communications network.

[11] For example, in the absence of communications with hydro plants, operators can be forced to shut down hydro to protect the asset. This lost generation may require thermal support.

[12] This work was completed by BBA in June 2016. It included an analysis of the current network and communications infrastructure, a description of the available replacement technology and the optimization of the Operations Technology (OT), and Information Technology (IT) network infrastructures operated by YEC.

system design was provided with recommendations for staged implementation focusing on the most critical assets or initiatives first, and progressing towards the less critical ones, with the eventual goal of covering the whole YEC communications system.

A project to replace communication network infrastructure and complete a number of specific communications upgrades was developed for execution over multiple years, with some of the upgrades planned to be completed in 2017 and 2018. The need for each planned upgrade (based on currently available upgrade options) was addressed versus the do-nothing alternative. Each specific upgrade comes into service (and into rate base) when it is completed.

The project includes the following specific upgrades to the communication system, with a total of approximately $1.003 million forecast capital costs for upgrades to be completed by the end of 2018:[13]

- ***Satellite Installations for SCADA ($0.150 million)*** – This upgrade is a key building block towards the creation of a fully redundant communications infrastructure as required for enhanced system reliability and efficiency. Installations planned for Dawson City, Faro and Carmacks will provide redundancy for network access to these remote sites, and result in quicker response times, reduced system outages and increased reliability at these sites (third party network service providers do not provide 24 hour response). Satellite connections will also provide an Internet Protocol (IP) backbone allowing YEC to run many new services and protocols to these sites when compared to the existing serial links. This work, which is planned for Dawson City in 2017 and Faro and Carmacks in 2018, has forecast expenditures of $0.050 million in 2017 and $0.100 million in 2018.

  If this work is not undertaken, YEC will be forced to rely on old technology which is harder to support and will not scale to meet new communications needs. Absent implementation, the risk of service outages and/or difficulties increases.

- ***Network Access Controls ($0.035 million)*** – This upgrade involves the implementation of automated network access protocols to control access by any device attempting to gain access to the network, and is required to mitigate access risks that will result from new IP technologies proposed in the Satellite Installations for SCADA project. In the absence of network access controls, YEC's communications system would be permanently locked down, and access would

[13] SCADA communications upgrades include $0.275 million forecast spending after 2018. Disaster Recovery Site upgrade is forecast after 2018 at a forecast cost of $0.250 million.

require manual intervention by IT staff on a case-by-case basis. This would significantly compromise effective delivery of services due to finite IT resources available. The upgrade is to be completed in 2017 at a forecast cost of $0.035 million.

- ***Community Servers ($0.050 million)*** – This upgrade involves the installation of servers in YEC's offices in Dawson and Mayo, to act as a physical hub from which YEC IT support can locally or remotely deploy software and provide enhanced computer services and resources. In the absence of this project, support would require IT staff to drive to the affected community, or (depending on the issue) would require the user to ship their hardware to YEC's head office in Whitehorse for service. The upgrade is to be completed in 2017 at a forecast cost of $0.050 million.

- ***Fibre Communications Upgrades ($0.363 million)*** – This project involves installing a fiber optic link from WRGS to Takhini Substation ($0.200 million), MacIntyre Substation ($0.030 million) and Kulan Warehouse ($0.020 million). The fiber connection will allow for more reliable and flexible communication as well as creating the backbone for a redundant data centre at Takhini Substation planned for 2019. $0.113 of spending occurred in 2015 to install a fiber link at WRGS between SCC, Riverside substation (S171), WH4, and the fish ladder.

- ***SCADA Communications Upgrades ($0.405 million in 2018 and $0.275 million thereafter)*** – The current SCADA infrastructure uses serial communication through the Whitehorse System Control Centre which significantly limits operational flexibility and redundancy. This project includes the installation of the required networking equipment to support Multiprotocol Label Switching (MPLS) and satellite communication at the following locations:

  - Aishihik - $0.200 million;
  - Mayo, Stewart, and surrounding area - $0.070 million;
  - Whitehorse area - $0.050 million;
  - Faro, Pelly Crossing, Dawson, and Takhini - $0.085 million; and
  - Carmacks, Minto and Takhini - $0.275 million (2019).

#### 5.2.1.5 Hydro Unit #WH4 Overhaul – ($0.591 million by end of 2016, $3.700 million in 2017)

The Whitehorse #4 (WH4) hydro unit (20 MW installed capacity commissioned in 1984) is a critical hydro generation asset to YEC. As part of YEC's on-going preventative maintenance program for hydro units, a 10 Year Major Overhaul of the WH4 hydro unit is scheduled for spring 2017 (from April to June) at a forecast total cost of approximately $4.3 million ($3.7 million forecast in 2017).

This overhaul requires that the unit be removed from service in early April 2017. All unit components will be disassembled and inspected and standard maintenance and repairs will be performed as required. The 10-Year Major Overhaul will also include any additional "discovery" work associated with the unit that cannot be identified until the unit is dewatered and a full inspection is performed. This inspection may identify repairs required to electrical or mechanical components of the unit or the surrounding supporting infrastructure that enables the unit to function (i.e., stator, governor or headgate systems; bearings, draft tubes, wicket gate repairs etc.). The forecast cost in 2017 for the 10-Year Major Overhaul is approximately $1.9 million, including $0.978 million intended to cover a variety of potential contingency events ranging from overruns on key contracts, significant additional "discovery" work and/or thermal generation costs due to extension of schedule.

During the 10-Year Major Overhaul process the following two additional replacement activities related to the WH4 hydro unit will also be undertaken as part of this project.

- ***WH4 Rotor Spider Replacement*[14] *– ($1.439 million)*** – Stress cracks, which required immediate and extensive repair, were observed on the rotor spider during overhauls and inspections performed in 2007, 2012 and 2016. The original equipment manufacturer (OEM), Andritz Hydro, has confirmed that the original rotor design is flawed and recommended that during the next overhaul YEC install a new replacement rotor spider of more durable design in order to improve the long term reliability of this unit. The OEM has confirmed this new design has been successfully implemented in other plants with similar issues.

[14] The rotor spider is the main component within a hydro generating unit and is responsible for generation of energy and for stopping (braking) the unit while operating.

- ***WH4 Excitation Replacement[15] – ($0.977 million)*** – Technical support and parts to maintain the existing excitation system are becoming more difficult to procure. In 2014, two outages of WH4 occurred.[16] The post-event analysis of these outages resulted in a recommendation to replace the WH4 excitation system. Subsequently, another outage occurred on February 18, 2017 that was a direct result of a failure of a component of the MH4 exciter.

YEC has awarded a contract to Andritz Hydro (the original equipment manufacturer) to install the new rotor spider and to perform the 10-Year Major Overhaul. Andritz will be responsible for providing technical advisory services and for overseeing the mechanical services contractor performing the work.

- Detailed design for the new rotor spider was completed in 2016 and it is currently being fabricated. The rotor spider was delivered to site in April 2017. Installation of the new spider will take place during the WH4 10-Year Major Overhaul scheduled for April through June 2017.

- In 2016, YEC tendered contracts for the detailed design and the manufacture and supply of a new excitation system. The supply contract was awarded in December 2016 and was delivered to site in April 2017. In early 2017, a separate contract was issued for installation of the new excitation system to take place during the WH4 10-Year Major Overhaul scheduled for April through June 2017.

#### 5.2.1.6 Hydro Unit #MH2 Overhaul - ($0.002 million to end of 2015, and $1.655 million in 2018)

The Mayo #2 (MH2) hydro unit (2.55 MW installed capacity commissioned in 1952 at the Mayo A facility) was fitted with new runners in 2002 and is currently rated at 2.9 MW. A 10 Year Major Overhaul of the MH2 hydro unit and general facility upgrades is scheduled in 2018 at a forecast total cost of $1.655 million.

The last ten year overhaul of MH2 was performed in 2002 – approximately 15 years ago. Due to the recent addition of the more efficient Mayo B units, only one of the two Mayo A units can now be operated at any one time when both Mayo B units are in operation. Accordingly, the MH2 unit has not been run on a full-time basis since 2011 and this has deferred the requirement for a major overhaul beyond the

[15] The excitation system controls the energy created by the hydro unit and is also integral to ensuring the quality of that energy.
[16] On April 15, 2014, a failed governor PLC resulted in an outage affecting 1,563 customers. On May 2, 2014, a failed governor PLC resulted in an outage affecting 842 customers.

normal 10 year period. 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.

As reviewed in the 2016 Resource Plan (Chapter 5), a study of four options for the future of the Mayo A facility was completed for Yukon Energy by KGS Group in 2016 to address the fact that many components in this facility were coming to end of life. A conceptual, high level cost estimate and economic analysis was prepared for each option (i.e., replacement, refurbishment, removal of the facility with return of site to near greenfield condition, and decommissioning of the facility with abandonment in-situ). This study found that the optimal solution in terms of the cost and energy generation would be to replace the existing two units with a new single 2.3 MW unit. The 2016 Resource Plan action plan assumes that this Mayo Hydro Refurbishment project will proceed for in-service in 2022.

Given that continued operation of the Mayo A facility has been determined to be economic, the 10-Year Major Overhaul and upgrades of MH2 are required to enable ongoing operation prior to the full Mayo Refurbishment. The overhaul and upgrades related specifically to MH2 involve the following:

1. 10-Year Major Overhaul - this includes:
    a. A complete tear-down of the unit, inspection and replacement or refurbishment where necessary;
    b. Cleaning of the stator and rotor as required; and
    c. Reassembly, alignment, and commissioning of the unit to manufacturer's specifications.
2. MH2 Upgrades - these upgrades, which will be completed while the unit is out of service, include:
    a. Addition of vibration monitoring equipment and shear pin breakage sensors, allowing SCC to remotely detect problems with the unit in the absence of an operator;
    b. Thrust block replacement, which was identified for replacement during a 2008 disassembly; and
    c. Installation of a lift pump for the rotor, preventing unnecessary starting and stopping of units when generation is not needed. This will also ensure an oil wedge between the rotating components and help to prevent catastrophic mechanical failure.

The planned overhaul and MH2 upgrades will result in improved reliability (reducing the likelihood of unplanned outages through to the planned rebuild of this plant in 2022), increased asset life, and a reduced risk of major equipment damage.

The following upgrades are also planned to be undertaken at the Mayo A hydro facility (this work will be coordinated with the work specific to MH2, and will have continuing value for the future planned refurbishment of the Mayo A facility):

- Assess, design, and install a fire suppression system for the generators (currently no system);
- Various building upgrades – based on a 2014 report by an external party, a number of repairs are required to the 1950’s era powerhouse building (roofing, HVAC, concrete, etc.);
- Inspect, sand-blast, and paint spiral cases;
- Certify turbine inlet valves as a single point of isolation in order to allow maintenance on other parts of the system;
- Installation of sediment separator to avoid clogging of the cooling water filters; and
- Installation of generator isolation links to allow for modern, safe isolation practices.

#### 5.2.1.7 T&D – Breaker Replacements – ($1.35 million by end of 2018)

This project consists of two sub-projects to procure both medium voltage and high voltage breakers used in YEC's substations. In both cases the breakers were installed in 1970's, and 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.

1. Replacement of 5 medium voltage (34.5kV) breakers in YEC substations S150(4) and S176(1): the sub-project to replace the medium voltage breakers will be initiated in 2017 with procurement of one spare breaker that will be installed in 2018 and other breakers procured in 2018 and installed in 2019.
2. Replacement of 7 high voltage (138kV) breakers in YEC substations S171(3), S164(2), S167(1) and S146(1): this sub-project will be initiated in 2018 and possibly completed in 2018 subject to lead time for these high voltage breakers.

This project will be capitalized as the breakers are replaced and put into service. The high voltage breaker replacement program will be completed in 2019 with an annual cost of $1.5 million.

Replacement of these assets will also result in O&M savings estimated of about $30,000 every 3 to 5 years. New breakers have similar maintenance cycles but generally only require testing along with some minor lubrication and tightening of components. This is within the capabilities of YEC staff and is expected to only take a few hours per breaker.

#### 5.2.1.8 T&D - Line Replacement – ($2.0 million in 2018, work continuing to 2022 at total cost of $11.5 million)

This project addresses replacement of key components of the following YEC transmission lines which are approaching the end of their economic life:

| Line # | Route | Install Date |
|---|---|---|
| L170 | Takhini Sub to Carmacks | 1968 |
| L171 | Aishihik plant to Takhini Sub | 1975 |
| L178 | Carmacks to Faro | 1968 |

Certain components of these lines have begun exhibiting higher failure rates; for example:

- May 2015, L170, cross arm failure; and
- October 2015, L178, insulation failure (resulting in structure fire).

Based on these events, YEC commissioned external asset assessments of the key backbone lines on the integrated system as noted above. These assessments have indicated that a large number of cross arms and insulators are at end of life and a have a high risk of failure. This 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. Forecast spending in the 2018 test year is $2.0 million.

The following are the key elements of this project:

- **Insulator Replacements ($0.75 million in 2018) –** This element will replace all 1968 vintage insulators based on the condition of the structure.[17] End of life structures will be replaced in their entirety. Structures that are in good condition but over 40 years old will receive composite type insulators that have an expected life of 25 years (aligning with the remaining life of the structure). New structures will receive glass insulators which have an estimated life of over 40 years.

- **Crossarm Replacements ($1.25 million in 2018)** – This element will replace tangent and snow shed crossarms.

  - **Tangent Crossarm Replacements** – This element will replace single wood crossarms with steel crossarm structures, focusing on longs spans, crossing structures (roads and water), and structures having crossarms in poor condition (knots, checks, or splitting). A condition assessment[18] and strength evaluation performed on a sample of 138kV crossarms in service since 1968 indicates that these structures require replacement at this time. YEC will conduct a line inspection to determine a priority list for replacement over the budget years 2018 and 2019. Individual structures will be placed into service at completion.

  - **Snow Shed Crossarm Replacements** – These structures are found on sloped terrain and have an angled crossarm design that leads to premature deterioration of the wood where snow and water collect. This deterioration was demonstrated in 2015 when a failed snow shed arm resulted in a fire on the line between Whitehorse and Carmacks. A subsequent assessment[19] determined that the cross arms on this structure design are exhibiting signs of age. This project will replace all current structures of this design type with a longer downhill pole and steel tangent crossarms. A number of the structures that require replacement are located in terrain that is difficult to access and will result in significant costs.

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[17] An investigation into a 2015 structure fire on Line 178 between Carmacks and Faro found the cause to be a failed 138 kV insulator. Based on tests performed on a sample of insulators, it was found that 20% failed combined electrical and mechanical load tests (Powertech Labs Inc., July 2016).
[18] PowerTech Labs Inc., February 2015.
[19] PowerTech Labs Inc., June 2016

The alternative to proceeding with this project is to respond to structure and component failures as they occur. This may lead to significant reliability impacts as well as higher overall costs. Employee health and safety risk is also much higher for emergency response work compared to planned maintenance activities.

#### 5.2.1.9 Wareham Spillway Gate Hoist Replacement – ($2.700 million to end of 2015)

The hoist at the Mayo dam in Mayo was determined to be at end of life though both internal review and external assessment.[20] The project replaced the hoist, taking into consideration current operational requirements.

Water from the Wareham dam in Mayo is controlled by two 15 ton spill-gates and a common intake feeding four hydro generation units. This gate control system dates from the early 1950s when the Mayo A plant and dam was originally installed. It was designed and installed in an era when the spillway did not have to be operated in the winter; the gates were simply allowed to freeze in and operation of the hoist was unnecessary for half of the year.

Due to changes in how YEC manages water at this facility and the current Fisheries Act Authorization (FAA), the company must have operational control of the gates throughout the year. With Mayo B now in full operation, the water level in Wareham Lake is kept very close to its full supply level to ensure that optimal generation is achieved (i.e. the penstock remains full). Therefore, YEC has significantly less time to respond to potential overflowing of the spillway due to unit shutdowns or larger than expected inflows from upstream. Based on the age of these units and these current requirements, the hoist was determined to be at end of life though both internal review and external assessment.

Options considered to replace the hoist included an updated version of the cable system in use at the time as well as a screw-lift or rack & pinion system. The screw-lift system was chosen for a number of reasons including the more responsive and reliable gate action, as well as the ability to automate the operation of the gate in order to allow control by System Control in Whitehorse. The remote operation of the gate is important due to the water level that the forebay is regularly kept at as well as maintaining downstream flow changes within FAA limits.

The project was completed over the course of two years, with fabrication beginning in 2014 and final installation taking place during the summer of 2015. The total cost for this project is $2.7 million.

[20] International Quest Engineering, March 2014.

#### 5.2.1.10 Whistle Bend Supply/Takhini Upgrade - ($11.383 million to end of 2015)

The 2012/13 GRA 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. The approach to interconnection was not determined at that time and it was noted that Yukon Energy was working with the developer and ATCO Electric Yukon (AEY) to determine an approach to connecting the subdivision to the grid that would ensure adequate supply and overall system reliability and protection.

The project required that a new distribution supply source be established in the area; and the Takhini Transmission Switching Substation was identified as the preferred location due to its proximity to Whistle Bend, its connection to the Aishihik Generation Plant, and the ability to provide an alternate reliable supply source to Whitehorse. Additional upgrades to the Takhini Substation were also required in order to increase reliability and provide for future customer loads. Improvements included the construction of a 138 kV ring bus, installation of new substation station service, and remediation of several equipment deficiencies identified in a prior asset condition assessment performed by an external party.

Work was completed over three years with final connection to AEY occurring in early 2015. Total project costs were approximately $11.4 million which was over $0.6 million less than the original budget amount. The favourable budget variance was the result of effective use of internal YEC staff, as well as the installation of a substation bypass which enabled reduced diesel generation and greater schedule flexibility.

#### 5.2.1.11 LNG Plant - ($41.933 million cost to the end of 2016, less no cost capital contribution of $18.3 million)

The LNG Plant project at the Whitehorse Thermal Generating Station (WTGS) came into service July 1, 2015 with two new natural gas engines (8.8 MW), provision for a third natural gas engine, and liquefied natural gas (LNG) offloading, storage, vapourization and other related infrastructure.

The Whitehorse Diesel-Natural Gas Conversion Project (the "LNG Plant" project or “LNG Project”) was undertaken to maintain Yukon Energy's capacity requirements for the Yukon grid. The project was proposed to modernize Yukon Energy's WTGS to meet growing requirements for reliable and flexible thermal generation on the Yukon grid, with conversion of WTGS thermal generation units scheduled for retirement from diesel fuel to cheaper and cleaner-burning natural gas fuel supplied by truck from Alberta or British Columbia.

### Prior YUB Review

The LNG Plant project was reviewed by the YUB as a supply planning project in the 2012/2013 General Rate Application and in the 2014 project-specific review under Part 3 of the *Public Utilities Act* (Part 3 hearing). The project as ultimately reviewed by the YUB in 2014 included the following key elements:

- Acquisition of approximately 0.9 ha of Public Utility zoned Yukon Government lands and creation of access and utility crossings at various locations along the 0.6 ha of privately held railway right of way adjacent to the south of the existing WTGS site (the "Expanded Site Area").

- Replacement of two Mirrlees diesel generating units scheduled for retirement in the existing WTGS by 2015 (9.1 MW total nameplate capacity) with up to three new modular natural gas-fired generating units (13.1 MW total capacity), and the installation of LNG truck offloading, storage, vapourization and related infrastructure (including transformers) on the Expanded Site Area plus gas line connection to the existing diesel plant to combust boil off gas in the diesel plant boiler and to facilitate potential future LNG fueled generation options at this facility.

- The two natural gas-fired units (8.8 MW total capacity) were anticipated to be in service before the end of Q4 2014 to provide capacity and fuel cost savings during the winter of 2014/2015, with an estimated capital cost (2013$) of $36.5 million. The third unit was planned to be installed as required to meet grid capacity planning requirements at a capital cost of $5.5 million.[21]

- LNG was to be supplied initially by truck from the FortisBC at Tilbury (Delta BC), until such time as a lower cost source of LNG is available.

### Update on Final Costs

The final completion costs for the project were approximately $41.933 million.[22] However, the net impact of the project on ratebase is considerably lower due to YDC contributions of $18.3 million that were applied to the LNG project in 2015. This reduces the total project costs funded by ratepayers to $23.63 million.

The costs reviewed during the Part 3 hearing and the final costs on completion of the project are reviewed below.

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[21] Capital cost estimates and feasibility assessments as updated by YEC during the LNG Project Part 3 proceeding (Exhibit B-13).
[22] Includes $1.071 million spending in 2012; and $40.862 million spending between 2013 and 2016 as shown on Table 5.2.

The capital cost estimate of $36.48 million (per the Part 3 hearing filing; see response to YUB-YEC-1-1(d) in that proceeding) was prepared in late January 2014 when the project was in the midst of the Yukon Environmental and Socio-economic Assessment Board (YESAB) Executive Committee regulatory review. This phase 1 cost included installing two engines (8.8 MW) and other project activities (excluding only the third engine). These estimates were based on the current regulatory review process filings, final site configuration, contractual costs for selected key long lead equipment (two GE engines [Gas Drive], three LNG storage tanks [499.5 m3 total capacity], skid mounted vapourization and related equipment and transformer), updated site layout design, and contractual costs for Project Management and Project Engineering. Contingencies of $1.45 million were included, with $1 million for construction contracts (primarily for the untendered civil, mechanical and electrical contracts estimates at $6.8 million as part of the Site Development costs) and the balance for Engineering, Project Management and Owners Costs.

Subsequent to the YUB review in April 2014, the project experienced unexpected major delays and changes arising from the YESAB review process and the Yukon Oil & Gas Act (YOGA) permitting. All permits required to start construction on the project were secured as of July 11, 2014 - almost two full months beyond the mid-May expected construction start identified in February/March submissions to the YUB. Several regulatory parties contributed to these delays, including YESAB (YESAB Final Report delayed over a month until June 10, 2014 versus the May 8, 2014 date anticipated as late as April 2014), the Yukon Government Decision Body (Decision Document took a month after the YESAB Final Report, until July 7, 2014 versus the May 15, 2014 date anticipated as late as April 2014), the YOGA permitting process, and cabinet (approval of the OIC revising the boundary of the Chadburn Lake Park reserve as needed to allow the project to proceed).

The YESAB Final Report and YOGA permitting process also introduced new requirements not anticipated based on the YESAB Draft Screening Report, including added risk assessments and material site layout design changes to accommodate YOGA permitting in particular. These added requirements and the material delay in construction start resulted in the multi-month delay of project in-service and a range of added costs (including added construction costs related to delays into the winter season).

A summary of the $5.45 million increase (14.9%) in the final project capital cost over the Part 3 hearing January 2014 cost estimate of $36.48 million is provided below:

1. **Construction Contracts** – $4.09 million increase over Part 3 hearing estimate of $27.5 million:

    - Increased costs were incurred for Site Development ($4.96 million increase over the $6.78 million Part 3 hearing estimate) and LNG Engines ($0.67 million increase over the

$10.95 Part 3 estimate), fully utilizing the $1.0 million contingency included in the Part 3 hearing estimate.

- Added Site Development costs reflect the impact of final tendering costs for this work, construction start delay, added regulatory requirements for the impoundment pit and vapour fence, higher than expected costs for impoundment pit dewatering and for piling, added costs for fire protection water line excavation and a fire water diesel pump and enclosure, design changes to the glycol loop, and added costs for commissioning.

- Added LNG Engines costs mainly reflect added costs to remove the glycol loop, and costs arising from delays in construction and permitting requirements.

- Decreased costs of $0.55 million occurred for other LNG Plant Equipment and Grid Connection (Part 3 hearing estimate of $8.78 million).

2. **Engineering & Management** – $1.54 million increase over Part 3 hearing estimate of $3.48 million:

- These increased costs were incurred mainly for Detailed Engineering ($0.914 million increase over the $1.24 million Part 3 hearing estimate) and Project Management ($0.77 million increase over Part 3 hearing estimate of $2.62 million), fully utilizing the $0.20 million contingency.

  - Added Detailed Engineering costs mainly reflect increased engineering for permitting, resulting changes required to site layout, design and construction support to completion, glycol loop redesign, procurement and quality assurance activities.

  - Added Project Management costs mainly reflect cost arising from project schedule extension and higher than estimated site development costs.

3. **Owners Costs** – $0.6 million increase over Part 3 hearing estimate of $2.43 million:

- These increased costs were incurred mainly for YEC labour ($0.53 million increase over the $0.62 million Part 3 hearing estimate) and AFUDC ($0.13 million increase over the $0.45 million Part 3 hearing estimate).

4. **Planning & Permitting** – $0.18 million increase over Part 3 hearing estimate of $2.51 million, reflecting added costs arising from the permitting and other issues (note that some costs are subsequently removed from this category – see #6 below).

5. **Demolition** – Decommissioning and removal of WD1 and WD2 (Part 3 hearing cost estimate of $0.55 million) has been redefined as a post project construction activity that is not required to operate the new facility. This work will now be conducted in the future when it is necessary and cost effective (which was anticipated to be when WD3, the third Mirrlees diesel, is decommissioned and removed).

6. **Other Activities** removed from the above actual LNG Plant costs ($0.42 million):

   - **LNG Transportation Costs ($0.33 million)** – covered work by YEC toward the design and regulatory approval of a King B trailer for increased LNG haul unit volumes (at 85-90 $m^3$ versus 40-50 $m^3$ with existing units). This activity has been moved to Feasibility Studies as this work has been on-going and was not completed when the LNG Plant project came into service.

   - **First Nation Benefits ($0.09 million)** – these costs are to be paid by YEC with offset funding from YDC.

The Yukon Government contributions of $18.3 million that were applied in 2015 to the LNG project more than offset the added costs incurred since the Part 3 hearing estimate and result in a final LNG Plant project cost of $23.63 million. Provided that the third natural gas engine cost is (as expected) less than $9 million, the resulting final LNG Plant project cost with three natural gas engines will be less than the new 13.4 MW diesel plant option cost of $32.7 million estimated in the Part 3 hearing.

#### 5.2.1.12 LNG Third Engine – ($0.21 million to end of 2016; $3.04 million in 2017 and $2.70 million in 2018; project to be completed in Q1 2019)

The LNG Third Engine project will provide a third natural gas-fired generation unit at the Whitehorse thermal plant of approximately 4.4 MW to assist in reducing the current capacity shortfall in a cost effective manner by early 2019.

The forecast capital cost for this project is approximately $6.2 million, with $3.04 million forecast in 2017 and $2.7 million forecast in 2018 (approximately $0.2 million was spent prior to 2017 for foundation work completed in the first stage of development, and the balance of approximately $0.5 million is forecast in Q1 of 2019).

The 2016 Resource Plan identified a dependable capacity shortfall for the Yukon Integrated System under its single contingency (N-1) capacity reliability criterion that approximates 6 MW in 2017, increasing to 10-11 MW by 2019.[23] Yukon Energy is required to provide sufficient dependable winter capacity to meet the single contingency capacity reliability criterion, i.e., there is no acceptable "do nothing" option given the need to maintain reliable service, and permanent solutions (rather than relying upon temporary options such as mobile diesel) are needed to address an ongoing and growing dependable capacity shortfall.

The 2016 Resource Plan identifies construction of the LNG Third Engine as one of the preferred options for addressing a portion of the dependable capacity gap in a cost-effective manner in the near term, i.e., for use by 2019. Other projects are also proposed to address the dependable capacity shortfall, including development of the Battery (4 MW) project near the Takhini substation to provide an Energy Storage System (ESS) by winter 2019/20, and development of additional new thermal capacity (the Thermal Plant project) as required as soon as is feasible (currently planned by winter of 2020/21).

Regulatory reviews have already been concluded for the LNG Third Engine project. The 2013/2014 regulatory review (YESAB and YUB Part 3 hearing) of the LNG Plant project addressed development of up to 13.1 MW of additional thermal capacity as required to remove capacity shortfalls, with the first two LNG units (approximately 8.8 MW in total) to be installed in 2014-15 and the third LNG engine to be installed when new grid generation capacity was next required.

YEC commissioned a small study in late 2016 to review options for commercially available gas-fired engines to meet desired performance requirements with the third LNG engine at the current LNG facility. The results of the assessment will support YEC's decision with respect to the selection of the single engine or multiple engines with total installed capacity of 4.4 megawatts, and confirm current costs and schedule for commercially available options.

The project to design, procure and install a third LNG engine will be completed mainly during 2017 and 2018, with the engine currently planned to be in service in Q1 2019. Other activities to be completed in

[23] The 2017/18 GRA Application Tab 2 includes a forecast dependable capacity shortfall on this same basis at 5.6 MW in 2017 and 6.9 MW in 2018.

2017 include preliminary engineering, development of equipment specification documents, grid impact study, detailed engineering and procurement of long-lead equipment.

### 5.2.2 Projects $100,000 to $1 Million

Growth in net rate base reflects ongoing need to refurbish old assets and improve grid reliability. Significant re-investment in existing infrastructure has been undertaken since 2013 to ensure that the Yukon integrated grid can continue to meet the unprecedented level of growth on the system in a safe and reliable manner.

This Application includes approximately $6.3 million of earlier deferred overhaul costs being bought into the property, PP&E capital works rate base as of January 1, 2017. No spending on overhauls is included for the test years.

Excluding overhauls, total spending on PP&E from 2013 to 2016 for projects less than $1 million averaged $6.770 million. The ongoing capital works spending on PP&E is forecast at $4.753 million for projects added to rate base in 2017 and $5.933 for 2018, as set out in Table 5.1 (with details in Table 5.2); forecast customer contributions related to these capital works is $0.400 million (excluding contributions for major projects) for each test year.

Appendix 5.3 provides descriptions for capital projects in excess of $100,000 and up to $1 million forecast to occur in 2017 and 2018. A summary by function of forecast costs for projects with less than $1 million forecast spending in the test years is provided below.

- **Generation Projects** ($1.065 million in 2017 and $1.094 million in 2018) – Generation project expenditures forecast in 2017 and 2018 include small projects under $100,000 in each year (totalling $0.409 million in 2017[24] and $0.194 million in 2018). There was approximately $8.260 million in spending on generation projects $100,000 to $1 million prior to 2017 (2013-2016).

  As reviewed in Appendix 5.3, spending on generation projects in the test years includes a number of civil works at Aishihik in response to a recent asset assessment as well as some electrical and control work at the WRGS.

[24] Includes $0.204 million on projects specifically identified in Table 5.2 as well as $0.205 shown as "Other projects under $100k".

- **Transmission Projects** ($1.615 million in 2017 and $1.625 million in 2018) – Transmission project expenditures forecast in 2017 and 2018 include small projects under $100,000 in each year (totalling $0.140 million in 2017 and $0.125 million in 2018).[25] There was approximately $5.710 million in spending on transmission projects $100,000 to $1 million prior to 2017 (2013-2016).

  Test year spending on transmission projects is focused primarily on upgrading both transmission lines as well as substations. This will result in an extended life for the WAF line along with improved outage protection throughout the grid.

- **Distribution Projects** ($0.500 million in 2017 and $0.715 million in 2018) – Distribution project expenditures in 2017 and 2018 include no routine spending on small projects under $100,000, although $0.025 million is forecast each test year for one project. Customer extensions are forecast at $0.475 million each year (net cost of $0.075 million forecast each year after contributions). There was approximately $3.102 million in spending on distribution projects $100,000 to $1 million prior to 2017 (2013-2016). In addition to customer extensions, test year spending on distribution projects is focused on cut-out replacement to increase employee and public safety as well as a voltage regulator automation project to improve system control response times.

- **General Plant and Equipment Projects** ($1.574 million in 2017 and $2.499 million in 2018) – General Plant and equipment project expenditures forecast in 2017 and 2018 include small projects under $100,000, in each test year (totalling $0.799 million in 2017 and $0.710 million in 2018).[26] There was approximately $7.171 million in spending on general plant and equipment projects $100,000 to $1 million prior to 2017 (2013-2016).

  As reviewed in Appendix 5.3, test year spending on general plant and equipment includes upgrades to a number of buildings and facilities in response to items identified in a recent asset assessment. Regular annual vehicle replacement spending is highlighted by the acquisition of a new truck and digger derrick for Dawson. The balance of spending is on communication improvements, hazardous material containment, Mayo staff accommodation, and critical spare parts.

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[25] Includes $0.050 million in each test year on projects specifically identified in Table 5.2; the balance is shown in Table 5.2 as "Other projects under $100k".

[26] Includes $0.499 million in 2017 and $0.455 million in 2018 on projects specifically identified in Table 5.2; the balance ($0.3 million in 2017 and $0.255 million in 2018) is shown as "Other projects under $100k".

## 5.3 DEFERRED COSTS

This section reviews (a) major deferred cost projects (projects over $1 million) and (b) other deferred cost projects between $100,000 and $1 million, undertaken by Yukon Energy since the 2012/2013 General Rate Application, focusing on the 2017 and 2018 period.

Deferred costs include feasibility studies for a wide range of projects (focused mainly on potential new generation or transmission options and includes the 2016 Resource Plan Update), continued relicensing work (for this Application, this grouping includes water licence renewal activities as well as water licence amendment projects, e.g., Mayo Lake Storage Enhancement Project),[27] regulatory work (includes DSM), and dam safety review work. Overhauls, which in prior GRAs were included as a separate deferred cost, are now included under PP&E capital works (see Table 5.2) as per new accounting regulations.

Deferred costs in rate base net of contributions approximated $11.1 million at the end of 2013 and are forecast at approximately $2.5 million at the end of 2016. Between the end of 2013 and the end of 2016, amortization and contributions (including a $4.135 million YDC contribution in 2015) more than offset additions to deferred costs for closed projects. Deferred costs in rate base are forecast at approximately $13.9 million at the end of 2017 and $15.0 million at the end of 2018, reflecting mainly the impact of approximately $13.9 million of deferred costs being transferred to rate base at the start of 2017 as a result of this Application (includes closing of projects as well as deferred costs carried over from the last GRA at direction of the Board, i.e., projects with deferred costs forecast at less than $1 million during 2012/13[28] and completion of the 2016 Resource Plan [$2.275 million]).

Deferred expenditures in WIP each year from 2013 to 2016 ranged between $2.9 million and $5.8 million. WIP deferred expenditures are forecast at approximately $4.5 million in 2017 and $15.5 million in 2018, reflecting, in particular, forecast spending on capacity-related projects.

The Application includes, as appendices to this section for approval by the YUB, Yukon Energy's Planning Cost Accounting Policy (Appendix 5.1) and DSM Accounting Policy (Appendix 5.2) to address amortization of these cost for regulated revenue requirement purposes.

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[27] The deferred cost tables in Tab 5 (Tables 5.3 to 5.8) continue (as per the 2012/13 GRA) to show the Mayo Storage Enhancement Project under "Relicensing" while the Marsh Lake Storage Enhancement Project is shown under "Feasibility Study". Both projects require relicensing of existing facilities; however, the Marsh Lake Storage Enhancement Project involves a number of other project mitigation works.

[28] YEC's Compliance Filing in June 2013 [Table 1.1-3] indicated that this direction resulted in approximately $3.734 million of deferred costs as at the end of 2013 being delayed for future review, including about $1.8 million of deferred overhauls.

### 5.3.1 Major Projects Over $1 Million

Deferred expenditure test year spending on major projects is focused on projects required to address sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance), investments to ensure sufficient dependable capacity for the integrated grid, and continued planning expenditures to meet other potential future generation and transmission requirements.

Approximately $9.8 million will be added to net rate base for major projects (i.e., projects with deferred costs over $1 million) by the end of 2018. One other major project has incurred approximately $2.8 million of rate base costs which are fully offset by contributions. An additional $27.5 million of deferred costs are forecast to be incurred in WIP for major projects by the end of 2018.

Each major project is reviewed separately below (see Tables 5.3 to 5.8 at the end of Tab 5):

- **Spending on Sustaining Capital**: No net rate base impact in test years. Net deferred costs in WIP by end of 2018 of approximately $2.899 million:
    - **Stewart Keno City Transmission Project** – ($2.807 million in rate base by end of 2016 for planning and permitting, with these costs fully offset by contributions).
    - **Aishihik Relicensing** – (forecast WIP cost of approximately $2.899 million by end of 2018 - project planned for completion in 2019).
- **Spending to address Capacity Planning Requirements:** No net rate base impact in test years. Net deferred costs in WIP by end of 2018 of approximately $13.067 million:
    - **Battery Project** – (forecast WIP cost of approximately $8.856 million by end of 2018 for planning, engineering, permitting, long-lead equipment procurement, civil work - project planned for completion in 2019).
    - **Thermal Plant Project** – (forecast WIP cost of approximately $4.211 million by end of 2018 planning, engineering, permitting, long-lead equipment procurement - project planned for completion in 2020).
- **Spending on planning to meet other potential Future Generation and Transmission Requirements:** 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 end of 2018 of approximately $11.512 million:

- **Demand Side Management (DSM)** – ($3.319 million net increase in rate base costs by end of 2018, excluding reductions due to amortization).
- **Resource Plan Update 2016** – ($2.004 million net increase in rate base costs by end of 2017, excluding reductions due to amortization).
- **Gladstone Diversion Project** – ($4.521 million net increase in rate base costs by start of 2017).
- **Marsh Lake Storage Enhancement Project** – (forecast WIP cost of approximately $8.156 million by end of 2018 - project subject to ongoing review, potential in-service by 2022).
- **Mayo Lake Storage Enhancement Project** – (forecast WIP cost of approximately $3.356 million by end of 2018 - project subject to ongoing review, potential in-service by 2022).

#### 5.3.1.1 Stewart Keno City Transmission Line Project (SKTP) – ($2.807 million forecast to end of 2016, all funded by contributions)

The Stewart Keno Transmission Line (SKTL) project will improve the electrical transmission infrastructure in central Yukon between Stewart Crossing and Keno City; reinforce and strengthen the grid between Stewart Crossing and Mayo; and replace and remove deteriorated and 'end of life' transmission infrastructure between Mayo and Keno City. The project is being planned to ensure continued safe and reliable service and to facilitate future economic development within the territory.

An initial $5.3 million tranche of funding was provided by the Yukon Government for the costs required to advance the project to a shovel ready stage by Q4 2016.

Initial engineering, planning and assessment activities required to prepare and submit a Yukon Environmental and Socio-economic Assessment Act (YESAA) project proposal to YESAB were undertaken in Q3 and Q4 2015. A YESAA Project Proposal for a 138 kV transmission line (with related substation infrastructure) between Stewart and Keno City was submitted to YESAB before the end of 2015, with the YESAB screening completed in May of 2016. A Land Use application was submitted to the Yukon government and authorizations required to proceed with geo-technical and survey work to complete detailed engineering were obtained in September 2016.

Preliminary design work oriented to confirming the technical ability to construct the project, and the timing and configuration of major Project components has been undertaken, and has provided cost estimates within a +20-15% range. However, a material component of the Project costing cannot be confirmed with reasonable certainty until the Project is tendered.

Detailed line design and detailed substation design contracts were competitively tendered and awarded in 2016, with this work to be completed in Q1 2017.

A decision to advance the project will be undertaken once Yukon Energy has confirmed the project costs and potential funding availability. Yukon Energy is considering options for a staged project development, with the initial stage to remove and replace deteriorated and 'end of life' transmission infrastructure between Mayo and Keno City, in the event that third party funding is not available.

#### 5.3.1.2 Aishihik Generating Station Water Use Licence Renewal – (Total Deferred Costs of $2.899 million to end of 2018; remains in WIP, projected completion in 2019)

The Aishihik Generating Station (AGS) facility licence was last renewed in 2002 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 the largest winter peak hydro generation capability on the Yukon Integrated System. Yukon Energy plans to seek a 25-year licence renewal (the maximum allowed term).

The total budget for the project is forecast at $3.569 million spread over five years (2015 – 2019). Total deferred costs to the end of 2018 are forecast at $2.899 million. The last Aishihik licence renewal project cost approximately $8.791 million.

The licence renewal process will include undertaking environmental and socio-economic studies required to support a YESAA Project Proposal (currently targeted for a Designated Office filing in mid-2018), followed by the development and securing of a Yukon Water Board Application and an application for a Fisheries Act Authorization. The relicensing process will address issues related to allowed minimum and maximum lake and flow levels, constraints on operation within these ranges, ongoing mitigation and monitoring requirements (including any compensation requirements), and any other related matters regarding environmental, social and economic effects expected from Aishihik facility operation over the new licence term.

Recognizing that the Aishihik hydro facility has had long term impacts on the Champagne and Aishihik First Nations (CAFN), Yukon Energy and CAFN are working in partnership on proposed terms and conditions for the new Aishihik water license. In January of 2016 Yukon Energy and CAFN entered into a Protocol Agreement which established shared objectives, procedures and governance of the new relationship, including:

- Both CAFN and Yukon Energy recognize that the Aishihik hydro facility has had long term impacts on the Champagne and Aishihik First Nations land, water and people, and want to improve relationships by working together on issues related to the Aishihik reservoir/watershed.
- A new, more collaborative approach has been established with regard to renewing this water licence whereby Yukon Energy and CAFN are working in partnership on proposed terms and conditions for a new licence.
- Yukon Energy and CAFN have established a steering committee (one member each from CAFN and Yukon Energy) to oversee the work and provide high level guidance, and an advisory committee (of CAFN, Yukon Energy, various government departments and agencies, as well as non-governmental organizations) that makes recommendations on technical issues such as the process for collecting baseline information, lake operational alternatives, effects assessment, etc.
- CAFN citizens provide input to this group through a Champagne Aishihik Community Advisory Committee and directly through consultation and other engagement activities.
- The Protocol Agreement recognizes the importance of CAFN traditional knowledge and it will play a key role in documenting traditional land use and CAFN social and cultural values. This will help build an understanding of the impacts from the operation of the dam in an appropriate context.
- The Protocol Agreement also respects the rights and interests of CAFN under the Final Agreement, the duty to consult and accommodate, and recognizes that the agreement does not commit CAFN to endorse any or all aspects of the project.

#### 5.3.1.3 Battery Project– Energy Storage System ($0.500 million in 2017 and $8.356 million in 2018; remains in WIP – planned in-service 2019)

The Battery project will provide a Battery Energy Storage System (BESS) to assist in addressing the current dependable capacity shortfall in a cost-effective manner by 2020.

The 2016 Resource Plan identified a dependable capacity shortfall for the Yukon Integrated System under its single contingency (N-1) capacity reliability criterion that approximates 6 MW in 2017, increasing to about 13 MW by 2020.[29] Yukon Energy is required to provide sufficient dependable winter capacity to meet the single contingency capacity reliability criterion, i.e., there is no acceptable "do nothing" option given the need to maintain reliable service, and permanent solutions (rather than relying upon temporary options such as mobile diesel) are needed to address an ongoing and growing dependable capacity shortfall.

The 2016 Resource Plan identifies construction of the Battery (4MW) ESS located near the Takhini substation as one of the preferred options for addressing a portion of the dependable capacity gap in a cost-effective manner in the near term, i.e., for use by the winter of 2019/20. Other projects are also proposed to address the dependable capacity shortfall, including near-term installation (i.e., by winter 2018/19) of the third LNG engine (4.4 MW) at the existing Whitehorse Thermal Plant plus development of additional new thermal capacity as required as soon as is feasible (currently planned by the winter of 2020/21).

The study completed by TransGrid Solutions Inc. (TGS) identified four electrochemical battery technologies as potentially optimal to displace thermal generation. One advantage noted for batteries in the TGS study is that the systems are modular, and can therefore be added in a reasonable timeframe as well as in increments as the demand grows and as the technology improves. Only two battery options, lead acid and lithium ion batteries, were selected by TGS based on safety, overall cost and the maturity of the technology. Using YEC's known diesel power generation profile for the year 2015,[30] TGS identified the operational requirements of the BESS as a power rating of 4 MW, an energy rating of 40 MW.h, and a discharge time of 10 hours. The TGS study estimated the net present value for a range of options, assessing benefits from diesel generation cost savings (based on the 2015 load profile) versus the estimated capital and operating costs of each BESS option. Over the lifetime of the projects, TGS estimated that the lead acid 4 MW, 40 MW.h BESS had the best NPV followed by the lithium ion 8 MW, 40 MW.h BESS. TGS estimated the time period for bringing such a BESS system on line as approximately

[29] The 2017/18 GRA Application Tab 2 includes a forecast dependable capacity shortfall on this same basis at 5.6 MW in 2017 and 6.9 MW in 2018.

[30] Figure 24 in the TGS study provides a histogram of diesel generation (MW) in 2015 indicating that 85% of the time the peak diesel power demand (about 2,443 MW.h/year) was equal to or less than 4.0 MW. The TGS study indicated that a 4 MW Battery option, operating only about 60 days per year (i.e., about 17% of the full 365 days per year), could displace this 2,443 MW.h of diesel generation. The Battery project's dependable capacity is conditional on the battery being recharged, which would normally be done with surplus hydro generation within the same day that the battery has been used.

18 months, including engineering and drawing, preparatory civil works, purchase and delivery of the system components, construction, and testing.[31]

A final technical decision on lead acid (4 MW) vs lithium ion (8 MW) options has not yet been made by Yukon Energy, in particular to take into consideration some technical limitations of lead-acid batteries under high cycling circumstances. In addition, the final location of the BESS needs to be confirmed. Final selection of the battery technology and project location will take place following preliminary engineering. Provided necessary planning and studies work commences in the 2017 field season, it is anticipated that the project may be permitted and constructed for in-service by the end of 2019. The current project schedule is as follows:

- 2017: Completion of environmental and socio-economic baseline studies, stakeholder engagement and consultation, preliminary engineering, grid impact study followed by a Stagegate 3 project review in the 4th quarter of 2017. A project proposal will be submitted to YESAB should the project successfully pass the Stagegate 3 review.

- 2018: Permit acquisition, detailed design, procurement of long-lead equipment, civil work.

- 2019: Construction and commissioning.

Depending on the option selected, the TGS study indicates forecast costs for the Battery project between \$21.7 and \$27.4 million (including costs for planning, permitting and construction) for an initial 15 to 20 year life, after which a replacement battery is estimated to cost between \$17.4 and \$22.1 million (2016\$).

#### 5.3.1.4 Thermal Plant – (\$0.750 million forecast in 2017 and \$3.461 forecast in 2018; remains in WIP – planned in-service 2020)

The Thermal Plant project will provide up to 20 MW of new diesel or natural gas thermal generation capacity to assist in addressing the current dependable capacity shortfall in a cost-effective manner by 2021. Forecast spending during 2017 and 2018 is on planning, preliminary engineering, environmental permitting, and the start of detailed design for this project.

[31] TGS study, section 7 (Conclusions); YEC 2016 Resource Plan, Appendix 5.17. The NPV assessments in the TGS study examined the extent that operating cost savings from displacing 2,443 MW.h per year of diesel generation could offset Battery capital and O&M costs over the project life.

The 2016 Resource Plan identified a dependable capacity shortfall for the Yukon Integrated System under its single contingency (N-1) capacity reliability criterion that approximates 6 MW in 2017, increasing to about 13 MW by 2020 and 23 to 24 MW by 2021.[32] Yukon Energy is required to provide sufficient dependable winter capacity to meet the single contingency capacity reliability criterion, i.e. there is no acceptable "do nothing" option given the need to maintain reliable service, and permanent solutions (rather than relying upon temporary options such as mobile diesel) are needed to address an ongoing and growing dependable capacity shortfall.

The 2016 Resource Plan identifies construction of a new 20 MW greenfield diesel plant (20 MW Diesel Plant option) located next to the Takhini substation, scalable to accommodate future expansions of up to 10 MW, as one of the preferred options for addressing a major portion of the dependable capacity gap in a cost-effective manner by winter 2020/21. Other projects are also proposed to address the dependable capacity shortfall, including near-term installation (i.e., during winter 2018/19) of the third LNG engine (4.4 MW) at the existing Whitehorse Thermal Plant, plus development of the Battery (4 MW) project near the Takhini substation to provide an Energy Storage System (ESS) by the winter of 2019/20.

The 20 MW Diesel Plant option for new thermal capacity was selected in the 2016 Resource Plan after review of new greenfield diesel and natural gas thermal generating station options in the Whitehorse area by Stantec Consulting Ltd. (Stantec)[33] and the Resource Plan's assessment of portfolio options.

- The Stantec study considered potential sites. For the two best sites, conceptual layouts were produced for both diesel and natural gas plants at 5 MW, 10 MW and 20 MW along with a high level cost estimate. Capital costs for 20 MW options at the Takhini site were estimated at $62.2 million for diesel and $100.0 million for natural gas. A four year lead time was estimated for development of these greenfield options.

- The 2016 Resource Plan portfolio options analysis selected the 20 MW diesel option to be developed as soon as possible (i.e., within the four year lead time identified in the Stantec study [by 2021]) under all load scenarios in order to address the forecast dependable capacity shortfall on a cost effective basis, with a further 10 MW expansion of this diesel plant anticipated to be required by 2026 under three of the five load scenarios examined for the portfolio options. Diesel was assessed in the portfolio analysis to be more cost effective than natural gas for the new

[32] Tab 2 of the 2017/18 GRA Application includes a forecast dependable capacity shortfall on this same basis at 5.6 MW in 2017 and 6.9 MW in 2018. The 2021 shortfall assumes retirement of two Mirrlees units (8.5 MW) located in Whitehorse and Faro in the summer of 2021.
[33] See Appendix 5.15 of the 2016 Resource Plan.

greenfield thermal plant options, indicating that under the low levels of expected thermal generation the present value fuel cost savings with natural gas versus diesel would not be sufficient to offset the estimated capital cost penalty for the natural gas greenfield option.

- Planning for the 20 MW Diesel Plant option for in-service by 2021 involves the following schedule and budget:
  - 2017: Completion of environmental and socio-economic baseline studies, stakeholder engagement and consultation, preliminary engineering and grid impact study ($0.75 million).
  - 2018: Stagegate 3 project review in the first quarter of 2018; subject to the project successfully passing the Stagegate 3 review, followed by the submission of a YESAB proposal, start of detailed design and procurement of long-lead equipment near end of year ($3.46 million).
  - 2019: Permitting, procurement and start of construction ($38 million).
  - 2020: Construction and commissioning ($20.1 million).

In addition, the 2017 work plan for the Thermal Plant project will include a final review of all new fossil fuel thermal generation options as required for proceeding on a timely basis, including options not considered in the 2016 Resource Plan portfolio analysis, in order to confirm a final project that provides the needed new capacity as soon as possible and at minimum costs (including, where feasible, flexibility to address potential short term thermal generation requirements during droughts or short-term mine loads with minimum thermal generation fuel costs). One of the options to be considered will be a greenfield LNG option with third party gas supply; with LNG storage managed by others, it is possible this option could result in low enough CAPEX to enable use of natural gas in a greenfield facility.

Specifically, the 2017 work will review options to refurbish the existing Whitehorse thermal plant as discussed in YEC's 2013/14 Part 3 Application and YUB hearing for the Diesel to Natural Gas Conversion Project (initial LNG Project). The Initial LNG Project included assessments of options within the existing Whitehorse diesel plant to install 13.4 MW of new dual fuel (natural gas and diesel) generation in bays for the two Mirrlees that were to be retired at that time. The final LNG project proposed in 2013/14 selected modular natural gas units to be installed external to the diesel plant, but included installation of a natural gas line from the new LNG facilities to the Whitehorse diesel plant to facilitate future implementation of both new dual fuel generation capacity (in the retired Mirrlees bays) as well as blend fuel options with existing diesel units.

#### 5.3.1.5 Demand Side Management ($2.484 million to the end of 2016, $0.210 million in 2017 and $0.625 million in 2018)

The Demand Side Management (DSM) project involves several components, each of which is reviewed separately below.

**inCharge Program Development and Delivery**

Beginning in 2010, Yukon Energy, in partnership with AEY and in consultation with stakeholders, developed a Five Year Demand Side Management Plan for the Yukon (the Plan). The Plan included a suite of programs for residential and general service customers and associated communications tasks as well as a Program Implementation Plan and an Evaluation, Measurement and Verification plan. The Plan was presented for review as part of AEY's 2013-15 General Rate Application, and Yukon Energy and AEY presented a joint panel at the oral hearing to answer questions regarding the DSM program.

In Order 2014-06 the Board approved 2014 and 2015 program elements of the residential non-government DSM portfolio[34] that pass all of the four cost-effectiveness measures,[35] which included the 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. The inCharge program was launched in late 2014, and has been delivered to customers jointly by YEC and AEY in 2016.

Third-party reviewed evaluations of the inCharge program were conducted in 2015 and 2016. A summary of the energy savings and costs, updated to the end of 2016 and reviewed by the third party evaluation advisor, can be seen below in Figure 5.1. In terms of the cost-benefit ratios, the programs achieved an overall Ratepayer Impact Measure (RIM) ratio of 1.1, in keeping with direction from the YUB. The programs also achieved a very high Participant Cost (PC) ratio and high Program Administrator Cost (PAC) ratio results, showing they are very beneficial to the participants of the program and the utilities, who are the administrators of the programs. Most significantly, the program achieved a high Total

[34] This included LED Lighting and Automotive Heater Timer Rebates and the Low-cost Energy Efficient Products program elements.
[35] The Board indicated concern that not all of the program elements pass the Rate Impact Measure (RIM), and noted that "….in the Board's view, all program elements must at least be rate-neutral for all ratepayers."

Resource Cost (TRC) ratio. This shows that in the context of the comparison with other electricity resource options, the conservation programs performed very well.

**Figure 5.1: inCharge Program Energy Savings and Costs (actuals updated to end of 2016 – Year 3)**

| Program Elements | Net Savings with T&D Losses | | | | | | | Utility Expenditure ($1,000s) | | | | | | | Benefit/Cost Ratios for the 5-Year Period | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Total | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Total | TRC | PAC | PC | RIM |
| LED Lighting and Automotive Heater Timer Rebates | Lifetime MWh: | 2,418 | 3,893 | 9,852 | 8,128 | 8,128 | 32,419 | Incentive: | $19 | $31 | $81 | $77 | $77 | $284 | 6.8 | 6.0 | 13.5 | 1.3 |
| | Annual MWh: | 121 | 331 | 828 | 1,273 | 1,699 | N/A | Non-Incen: | $77 | $73 | $87 | $98 | $98 | $433 | | | | |
| | Coincident kW: | 29 | 88 | 210 | 337 | 452 | N/A | Total: | $96 | $105 | $167 | $175 | $175 | $717 | | | | |
| Low-cost Energy Efficient Products | Lifetime MWh: | 3,208 | 2,313 | 2,196 | 2,196 | 2,196 | 12,110 | Incentive: | $71 | $51 | $47 | $47 | $47 | $264 | 2.9 | 2.8 | 6.0 | 1.0 |
| | Annual MWh: | 298 | 503 | 702 | 828 | 945 | N/A | Non-Incen: | $110 | $154 | $50 | $48 | $48 | $410 | | | | |
| | Coincident kW: | 81 | 169 | 256 | 293 | 325 | N/A | Total: | $181 | $205 | $97 | $96 | $96 | $674 | | | | |
| Engagement, Education and Communication | Lifetime MWh: | N/A | N/A | N/A | N/A | N/A | N/A | Incentive: | $0 | $0 | $0 | $0 | $0 | $0 | N/A | N/A | N/A | N/A |
| | Annual MWh: | N/A | N/A | N/A | N/A | N/A | N/A | Non-Incen: | $86 | $108 | $159 | $191 | $191 | $736 | | | | |
| | Coincident kW: | N/A | N/A | N/A | N/A | N/A | N/A | Total: | $86 | $108 | $159 | $191 | $191 | $736 | | | | |
| Total for the Residential Program | Lifetime MWh: | 5,625 | 6,207 | 12,049 | 10,324 | 10,324 | 44,529 | Incentive: | $90 | $82 | $128 | $124 | $124 | $548 | 3.1 | 3.0 | 9.4 | 1.1 |
| | Annual MWh: | 419 | 834 | 1,530 | 2,101 | 2,644 | N/A | Non-Incen: | $272 | $336 | $296 | $337 | $337 | $1,579 | | | | |
| | Coincident kW: | 110 | 257 | 466 | 630 | 776 | N/A | Total: | $363 | $418 | $424 | $461 | $461 | $2,127 | | | | |

These evaluations noted the performance of the program compared with a set of established key performance indicators, feedback from program participants as well as the four industry standard cost-benefit ratios. Overall the evaluations showed that the programs have been well received by Yukoners and the key performance indicators have been met or exceeded.

Yukon Energy plans to continue the delivery of the approved inCharge program for the test years. Funding as proposed for 2017 and 2018 reflects that AEY has chosen to discontinue partnership in program delivery resulting in YEC carrying the full cost of these programs.

The net cost of conducting initial research into potential for electricity conservation programming, designing the DSM Plan, in consultation with stakeholders and delivering the inCharge program until the end of 2016 was $1.291 million. The costs for continuing delivery of the inCharge program in 2017 and 2018 are $0.190 million and $0.290 million for 2018.

### New Program Development

The 2016 Resource Plan recommends that additional DSM programs are a cost effective way to meet energy and capacity demands and should be included in the proposed future portfolio of energy supply projects. These additional DSM programs must be designed prior to submission to the YUB for approval. To have sufficient Yukon-specific data to use in program design, YEC plans to develop residential and commercial customer end use surveys to be conducted by Yukon Bureau of Statistics. These surveys will gather information on how Yukon homes and businesses currently use energy. YEC also plans to update the Conservation Potential Review (CPR) model used to inform DSM program design, to better match the inputs needed for resource planning. This process will include developing in-house capacity to use the CPR model to extract data for resource planning and program design purposes.

As the work done on DSM to date has focused mainly on energy DSM, YEC will also perform a Capacity DSM Feasibility Study to quantify the potential cost and achievable uptake of capacity-focused DSM programs such as demand response, behavior change and other demand-focused measures.

Using the End-Use Survey data, Capacity DSM Feasibility Study and updated CPR model, the next step will be to design a suite of new DSM programs to complement the existing inCharge program. This work will be completed in 2019. YEC also plans to engage with ESC to explore opportunities for joint delivery of identified capacity-focused DSM programs.

The cost of new program development will be $0.190 million in 2018.

**Industrial DSM**

Yukon Energy partnered with each of its industrial customers, Alexco and Capstone, to complete energy audits of their mining operations. The net cost for industrial DSM to 2016 is $0.082 million.

**Pilot DSM Projects**

Yukon Energy has undertaken a number of DSM related pilot projects focused on building the culture of electricity conservation, learning how the Yukon market reacted to electricity conservation programs, how certain electricity technologies performed in Yukon's harsh climate. The learnings from these pilots helped to lay the groundwork for the launch of the inCharge program and build capacity within Yukon Energy to administer DSM programs. These projects included basic energy management training for businesses and municipalities,[36] education events for children and schools,[37] energy conservation ambassador campaign, presentations at community events,[38] piloting of retail coupons and energy efficient products distribution,[39] partnership with City of Whitehorse on an energy audit of their facilities, contributions to Yukon Government's fridge retirement and commercial lighting programs. Yukon Energy plans to continue to contribution to the Yukon Government's commercial lighting program in 2018.

[36] Delivery of the Natural Resource Canada Dollars to $ense course. Some course offerings were in partnership with YECL.
[37] Conservation Kids program undertaken in partnership with YCS, presentation to the Vanier social justice class with ESC and Northern Climate Exchange.
[38] Whitehorse Lions tradeshows and Association of Yukon Communities.
[39] Coupons on LED lightbulbs, programmable thermostats and automotive heater timers and a giveaway of home energy monitors.

The net cost of the pilot programs to 2016 is $0.051 million, which includes a contribution of $0.500 million from Yukon Development Corporation. Costs to continue contribution to Yukon Government's commercial lighting program will be $0.020 million in 2018.

**LED Streetlight Retrofits**

Yukon Energy began piloting LED streetlights in 2011 to determine if the technology was suitable for the Yukon climate, gather customer feedback and analyze the business case for retrofitting existing high pressure sodium streetlights. The piloting of LED streetlights showed that they were effective in the Yukon climate and positive feedback was received from customers in the areas where the LED streetlights were tested.

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

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

**Internal Energy Conservation**

A number of DSM projects were undertaken on Yukon Energy's existing buildings and facilities. The benefit of this form of DSM is that as Yukon Energy is carrying out the projects, there is assurance that the efficiency upgrades will be made and targeted savings achieved. These projects included retaining a third party consultant to conduct an energy audit of 25 Yukon Energy buildings to determine areas where cost effective energy efficiency upgrades could be made. From the results of this audit six buildings were chosen for detailed energy audits and energy upgrades. Energy upgrades focused on upgrading lighting.

Work to continue to increase the efficiency of Yukon Energy's facilities will continue in 2018 with the development of an energy management system.

The cost of conservation projects on Yukon Energy's assets up to 2016 is $0.353 million. The cost for the energy management system will be $0.025 million in 2018.

**Administration**

In 2011, Yukon Energy opened an Energy Conservation office and dedicated two full time employees to the management of research, pilot programs and development of the DSM Plan. Through this office Yukon Energy acted as Chair of the DSM Working Group with AEY and Yukon Government, as well as managing all contractors working on behalf of the DSM Work Group partners. With the YUB's 2014 decision to approve only three of the residential programs, the decision was made to close the Energy Conservation office and merge the roles of the two employees dedicated to DSM into one position.

Administration costs included chairing of the DSM working group, general administration tasks, overhead for the operation of the Energy Conservation office including rent, utilities, supplies and communications, staff training or specific expenditures not directly attributed to a specific DSM project, memberships and dues and attendance at energy conservation related events.

In the Order 2013-01 the Board directed Yukon Energy to create a deferral account wherein DSM administration-related costs were to be held in WIP until YEC and YECL had filed a joint DSM Plan. The cost of DSM administration is $0.397 at the end 2016 and will cost $0.020 million in both 2017 and 2018.

All new DSM programs will be filed with the YUB in advance of delivery.

Pursuant to the DSM Accounting Policy provided in Appendix 5.2, project related DSM costs are proposed to be closed out and amortized each year over a ten year period.

#### 5.3.1.6 Resource Plan Update 2016 – ($1.854 million to end of 2016; $0.150 million forecast in 2017)

In late 2005, Yukon Energy completed a 20-year Resource Plan for the years 2006-2025 and the Yukon Utilities Board recommended that YEC file an update to its resource plan within five years.

- An update was undertaken in 2011 covering the period from 2011 to 2030. The 2011 Resource Plan Update assisted ongoing decision making on new infrastructure projects. This review assessed updated forecasts for integrated grid energy and capacity requirements, impacts on the integrated grid from the addition of major new assets to the system, and new generation and transmission options for both the near-term (up to 2015) and longer-term (after 2015). The 2011 Resource Plan Update Overview report was reviewed during the 2012/13 GRA proceeding.

- A second update to the 20-Year Resource Plan was undertaken starting in 2015 and 2016 to address planning requirements for the period from 2016 to 2035. The 2016 Resource Plan Update is provided with the 2017/18 General Rate Application filing (see Volume 2).

The 2016 Resource Plan update is forecast to cost $2.004 million and will be completed in 2017. These costs will be amortized over five years, starting in 2017. Costs incurred primarily relate to internal and external consultant costs for the following activities:

- Update to the 20 year load forecast;
- Production of a load resource balance that balances the load forecast with existing generation;
- Assessment of available resource options for analysis by assigning technical, financial, environmental and socio-economic attributes;
- Completion of a portfolio analysis of resource options based on defined objectives;
- Development of a preferred resource portfolio for the short and long term as well as some contingency portfolio options;
- Documentation of external risks and uncertainties and how they could impact preferred options;
- Generation of a short-term (5-year), long-term (20-year) and contingency action plan for YEC to act upon in its resource planning activities; and
- Significant First Nation and stakeholder engagement component focused on documenting the values related to future electricity supply options. This included use of digital kiosks, online surveys, phone surveys, door to door surveys and traditional public meetings.

The 2016 Resource Plan document is provided for references as Volume 2 of this filing (absent the Appendices). The 2016 Resource Plan Appendices are available on Yukon Energy's website at the following link: http://resourceplan.yukonenergy.ca/more/.

#### 5.3.1.7 Gladstone Diversion– ($4.429 million to end of 2015; and $0.092 million in 2016; total costs to be amortized at end of 2017 of $4.521 million – project not to proceed)

The Gladstone Diversion is a cost effective means of increasing the amount of water available in winter months for hydroelectric generation at the Aishihik hydro facility in order to displace higher cost diesel generation that would otherwise be required.

The 2012/13 General Rate Application noted that the project had an LCOE (2010$) over the 65 year estimated project life of 6.3 cents/kWh (assuming an estimated cost of $40 million and full utilization of added energy generation of up to 36.6 GW.h/year). At the time of the 2012/13 GRA, earliest potential in-service for the project was estimated to be late 2017.[40] Planning and feasibility costs to the end of 2011 were $3.694 million, and spending over the 2012 and 2013 test years was forecast to be $0.700 million. Third party environmental assessment, engineering and project management costs comprised approximately 90% of these costs. The Board, in Order 2013-01, found that the project has the potential to be viable and directed that all costs be held in WIP until the project is completed or otherwise ended.

During the 2012/13 GRA process, the project remained at a prefeasibility stage and prior to a decision to prepare any regulatory filings to secure approvals. The ongoing risks and uncertainties for the project related to regulatory risks and the need to complete consultation with the local First Nations. Activities during 2012 were directed at addressing and resolving these key risks, and ongoing expenditures and activities beyond 2012 were recognized to be dependent on Yukon Energy's success in this regard. Yukon Energy noted in the 2012/13 GRA process that it would not proceed with the next phase of material spending (related to engineering and field studies in preparation of a YESAB submission) prior to gaining clarity from CAFN regarding whether or not CAFN would support the project. Yukon Energy noted that it was committed to working with the CAFN until they were able to make a decision regarding whether or not they would support the project; and that this decision was not expected until late 2012 or early 2013.

Yukon Energy continued to engage with CAFN as well as Kluane First Nation (KFN) subsequent to the 2012/13 GRA. However, both CAFN and KFN have indicated that they will not support the project.[41] Consequently Yukon Energy has concluded that the project no longer offers any net economic benefit to ratepayers as there is no reasonable probability that the project will proceed, and Yukon Energy, as

[40] Reflects time needed for YESAA, FAA and other permit processes and YWB licensing plus two construction seasons; the YESAA and FAA applications were assumed to be delayed due to need for up to two years of further pathogen studies required by DFO and delays until YEC can resolve arrangements with the local First Nation.

directed by the Board in Order 2013-01, has therefore ceased work on the project. Based on Yukon Energy's decision not to proceed further with the project, feasibility study costs to date of approximately $4.521 million will be amortized over 10 years, starting in 2017. As noted above, approximately $4.3 million of these costs were reviewed in the 2012/13 GRA.

#### 5.3.1.8 Marsh Lake Storage – ($6.517 million to end of 2015; $0.365 million in 2016; $0.250 million forecast in 2017 and $1.025 million forecast in 2018; remains in WIP – potential in-service 2022)

The Marsh Lake Storage Project (recently renamed the Southern Lakes Enhanced Storage Project, or SLESP) is a means of enhancing winter energy at the Whitehorse Rapids generating station to displace higher cost thermal generation that would otherwise be required. As reviewed in the 2012/13 GRA, the project includes capital improvements to the Lewes Lake control structure, shoreline mitigation, First Nation consultation and an amendment to YEC's water licence to increase the full supply level by 0.3 meters and reduce the low supply level by 0.1 meters. This additional water storage would be available to YEC for hydro generation over the winter period. The 2012/13 GRA identified this project as a relatively small project, with earliest in-service assumed in 2014 (first full year 2015) at a capital cost (2010$) of $10.5 million, with mitigation design (shoreline erosion and surface water) expected to comprise about one-half of this total cost (actual costs for mitigation were stated in the 2012/13 GRA as an item that at that time could not be known with any certainty). Annual incremental hydro generation was estimated at 6.4 GW.h on average, focused in winter months at the current Whitehorse plant. Annual operating cost (2010$) was estimated at $8/MW.h. Full Utilization LCOE (2010$) was estimated at 8.5 cents/ kW.h. Marsh Lake Storage was also assumed in the 2012/13 GRA to provide 1 MW of added reliable peak winter capacity.

In the 2012/13 GRA, the project remained at a prefeasibility stage and prior to a decision to prepare any regulatory filings to secure approvals. Significant physical or environmental effects due to the project were not expected. However, given notable public concerns, the planning and permitting processes were expected to be complex with potential for delay in the regulatory review and permitting process and risks related to increased regulatory costs (including mitigation cost requirements beyond those currently estimated). At that time, YEC expected that a decision would need to be made prior to the end of 2012 as to whether or not to proceed with the project.

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[41] CAFN confirmed during 2016 that their original opposition to the project, as expressed in resolutions by Chief and Council in 2010 and 2011 still stands; Kluane First Nation confirmed their opposition by resolution in September 2014.

Planning and feasibility costs to the end of 2011 were $3.231 million with forecast spending over the 2012/13 test years of $1.6 million (total projected deferred cost of $4.83 million was projected for the end of 2013). The third party engineering, environmental assessment and project management components of the project comprised the majority of the project costs incurred to that point (approximately $2.9 million of the total $3.2 million).

In Order 2013-01, the Board found that Marsh Lake Storage was currently a viable project, and as such, all Marsh Lake-related project costs were to be held in WIP, until the project was completed. The Board noted that YEC was to cease work on the project if and when YEC concludes that there is no net economic benefit of the project to ratepayers.

Work completed since the 2012/2013 GRA includes technical studies and assessments, engagement and consultation with various stakeholders, and extensive meetings with property owners that will be directly impacted by the project. These meetings included discussion of project effects, exploration of mitigation options for specific properties (including identifying solution for groundwater impacts), and group consultation on six 'shoreline neighborhoods', resulting in the down-selection of preferred options to protect the shoreline of each neighborhood. The next major milestone is obtaining First Nations support for the project in order to progress to the YESAB assessment stage. Without such support the project will be cancelled as there will be no reasonable possibility of successful implementation and any further costs will have no economic benefit to ratepayers. It is expected that a decision to proceed to the YESAB assessment phase will be made at a Stagegate 3 project review planned for the 4th quarter of 2017.

The deferred cost forecasts in the Application assume that the project continues, with spending in WIP increasing from $6.517 million at the end of 2015 to $8.156 million by the end of 2018. Potential in-service for this project in 2022 is provided in the 2016 Resource Plan.

#### 5.3.1.9 Mayo Lake Storage – ($2.121 million to end of 2015; $0.285 million in 2016; $0.100 million forecast in 2017 and $0.850 million forecast in 2018; remains in WIP – potential in-service 2022)

The Mayo Lake Enhanced Storage Project (MLESP) will amend the Mayo Generation Station Water Use Licence to provide for up to one metre of additional draw down of Mayo Lake that would enhance the long-term average renewable power generation capability of the Mayo hydro facility and displace diesel generation that would otherwise be required.

The MLESP was previously reviewed during the 2012/2013 General Rate Application[42] as a major deferred project that would require a licence amendment without any physical works. The 2012/ 2013 GRA estimated total project costs over the life of the project at $5.4 million (2012$) (including mitigation and monitoring costs) with an LCOE (2010$) of 6.3 cents/kWh for approximately 4 GW.h/year of added long term average hydro grid energy with 1 metre of added storage at Mayo lake. At the time of the 2012/13 GRA filing, YEC was in the final steps of preparing a submission to YESAB targeted for the end of 2012 for regulatory review of the project, and it was noted that the earliest potential project in-service was estimated to be during 2013. The Application forecast $2.1 million going into rate base on or before the end of 2013. These costs were assumed to be amortized over the remaining term of the Mayo licence (13 years at that time).

In Order 2013-01, the Board approved the project as proposed in the GRA Application, noting that the amended water use licence would result in increased renewable power generation capability, would require no physical works, and would be amortized over the term of the Mayo generation facility water use licence.

The LNG Part 3 application in December 2013 subsequently noted (as an update) that the earliest potential timing for securing new hydro generation benefits from the MLESP was winter 2015/16 (thermal energy savings in 2016), and also noted YECSIM power benefit model updates that included (among other updates) changes to reflect Mayo Lake outlet channel conditions that had recently been discovered, i.e., a recent study by external engineers[43] had shown that sediment in the Mayo Lake outlet channel is constraining water flow through the channel at the low end of the licensed storage range, reducing long-term average (LTA) hydro generation from existing Mayo hydro facilities and preventing any benefit from being realized by the MLESP reducing the Low Supply Level (LSL) at Mayo Lake.

It was determined that removal of the sediment deposits in the Mayo Lake outlet channel would be required in order to utilize additional storage at Mayo Lake as provided for in the proposed MLESP, and that a separate design, assessment and regulatory review process was required to remove these sediment deposits (with or without the MLESP) in order to restore the full hydro energy capacity at the

[42] Section 5.3.1.4 of the 2012/13 GRA Application reviewed the project concept, work completed to date (including environmental and socio-economic fieldwork activities, analysis and assessment, project proposal preparation, engineering support, and public consultation), and project risks, costs and benefits. The project was included in the 2012/13 GRA under Relicensing rather than Feasibility Study deferred cost projects, reflecting the central objective to modify the current water licence affecting water storage at Mayo Lake. The project continues to be included under Relicencing.
[43] KGS Group, April 2013.

Mayo hydro facilities, and to enable the opportunity to expand LTA hydro energy ability to displace thermal generation through the extra storage proposed by the MLESP.

The MLESP proposal was submitted to the YESAA Designated Office in August 2015 (noting that a Mayo Outlet Dredging Project would be pursued separately in the future), with provision for the full one metre of added drawdown after an initial 0.5 metre drawdown and subject to adaptive management provisions that was co-developed, and would be implemented, with the First Nation of Na-Cho Nyak Dun. The YESAA Designated Office suggested that review of the MLESP be grouped with an unrelated YG project proposed for the lower Mayo River, and also required that the Mayo Lake Outlet Dredging Project be included in the MLESP review as an accessory project. In order to let the YG proposal move forward in a timely way the Yukon Energy MLESP proposal was withdrawn, on the understanding that it would be resubmitted at a later time with additional information regarding the Mayo Lake Outlet Dredging Project.

Project spending during 2016 includes environmental monitoring and phase 1 of the dredging work, a desktop analysis. Environmental monitoring makes up the majority of the 2017 costs and will continue through 2018. Phase 2 of the dredging work, detailed modelling and design, will take place during 2018. Once phase 2 of the dredging work is complete, YEC will have a much better estimate of the total costs to complete the project. At this point, a detailed economic analysis will be performed to re-evaluate the overall project benefit to ratepayers. A Stagegate 3 project review will be completed at that time to determine whether or not to proceed with the project.

The deferred cost forecasts spending in WIP increasing from $2.406 million at the end of 2016 to $3.356 million by the end of 2018. Potential in-service for this project in 2022 is provided in the 2016 Resource Plan.

### 5.3.2 Projects between $100,000 and $1 Million

The projected total 2017 and 2018 spending in deferred cost activities excluding major projects over $1 million (as described in Section 5.3.1) totals approximately $2.2 million in 2017 ($0.7 million in closed projects), as set out in detail in Table 5.7, and a total of approximately $2.9 million for 2018 ($1.5 million in closed projects for 2018 spending and $0.7 million in closed projects from 2017 spending) as set out in detail in Table 5.8. Total increase to rate base from deferred cost activities excluding major projects over $1 million, but including transfers from WIP spending prior to 2017, is $4.9 million in 2017 and $3.3 million in 2018.

Spending in 2017 and 2018 on each deferred cost activity totalling between $100,000 and $1 million as reviewed in Appendix 5.4 is summarized below (totalling $1.851 million for 2017 and $2.5 million for

2018, with total rate base impact in test years of $3.302 million and total WIP of $1.866 million), with key areas of spending including feasibility studies, relicensing, dam safety and regulatory.

- **Feasibility** (spending from 2013 to 2016 of $0.712 million, with $0.888 million in 2017 and $2.250 million in 2018; total rate base impact in test years of $1.984 million, total WIP $1.867 million).[44]
    - Studies undertaken to determine feasibility of potential supply options to displace higher cost thermal generation include ($0.540 million prior to 2017, $0.15 million in 2017 and $1.325 million in 2018; total test years' rate base impact of $0.940 million, and total WIP of $1.075 million):
        - Time of Use Rate Structure and Smart Grid ($0.1 million in 2017, impacts rate base);
        - Mt Sumanik Wind Feasibility Study ($0.540 million prior to 2017, $0.05 million in 2017 and $0.25 million in 2018; impacts rate base in 2018);
        - Whitehorse Hydro Uprate ($0.45 million in 2018; WIP); and
        - Small Hydro ($0.625 million in 2018; WIP).
    - Studies undertaken to ensure continued reliability or to determine requirement for business improvements for existing assets include ($0.172 million prior to 2017, $0.738 million in 2017 and $0.925 million in 2018; total test years rate base impact $1.043 million, total WIP $0.792 million):
        - Detailed Line Inspection ($0.050 million prior to 2017, $0.378 million in 2017, $0.30 million in 2018, impacts rate base);
        - Development of Asset Management Program ($0.2 million in 2017, $0.15 million in 2018, WIP);

[44] Moon Lake Hydro has test year rate base impact in excess of $0.1 million due to spending prior to 2017 (total $0.182 million with only $0.034 million spending in test years). Other feasibility projects without test year spending of at least $0.1 million that are added to 2017 test year rate base (with spending prior to 2017) total approximately $3.8 million.

- Mayo and Aishihik Hydro Climate Change Study ($0.122 million prior to 2017, $0.16 million in 2017, $0.16 million in 2018, WIP);
- Forecasting Model Integration ($0.115 million in 2018, impacts rate base);
- Asset Appraisal ($0.10 million in 2018, impacts rate base); and
- Northern Diesel Plant Relocation Study ($0.10 million in 2018, impacts rate base).

- **Hearing Reserve Account** (spending from 2013 to 2016 of $0.105 million, with $0.713 million in 2017; $0.818 million total test years' rate base impact) – spending on General Rate Application for 2017/18 test years. Costs are closed to Hearing Reserve Account in 2018.
- **Relicensing** (no spending from 2013 to 2016, with $0.25 million in 2017 and $0.25 million in 2018; $0.50 million total test years' rate base impact) – test year spending is on Aishihik Remediation Work initiated as part of the water licence heritage mitigation plan.
- **Regulatory** and **Dam Safety Review** (no projects in Tables 5.7 and 5.8 with spending in 2017 and 2018 totalling between $100,000 and $1 million.[45]

Appendix 5.4 provides a description (including need for and justification) of each of the deferred cost projects with total spending greater than $100,000 million and less than $1 million in each of the test years).

[45] Projects with test year rate base impacts in excess of $0.1 million due to spending prior to 2017 include: under Regulatory, "International Financial Reporting Standards" ($0.183 million test years rate base impact) and "Resource Plan Update - 2011" ($0.233 million); under Dam Safety Review, completed projects total $0.148 million test years impact. "Regulatory" in Tables 5.7 and 5.8 does not include other deferral accounts addressed in Tab 3 (Hearing Reserve Continuity Schedule, FRSR, and Deferred Vegetation Management Continuity Schedule).

**YUKON ENERGY CORPORATION** **Table 5.1**
**EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT - SUMMARY** **June 2017**
**($000S)**

| Description | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | BP 2017 | BP 2018 |
|---|---|---|---|---|---|---|
| **SUMMARY - RECONCILIATION OF PROPERTY, PLANT AND EQUIPMENT** | | | | | | |
| **Work in Progress (WIP), Beginning of Year** | 3,327 | 24,137 | 53,893 | 13,352 | 18,618 | 4,358 |
| **Total Major Projects** | 15,755 | 28,508 | 16,162 | 5,512 | 9,852 | 8,700 |
| **Ongoing Capital** | | | | | | |
| Total Transmission | 2,178 | 1,372 | 1,496 | 1,010 | 1,615 | 1,625 |
| Total Distribution | 537 | 873 | 1,115 | 753 | 500 | 715 |
| Total Generation | 2,259 | 3,159 | 2,024 | 1,817 | 1,065 | 1,094 |
| Total General Plant & Equipment | 1,738 | 2,083 | 2,172 | 2,493 | 1,574 | 2,499 |
| Total Overhaul | 2,903 | 1,669 | 122 | 888 | 0 | 0 |
| **Subtotal Ongoing Capital** | 9,614 | 9,156 | 6,928 | 6,962 | 4,753 | 5,933 |
| **Total Expenditures** | 25,370 | 37,664 | 23,090 | 12,474 | 14,605 | 14,633 |
| Transfer to RFSR | -40 | 0 | 0 | -8 | -112 | 0 |
| Transfers (Income Statement, Feasibility and other) | 387 | -82 | -362 | -153 | -2 | -2 |
| **Total WIP Adjustments and Transfers** | 347 | -82 | -362 | -161 | -114 | -2 |
| **Transfer to Ratebase** | -4,907 | -7,826 | -63,269 | -7,048 | -28,752 | -10,715 |
| **WIP end of year** | **24,137** | **53,893** | **13,352** | **18,618** | **4,358** | **8,274** |
| **Opening PPE in-service** | 492,468 | 496,269 | 501,659 | 564,536 | 570,769 | 599,521 |
| Net transfer from WIP | 4,907 | 7,826 | 63,269 | 7,048 | 28,752 | 10,715 |
| Retirements and other adjustments | -1,106 | -2,437 | -392 | -815 | 0 | 0 |
| **Closing PPE in-service** | **496,269** | **501,659** | **564,536** | **570,769** | **599,521** | **610,236** |
| **Opening Total PPE (in-service plus WIP)** | 495,795 | 520,406 | 555,552 | 577,888 | 589,387 | 603,879 |
| Change to total PPE | 24,611 | 35,146 | 22,336 | 11,500 | 14,492 | 14,631 |
| **Closing total PPE** | **520,406** | **555,552** | **577,888** | **589,387** | **603,879** | **618,511** |
| **RECONCILIATION OF CUSTOMER CONTRIBUTIONS** | | | | | | |
| **Opening Customer Contributions WIP** | **13** | **174** | **262** | **605** | **167** | **0** |
| Customer Contributions Received | 339 | 581 | 19,004 | 400 | 400 | 400 |
| Adjustments | 0 | | | | | |
| less: transfer to Rate Base | -179 | -493 | -18,660 | -838 | -567 | -400 |
| **Customer Contributions WIP end of year** | **174** | **262** | **605** | **167** | **0** | **0** |
| **Opening Gross Customer Contributions in Service** | **180,229** | **180,408** | **180,901** | **199,561** | **200,399** | **200,967** |
| Transfers from WIP | 179 | 493 | 18,660 | 838 | 567 | 400 |
| Retirements, Disposals and Adjustments | | | | | | |
| **Closing Gross Customer Contributions in Service** | **180,408** | **180,901** | **199,561** | **200,399** | **200,967** | **201,367** |
| **Opening Total Contribution (in-service plus WIP)** | 180,243 | 180,582 | 181,163 | 200,167 | 200,500 | 200,900 |
| Change to total Contribution | 339 | 581 | 19,004 | 333 | 400 | 400 |
| **Closing total Contribution** | **180,582** | **181,163** | **200,167** | **200,500** | **200,900** | **201,300** |

Notes:
1. Based on IFRS requirements, the financial statement accumulated depreciation at January 1, 2014 was rebased to $0 and total costs adjusted accordingly. Therefore, the total gross plant in Table 5.1 is not the same as gross plant in the financial statements.

**YUKON ENERGY CORPORATION** **Table 5.2**
**EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT** **June 2017**
**($000S)**

| Description | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | BP 2017 | BP 2018 |
|---|---|---|---|---|---|---|
| **Major Projects** | | | | | | |
| AH Elevator Shaft Structural Steel Rehabilitation | | 84 | 3,853 | 4,587 | 1,593 | |
| Aishihik AH3[4] | 325 | -8 | 281 | 67 | | |
| Aishihik Electrical & Control Upgrades | | 152 | 475 | 259 | 1,284 | 340 |
| Communications Upgrade | | | 113 | | 135 | 755 |
| Hydro Unit #WH4 Overhaul | | 10 | | 581 | 3,700 | |
| LNG Plant | 10,297 | 20,770 | 9,782 | 13 | | |
| LNG Third Engine | | 200 | 5 | 5 | 3,040 | 2,700 |
| Hydro Unit #MH2 Overhaul | | | 2 | | | 1,655 |
| T&D - Breaker Replacements | | | | | 100 | 1,250 |
| T&D - Line Replacement | | | | | | 2,000 |
| Wareham Spillway Gate Hoist Replacement | | 1,227 | 1,473 | | | |
| Whistle Bend Supply / Takhini Upgrade | 5,134 | 6,072 | 178 | | | |
| Total Major Projects | **15,755** | **28,508** | **16,162** | **5,512** | **9,852** | **8,700** |
| **Generation** | | | | | | |
| AH Cable Improvements-Elevator | | 490 | 6 | | | |
| AH3 Lifting Device | 150 | 75 | 5 | 5 | 50 | |
| Aishihik Annunciator Upgrades | 39 | 635 | 31 | | | |
| Aishihik Control Structure Refurbishment | | | | | | 325 |
| Aishihik Generator Fire Protection | | | | | | 125 |
| Aishihk Tailrace Road and Slope | | | 15 | 1 | 44 | 150 |
| Canyon Lake Control Structure & Dyke Refurbishment | | | | | 125 | |
| Dam Safety Recommendations | | | | 74 | 75 | 100 |
| Dawson Diesel Plant - Oil/Fuel Handling | | | 145 | 100 | | |
| Faro Diesel Building Ventilation | | | | | | 100 |
| Faro Diesel Relocation to Dawson (FD5 -> DD4) | | 231 | 46 | | | |
| Faro Plant Remote Control Automation Upgrades | 234 | 43 | | | | |
| Faro Switchgear FD3, FD5, FD7 | 377 | 4 | | | | |
| LNG Spares | | 64 | 185 | 17 | | |
| Marsh Lake Control Structure Upgrades | 362 | 5 | | | | |
| Mayo B | 239 | 350 | | | | |
| Mayo Lake Control Structure | | 407 | | | | |
| MCC Equipment for AHO Station | | | 147 | | | |
| Mechanical Seals on MBH1 & 2 | | | | 81 | 79 | |
| MH1 and MH2 TIV Certification | | 110 | 15 | 3 | | |
| MH2 Air Emission Diffuser Support Crack | | | | 234 | | |
| NG Piping P126 (Diesel Plant) | | | 117 | | | |
| Upgrade IDEC PLCs on FD-3,5, WD1,2,3,4,5,6 and YM-1 | | 26 | 53 | 109 | | |
| Vibration Monitoring MBH1 | | | 200 | 36 | | |
| Vibration Monitoring MBH2 | | | 117 | 25 | | |
| Wareham Dam Blackstart Generator | | | | | 120 | |
| Wareham Spillgate Automation | | | 129 | | | |
| Wareham Spillway Gate Remediation | | | | 90 | 75 | |
| WH4 Monitoring Equipment | 146 | | | | | |
| Whitehorse Diesel System Grounding for Generators | | | | | | 100 |
| Whitehorse Fuel Tank Replacement | 31 | 113 | 76 | 173 | | |
| Whitehorse Hydro (1,2,3) Parking Area Drainage Rehabillitation | | | 81 | 601 | | |
| Whitehorse Hydro Control PLC Replacement | | | | 219 | | |
| Whitehorse Hydro Local HMI/Historian Upgrade | | | | | 180 | |
| Whitehorse Spill Booms | | | 128 | | | |
| Whitehorse Spillway Diesel Refurbishment | | 145 | | | | |
| Whitehorse Spillway Improvements | 469 | 236 | | | | |
| Whitehorse Wind 1 Decommission (site restoration) | | | 8 | 8 | 112 | |
| Other projects under $100K | 212 | 225 | 519 | 42 | 205 | 194 |
| Total Generation | **2,259** | **3,159** | **2,024** | **1,817** | **1,065** | **1,094** |
| **Transmission** | | | | | | |
| CSTL Stage 2 | 255 | 153 | 344 | 5 | | |
| Dawson P158 T1/T2 Transformer | | | | | | 200 |
| L170 Carmacks Forest Fire 2013 | 343 | | | | | |
| L170 Gang Switch Installation 2013 | 119 | | | | | |
| L170 Line access | | | | | 350 | 350 |
| L250 Transmission Line Upgrades | 48 | 61 | 57 | 50 | 50 | 50 |
| Mayo Hydro Substation Enhancements Wrap-up | 187 | | | | | |
| Mendenhall PT Sub Capacity Upgrade | 193 | 166 | | | | |
| S150 - Whitehorse Main RTU Upgrade | | | | | 125 | |
| S171 VT Installation | 42 | 159 | | | | |
| Substation Protection and Control Minor Upgrades | 91 | 24 | 52 | 45 | 50 | 100 |
| Transmission Pole Test and Treat | 246 | | | | | |
| Transmission System Protection Settings | | | | | 100 | |
| WAF Transmission Upgrades | 566 | 730 | 892 | 881 | 850 | 850 |
| Other projects under $100K | 86 | 79 | 151 | 29 | 90 | 75 |
| Total Transmission | **2,178** | **1,372** | **1,496** | **1,010** | **1,615** | **1,625** |

**YUKON ENERGY CORPORATION** **Table 5.2**
**EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT** **June 2017**
**($000S)**

| Description | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | BP 2017 | BP 2018 |
|---|---|---|---|---|---|---|
| **Distribution** | | | | | | |
| 25kV Distribution Cut-Out Replacement | | | | 82 | | 100 |
| Callison Voltage Regulator Automation | | | | | | 115 |
| Customer Extensions | 303 | 750 | 810 | 578 | 475 | 475 |
| Dawson 25KV Gang Switch Replacment | 167 | | | | | |
| Dawson Dome Distribution Extension | 59 | 91 | 125 | 83 | | |
| Land Management & Easement Project | 8 | 19 | 23 | 4 | 25 | 25 |
| Other projects under $100K | | 13 | 156 | 7 | | |
| Total Distribution | **537** | **873** | **1,115** | **753** | **500** | **715** |
| **General Plant & Equipment** | | | | | | |
| Aishihik Emergency Signage and Lighting Upgrade | | | | | | 100 |
| Backup SCC | | | 110 | | | |
| Biennial ERP System Upgrades | | | | 66 | | 40 |
| Bucket Truck for Whitehorse | | | | 352 | | |
| Building Condition Report Response | | | | | | 299 |
| Computer Replacements | 32 | 20 | 20 | 31 | 20 | 20 |
| Critical Spares - System Requirement | | | 100 | 100 | 100 | 100 |
| Data Storage Replacements and Additions | 24 | 23 | 25 | | 35 | 25 |
| Dawson Derrick Digger | | | | | 350 | |
| Eng Services Tools & Equipment - Blanket | 21 | 22 | 27 | 21 | 25 | 25 |
| Enterprise System Enhancements | 366 | 15 | 5 | 13 | 17 | |
| ERP Enhancement - Timekeeping Software | | 18 | 3 | 28 | 57 | |
| Fall Arrest Systems | | 78 | 65 | 23 | 75 | 75 |
| Fencing Upgrades - Various Sites | | | 100 | 48 | 75 | 125 |
| Fish Ladder & Building Improvement | 41 | 86 | 14 | | | |
| FOB Upgrade to Kenteck Access Control for YEC Sites | | 118 | 158 | | | |
| Hatchery Upgrades - Blanket | 4 | 20 | 6 | 19 | 25 | 25 |
| IT Equipment & Software - Blanket | 19 | 19 | 26 | 26 | 25 | 25 |
| L170 Access Construction Between S164 and Structure 524 | | | | 350 | | |
| Mayo A Powerhouse Slope Scaling | | | | 304 | | |
| Mayo B Door Installation for Crane Inspection | | | | | | 100 |
| Mayo House Acquisition | | 332 | | | | |
| Mayo Transient Trailer Unit | | | | | | 250 |
| Network Improvements | 48 | 50 | 51 | 50 | 50 | 50 |
| Office Furniture and Fixtures - Blanket | 21 | 9 | 15 | 15 | 25 | 25 |
| Operations Tools & Equipment - Blanket | 25 | 33 | 26 | 28 | 25 | 25 |
| P125 Firemain Suction System Upgrades | | 110 | 41 | | | |
| Printers/Scanners/Copiers/Fax Machine | 9 | 18 | 40 | 31 | 15 | 15 |
| Prophix Implementation Phase 2 | | 77 | 81 | | | |
| Safety Improvements - Blanket | 28 | 9 | 6 | 22 | 25 | 25 |
| Satellite Mesh Network | | 151 | | | | |
| Security Risk Management - Blanket | 57 | 22 | 21 | 19 | 25 | 25 |
| Server Replacements | 152 | 22 | 25 | 25 | 25 | 25 |
| Specialized Vehicle Purchases | | 25 | 29 | 30 | 30 | 30 |
| Stewart-Minto Local SCADA | | | | | | 165 |
| Vehicle Purchases | 351 | 317 | 330 | 403 | 250 | 300 |
| Voice Repeater Site for Little Salmon Area | | | | | | 125 |
| Voice Repeater Site for Mendenhall/Champagne | | | | | | 100 |
| VOIP Assessment | | 116 | 74 | | | |
| Wareham Spillway Hoist Upgrade | 327 | | | | | |
| Whitehorse Spillway Bridge Repairs | | | 30 | 158 | | |
| WRGS Paving Requirements 2015 | | | 341 | | | |
| WRGS Hazardous Materials Containment | | | | | | 125 |
| Other projects under $100K | 212 | 372 | 402 | 331 | 300 | 255 |
| Total General PPE | **1,738** | **2,083** | **2,172** | **2,493** | **1,574** | **2,499** |
| **Overhauls (-)** | | | | | | |
| AH1 Ten Year Overhaul | 659 | 25 | 15 | 15 | | |
| AH2 Ten Year Overhaul | 583 | 23 | 14 | 14 | | |
| DD2 Engine Overhaul | 362 | 13 | 8 | 8 | | |
| DD3 Engine Overhaul | | 374 | 9 | 9 | | |
| DD5 Bottom End Overhaul | 359 | 40 | 25 | 25 | | |
| FD7 Engine Overhaul | | | | 121 | | |
| WD4 Engine Overhaul | | 507 | 12 | 12 | | |
| WD5 Engine Overhaul | 348 | 17 | 8 | 8 | | |
| WH1 Ten Year Overhaul | | | | 648 | | |
| WH2 Ten Year Overhaul | | 648 | 16 | 15 | | |
| WH3 Ten Year Overhaul | 591 | 23 | 14 | 14 | | |
| Total Overhaul | **2,903** | **1,669** | **122** | **888** | **0** | **0** |
| TOTAL | **25,370** | **37,664** | **23,090** | **12,474** | **14,605** | **14,633** |

Notes:
1. Numbers include AFUDC where applicable.
2. Numbers incude tranfers from planning and study cost and transfers from other projects where the capital expenditures may not be in the year shown.
3. Overhauls included in WIP from 2013 to 2016 as per Order 2013-01.
4 Total spending for AH3 Contract Dispute in 2016 was $2.117 million, the majority being legal costs required to be expensed during the year for accounting purposes. YEC consider these costs to be prudently incurred in order to defend the company against legal action resulting from the AH3 project. Upon final settlement of the lawsuit (under appeal as of 2017-2018 GRA filing), total project costs will be presented to the board for review.

**YUKON ENERGY CORPORATION** **Table 5.3**
**Continuity Schedule of Deferred Costs (2013)** **June 2017**
($000S)

| | Total expenditures | | | | | Accumulated Amortization | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Dec 31 2012 | Act 2013 Additions | Act 2013 Transfers/ Retired | Actual 2013 | Amortization Rate and Method | Dec 31 2012 | Act 2013 Expenses | Act 2013 Retired | Actual 2013 |
| **Feasibility Study** | | | | | | | | | |
| Completed Projects: | | | | | | | | | |
| Substation Asset Assessment | 84,589 | | (84,589) | - | SL-10 years | 77,540 | 7,049 | (84,589) | - |
| Infrastructure Plan (Phase 2) | 125,100 | | (125,100) | - | SL-10 years | 114,675 | 10,425 | (125,100) | - |
| Transmission Extension | 84,762 | | | 84,762 | SL-10 years | 74,873 | 8,476 | | 83,349 |
| 2006 Dam Safety Upgrades | 110,244 | | (110,244) | - | SL-5 years | 99,220 | 11,024 | (110,244) | - |
| Hydro Storage & Generation Pre-Feasibility | 409,335 | | (409,335) | - | SL-5 years | 361,580 | 47,756 | (409,335) | - |
| Mayo Wareham Liquefaction Analysis | 72,876 | | (72,876) | - | SL-5 years | 63,159 | 9,717 | (72,876) | - |
| Wareham Liquefaction Assessment | 37,904 | | (37,904) | - | SL-5 years | 30,323 | 7,581 | (37,904) | - |
| Southern Lakes Hydrology Study | 170,243 | | (170,243) | - | SL-5 years | 136,194 | 34,048 | (170,243) | - |
| Hydro Storage & Gen Pre-Feasibility | 185,082 | | (185,082) | - | SL-5 years | 148,066 | 37,017 | (185,082) | - |
| L170 Trx Line Assessment Carmacks | 206,721 | | (206,721) | - | SL-5 years | 165,376 | 41,344 | (206,721) | - |
| Wareham Liquefaction Assessment | 3,021 | | | 3,021 | SL-5 years | 2,316 | 604 | | 2,920 |
| Wareham Dam Reliability | 21,365 | | | 21,365 | SL-5 years | 15,668 | 4,273 | | 19,941 |
| Aishihik Unit Up-rate Study | 5,454 | | | 5,454 | SL-5 years | 3,999 | 1,091 | | 5,090 |
| Wareham Rock Face Feasibility Phase 2 | 55,902 | | | 55,902 | SL-5 years | 40,995 | 11,180 | | 52,175 |
| Mayo Lake Structure Integrity Assessment | 25,467 | | | 25,467 | SL-5 years | 15,280 | 5,093 | | 20,373 |
| Wareham Liquefaction Assessment | 22,117 | | | 22,117 | SL-5 years | 13,270 | 4,423 | | 17,694 |
| Wareham Spillway Hoist Upgrade | 41,617 | | | 41,617 | SL-5 years | 24,970 | 8,323 | | 33,293 |
| Metering Audit 2009 | 30,510 | | | 30,510 | SL-5 years | 18,306 | 6,102 | | 24,408 |
| Protection Event Collection System | 28,187 | | | 28,187 | SL-5 years | 16,912 | 5,637 | | 22,549 |
| AH0 Deluge System | 25,519 | | | 25,519 | SL-5 years | 10,208 | 5,104 | | 15,312 |
| P125 Headgates Single Point | 50,419 | | | 50,419 | SL-5 years | 20,168 | 10,084 | | 30,252 |
| Wareham Consequence Category Assessment | 62,882 | | | 62,882 | SL-5 years | 31,441 | 12,576 | | 44,017 |
| Mayo/Wareham Geotechnical Investigation | 44,562 | | | 44,562 | SL-5 years | 17,825 | 8,912 | | 26,737 |
| Hydro Unit Performance Test | 340,200 | | | 340,200 | SL-5 years | 102,060 | 68,040 | | 170,100 |
| WAF/MD Modeling and Stability | 447,536 | | | 447,536 | SL-5 years | 141,720 | 89,507 | | 231,227 |
| P125/126 Hydrocarbon Containment | 27,572 | | | 27,572 | SL-5 years | 9,191 | 5,514 | | 14,705 |
| Communications Strategy Study | 80,575 | | | 80,575 | SL-5 years | 16,159 | 16,115 | | 32,274 |
| System Stability Review | 99,961 | | | 99,961 | SL-5 years | 20,047 | 19,992 | | 40,039 |
| IT Security Audit | 38,071 | | | 38,071 | SL-3 years | 12,725 | 12,690 | | 25,415 |
| Mayo River Salmon Enhancement | 7,212 | | | 7,212 | SL-5 years | 1,446 | 1,442 | | 2,889 |
| Mayo Lake Control Structure - Fish passage | 2,569 | | | 2,569 | SL-5 years | 515 | 514 | | 1,029 |
| Atlin Storage | 2,230,652 | | | 2,230,652 | SL-10 years | 223,065 | 223,065 | | 446,130 |
| Annunciator RTU Upgrade | 43,125 | | | 43,125 | SL-5 years | 24 | 8,625 | | 8,649 |
| Mayo Hydro Plant Extension | 132,738 | | | 132,738 | SL-5 years | 73 | 26,548 | | 26,620 |
| Mayo Switchgear Phase 1 | 73,972 | | | 73,972 | SL-5 years | 40 | 14,794 | | 14,835 |
| Waste To Energy | 1,379,039 | 288,332 | | 1,667,371 | SL-10 years | - | 159,529 | | 159,529 |
| Geothermal | 2,072,347 | 324 | | 2,072,671 | SL-10 years | 194,741 | 219,728 | | 414,469 |
| Wind Feasibility - Ferry Hill (2011) | 427,617 | | | 427,617 | SL-5 years | 85,523 | 85,523 | | 171,047 |
| Mayo Hydro Bridge Icing Upgrade | 179,265 | | | 179,265 | SL-5 years | 35,853 | 35,853 | | 71,706 |
| Atlin Grid Connection | 109,941 | | | 109,941 | SL-5 years | 22,048 | 21,988 | | 44,037 |
| Large Hydro- Upper Pelly (2011) | 671,758 | | | 671,758 | SL-5 years | 134,352 | 134,352 | | 268,703 |
| Short Term Energy Storage | 44,307 | | | 44,307 | SL-5 years | 8,886 | 8,861 | | 17,747 |
| Mayo Lake Outlet Channel | 13,250 | | | 13,250 | SL-5 years | 2,650 | 2,650 | | 5,300 |
| Net Metering Demonstration Project | 28,798 | | | 28,798 | SL-5 years | 991 | 5,760 | | 6,751 |
| Hydraulic Wood Removal System | - | | 18,556 | 18,556 | SL-5 years | - | 619 | | 619 |
| Power Canal Leak Investigation | - | | 61,525 | 61,525 | SL-5 years | - | | | - |
| Assessment of Fuel Tank Whitehorse | - | 30,528 | | 30,528 | SL-5 years | - | 1,018 | | 1,018 |
| Disaster Recovery Plan | - | 21,162 | | 21,162 | SL-5 years | - | | | - |
| Enterprise Risk Management Report | - | 43,767 | | 43,767 | SL-5 years | - | | | - |
| Waste To Energy Contribution | (515,000) | (267,591) | | (782,591) | SL-10 years | - | (71,569) | | (71,569) |
| Geothermal 2013 Contribution | - | | (3,414) | (3,414) | SL-5 years | - | | | - |
| Total Feasibility Study Closed | 9,839,380 | 116,522 | (1,325,427) | 8,630,475 | | 2,514,473 | 1,389,000 | (1,402,094) | 2,501,379 |
| Work in Progress: | | | | | | | | | |
| Mayo Lake Outlet Channel | 39,937 | 86,720 | | 126,657 | | | | | |
| Western Copper - Aerial Photo Mapping & Route Selection | 31,501 | 8,833 | (40,334) | - | | | | | |
| Wind Feasibility - Ferry Hill | 36,902 | 36,715 | | 73,617 | | | | | |
| Victoria Gold - Grid Connection | 45,990 | 67,956 | | 113,947 | | | | | |
| Mayo Hydro Bridge Icing Upgrade (2011) | 14,499 | 551 | | 15,050 | | | | | |
| LNG Feasibility Study | 1,071,391 | | (1,071,391) | - | | | | | |
| Climate Change Study | 127,951 | 144,488 | | 272,439 | | | | | |
| System Stability Review | 98,333 | (12,953) | | 85,380 | | | | | |
| Aishihik Turbine Re-runnering | 1,108 | 880 | | 1,988 | | | | | |
| Wareham Spillway Hoist Upgrade | 58,081 | | (58,081) | - | | | | | |
| Power Canal Leak Investigation | 54,005 | 7,520 | (61,525) | - | | | | | |
| Hydraulic wood removal system | 13,499 | 5,058 | (18,556) | - | | | | | |
| Whitehorse Diesel Plant Conversion | 43,512 | 249,950 | | 293,462 | | | | | |
| Golden Predator-Grid Connection | 5,830 | 2,042 | (7,872) | - | | | | | |
| Condition Assessment of Selected YEC Assets | - | 115,804 | | 115,804 | | | | | |
| Fish Ladder & Building Improvement | - | 41,278 | | 41,278 | | | | | |
| Marsh Lake Storage | 4,304,948 | 623,470 | | 4,928,418 | | | | | |
| Gladstone | 4,029,273 | 159,757 | | 4,189,030 | | | | | |
| Large Hydro | 113,941 | 95,054 | | 208,995 | | | | | |
| Geothermal Contribution | (3,414) | - | 3,414 | 0 | | | | | |
| LNG Feasibility Study Contribution | (100,000) | (50,000) | 150,000 | - | | | | | |
| Wareham Spillway Hoist Upgrade Contribution | (96) | | 96 | (0) | | | | | |
| Victoria Gold - Grid Connection Contribution | - | (113,947) | | (113,947) | | | | | |
| Total Feasibility Study WIP | 9,987,191 | 1,469,176 | (1,104,249) | 10,352,118 | | | | | |
| Total Feasibility | 19,826,571 | 1,585,698 | (2,429,676) | 18,982,593 | | 2,514,473 | 1,389,000 | (1,402,094) | 2,501,379 |
| **Regulatory** | | | | | | | | | |
| Completed Projects: | | | | | | | | | |
| Minto Mine PPA | 769,057 | | | 769,057 | SL-12 years | 261,693 | 64,088 | | 325,781 |
| YUB 2007-7 & 9 - Resource Plan | 642,853 | | | 642,853 | SL-10 years | 321,427 | 64,285 | | 385,712 |
| YUB 2007-7 & 9 - PPA Review | 243,045 | | | 243,045 | SL-12 years | 101,269 | 20,254 | | 121,522 |
| YUB 2007-8 - Part 3 Hearing | 185,011 | | | 185,011 | SL-45 years | 20,557 | 4,111 | | 24,668 |
| Reserve for Injuries & Damages - Study | 42,500 | | (42,500) | - | SL-2 years | 21,250 | 21,250 | (42,500) | - |
| 2008/2009 GRA Phase 2 | 312,537 | | (312,537) | - | SL-2 years | 156,269 | 156,269 | (312,537) | - |
| Rate Schedule 39 Inflation Update | 25,691 | | (25,691) | - | SL-2 years | 12,846 | 12,846 | (25,691) | - |
| Alexco PPA Regulatory Costs | 53,854 | | | 53,854 | SL-5 years | 10,800 | 10,771 | | 21,571 |
| Brushing & ROW Veg Management | 173,227 | | (173,227) | - | SL-2 years | 86,614 | 86,614 | (173,227) | - |
| Rider F Policy Review | 24,307 | | | 24,307 | SL-2 years | 9,132 | 12,154 | | 21,285 |
| Resource Plan Update 2011 | 740,165 | | | 740,165 | SL-5 years | 148,033 | 148,033 | | 296,066 |
| International Financial Reporting Standards | 565,769 | | | 565,769 | SL-5 years | 113,154 | 113,154 | | 226,308 |
| Total Regulatory Closed | 3,778,016 | - | (553,956) | 3,224,060 | | 1,263,041 | 713,827 | | 1,422,913 |
| Work in Progress: | | | | | | | | | |
| International Financial Reporting Standards | 15,520 | 589 | | 16,109 | | | | | |
| General Rate Application 12-13 (2012) | 354,561 | 32,223 | (386,785) | - | | | | | |
| DCF ERA Regulatory Review | - | 25,139 | | 25,139 | | | | | |
| LNG - Part 3 | - | 43,653 | | 43,653 | | | | | |
| DSM | 828,466 | 648,030 | (76,884) | 1,399,612 | | | | | |
| Resource Plan Update | 211,676 | 7,939 | | 219,615 | | | | | |
| Total Regulatory WIP | 1,410,224 | 757,573 | (463,669) | 1,704,128 | | | | | |
| Total Regulatory | 5,188,240 | 757,573 | (1,017,625) | 4,928,188 | | 1,263,041 | 713,827 | | 1,422,913 |

**YUKON ENERGY CORPORATION** **Table 5.3**
**Continuity Schedule of Deferred Costs (2013)** **June 2017**
($000S)

| | Total expenditures | | | | | Accumulated Amortization | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Dec 31 | Act 2013 | | Actual | Amortization | Dec 31 | Act 2013 | | Actual |
| | 2012 | Additions | Transfers/ Retired | 2013 | Rate and Method | 2012 | Expenses | Retired | 2013 |
| **Relicensing** | | | | | | | | | |
| Completed Projects: | | | | | | | | | |
| Aishihik Relicensing | 8,877,606 | | | 8,877,606 | | 5,391,836 | 523,981 | | 5,915,817 |
| Whitehorse Relicensing | 167,285 | | | 167,285 | | 57,774 | 8,745 | | 66,519 |
| Mayo Relicensing | 27,848 | 51,362 | | 79,210 | | 16,746 | 1,443 | | 18,190 |
| Air Emission Licence Renewal | 289,787 | | (200,359) | 89,429 | | 230,168 | 29,810 | (200,359) | 59,619 |
| Mayo Lake Assessment & Permitting | - | | 1,249,262 | 1,249,262 | | - | 1,249,263 | | 1,249,263 |
| Total Relicensing Closed | 9,362,526 | 51,362 | 1,048,903 | 10,462,792 | | 5,696,524 | 1,813,242 | | 7,309,408 |
| Work in Progress: | | | | | | | | | |
| Mayo Lake - Env. Assessment & Permitting | 1,982,021 | 621,293 | (1,249,262) | 1,354,052 | | | | | |
| Air Emission Permit Renewal | 90,044 | 3,480 | | 93,524 | | | | | |
| Lewes Control Structure | 44,859 | 1,742 | | 46,600 | | | | | |
| Whitehorse Dam Break &Mapping | 65,174 | 2,527 | | 67,701 | | | | | |
| Total Relicensing WIP | 2,182,097 | 629,042 | (1,249,262) | 1,561,877 | | | | | |
| Total Relicensing | 11,544,623 | 680,404 | (200,359) | 12,024,669 | | 5,696,524 | 1,813,242 | | 7,309,408 |
| **Dam Safety Review** | | | | | | | | | |
| Completed projects | 331,597 | - | - | 331,597 | | 260,356 | 23,747 | | 284,103 |
| **Deferred Overhauls (In Tab 5.2)** | | | | | | | | | |
| Completed projects | | | | | | | | | |
| **Total Deferred Costs** | **36,891,031** | **3,023,674** | **-3,647,659** | **36,267,046** | | **9,734,394** | **3,939,816** | | **11,517,803** |
| **Closed** | | | | **22,648,924** | | | | | |
| **WIP** | | | | **13,618,123** | | | | | |
| **Net Deferred Costs (excluding WIP)** | | | | | | | | | **11,131,121** |

Note: This table does not include projects with zero net book value in the beginning of the year.

**YUKON ENERGY CORPORATION** **Table 5.4**
**Continuity Schedule of Deferred Costs (2014)** **June 2017**
($000S)

| | Total expenditures | | | | | Accumulated Amortization | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Dec 31 2013 | Act 2014 Additions | Act 2014 Transfers/ Retired | Actual 2014 | Amortization Rate and Method | Dec 31 2013 | Act 2014 Expenses | Act 2014 Retired | Actual 2014 |
| **Feasibility Study** | | | | | | | | | |
| Completed Projects: | | | | | | | | | |
| Transmission Extension | 84,762 | | (84,762) | - | SL-10 years | 83,349 | 1,413 | (84,762) | - |
| Wareham Liquefaction Assessment | 3,021 | | (3,021) | - | SL-5 years | 2,920 | 101 | (3,021) | - |
| Wareham Dam Reliability | 21,365 | | (21,365) | - | SL-5 years | 19,941 | 1,424 | (21,365) | - |
| Aishihik Unit Up-rate Study | 5,454 | | (5,454) | - | SL-5 years | 5,090 | 364 | (5,454) | - |
| Wareham Rock Face Feasibility. Phase 2 | 55,902 | | (55,902) | - | SL-5 years | 52,175 | 3,727 | (55,902) | - |
| Mayo Lake Structure Integrity Assessment | 25,467 | | (25,467) | - | SL-5 years | 20,373 | 5,093 | (25,467) | - |
| Wareham Liquefaction Assessment | 22,117 | | (22,117) | - | SL-5 years | 17,694 | 4,423 | (22,117) | - |
| Wareham Spillway Hoist Upgrade | 41,617 | | (41,617) | - | SL-5 years | 33,293 | 8,323 | (41,617) | - |
| Metering Audit 2009 | 30,510 | | (30,510) | - | SL-5 years | 24,408 | 6,102 | (30,510) | - |
| Protection Event Collection System | 28,187 | | (28,187) | - | SL-5 years | 22,549 | 5,637 | (28,187) | - |
| AH0 Deluge System | 25,519 | | | 25,519 | SL-5 years | 15,312 | 5,104 | | 20,415 |
| P125 Headgates Single Point | 50,419 | | | 50,419 | SL-5 years | 30,252 | 10,084 | | 40,335 |
| Wareham Consequence Category Assessment | 62,882 | | | 62,882 | SL-5 years | 44,017 | 12,576 | | 56,594 |
| Mayo/Wareham Geotechnical Investigation | 44,562 | | | 44,562 | SL-5 years | 26,737 | 8,912 | | 35,650 |
| Hydro Unit Performance Test | 340,200 | | | 340,200 | SL-5 years | 170,100 | 68,040 | | 238,140 |
| WAF/MD Modeling and Stability | 447,536 | | | 447,536 | SL-5 years | 231,227 | 89,507 | | 320,734 |
| P125/126 Hydrocarbon Containment | 27,572 | | | 27,572 | SL-5 years | 14,705 | 5,514 | | 20,219 |
| Communications Strategy Study | 80,575 | | | 80,575 | SL-5 years | 32,274 | 16,115 | | 48,389 |
| System Stability Review | 99,961 | | | 99,961 | SL-5 years | 40,039 | 19,992 | | 60,031 |
| IT Security Audit | 38,071 | | (38,071) | - | SL-3 years | 25,415 | 12,656 | (38,071) | - |
| Mayo River Salmon Enhancement | 7,212 | | | 7,212 | SL-5 years | 2,889 | 1,442 | | 4,331 |
| Mayo Lake Control Structure - Fish passage | 2,569 | | | 2,569 | SL-5 years | 1,029 | 514 | | 1,543 |
| Atlin Storage | 2,230,652 | | | 2,230,652 | SL-10 years | 446,130 | 223,065 | | 669,196 |
| Annunciator RTU Upgrade | 43,125 | | | 43,125 | SL-5 years | 8,649 | 8,625 | | 17,274 |
| Mayo Hydro Plant Extension | 132,738 | | | 132,738 | SL-5 years | 26,620 | 26,548 | | 53,168 |
| Mayo Switchgear Phase 1 | 73,972 | | | 73,972 | SL-5 years | 14,835 | 14,794 | | 29,629 |
| Waste To Energy | 1,667,371 | | | 1,667,371 | SL-10 years | 159,529 | 166,737 | | 326,266 |
| Geothermal | 2,072,671 | | | 2,072,671 | SL-10 years | 414,469 | 219,793 | | 634,262 |
| Wind Feasibility - Ferry Hill | 427,617 | | | 427,617 | SL-5 years | 171,047 | 85,523 | | 256,570 |
| Mayo Hydro Bridge Icing Upgrade | 179,265 | | | 179,265 | SL-5 years | 71,706 | 35,853 | | 107,559 |
| Atlin Grid Connection | 109,941 | | | 109,941 | SL-5 years | 44,037 | 21,988 | | 66,025 |
| Large Hydro - Upper Pelly (2011) | 671,758 | | | 671,758 | SL-5 years | 268,703 | 134,352 | | 403,055 |
| Short Term Energy Storage | 44,307 | | | 44,307 | SL-5 years | 17,747 | 8,861 | | 26,609 |
| Mayo Lake Outlet Channel | 13,250 | | | 13,250 | SL-5 years | 5,300 | 2,650 | | 7,950 |
| Net Metering Demonstration Project | 28,798 | | | 28,798 | SL-5 years | 6,751 | 5,760 | | 12,510 |
| Hydraulic Wood Removal System | 18,556 | | | 18,556 | SL-5 years | 619 | 3,711 | | 4,330 |
| Power Canal Leak Investigation | 61,525 | | | 61,525 | SL-5 years | - | 12,305 | | 12,305 |
| Assessment of Fuel Tank Whitehorse | 30,528 | | | 30,528 | SL-5 years | 1,018 | 6,106 | | 7,123 |
| Disaster Recovery Plan | 21,162 | | | 21,162 | SL-5 years | - | 4,232 | | 4,232 |
| Enterprise Risk Management Report | 43,767 | | | 43,767 | SL-5 years | - | 8,753 | | 8,753 |
| Biogas Study | - | 23,469 | | 23,469 | SL-5 years | | | | - |
| L170 Cross Arm Testing & Change | - | 50,824 | | 50,824 | SL-5 years | | | | - |
| WRGS Contamination Assessment | - | 35,307 | | 35,307 | SL-5 years | | | | - |
| Waste To Energy Contribution | (782,591) | | | (782,591) | SL-10 years | (71,569) | (78,259) | | (149,828) |
| Geothermal 2013 Contribution | (3,414) | | | (3,414) | SL-5 years | - | (683) | | (683) |
| Biogas Study Contribution | 0 | (7,000) | | (7,000) | SL-5 years | | | | - |
| Total Feasibility Study Closed | 8,630,475 | 102,599 | (356,472) | 8,376,602 | | 2,501,379 | 1,197,779 | (356,472) | 3,342,686 |
| Work in Progress: | | | | | | | | | |
| Wind Feasibility- Ferry Hill (2011) | 73,617 | 39,944 | | 113,561 | | | | | |
| Victoria Gold - Grid Connection | 113,947 | (545) | (113,402) | - | | | | | |
| Mayo Hydro Bridge Icing Upgrade (2011) | 15,050 | 553 | | 15,603 | | | | | |
| Mayo Lake Outlet Channel | 126,657 | 143,869 | | 270,526 | | | | | |
| Climate Change Study | 272,439 | 169,511 | | 441,950 | | | | | |
| System Stability Review | 85,380 | 3,164 | | 88,544 | | | | | |
| Aishihik Turbine Re-runnering | 1,988 | 28,280 | | 30,268 | | | | | |
| Whitehorse Diesel Plant Conversion | 293,462 | 11,352 | | 304,813 | | | | | |
| Condition Assessment of Selected YEC Assets | 115,804 | 104,531 | | 220,334 | | | | | |
| Fish Ladder & Building Improve | 41,278 | 86,057 | | 127,336 | | | | | |
| Enterprise Risk Management | | 100,542 | | 100,542 | | | | | |
| Carmacks Airport Substation | | 26,220 | | 26,220 | | | | | |
| Life Cycle Analysis LNG/Diesel | | 112,580 | | 112,580 | | | | | |
| LNG Supply Option | | 210,807 | | 210,807 | | | | | |
| LNG Transportation Options | | 193,577 | | 193,577 | | | | | |
| Mt Sumanik Wind Feasibility Study | | 12,607 | | 12,607 | | | | | |
| Marsh Lake Storage | 4,928,418 | 605,333 | | 5,533,751 | | | | | |
| Gladstone | 4,189,030 | 147,874 | | 4,336,904 | | | | | |
| Large Hydro | 208,995 | 69,447 | | 278,442 | | | | | |
| Victoria Gold - Grid Connection Contribution | (113,947) | | 113,947 | - | | | | | |
| Total Feasibility Study WIP | 10,352,118 | 2,065,701 | 545 | 12,418,364 | | | | | |
| Total Feasibility | 18,982,593 | 2,168,300 | (355,927) | 20,794,966 | | 2,501,379 | 1,197,779 | (356,472) | 3,342,686 |
| **Regulatory** | | | | | | | | | |
| Completed Projects: | | | | | | | | | |
| Minto Mine PPA | 769,057 | | | 769,057 | SL-12 years | 325,781 | 64,088 | | 389,869 |
| YUB 2007-7 & 9 - Resource Plan | 642,853 | | | 642,853 | SL-10 years | 385,712 | 64,285 | | 449,997 |
| YUB 2007-7 & 9 - PPA Review | 243,045 | | | 243,045 | SL-12 years | 121,522 | 20,254 | | 141,776 |
| YUB 2007-8 - Part 3 Hearing | 185,011 | | | 185,011 | SL-45 years | 24,668 | 4,111 | | 28,779 |
| Alexco PPA Regulatory Costs | 53,854 | | | 53,854 | SL-5 years | 21,571 | 10,771 | | 32,342 |
| Rider F Policy Review | 24,307 | | (24,307) | - | SL-2 years | 21,285 | 3,022 | (24,307) | - |
| Resource Plan Update 2011 | 740,165 | | | 740,165 | SL-5 years | 296,066 | 148,033 | | 444,099 |
| International Financial Reporting Standards | 565,769 | | | 565,769 | SL-5 years | 226,308 | 113,154 | | 339,461 |
| Total Regulatory Closed | 3,224,060 | - | (24,307) | 3,199,753 | | 1,422,913 | 427,718 | | 1,826,324 |
| Work in Progress: | | | | | | | | | |
| International Financial Reporting Standards | 16,109 | 64,715 | | 80,823 | | | | | |
| DCF ERA Regulatory Review | 25,139 | 160,155 | | 185,294 | | | | | |
| LNG - Part 3 | 43,653 | 499,746 | (543,399) | - | | | | | |
| DSM | 1,399,612 | 443,794 | (60,611) | 1,782,795 | | | | | |
| Resource Plan Update | 219,615 | 8,332 | | 227,947 | | | | | |
| Total Regulatory WIP | 1,704,128 | 1,176,741 | (604,010) | 2,276,859 | | | | | |
| Total Regulatory | 4,928,188 | 1,176,741 | (628,317) | 5,476,612 | | 1,422,913 | 427,718 | | 1,826,324 |
| **Relicensing** | | | | | | | | | |
| Completed projects: | | | | | | | | | |
| Aishihik Relicensing | 8,877,606 | | | 8,877,606 | | 5,915,817 | 523,981 | | 6,439,799 |
| Whitehorse Relicensing | 167,285 | | | 167,285 | | 66,519 | 8,745 | | 75,264 |
| Mayo Relicensing | 79,210 | | | 79,210 | | 18,190 | 5,367 | | 23,557 |
| Air Emission Licence Renewal | 89,429 | | (89,429) | - | | 59,619 | 29,810 | (89,429) | - |
| Mayo Lake Assessment & Permitting | 1,249,262 | | (1,249,262) | - | | 1,249,263 | | (1,249,263) | - |
| Total Relicensing Closed | 10,462,792 | - | (1,338,691) | 9,124,101 | | 7,309,408 | 567,903 | (1,338,691) | 6,538,620 |
| Work in Progress: | | | | | | | | | |
| Mayo Lake - Env. Assessment & Permitting | 1,354,052 | 508,149 | | 1,862,201 | | | | | |
| Air Emission Permit Renewal | 93,524 | 3,491 | | 97,015 | | | | | |
| Lewes Control Structure | 46,600 | 1,747 | | 48,347 | | | | | |
| Whitehorse Dam Break &Mapping | 67,701 | 2,534 | | 70,235 | | | | | |
| Total Relicensing WIP | 1,561,877 | 515,921 | - | 2,077,798 | | | | | |
| Total Relicensing | 12,024,669 | 515,921 | (1,338,691) | 11,201,899 | | 7,309,408 | 567,903 | | 6,538,620 |
| **Dam Safety Review** | | | | | | | | | |
| Completed projects | 331,597 | | | 331,597 | | 284,103 | 23,747 | | 307,850 |
| **Deferred Overhauls (In Tab 5.2)** | | | | | | | | | |
| Completed projects | | | | | | | | | |
| **Total Deferred Costs** | **36,267,046** | **3,860,962** | **-2,322,935** | **37,805,073** | | **11,517,803** | **2,217,147** | | **12,015,480** |
| **Closed** | | | | **21,032,053** | | | | | |
| **WIP** | | | | **16,773,020** | | | | | |
| **Net Deferred Costs (excluding WIP)** | | | | | | | | | **9,016,573** |

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.
2. 2008/2009 GRA Phase 1 Revenue Review cost amortized over 2008 and 2009 as per YUB 2009-11.

**YUKON ENERGY CORPORATION** **Table 5.5**
**Continuity Schedule of Deferred Costs (2015)** **June 2017**
($000S)

| | Total expenditures | | | | Amortization Rate and Method | Accumulated Amortization | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Dec 31 2014 | Act 2015 Additions | Transfers /Retired | Actual 2015 | | Dec 31 2014 | Act 2015 Expenses | Retired | Actual 2015 |
| **Feasibility Study** | | | | | | | | | |
| Completed Projects: | | | | | | | | | |
| AH0 Deluge System | 25,519 | | (25,519) | - | SL-5 years | 20,415 | 5,104 | (25,519) | - |
| P125 Headgates Single Point | 50,419 | | (50,419) | - | SL-5 years | 40,335 | 10,084 | (50,419) | - |
| Wareham Consequence Category Assessment | 62,882 | | (62,882) | - | SL-5 years | 56,594 | 6,288 | (62,882) | - |
| Mayo/Wareham Geotechnical Investigation | 44,562 | | (44,562) | - | SL-5 years | 35,650 | 8,913 | (44,562) | - |
| Hydro Unit Performance Test | 340,200 | | | 340,200 | SL-5 years | 238,140 | 68,040 | | 306,180 |
| WAF/MD Modeling and Stability | 447,536 | | | 447,536 | SL-5 years | 320,734 | 89,507 | | 410,241 |
| P125/126 Hydrocarbon Containment | 27,572 | | | 27,572 | SL-5 years | 20,219 | 5,514 | | 25,734 |
| Communications Strategy Study | 80,575 | | | 80,575 | SL-5 years | 48,389 | 16,115 | | 64,504 |
| System Stability Review | 99,961 | | | 99,961 | SL-5 years | 60,031 | 19,992 | | 80,023 |
| Mayo River Salmon Enhancement | 7,212 | | | 7,212 | SL-5 years | 4,331 | 1,442 | | 5,774 |
| Mayo Lake Control Structure - Fish passage | 2,569 | | | 2,569 | SL-5 years | 1,543 | 514 | | 2,057 |
| Atlin Storage | 2,230,652 | | | 2,230,652 | SL-10 years | 669,196 | 223,065 | | 892,261 |
| Annunciator RTU Upgrade | 43,125 | | | 43,125 | SL-5 years | 17,274 | 8,625 | | 25,899 |
| Mayo Hydro Plant Extension | 132,738 | | | 132,738 | SL-5 years | 53,168 | 26,548 | | 79,715 |
| Mayo Switchgear Phase 1 | 73,972 | | | 73,972 | SL-5 years | 29,629 | 14,794 | | 44,423 |
| Waste To Energy | 1,667,371 | | | 1,667,371 | SL-10 years | 326,266 | 166,737 | | 493,003 |
| Geothermal | 2,072,671 | | | 2,072,671 | SL-10 years | 634,262 | 219,793 | | 854,056 |
| Wind Feasibility - Ferry Hill (2011) | 427,617 | | | 427,617 | SL-5 years | 256,570 | 85,523 | | 342,093 |
| Mayo Hydro Bridge Icing Upgrade | 179,265 | | | 179,265 | SL-5 years | 107,559 | 35,853 | | 143,412 |
| Atlin Grid Connection | 109,941 | | | 109,941 | SL-5 years | 66,025 | 21,988 | | 88,013 |
| Large Hydro - Upper Pelly (2011) | 671,758 | | | 671,758 | SL-5 years | 403,055 | 134,352 | | 537,406 |
| Short Term Energy Storage | 44,307 | | | 44,307 | SL-5 years | 26,609 | 8,861 | | 35,470 |
| Mayo Lake Outlet Channel | 13,250 | | | 13,250 | SL-5 years | 7,950 | 2,650 | | 10,600 |
| Net Metering Demonstration Project | 28,798 | | | 28,798 | SL-5 years | 12,510 | 5,760 | | 18,270 |
| Hydraulic Wood Removal System | 18,556 | | | 18,556 | SL-5 years | 4,330 | 3,711 | | 8,041 |
| Power Canal Leak Investigation | 61,525 | | | 61,525 | SL-5 years | 12,305 | 12,305 | | 24,610 |
| Assessment of Fuel Tank Whitehorse | 30,528 | | | 30,528 | SL-5 years | 7,123 | 6,106 | | 13,229 |
| Disaster Recovery Plan | 21,162 | | | 21,162 | SL-5 years | 4,232 | 4,232 | | 8,465 |
| Enterprise Risk Management Report | 43,767 | | | 43,767 | SL-5 years | 8,753 | 8,753 | | 17,507 |
| Biogas Study | 23,469 | | | 23,469 | SL-5 years | - | 4,694 | | 4,694 |
| L170 Cross Arm Testing & Change | 50,824 | | | 50,824 | SL-5 years | - | 10,165 | | 10,165 |
| WRGS Contamination Assessmt | 35,307 | | | 35,307 | SL-5 years | - | 7,061 | | 7,061 |
| Mayo Hydro Bridge Icing Upgrade (2011) | - | | 15,603 | 15,603 | SL-5 years | - | 3,121 | | 3,121 |
| System Stability Review | - | | 88,544 | 88,544 | SL-5 years | - | 17,709 | | 17,709 |
| Carmacks Airport Substation | - | | 50,627 | 50,627 | SL-5 years | - | 815 | | 815 |
| Solar PV Installation-WH | - | 48,901 | | 48,901 | SL-5 years | - | - | | - |
| Hoole Canyon and Slate Rapids | - | 40,845 | | 40,845 | SL-5 years | - | - | | - |
| Load Forecasting | - | 17,148 | | 17,148 | SL-5 years | - | - | | - |
| Faro Mine Pumped Storage Project | - | 21,634 | | 21,634 | SL-5 years | - | - | | - |
| Waste To Energy Contribution | (782,591) | | | (782,591) | SL-10 years | (149,828) | (78,259) | | (228,087) |
| Geothermal 2013 Contribution | (3,414) | | | (3,414) | SL-5 years | (683) | (683) | | (1,366) |
| Biogas Study Contribution | (7,000) | | | (7,000) | SL-5 years | - | (1,400) | | (1,400) |
| 2015 YDC Contribution to offset all feasibility asset | - | (4,135,018) | | (4,135,018) | SL-5 years | - | - | | - |
| | | | | | | | | | - |
| Total Feasibility Study Closed | 8,376,602 | (4,006,489) | (28,609) | 4,341,504 | | 3,342,686 | 1,184,392 | (183,382) | 4,343,697 |
| Work in Progress: | | | | | | | | | |
| Wind Feasibility- Ferry Hill | 113,561 | 2,620 | | 116,181 | | | | | |
| Mayo Hydro Bridge Icing Upgrade | 15,603 | | (15,603) | - | | | | | |
| Mayo Lake Outlet Channel | 270,526 | 144,813 | | 415,340 | | | | | |
| Climate Change Study | 441,950 | 116,509 | | 558,459 | | | | | |
| System Stability Review | 88,544 | | (88,544) | - | | | | | |
| Aishihik Turbine Re-runnering | 30,268 | 82,958 | | 113,226 | | | | | |
| Whitehorse Diesel Plant Conversion | 304,813 | 7,079 | | 311,892 | | | | | |
| Condition Assessment of Selected YEC Assets | 220,334 | 5,206 | | 225,541 | | | | | |
| Fish Ladder & Building Improve | 127,336 | 13,535 | (140,870) | - | | | | | |
| Enterprise Risk Management | 100,542 | 64,998 | | 165,540 | | | | | |
| Carmacks Airport Substation | 26,220 | 24,407 | (50,627) | - | | | | | |
| Life Cycle Analysis LNG/Diesel | 112,580 | 2,759 | | 115,338 | | | | | |
| LNG Supply Option | 210,807 | 56,037 | | 266,844 | | | | | |
| LNG Transportation Options | 193,577 | 53,987 | | 247,564 | | | | | |
| LNG Transportation Options - Contributions | - | (15,000) | | (15,000) | | | | | |
| Mt Sumanik Wind Feasibility Study | 12,607 | 372,821 | | 385,428 | | | | | |
| Condition Assessment of WH & WD Assets | | 214,870 | | 214,870 | | | | | |
| Moon Lake Hydro Project | | 104,564 | | 104,564 | | | | | |
| Biogas Preliminary Design 2 | | 71,468 | | 71,468 | | | | | |
| Biogas Preliminary Design 2 - Contributions | | (16,500) | | (16,500) | | | | | |
| Home Heating Retrofit Options | | 6,270 | | 6,270 | | | | | |
| Building Condition Report 2015 | | 133,749 | | 133,749 | | | | | |
| L170/L178 Snow Shed Crossarm | | 26,535 | | 26,535 | | | | | |
| Mayo & Aishihik Climate Change | | 19,061 | | 19,061 | | | | | |
| Electric Vehicle Technical Study | | 52,444 | | 52,444 | | | | | |
| SKTP | | 1,170,986 | | 1,170,986 | | | | | |
| SKTP-YG Funding | | (2,000,000) | | (2,000,000) | | | | | |
| Resource Plan Update - 2016 | | 293,182 | | 293,182 | | | | | |
| Marsh Lake Storage | 5,533,751 | 983,000 | | 6,516,752 | | | | | |
| Gladstone | 4,336,904 | 92,219 | | 4,429,123 | | | | | |
| Large Hydro | 278,442 | 6,470 | | 284,911 | | | | | |
| Total Feasibility Study WIP | 12,418,364 | 2,091,049 | (295,644) | 14,213,769 | | | | | |
| Total Feasibility | 20,794,966 | (1,915,441) | (324,252) | 18,555,273 | | 3,342,686 | 1,184,392 | (183,382) | 4,343,697 |
| **Regulatory** | | | | | | | | | |
| Completed Projects: | | | | | | | | | |
| Minto Mine PPA | 769,057 | | | 769,057 | SL-12 years | 389,869 | 64,088 | | 453,957 |
| YUB 2007-7 & 9 - Resource Plan | 642,853 | | | 642,853 | SL-10 years | 449,997 | 64,285 | | 514,283 |
| YUB 2007-7 & 9 - PPA Review | 243,045 | | | 243,045 | SL-12 years | 141,776 | 20,254 | | 162,030 |
| YUB 2007-8 - Part 3 Hearing | 185,011 | | | 185,011 | SL-45 years | 28,779 | 4,111 | | 32,891 |
| Alexco PPA Regulatory Costs | 53,854 | | | 53,854 | SL-5 years | 32,342 | 10,771 | | 43,112 |
| Resource Plan Update 2011 | 740,165 | | | 740,165 | SL-5 years | 444,099 | 148,033 | | 592,132 |
| International Financial Reporting Standards | 565,769 | | | 565,769 | SL-5 years | 339,461 | 113,154 | | 452,615 |
| Total Regulatory Closed | 3,199,753 | - | - | 3,199,753 | | 1,826,324 | 424,696 | | 2,251,019 |
| Work in Progress: | | | | | | | | | |
| International Financial Reporting Standards | 80,823 | 98,514 | | 179,337 | | | | | |
| DCF ERA Regulatory Review | 185,294 | 38,875 | (224,169) | - | | | | | |
| DSM | 1,782,795 | 297,584 | | 2,080,379 | | | | | |
| Resource Plan Update - 2016 | | | | - | | | | | |
| Resource Plan Update - 2011 | 227,947 | 5,196 | | 233,143 | | | | | |
| Total Regulatory WIP | 2,276,859 | 440,169 | (224,169) | 2,492,859 | | | | | |
| Total Regulatory | 5,476,612 | 440,169 | (224,169) | 5,692,612 | | 1,826,324 | 424,696 | | 2,251,019 |

**YUKON ENERGY CORPORATION** **Table 5.5**
**Continuity Schedule of Deferred Costs (2015)** **June 2017**
($000S)

| | Total expenditures | | | | | Accumulated Amortization | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Dec 31 2014 | Act 2015 Additions | Act 2015 Transfers /Retired | Actual 2015 | Amortization Rate and Method | Dec 31 2014 | Act 2015 Expenses | Act 2015 Retired | Actual 2015 |
| **Relicensing** | | | | | | | | | |
| Completed Projects: | | | | | | | | | |
| Aishihik Relicensing | 8,877,606 | | (86,767) | 8,790,839 | | 6,439,799 | 523,702 | (86,767) | 6,876,733 |
| Whitehorse Relicensing | 167,285 | 118,582 | | 285,867 | | 75,264 | 20,604 | | 95,868 |
| Mayo Relicensing | 79,210 | | | 79,210 | | 23,557 | 5,367 | | 28,924 |
| Air Emission Licence Renewal | - | | 97,015 | 97,015 | | - | 32,338 | | 32,338 |
| Total Relicensing Closed | 9,124,101 | 118,582 | | 9,252,931 | | 6,538,620 | 582,011 | | 7,033,863 |
| Work in Progress: | | | | | | | | | |
| Mayo Lake - Env. Assessment & Permitting | 1,862,201 | 258,859 | | 2,121,060 | | | | | |
| Air Emission Permit Renewal | 97,015 | | (97,015) | - | | | | | |
| Lewes Control Structure | 48,347 | | (48,347) | - | | | | | |
| Whitehorse Dam Break & Mapping | 70,235 | | (70,235) | - | | | | | |
| Wareham Dam Break and Inundation Mapping | - | 47,512 | | 47,512 | | | | | |
| Aishihik Relicensing | - | 50,149 | | 50,149 | | | | | |
| Total Relicensing WIP | 2,077,798 | 356,520 | (215,597) | 2,218,721 | - | - | - | | - |
| Total Relicensing | 11,201,899 | 475,102 | (215,597) | 11,471,652 | | 6,538,620 | 582,011 | | 7,033,863 |
| **Dam Safety Review** | | | | | | | | | |
| Completed projects | 331,597 | | (331,597) | - | | 307,850 | 23,747 | (331,597) | - |
| Work in Progress | - | 144,263 | | 144,263 | | | | | |
| Total Dam Safety Review | 331,597 | 144,263 | (331,597) | 144,263 | | 307,850 | 23,747 | | - |
| **Deferred Overhauls (In Tab 5.2)** | | | | | | | | | |
| Completed projects | | | | | | | | | |
| **Total Deferred Costs** | **37,805,073** | **-855,906** | **-1,095,615** | **35,863,800** | | **12,015,480** | **2,214,846** | | **13,628,579** |
| **Closed** | | | | **16,794,188** | | | | | |
| **WIP** | | | | **19,069,612** | | | | | |
| **Net Deferred Costs (excluding WIP)** | | | | | | | | | **3,165,609** |

Note: This table does not include projects with zero net book value in the beginning of the year.

**YUKON ENERGY CORPORATION** **Table 5.6**
**Continuity Schedule of Deferred Costs (2016)** **June 2017**
($000S)

| | Total expenditures | | | | | Accumulated Amortization | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Dec 31 2015 | Forecast 2016 Additions | Forecast 2016 Transfers /Retired | Actual 2016 | Amortization Rate and Method | Dec 31 2015 | Act 2016 Expenses | Act 2016 Retired | Actual 2016 |
| **Feasibility Study** | | | | | | | | | |
| Completed Projects: | | | | | | | | | |
| Hydro Unit Performance Test | 340,200 | | (340,200) | - | SL-5 years | 306,180 | 34,020 | (340,200) | - |
| WAF/MD Modeling and Stability | 447,536 | | (447,536) | - | SL-5 years | 410,241 | 37,295 | (447,536) | - |
| P125/126 Hydrocarbon Containment | 27,572 | | (27,572) | - | SL-5 years | 25,734 | 1,838 | (27,572) | - |
| Communications Strategy Study | 80,575 | | (80,575) | - | SL-5 years | 64,504 | 16,071 | (80,575) | - |
| System Stability Review | 99,961 | | (99,961) | - | SL-5 years | 80,023 | 19,937 | (99,961) | - |
| Mayo River Salmon Enhancement | 7,212 | | (7,212) | - | SL-5 years | 5,774 | 1,438 | (7,212) | - |
| Mayo Lake Control Structure - Fish passage | 2,569 | | (2,569) | - | SL-5 years | 2,057 | 513 | (2,569) | - |
| Atlin Storage | 2,230,652 | | | 2,230,652 | SL-10 years | 892,261 | 223,065 | | 1,115,326 |
| Annunciator RTU Upgrade | 43,125 | | | 43,125 | SL-5 years | 25,899 | 8,625 | | 34,524 |
| Mayo Hydro Plant Extension | 132,738 | | | 132,738 | SL-5 years | 79,715 | 26,548 | | 106,263 |
| Mayo Switchgear Phase 1 | 73,972 | | | 73,972 | SL-5 years | 44,423 | 14,794 | | 59,218 |
| Waste To Energy | 1,667,371 | | | 1,667,371 | SL-10 years | 493,003 | 166,737 | | 659,741 |
| Geothermal | 2,072,671 | | | 2,072,671 | SL-10 years | 854,056 | 219,793 | | 1,073,849 |
| Wind Feasibility- Ferry Hill (2011) | 427,617 | | (427,617) | - | SL-5 years | 342,093 | 85,523 | (427,617) | - |
| Mayo Hydro Bridge Icing Upgrade | 179,265 | | (179,265) | - | SL-5 years | 143,412 | 35,853 | (179,265) | - |
| Atlin Grid Connection | 109,941 | | (109,941) | - | SL-5 years | 88,013 | 21,928 | (109,941) | - |
| Large Hydro- Upper Pelly (2011) | 671,758 | | (671,758) | - | SL-5 years | 537,406 | 134,352 | (671,758) | - |
| Short Term Energy Storage | 44,307 | | (44,307) | - | SL-5 years | 35,470 | 8,837 | (44,307) | - |
| Mayo Lake Outlet Channel | 13,250 | | (13,250) | - | SL-5 years | 10,600 | 2,650 | (13,250) | - |
| Net Metering Demonstration Project | 28,798 | | | 28,798 | SL-5 years | 18,270 | 5,760 | | 24,029 |
| Hydraulic Wood Removal System | 18,556 | | | 18,556 | SL-5 years | 8,041 | 3,711 | | 11,752 |
| Power Canal Leak Investigation | 61,525 | | | 61,525 | SL-5 years | 24,610 | 12,305 | | 36,915 |
| Assessment of Fuel Tank Whitehorse | 30,528 | | | 30,528 | SL-5 years | 13,229 | 6,106 | | 19,334 |
| Disaster Recovery Plan | 21,162 | | | 21,162 | SL-5 years | 8,465 | 4,232 | | 12,697 |
| Enterprise Risk Management Report | 43,767 | | | 43,767 | SL-5 years | 17,507 | 8,753 | | 26,260 |
| Biogas Study | 23,469 | | 71,819 | 95,288 | SL-5 years | 4,694 | 17,861 | | 22,554 |
| L170 Cross Arm Testing & Change | 50,824 | | | 50,824 | SL-5 years | 10,165 | 10,165 | | 20,329 |
| WRGS Contamination Assessment | 35,307 | | | 35,307 | SL-5 years | 7,061 | 7,061 | | 14,123 |
| Mayo Hydro Bridge Icing Upgrade (2011) | 15,603 | | | 15,603 | SL-5 years | 3,121 | 3,121 | | 6,241 |
| System Stability Review | 88,544 | | | 88,544 | SL-5 years | 17,709 | 17,709 | | 35,418 |
| Carmacks Airport Substation | 50,627 | | | 50,627 | SL-5 years | 815 | 10,125 | | 10,940 |
| Solar PV Installation-WH | 48,901 | | | 48,901 | SL-5 years | - | 9,780 | | 9,780 |
| Hoole Canyon and Slate Rapids | 40,845 | | | 40,845 | SL-5 years | - | 8,169 | | 8,169 |
| Load Forecasting | 17,148 | | | 17,148 | SL-5 years | - | 3,429 | | 3,429 |
| Faro Mine Pumped Storage Project | 21,634 | | | 21,634 | SL-5 years | - | 4,327 | | 4,327 |
| Home Heating Retrofit Options | - | | 9,684 | 9,684 | SL-5 years | - | 1,130 | | 1,130 |
| Electric Vehicle Technical Study | - | | 67,919 | 67,919 | SL-5 years | - | 9,056 | | 9,056 |
| Electric Vehicle Technical Study - Contributions | - | (3,500) | | (3,500) | SL-5 years | - | (467) | | (467) |
| Mayo A Hydro Assessment | - | 95,038 | | 95,038 | SL-5 years | - | 6,336 | | 6,336 |
| LNG Boil Off Gas Options | - | 46,317 | | 46,317 | SL-5 years | - | - | | - |
| Dawson Downtown Voltage Upgrade Assessment | - | 4,122 | | 4,122 | SL-5 years | - | - | | - |
| SKTP | - | - | | - | SL-5 years | - | - | | - |
| SKTP-YG Funding | - | - | | - | SL-5 years | - | - | | - |
| Waste To Energy Contribution | (782,591) | | | (782,591) | SL-10 years | (228,087) | (78,259) | | (306,346) |
| Geothermal 2013 Contribution | (3,414) | | | (3,414) | SL-5 years | (1,366) | (683) | | (2,048) |
| Biogas Study Contribution | (7,000) | | | (7,000) | SL-5 years | (1,400) | (1,400) | | (2,800) |
| YDC Feasibility Asset Contribution | (4,135,018) | | 400,255 | (3,734,763) | SL-5 years | - | (1,100,191) | 400,255 | (699,936) |
| Biogas Preliminary Design 2 Contribution | - | | (16,500) | (16,500) | SL-5 years | - | (3,025) | | (3,025) |
| Total Feasibility Study Closed | 4,341,504 | 141,977 | (1,918,585) | 2,564,896 | | 4,343,697 | 24,929 | (2,051,507) | 2,317,119 |
| Work in Progress: | | | | | | | | | |
| Wind Feasibility - Ferry Hill | 116,181 | 2,562 | | 118,743 | | | | | |
| Mayo Lake Outlet Channel | 415,340 | 11,036 | | 426,376 | | | | | |
| Climate Change Study | 558,459 | 39,661 | | 598,120 | | | | | |
| Aishihik Turbine Re-runnering | 113,226 | 2,668 | | 115,894 | | | | | |
| Whitehorse Diesel Plant Conversion | 311,892 | 6,922 | | 318,814 | | | | | |
| Condition Assessment of Selected YEC Assets | 225,541 | 5,091 | | 230,631 | | | | | |
| Enterprise Risk Management | 165,540 | 3,858 | | 169,398 | | | | | |
| Life Cycle Analysis LNG/Diesel | 115,338 | 2,697 | | 118,036 | | | | | |
| LNG Supply Option | 266,844 | 6,251 | | 273,095 | | | | | |
| LNG Transportation Options | 247,564 | 30,136 | | 277,700 | | | | | |
| LNG Transportation Options - Contributions | (15,000) | | | (15,000) | | | | | |
| Mt Sumanik Wind Feasibility Study | 385,428 | 154,852 | | 540,280 | | | | | |
| Condition Assessment of WH & WD Assets | 214,870 | 13,099 | | 227,969 | | | | | |
| Moon Lake Hydro Project | 104,564 | 32,948 | | 137,512 | | | | | |
| Biogas Preliminary Design 2 | 71,468 | 350 | (71,819) | - | | | | | |
| Biogas Preliminary Design 2 - Contributions | (16,500) | | 16,500 | - | | | | | |
| Home Heating Retrofit Options | 6,270 | 3,414 | (9,684) | - | | | | | |
| Building Condition Report | 133,749 | (29,344) | | 104,405 | | | | | |
| L170/L178 Snow Shed Crossarm | 26,535 | 163,079 | | 189,614 | | | | | |
| Mayo & Aishihik Climate Change | 19,061 | 102,469 | | 121,530 | | | | | |
| Electric Vehicle Technical Study | 52,444 | 15,475 | (67,919) | - | | | | | |
| SKTP | 1,170,986 | 1,635,989 | | 2,806,975 | | | | | |
| SKTP-YG Funding | (2,000,000) | (825,000) | | (2,825,000) | | | | | |
| Whitehorse Turbine Re-runnering | | 145,205 | | 145,205 | | | | | |
| Assessment of Transformer T9 | | 105,337 | | 105,337 | | | | | |
| Asset Condition Assessment | | 127,545 | | 127,545 | | | | | |
| LNG Third Engine Assessment | | 25,464 | | 25,464 | | | | | |
| Detailed Line Inspection | | 50,362 | | 50,362 | | | | | |
| Vegetation Management on Powerlines | - | 45,153 | | 45,153 | | | | | |
| Resource Plan Update - 2016 | 293,182 | 1,561,284 | | 1,854,466 | | | | | |
| Marsh Lake Storage | 6,516,752 | 364,603 | | 6,881,354 | | | | | |
| Gladstone | 4,429,123 | 92,142 | | 4,521,265 | | | | | |
| Large Hydro | 284,911 | 6,326 | | 291,237 | | | | | |
| Total Feasibility Study WIP | 14,213,769 | 3,901,634 | (132,922) | 17,982,480 | | | | | |
| Total Feasibility | 18,555,273 | 4,043,610 | (2,051,507) | 20,547,376 | | 4,343,697 | 24,929 | (2,051,507) | 2,317,119 |

**YUKON ENERGY CORPORATION** **Table 5.6**
**Continuity Schedule of Deferred Costs (2016)** **June 2017**
($000S)

| | Total expenditures | | | | | Accumulated Amortization | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Dec 31 | Forecast 2016 | | Actual | Amortization | Dec 31 | Act 2016 | | Actual |
| | 2015 | Additions | Transfers /Retired | 2016 | Rate and Method | 2015 | Expenses | Retired | 2016 |
| **Regulatory** | | | | | | | | | |
| Completed Projects: | | | | | | | | | |
| Minto Mine PPA | 769,057 | | | 769,057 | SL-12 years | 453,957 | 64,088 | | 518,045 |
| YUB 2007-7 & 9 - Resource Plan | 642,853 | | | 642,853 | SL-10 years | 514,283 | 64,285 | | 578,568 |
| YUB 2007-7 & 9 - PPA Review | 243,045 | | | 243,045 | SL-12 years | 162,030 | 20,254 | | 182,284 |
| YUB 2007-8 - Part 3 Hearing | 185,011 | | | 185,011 | SL-45 years | 32,891 | 4,111 | | 37,002 |
| Alexco PPA Regulatory Costs | 53,854 | | (53,854) | - | SL-5 years | 43,112 | 10,741 | (53,854) | - |
| Resource Plan Update - 2011 | 740,165 | | (740,165) | - | SL-5 years | 592,132 | 148,033 | (740,165) | - |
| International Financial Reporting Standards | 565,769 | | (565,769) | - | SL-5 years | 452,615 | 113,154 | (565,769) | - |
| Total Regulatory Closed | 3,199,753 | - | (1,359,787) | 1,839,965 | | 2,251,019 | 424,666 | | 1,315,898 |
| Work in Progress: | | | | | | | | | |
| International Financial Reporting Standards | 179,337 | 1,743 | | 181,080 | | | | | |
| DSM | 2,080,379 | 403,474 | | 2,483,854 | | | | | |
| Resource Plan Update - 2011 | 233,143 | 5,080 | | 238,223 | | | | | |
| Arc- Flash study | - | 178,903 | | 178,903 | | | | | |
| General Rate Application - 2017/18 | - | 104,644 | | 104,644 | | | | | |
| Total Regulatory WIP | 2,492,859 | 693,844 | - | 3,186,704 | | | | | |
| Total Regulatory | 5,692,612 | 693,844 | (1,359,787) | 5,026,669 | | 2,251,019 | 424,666 | | 1,315,898 |
| **Relicensing** | | | | | | | | | |
| Completed Projects: | | | | | | | | | |
| Aishihik Relicensing | 8,790,839 | | | 8,790,839 | | 6,876,733 | 518,559 | | 7,395,292 |
| Whitehorse Relicensing | 285,867 | | | 285,867 | | 95,868 | 20,604 | | 116,471 |
| Mayo Relicensing | 79,210 | | 59,795 | 139,006 | | 28,924 | 10,366 | | 39,290 |
| Air Emission Licence Renewal | 97,015 | | | 97,015 | | 32,338 | 32,338 | | 64,676 |
| Total Relicensing Closed | 9,252,931 | - | | 9,312,727 | | 7,033,863 | 581,867 | | 7,615,730 |
| Work in Progress: | | | | | | | | | |
| Mayo Lake | 2,121,060 | 285,042 | | 2,406,102 | | | | | |
| Wareham Dam Break and Inundation Mapping | 47,512 | 12,284 | (59,795) | - | | | | | |
| Aishihik Relicensing | 50,149 | 954,936 | | 1,005,086 | | | | | |
| Total Relicensing WIP | 2,218,721 | 1,252,262 | (59,795) | 3,411,188 | - | - | - | | - |
| Total Relicensing | 11,471,652 | 1,252,262 | (59,795) | 12,723,914 | | 7,033,863 | 581,867 | | 7,615,730 |
| **Dam Safety Review** | | | | | | | | | |
| Completed Projects | - | - | - | - | | - | - | | - |
| Work in Progress | 144,263 | 3,449 | - | 147,712 | | | | | |
| Total Dam Safety Review | 144,263 | 3,449 | - | 147,712 | | - | - | | - |
| **Deferred Overhauls (In Tab 5.2)** | | | | | | | | | |
| **Total Deferred Costs** | **35,863,800** | **5,993,166** | **-3,471,090** | **38,445,671** | | **13,628,579** | **1,031,462** | | **11,248,747** |
| **Closed (includes Rate Case WIP)** | | | | **13,717,587** | | | | | |
| **WIP** | | | | **24,728,084** | | | | | |
| **Net Deferred Costs (excluding WIP)** | | | | | | | | | **2,468,841** |

Note: This table does not include projects with zero net book value in the beginning of the year.

**YUKON ENERGY CORPORATION** **Table 5.7**
**Continuity Schedule of Deferred Costs (2017)** **June 2017**
($000S)

| | Total expenditures | | | | | Accumulated Amortization | | |
|---|---|---|---|---|---|---|---|---|
| | Dec 31 2016 | Forecast 2017 Additions | Forecast 2017 Transfers /Retired | Forecast 2017 | Amortization Rate and Method | Dec 31 2016 | 2017 Forecast Expenses | Forecast 2017 |
| **Feasibility Study** | | | | | | | | |
| Completed Projects: | | | | | | | | |
| Atlin Storage | 2,230,652 | | | 2,230,652 | SL-10 years | 1,115,326 | 223,065 | 1,338,391 |
| Annunciator RTU Upgrade | 43,125 | | | 43,125 | SL-5 years | 34,524 | 8,601 | 43,125 |
| Mayo Hydro Plant Extension | 132,738 | | | 132,738 | SL-5 years | 106,263 | 26,475 | 132,738 |
| Mayo Switchgear Phase 1 | 73,972 | | | 73,972 | SL-5 years | 59,218 | 14,754 | 73,972 |
| Waste To Energy | 1,667,371 | | | 1,667,371 | SL-10 years | 659,741 | 166,737 | 826,478 |
| Geothermal | 2,072,671 | | | 2,072,671 | SL-10 years | 1,073,849 | 219,793 | 1,293,642 |
| Net Metering Demonstration Project | 28,798 | | | 28,798 | SL-5 years | 24,029 | 4,768 | 28,798 |
| Hydraulic Wood Removal System | 18,556 | | | 18,556 | SL-5 years | 11,752 | 3,711 | 15,463 |
| Power Canal Leak Investigation | 61,525 | | | 61,525 | SL-5 years | 36,915 | 12,305 | 49,220 |
| Assessment of Fuel Tank Whitehorse | 30,528 | | | 30,528 | SL-5 years | 19,334 | 6,106 | 25,440 |
| Disaster Recovery Plan | 21,162 | | | 21,162 | SL-5 years | 12,697 | 4,232 | 16,930 |
| Enterprise Risk Management Report | 43,767 | | | 43,767 | SL-5 years | 26,260 | 8,753 | 35,014 |
| Biogas Study | 95,288 | | | 95,288 | SL-5 years | 22,554 | 19,058 | 41,612 |
| L170 Cross Arm Testing & Change | 50,824 | | | 50,824 | SL-5 years | 20,329 | 10,165 | 30,494 |
| WRGS Contamination Assessment | 35,307 | | | 35,307 | SL-5 years | 14,123 | 7,061 | 21,184 |
| Mayo Hydro Bridge Icing Upgrade | 15,603 | | | 15,603 | SL-5 years | 6,241 | 3,121 | 9,362 |
| System Stability Review | 88,544 | | | 88,544 | SL-5 years | 35,418 | 17,709 | 53,126 |
| Carmacks Airport Substation | 50,627 | | | 50,627 | SL-5 years | 10,940 | 10,125 | 21,066 |
| Solar PV Installation-WH | 48,901 | | | 48,901 | SL-5 years | 9,780 | 9,780 | 19,561 |
| Hoole Canyon and Slate Rapids | 40,845 | | | 40,845 | SL-5 years | 8,169 | 8,169 | 16,338 |
| Load Forecasting | 17,148 | | | 17,148 | SL-5 years | 3,429 | 3,430 | 6,859 |
| Faro Mine Pumped Storage Project | 21,634 | | | 21,634 | SL-5 years | 4,327 | 4,327 | 8,654 |
| Home Heating Retrofit Options | 9,684 | | | 9,684 | SL-5 years | 1,130 | 1,937 | 3,067 |
| Electric Vehicle Technical Study | 67,919 | | | 67,919 | SL-5 years | 9,056 | 13,584 | 22,640 |
| Electric Vehicle Technical Study - Contributions | (3,500) | | | (3,500) | SL-5 years | (467) | (700) | (1,167) |
| Vegetation Management on Powerline Rights of Way | - | | 45,153 | 45,153 | SL-5 years | - | - | - |
| LNG Boil Off Gas Options | 46,317 | | | 46,317 | SL-5 years | - | 9,263 | 9,263 |
| Mayo A Hydro Assessment | 95,038 | | | 95,038 | SL-5 years | 6,336 | 19,008 | 25,343 |
| Diesel Generator Protection | | 85,000 | | 85,000 | SL-5 years | - | 8,500 | 8,500 |
| Dawson Downtown Voltage Upgrade Assessment | 4,122 | 50,000 | | 54,122 | SL-5 years | - | 5,824 | 5,824 |
| Resource Plan Update - 2016 | | | 2,004,466 | 2,004,466 | SL-5 years | - | 300,670 | 300,670 |
| EDMS Investigation | | 50,000 | | 50,000 | SL-5 years | - | 5,000 | 5,000 |
| Disaster Recovery Plan/Business Continuity Plan | | 25,000 | | 25,000 | SL-5 years | - | 2,500 | 2,500 |
| Evaluation of CIS Options | | 50,000 | | 50,000 | SL-5 years | - | 5,000 | 5,000 |
| LNG Third Engine Assessment | | | 40,464 | 40,464 | SL-5 years | - | 4,046 | 4,046 |
| Gladstone | | | 4,521,265 | 4,521,265 | SL-10 years | - | 452,126 | 452,126 |
| Large Hydro | | | 291,237 | 291,237 | SL-5 years | - | 58,247 | 58,247 |
| Whitehorse Turbine Re-runnering | | | 145,205 | 145,205 | SL-5 years | - | 29,041 | 29,041 |
| Aishihik Turbine Re-runnering | | | 115,894 | 115,894 | SL-5 years | - | 23,179 | 23,179 |
| Wind Feasibility - Ferry Hill | | | 118,743 | 118,743 | SL-5 years | - | 23,749 | 23,749 |
| Condition Assessment of Selected YEC Assets | | | 230,631 | 230,631 | SL-5 years | - | 46,126 | 46,126 |
| Climate Change Study | | | 598,120 | 598,120 | SL-5 years | - | 119,624 | 119,624 |
| Whitehorse Diesel Plant Conversion | | | 318,814 | 318,814 | SL-5 years | - | 63,763 | 63,763 |
| Enterprise Risk Management | | | 169,398 | 169,398 | SL-5 years | - | 33,880 | 33,880 |
| Building Condition Reports | | | 104,405 | 104,405 | SL-5 years | - | 20,881 | 20,881 |
| Condition Assessment of WH & WD Assets | | | 227,969 | 227,969 | SL-5 years | - | 45,594 | 45,594 |
| Asset Condition Assessment | | | 127,545 | 127,545 | SL-5 years | - | 25,509 | 25,509 |
| LNG Supply Option | | | 273,095 | 273,095 | SL-5 years | - | 54,619 | 54,619 |
| Life Cycle Analysis of LNG/Diesel | | | 118,036 | 118,036 | SL-5 years | - | 23,607 | 23,607 |
| LNG Transportation Options | | | 277,700 | 277,700 | SL-5 years | - | 55,540 | 55,540 |
| Cross Arm Replacements Evaluation | | | 189,614 | 189,614 | SL-5 years | - | 37,923 | 37,923 |
| Detailed Line Inspection | | | 428,362 | 428,362 | SL-5 years | - | 85,672 | 85,672 |
| Time of Use Rate Structure and Smart Grid | - | | 100,000 | 100,000 | SL-5 years | - | 5,000 | 5,000 |
| SKTP | - | | | - | SL-5 years | - | - | - |
| SKTP-YG Funding | - | | | - | SL-5 years | - | - | - |
| Waste To Energy Contribution | (782,591) | | | (782,591) | SL-10 years | (306,346) | (78,259) | (384,605) |
| Geothermal 2013 Contribution | (3,414) | | | (3,414) | SL-5 years | (2,048) | (683) | (2,731) |
| Biogas Study Contribution | (7,000) | | | (7,000) | SL-5 years | (2,800) | (1,400) | (4,200) |
| Biogas Preliminary Design 2 Contribution | (16,500) | | | (16,500) | SL-5 years | (3,025) | (3,300) | (6,325) |
| YDC Feasibility Asset Contribution | (3,734,763) | | | (3,734,763) | SL-5 years | (699,936) | (698,804) | (1,398,740) |
| LNG Transportation Options Contribution | - | | (15,000) | (15,000) | SL-5 years | - | (3,000) | (3,000) |
| Total Feasibility Study Closed | 2,564,896 | 260,000 | 10,431,116 | 13,256,011 | | 2,317,119 | 1,585,511 | 3,902,630 |
| Work in Progress: | | | | | | | | |
| Wind Feasibility- Ferry Hill | 118,743 | | (118,743) | - | | | | |
| Mayo Lake Outlet Channel | 426,376 | | - | 426,376 | | | | |
| Climate Change Study | 598,120 | | (598,120) | - | | | | |
| Aishihik Turbine Re-runnering | 115,894 | | (115,894) | - | | | | |
| Whitehorse Diesel Plant Conversion | 318,814 | | (318,814) | - | | | | |
| Condition Assessment of Selected YEC Assets | 230,631 | | (230,631) | - | | | | |
| Enterprise Risk Management | 169,398 | | (169,398) | - | | | | |
| Life Cycle Analysis LNG/Diesel | 118,036 | | (118,036) | - | | | | |
| LNG Supply Option | 273,095 | | (273,095) | - | | | | |
| LNG Transportation Options | 277,700 | | (277,700) | - | | | | |
| LNG Transportation Options - Contributions | (15,000) | | 15,000 | - | | | | |
| Mt Sumanik Wind Feasibility Study | 540,280 | 50,000 | | 590,280 | | | | |
| Condition Assessment of WH & WD Assets | 227,969 | | (227,969) | - | | | | |
| Moon Lake Hydro Project | 137,512 | 34,000 | | 171,512 | | | | |
| Building Condition Report 2015 | 104,405 | | (104,405) | - | | | | |
| L170/L178 Snow Shed Crossarm | 189,614 | | (189,614) | - | | | | |
| Mayo & Aishihik Climate Change | 121,530 | 160,000 | | 281,530 | | | | |
| SKTP | 2,806,975 | | | 2,806,975 | | | | |
| SKTP-YG Funding | (2,825,000) | | | (2,825,000) | | | | |
| Whitehorse Turbine Re-runnering | 145,205 | | (145,205) | - | | | | |
| Assessment of Transformer T9 | 105,337 | | | 105,337 | | | | |
| Asset Condition Assessment | 127,545 | | (127,545) | - | | | | |
| Detailed Line Inspection | 50,362 | 378,000 | (428,362) | - | | | | |
| Vegetation Management on Powerlines | 45,153 | | (45,153) | - | | | | |
| Resource Plan Update - 2016 | 1,854,466 | 150,000 | (2,004,466) | - | | | | |
| Time of Use Rate Structure and Smart Grid | - | 100,000 | (100,000) | - | | | | |
| Development of Asset Management Program | - | 200,000 | | 200,000 | | | | |
| #REF! | 25,464 | 15,000 | (40,464) | - | | | | |
| Marsh Lake Storage | 6,881,354 | 250,000 | | 7,131,354 | | | | |
| Battery | - | 500,000 | | 500,000 | | | | |
| Thermal Plant | - | 750,000 | | 750,000 | | | | |
| Gladstone | 4,521,265 | | (4,521,265) | - | | | | |
| Large Hydro | 291,237 | | (291,237) | - | | | | |
| Total Feasibility Study WIP | 17,982,480 | 2,587,000 | (10,431,116) | 10,138,364 | | | | |
| Total Feasibility | 20,547,376 | 2,847,000 | - | 23,394,376 | - | 2,317,119 | 1,585,511 | 3,902,630 |

**YUKON ENERGY CORPORATION** — **Table 5.7**
**Continuity Schedule of Deferred Costs (2017)** — **June 2017**
($000S)

| | Total expenditures | | | | | Accumulated Amortization | | |
|---|---|---|---|---|---|---|---|---|
| | Dec 31 | Forecast 2017 | | Forecast | Amortization | Dec 31 | 2017 Forecast | Forecast |
| | 2016 | Additions | Transfers /Retired | 2017 | Rate and Method | 2016 | Expenses | 2017 |
| **Regulatory** | | | | | | | | |
| Completed Projects: | | | | | | | | |
| Minto Mine PPA | 769,057 | | | 769,057 | SL-12 years | 518,045 | 64,088 | 582,133 |
| YUB 2007-7 & 9 - Resource Plan | 642,853 | | | 642,853 | SL-10 years | 578,568 | 64,285 | 642,853 |
| YUB 2007-7 & 9 - PPA Review | 243,045 | | | 243,045 | SL-12 years | 182,284 | 20,254 | 202,537 |
| YUB 2007-8 - Part 3 Hearing | 185,011 | | | 185,011 | SL-45 years | 37,002 | 4,111 | 41,113 |
| Arc Flash Study | - | | 178,903 | 178,903 | SL-5 years | - | 35,781 | 35,781 |
| International Financial Reporting Standards | - | | 181,080 | 181,080 | SL-5 years | - | 36,216 | 36,216 |
| DSM | - | | 2,693,854 | 2,693,854 | SL-10 years | - | 250,984 | 250,984 |
| Resource Plan Update - 2011 | - | | 238,223 | 238,223 | SL-5 years | - | 47,645 | 47,645 |
| Total Regulatory Closed | 1,839,965 | - | 3,292,060 | 5,132,025 | | 1,315,898 | 523,364 | 1,839,262 |
| Work in Progress: | | | | | | | | |
| International Financial Reporting Standards | 181,080 | | (181,080) | - | | | | |
| DSM | 2,483,854 | 210,000 | (2,693,854) | - | | | | |
| Resource Plan Update - 2011 | 238,223 | | (238,223) | - | | | | |
| Arc- Flash study | 178,903 | | (178,903) | - | | | | |
| General Rate Application - 2017/18 | 104,644 | 713,000 | - | 817,644 | | | | |
| Total Regulatory WIP | 3,186,704 | 923,000 | (3,292,060) | 817,644 | | | | |
| Total Regulatory | 5,026,669 | 923,000 | - | 5,949,669 - | - | 1,315,898 | 523,364 | 1,839,262 |
| **Relicensing** | | | | | | | | |
| Completed Projects: | | | | | | | | |
| Aishihik Relicensing | 8,790,839 | | | 8,790,839 | | 7,395,292 | 518,165 | 7,913,457 |
| Whitehorse Relicensing | 285,867 | | | 285,867 | | 116,471 | 10,713 | 127,184 |
| Mayo Relicensing | 139,006 | | | 139,006 | | 39,290 | 21,237 | 60,527 |
| Air Emission Licence Renewal | 97,015 | | | 97,015 | | 64,676 | 32,338 | 97,015 |
| Total Relicensing Closed | 9,312,727 | - | | 9,312,727 | | 7,615,730 | 582,453 | 8,198,183 |
| Work in Progress: | | | | | | | | |
| Mayo Lake | 2,406,102 | 100,000 | | 2,506,102 | | | | |
| Aishihik Relicensing | 1,005,086 | 1,450,000 | | 2,455,086 | | | | |
| Aishihik Remediation Work | | 250,000 | | 250,000 | | | | |
| Total Relicensing WIP | 3,411,188 | 1,800,000 | - | 5,211,188 | - | - | - | - |
| Total Relicensing | 12,723,914 | 1,800,000 | - | 14,523,914 - | - | 7,615,730 | 582,453 | 8,198,183 |
| **Dam Safety Review** | | | | | | | | |
| Completed Projects | | | 147,712 | 147,712 | SL-5 years | - | 29,542 | 29,542 |
| Work in Progress | 147,712 | | (147,712) | - | | | | |
| Total Dam Safety Review | 147,712 | - | - | 147,712 | | - | 29,542 | 29,542 |
| **Total Deferred Costs** | **38,445,671** | **5,570,000** | **0** | **44,015,671** | | **11,248,747** | **2,720,871** | **13,969,618** |
| **Closed** | | | | **27,848,475** | | | | |
| **WIP** | | | | **16,167,196** | | | | |
| **Net Deferred Costs (excluding WIP)** | | | | | | | | **13,878,858** |

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.
2. Per paragraph 4.2 (a) of the proposed Planning Accounting Policy the 2011 major WIP projects that close out with costs exceeding $1 million amortizes over 10 years. The costs incurred in 2012 amortizes over 5 years (based on paragraph 2.3 of the mentioned Policy).

**YUKON ENERGY CORPORATION** **Table 5.8**
**Continuity Schedule of Deferred Costs (2018)** **June 2017**
($000S)

| | Total Expenditures | | | | | Accumulated Amortization | | |
|---|---|---|---|---|---|---|---|---|
| | Dec 31 2017 | Forecast 2018 Additions | Forecast 2018 Transfers /Retired | Forecast 2018 | Amortization Rate and Method | Dec 31 2017 | 2018 Forecast expenses | Forecast 2018 |
| **Feasibility Study** | | | | | | | | |
| Completed Projects: | | | | | | | | |
| Atlin Storage | 2,230,652 | | | 2,230,652 | SL-10 years | 1,338,391 | 223,065 | 1,561,457 |
| Annunciator RTU Upgrade | 43,125 | | | 43,125 | SL-5 years | 43,125 | - | 43,125 |
| Mayo Hydro Plant Extension | 132,738 | | | 132,738 | SL-5 years | 132,738 | - | 132,738 |
| Mayo Switchgear Phase 1 | 73,972 | | | 73,972 | SL-5 years | 73,972 | - | 73,972 |
| Waste To Energy | 1,667,371 | | | 1,667,371 | SL-10 years | 826,478 | 166,737 | 993,215 |
| Geothermal | 2,072,671 | | | 2,072,671 | SL-10 years | 1,293,642 | 194,806 | 1,488,448 |
| Net Metering Demonstration Project | 28,798 | | | 28,798 | SL-5 years | 28,798 | - | 28,798 |
| Hydraulic Wood Removal System | 18,556 | | | 18,556 | SL-5 years | 15,463 | 3,093 | 18,556 |
| Power Canal Leak Investigation | 61,525 | | | 61,525 | SL-5 years | 49,220 | 12,305 | 61,525 |
| Assessment of Fuel Tank Whitehorse | 30,528 | | | 30,528 | SL-5 years | 25,440 | 5,088 | 30,528 |
| Disaster Recovery Plan | 21,162 | | | 21,162 | SL-5 years | 16,930 | 4,232 | 21,162 |
| Enterprise Risk Management Report | 43,767 | | | 43,767 | SL-5 years | 35,014 | 8,753 | 43,767 |
| Biogas Study | 95,288 | | | 95,288 | SL-5 years | 41,612 | 19,058 | 60,669 |
| L170 Cross Arm Testing & Change | 50,824 | | | 50,824 | SL-5 years | 30,494 | 10,165 | 40,659 |
| WRGS Contamination Assessment | 35,307 | | | 35,307 | SL-5 years | 21,184 | 7,061 | 28,245 |
| Mayo Hydro Bridge Icing Upgrade | 15,603 | | | 15,603 | SL-5 years | 9,362 | 3,121 | 12,482 |
| System Stability Review | 88,544 | | | 88,544 | SL-5 years | 53,126 | 17,709 | 70,835 |
| Carmacks Airport Substation | 50,627 | | | 50,627 | SL-5 years | 21,066 | 10,125 | 31,191 |
| Solar PV Installation-WH | 48,901 | | | 48,901 | SL-5 years | 19,561 | 9,780 | 29,341 |
| Hoole Canyon and Slate Rapids | 40,845 | | | 40,845 | SL-5 years | 16,338 | 8,169 | 24,507 |
| Load Forecasting | 17,148 | | | 17,148 | SL-5 years | 6,859 | 3,429 | 10,288 |
| Faro Mine Pumped Storage Project | 21,634 | | | 21,634 | SL-5 years | 8,654 | 4,327 | 12,981 |
| Home Heating Retrofit Options | 9,684 | | | 9,684 | SL-5 years | 3,067 | 1,936.80 | 5,003 |
| Electric Vehicle Technical Study | 67,919 | | | 67,919 | SL-5 years | 22,640 | 13,584 | 36,224 |
| Electric Vehicle Technical Study - Contributions | (3,500) | | | (3,500) | SL-5 years | (1,167) | (700) | (1,867) |
| Vegetation Management on Powerline Rights of Way | 45,153 | | | 45,153 | SL-5 years | - | 9,031 | 9,031 |
| LNG Boil Off Gas Options | 46,317 | | | 46,317 | SL-5 years | 9,263 | 9,263 | 18,527 |
| Mayo A Hydro Assessment | 95,038 | | | 95,038 | SL-5 years | 25,343 | 19,008 | 44,351 |
| Diesel Generator Protection | 85,000 | | | 85,000 | SL-5 years | 8,500 | 17,000 | 25,500 |
| Dawson Downtown Voltage Upgrade Assessment | 54,122 | | | 54,122 | SL-5 years | 5,824 | 10,824 | 16,649 |
| Resource Plan Update - 2016 | 2,004,466 | | | 2,004,466 | SL-5 years | 300,670 | 400,893 | 701,563 |
| EDMS Investigation | 50,000 | | | 50,000 | SL-5 years | 5,000 | 10,000 | 15,000 |
| Disaster Recovery Plan/Business Continuity Plan | 25,000 | | | 25,000 | SL-5 years | 2,500 | 5,000 | 7,500 |
| Evaluation of CIS Options | 50,000 | | | 50,000 | SL-5 years | 5,000 | 10,000 | 15,000 |
| LNG Third Engine Assessment | 40,464 | | | 40,464 | SL-5 years | 4,046 | 8,093 | 12,139 |
| Gladstone | 4,521,265 | | | 4,521,265 | SL-10 years | 452,126 | 452,126 | 904,253 |
| Large Hydro | 291,237 | | | 291,237 | SL-5 years | 58,247 | 58,247 | 116,495 |
| Whitehorse Turbine Re-runnering | 145,205 | | | 145,205 | SL-5 years | 29,041 | 29,041 | 58,082 |
| Aishihik Turbine Re-Runnering | 115,894 | | | 115,894 | SL-5 years | 23,179 | 23,179 | 46,358 |
| Wind Feasibility - Ferry Hill | 118,743 | | | 118,743 | SL-5 years | 23,749 | 23,749 | 47,497 |
| Condition Assessment of Selected YEC Assets | 230,631 | | | 230,631 | SL-5 years | 46,126 | 46,126 | 92,252 |
| Climate Change Study | 598,120 | | | 598,120 | SL-5 years | 119,624 | 119,624 | 239,248 |
| Whitehorse Diesel Plant Conversion | 318,814 | | | 318,814 | SL-5 years | 63,763 | 63,763 | 127,526 |
| Enterprise Risk Management | 169,398 | | | 169,398 | SL-5 years | 33,880 | 33,880 | 67,759 |
| Building Condition Reports | 104,405 | | | 104,405 | SL-5 years | 20,881 | 20,881 | 41,762 |
| Condition Assessment of WH & WD Assets | 227,969 | | | 227,969 | SL-5 years | 45,594 | 45,594 | 91,188 |
| Asset Condition Assessment | 127,545 | | | 127,545 | SL-5 years | 25,509 | 25,509 | 51,018 |
| LNG Supply Option | 273,095 | | | 273,095 | SL-5 years | 54,619 | 54,619 | 109,238 |
| Life Cycle Analysis of LNG/Diesel | 118,036 | | | 118,036 | SL-5 years | 23,607 | 23,607 | 47,214 |
| LNG Transportation Options | 277,700 | | | 277,700 | SL-5 years | 55,540 | 55,540 | 111,080 |
| Cross Arm Replacements Evaluation | 189,614 | | | 189,614 | SL-5 years | 37,923 | 37,923 | 75,845 |
| Detailed Line Inspection | 428,362 | 300,000 | | 728,362 | SL-5 years | 85,672 | 105,672 | 191,344 |
| Time of Use Rate Structure and Smart Grid | 100,000 | | | 100,000 | SL-5 years | 5,000 | 20,000 | 25,000 |
| Northern Diesel Plan Relocation Study | - | 100,000 | | 100,000 | SL-5 years | - | - | - |
| SKTP | - | | | - | SL-5 years | - | - | - |
| SKTP-YG Funding | - | | | - | SL-5 years | - | - | - |
| Diesel Seismic Study | - | 70,000 | | 70,000 | SL-5 years | - | 7,000 | 7,000 |
| Corona Investigation on L173 | - | 50,000 | | 50,000 | SL-5 years | - | 5,000 | 5,000 |
| Electric Vehicle Infrastructure Siting Assessment | - | 65,400 | | 65,400 | SL-5 years | - | 6,540 | 6,540 |
| GIS Assessment | - | 50,000 | | 50,000 | SL-5 years | - | 5,000 | 5,000 |
| Prophix Regulatory Modeling | - | 40,000 | | 40,000 | SL-5 years | - | 4,000 | 4,000 |
| Moon Lake Hydro Project | - | | 171,512 | 171,512 | SL-5 years | - | - | - |
| Mount Sumanik Wind Feasibility Study | - | | 840,280 | 840,280 | SL-5 years | - | - | - |
| Asset Appraisal | - | 100,000 | | 100,000 | SL-5 years | - | - | - |
| Forecasting Model Integration | - | 115,000 | | 115,000 | SL-5 years | - | - | - |
| Boil-off Gas - Detailed Investigation | - | 95,000 | | 95,000 | SL-5 years | - | - | - |
| Waste To Energy Contribution | (782,591) | | | (782,591) | SL-10 years | (384,605) | (78,259) | (462,864) |
| Geothermal 2013 Contribution | (3,414) | | | (3,414) | SL-5 years | (2,731) | (683) | (3,414) |
| Biogas Study Contribution | (7,000) | | | (7,000) | SL-5 years | (4,200) | (1,400) | (5,600) |
| Biogas Preliminary Design 2 Contribution | (16,500) | | | (16,500) | SL-5 years | (6,325) | (3,300) | (9,625) |
| YDC Feasibility Asset Contribution | (3,734,763) | | | (3,734,763) | SL-5 years | (1,398,740) | (617,580) | (2,016,320) |
| LNG Transportation Options Contribution | (15,000) | | | (15,000) | SL-5 years | (3,000) | (3,000) | (6,000) |
| Total Feasibility Study Closed | 13,256,011 | 985,400 | 1,011,792 | 15,253,204 | | 3,902,630 | 1,787,353 | 5,689,983 |
| Work in Progress: | | | | | | | | |
| Mayo Lake Outlet Channel | 426,376 | | | 426,376 | | | | |
| Mt Sumanik Wind Feasibility Study | 590,280 | 250,000 | (840,280) | - | | | | |
| Moon Lake Hydro Project | 171,512 | | (171,512) | - | | | | |
| Mayo & Aishihik Climate Change | 281,530 | 160,000 | | 441,530 | | | | |
| SKTP | 2,806,975 | | | 2,806,975 | | | | |
| SKTP-YG Funding | (2,825,000) | | | (2,825,000) | | | | |
| Assessment of Transformer T9 | 105,337 | - | | 105,337 | | | | |
| Development of Asset Management Program | 200,000 | 150,000 | | 350,000 | | | | |
| Marsh Lake Storage | 7,131,354 | 1,025,000 | | 8,156,354 | | | | |
| Battery | 500,000 | 8,356,000 | | 8,856,000 | | | | |
| Thermal Plant | 750,000 | 3,461,000 | | 4,211,000 | | | | |
| Whitehorse Hydro Uprate | - | 450,000 | | 450,000 | | | | |
| Small Hydro | - | 625,000 | | 625,000 | | | | |
| Total Feasibility Study WIP | 10,138,364 | 14,477,000 | (1,011,792) | 23,603,572 | | | | |
| Total Feasibility | 23,394,376 | 15,462,400 | - | 38,856,776 | - - | 3,902,630 | 1,787,353 | 5,689,983 |

**YUKON ENERGY CORPORATION** **Table 5.8**
**Continuity Schedule of Deferred Costs (2018)** **June 2017**
($000S)

| | Total Expenditures | | | | | Accumulated Amortization | | |
|---|---|---|---|---|---|---|---|---|
| | Dec 31 | Forecast 2018 | | Forecast | Amortization | Dec 31 | 2018 Forecast | Forecast |
| | 2017 | Additions | Transfers /Retired | 2018 | Rate and Method | 2017 | expenses | 2018 |
| **Regulatory** | | | | | | | | |
| Completed Projects: | | | | | | | | |
| Minto Mine PPA | 769,057 | | | 769,057 | SL-12 years | 582,133 | 64,088 | 646,221 |
| YUB 2007-7 & 9 - Resource Plan | 642,853 | | | 642,853 | SL-10 years | 642,853 | - | 642,853 |
| YUB 2007-7 & 9 - PPA Review | 243,045 | | | 243,045 | SL-12 years | 202,537 | 20,254 | 222,791 |
| YUB 2007-8 - Part 3 Hearing | 185,011 | | | 185,011 | SL-45 years | 41,113 | 4,111 | 45,225 |
| Arc Flash Study | 178,903 | | | 178,903 | SL-5 years | 35,781 | 35,781 | 71,561 |
| International Financial Reporting Standards | 181,080 | | | 181,080 | SL-5 years | 36,216 | 36,216 | 72,432 |
| DSM | 2,693,854 | 625,000 | | 3,318,854 | SL-10 years | 250,984 | 270,635 | 521,619 |
| General Rate Application - 2017/18 | - | | 817,644 | 817,644 | | - | - | - |
| Resource Plan Update - 2011 | 238,223 | | | 238,223 | SL-5 years | 47,645 | 47,645 | 95,290 |
| Total Regulatory Closed | 5,132,025 | 625,000 | 817,644 | 6,574,669 | | 1,839,262 | 478,729 | 2,317,992 |
| Work in Progress: | | | | | | | | |
| General Rate Application - 2017/18 | 817,644 | | (817,644) | - | | | | |
| Total Regulatory WIP | 817,644 | - | (817,644) | - | | | | |
| Total Regulatory | 5,949,669 | 625,000 | - | 6,574,669 | | 1,839,262 | 478,729 | 2,317,992 |
| **Relicensing** | | | | | | | | |
| Completed Projects: | | | | | | | | |
| Aishihik Relicensing | 8,790,839 | | | 8,790,839 | | 7,913,457 | 483,319 | 8,396,776 |
| Whitehorse Relicensing | 285,867 | | | 285,867 | | 127,184 | 10,713 | 137,897 |
| Mayo Relicensing | 139,006 | | | 139,006 | | 60,527 | 21,237 | 81,765 |
| Air Emission Licence Renewal | 97,015 | | | 97,015 | | 97,015 | - | 97,015 |
| Aishihik Remediation Work | - | | 500,000 | 500,000 | SL-5 years | - | - | - |
| Total Relicensing Closed | 9,312,727 | - | 500,000 | 9,812,727 | | 8,198,183 | 515,269 | 8,713,452 |
| Work in Progress: | | | | | | | | |
| Mayo Lake | 2,506,102 | 850,000 | | 3,356,102 | | | | |
| Aishihik Relicensing | 2,455,086 | 444,000 | | 2,899,086 | | | | |
| Aishihik Remediation Work | 250,000 | 250,000 | (500,000) | - | | | | |
| Total Relicensing WIP | 5,211,188 | 1,544,000 | (500,000) | 6,255,188 | - | - | - | - |
| Total Relicensing | 14,523,914 | 1,544,000 | - | 16,067,914 - | - | 8,198,183 | 515,269 | 8,713,452 |
| **Dam Safety Review** | | | | | | | | |
| Completed projects | 147,712 | | | 147,712 | SL-5 years | 29,542 | 29,542 | 59,085 |
| Work in Progress | - | | | - | | - | | - |
| Total Dam Safety Review | 147,712 | - | - | 147,712 | | 29,542 | 29,542 | 59,085 |
| **Total Deferred Costs** | **44,015,671** | **17,631,400** | **0** | **61,647,071** | | **13,969,618** | **2,810,894** | **16,780,512** |
| **Closed** | | | | **31,788,311** | | | | |
| **WIP** | | | | **29,858,760** | | | | |
| **Net Deferred Costs (excluding WIP)** | | | | | | | | **15,007,800** |

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

# APPENDIX 5.1
# PLANNING COST ACCOUNTING POLICY

| YUKON ENERGY | FINANCE POLICY FA-016 | DEPARTMENT: | INQUIRIES TO: | TOPIC: |
|---|---|---|---|---|
| | | All | Chief Financial Officer | Planning Cost Accounting Policy |
| | | ISSUED: | REVIEW DATE: | APPROVED BY: |
| | | March 2012 | February 2015 | Chief Financial Officer |

**1.0 Purpose**

1.1 The purpose of this policy is to define the accounting policy for costs incurred in relation to planning activities.

1.2 Planning activities can include, but are not limited to, the following:

- New Generation Supply planning;
- Pre-feasibility and feasibility;
- Environmental;
- Water management;
- Fisheries;
- Reconnaissance;
- Survey and investigation; and
- Water license renewal studies

**2.0 Policy**

2.1 The following planning and study costs will be recorded as an expense of the period in which they are incurred:

a. Planning and study costs which are pure research in nature. It should be noted that costs of this type, if any, are not expected to be significant.

b. Planning and study costs related to ongoing operations, unless it can be demonstrated that these costs provide long-term or multi-year benefits to the system.

2.2 When the expected outcome of planning and study costs is to enhance the service potential or extend the useful life of an existing asset or to add new assets to the system, the related costs shall be capitalized to, and amortized on the same basis as, the related asset.

2.3 Planning cost project categories:

a. **New generation supply –** New supply projects, whether being built for energy or capacity or both, must include an economic analysis that demonstrates a net benefit to rate payers. For energy projects, this analysis will typically compare a project life cycle costs to a thermal option[1]; although other criteria may be warranted depending on the circumstances. Because of the large dollars and complex nature of these project, the Corporation employs a stage gate process[2] to financing. At each stage, the project team has to justify the economics of the project prior to receiving funding for

[1] Lowest cap-ex, highest op-ex supply solution.

[2] See Attachment A attached for a description of this process.

the next stage. In this way, the Corporation minimizes the risk of spending capital dollars on unsupportable projects.; or

b. **Regulatory** - Where a project is driven by regulatory requirement (e.g. water licence renewal), the legal background will be documented on the project approval. Note the cost of regulatory proceedings initiated as part of project assessment (as defined in a) will form part of the cost of constructed asset as described in 2.2 above.

c. **System Improvements –** Relates to studies on existing infrastructure. The focus of the study is generally on a) end of life components; or b) system equipment failing to perform or performing inappropriately due to a change in operating circumstances. The objective of the study is to assess options for replacement. The assessment will look at the cost of upgrade versus the benefit achieved (e.g. improved reliability, increase functionality or flexibility, etc.).

2.4 Where a determination is made that a project is, or continues to be, economically viable, all project expenditures will be held in WIP until the project is completed.

2.5 If the project does not proceed, the capitalized development costs shall be amortized on a straight-line basis as follows, commencing with the next rate application period following the decision not to proceed with the project.

a. Where accumulated planning and studies costs are less than $1 million – the planning and studies costs will be amortized over five years.

b. Where accumulated planning and studies costs have exceeded $1 million – the planning and studies costs will be amortized over ten years.

2.6 Planning and study costs related to water license renewals shall be deferred and amortized over the term of the renewed license.

## 3.0 Application

3.1 Management should use its best judgment in determining which of the above categories each specific study applies to.

## 4.0 Rate Impact

4.1 For clarity, this policy only addresses the accounting treatment of costs. In keeping with standard regulatory process, the utility is required to file with the YUB to adjust rates for changes in corporate revenue requirement. In summary, YEC will close and begin amortization of studies as prescribed by this policy. Any rate changes created by these costs will be subject to a prudency review by the YUB prior to the rate change.


CLASS 5 COST ESTIMATE
-35% / +100%
Prefeasibility level estimate to include:
• Proposed facility layout
• Project location
• Generation capacity based on a statement of objectives
CLASS 4 COST ESTIMATE
-15% / +50%
Feasibility design for several alternative layouts to include:
• Design criteria
• Generation capacity
• Feasibility level drawings
• Preliminary diagrams
• Comprehensive user requirements
CLASS 3 COST ESTIMATE
-10% / +15%
Preliminary engineering design to include:
• General arrangement drawings,
• Major components drawings and specifications,
• Near completed geotechnical investigations and technical studies,
• Preliminary earthwork drawings for excavation
• Complete one-line diagrams,
• equipment performance specifications
• Preliminary auxiliary mechanical and electrical systems, Preliminary P&ID and P&C diagrams
• Completed procurement strategy identifying
REGULATORY
CLASS 2 COST ESTIMATE
-5% / +10%
Detailed engineering design that include at a minimum the following:
• Final geotechnical investigations and technical reports,
• Issued for tender sealed drawings and specifications for general arrangements, earthwork excavation and embankments, powerhouse, balance of plant (for all engineering disciplines), major equipment, auxiliary mechanical and electrical systems
• Final one-line diagrams, P&IDs and P&C diagrams
• Final drawings on permanent/temporary infrastructure
• Vendor quotations,
• Detailed project execution plans and procurement strategy identifying all major items of equipment
• Detailed resourcing and work force plans
CLASS 1 COST ESTIMATE
-5% / +10%
ATTACHMENT A
Cost estimate generally prepared for sections of the total project. Estimate typically be used by subcontractors for bids, or by owners for check estimates.
Cost estimate would comprise the following:
• Virtually all engineering and design documentation of the project
• Complete project execution
• Commissioning plans
Reference: AACE International Recommended Practice No. 17R-97, Cost Estimate Classification System, AACE International, Morgantown, WV. (rev. January 25, 2013)
ENGINEERING
Prefeasibility
Gate #1
PASS
Feasibility
Gate #2
PASS
Preliminary Engineering
FAIL
FAIL
Project Closure
FAIL
Gate #3 Project Sanction by YEC BoD
PASS
YESAB Submission
Decision Document
Permits
Detailed Engineering
Gate #4
PASS
Project Construction
Commissioning and Documentation
FAIL
SOCIO-ECONOMIC AND ENVIRONMENT
• Identification of Regulatory Requirements
• Environmental Screening
• Data Gap Analysis and Scoping of Significant Issues
• Baseline and Field Data Collection
• Detailed Assessment of Issues
• Identification of Mitigation Needs
• Environmental and Socio-Economic Baseline Report
• Effect Assessment Reports
• Mitigation Design
• Adaptive Management
• Construction Monitoring
• Mitigation Measures Implementation
• Post-project Monitoring
CONTRACTING AND PROCUREMENT
• Procurement Strategy
• Procurement Best Practices
• Define Contracting Strategy
• Procurement of Long Lead Items
• Tender for Construction
• Procurement of Short Lead Items
FIRST NATION ENGAGEMENT
• Identify FN involved
• Define engagement strategy
• Create Communication protocol
• Engage FN on the impacts and opportunities of the project
MoU
• Update on progress
• Engage
• Implement feedback
• Update on progress
• Engage
• Implement feedback
• Define benefits framework
Regulatory Process Support
Project Agreement
• Update on progress, engagement
• Investment opportunity
• Update on progress
• Contracting, Employment, Training
PUBLIC ENGAGEMENT
• Identify stakeholders
• Define engagement strategy
• Engage stakeholders on the needs of the project
• Update on progress
• Update on progress
• Share technical details
• Solicit feedback
• Implement feedback
• Update on progress
• Share technical details
• Solicit feedback
• Implement feedback
Social License
• Respond to Interveners' Information Requests
• Further Engagement
• Update on project progress
• Update on progress

# APPENDIX 5.2
# DEMAND SIDE MANAGEMENT (DSM) POLICY

| YUKON ENERGY | FINANCE POLICY FA-015 | DEPARTMENT: | INQUIRIES TO: | TOPIC: |
|---|---|---|---|---|
| | | All | Chief Financial Officer | Demand Side Management Accounting |
| | | ISSUED: | REVIEW DATE: | APPROVED BY: |
| | | March 2012 | February 2015 | President & CEO |

**1.0 Purpose**

1.1 The purpose of this policy is to outline the accounting policy for costs incurred in relation to Demand Side Management (DSM) activities.

1.2 DSM is defined as "options available to electric utilities to alter the volume and pattern of electricity end-use, so as to improve or increase the efficiency of electricity production and system performance". This includes any improvements in Corporation "end use" such as insulation in its buildings, but does not include Supply Side Enhancements that the Corporation does to improve efficiency of generation and transmission activities**.**

1.3 The intent of DSM programming is to implement programs or rate structures designed to influence electricity consumption patterns by reducing and/or shifting loads. The primary benefits of DSM for the Yukon were seen to be lower costs of providing electrical service and enhanced customer relations.

**2.0 Policy**

2.1 Costs associated with specific DSM programs will be deferred and amortized on a straight-line basis:

a. DSM program expenditures will be deferred where a specific program is defined and is expected to proceed to the development stage and is expected to achieve net benefits. The following conditions may be relevant to this determination:
   i. A defined plan, product or program has been identified.
   ii. The technical feasibility of the defined plan product or program and its benefits have been established, a future market is defined and adequate financial resources are expected to be available to complete the plan, product or program.
   iii. Management has indicated its intention to proceed with the program.

b. Research related activities not associated with a specific program will be expensed in the year incurred.

2.2 The following DSM-related costs shall be expensed as incurred:

a. Administrative and other general overhead expenditures are expensed unless the expenditure can be directly attributed to a specific DSM program.
b. Expenditures related to information programs and advertising unless directly attributed to a specific DSM program.
c. Expenditures on training staff shall be expensed.

2.3 The amortization period for deferred DSM expenditures shall be ten years. Qualifying expenditures will be closed out on an annual basis.

# APPENDIX 5.3
# CAPITAL PROJECTS BETWEEN $100,000 AND $1 MILLION

# APPENDIX 5.3: CAPITAL PROJECTS BETWEEN $100,000 AND $ 1 MILLION

Appendix 5.3 provides descriptions for projects in excess of $100,000 and up to $1 million forecast to occur in 2017 and 2018.

**Generation:**

| Project | Description/Rationale | 2013 to 2016 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| Aishihik Control Structure Refurbishment | The bridge section of the Aishihik lake auxiliary control structure is in very poor condition and must be repaired or replaced. The deck timbers are worn and rotting and some of the support beams are crushed and are in danger of failing completely. The entire structure will be assessed for the requirement to regulate water passage and either repaired or replaced based on the results of the assessment. | | | $325,000 |
| Aishihik Generator Fire Protection | The original Aishihik generators (AH1 & AH2) do not have a fire suppression system, leaving these assets exposed to significant damage in the case of a fire. A preliminary design report was undertaken to assess different suppression agent options and costs. This project will undertake final design, installation, and commissioning of a fire suppression system based on the outcomes of the preliminary design report. | | | $125,000 |
| Aishihik Tailrace Road and Slope | Since its construction in 1975, there has been ongoing development of erosion gullies on the cut slope above the tailrace tunnel portal. A number of tension cracks have been observed more recently through the overburden material along the cut slope. A stability assessment of the tailrace slope is planned for 2017 to evaluate the risk of failure and to develop mitigation measures. Work planned for 2018 will remediate deficiencies as recommended by the stability assessment. | $15,818 | $44,000 | $150,000 |
| Canyon Lake Control Structure & Dyke Refurbishment | The original design of the dyke and power canal requires ongoing capital refurbishment based on periodic condition assessments and regular observation of erosion or sloughing. Based on the most recent condition assessment as well as recent observations of the dyke and power canal by Yukon Energy, the following improvements are planned as part of this project:<br>• This project will extend the granular | | $125,000 | |

| Project | Description/Rationale | 2013 to 2016 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| | blanket in sections of the dyke to improve the stability and mitigate observed tension cracks; and grade sections of the dyke that exhibit longitudinal cracking to prevent further deterioration and minimize water infiltration.<br>• This project will also replace backfill material that washes away when the control structure at Canyon Lake is overtopped during high water events.[1]<br>• This project includes other improvements to re-establish remote control capabilities of the structure's valves. | | | |
| Dam Safety Recommendations | As part of YEC's Water License and internal policies, a Dam Safety Review (DSR) is required every 5 years. The most recent DSR was performed in 2015 and contains a list of observed deficiencies with corresponding recommendations to eliminate any hazardous conditions which could affect the safety of the public and YEC staff. This project addresses the remaining "High" priority recommendations to be completed within a period of one to three years following the DSR (2016-2018). | $74,425 | $75,000 | $100,000 |
| Faro Diesel Building Ventilation | The present extractor fan system in Faro pulls air across the unit to cool it which is inefficient and results in overheating whenever the outside ambient temperature is above 10 C. This project involves the installation of appropriate exhaust fans to improve heat and smoke removal from the building. | | | $100,000 |
| Wareham Dam Blackstart Generator | The Wareham lake dam has two spill gates and a head gate that can be remotely operated from SCC and are supplied power from S249. There is currently no method for manually opening the spill gates. In the event of a loss of power, the | | $120,000 | |

[1] The control structure at Canyon lake is designed to be overtopped during high water events, however this results in the need to replace backfill material that washes away.

| Project | Description/Rationale | 2013 to 2016 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| | potential exists for water to overtop the dam. The installation of a blackstart generator at the dam will allow for full operational power to the spill gates and head gate. In the case of an extended cold temperature outage, the generator will also be able to power heaters and bubblers which will prevent the gates from freezing shut. | | | |
| Whitehorse Diesel System Grounding for Generators | The grounding equipment in the Whitehorse diesel plant is either non-existent or not optimally configured. WD4 and WD5 are ungrounded, and there is risk of significant damage to this equipment in the case of a ground fault. The grounding for WD6 and WD7 is not identical, an inadequate configuration when several generators are running in parallel. This project will prepare grounding calculations and install acceptable grounding equipment for all Whitehorse diesel generators. | | | $100,000 |
| Whitehorse Local HMI /Historian Upgrade | The current P125 switchgear Human Machine Interface (HMI) hardware is obsolete and the central HMI software is no longer supported. Furthermore, the plant does not have a local historian (a common industry standard) which can provide diagnostic information and root cause analysis for outage troubleshooting.<br><br>This project will upgrade the central HMI software, replace the switchgear HMI screen hardware, and add a local plant historian. The project will ensure that YEC will no longer be exposed to the risk of unsupported hardware or software failure, and that YEC will have access to trending and historical data tools for use in predictive asset maintenance planning and analysis of equipment failure. | | $180,000 | |
| Whitehorse Wind 1 Decommission (site restoration) | The existing Bonus wind turbine (WW1) was retired from service on December 2, 2014 as it was determined to be at the end of its useful life. Decommissioning the unit includes electrically isolating it from the grid and | $16,705 | $111,557 | |

| Project | Description/Rationale | 2013 to 2016 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| | removing the blades, nacelle, and tower. The transformer, communication building, concrete base, and associated fencing will remain at the site. | | | |

**Transmission:**

| Project | Description / Rationale | 2013 to 2016 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| Dawson P158 T1/T2 Transformer | There are a number of significant safety concerns with the configuration of the main transformer at the Dawson Diesel Plant. The clearance to ground of live conductors is inadequate and the fence around the installation is only 6' tall and adjacent to a public area. This project involves expanding the ground grid, moving the current overhead express feeder connection lines underground, and securing the area with appropriately sized fencing. | | | $200,000 |
| L170 Line Access | YEC requires access to transmission lines for maintenance, inspection, and brushing activities. Currently a number of temporary access points are used that lack the necessary permitting and may not be constructed to an acceptable standard. This project will complete the required assessment process in order to obtain the necessary permits for both new and existing accesses. It also includes the construction of new accesses and upgrades to existing ones, resulting in faster response times for emergency line work and reliable access to key YEC assets. | | $350,000 | $350,000 |
| S-150 – Whitehorse Main RTU Upgrade | The current remote terminal unit (RTU) is an older model that cannot take advantage of the upgraded annunciator PLC's and is suffering from ongoing support issues. Under the existing system, alarms are grouped as simply minor or major and any outstanding alarm masks the ability of SCC to see a new alarm. An upgraded RTU will be able to communicate detailed alarm specifics (roughly 80 unique alarms) to SCC instead of the current grouped method. | | $125,000 | |
| Substation Protection and Control Minor Upgrades | Yukon Energy substations require a number of improvements to ensure continued safe and reliable service. Specifically, to ensure a more consistent standard for all Yukon Energy substations, substation protection and control | $212,607 | $50,000 | $100,000 |

| Project | Description/Rationale | 2013 to 2016 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| | systems will be reviewed to identify and address the following issues: indication of relay failure to SCC (this is often either nonexistent or the flagging shares common failure modes with the relay itself); trip circuit monitoring scheme that are installed but do not indicate to SCADA at all; and incomplete backup protection. | | | |
| Transmission System Protection Upgrades | Currently, faults on L178 (Carmacks to Faro) often result in the separation of northern and southern grids, increasing the risk of a larger outage. This project will install a communications-assisted tripping scheme between Takhini, Minto Landing, and Faro, reducing the extent of outages and eliminating grid separation caused by faults on L178. | | $100,000 | |
| WAF Transmission Upgrades | The WAF transmission system allows low cost hydro generation supplied from Aishihik, Whitehorse, or Faro to be transmitted to other locations on the grid. A failure of a transmission line structure would interrupt this supply, potentially resulting in a wider grid collapse. The structures on this transmission line were built in the 1960s through 1970s and are in various stages of deterioration. A recently performed test and treat program has identified the structures that are at the highest risk of failure. This project replaces the identified structures, along with any end-of-life cross arms and insulators that are discovered. | $3,068,587 | $850,000 | $850,000 |

**Distribution:**

| Project | Description/Rationale | 2013 to 2016 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| 25kV Distribution Cut-Out Replacement | Close to 500 porcelain 25kV fused and solid-blade cutouts have been identified for replacement due to age and increased failure rate. The unexpected failure of these devices is both a reliability concern for customers as well as a safety hazard for YEC employees. So far, a number of switches in Dawson and Mayo have been replaced and the remaining cutouts on YEC distribution network are scheduled for completion by the end of 2019. | $81,877 | | $100,000 |
| Callison Voltage Regulator Automation | When Dawson Diesel is islanded from, or restored to, the grid (Mayo Hydro Plant), an operator is needed at Callison to manually control the S250-RT1 regulating transformer. This project will allow either the SCC operator or the Dawson Operator to control RT1 without having to be physically present in the Callison substation (-6km from Dawson Diesel Plant). The automation will speed up Dawson's restoration to Hydro power following an outage, resulting in less diesel burned. Further, the modifications will improve SCC's control and reliability of the Dawson/Callison plant. | | | $115,000 |
| Customer Extensions | Yukon Energy is required to provide service to new customers coming onto the system. Customer extensions are forecast and budgeted as capital items without identifying specific projects. Most costs of customer extensions are covered by customer contributions pursuant to the Electrical Service Regulations. | 2,441,000 | $475,000 (offset by customer contributions - $400,000) | $475,000 (offset by customer contributions - $400,000) |

**General Plant and Equipment Projects:**

| Project | Description/Rationale | 2013 to 2016 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| Aishihik Emergency Signage and Lighting upgrade | The Aishihik facility's emergency and exit lighting is not adequate when compared to modern standards. The lighting is especially deficient in the riser ladder area connecting the generator floor to the service building. This project will develop a life safety / egress plan for the facility and install the appropriate signage and lighting. | | | $100,000 |
| Building Condition Report Response | During 2016 an external consultant was hired to perform an asset assessment on YEC-owned buildings and facilities that have not recently been evaluated, mainly consisting of staff houses and administration buildings. A number of building components were identified at each location as being at end of life or not in compliance with applicable code regulations. This project will address the concerns identified by the report and bring YEC buildings up to an acceptable condition. | | | $299,000 |
| Critical Spares – System Requirement | There are a number of specialized components of YEC's generation, transmission, and communications equipment that, if they failed, would cause a significant disruption in service. These components are either critical to the operation of the system or have long lead times for replacement. A prioritized list of these components has been developed and items will be purchased over the next 2 years. | $200,000 | $100,000 | $100,000 |
| Dawson Derrick Digger | The existing Dawson truck and digger are old and worn out, resulting in major expenses for repairs and substantial down time. This unit is used for digging holes and setting poles (30-50' length) as well as installing anchors. This replacement will allow the power line technicians in Dawson to perform their work in a safe and efficient manner. | | $350,000 | |
| Fencing Upgrades – Various Sites | A number of YEC facilities have been identified as lacking appropriate fencing. Sites include everything from small transformer locations to | $148,367 | $75,000 | $125,000 |

| Project | Description/Rationale | 2013 to 2016 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| | generation plants and prioritization for work is based on the condition of existing fencing or existence of fencing. This project is being undertaken to address safety concerns for the general public, contractors, and YEC staff posed by inadequate fencing and access control. | | | |
| Mayo B Door Installation for Crane Inspection | The exterior overhead crane is located directly over the water of the tailrace. As a result, the only way to inspect it involves moving it to the far end of the building and renting a large boom hoist from Whitehorse. If the crane were to suffer a mechanical failure in the middle of the span, there would be no way to access it for repairs.<br>This project involves the installation of an interior ladder and platform, a door in the wall adjacent to the crane, and an external platform for inspection and maintenance activities. A small man-basket will also be installed to allow access to the crane at any point along the span. | | | $100,000 |
| Mayo Transient Trailer Unit | YEC currently does not have transient accommodation available in Mayo for staff or contractors that are based outside of Mayo. As a result, personnel are limited to the local accommodation services that have unreliable availability and quality. This results in significant costs for lodging, unnecessary travel time to Dawson, or project/work delays during busy times of the year. This project includes the purchase of a trailer with a minimum of three bedrooms and installation on a lot in Mayo that is currently owned by YEC. | | | $250,000 |
| Stewart-Minto Local SCADA | The limited communication capabilities of S251, S253, and S256 substations require the on-site presence of personnel in order to collect data and modify protection settings. The installation of a SEL-RTAC data concentrator will allow improved SCADA control of the substations as well as remote diagnostic capability for engineering staff. | | | $165,000 |

| Project | Description/Rationale | 2013 to 2016 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| Vehicle Purchases | YEC fleet vehicles are replaced at regular intervals based on age and mileage due to decreased reliability and increased maintenance costs. The forecast amounts for the test years include the purchase of pickup trucks with and without service bodies as well as one or more pool vehicles. | $1,401,948 | $250,000 | $300,000 |
| Voice Repeater Site for Little Salmon Area | The Little Salmon Lake area falls within a dead zone of YEC's radio network and is outside of cell phone coverage. As a result, the only current method of communication is via satellite phone which isn't reliable in a number of locations. There is often difficulty contacting personnel working in the area, causing delays in switching and system recovery. By installing a radio repeater in the area, employee safety and work efficiency will be significantly improved. | | | $125,000 |
| Voice Repeater Site for Mendenhall / Champagne | The current radio network in the Mendenhall and Champagne areas is spotty and unreliable, often requiring vehicle movement in order to communicate. There is often difficulty contacting personnel working in the area, causing delays in switching and system recovery. By installing a radio repeater in the area, employee safety and work efficiency will be significantly improved. | | | $100,000 |
| WRGS Hazardous Materials Containment | An assessment of the Whitehorse Rapids Generating Station was performed to identify risks associated with the waste water handling system and recommend improvements. This project will implement all of the recommendations that have not yet been completed, including modifications to drain receptors, sealing trenches and pit drains, installation of leak detection equipment, and construction of containment curbs. | | | $125,000 |

# APPENDIX 5.4
# DEFERRED PROJECTS BETWEEN $100,000 AND $ 1 MILLION

## APPENDIX 5.4: DEFERRED PROJECTS BETWEEN $100,000 AND $ 1 MILLION

Appendix 5.4 provides descriptions for projects in excess of $100,000 and up to $1 million forecast to occur in 2017 and 2018.

**Feasibility:**

| Project | Description/Rationale | Prior to 2017 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| Detailed Line Inspection | In order to properly plan and execute transmission line maintenance in an efficient and cost effective manner, having detailed and accurate information is critical. This project involves engaging a contractor to perform a ground and aerial survey in order to inspect and document the condition of every component of the transmission line structures. During the test years, the lines planned for inspection are L171 (Takhini to Aishihik), L172 (Riverside to Takhini), L169 (L172 to McIntyre Substation), L170 (Takhini to Carmacks), and L178 (Carmacks to Faro). | $50,362 | $378,000 | $300,000 |
| Development of Asset Management Program | Currently there is no asset management methodology or plan for managing critical hydro and transmission assets at YEC. This results in ad hoc repairs and replacement projects that are costly and unplanned. An asset management program will consist of documented plans to systematically assess major asset groups (Hydro, Substations, T&D) and manage the planning of investments to meet overall corporate goals. This project will develop the asset management program and involves defining program goals and scope, a gap analysis of current state and desired future state, development of strategies for assessing and managing the different asset groups, and the creation of an implementation plan for the program. | | $200,000 | $150,000 |
| Mayo and Aishihik Hydro Climate Change Study | In order to make the best use of our Aishihik and Mayo hydro assets, it is important to have accurate forecasts for water flow volume and timing. This project will deliver research and modelling to YEC in order to better understand how climate change will impact the Aishihik and Mayo drainages. YEC funds will be used to leverage funding from NSERC (project has been approved), allowing the scope to include both drainages. The primary deliverable is a hydrological model that will deliver short and long term forecasts of flow volume and timing to be used as inputs in YEC's generation model. | $121,530 | $160,000 | $160,000 |

| Project | Description/Rationale | Prior to 2017 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| Time of Use Rate Structure and Smart Grid | Currently, peak demand is supplied by thermal generation. This project will assess the potential for a time of use rate structure and associated smart grid to shift electricity demand to off-peak times. This could delay the need for YEC to build additional generating capacity and improve utilization of non-dispatchable energy generation assets. Additional project deliverables include implementation cost and schedule estimates, estimate of demand offset and potential savings, and development of smart grid conceptual network architecture. | | $100,000 | |
| Mt Sumanik Wind Feasibility Study | This multi-year project involves the completion of early planning studies for potential wind farm sites throughout the Yukon as well as the installation of monitoring equipment on Mt Sumanik. Without the addition of new generation from renewable sources, increasing loads will be met with thermal generation. The data collected over the life of the project will enable YEC to confirm the validity of potential future wind generation options. | $540,280 | $50,000 | $250,000 |
| Forecasting Model Integration | As electricity demand increases, it is increasingly important to operate the integrated grid as efficiently as possible. This is currently accomplished through historical experience and operator judgement. YEC has recently acquired proprietary optimization software that will allow the company to meet a given load at the lowest cost. This project will integrate the software with operations in order to support day-to-day activities. | | | $115,000 |
| Asset Appraisal | It is important to have accurate replacement cost values of major assets for insurance purposes in order to maintain adequate coverage at an appropriate cost. This project will provide an independent appraisal of our three major hydro facilities to be used for our 2018 property insurance renewal. This work has been recommended by our insurance broker as it has been over ten years since it was last performed. | | | $100,000 |
| Northern Diesel Plant | This project will assess the options of moving the | | | $100,000 |

| Project | Description/Rationale | Prior to 2017 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| Location Study | Dawson and Mayo Diesel plants from their present locations. There are a number of reasons this is being considered including plant noise and flood risk at the current downtown locations as well as the benefits of having the diesel generators closer to substations (Mayo Hydro and Callison). The study will determine the costs, impacts, and options and make a recommendation of relocating each diesel plant. | | | |
| Whitehorse Hydro Uprate | As part of the Resource Plan, a preliminary assessment of the Whitehorse hydro units was completed which identified a number of potential uprating (or re-runnering) scenarios. An uprate project was identified to provide both additional firm energy and dependable capacity. Additional benefits of the project could potentially include an improved efficiency curve allowing increased operational flexibility.<br><br>Spending of $0.450 million in 2018 will be used for a detailed investigation of which alternative to proceed with as well as selecting an owner's engineer to represent YEC throughout the project. A scope of work will be created and the construction contract could possibly be awarded by the end of the year. This project is expected to be complete and in service by 2020. | | | $450,000 |
| Small Hydro | The 2016 Resource Plan identified small hydro as a potential resource option included as part of the Low with Early Minto Closure, Medium and High Industrial Activity planning scenarios.<br><br>The small hydro resource option is at a pre-feasibility stage and further studies will be undertaken in 2018 to confirm site selection and project need. This may include the following activities with regard to site options:<br><br>• Environmental baseline monitoring (Lidar/ detailed topography; program design);<br>• First Nations consultation; and<br>• Potential geotechnical investigations. | | | $625,000 |

**Regulatory:**

| Project | Description / Rationale | Prior to 2017 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| General Rate Application – 2017/18 | Deferred costs for the current GRA preparation and hearing. | $104,644 | $713,000 | |

**Relicensing:**

| Project | Description / Rationale | Prior to 2017 | Forecast 2017 | Forecast 2018 |
|---|---|---|---|---|
| Aishihik Remediation Work | This project involves shoreline erosion protection at the north end of Canyon Lake and the installation of a secondary well at the Aishihik Village. This work was initiated as part of the water license heritage mitigation project plan. | | $250,000 | $250,000 |

# TAB 6
# BOARD DIRECTIVES

# 6.0 BOARD DIRECTIVES

This Tab reviews outstanding directives contained in prior Yukon Utilities Board (YUB) Decisions and, where relevant, Yukon Energy's response.

Order 2010-13 provided the Board's decision following the 2009 Phase II Rate Application and resulted in a number of directives related to cost of service and rate design issues that were not addressed in the compliance filing following that proceeding.

Tab 6 of the 2012/13 GRA outlined Yukon Energy's response to directives related to these cost of service (COS) and rate design issues as follows:

- In Order 2010-13 the Board "[did] not accept the COS study as filed by the Companies", "an updated COS study approved by the Board is essential to establishing a future rate restructuring process" and directed the Companies to "file a joint COS study within six months of the expiry of OIC 2008/149" that "incorporate[s] all findings and directions of the decision."

- The Board directives regarding Cost of Service and Rate Design consequently cannot be addressed until the next joint cost of service study is filed by the Companies.

- The latest Order in Council (OIC) direction provided in February 2014 (OIC 2014/23) effectively provides that material rate design changes that would result in rebalancing of rates between different customer classes cannot be undertaken until 2019 at the earliest. The remaining outstanding directives in Order 2010-13 will be addressed in the next joint cost of service and rate design application. This includes directives #1 to #12 and #19 (as summarized in Tab 6 of the 2012/13 GRA filing).

The balance of the information reviewed in Tab 6 relates to outstanding directives since the submission of the 2012/13 General Rate Application (GRA).

## 6.1 BOARD ORDER 2013-01, ORDER 2013-03 AND ORDER 2013-04 – YUKON ENERGY 2012-2013 GENERAL RATE APPLICATION & COMPLIANCE FILING

On April 27, 2012, Yukon Energy filed with the YUB an Application pursuant to the Public Utilities Act (PUA) and OIC 1995/90. The 2012 and 2013 revenue requirements were approved subject to Board ordered adjustments pursuant to directions provided in Order 2013-01 and Order 2013-03, and Yukon

Energy re-filed amended schedules as part of the compliance filing approved by the Board in Order 2013-04.

**Board Order 2013-01 Directives**

Order 2013-01 resulted in a number of specific Board directions. Most of these directives related to 2012 and 2013 revenue requirements, and accordingly were incorporated into the revised re-filing approved in Order 2013-04. The remaining outstanding directives are noted below:[1]

***Directive #7 and #24 – Demand Side Management (DSM) Expenditures***

- ***The Board directs YEC to remove all labour costs attributable to DSM and the ECD from the revenue requirement for the 2012 and 2013 test years in its compliance filing. The Board directs YEC to track and defer these costs until the Board approves a final DSM policy for YEC, as discussed in Section 5.3. [Paragraph 85]***

- ***Until the plan is filed, the Board directs that:***

    ***a) YEC create a deferral account wherein DSM O&M related costs are to be held, and***

    ***b) All DSM-related capital costs be held in WIP. [Paragraph 367]***

As directed, all labour costs attributable to DSM and ECD were removed from the revenue requirement for 2012 and 2013 test years in the compliance filing.

A five year plan (2013-2018) to implement and measure DSM programs for Yukon was presented for review as part of AEY's 2013-15 General Rate Application, and Yukon Energy and AEY presented a joint panel at the oral hearing to answer questions regarding the DSM program.

In Order 2014-06 (regarding the AEY 2013-15 General Rate Application), the Board noted that the estimates provided demonstrate a substantial opportunity for cost savings over the lifetime of the DSM program. However, the Board indicated a number of reservations with respect to the DSM program, and consequently did not approve the program in its entirety, providing the following comments and direction:

- Program elements of the residential non-government DSM portfolio[2] that pass all of the four cost-effectiveness measures were approved for 2014 and 2015;[3] AEY was directed to provide a revised budget for DSM programming in 2014 and 2015 in its compliance filing. The Utilities were directed to make a formal application to the Board before expanding DSM program elements "beyond that approved above and beyond 2015".

- The Utilities were ordered to reduce DSM-related administrative and overhead costs, communication and engagement costs, and staffing costs, on a pro-rata basis with the new DSM budget and to file these costs with the Board in the compliance filing.

- AEY was ordered to provide a schedule outlining targets (key performance indicators) for approved DSM program elements for each of 2014 and 2015 in the compliance filing.

- Given the substantial reduction in the scope of the DSM program, the Utilities were ordered to reduce the amount of identified costs for 2011, 2012 and 2013 (not related to "development of the plan or policy paper") on a pro-rata basis with the new DSM budget and to file these costs with the Board in the compliance filing. AEY was ordered to capitalize the amounts spent in 2011, 2012 and 2013 related to "Development of the plan or policy paper" and the pro-rata amount of the costs already spent in 2011, 2012 and 2013 not related to "development of the plan or policy paper," and to amortize these costs over the 2014 to 2018 period.

- The Board determined that a deferral account would protect ratepayers and normalize the incentive for the Utilities to maximize participation in the DSM program and ordered AEY to track all DSM programming costs occurring in 2014 and 2015 in a deferral account and to apply for recovery of these costs at the next GRA.

Tab 5 of the 2017/2018 GRA provides for review a summary of deferred DSM program costs related to the existing program, as well as additional costs for DSM program elements proposed for 2017 and 2018.

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[1] Note the numbering provided in Section 6.1 relates to the numbering for directions provided in Appendix 1 – Partial Summary of Board Directions provided in Appendix A to Board Order 2013-01.

[2] This included LED Lighting and Automotive Heater Timer Rebates and the Low-cost Energy Efficient Products program elements.

[3] The Board indicated concern that not all of the program elements pass the Rate Impact Measure (RIM), and noted that "….in the Board's view, all program elements must at least be rate-neutral for all ratepayers."

***Directives #8, #9, #10 and #11 - Brushing Costs / Transmission & Distribution Vegetation Management Deferral Accounts and Related Policies and Plans***

- ***For the period beyond the test years (future years), the Board directs YEC to create a transmission vegetation management deferral account. In future years, distribution and transmission vegetation management related costs greater than 2011 actual brushing costs are to be held be in the newly created vegetation management deferral account. [Paragraph 108]***

- ***The Board further directs [YEC] in its next GRA to provide its transmission vegetation management policy. At that time, the Board and interveners will have the opportunity to test reasonableness of the proposed policy and the costs held in the vegetation management deferral account. [Paragraph 109]***

- ***As was done respecting transmission vegetation management costs, the Board accepts YEC's proposed distribution brushing costs for the test years. However, for the period beyond the test years (future years) the Board directs YEC to create a distribution vegetation management deferral account. In future years, distribution vegetation management related costs greater than 2011 actual brushing costs are to be held in the newly created distribution vegetation management deferral account. [Paragraph 117]***

- ***The Board further directs YEC, in its next GRA, to provide its distribution and transmission vegetation management plan. At that time, the Board and interveners will have the opportunity to test the reasonableness of the proposed policy and the costs held in the vegetation management deferral account. [Paragraph 118]***

Yukon Energy's distribution and vegetation management policy has been provided as Appendix 3.1 of Tab 3 of the 2017/ 2018 GRA.

Distribution and transmission brushing costs incurred in 2014, 2015 and 2016 that were greater than 2011 actual brushing costs have been held in a distribution vegetation management deferral account. These costs are reviewed in Tab 3 of the 2017/2018 GRA (see Sections 3.3.2 and 3.3.3; Transmission and Distribution Brushing Costs are reviewed in Table 3.6, 3.6.1 and 3.7; a continuity schedule for deferred vegetation management costs is provided in Section 3.4 [see Table 3.14.2]).

***Directives #16 and #18 – Diesel Contingency Fund (DCF) and Rate Schedule 42***

- ***The Board does not approve YEC's proposed DCF but directs YEC to provide a revised DCF proposal. In the revised DCF proposal, YEC is to incorporate other non-diesel generation facilities (wind, Fish Lake hydro) forecasts into its model. In addition, YEC is to incorporate the suggestions of CW and UCG as to how DCF transactions are to be reported. Further, in that submission, YEC is to provide an example of approximately five years of transactions that will show how the balance in the DCF will change and how those changes will be reported. Finally, YEC is to work with YECL, and the two utilities will provide a joint recommendation on how the DCF will affect the Energy Reconciliation Account in Rate Schedule 42 and any proposed wording changes to that rate schedule. The Board will leave it to the discretion of YEC and YECL as to when the revised DCF proposal is to be filed with the Board. Given the foregoing, the Board does not approve YEC's requests regarding the DCF and therefore does not approve YEC's proposed changes to Rider F. Secondary sales, as they occur, will continue to be credited to the Rider F account. [Paragraph 255]***

- ***As the Board has requested YEC to file a revised DCF, and to address the concerns raised by the Board in that filing, the Board directs YEC to refile a Rate Schedule 42 in cooperation with YECL as directed in Section 3.6.2 of this decision. [Paragraph 260]***

YEC's May 1, 2013 Compliance Filing provided a Revised DCF that included the following changes from the 2012/2013 GRA filing:

1. As directed in Order 2013-1, the Revised DCF reflected diesel generation costs at 100% of LTA hydro generation, removed secondary sales impacts on the DCF, incorporated other non-diesel generation facilities (wind, Fish Lake Hydro) forecasts into YEC's DCF model, incorporated suggestions made by intervenors in argument during the 2012/2013 GRA regarding how DCF transactions are to be reported, and provided an example of approximately five years of transactions to show how the balance of the DCF will change and how those changes will be reported.

2. The revised DCF also recommended increasing the current DCF threshold cap from +/-$4 million to +/-$8 million, and included setting DCF determinations based on the Board's approved diesel fuel costs per kW.h (without any O&M costs).

Board Order 2013-03 did not approve Yukon Energy's revised DCF as provided in the May 2013 Compliance Filing and reiterated the Board's direction in Order 2013-01 for YEC to work with ATCO Electric Yukon (AEY or YECL), and for the two utilities to provide a joint recommendation. Board Order 2013-03 also clarified that "YEC may file a future revised DCF proposal and ERA application", noting that the Board prefers a joint filing from YEC and AEY, but "if agreement cannot be reached, a filing in which the companies state which aspects they agree upon, and the position of each company on those aspects they disagree upon is acceptable".

As directed, the Companies consulted on this matter, including exchange of documents setting out their respective positions. However, the Companies were not able to agree on any specific elements of either the DCF or the ERA. In accordance with the Board's direction, on January 31, 2014 Yukon Energy and AEY each provided a submission setting out their position and proposal regarding the DCF and the ERA. This was reviewed subsequently as part of a separate written proceeding (see Section 6.2 below).

***Directive #20 - Aishihik Generation Station Redundancy Project***

- ***The Board has concerns with the escalation of costs, but the Board notes that additional projects were undertaken at the time when the redundant cabling system was replaced. The Board has reviewed the project costs and has not seen any evidence that the additions to the project were unnecessary or not useful. Therefore, the Board approves the project costs as filed. However, in future, the Board directs YEC is to provide business cases for all projects, including reliability projects, greater than $1 million. These business cases are to include alternatives to the recommended projects as well as the economic impact to ratepayers of the recommended projects. [Paragraph 313]***

Business cases for projects greater than $1 million (i.e., "major projects") are provided in Tab 5 of this General Rate Application.

In addressing reliability as well as other types of major projects, it is noted that the nature of the business case analysis may take on different forms depending on the nature or reason for undertaking the Project (i.e., the business case information and analysis may differ when the reason for undertaking the project is for reliability or safety purposes versus projects intended to add supply or reduce costs to the system).

- Projects undertaken to add supply or reduce costs may include quantitative analysis (rate impact or cost benefit assessments).

- These types of assessments may not be appropriate, however, for projects undertaken for safety or reliability purposes (whether there may be no alternative but to undertake the project and limited options regarding how to undertake the project); in these cases more qualitative assessments may be provided.

- Where appropriate, information regarding alternatives to the recommended project and the economic impact to ratepayers of the recommended project is provided for each major project.

***Directive #21 - Capital Projects - Specific Impacts on YECL***

- ***The Board notes that the invoices relate to a YEC planned outage in respect of one of its major projects. As part of YEC's feasibility study work leading up to the decision, whether or not the project is given the go ahead, the Board considers that YEC would investigate and determine all costs that relate to such projects. The Board finds that it is YEC's obligation to forecast all future costs, including all third party costs, such as YECL utility costs that relate to YEC's proposed capital projects. The Board directs YEC to consult with YECL to determine costs that are to be incurred by YECL, as a result of YEC's proposed capital project costs. The Board further directs YEC to include such costs in future GRAs for Board and intervener review. [Paragraph 316]***

Yukon Energy has reviewed, as part of this General Rate Application, whether there are any applicable third party costs related to capital projects that should be considered in its revenue requirement for the test years. There are no such applicable costs for the test years in this Application.

***Directive #23 - Gladstone Hydro Enhancement Project***

- ***The Board finds that Gladstone hydro enhancement project has potential to be a viable project 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. [Paragraph 344]***

Tab 5, Section 5.3.1.7 reviews the current status of the Gladstone Hydro Enhancement Project and notes that Yukon Energy has concluded that the project no longer offers any net economic benefit to ratepayers as there is no reasonable probability that the project will proceed.

Following the Board's direction in Order 2013-01, Yukon Energy has ceased work on the project.

Based on Yukon Energy's decision not to proceed further with the project, feasibility study costs to date of approximately $4.521 million will be amortized over 10 years, starting in 2017.

***Directive #27 - Projects Between $100,000 and $1 Million (Deferred Costs)***

- ***The Board notes that interveners did not take issue with expenditures prior to the 2012 test year. Having reviewed the project expenditures YEC incurred prior to year-end 2011, the Board finds the expenditures prudent and directs that they be capitalized. Moreover, for project expenditures incurred in the test years and beyond, the Board directs that these expenditures be held in WIP until such time the costs are brought before the Board for a prudence review and have been approved. The Board directs YEC to incorporate these findings into its compliance filing. [Paragraph 398]***

Deferred cost expenditures for projects between $100,000 and $1 million for 2012, 2013 and subsequent years were held in WIP, as directed.

These deferred cost expenditures are included in Tab 5 of this Application for review by the Board.

***Directive #28 - New Planning Cost Accounting Policy***

- ***The Board does not accept the planning cost accounting policy as the Board and interveners must be given the opportunity to test the prudence of all costs incurred by YEC in respect of deferred costs. Accordingly, the Board considers that the policy as proposed would allow the inclusion of these costs without any prior scrutiny by the Board and interveners. Considering the above, the Board rejects YEC's proposed planning cost accounting policy. [Paragraph 405]***

An updated Planning Cost Accounting Policy that reflects the Board's prior directions from Order 2013-01 is included as Appendix 5.1 of this Application.

***Directive #29 - New Demand-Side Management Accounting Policy***

- ***The Board defers its findings and directions regarding YEC's DSM accounting policy until YEC and YECL have jointly filed a DSM plan as directed in a prior section. [Paragraph 407]***

An updated DSM Accounting Policy is provided as Appendix 5.2 of this Application.

**Board Order 2013-03 Directives**

On May 1, 2013, Yukon Energy filed its compliance filing pursuant to Board Order 2013-01. In Order 2013-03,[4] the Board denied the requested approvals pertaining to Rider J, Rider R and the DCF, as the requested approvals were not in accordance with Board Order 2013-01, and directed Yukon Energy to refile its compliance filing within 10 days of the issuance of the Order. Order 2014-03 also provided the following directions:

- The Board approved YEC's request to establish and maintain a hearing cost reserve account going forward.
- The Board directed YEC to continue to apply any secondary sales to income (with adjustments to the Rider F account as currently occurs for variances in the rate from the GRA forecast).
- The Board did not approve YEC's revised Diesel Contingency Fund.
- The Board noted that in future, YEC must file Excel versions, with formulae intact, of all schedules and tables used to support its filings.

A revised compliance filing was filed with the Board on June 20, 2013. Order 2013-04 approved the revised compliance filing provided in response to Board Order 2013-03.

## 6.2 BOARD ORDERS 2015-01, 2015-03 AND 2015-06 - DCF/ERA PROCEEDING

On January 31, 2014, Yukon Energy and AEY each filed an application with the YUB seeking an Order from the Board for approval of their proposals for revisions to the Diesel Contingency Fund and the Energy Reconciliation Adjustment (ERA) element of Rate Schedule 42 (wholesale rate to AEY). Following a written proceeding, the Board in Order 2015-01 approved DCF and ERA amendments proposed by YEC subject to specific directions outlined in the Reasons for Decision outlined in Appendix A to that Order, noting that YEC was to commence quarterly reports regarding the balance in the DCF account (effective March 31, 2015) and provide a compliance filing within 60 days of the issuance of the decision.

[4] Order 2013-03 the Board provided the following additional approvals and directions: (1) The Board did not approve YEC's revised Diesel Contingency Fund; (2) The Board approved YEC's request to establish and maintain a hearing cost reserve account going forward; (3) The Board directed YEC to continue to apply any secondary sales to income (with adjustments to the Rider F account as currently occurs for variances in the rate from the GRA forecast). YEC will use for the forecast secondary sales revenues to the Rider F account of 8.7 cents/kW.h for retail secondary sales and 7.6 cents/kW.h for wholesale secondary sales; and (4) The Board directed that in future YEC must file Excel versions, with formulae intact of all schedules and tables used to support its filings.

Specific directions regarding the DCF that were provided at the end of Section 2.1.1 of Appendix A to Order 2015-01 were as follows:

- ***To summarize, secondary sales or diesel being "on the margin" are not hurdles to be overcome before the DCF is applied. The Board accepts there is sufficient load on the system for diesel to form part of baseload generation and therefore to apply to the DCF.***

- ***Whatever model YEC uses to determine LTA hydro generation, DCF calculations or other forecast process, that model and its results, or other forecast process must be made available for testing by the Board and intervenors.***

- ***The DCF is to be used for variations in LTA hydro availability. Any application of the DCF outside of this intended use may result in the cessation of the DCF, the dispensation of any balance in the DCF, and the use of short-term forecasts for hydro generation in future GRAs.***

- ***The DCF will have a cap of +/- $8 million as proposed by YEC. If the balance in the DCF falls out of the +/- $8 million range, YEC shall make an application to the Board to dispense with the balance that is outside of that range within 60 days of the outside-the-range occurrence.***

With regard to the ERA, the Board indicated concerns regarding the YECSIM model,[5] noting that it was a "planning model" and did not "lend itself to retrospective verification." The Board also noted that it interpreted costs referenced in Section 7 of OIC 1995/90[6] narrowly, specifying "costs are for actual diesel generation costs, not forecast or derived costs from the YECSIM model."[7] The Board did not accept the ERA as proposed by YEC. Specifically, the Board found that the ERA need not be tied to the DCF, and noted that ERA charges or credits are to be based on actual costs versus forecast costs. The Board also noted that on a go-forward basis, ERA charges must be billed, or credited, within 30 days of the close of the year to which those changes relate.

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[5] See Board Oder 2015-01, Section 2.2.1.4, page 23.

[6] Section 7 of OIC 1995/90 notes that "The Board must fix rates of Yukon Energy Corporation for the wholesale power customer in accordance with the following rate policy for Yukon: (a) Yukon Energy Corporation shall sell electricity to The Yukon Electrical Company Limited at the same demand rate and the same energy rate throughout the Yukon and those rates must be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other customers; (b) the wholesale rate to The Yukon Electrical Company Limited shall include appropriate provisions to ensure that Yukon Energy Corporation will recover its costs for retail and major industrial power service with adoption of the rates for retail power customers and major industrial power customers as specified herein."

[7] See Board Order 2015-01, Section 2.2.1.4, page 23.

Specific compliance filing directions regarding the ERA as provided in Section 2.2.1.4 of Appendix A to Order 2015-01 were as follows:

- ***In its compliance filing to this decision, YEC is to provide a revised ERA that is based on actual diesel costs. That is, if actual diesel costs are higher than the levels of diesel contained in YEC's latest approved forecast, then those costs which are attributable to YECL's wholesale purchase that are in excess of those in the last approved forecast will become billable to YECL. The converse is also true: a credit applies when diesel costs are lower and that reduction in cost relates to YECL wholesale loads being less than forecast. Further, in the event ERA costs are billable to YECL, YEC must provide those charges to YECL within 30 days of the close of the year to which those charges relate.***

- ***With its compliance filing, YEC is to update the Board regarding any ERA charges for the years 2012, 2013, and a forecast for 2014.***

Yukon Energy provided its compliance filing on April 7, 2015 and requested the following approvals:

1. Approval of Revised DCF Term Sheet as set out in Attachment 1 [of the Compliance Filing].

2. Approval of DCF amounts as provided in Table A1 of Appendix A for 2012 and 2013 as final and for 2014 as preliminary.

3. Approval of a DCF Rider rate schedule as set out in Attachment 2, applied to consumption on or after the effective date of May 1, 2015 and until or on March 31, 2016.

4. In any future year when the balance in the DCF falls outside of the +/- $8 million range at the fiscal year end, approval for YEC to file an application to the Board within 60 days of the fiscal year end for a rate rider to deal with the balance in the DCF that is outside of that range.

5. Approval of ERA charges as per Table B3 of Appendix B [of the compliance filing] for 2012, 2013 and 2014 as final, and approval that in future years the ERA be determined concurrent with the DCF within 60 days of year end, and that the Board be provided with a copy of such determinations.

The compliance filing noted that YEC had sought to implement the directions of the Board to assign costs (or credits) to AEY that are attributable to AEY's wholesale purchases that are in excess of (or less than) the wholesale forecast approved for YEC's last GRA in years when AEY's variance from this approved forecast is in the same direction as YEC's variance of actual diesel costs from the last approved forecast. Appendix B of the compliance filing outlined the concern of YEC that the ERA determination is dependent on confirmation of the definition of "actual diesel costs" for the purposes of the ERA. To ensure that the ERA determination did not yield unacceptable results, Yukon Energy incorporated into its calculations the definition for "actual fuel costs" set out in Section 2.1.1.4 of Order 2015-01.

Following Yukon Energy providing its compliance filing pursuant to Order 2015-01, the Board issued Order 2015-03. This Board Order included as Attachment A, interrogatories for YEC seeking clarification regarding certain items included in Yukon Energy's compliance filing. The Order outlined a process and schedule for YEC's responses to the Board's interrogatories, intervenor comments on Yukon Energy's compliance filing and Yukon Energy's response to intervenor comments.

Yukon Energy provided responses to information requests outlined in Order 2015-03 on May 8, 2015, intervenor comments were received from AEY and UCG on May 21, 2015, and Yukon Energy provided its reply to intervenor comments on June 3, 2015. Further comments were provided by UCG on June 8, 2015 and responded to by YEC on June 10, 2015.

In Order 2015-06, issued on August 18, 2015, the Board noted in Section 2.1.1.4 with regard to the DCF that subject to its direction regarding the quarterly reports, and directions regarding the ERA that affect the DCF, that it accepted the submissions from YEC in its compliance filing and found that YEC had complied with the directions regarding the DCF in Order 2015-01.

With regard to the ERA, the Board reiterated in Section 2.2.1.4 of Order 2015-06 the comments it provided in Order 2015-01. Specifically, that the YECSIM is not verifiable for purposes of the ERA and that the YECSIM had not been tested. The Board noted that it was not persuaded that the definition of "actual costs" for ERA purposes (as provided in Appendix A to Order 2015-01) should be changed and that as long as actual diesel generation costs are recovered, the criteria in Section 7 of OIC 1995/90 are met. The Board further noted that by using the Board's definition of actual costs the Board was of the view that the "perverse outcome" described by YEC in Appendix B to its compliance filing would not occur during high-water years as YEC will recover its actual diesel generation costs. The Board directed that any "perverse outcome" which can occur during drought periods, i.e., where ratepayers could be charged twice (once through the DCF and a second time through the ERA), can be addressed by amending Rate Schedule 42 to reflect that during drought periods, when diesel generation costs are recovered through DCF, YEC cannot invoke the ERA.

Order 2015-06 provided the following specific directions with regard to the DCF and ERA:

1. ***The Board does not accept the ERA portion of the compliance filing as submitted by YEC for the reasons set out in the Reasons for Decision, Appendix A, to this Order. YEC is to issue its refund of excess DCF contributions (Rider E) estimated at 0.68 cents/kW.h effective September 1, 2015.***

2. ***YEC is to update its Rate 42 schedule based on the determinations made by the Board in Appendix A of this decision.***

3. ***The Board does not approve the request of YEC for the change to the quarterly returns.***

4. ***YEC is to file quarterly returns and applications when the balance in the DCF falls outside of the +/- $8 million range, in accordance with Board Order 2015-01.***

With regard to the DCF, Rider E refunds at 0.68 cents per kW.h were initiated as at September 1, 2015 and commencing with Q3 2015, Yukon Energy has provided regular quarterly DCF filings to the Board. Yukon Energy's annual DCF filing for 2015 provided a proposal for incorporating LNG into DCF determinations.[8] The Board in correspondence dated March 7, 2016 and March 31, 2016 noted that it was not prepared to make any determinations regarding LNG in the DCF or Rider F until such time as YEC files a full rate rider application or a GRA. The Board also noted in its March 31, 2016 correspondence that "as the DCF is a deferral account, final Rider E amounts for the years 2015 and forward can be finalized once either the rate rider or GRA proceeding is completed". Tab 3 of this Application, including Appendix 3.4, provides Yukon Energy's proposed approach for incorporating LNG into both the DCF and Rider F.

With regard to the ERA, Yukon Energy on October 13, 2015 filed a request for review and variance of Order 2015-06 pursuant to Section 62 of the PUA and Section 31 of the YUB Rules of Practice. Yukon Energy requested that the Board convene a phase II review on the merits in relation to the ERA or proceed directly to vary the ERA findings by approving the ERA as provided for in Yukon Energy's April 7, 2015 compliance filing. Board Order 2015-07 denied the review and variance application. Following this

[8] The Q3 2015 quarterly report excluded LNG generation noting YEC's LNG facilities at the Whitehorse thermal plant were available for service in July 2015 – but deficiency correction and various commissioning activities continued into Q4 2015. Due to these ongoing commissioning activities YEC was not able at that time to set out proposals for inclusion of LNG in ongoing DCF determinations. YEC noted that it would provide a proposed approach for including LNG in ongoing DCF determinations in the December 31, 2015 year-end DCF filing. It was also noted that because the year-end DCF filing will determine final DCF amounts for 2015, the delay in dealing with LNG would not prejudice these final 2015 determinations.

decision, Yukon Energy filed a leave to appeal with the Yukon Court of Appeal. The matter was argued before the Court of Appeal on December 7, 2016 and a determination is forthcoming.

## 6.3 BOARD ORDERS 2013-08, 2014-12 (REVISED BY ORDER 2014-13), AND 2015-04

Cost awards were determined subsequent to the Yukon Energy 2012/13 General Rate Application, the Diesel-Natural Gas Conversion Project Part 3 Hearing (LNG Part 3 Proceeding), and the Yukon Energy Application to Revise the DCF and Related ERA Adjustment Proceeding (DCF Proceeding). The Board provided the following directives related to hearing cost awards for each of these proceedings:

- 2012/13 General Rate Application (Order 2013-08):
    - "YEC shall pay the following amounts to interveners identified and the Government of the Yukon within 30 days of the issuance of this Order. The Board directs YEC to amortize these hearing-related costs."
- LNG Part 3 Proceeding (Order 2014-12, revised by Order 2014-13):
    - "YEC shall pay the following amounts to interveners identified and the Government of the Yukon within 30 days of the issuance of this Order. The Board directs YEC to amortize these hearing-related costs."
- DCF/ERA Proceeding (Order 2015-04):
    - "YEC and YECL shall pay 50 percent of the following amounts to UCG and the Government of Yukon within 30 days of the issuance of this Order. The Board directs YEC to amortize its hearing-related costs and YECL to record its hearing-related costs in its hearing costs reserve account."

Yukon Energy has established a Hearing Cost Reserve Account in accordance with the direction provided in Board Order 2013-03, and YEC has amortized hearing-related costs to this account for the above proceedings as directed by the Board (see Table 6.1 for a summary of the hearing-related costs for each of the above proceedings).

**Table 6.1:**
**Cost Awards Order 2013-08, Order 2014-12 (and errata), and Order 2015-04**

| | Yukon Energy 2012-2013 GRA [Order 2013-08] | Diesel-Natural Gas Conversion Project Part 3 Application [Order 2014-12] | Yukon Energy DCF/ERA Proceeding [Order 2015-04] |
|---|---|---|---|
| **Yukon Energy** | 556,026.07 | 194,995.42 | 116,675.19 |
| **City of Whitehore (CW)** | 59,396.24 | 10,699.10 | |
| **Utility Consumers' Group (UCG)** | 41,462.62 | 34,617.70 | 9,435.00 |
| **Yukon Electrical YECL [AEY]** | 32,157.39 | | 22,211.00 |
| **Yukon Conservation Society (YCS)** | 3,610.00 | | |
| **Leading Edge/ John Maissan (LE)** | 7,919.06 | | |
| **YCS/ LE (Joint intervention)** | | 36,006.80 | |
| **Yukon Government** | 236,213.27 | 158,537.62 | 63,958.00 |
| **Total** | **936,784.65** | **434,856.64** | **212,279.19** |

Notes:

1. For the Diesel- Natural Gas Conversion Project, YCS and LE filed a combined claim.
2. YEC and YECL (AEY) were ordered to pay 50% of the amoutns awarded to UCG and the Government of Yukon.
3. Order 2014-13 revised Order 2014-12 and UCG costs were adjusted from $24,730.20 to $34,617.70 and total award from $424,969.14 to $434,856.64.

# TAB 7
# FINANCIAL SCHEDULES

**Yukon Energy Corporation**
June 2017

# Schedule Index

**Yukon Energy Corporation**
**Computation of Rate Base**
**($000s)**

Schedule 1
June 2017

| Line No. | Description | Cross Ref. | 2013 Approved | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Property, Plant and Equipment** | | | | | | | | | | |
| 2 | Year end balance | S.3 L.5 | 520,651 | 520,406 | 555,552 | 577,888 | 589,387 | 603,879 | 603,879 | 618,511 | 618,511 |
| | Deduct: | | | | | | | | | | |
| 3 | Accumulated depreciation (note 1) | S.3 L.10 | 120,694 | 119,279 | 125,757 | 134,978 | 144,703 | 155,760 | 156,806 | 166,927 | 169,223 |
| 4 | Construction-in-progress | S.3 L.11 | 19,798 | 24,137 | 53,893 | 13,362 | 18,467 | 9,277 | 4,358 | 14,851 | 8,274 |
| 5 | Disallowed assets | S.3 L.12 | 691 | 691 | 691 | 691 | 691 | 691 | 691 | 691 | 691 |
| 6 | Miscellaneous reserves | S.3 L.13 | 5,904 | 5,684 | 5,452 | 5,223 | 4,169 | 3,830 | 4,119 | 3,491 | 4,069 |
| 7 | Total deductions | | 147,087 | 149,792 | 185,794 | 154,254 | 168,030 | 169,559 | 165,974 | 185,960 | 182,257 |
| | Add: | | | | | | | | | | |
| 8 | Deferred study costs (note 2) | S.3 L.15 | 27,891 | 24,106 | 24,615 | 21,957 | 27,212 | 32,031 | 29,346 | 50,232 | 44,917 |
| 9 | Less: Studies in Progress | S.3 L.16 | (14,742) | (13,618) | (16,773) | (19,070) | (24,728) | (33,625) | (16,167) | (50,069) | (29,859) |
| 10 | Other deferred costs | S.3 L.17 | - | - | - | - | - | - | - | - | - |
| 11 | Accum. Disallowed depreciation | S.3 L.18 | 119 | 119 | 135 | 151 | 167 | 184 | 184 | 200 | 200 |
| 12 | Total additions | | 13,267 | 10,607 | 7,977 | 3,038 | 2,651 | (1,411) | 13,363 | 364 | 15,258 |
| | **Net plant in Service** | | | | | | | | | | |
| 13 | Current year-end balance | S.3 L.20 | 386,831 | 381,221 | 377,735 | 426,672 | 424,009 | 432,910 | 451,268 | 432,914 | 451,511 |
| 14 | Previous year-end balance | | 387,051 | 383,931 | 381,221 | 377,735 | 426,672 | 424,009 | 424,009 | 432,910 | 451,268 |
| 15 | Total | | 773,882 | 765,152 | 758,956 | 804,407 | 850,681 | 856,918 | 875,276 | 865,824 | 902,779 |
| 16 | Mid-year balance | | 386,941 | 382,576 | 379,478 | 402,204 | 425,340 | 428,459 | 437,638 | 432,912 | 451,390 |
| 18 | Mid-year regulatory deferral | | 1,486 | 1,693 | 1,367 | 2,007 | 2,061 | 2,660 | 2,447 | 2,955 | 2,208 |
| 19 | Working capital | S.2 L.8 | 4,280 | 4,520 | 4,495 | 4,791 | 4,928 | 5,138 | 5,200 | 5,152 | 5,210 |
| 20 | **Gross Rate Base** | | 392,707 | 388,789 | 385,340 | 409,002 | 432,329 | 436,257 | 445,285 | 441,019 | 458,808 |
| | Deduct: | | | | | | | | | | |
| | **Contributions for extensions** | | | | | | | | | | |
| 21 | Current year-end balance | | 191,243 | 180,582 | 181,163 | 200,167 | 200,500 | 200,900 | 200,900 | 201,300 | 201,300 |
| 22 | Contributions in WIP | | 10,500 | 174 | 262 | 605 | 167 | 150 | - | 150 | - |
| 23 | Current year-end balance in-service | | 180,743 | 180,408 | 180,901 | 199,561 | 200,332 | 200,750 | 200,900 | 201,150 | 201,300 |
| 24 | Accumulated amortization of contributions | | 16,305 | 16,390 | 20,002 | 23,626 | 27,729 | 31,847 | 31,851 | 35,978 | 35,986 |
| 25 | Net current year-end balance in-service | | 164,438 | 164,018 | 160,899 | 175,935 | 172,604 | 168,902 | 169,049 | 165,172 | 165,314 |
| 26 | Previous year-end balance | | 167,607 | 167,445 | 164,018 | 160,899 | 175,935 | 172,604 | 172,604 | 168,902 | 169,049 |
| 27 | Total | | 332,046 | 331,463 | 324,917 | 336,834 | 348,539 | 341,506 | 341,652 | 334,074 | 334,363 |
| 28 | Mid-year balance | | 166,023 | 165,732 | 162,459 | 168,417 | 174,269 | 170,753 | 170,826 | 167,037 | 167,181 |
| 29 | **Net Rate Base** | S.5 L.1 | 226,684 | 223,058 | 222,882 | 240,584 | 258,060 | 265,504 | 274,459 | 273,982 | 291,627 |

Note 1: Including Reserve for Future Removal and Site Restoration
Note 2: Planning and Study costs, Relicencing, Dam Safety costs and Vegetation Management. Net of contributions.

**Yukon Energy Corporation**
**Computation of Allowance for Working Capital**
**($000s)**

Schedule 2
June 2017

| Line No. | Description | Cross Ref. | 2013 Approved | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Operating and maintenance | S.5 L.5 | 20,844 | 22,786 | 21,052 | 21,723 | 21,812 | 22,212 | 23,363 | 22,168 | 23,336 |
| 2 | Taxes other than income | S.5 L.6 | 326 | 331 | 331 | 473 | 686 | 696 | 696 | 708 | 708 |
| 3 | Non-allowable expenses | | (85) | (84) | (85) | (86) | (95) | (96) | (96) | (100) | (100) |
| 4 | Cash operating expenses | | 21,085 | 23,033 | 21,298 | 22,110 | 22,403 | 22,811 | 23,962 | 22,776 | 23,944 |
| 5 | 27/365 | | 1,560 | 1,704 | 1,575 | 1,636 | 1,657 | 1,687 | 1,773 | 1,685 | 1,771 |
| 6 | Inventory (three year average) | | 2,830 | 2,948 | 3,026 | 3,300 | 3,426 | 3,603 | 3,603 | 3,598 | 3,598 |
| 7 | GST Impact on working capital | S.2A L.11 | (110) | (131) | (106) | (145) | (155) | (153) | (176) | (131) | (159) |
| 8 | Working capital | S.1 L.19 | 4,280 | 4,520 | 4,495 | 4,791 | 4,928 | 5,138 | 5,200 | 5,152 | 5,210 |

**Yukon Energy Corporation**
**Effect of GST on Working Capital**
**($000s)**

Schedule 2A
June 2017

| Line No. | Description | Cross Ref. | 2013 Approved | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Expenses subject to GST | | 39,395 | 33,079 | 47,770 | 29,427 | 26,210 | 28,751 | 29,575 | 40,552 | 41,694 |
| 2 | GST Rate | | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| 3 | GST Recoverable | | 1,970 | 1,654 | 2,388 | 1,471 | 1,310 | 1,438 | 1,479 | 2,028 | 2,085 |
| 4 | Day Factor | | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 |
| 5 | Recoverable portion of GST impact | | 76 | 63 | 92 | 56 | 50 | 55 | 57 | 78 | 80 |
| 6 | Revenue subject to GST | | 42,263 | 40,492 | 41,245 | 41,855 | 42,686 | 43,425 | 48,544 | 43,508 | 49,864 |
| 7 | GST blended rate (2009 GRA) | | 4.58% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| 8 | GST payable | | 1,935 | 2,025 | 2,062 | 2,093 | 2,134 | 2,171 | 2,427 | 2,175 | 2,493 |
| 9 | Day factor | | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| 10 | Payable portion of GST impact | | 186 | 194 | 198 | 201 | 205 | 208 | 233 | 209 | 239 |
| 11 | Net impact of GST on working capital | S.2 L.7 | (110) | (131) | (106) | (145) | (155) | (153) | (176) | (131) | (159) |

**Yukon Energy Corporation**
**Continuity Schedule of Property, Plant and Equipment**
**($000s)**

Schedule 3
June 2017

| Line No. | Description | Cross Ref. | 2013 Approved | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Property, Plant and Equipment** | | | | | | | | | | |
| 2 | Balance at beginning of year | | 496,938 | 495,795 | 520,406 | 555,552 | 577,888 | 589,387 | 589,387 | 603,879 | 603,879 |
| 3 | Net Increases to PPE (Table 5.1) | | 23,713 | 25,717 | 37,583 | 22,728 | 12,314 | 14,492 | 14,492 | 14,631 | 14,631 |
| 4 | Retirements, disposals and adjustments | | - | (1,106) | (2,437) | (392) | (815) | - | - | - | - |
| 5 | Balance at end of year | S.1 L.2 | 520,651 | 520,406 | 555,552 | 577,888 | 589,387 | 603,879 | 603,879 | 618,511 | 618,511 |
| 6 | **Accumulated depreciation (including Future Removal Reserve)** | | | | | | | | | | |
| 7 | Balance at beginning of year | | 111,706 | 111,476 | 119,279 | 125,757 | 134,978 | 144,703 | 144,703 | 155,760 | 156,806 |
| 8 | Depreciation expense | S.6 L.7 | 8,989 | 8,854 | 8,906 | 9,524 | 10,607 | 11,059 | 12,105 | 11,168 | 12,419 |
| 9 | Retirements, disposals and adjustments | | - | (1,051) | (2,428) | (303) | (882) | (2) | (2) | (2) | (2) |
| 10 | Balance at end of year | | 120,694 | 119,279 | 125,757 | 134,978 | 144,703 | 155,760 | 156,806 | 166,927 | 169,223 |
| | **Depreciation Proper** | | | | | | | | | | |
| | Balance at beginning of year | S.3 L.10 | 106,995 | 106,765 | 114,608 | 121,086 | 130,611 | 140,344 | 140,344 | 151,513 | 152,559 |
| | Depreciation expense | S.6 L.6 | 8,989 | 8,894 | 8,906 | 9,828 | 10,615 | 11,171 | 12,217 | 11,168 | 12,419 |
| | Retirements, disposals and adjustments | | | (1,051) | (2,428) | (303) | (882) | (2) | (2) | (2) | (2) |
| | Balance at end of year | S.1 L.4 | 115,983 | 114,608 | 121,086 | 130,611 | 140,344 | 151,513 | 152,559 | 162,680 | 164,976 |
| | **Reserve for Future Removal and Site Restoration** | | | | | | | | | | |
| | Balance at beginning of year | | 4,711 | 4,711 | 4,671 | 4,671 | 4,367 | 4,359 | 4,359 | 4,247 | 4,247 |
| | Site Restoration expense | | | (40) | - | (304) | (8) | (112) | (112) | - | - |
| | Retirements, disposals and adjustments | | | - | - | - | - | - | - | - | - |
| | Balance at end of year | | 4,711 | 4,671 | 4,671 | 4,367 | 4,359 | 4,247 | 4,247 | 4,247 | 4,247 |
| | | | 385,232 | 384,319 | 401,127 | 429,795 | 442,910 | 444,685 | 444,685 | 448,119 | 447,073 |
| | Deduct: | | | | | | | | | | |
| 11 | Construction-in-progress | S.1 L.4 | 19,798 | 24,137 | 53,893 | 13,362 | 18,467 | 9,277 | 4,358 | 14,851 | 8,274 |
| 12 | Disallowed assets | S.1 L.5 | 691 | 691 | 691 | 691 | 691 | 691 | 691 | 691 | 691 |
| 13 | Miscellaneous reserves (note 1) | S.1 L.6 | 5,904 | 5,684 | 5,452 | 5,223 | 4,169 | 3,830 | 4,119 | 3,491 | 4,069 |
| 14 | Total | | 26,393 | 30,513 | 60,037 | 19,276 | 23,328 | 13,798 | 9,168 | 19,033 | 13,034 |
| | Add: | | | | | | | | | | |
| 15 | Deferred study costs (note 2) | S.1 L.8 | 27,891 | 24,106 | 24,615 | 21,957 | 27,212 | 32,031 | 29,346 | 50,232 | 44,917 |
| 16 | Less: Studies in Progress | S.1 L.9 | (14,742) | (13,618) | (16,773) | (19,070) | (24,728) | (33,625) | (16,167) | (50,069) | (29,859) |
| 17 | Other deferred costs | S.1 L.10 | - | - | - | - | - | - | - | - | - |
| 18 | Accum. Disallowed depreciation | S.1 L.11 | 119 | 119 | 135 | 151 | 167 | 184 | 184 | 200 | 200 |
| 19 | Total | | 13,267 | 10,607 | 7,977 | 3,038 | 2,651 | (1,411) | 13,363 | 364 | 15,258 |
| 20 | Net Property, Plant and Equipment | S.1 L.13 | 386,831 | 381,221 | 377,735 | 426,672 | 424,009 | 432,910 | 451,268 | 432,914 | 451,511 |

Note 1: Includes Fire Insurance Reserve and the Reserve for Injuries and Damages
Note 2: Planning and Study costs, Relicencing, Dam Safety costs and Deferred Overhauls. Net of contributions.

**Yukon Energy Corporation**
**Cost of Capital Calculation**
**2013 Approved and 2013-2015 Actual**
**($000s)**

Schedule 4A
June 2017

| Line No. | Description | Cross Ref. | Mid Year Balance | Ratio | Mid Year Rate Base | Mid Year Cost Rate | Return |
|---|---|---|---|---|---|---|---|
| | **2013 Approved** | | | | | | |
| 1 | Long-Term debt | S.11 L.18 | 137,410 | 60.0% | 136,010 | 3.58% | 4,867 |
| 2 | Common Stock | S.7 L. 8 | 91,607 | 40.0% | 90,674 | 8.25% | 7,481 |
| 3 | Total | S.5 L.3 | 229,017 | 100.0% | 226,684 | 5.45% | 12,348 |
| | **2013 Actual** | | | | | | |
| 4 | Long-Term debt | S.11 L.18 | 133,482 | 60.0% | 133,925 | 3.38% | 4,522 |
| 5 | Common Stock | S.7 L. 8 | 88,837 | 40.0% | 89,132 | 7.42% | 6,617 |
| 6 | Total | S.5 L.3 | 222,319 | 100.0% | 223,058 | 4.99% | 11,138 |
| | **2014 Actual** | | | | | | |
| 7 | Long-Term debt | S.11 L.18 | 133,636 | 59.0% | 131,486 | 3.22% | 4,228 |
| 8 | Common Stock | S.7 L. 8 | 92,891 | 41.0% | 91,396 | 8.44% | 7,710 |
| 9 | Total | S.5 L.3 | 226,527 | 100.0% | 222,882 | 5.36% | 11,938 |
| | **2015 Actual** | | | | | | |
| 10 | Long-Term debt | S.11 L.18 | 141,509 | 59.0% | 141,951 | 2.00% | 2,840 |
| 11 | Common Stock | S.7 L. 8 | 98,327 | 41.0% | 98,634 | 8.10% | 7,989 |
| 12 | Total | S.5 L.3 | 239,837 | 100.0% | 240,584 | 4.50% | 10,829 |

**Yukon Energy Corporation**
**Cost of Capital Calculation**
**2016 Forecast and 2017 Forecast (Existing / GRA)**
**($000s)**

Schedule 4B
June 2017

| Line No. | Description | Cross Ref. | Mid Year Balance | Ratio | Mid Year Rate Base | Mid Year Cost Rate | Return |
|---|---|---|---|---|---|---|---|
| | **2016 Actual** | | | | | | |
| 1 | Long-Term debt | S.11 L.18 | 152,363 | 59.8% | 154,412 | 2.10% | 3,239 |
| 2 | Common Stock | S.7 L. 8 | 102,272 | 40.2% | 103,648 | 8.69% | 9,002 |
| 3 | Total | S.5 L.3 | 254,636 | 100.0% | 258,060 | 4.74% | 12,242 |
| | **Forecast for 2017 - Existing** | | | | | | |
| 4 | Long-Term debt | S.11 L.18 | 159,392 | 59.9% | 158,996 | 2.25% | 3,577 |
| 5 | Common Stock | S.7 L. 8 | 106,774 | 40.1% | 106,508 | 8.17% | 8,704 |
| 6 | Total | S.5 L.3 | 266,166 | 100.0% | 265,504 | 4.63% | 12,282 |
| | **Proposed 2017 - GRA** | | | | | | |
| 7 | Long-Term debt | S.11 L.18 | 164,747 | 59.9% | 164,369 | 2.18% | 3,578 |
| 8 | Common Stock | S.7 L. 8 | 110,343 | 40.1% | 110,090 | 8.82% | 9,711 |
| 9 | Total | S.5 L.3 | 275,090 | 100.0% | 274,459 | 4.84% | 13,289 |

**Yukon Energy Corporation**
**Cost of Capital Calculation**
**2018 Forecast (Existing / GRA)**
**($000s)**

Schedule 4C
June 2017

| Line No. | Description | Cross Ref. | Mid Year Balance | Ratio | Mid Year Rate Base | Mid Year Cost Rate | Return |
|---|---|---|---|---|---|---|---|
| | **Forecast for 2018 - Existing** | | | | | | |
| 1 | Long-Term debt | S.11 L.18 | 164,385 | 60.0% | 164,387 | 2.33% | 3,827 |
| 2 | Common Stock | S.7 L. 8 | 109,594 | 40.0% | 109,595 | 7.89% | 8,651 |
| 3 | Total | S.5 L.3 | 273,979 | 100.0% | 273,982 | 4.55% | 12,479 |
| | **Proposed 2018 - GRA** | | | | | | |
| 4 | Long-Term debt | S.11 L.18 | 174,973 | 60.0% | 174,974 | 2.32% | 4,058 |
| 5 | Common Stock | S.7 L. 8 | 116,653 | 40.0% | 116,653 | 8.82% | 10,290 |
| 6 | Total | S.5 L.3 | 291,625 | 100.0% | 291,627 | 4.92% | 14,348 |

## Yukon Energy Corporation

**Utility Revenue Requirement**
**($000s)**

Schedule 5
June 2017

| Line No. | Description | Cross Ref. | 2013 Approved | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Net rate base | S.1 L.30 | 226,684 | 223,058 | 222,882 | 240,584 | 258,060 | 265,504 | 274,459 | 273,982 | 291,627 |
| 2 | Average Rate of return on rate base | | 5.45% | 4.99% | 5.36% | 4.50% | 4.74% | 4.63% | 4.84% | 4.55% | 4.92% |
| 3 | Utility income | S.8 L.1 | 12,348 | 11,138 | 11,938 | 10,829 | 12,242 | 12,282 | 13,289 | 12,479 | 14,348 |
| 4 | Utility expenses | | | | | | | | | | |
| 5 | Operating and maintenance (note 1) | S.6 L.3 | 20,844 | 22,786 | 21,052 | 21,723 | 21,812 | 22,212 | 23,363 | 22,168 | 23,336 |
| 6 | Taxes other than income | S.6 L.4 | 326 | 331 | 331 | 473 | 686 | 696 | 696 | 708 | 708 |
| 7 | Amortization of deferred costs | S.6 L.5 | 3,462 | 4,561 | 2,846 | 2,764 | 1,581 | 2,152 | 3,883 | 2,006 | 3,891 |
| 8 | Reserve for Injuries and Damages | S.6 L.6 | 226 | 226 | 226 | 226 | 226 | 190 | 479 | 190 | 479 |
| 9 | Depreciation | S.6 L.7 | 8,989 | 8,894 | 8,906 | 9,828 | 10,615 | 11,171 | 12,217 | 11,168 | 12,419 |
| 10 | Amortization of contributions and fire insurance recoveries | S.6 L.8 | (3,831) | (3,939) | (3,953) | (3,886) | (4,364) | (5,164) | (5,269) | (5,094) | (5,200) |
| 11 | Disallowed depreciation | | (16) | (16) | (16) | (16) | (16) | (16) | (16) | (16) | (16) |
| 12 | Donations | | (85) | (84) | (85) | (86) | (95) | (96) | (96) | (100) | (100) |
| 13 | Total utility expenses | | 29,915 | 32,759 | 29,307 | 31,026 | 30,445 | 31,144 | 35,255 | 31,030 | 35,516 |
| 14 | Revenue Requirement | S.6 L.1 | 42,263 | 43,897 | 41,245 | 41,855 | 42,686 | 43,426 | 48,544 | 43,508 | 49,864 |

Note 1: Includes fuel expenses and purchased power.

# Yukon Energy Corporation

**Statement of Earnings**
**($000s)**

Schedule 6
June 2017

| Line No. | Description | Cross Ref. | 2013 Approved | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Revenues (note 1) | S.5 L.14 | 42,263 | 43,897 | 41,245 | 41,855 | 42,686 | 43,425 | 48,544 | 43,508 | 49,864 |
| 2 | **Operating expenses** | | | | | | | | | | |
| 3 | Operating and maintenance | S.10 L.15 | 20,844 | 22,786 | 21,052 | 21,723 | 21,812 | 22,212 | 23,363 | 22,168 | 23,336 |
| 4 | Taxes other than income | S.5 L.6 | 326 | 331 | 331 | 473 | 686 | 696 | 696 | 708 | 708 |
| 5 | Amortize deferred costs | S.5 L.7 | 3,462 | 4,561 | 2,846 | 2,764 | 1,581 | 2,152 | 3,883 | 2,006 | 3,891 |
| 6 | Reserve for Injuries and Damages | S.5 L.8 | 226 | 226 | 226 | 226 | 226 | 190 | 479 | 190 | 479 |
| 7 | Depreciation | S.3 L.8 | 8,989 | 8,894 | 8,906 | 9,828 | 10,615 | 11,171 | 12,217 | 11,168 | 12,419 |
| 8 | Amortization of contributions and fire insurance recoveries | S.5 L.10 | (3,831) | (3,939) | (3,953) | (3,886) | (4,364) | (5,164) | (5,269) | (5,094) | (5,200) |
| 9 | Total | | 30,016 | 32,859 | 29,408 | 31,129 | 30,556 | 31,256 | 35,367 | 31,146 | 35,633 |
| 10 | **Operating income** | | 12,247 | 11,038 | 11,837 | 10,727 | 12,130 | 12,169 | 13,177 | 12,362 | 14,231 |
| 11 | **Other income** | | | | | | | | | | |
| 12 | Allowed for Funds Used | S.8 L.2 | 500 | 927 | 1,188 | 714 | 819 | 1,093 | 863 | 1,261 | 719 |
| 13 | Miscellaneous (note 2) | S.8 L.3 | (23) | (492) | (86) | (98) | (1,592) | (32) | (32) | (32) | (32) |
| 14 | Total | | 477 | 435 | 1,102 | 616 | (772) | 1,061 | 831 | 1,229 | 688 |
| 15 | **Other expenses** | | | | | | | | | | |
| 16 | Interest expense | S.8 L.4 | 4,917 | 4,128 | 5,225 | 3,662 | 3,356 | 3,961 | 3,945 | 4,259 | 4,201 |
| 17 | Total | | 4,917 | 4,128 | 5,225 | 3,662 | 3,356 | 3,961 | 3,945 | 4,259 | 4,201 |
| 18 | **Net earnings** | S.8 L.8 | 7,807 | 7,345 | 7,713 | 7,681 | 8,001 | 9,269 | 10,063 | 9,332 | 10,718 |

Note 1: Includes revenues from sales and other revenues.
Note 2: Miscellaneous primarily consistent of Regulatory gain/losses and other interest income/expenses.

## Yukon Energy Corporation
**Statement of Retained Earnings**
**($000s)**

Schedule 7
June 2017

| Line No. | Description | Cross Ref. | 2013 Approved | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Balance at beginning of year | | 37,270 | 35,040 | 35,434 | 43,147 | 46,307 | 51,037 | 51,037 | 55,310 | 61,101 |
| | Add: | | | | | | | | | | |
| 2 | Net earnings | S.6 L.18 | 7,807 | 7,345 | 7,713 | 7,681 | 8,001 | 9,269 | 10,063 | 9,332 | 10,718 |
| 3 | IFRS Comprehensive Income Adjustment | | - | - | - | (4,521) | (430) | - | - | - | - |
| 4 | Balance at end of year before dividend | | 45,076 | 42,385 | 43,147 | 46,307 | 53,878 | 60,307 | 61,101 | 64,643 | 71,819 |
| | Less: | | | | | | | | | | |
| 5 | Common Dividends/(Injection) (note 1) | | 6,332 | 6,951 | - | - | 2,841 | 4,997 | - | 7,965 | 9,512 |
| 6 | Balance at end of year | | 38,744 | 35,434 | 43,147 | 46,307 | 51,037 | 55,310 | 61,101 | 56,678 | 62,307 |
| | **Shareholder's Equity** | | | | | | | | | | |
| 7 | Common shares | | 53,600 | 53,600 | 53,600 | 53,600 | 53,600 | 53,600 | 54,948 | 53,600 | 54,948 |
| 8 | Retained earnings | | 38,744 | 35,434 | 43,147 | 46,307 | 51,037 | 55,310 | 61,101 | 56,678 | 62,307 |
| 9 | Total | | 92,344 | 89,034 | 96,747 | 99,907 | 104,637 | 108,910 | 116,049 | 110,278 | 117,256 |

Note:
1. YDC equity injection/divident estimates required in order to maintain 60/40 debt to equity ratio.

**Yukon Energy Corporation**
**Reconciliation of Utility Income to Net Earnings**
**($000s)**

Schedule 8
June 2017

| Line No. | Description | Cross Ref. | 2013 Approved | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Utility Income (Return on Rate Base) | S.5 L.3 | 12,348 | 11,138 | 11,938 | 10,829 | 12,242 | 12,282 | 13,289 | 12,479 | 14,348 |
| | Add: | | | | | | | | | | |
| 2 | Allowance for funds used | S.6 L.12 | 500 | 927 | 1,188 | 714 | 819 | 1,093 | 863 | 1,261 | 719 |
| 3 | Other income (expenses) | S.6 L.13 | (23) | (492) | (86) | (98) | (1,592) | (32) | (32) | (32) | (32) |
| | | | 12,825 | 11,573 | 13,040 | 11,445 | 11,469 | 13,343 | 14,121 | 13,708 | 15,035 |
| | Less: | | | | | | | | | | |
| 4 | Interest - long-term | S.6 L.17 | 4,917 | 4,128 | 5,225 | 3,662 | 3,356 | 3,961 | 3,945 | 4,259 | 4,201 |
| 5 | Donations | S.5 L.12 | 85 | 84 | 85 | 86 | 95 | 96 | 96 | 100 | 100 |
| 6 | Disallowed costs | S.5 L.13 | - | - | - | - | - | - | - | - | - |
| 7 | Disallowed depreciation | S.5 L.11 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 |
| | | | 5,019 | 4,229 | 5,327 | 3,765 | 3,468 | 4,073 | 4,057 | 4,375 | 4,317 |
| 8 | Net earnings | S.6 L.18 | 7,807 | 7,344 | 7,713 | 7,681 | 8,002 | 9,270 | 10,064 | 9,333 | 10,718 |

**Yukon Energy Corporation**
**Summary of Customers, Energy Sales and Revenues**
**($000s)**

Schedule 9
June 2017

| Line No. | Description | 2013 Approved | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Proposed 2017 | Proposed 2018 |
|---|---|---|---|---|---|---|---|---|
| 1 | **Residential** | | | | | | | |
| 2 | Customers | 1,536 | 1,559 | 1,561 | 1,588 | 1,609 | 1,624 | 1,635 |
| 3 | Sales in MWh | 12,408 | 13,385 | 13,327 | 13,121 | 13,390 | 13,622 | 13,719 |
| 4 | MWh sales per customer | 8 | 8.6 | 8.5 | 8.3 | 8.3 | 8.4 | 8.4 |
| 5 | Revenue ($000s) | 1,815 | 1,943 | 1,938 | 1,913 | 1,956 | 2,002 | 2,016 |
| 6 | Cents per KWh | 14.6 | 14.5 | 14.5 | 14.6 | 14.6 | 14.7 | 14.7 |
| 7 | **General Service** | | | | | | | |
| 8 | Customers | 467 | 470 | 475 | 480 | 488 | 490 | 490 |
| 9 | Sales in MWh | 22,620 | 22,283 | 23,616 | 24,551 | 24,994 | 25,318 | 25,436 |
| 10 | MWh sales per customer | 48 | 47.4 | 49.8 | 51.1 | 51.2 | 51.7 | 51.9 |
| 11 | Revenue ($000s) | 3,735 | 3,621 | 3,894 | 4,048 | 4,180 | 4,036 | 4,054 |
| 12 | Cents per KWh | 16.5 | 16.3 | 16.5 | 16.5 | 16.7 | 15.9 | 15.9 |
| 13 | **Industrial** | | | | | | | |
| 14 | Sales in MWh | 40,592 | 40,513 | 36,302 | 37,186 | 41,169 | 38,219 | 38,219 |
| 15 | Revenue ($000s) | 4,787 | 4,595 | 3,958 | 4,159 | 4,478 | 4,198 | 4,198 |
| 16 | Cents per KWh | 11.8 | 11.3 | 10.9 | 11.2 | 10.9 | 11.0 | 11.0 |
| 17 | **Street lights** | | | | | | | |
| 18 | Sales in MWh | 279 | 281 | 290 | 290 | 256 | 225 | 214 |
| 19 | Revenue ($000s) | 88 | 89 | 92 | 92 | 88 | 58 | 56 |
| 20 | Cents per KWh | 31.6 | 31.6 | 31.6 | 31.6 | 34.5 | 26.0 | 26.0 |
| 21 | **Space lights** | | | | | | | |
| 22 | Sales in MWh | 15 | 14 | 14 | 14 | 14 | 12 | 12 |
| 23 | Revenue ($000s) | 4 | 4 | 4 | 4 | 4 | 3 | 3 |
| 24 | Cents per KWh | 26.8 | 26.5 | 26.6 | 25.9 | 26.0 | 22.5 | 22.5 |
| 25 | **Total Company - Firm Retail and Industrial** | | | | | | | |
| 26 | Customers | 2,003 | 2,029 | 2,036 | 2,068 | 2,098 | 2,114 | 2,126 |
| 27 | Sales in MWh | 75,913 | 76,476 | 73,549 | 75,162 | 79,823 | 77,395 | 77,599 |
| 28 | Revenue ($000s) | 10,429 | 10,252 | 9,886 | 10,214 | 10,705 | 10,297 | 10,327 |
| 29 | Cents per KWh | 13.7 | 13.4 | 13.4 | 13.6 | 13.4 | 13.3 | 13.3 |
| 30 | **Wholesale sales** | | | | | | | |
| 31 | Sales in MWh | 307,147 | 307,927 | 295,284 | 297,961 | 301,207 | 309,000 | 309,519 |
| 32 | Revenue ($000s) | 25,487 | 25,546 | 24,503 | 24,725 | 24,994 | 25,641 | 25,684 |
| 33 | Cents per KWh | 8.3 | 8.3 | 8.3 | 8.3 | 8.3 | 8.3 | 8.3 |
| 34 | **Total Company - Firm** | | | | | | | |
| 35 | Sales in MWh | 383,061 | 384,403 | 368,833 | 373,122 | 381,030 | 386,395 | 387,118 |
| 36 | Revenue ($000s) | 35,916 | 35,798 | 34,388 | 34,939 | 35,700 | 35,938 | 36,011 |
| 37 | Cents per KWh | 9.4 | 9.3 | 9.3 | 9.4 | 9.4 | 9.3 | 9.3 |
| 38 | **Secondary** | | | | | | | |
| 39 | Sales in MWh | 0 | 3,959 | 5,415 | 7,030 | 4,835 | 11,464 | 11,464 |
| 40 | Revenue ($000s) | 0 | 275 | 410 | 544 | 371 | 642 | 642 |
| 41 | Cents per KWh | | 6.9 | 7.6 | 7.7 | 7.7 | 5.6 | 5.6 |
| 42 | **Total Company** | | | | | | | |
| 43 | Sales in MWh | 383,061 | 388,363 | 374,248 | 380,152 | 385,865 | 397,859 | 398,582 |
| 44 | Revenue ($000s) | 35,916 | 36,073 | 34,798 | 35,483 | 36,071 | 36,580 | 36,653 |
| 45 | Cents per KWh | 9.4 | 9.3 | 9.3 | 9.3 | 9.3 | 9.2 | 9.2 |
| 46 | Rider J | | 6,288 | 6,167 | 6,172 | 6,342 | 6,363 | 6,373 |
| 47 | Post-GRA Reconcil Req'd | | | | | | | |
| 48 | GRA Increase Req'd | 6,163 | | | | | 5,348 | 6,585 |
| 49 | Total Sales of Power | 42,079 | 42,360 | 40,966 | 41,655 | 42,413 | 48,291 | 49,611 |
| 50 | Other Revenues | 184 | 1,537 | 280 | 200 | 273 | 253 | 253 |
| 51 | Total Revenues | 42,263 | 43,897 | 41,246 | 41,855 | 42,686 | 48,544 | 49,864 |

**Yukon Energy Corporation**
**Summary of Operating and Maintenance Expenses**
**($000s)**

Schedule 10
June 2017

| Line No. | Description | Cross Ref. | 2013 Approved | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Utility operations** | | | | | | | | | | |
| 2 | Production | | 4,494 | 5,310 | 5,588 | 5,472 | 6,039 | 5,760 | 5,760 | 5,907 | 5,907 |
| 3 | Transmission and distribution | | 2,112 | 2,960 | 2,565 | 2,530 | 2,450 | 2,368 | 3,352 | 2,374 | 3,364 |
| 4 | General | | 1,405 | 1,485 | 1,735 | 1,749 | 1,522 | 1,633 | 1,633 | 1,614 | 1,614 |
| 5 | Administration and general | | 8,654 | 8,080 | 8,495 | 8,101 | 8,509 | 9,110 | 9,110 | 8,912 | 8,912 |
| 6 | Insurance | | 895 | 990 | 1,017 | 1,030 | 1,037 | 1,031 | 1,031 | 1,031 | 1,031 |
| 7 | Sub-total | | 17,559 | 18,824 | 19,400 | 18,881 | 19,557 | 19,901 | 20,886 | 19,839 | 20,829 |
| 8 | Donations | | 85 | 84 | 85 | 86 | 95 | 96 | 96 | 100 | 100 |
| 9 | Sub-total | | 85 | 84 | 85 | 86 | 95 | 96 | 96 | 100 | 100 |
| 10 | O&M not including fuel and | | | | | | | | | | |
| 11 | purchased power | | 17,644 | 18,908 | 19,485 | 18,967 | 19,653 | 19,997 | 20,982 | 19,939 | 20,929 |
| 12 | Fuel | | 3,160 | 3,848 | 1,528 | 2,720 | 2,114 | 2,175 | 2,342 | 2,190 | 2,368 |
| 13 | Purchased power | | 40 | 30 | 41 | 36 | 45 | 39 | 39 | 39 | 39 |
| 14 | Sub-total | | 3,200 | 3,878 | 1,569 | 2,756 | 2,159 | 2,214 | 2,381 | 2,229 | 2,407 |
| 15 | Total operating and maintenance | S.6 L.3 | 20,844 | 22,786 | 21,054 | 21,723 | 21,812 | 22,212 | 23,363 | 22,168 | 23,336 |
| | ***Operating and Maintenance Expense Reported in Tab 3 excludes fuel and purchase power, but also includes the following:*** | | | | | | | | | | |
| *16* | *Reserve for Injuries and Damages* | | *226* | *226* | *226* | *226* | *226* | *190* | *479* | *190* | *479* |
| *17* | *Property Taxes* | | *326* | *331* | *331* | *473* | *686* | *696* | *696* | *708* | *708* |
| *18* | *less: Donations* | | *-85* | *-84* | *-85* | *-86* | *-95* | *-96* | *-96* | *-100* | *-100* |
| *19* | *O&M per Table 3.3 (Tab 3)* | | *18,111* | *19,381* | *19,957* | *19,580* | *20,470* | *20,787* | *22,060* | *20,737* | *22,016* |

**Yukon Energy Corporation**
**Summary of Cost of Long - Term Debt**
**($000s)**

Schedule 11
June 2017

| Line No. | Description | Cross Ref. | 2013 Approved | Actual 2013 | Actual 2014 | Actual 2015 | Actual 2016 | Forecast Existing 2017 | Forecast Proposed 2017 | Forecast Existing 2018 | Forecast Proposed 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **General Purpose Long-Term Debt Balance** | | | | | | | | | | |
| 1 | TD Canada Trust (4.02%) | | 2,945 | 2,946 | 1,912 | 837 | 0 | 0 | 0 | 0 | 0 |
| 2 | YDC $81.9M Loan (4.25%) | | 72,891 | 72,891 | 69,891 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | YDC Mayo B Flexible Term Debt | | 21,226 | 21,226 | 20,889 | 20,552 | 20,215 | 19,878 | 19,878 | 19,542 | 19,542 |
| 4 | TD Bank Swap (2.69%) | | 15,900 | 10,687 | 10,366 | 10,036 | 9,697 | 9,348 | 9,348 | 8,991 | 8,991 |
| 5 | YDC $17.1M Debt (3.69%) | | 17,780 | 15,727 | 15,044 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | YDC $2.1M Debt (3.97%) | | | 2,053 | 2,053 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | YDC $5.5M Debt (4.27%) | | 7,774 | 5,471 | 5,471 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | Minto Decommissioning Reserve | | | 2,553 | 2,586 | 2,613 | 2,636 | 2,660 | 2,660 | 2,684 | 2,684 |
| 9 | YDC $5.5M Debt (2.40%) | | | | 5,505 | 5,505 | 5,505 | 5,505 | 5,505 | 5,505 | 5,505 |
| 10 | YDC $92.5M Debt (2.40%) | | | | | 88,775 | 85,091 | 81,407 | 81,407 | 77,723 | 77,723 |
| 11 | YDC $21.0M Debt (2.21%) | | | | | 20,984 | 20,145 | 19,306 | 19,306 | 18,466 | 18,466 |
| 12 | YDC $12.1M Debt (2.10%) | | | | | | 12,136 | 12,136 | 12,136 | 12,136 | 12,136 |
| 13 | New 2017 Debt (2.15%) | | | | | | | 13,118 | 23,828 | 13,118 | 23,828 |
| 14 | New 2018 Debt | | | | | | | | | 7,246 | 7,004 |
| 15 | Current year-end balance | | 138,516 | 133,555 | 133,717 | 149,302 | 155,425 | 163,359 | 174,068 | 165,411 | 175,878 |
| 16 | Previous year-end balance | | 136,304 | 133,409 | 133,555 | 133,717 | 149,302 | 155,425 | 155,425 | 163,359 | 174,068 |
| 17 | Mid Year | | 137,410 | 133,482 | 133,636 | 141,509 | 152,363 | 159,392 | 164,747 | 164,385 | 174,973 |
| | **Interest Costs** | | | | | | | | | | |
| 18 | TD Canada Trust (4.02%) | | 140 | 140 | 99 | 57 | 14 | 0 | 0 | 0 | 0 |
| 19 | YDC $81.9M Loan (4.25%) | | 3,225 | 3,225 | 3,098 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | YDC Mayo B Flexible Term Debt | | 212 | 130 | -112 | 128 | 167 | 432 | 432 | 507 | 507 |
| 21 | TD Bank Swap (2.69%) | | 687 | 292 | 284 | 275 | 266 | 257 | 257 | 247 | 247 |
| 22 | YDC $17.1M Debt (3.69%) | | 653 | 606 | 580 | 0 | 0 | 0 | 0 | 0 | 0 |
| 23 | YDC $2.1M Debt (3.97%) | | | 82 | 82 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | YDC $5.5M Debt (4.27%) | | | | 234 | 0 | 0 | 0 | 0 | 0 | 0 |
| 25 | Minto Decommissioning Reserve | | | 31 | 33 | 26 | 23 | 24 | 24 | 24 | 24 |
| 26 | YDC $5.5M Debt (2.40%) | | | | | 132 | 132 | 132 | 132 | 132 | 132 |
| 27 | YDC $92.5M Debt (2.40%) | | | | | 2,213 | 2,131 | 2,042 | 2,042 | 1,954 | 1,954 |
| 28 | YDC $21.0M Debt (2.21%) | | | | | | 464 | 445 | 445 | 427 | 427 |
| 29 | YDC $12.1M Debt (2.10%) | | | | | | | 255 | 255 | 255 | 255 |
| 30 | New 2017 Debt (2.15%) | | | | | | | | | 282 | 512 |
| 31 | New 2018 Debt | | | | | | | | | | 0 |
| 32 | **Total Cost of Interest** | | 4,917 | 4,507 | 4,297 | 2,831 | 3,196 | 3,586 | 3,586 | 3,827 | 4,058 |
| 33 | Mid-Year Cost of Debt | | 3.58% | 3.38% | 3.22% | 2.00% | 2.10% | 2.25% | 2.18% | 2.33% | 2.32% |

# TAB 8
# RETURN ON EQUITY

# 8.0 RETURN ON EQUITY

Tab 8 reviews the proposed basis for determining the return on equity (ROE) for Yukon Energy in 2017 and 2018, including the following:

- Background;
- Yukon Energy Fair ROE for 2017 and 2018; and
- Basis for Risk Premium Adder.

## 8.1 BACKGROUND

Yukon Energy's rate base is financed by two main sources of capital: long-term debt and shareholder's equity. With respect to the equity component, Yukon Energy's rates are required to include "provision to recover a fair return on the Corporation's equity, less one-half of one per cent (0.5%)" per Order in Council (OIC) 1995/90 Section 2 (see Tab 10 of this Application).

In determining a "fair return" for Yukon Energy as required by this OIC directive, Yukon Energy as primarily a generation utility faces considerably higher risk levels than ATCO Electric Yukon (AEY) with its focus on distribution.

Approaches used in Yukon to determine a fair level of return on equity since 1998 are reviewed below.

- **The 1998 rate revision,[1] the 2005 Required Revenues and Related Matters proceeding, and the 2008/2009 Yukon Energy General Rate Application:** Yukon Energy proposed that the return on equity be set by reference to the British Columbia Utilities Commission (BCUC) formulaic approach. Under this "benchmark approach" the forecast Long Canada Bond Yields were used by the BCUC as a proxy for a "risk-free" cost of capital, with appropriate adjustments incorporated to reflect additional risks of equity compared to debt (to yield a benchmark cost of equity of a low risk utility), and with further adjustments to reflect any specific added risks related to each specified utility that is not a low risk utility.

[1] Yukon Energy revised 1997 and 1998 Rate Application to YUB related to Board Order 1997-6 and related to the 1998 closure of the Faro Mine.

In the 2005 hearing, the Yukon Utilities Board (YUB) determined that the requested rate of return and the application of the BCUC approach were reasonable given Yukon Energy's level of risk in relation to other utilities within their peer group.

It was noted by the Board that this was an expedient means of determining return for that period and did not necessarily impose a precedent in the Yukon. The Board agreed with Yukon Energy's assessment with respect to risk premiums relative to a low risk utility given the level of risk experienced by Yukon Energy in relation to other utilities within its peer group (i.e., that it fell somewhere between PNG-West at 65 basis points and Aquila, now FortisBC Electric, at 40 basis points).

In Yukon Energy's 2008/2009 GRA, Board Order 2009-08 followed the same approach used in 1998 and in 2005 for setting Yukon Energy's ROE.[2] Order 2009-08 also stated that the BCUC approach would be the precedent for Yukon and would continue to be a precedent for the jurisdiction until otherwise ordered.

- **Yukon Energy's 2012/13 GRA:** Described changes that occurred after 2009 in how return on equity was determined by the BCUC, noting that the BCUC Terasen ROE decision (Order G-158-09) eliminated the automatic adjustment mechanism and ordered Terasen Gas Inc. (now FortisBC Energy)[3] to complete a study of alternative formulae for an automatic adjustment mechanism and report the results to the BCUC by December 31, 2010. The BCUC determined that the 2009 approved ROE for Terasen (9.5%) could continue to be used as the Benchmark ROE in establishing the ROE for rate-setting purposes for other BCUC utilities.[4]

Due to the status of the BCUC's proceedings affecting return on equity determinations, Yukon Energy's 2012/13 GRA did not rely on the BCUC benchmark. YEC's 2012/13 GRA noted that the latest ROE approved by the BCUC was established in 2009, was in the process of being reviewed by the BCUC, and that the BCUC proceeding would not be completed prior to Yukon Energy's GRA proceeding. Yukon Energy therefore relied on the more recent Alberta Utilities Commission (AUC) benchmark ROE of 8.75% for the 2012/2013 GRA test years and sought to also apply the 52% risk premium previously used in 2005 and 2008/09. In Order 2013-01, the YUB approved

[2] Based on the then most recent BCUC generic benchmark ROE, adjusted as required for the risk specific to Yukon Energy (and using the same risk adjustment in this regard as had been previously approved for Yukon Energy based on BCUC decisions for similar risk utilities).
[3] The 2012/13 GRA noted that as of March 2011, Terasen Gas Inc., is FortisBC Energy Inc.
[4] See Order G-158-09. The 2012/13 YEC GRA noted that BC utilities continued to reference this benchmark and apply utility-specific risk premiums as approved by the BCUC.

the use of the AUC benchmark for the 2012/13 test years, noting that results of the BCUC model were not yet available; however, the Board did not approve the use of the 52% risk premium as proposed by YEC (as a risk premium was not used as part of the AUC approach). This resulted in an approved ROE for Yukon Energy of 8.25% for the 2012/13 test years.

- **AEY 2013-15 GRA:** Subsequent to the Yukon Energy 2012/2013 GRA, the BCUC completed the Stage 1 Cost of Capital Proceeding and approved a low risk utility benchmark of 8.75% for FortisBC Electric. This low risk utility benchmark was adopted by AEY in its 2013-15 General Rate Application and approved by the Board in Order 2014-06. However, the Board did not approve AEY's proposed risk premium[5] indicating that AEY had not established a prima facie case to quantify a risk premium over the low risk benchmark utility.

- **AEY 2016-17 GRA:** AEY's GRA Application sought approval of an ROE based on the results of the latest BCUC GCOC proceeding, as well as a risk premium of 60 basis points. The Board in Order 2017-01 noted that it "continues to be of the view that the BCUC GCOC model is the most appropriate for Yukon" and ordered that AEY use the BCUC GCOC benchmark for ROE of 8.75%.[6] The Board also agreed that a risk premium is appropriate and ordered AEY to apply a risk premium of 25 basis points. The Board concluded that "in determining relative risk for AEY, [it] should look at size and generation risk".[7]

## 8.2 YUKON ENERGY FAIR ROE FOR 2017 AND 2018

Reference to a benchmark return on equity 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.[8] Yukon Energy proposes to apply the following steps (similar to the 2005 and 2008/09 GRAs):

- **Step 1 – Determine Low-Risk Benchmark Utility ROE:** For the 2017 and 2018 test years, Yukon Energy proposes to use the recently established BCUC benchmark ROE of 8.75%.[9] This

[5] AEY sought a risk premium of 46% (based on the risk premium previously approved in Order 2009-02).
[6] Order 2017-01, page 37, para 182.
[7] Order 2017-01, page 43, para 211.
[8] The precedent of relying on a benchmarking mechanism for determining the return on equity for a single application extends beyond the 2005 and 2008/2009 proceedings. This approach was also used to a limited extent in determining Yukon Energy's fair return on equity during the 1998 hearing.
[9] BCUC Generic Cost of Capital (GCOC) benchmark rate as set in BCUC Decision and Order G-129-16.

benchmark was also recently used by AEY in its 2016-2017 General Rate Application, and was recently approved for the AEY GRA by the Board in Board Order 2017-01.

- **Step 2 – Apply Yukon Energy Fair ROE by Incorporating the Risk Premium for Yukon Energy:** The established approach, confirmed recently in Board Order 2017-01, requires that the appropriate fair return on common equity for individual utilities incorporate a risk premium determined for each utility relative to the benchmark utility ROE. As described above, the Board in Order 2005-12 approved Yukon Energy's proposal to set its fair return at 52 basis points (0.52%) above the BCUC low-risk benchmark utility ROE being the mid-point between FortisBC Electric (40 basis points) and PNG-West (65 basis points). Yukon Energy proposes to use the same approach for the 2017 and 2018 test years. Considering the most recent BCUC Generic Cost of Capital Proceeding – Stage 2 decision,[10] this results in a risk premium of 57.5 basis points for Yukon Energy[11] and a fair return on common equity for Yukon Energy of 9.325% (8.75 plus 0.575). [Section 8.3 below provides further review of the determination of this risk premium].

- **Step 3 – Determine Yukon Energy Allowed ROE by Deducting 50 Basis Points from the Yukon Energy Fair Return on Equity:** To reflect OIC 1995/90, Section 2, for each test year, Yukon Energy's allowed ROE is required to be set equal to the Yukon Energy fair return on common equity less 50 basis points (0.5%). This results in an allowed ROE for Yukon Energy of 8.825% that is 7.5 basis points above the low-risk benchmark utility rate of return determined by the BCUC (57.5 basis point utility specific adder less 50 basis point OIC reduction).

Accordingly, the Yukon Energy proposed ROE in this Application for each test year is 8.82%.

## 8.3 BASIS FOR RISK PREMIUM ADDER

In arriving at the 57.5 basis point risk premium Yukon Energy reviewed and relied upon past Yukon precedents as well as relevant BCUC decisions which demonstrate a current risk premium in the range of 40 to 75 basis points above the benchmark ROE for BCUC-regulated utilities that are potentially comparable with Yukon Energy.

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[10] Generic Cost of Capital Proceeding (Stage 2) Decision on March 25, 2014 and Order G-47-14.

[11] The risk premium approved for FortisBC Electric in BCUC Order G-47-14 (following the Generic Cost of Capital Proceeding - Stage 2) remains 40%, confirming that the risk premium applicable to YEC is higher than 40%. The risk premiums approved today for the PNG gas utilities are 50% and 75% (the latter for the PNG West utility used as a prior reference when setting the range for YEC's risk premium). This indicates that the risk premium applicable today for YEC, at a midpoint between the FortisBC electric and the PNG West, is 57.5%.

The proposed 57.5 basis point risk premium for Yukon Energy was selected as the mid-point of this range following past practice for Yukon Energy (established in Order 2005-12 and in Order 2009-08) and current information relating to the comparability of size of Yukon Energy operations to other utilities, and its financial structure, mix of customers serviced and source of energy supply.[12]

**Past Yukon Precedents**

As noted above, for the 2005 and 2008/09 GRA applications, YEC used a 52 basis point risk premium adder which was considered to be the mid-point of the range of risk premium adders used for BCUC-regulated utilities considered potentially comparable with Yukon Energy. Specifically, Yukon Energy was considered more risky than Aquila/West Kooteney Power (now FortisBC Electric) at the lower end of the range (with a 40% risk premium at that time) and less risky than PNG-West near the top end of the range (with a 65% risk premium at that time).

The 2005 Application compared business operations of Yukon Energy with Aquila/West Kooteney Power (now FortisBC Electric) and the various PNG operations examining size of operations, financial structure, mix of customers served, and source of energy supply. At the time, it was noted that looking at only FortisBC Electric (the only electric utility in the mix of utilities considered):

- Yukon Energy displays roughly similar business risk related to the mix of customers (i.e., at the time it was noted that with mines being closed in Yukon, Yukon Energy was no longer exposed to risks related to a relatively high reliance on large industrial customers);

- A similar financial risk based on capital structure; and

- A somewhat greater business risk based on all measures of utility size (YEC is much smaller than FortisBC Electric), its reliance on its own generation and its lack of any interconnection with external electricity markets. This last set of factors was seen as conclusive evidence that YEC's risk was materially greater than FortisBC Electric. YEC's submission was that its risk lay between that of FortisBC Electric and the higher risk PNG gas utilities.

In the 2008/2009 GRA, Yukon Energy applied the 52 basis point risk premium, noting that "there is no information available that would suggest YEC's business risk today is closer to Fortis BC's than at the time

[12] See summary information as described below and updated in Table 8.1 and Table 8.2.

of the 2005 Required Revenues and Related Matters Application." In support of this, Yukon Energy noted as follows:

- FortisBC's 2009 Revenue Requirements Application forecast approximately $914 million in ratebase and 112,000 customers in 2009. This compared to YEC's forecasts of 1,889 customers (2% of FortisBC's) and proposed mid-year rate base of $153 million (17% of FortisBC's) for 2009. These statistics indicated no material change from the comparisons provided in the 2005 YEC application.

- YEC noted that other material differences noted in 2005 between YEC and FortisBC/WKP had not changed, including a somewhat greater business risk than the relevant BC utilities based on its reliance on its own generation (far higher than for FortisBC) and its lack of any interconnection with external electricity markets.

- YEC also noted that since the 2005 application, YEC's business risk had increased somewhat due to connection of a new industrial customer.

**Updated Comparisons of Yukon Energy and BC Utilities**

Summary tables relied upon in prior YEC GRAs to support YEC's approved risk premium are updated for 2016 as Tables 8.1 and 8.2.

These tables indicate as follows for the proposed YEC risk premium:

- **Comparison of YEC to BC Utilities Size of Operations and Financial Structure –** In summary, updated information on FortisBC Electric operations relative to Yukon Energy's operations remains similar to comparisons provided in 2005 and 2009.

  FortisBC Electric operations in 2016 had approximately 133,550 customers, approximately $1,286 million in rate base, and a 60/40 debt/equity financial structure. This is compared to YEC's 2,079 customers and $257.6 million in rate base in 2016, including YEC's material hydro and transmission assets. YEC's customer counts and rate base were approximately 1.6% and 20% of FortisBC's, but the financial structure was the same for these two utilities. This is similar to the comparisons provided in 2005 and in 2009.

The risk premium approved for FortisBC Electric also remains at 40 basis points, confirming that the risk premium applicable to YEC continues to be higher than 40 basis points.

In contrast, Table 8.1 updated information indicates that PNG West (which has a risk premium today of 75 basis points) has about 10 times more customers than YEC, a much lower rate base than YEC (about 52% of YEC rate base), a 53.5/46.5 debt/equity financial structure, and is able to purchase all of its (gas) energy.

- **Comparison of YEC to BC Utilities - Nature of Business** - YEC continues to have a greater business risk than the relevant BC utilities based on its reliance on its own generation (far higher than for FortisBC Electric), and its lack of any interconnection with external electricity markets. These material differences have not changed from the assessments provided in 2005 and 2009.

  YEC's business risk related to industrial customers has fluctuated since 2005 due to the connection of new industrial customers and the subsequent loss of Alexco (after rates were set based on its forecast loads). As noted in Tab 1 and Tab 2, the 2017 and 2018 forecast for Minto mine load has changed significantly since early 2017.[13]

In summary, the updated information in Tables 8.1 and 8.2 confirms the continuing applicability of setting the YEC risk premium relative to the BCUC ROE benchmark based on the mid-point between FortisBC [Electric], at 40 basis points today, and PNG West, at 75 basis points today.

[13] See Tab 1 which notes that through early January 2017, it was understood that the mine would cease operations in late 2017; however, the Application now assumes continued Minto mine operation through 2018, based on updated information provided in April 2017.

**Table 8.1:**

**Comparison of YEC to BC Utilities Size of Operations and Financial Structure**

| | YEC (2016 ) | Fortis BC Inc. (Electric) (2016) | PNG West (2016) | PNG NE Fort St. John/ Dawson Creek (2016) |
|---|---|---|---|---|
| Revenues ($millions) | 42.7 | 335.0 | 40.6 | 22.8 |
| Rate base ($millions) | 257.6 | 1,286.0 | 135.1 | 64.6 |
| Number of employees | 100 | 490 | 88 | 33 |
| Number of customers | 2,079 | 133,550 | 20,397 | 12,570 |
| Capital Structure Debt/Equity ratio | 60%/40% | 60%/40% | 53.5%/46.5% | 59%/41% |
| ROE Benchmark | | 8.75% | 8.75% | 8.75% |
| ROE Risk Adder | | 0.40% | 0.75% | 0.50% |
| Fair ROE Approved | | 9.15% | 9.50% | 9.25% |

Notes:

1. The information for Yukon Energy as provided in Tab 2 and Tab 3 tables.
2. The information for Fortis BC is based on 2016 Annual Information Form available at https://www.fortisbc.com/About/InvestorCentre/ElectricityUtility/ElecAnnualInfoForm/Documents/FBC_AIF_2016_Post_Audit__Final_for_Posting.pdf [accessed on June 12, 2017]. The customer and revenue information is summarized on page 7; number of employees on page 11; rate base, capital structure and ROE information on page 13.
3. The information for PNG West is based on 2016 and 2017 Revenue Requirement application before BCUC [http://www.png.ca/wp-content/uploads/2016/03/Amended-Application-Narrative-PNG-West-2016-2017-RRA.pdf, accessed on June 12, 2017]. Revenues are from SUMMARY OF GROSS REVENUE, COST OF GAS, GROSS MARGIN Tab 6, Page 7; rate base from Tab 2, Page 1, Schedule 2; number of customers from Table 10. Number of employees is from Response to BCOAPO IR No. 1 provided on April 20, 2016, Page 14 http://www.bcuc.com/Documents/Proceedings/2016/DOC_46132_B-5_PNG-Resp-to-BCOAPO-IR-No1.pdf [accessed on June 12, 2017]. Capital structure and ROE information from AltaGas 2016 Annual Report, page 27. https://www.altagas.ca/sites/default/files/quarterly_reports/2016%20Anual%20Report%20web_0.pdf [accessed on June 12, 2017].
4. The information for PNG NE Fort St. John/Dawson Creek is based on 2016 and 2017 Revenue Requirement application before BCUC [http://www.png.ca/wp-content/uploads/2016/03/Amended-Application-Narrative-PNGNE-FSJ-DC-2016-2017-RRA.pdf, accessed on June 12, 2017]. Revenues are from SUMMARY OF GROSS REVENUE, COST OF GAS, GROSS MARGIN Tab 6, Page 10; rate base from Tab 2, Page 1, Schedule 2; number of customers from Table 12 and section 2.1.3 Other Customer Classes. Number of employees is from Response to BCUC IR 46.5.1 Round No. 2 provided on May 27, 2016, Page 23 http://www.bcuc.com/Documents/Proceedings/2016/DOC_46409_B-9_PNGNE_Resp-BCUC-IR2-FSJ-DC.pdf [accessed on June 12, 2017]. Capital structure and ROE information from AltaGas 2016 Annual Report, page 27. https://www.altagas.ca/sites/default/files/quarterly_reports/2016%20Anual%20Report%20web_0.pdf [accessed on June 12, 2017].
5. The capital structure and ROE for Fortis BC, PNG West and PNG NE FSJ reflect allowed structure and allowed ROE.

**Table 8.2:**

**Comparison of YEC to BC Utilities - Nature of Business**

| | YEC (2016) | Fortis BC Inc. (Electricity) (2015) | PNG West (2016) | PNG NE Fort St. John/ Dawson Creek (2016) |
|---|---|---|---|---|
| Main Product | Electricity | Electricity | Gas | Gas |
| Acquisition of Product | | | | |
| Hydroelectric | 98% | 45% | | |
| Thermal/Other | 2% | | | |
| Purchased | | 55% | 100% | 100% |
| Revenue share by customer type | | | | |
| Residential | 5.4% | 50.0% | 47.4% | 51.0% |
| Commercial | 11.5% | 27.4% | 32.6% | 37.2% |
| Industrial | 12.4% | 9.2% | 18.7% | 11.8% |
| Wholesale | 70.0% | 13.4% | 0.0% | 0.0% |
| Other/misc | 0.7% | 0.0% | 1.3% | 0.0% |
| Energy sales share | | | | |
| Residential | 3.5% | 40.4% | 25.5% | 36.9% |
| Commercial | 6.5% | 29.7% | 23.6% | 36.4% |
| Industrial | 9.8% | 12.3% | 50.2% | 26.8% |
| Wholesale | 80.2% | 17.7% | 0.0% | 0.0% |
| Other/misc | 0.0% | 0.0% | 0.8% | 0.0% |

Notes:

1. The information for Yukon Energy is from Tab 2 tables.
2. The information for Fortis BC is based on 2016 Annual Information Form available at https://www.fortisbc.com/About/InvestorCentre/ElectricityUtility/ElecAnnualInfoForm/Documents/FBC_AIF_2016_Post_Audit__Final_for_Posting.pdf [accessed on June 12, 2017]. The customer and revenue information is summarized on page 7.
3. The information for PNG West is based on 2016 and 2017 Revenue Requirement application before BCUC. Revenues are from SUMMARY OF GROSS REVENUE, COST OF GAS, GROSS MARGIN Tab 6, Page 7; Energy sales from Table 9: Forecast Gas Deliveries http://www.png.ca/wp-content/uploads/2016/03/Amended-Application-Narrative-PNG-West-2016-2017-RRA.pdf [accessed on June 12, 2017].
4. The information for PNG NE FSJ and DC is based on 2016 and 2017 Revenue Requirement application before BCUC: Revenues are from Tab 6, Page 10 and energy sales from Tab 6, Page 9. http://www.png.ca/wp-content/uploads/2016/03/Amended-Application-Narrative-PNGNE-FSJ-DC-2016-2017-RRA.pdf [accessed on June 12, 2017].

# TAB 9

# 2015 AUDITED FINANCIAL STATEMENTS

# Yukon Energy Corporation

## Financial Statements

## December 31, 2015

## Yukon Energy Corporation

**Financial Statements**

**December 31, 2015** **Page**

# Yukon Energy Corporation
## Statement of Financial Position
(in thousands of Canadian dollars)

| As at | December 31 2015 | December 31 2014 | January 1 2014 |
|---|---|---|---|
| **Assets** | | | |
| **Current** | | | |
| Cash (Note 4) | $ 1,672 | $ 160 | $ 8,315 |
| Accounts receivable (Note 5) | 6,347 | 7,062 | 8,409 |
| Inventories (Note 6) | 3,614 | 3,065 | 3,222 |
| Derivative related asset (Note 24) | - | - | 430 |
| Prepaid expenses | 828 | 719 | 672 |
| | 12,461 | 11,006 | 21,048 |
| **Non-current** | | | |
| Property, plant and equipment (Note 7) | 443,194 | 431,286 | 403,014 |
| Intangible assets (Note 8) | 6,992 | 7,248 | 7,683 |
| **Total assets** | **462,647** | 449,540 | 431,745 |
| Regulatory deferral account debit balances (Note 9) | 21,241 | 22,927 | 20,186 |
| **Total assets and regulatory deferral account debit balances** | **$ 483,888** | $ 472,467 | $ 451,931 |
| **Liabilities** | | | |
| **Current** | | | |
| Bank indebtedness (Note 10) | $ - | $ 1,331 | $ - |
| Accounts payable and accrued liabilities (Note 11) | 7,310 | 14,917 | 12,303 |
| Construction financing (Note 12) | 23,280 | 42,880 | 20,385 |
| Derivative related liability (Note 24) | 553 | 213 | - |
| Current portion of long-term debt (Note 13) | 6,066 | 72,347 | 5,406 |
| | **37,209** | 131,688 | 38,094 |
| **Non-current** | | | |
| Long-term construction financing (Note 12) | - | - | 12,000 |
| Post-employment benefits (Note 14) | 5,436 | 6,018 | 4,668 |
| Contributions in aid of construction (Note 15) | 176,540 | 161,160 | 164,191 |
| Decommissioning fund (Note 16) | 2,612 | 2,586 | 2,553 |
| Long-term debt (Note 13) | 140,874 | 59,064 | 125,906 |
| **Total liabilities** | **362,671** | 360,516 | 347,412 |
| **Equity** | | | |
| Share capital | | | |
| Authorized: Unlimited number of a single class of shares with no par value | | | |
| Issued and fully paid: 3,900 shares | 39,000 | 39,000 | 39,000 |
| Contributed surplus | 14,600 | 14,600 | 14,600 |
| Retained earnings | 46,303 | 38,076 | 31,929 |
| **Total equity** | **99,903** | 91,676 | 85,529 |
| **Total liabilities and equity** | **462,574** | 452,192 | 432,941 |
| Regulatory deferral account credit balances (Note 9) | 21,314 | 20,275 | 18,990 |
| **Total liabilities, equity and regulatory deferral account credit balances** | **$ 483,888** | $ 472,467 | $ 451,931 |

**Commitments and contingencies (Notes 21, 22, and 23)**

The accompanying notes are an integral part of these financial statements.

**Approved by the Board**

_______________________, Chair _______________________, Director

# Yukon Energy Corporation
## Statement of Operations and Other Comprehensive Income
(in thousands of Canadian dollars)

| For the year ended December 31 | | 2015 | | 2014 |
|---|---|---|---|---|
| **Revenues** | | | | |
| Sales of power (Note 17) | $ | 40,948 | $ | 41,053 |
| Funding from parent (Note 20) | | 6,135 | | - |
| Other | | 383 | | 472 |
| | | **47,466** | $ | 41,525 |
| **Operating expenses** | | | | |
| Operations and maintenance (Note 18) | | 17,376 | | 15,186 |
| Administration (Note 19) | | 9,891 | | 10,173 |
| Depreciation and amortization (Notes 7 and 8) | | 10,438 | | 9,571 |
| | | **37,705** | | 34,930 |
| **Income from operations** | | **9,761** | | 6,595 |
| **Other income** | | | | |
| Allowance for funds used during construction | | 714 | | 1,188 |
| Amortization of contributions in aid of construction (Note 15) | | 3,624 | | 3,613 |
| Interest income | | - | | 113 |
| | | **4,338** | | 4,914 |
| **Other expenses** | | | | |
| Interest on borrowings | | 3,319 | | 4,662 |
| Unrealized loss (gain) on interest rate swap (Note 24) | | 340 | | 644 |
| | | **3,659** | | 5,306 |
| **Net income for the year before net movements in regulatory deferral account balances** | | **10,440** | | 6,203 |
| **Net movement in regulatory deferral account balances related to net income (Note 9 (d))** | | (2,725) | | **1,456** |
| **Net income for the year and net movements in regulatory deferral account balances** | | **7,715** | | **7,659** |
| **Other Comprehensive Income (Note 3 (p))** | | | | |
| **Remeasurement of defined benefit pension plans (Note 14)** | | 512 | | (1,512) |
| **Total comprehensive income for the year** | **$** | **8,227** | $ | 6,147 |

The accompanying notes are an integral part of these financial statements.

# Yukon Energy Corporation
## Statement of Changes in Equity
(in thousands of Canadian dollars)

| | Share Capital Number of shares | Share Capital $ | Contributed surplus | Retained earnings | Accumulated other comprehensive income (loss) | Total |
|---|---|---|---|---|---|---|
| **Balance at January 1, 2014** | **3,900** | **$ 39,000** | **$ 14,600** | **$ 31,929** | **-** | **85,529** |
| Net income for the year and net movement in regulatory deferral account balances | - | - | - | 7,659 | - | 7,659 |
| Other comprehensive income | - | - | - | - | (1,512) | (1,512) |
| Transfer of remeasurement of defined benefit pension plans to retained earnings | - | - | - | (1,512) | 1,512 | - |
| **Balance at December 31, 2014** | **3,900** | **39,000** | **14,600** | **38,076** | **-** | **91,676** |
| Net income for the year and net movement in regulatory deferral account balances | - | - | - | 7,715 | - | 7,715 |
| Other comprehensive income | - | - | - | - | 512 | 512 |
| Transfer of remeasurement of defined benefit pension plans to retained earnings | - | - | - | 512 | (512) | - |
| **Balance at December 31, 2015** | **3,900** | **$ 39,000** | **$ 14,600** | **$ 46,303** | **-** | **$ 99,903** |

The accompanying notes are an integral part of these financial statements.

## Yukon Energy Corporation
**Statement of Cash Flows**
(in thousands of Canadian dollars)

| For the year ended December 31 | 2015 | 2014 |
|---|---|---|
| **Operating activities** | | |
| Cash receipts from customers | $ 42,072 | $ 42,406 |
| Cash receipts from parent | 2,000 | - |
| Cash receipts from contributions in aid of construction | 739 | 600 |
| Cash paid to suppliers | (16,906) | (12,150) |
| Cash paid to employees | (11,341) | (10,621) |
| Interest paid | (3,319) | (4,663) |
| Interest received | - | 113 |
| Cash provided by operating activities | **13,245** | 15,685 |
| **Financing activities** | | |
| Receipt of construction financing | 11,200 | 16,000 |
| Repayment of construction financing | (8,400) | - |
| Issuance of long-term debt | 20,984 | - |
| Repayment of long-term debt | (5,455) | (5,406) |
| Cash provided by financing activities | **18,329** | 10,594 |
| **Investing activities** | | |
| Additions to property, plant and equipment | (28,024) | (35,222) |
| Additions to intangible assets | (707) | (543) |
| Cash used in investment activities | **(28,731)** | (35,765) |
| **Net increase (decrease) in cash** | 2,843 | (9,486) |
| **Cash, beginning of year** | **(1,171)** | 8,315 |
| **Cash, end of year** | **$ 1,672** | $ (1,171) |

| | | |
|---|---|---|
| Cash includes: | | |
| Cash | $ 1,672 | $ 160 |
| Bank indebtedness | - | (1,331) |
| Total | $ 1,672 | $ (1,171) |

The accompanying notes are an integral part of these financial statements.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**1. NATURE OF OPERATIONS**

**a) General**

Yukon Energy Corporation ("the Utility") is incorporated under the Yukon *Business Corporations Act* and is a wholly-owned subsidiary of Yukon Development Corporation ("YDC" or "the Parent"), a corporation owned by the Yukon Government ("YG" or "the Government"). The Utility generates, transmits, distributes and sells electrical energy in the Yukon. The Utility is not subject to income taxes.

The Utility is subject to overall regulation by the Yukon Utilities Board (YUB) and specific regulation by the Yukon Water Board. Both boards are consolidated by the Government and as such are considered to be related parties for accounting purposes. Management believes these boards operate independently from the Utility from a rate setting and operating perspective.

**b) Rate regulation**

The operations of the Utility are regulated by the YUB pursuant to the *Public Utilities Act*. There is no minimum requirement for the Utility to appear before the YUB to review rates. However, the Utility is not permitted to charge any rate for the supply of power that is not approved by an Order of the YUB. The Utility is subject to a cost of service regulatory mechanism under which the YUB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment in rate base. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

The regulatory hearing process used to establish or change rates typically begins when the Utility files a General Rate Application (GRA) for its proposed electricity rate changes over the next one or two forecast years. The YUB must ensure that its decision, which fixes electricity rates, complies with appropriate principles of rate making, all relevant legislation including the *Public Utilities Act* and directives issued by the YG through Orders-In-Council ("OIC") that specify how the interests of the customer and Utility are to be balanced.

The YUB typically follows a two-stage decision process. In the first stage, the total costs that the Utility will incur to provide electricity to its customers over the immediate future are reviewed and approved. The approval of these costs determines the total revenues the Utility is allowed to collect from its customers. It is the responsibility of the YUB to examine the legitimacy of three classes of costs:

- the costs to the Utility to run its operations and maintain its equipment (personnel and materials);
- the cost associated with the depreciation of all capital equipment; and
- the return on rate base (the borrowing costs related to borrowing that portion of the rate base which is financed with debt plus the costs to provide a reasonable rate of return on that portion of the rate base which is financed with equity).

The YUB assesses the prudency of costs added to rate base, which includes an allowance for funds used during construction ("AFUDC") charged to capital projects. The YUB also reviews the appropriateness of property, plant and equipment depreciation rates, which are periodically updated by the Utility through depreciation studies.

In the second stage, the YUB approves how the revenue will be raised. This stage essentially determines the electricity rates for the various customer classes in the Yukon: residential, government, commercial and industrial. This process is guided mainly by requirements of OIC 1995/90 and can include a cost-of-service study which allocates the Utility's overall cost of service to the various customer classes on the basis of appropriate costing principles.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**1. NATURE OF OPERATIONS - continued**

**c) Water regulation**
The Yukon Water Board pursuant to the Yukon *Waters Act* decides if and for how long the Utility will have a water license for the purposes of operating hydro generation stations in the Yukon. The licenses will also indicate terms and conditions for the operation of these facilities.

**d) Capital structure**
The Utility's policy which has been approved by the YUB is to maintain a capital structure of 60% debt and 40% equity (Note 25). Dividends are normally declared annually to the Parent and are typically loaned back in order to maintain this ratio during normal on-going operations. When large assets are purchased or constructed, the Parent may be required to make an equity or capital contribution.

**2. BASIS OF PRESENTATION**

**a) Statement of compliance**
These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). These are the Utility's first financial statements prepared in accordance with IFRS and IFRS 1, *First-time Adoption of International Financial Reporting Standards*. An explanation of how the transition to IFRSs has affected the reported financial position, financial performance and cash flows of the Utility is provided in Note 26. This note includes reconciliations of equity and total comprehensive income for the comparative period and of equity at the date of transition (January 1, 2014) reported under Part V of the CPA Handbook ("previous GAAP") to those reported under IFRS.

These financial statements were authorized for issue by the Board of Directors on May 18, 2016.

**b) Basis of measurement**
The financial information included in the financial statements for the year ended December 31, 2015, and for the related comparative periods, has been prepared under the historical cost basis, except for financial instruments which are measured at fair value. The Utility's policy for these items is described in Note 3 below.

**c) Adoption of new and revised standards and interpretations**
The IASB issued IFRS 14, *Regulatory Deferral Accounts*, which allows an entity subject to rate regulation to continue to apply its previous GAAP accounting policies for regulatory deferral account balances when it first adopts IFRS. IFRS 14 provides certain exceptions to, or exemptions from other standards, modifies the presentation requirements of regulatory deferral account balances and related activity and adds disclosure on the amount, timing and uncertainty of future cash flows from any regulatory account balances. The standard is effective for fiscal years beginning on or after January 1, 2016 and earlier adoption is permitted. The Utility has elected to early adopt this standard. The changes are outlined in Note 26.

**3. SIGNIFICANT ACCOUNTING POLICIES**
The accounting policies set out below have been applied to all periods presented in these financial statements and in preparing the opening IFRS statement of financial position at January 1, 2014 for the purpose of the transition to IFRS, unless otherwise indicated.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**3. SIGNIFICANT ACCOUNTING POLICIES - continued**

**a) Significant accounting judgments, estimates and assumptions**
The preparation of financial statements requires the use of judgment in applying accounting policies and in making critical accounting estimates that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of any contingent assets and liabilities. These judgments and estimates are based on management's best knowledge of the relevant facts and circumstances, having regard to previous experience, but actual results may differ from the amounts included in the financial statements. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which estimates are revised and in any future periods affected. Information about such judgments and estimates is contained in the accounting policies and/or the Notes to the financial statements, and the key areas are summarized below.

The significant areas of judgment, estimates and assumptions are as follows:

Revenue
Estimate of the usage not yet billed at year end, which is included in revenues from sale of power. This accrual is based on an assessment of unbilled electricity supplied to customers between the date of the last meter reading and the year end. Management applies judgement to the measurement of the estimated consumption.

Depreciation and amortization
Significant components of property, plant and equipment are depreciated over their estimated useful lives. Useful lives are determined based on current facts and past experience and employment of experts to perform depreciation studies. While these useful life estimates are reviewed on a regular basis and depreciation calculations are revised accordingly, actual lives may differ from the estimates. As such, assets may continue in use after being fully depreciated, or may be retired or disposed of before being fully depreciated. The latter could result in additional depreciation expense in period of disposition.

Impairment of long-lived assets
An evaluation of whether or not an asset is impaired involves consideration of whether indicators of impairment exist. Management continually monitors the Utility's operations and makes judgements and assessments about conditions and events in order to conclude whether possible impairment exists.

Asset retirement obligations
In determining the present value of the obligation, the Utility must estimate the amount and timing of the future cash payments and then apply an appropriate risk-free interest rate. Any changes to the anticipated amounts or timing of future payments or risk-free interest rate can result in a change to the obligation.

Post-employment benefits
The Utility accrues for its obligations under defined benefit pension plans using actuarial valuation methods and other assumptions to estimate the projected benefit obligation and the associated expense related to the current period, as well as the return on plan assets. The key assumptions utilized include the long-term rate of inflation, rates of future compensation, liability discount rates and the expected return on plan assets. Changes in these assumptions give rise to gains and losses which are recognized immediately in other comprehensive income and then are reclassified to retained earnings each year. The obligations are measured by discounting the Utility's future payments under these plans. In addition, actual payments may vary from the estimates used to project the obligations and the net expense.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**3. SIGNIFICANT ACCOUNTING POLICIES - continued**

**b) Revenue recognition**
All revenues are recognized in the period earned. Revenue from the sale of power is recognized based on cyclical meter readings. Sales of power includes an accrual for electricity deliveries not yet billed at year-end.

**c) Translation of foreign currencies**
The functional currency of the Utility is the Canadian Dollar. Revenue and expense items denominated in foreign currencies are translated at exchange rates prevailing during the period. Monetary assets and liabilities denominated in foreign currencies are translated at period-end exchange rates. Non-monetary assets and liabilities are translated at exchange rates in effect when the assets are acquired or the obligations are incurred. Foreign exchange gains and losses are reflected in net income for the period.

**d) Allowance for funds used during construction**
The cost of the Utility's property, plant and equipment and deferred charges includes an allowance for funds used during construction (AFUDC) as allowed by the regulator. The AFUDC rate is based on the Utility's weighted average cost of debt. The AFUDC capitalized for 2015 was $714,000 (2014 - $1,188,000). The AFUDC rate estimate was 2.46% for 2015 (2014 - 4.01%).

**e) Cash**
Cash is comprised of bank account balances (net of outstanding cheques).

**f) Inventories**
Inventories consist of materials and supplies, diesel fuel and liquefied natural gas. Inventories are recorded at the lesser of weighted average cost and net realizable value. Cost includes all expenditures incurred in acquiring the items and bringing them to their existing condition and location. Critical spare parts are recorded in the Utility's books as property, plant and equipment.

The recoverable value of inventory considers its net realizable value, including required processing costs, and is impacted by estimates and assumptions on prices, quality, recovery and exchange rates. Obsolete materials and supplies are recorded at salvage value in the period when obsolescence is determined.

**g) Financial instruments**
Financial assets and financial liabilities are recognized on the Utility's statement of financial position when the Utility becomes party to the contractual provisions of the instrument. Accounts receivable, classified as loans and receivables, are initially measured at fair value. Subsequent to initial recognition, accounts receivable are measured at amortized cost using the effective interest rate method less any impairment.

A provision for impairment of accounts receivable is established when there is objective evidence that the Utility will not be able to collect all amounts due according to the original terms of the receivables. Significant financial difficulties of the debtor, probability that the debtor will enter into bankruptcy or require financial reorganization, and default or delinquency in payments are considered indicators that the related accounts receivable are impaired. The accounts receivable carrying amount is reduced through the use of an allowance account and the loss is recognized in net income.

Bank indebtedness, accounts payable and accrued liabilities, construction financing and long term debt are classified as other financial liabilities and they are initially recognized at fair value. Subsequent to initial recognition, they are measured at amortized cost using the effective interest rate method (except for bank indebtedness which is measured at cost).

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**3. SIGNIFICANT ACCOUNTING POLICIES - continued**

Transaction costs are presented as a reduction from the carrying value of the related debt and are amortized using the effective interest rate method over the terms of the debts to which they relate. Transaction costs include fees paid to agents, brokers and advisors but exclude debt discounts and lender financing costs.

Derivative financial instruments are financial contracts that derive their value from changes in an underlying variable. The Utility has entered into an interest rate swap to manage interest rate risk. The Utility's interest rate swap is classified as held for trading and is thus recognized at fair value on the date the contract has been entered into with any subsequent realized and unrealized gains and losses recognized in net income during the period in which the fair value movement occurred.

**h) Property, plant and equipment**
Property, plant and equipment are carried at cost, less accumulated depreciation and any asset impairment charges. Cost includes the direct costs of acquisition and materials, direct labour, and, if applicable, an allocation of directly attributable overhead costs, AFUDC and any asset retirement costs associated with the property, plant and equipment.

AFUDC is based on the Utility's weighted average cost of borrowing and is applied to actual costs in work-in-progress less any contributions in aid of construction. For items of property, plant and equipment acquired prior to January 1, 2011, the AFUDC rate also included a regulatory cost of equity component as allowed by the YUB. Capitalization of AFUDC ceases when the asset being constructed is substantially ready for its intended purpose.

Assets under construction are recorded as in progress until they are operational and available for use, at which time they are transferred to property, plant and equipment.

Depreciation is recognized in net income based on the straight-line method over the estimated useful life of each major component of property, plant and equipment. The range of the estimated useful lives of the major classes and subclasses of property, plant and equipment is as follows:

| | |
|---|---|
| Generation | |
| Hydroelectric plants | 30 to 103 years |
| Thermal plants | 12 to 72 years |
| Wind turbines | 30 years |
| Transmission | 20 to 65 years |
| Distribution | 12 to 55 years |
| Buildings | 20 to 55 years |
| Transportation | 9 to 31 years |
| Other equipment | 5 to 20 years |

Depreciation commences when an asset is available for use. The estimated useful lives of the assets are based upon depreciation studies conducted periodically by the Utility and any changes in the estimated useful lives are accounted for prospectively.

Gains and losses on the disposal or retirement of property, plant and equipment, with the exception of land and vehicles, are deferred and amortized over the remaining expected useful life of the related assets under regulatory accounting (Note 9). These gains and losses are recognized immediately in net income under IFRS.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**3. SIGNIFICANT ACCOUNTING POLICIES - continued**

**h) Property, plant and equipment - continued**
Major overhaul costs are capitalized and depreciated on a straight-line basis over the period of the expected useful life (until the next major overhaul) which varies from 5 to 10 years. However, major overhaul costs cannot be depreciated for regulatory purposes until the costs are approved by the YUB (Note 9). Repairs and maintenance costs of property plant and equipment are expensed as incurred unless they meet the criteria of a betterment.

**i) Intangible assets**
Intangible assets are carried at cost less accumulated amortization and any asset impairment charges. Cost includes the direct costs of acquisition and materials, direct labour, and, if applicable, an allocation of directly attributable overhead costs and AFUDC.

Amortization is recognized in net income on a straight-line basis over the estimated useful lives as follows:

| | |
|---|---|
| Software | 5 years |
| Financial software | 10 years |
| Deferred customer service costs | 12 years |
| Licencing costs | |
| Hydro generation | 17 to 25 years |
| Diesel generation | 3 years |

**j) Impairment of non-financial and financial assets**
Property, plant and equipment, regulatory deferral debit balances and intangible assets with finite lives are reviewed for impairment on an annual basis if there is an indication that the carrying amount may not be recoverable. Impairment is assessed at the level of cash-generating units, which are identified as the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or group of assets.

When an impairment review is undertaken, the recoverable amount is assessed by reference to the higher of value in use and fair value less costs to sell ("FVLCS") for non-financial assets and objective evidence of impairment in the case of financial assets. Value in use is the net present value of expected future cash flows of the relevant cash-generating unit in its current condition. The best evidence of FVLCS is the value obtained from an active market or binding sale agreement. Where neither exists, FVLCS is based on the best information available to reflect the amount the Utility could receive for the cash generating unit in an arm's length transaction. This is often estimated using discounted cash flow techniques and where unobservable inputs are material to the measurement of the recoverable amount, the measurement is classified as level 3 in the fair value hierarchy. The cash flow forecasts for FVLCS purposes are based on management's best estimates of expected future revenues and costs, including the future cash costs of production, capital expenditure, closure, restoration and environmental cleanup. For regulatory deferral debit balances the impairment review focuses on whether the amount is considered collectible based on the expected cash flows from the rates approved by the YUB.

These determinations and their individual assumptions require that management make a decision based on the best available information at each reporting period. Changes in these assumptions may alter the results of non-financial asset and financial asset impairment testing, impairment charges recognized in net income and the resulting carrying amounts of the assets.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**3. SIGNIFICANT ACCOUNTING POLICIES - continued**

**k) Rate regulated accounting policies**
**Regulatory deferral accounts**
Regulatory deferral accounts in these financial statements are accounted for differently than they would be in the absence of rate regulation. Where regulatory decisions dictate, the Utility defers certain costs or revenues as regulatory deferral account debit balances or regulatory deferral account credit balances on the statement of financial position and recognizes them in the net movement in regulatory deferral account balances in the statement of operations and other comprehensive income as it collects or refunds amounts through future customer rates. Any adjustments to these regulatory deferral accounts are recognized in the net movement in regulatory deferral account balances in the period that the YUB renders a subsequent decision. All amounts maintained as regulatory deferral account debit balances and regulatory deferral account credit balances are expected to be recovered or settled and are assessed on a yearly basis by comparing the rates approved by the YUB to the current balances. The recovery or settlement of regulatory deferral account balances through future rates is impacted by demand risk and regulatory risks (e.g. potential future decisions of the YUB which could result in material adjustments to these regulatory deferral account debit balances and regulatory deferral account credit balances as described in Note 1(b)).

**i) Regulatory deferral account debit balances**
Regulatory deferral account debit balances represent incurred costs which have been deferred and are recognized or being amortized over various periods as approved by the YUB. Regulatory deferral account debit balances represent costs which are expected to be recovered from customers in future periods through the rate-setting process. In the absence of rate regulation and the Utility's adoption of IFRS 14 (see Note 2(c)), such costs would be expensed as incurred.

**ii) Regulatory deferral account credit balances**
Regulatory deferral account credit balances represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate setting process. In the absence of rate regulation and the Utility's adoption of IFRS 14, such amounts would be recorded in income as earned.

Note 9 describes the individual regulatory deferral accounts, the Utility's related regulatory deferral and amortization policies and describes the related account activity in the relevant periods.

**l) Provision for asset retirement obligations**
The Utility has legal obligations related to the closure and restoration of property, plant and equipment, which includes the costs of dismantling, demolition of infrastructure and the removal of residual materials and remediation of the disturbed areas.

Where a reliable estimate of the present value of these obligations can be determined, the total retirement costs are recorded as a provision in the accounting period when the obligation arises. There is also a corresponding increase to property, plant and equipment upon recognition of the obligation. Management estimates its costs based on feasibility and engineering studies and assessments using current restoration standards and techniques.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**3. SIGNIFICANT ACCOUNTING POLICIES - continued**

**m) Provision for environmental liabilities**
Environmental liabilities consist of the estimated costs related to the remediation of environmentally contaminated sites. The Utility will accrue a provision when it has a present obligation as a result of a past event to remediate the contaminated site, it is expected that future economic benefits will be given up to settle the obligation, and a reliable estimate of the amount of the obligation can be made.

If the likelihood of the Utility's obligation to incur these costs is either not determinable or the amount of the obligation cannot be reliably estimated, the contingency is disclosed in the notes to the financial statements.

The Utility reviews its provision for environmental liabilities on an ongoing basis and any changes are recognized in net income for the current period.

The Utility does not have a provision for environmental liabilities as there is no present obligation to remediate.

**n) Contributions in aid of construction**
Certain property, plant and equipment additions are made with the assistance of cash contributions from customers or capital assistance from the Utility's Parent, the YG, or the Government of Canada. These contributions are deferred upon receipt and amortized to income on the same basis as the assets to which they relate.

**o) Decommissioning fund**
The decommissioning fund represents monies paid in advance by an industrial customer to decommission the spur line that connects their operation to the Utility's grid. Under a power purchase agreement, the customer has the financial responsibility for decommissioning expenses to be performed by the Utility on its behalf. Any amounts not required for decommissioning will be refunded to the customer. This money accrues interest at the rate equal to the three month Canadian Dealer Offered Rate ("CDOR").

**p) Post-employment benefits and other comprehensive income**
The Utility sponsors an employee defined benefit pension plan which provides benefits based on the length of service and average salaries for the five highest paid consecutive years of service. Effective January 1, 2011, the Utility also sponsors an executive defined benefit pension plan and supplemental executive retirement plan. The Utility contributes amounts to the pension plans as recommended by an independent actuary.

For the defined benefit plan the cost of pension benefits is actuarially determined using the projected benefits method, prorated on service, and reflects management's best estimates of investment returns, wage and salary increases, and age at retirement. Remeasurements of the net defined benefit liability, including actuarial gains and losses and return on plan assets, are recognized in other comprehensive income ("OCI") and are not reclassified to net income in a subsequent period. The Utility's policy is to immediately transfer actuarial gains and losses recognized in OCI to retained earnings. The expected return on plan assets is based on the fair value of these assets.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**3. SIGNIFICANT ACCOUNTING POLICIES - continued**

**p) Post-employment benefits and other comprehensive income - continued**
Employees joining the Utility after January 1, 2002 are eligible for a defined contribution retirement plan and are not eligible to participate in the defined benefit pension plan. Contributions are required by both employees and the Utility to cover the current service cost of this defined contribution retirement plan. The Utility has no legal or constructive obligation to pay further contributions with respect to this plan. Consequently, contributions are recognized as an expense in the year when employees have rendered service and represents the obligation of the Utility.

**q) New standards and interpretations not yet adopted**
A number of new standards, and amendments to standards and interpretations, are not yet effective for the period ended December 31, 2015, and have not been applied in preparing these financial statements. None of these is expected to have a significant effect on the financial statements of the Utility, except for:

*i)* IFRS 9, *Financial Instruments,* which will replace IAS 39, Financial Instruments: Recognition and Measurement and IFRIC 9, Reassessment of Embedded Derivatives. The new standard is effective for fiscal years beginning on or after January 1, 2018 and is available for early adoption. The standard is expected to impact the classification and measurement of financial assets, introduce changes to financial liabilities and includes new hedge accounting requirements. The Utility intends to adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018. The extent of the impact of adoption of the standard has not yet been determined.

*ii)* On May 28, 2014, the IASB issued IFRS 15, *Revenue from Contracts with Customers*, which will replace IAS 18, *Revenue*. The new standard is effective for fiscal years beginning on or after January 1, 2018 and is available for early adoption. The standard contains a single model that applies to contracts with customers and two approaches to recognising revenue: at a point in time or over time. The model features a contract based five step analysis of transactions to determine whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. The Utility intends to adopt IFRS 15 in its financial statements for the annual period beginning on January 1, 2018. The extent of the impact of adoption of the standard has not yet been determined.

**4. CASH**

The cash balance includes an amount of $Nil (December 31, 2014 - $Nil, January 1, 2014 - $1,292,000) that is restricted for the payment of a contractor holdback.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

### 5. ACCOUNTS RECEIVABLE

| | December 31 2015 | December 31 2014 | January 1 2014 |
|---|---|---|---|
| Wholesale energy sales | $ 3,549 | $ 3,800 | $ 5,401 |
| Retail energy sales | 1,321 | 1,485 | 1,869 |
| Due from related parties (Note 20) | 850 | 807 | 548 |
| Other | 627 | 970 | 591 |
| | **$ 6,347** | $ 7,062 | $ 8,409 |

At December 31, 2015, the aging of accounts receivable is as follows:

| | Current | 31 - 90 Days | Over 90 Days | Total |
|---|---|---|---|---|
| Accounts receivable | $ 5,680 | $ 192 | $ 485 | $ 6,357 |
| Allowance for doubtful accounts | | | (10) | (10) |
| | $ 5,680 | $ 192 | $ 475 | $ 6,347 |

At December 31, 2014, the aging of accounts receivable is as follows:

| | Current | 31 - 90 Days | Over 90 Days | Total |
|---|---|---|---|---|
| Accounts receivable | $ 6,548 | $ 2 | $ 522 | $ 7,072 |
| Allowance for doubtful accounts | | | (10) | (10) |
| | $ 6,548 | $ 2 | $ 512 | $ 7,062 |

At January 1, 2014, the aging of accounts receivable is as follows:

| | Current | 31 - 90 Days | Over 90 Days | Total |
|---|---|---|---|---|
| Accounts receivable | $ 7,578 | $ 17 | $ 878 | $ 8,473 |
| Allowance for doubtful accounts | | | (64) | (64) |
| | $ 7,578 | $ 17 | $ 814 | $ 8,409 |

A reconciliation of the beginning and ending amount of allowance for doubtful accounts is as follows:

| | December 31 2015 | December 31 2014 |
|---|---|---|
| Allowance for doubtful accounts at beginning of year | $ (10) | $ (64) |
| Amounts written off as uncollectable | - | 54 |
| Allowance for doubtful accounts at end of year | $ (10) | $ (10) |

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

### 6. INVENTORIES

| | December 31 2015 | December 31 2014 | January 1 2014 |
|---|---|---|---|
| Materials and supplies | $ 3,105 | $ 2,661 | $ 2,796 |
| Diesel fuel | 333 | 404 | 426 |
| Liquefied natural gas | 176 | - | - |
| | $ 3,614 | $ 3,065 | $ 3,222 |

The amount of inventory expensed during the year is $781,000 (2014 - $227,000) for fuel as disclosed in note 18 and $75,000 (2014 - $145,000) for materials and supplies.

### 7. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

| | Generation | Transmission & Distribution | Land & Buildings | Transportation & Other | Construction Work-in Progress | Total |
|---|---|---|---|---|---|---|
| **Cost:** | | | | | | |
| At January 1, 2014 | $ 224,607 | $ 142,442 | $ 12,543 | $ 2,885 | $ 20,537 | $ 403,014 |
| Additions | - | - | - | - | 37,415 | 37,415 |
| Transfers | 6,088 | 2,144 | 1,420 | 349 | (10,001) | - |
| Disposals | - | - | (24) | - | - | (24) |
| At December 31, 2014 | 230,695 | 144,586 | 13,939 | 3,234 | 47,951 | 440,405 |
| Additions | - | - | - | - | 22,255 | 22,255 |
| Transfers | 44,519 | 15,908 | 1,913 | 359 | (62,699) | - |
| Disposals | (22) | - | - | (112) | - | (134) |
| At December 31, 2015 | $ 275,192 | $ 160,494 | $ 15,852 | $ 3,481 | $ 7,507 | $ 462,526 |
| **Accumulated depreciation:** | | | | | | |
| At January 1, 2014 | $ - | $ - | $ - | $ - | $ - | $ - |
| Depreciation* | 4,112 | 3,962 | 796 | 269 | - | 9,139 |
| Disposals | - | - | (20) | - | - | (20) |
| At December 31, 2014 | 4,112 | 3,962 | 776 | 269 | - | 9,119 |
| Depreciation* | 4,903 | 4,248 | 812 | 290 | - | 10,253 |
| Disposals | (1) | - | - | (39) | - | (40) |
| At December 31, 2015 | $ 9,014 | $ 8,210 | $ 1,588 | $ 520 | $ - | $ 19,332 |
| **Net book value:** | | | | | | |
| At January 1, 2014 | $ 224,607 | $ 142,442 | $ 12,543 | $ 2,885 | $ 20,537 | $ 403,014 |
| At December 31, 2014 | $ 226,583 | $ 140,624 | $ 13,163 | $ 2,965 | $ 47,951 | $ 431,286 |
| At December 31, 2015 | $ 266,178 | $ 152,284 | $ 14,264 | $ 2,961 | $ 7,507 | $ 443,194 |

* Included in generation depreciation is the annual depreciation for overhauls of $778,000 (2014 - $546,000) which is recorded in regulatory account expenses in Note 18.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

### 8. INTANGIBLE ASSETS

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

| | Software | Deferred Customer Service Costs | Financial Software | Aishihik Licensing | Other Licensing | Total |
|---|---|---|---|---|---|---|
| **Cost:** | | | | | | |
| At January 1 2014 | $ 119 | $ 443 | $ 2,406 | 2,991 | $ 1,724 | $ 7,683 |
| Additions | 27 | - | - | - | 516 | 543 |
| Disposals | (34) | - | - | - | (30) | (64) |
| At December 31, 2014 | 112 | 443 | 2,406 | 2,991 | 2,210 | 8,162 |
| Additions | 281 | - | - | 51 | 306 | 638 |
| Acquisitions | 69 | - | - | - | - | 69 |
| Disposals | - | - | - | (10) | - | (10) |
| At December 31, 2015 | $ 462 | $ 443 | $ 2,406 | 3,032 | $ 2,516 | $ 8,859 |
| **Accumulated amortization:** | | | | | | |
| At January 1, 2014 | - | - | - | - | - | - |
| Amortization | 62 | 64 | 284 | 524 | 44 | 978 |
| Disposals | (34) | - | - | - | (30) | (64) |
| At December 31, 2014 | 28 | 64 | 284 | 524 | 14 | 914 |
| Amortization | 33 | 64 | 284 | 524 | 58 | 963 |
| Disposals | - | - | - | (10) | - | (10) |
| At December 31, 2015 | $ 61 | $ 128 | $ 568 | $ 1,038 | $ 72 | $ 1,867 |
| **Net book value:** | | | | | | |
| At January 1, 2014 | $ 119 | $ 443 | $ 2,406 | $ 2,991 | $ 1,724 | $ 7,683 |
| At December 31, 2014 | 84 | 379 | 2,122 | 2,467 | 2,196 | 7,248 |
| At December 31, 2015 | 401 | 315 | 1,838 | 1,994 | 2,444 | 6,992 |

The internally generated costs and externally purchased costs included in these categories software, deferred customer service costs, financial software, Aishihik licensing and other licensing are approximately 50% internal and 50% external at December 31, 2015, December 31, 2014 and January 1, 2014.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

### 9. REGULATORY ACCOUNTS

**Regulatory deferral account debit balances**

| | Feasibility Studies (i) | IFRS Planning (ii) | Regulatory Costs (iii) | Vegetation Management (iv) | Dam Safety (v) | Uninsured Losses (vi) | Total |
|---|---|---|---|---|---|---|---|
| **Cost:** | | | | | | | |
| At January 1, 2014 | 18,983 | 566 | 3,593 | - | 332 | 330 | 23,804 |
| Costs incurred | 2,167 | - | 707 | 1,419 | - | 196 | 4,489 |
| Regulatory provision | - | - | - | (502) | - | (226) | (728) |
| Disposals | (356) | - | (24) | - | - | - | (380) |
| Contributions received | - | - | (132) | - | - | - | (132) |
| At December 31, 2014 | 20,794 | 566 | 4,144 | 917 | 332 | 300 | 27,053 |
| Costs incurred | 4,110 | - | 343 | 1,229 | 144 | 193 | 6,019 |
| Regulatory provision | - | - | - | (502) | - | (226) | (728) |
| Disposals | (183) | - | - | - | (332) | - | (515) |
| Contribution received | (6,166) | - | (127) | - | - | - | (6,293) |
| At December 31, 2015 | 18,555 | 566 | 4,360 | 1,644 | 144 | 267 | 25,536 |
| | | | | | | | |
| **Accumulated amortization:** | | | | | | | |
| At January 1, 2014 | 2,502 | 226 | 871 | - | 284 | - | 3,883 |
| Amortization | 1,196 | 113 | 252 | - | 24 | - | 1,585 |
| Disposals/Retirement | (356) | - | (24) | - | - | - | (380) |
| At December 31. 2014 | 3,342 | 339 | 1,099 | - | 308 | - | 5,088 |
| Amortization | 1,185 | 114 | 246 | - | 24 | - | 1,569 |
| Disposals | (183) | - | - | - | (332) | - | (515) |
| At December 31, 2015 | 4,344 | 453 | 1,345 | - | - | - | 6,142 |
| **Net book value:** | | | | | | | |
| At January 1, 2014 | 16,481 | 340 | 2,722 | - | 48 | 330 | 19,921 |
| At December 31, 2014 | 17,452 | 227 | 3,045 | 917 | 24 | 300 | 21,965 |
| At December 31, 2015 | 14,211 | 113 | 3,015 | 1,644 | 144 | 267 | 19,394 |
| Net increase (decrease) in regulatory deferral account debit balances (which are recognized in the net movement of regulatory deferral account balances related to net income on the statement of operations and other comprehensive income): | | | | | | | |
| December 31, 2014 | 971 | (113) | 323 | 917 | (24) | (30) | 2,044 |
| December 31, 2015 | (3,241) | (114) | (30) | 727 | 120 | (33) | (2,571) |
| Remaining recovery years | | | | | | | |
| At January 1, 2014 | 5 to 10 years | 3 years | 10 to 45 years | - | 2 years | Indeterminate | |
| At December 31, 2014 | 5 to 10 years | 2 years | 10 to 45 years | Indeterminate | 1 year | Indeterminate | - |
| At December 31, 2015 | 5 to 10 years | 1 year | 10 to 45 years | Indeterminate | 5 years | Indeterminate | - |
| Absent rate regulation, net income would increase (decrease) by: | | | | | | | |
| December 31, 2014 | (971) | 113 | (323) | (917) | 24 | 30 | (2,044) |
| December 31, 2015 | 3,241 | 114 | 30 | (727) | (120) | 33 | 2,571 |

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

### 9. REGULATORY ACCOUNTS - continued

| | Carry Forward | Deferred Overhauls (vii) | Fuel Price Adjustment (viii) | Deferred Gains And losses (ix) | Total |
|---|---|---|---|---|---|
| **Cost:** | | | | | |
| At January 1, 2014 | 23,804 | 259 | 6 | - | 24,069 |
| Cost incurred | 4,489 | 684 | 13 | - | 5,186 |
| Regulatory provision | (728) | - | - | - | (728) |
| Disposals | (380) | - | - | - | (380) |
| Contributions received | (132) | - | - | - | (132) |
| At December 31, 2014 | 27,053 | 943 | 19 | - | 28,015 |
| Cost incurred | 6,019 | 900 | - | - | 6,919 |
| Regulatory provision | (728) | - | - | - | (728) |
| Disposals | (515) | - | - | - | (515) |
| Contributions received | (6,293) | - | (15) | - | (6,308) |
| At December 31, 2015 | 25,536 | 1,843 | 4 | - | 27,383 |
| **Accumulated amortization:** | | | | | |
| At January 1, 2014 | 3,883 | - | - | - | 3,883 |
| Amortization | 1,585 | - | - | - | 1,585 |
| Disposals | (380) | - | - | - | (380) |
| At December 31 2014 | 5,088 | - | - | - | 5,088 |
| Amortization | 1,569 | - | - | - | 1,569 |
| Disposals | (515) | - | - | - | (515) |
| At December 31, 2015 | 6,142 | - | - | - | 6,142 |
| **Net book value:** | | | | | |
| At January 1, 2014 | 19,921 | 259 | 6 | - | 20,186 |
| At December 31, 2014 | 21,965 | 943 | 19 | - | 22,927 |
| At December 31, 2015 | 19,394 | 1,843 | 4 | - | 21,241 |
| Net increase (decrease) in regulatory deferral account debit balances (which are recognized in the net movement of regulatory deferral account balances on the statement of operations and other comprehensive income): | | | | | |
| December 31, 2014 | 2,044 | 684 | 13 | - | 2,741 |
| December 31, 2015 | (2,571) | 900 | (15) | - | (1,686) |
| Remaining recovery years | | | | | |
| At January 1, 2014 | | Indeterminate | 1 year | | |
| At December 31, 2014 | | Indeterminate | 1 year | | |
| At December 31, 2015 | | Indeterminate | 1 year | | |
| Absent rate regulation, Net Income would increase (decrease) by: | | | | | |
| December 31, 2014 | (2,044) | (684) | (13) | - | (2,741) |
| December 31, 2015 | 2,571 | (900) | 15 | - | 1,686 |

### (a) Regulatory deferral account debit balances

**(i) Feasibility studies and infrastructure planning**
The Utility undertakes certain studies to determine the feasibility of a range of projects and infrastructure proposals. While in progress, the costs of these studies are deferred within this account. Once the study is completed, the costs are amortized over a prescribed number of years ranging between five and ten years under regulatory reporting. In absence of rate regulation, IFRS would require these costs to be expensed as incurred.

**(ii) IFRS planning**
These deferred costs are associated with the conversion from previous GAAP to IFRS and are amortized over a term of 5 years. In absence of rate regulation, IFRS would require these costs to be expensed as incurred.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**9. REGULATORY ACCOUNTS - continued**

**(iii) Regulatory costs**
These costs are associated with the YUB regulatory proceedings. The costs consist primarily of various rate and project review proceedings but also include resource plans, hearing costs from before 2012 and demand side management costs. The Utility is directed to defer and amortize the costs over terms at the discretion of the YUB. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

**(iv) Vegetation management**
These deferred costs are annual brushing costs in excess of the maximum annual amount approved by the YUB. Amortization of these costs has not yet been approved. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

**(v) Dam safety review**
The Utility has a program of conducting safety reviews of its dams in accordance with standards set by the Canadian Dam Association. External consultants are hired every five years with intermittent costs incurred in the interim periods. These costs are being amortized over five years as approved by the YUB. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

**(vi) Uninsured losses**
The YUB has approved the use of a deferral account for uninsured damages and injuries as a means of self-insurance. The account is maintained through an annual provision approved by the YUB and collected through customer rates. Variances between the approved annual provision and actual costs incurred are deferred until the following GRA or until a specific application is made to the YUB requesting recovery from or refund to customers. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

**vii) Deferred overhauls**
Overhauls represent costs incurred to overhaul engines that are used in operations and these overhauls are recorded as property, plant and equipment. The Utility was directed by YUB Order 2013-01 to defer all overhaul costs incurred after 2011 until the Utility comes before the YUB for a prudence review and the costs are approved to be depreciated. IFRS requires these completed overhauls to be considered in service and they should be depreciated through net income. In addition, IFRS also requires that AFUDC would cease when the overhaul is substantially ready for its intended purpose. As a result the AFUDC capitalized on these completed overhauls of $122,000 (2014 - $138,000) and the associated depreciation on these overhauls of $778,000 (2014 - $546,000) are shown as a regulatory deferral account debit balance. The opening balance on transition was $259,000 at January 1, 2014,

**(viii) Fuel price adjustment**
OIC 1995/90 directs the YUB to permit the Utility to adjust electricity rates to reflect fluctuations in the price of diesel fuel. The amount by which actual fuel prices vary from the YUB approved rates is deferred and recovered from or refunded to customers in a future period. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

**(ix) Deferred gains and losses**
Deferred gains and losses represent amounts from disposals of property plant and equipment. There are no deferred gains or losses during any of the reporting years.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

### 9. REGULATORY ACCOUNTS - continued

**Regulatory deferral account credit balances**

| | Deferred Insurance Proceeds (i) | Hearing reserve (ii) | Diesel Contingency Fund (iii) | Future removal and site Restoration (iv) | Total |
|---|---|---|---|---|---|
| **Cost:** | | | | | |
| At January 1, 2014 | 11,602 | 106 | 8,198 | 4,671 | 24,577 |
| Cost incurred | - | (432) | - | - | (432) |
| Regulatory provision | - | 550 | - | - | 550 |
| Cash received | - | - | 1,429 | - | 1,429 |
| At December 31, 2014 | 11,602 | 224 | 9,627 | 4,671 | 26,124 |
| Cost incurred | - | (213) | - | (304) | (517) |
| Regulatory provision | - | 550 | - | - | 550 |
| Cash received | - | - | 2,027 | - | 2,027 |
| Cash refunded | - | - | (759) | - | (759) |
| At December 31, 2015 | 11,602 | 561 | 10,895 | 4,367 | 27,425 |
| **Accumulated amortization:** | | | | | |
| At January 1, 2014 | 5,587 | - | - | - | 5,587 |
| Amortization | 262 | - | - | - | 262 |
| At December 31. 2014 | 5,849 | - | - | - | 5,849 |
| Amortization | 262 | - | - | - | 262 |
| Disposals | - | - | - | - | - |
| At December 31, 2015 | 6,111 | - | - | - | 6,111 |
| Net book value | | | | | |
| At January 1, 2014 | 6,015 | 106 | 8,198 | 4,671 | 18,990 |
| At December 31, 2014 | 5,753 | 224 | 9,627 | 4,671 | 20,275 |
| At December 31, 2015 | 5,491 | 561 | 10,895 | 4,367 | 21,314 |
| Net (increase) decrease in regulatory deferral account credit balances (which are recognized in the net movement of regulatory deferral account balances related to net income on the statement of operations and other comprehensive income): | | | | | |
| December 31, 2014 | 262 | (118) | (1,429) | - | (1,285) |
| December 31, 2015 | 262 | (337) | (1,268) | 304 | (1,039) |
| Remaining recovery years | | | | | |
| At January 1, 2014 | 23 years | Indeterminate | Indeterminate | Indeterminate | |
| At December 31, 2014 | 22 years | Indeterminate | Indeterminate | Indeterminate | |
| At December 31, 2015 | 21 years | Indeterminate | Indeterminate | Indeterminate | |
| Absent rate regulation, net income would increase (decrease) by: | | | | | |
| December 31, 2014 | (262) | 118 | 1,429 | - | 1,285 |
| December 31, 2015 | (262) | 337 | 1,268 | (304) | 1,039 |

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**9. REGULATORY ACCOUNTS - continued**

**(b) Regulatory deferral account credit balances**

**(i) Deferred insurance proceeds**
The deferred insurance proceeds represents a gain on fire insurance proceeds related to a fire at the Whitehorse Rapids Generating Station in 1997 which, pursuant to YUB Order 2000-3, is being amortized to income at the same rate as depreciation of the related replacement assets. In the absence of rate regulation, IFRS would have required the gain to have been fully recognized as income in the year received.

**(ii) Hearing reserve**
Pursuant to YUB Order 2013-01, the Utility has established a deferral account for future regulatory hearing costs. A provision is made for $550,000 of hearing costs each year. Actual hearing costs will be applied to this regulatory deferral account. Variances between the annual provision and actual costs are deferred until the following GRA or until a specific application is make to the YUB requesting recover or a refund to customers. In the absence of rate regulation, IFRS would require hearing costs to be expensed as incurred.

**(iii) Diesel Contingency Fund and Energy Reconciliation Adjustment**
The Diesel Contingency Fund ("DCF") was established by YUB Order 1996-6 through the negotiated settlement process. The DCF is used to reimburse the Utility for costs associated with diesel generation required when there is a diesel cost variance due solely to water-related hydro and wind generation variances from YUB approved GRA forecasts. The DCF attracts interest based upon short/intermediate term bond rates. Any negative balance attracts interest at the lowest short-term bond rates available to the Utility through its line of credit. The Utility is required to file quarterly reports with the YUB on the DCF's activity.

As part of the 2012/13 GRA, the Utility filed for changes to the DCF and Energy Reconciliation Adjustment ("ERA") provisions of the Wholesale Primary Rate Schedule. The YUB deferred a decision on these two issues pending further consultation with affected utilities and a separate proceeding to review the impacts of proposed changes. In January 2014, the Utility filed an application to revise the DCF and ERA with the YUB. A decision was delivered February 6, 2015. In accordance with YUB Order 2015-01, the Utility defers recognition of the additional amounts collected from rate payers when the cost of diesel consumed in the period is less than the long-term average diesel requirements estimated for the actual annual generation load. These deferred revenues are recognized as revenue in the period when the cost of diesel fuel incurred for the period is greater than the long-term average diesel requirements and the reason for the shortfall is a shortage of water in the hydro system. The YUB has set a cap of +/- $8 million for the DCF. If the balance falls outside of this range, the Utility is to make an application to the YUB requesting recovery or a refund to customers. In accordance with YUB Order 2015-06, the Utility is providing a refund to the customers of 0.68 cents/kWh effective September 1, 2015.

In the 2012/13 GRA, the Utility applied to reactivate the Energy Reconciliation Adjustment provision in the Wholesale Primary Rate Schedule. In YUB Order 2015-06, the YUB rejected the proposal and as a result the Utility eliminated the ERA balances in accounts receivable and accounts payable for the years ended December 31, 2015 and 2014.

In the absence of rate regulation, IFRS would require any amounts earned or incurred related to the DCF to be included in the Utility's net income in the year incurred.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**9. REGULATORY ACCOUNTS - continued**

**(iv) Future removal and site restoration costs**
The Utility maintains a regulatory provision for future removal and site restoration related to property plant and equipment, which is incremental to that required to be recognized as an asset retirement provision under IAS 37. The reserve has been established through amortization rates approved by the YUB. The amortization rates supporting the provision are based upon depreciation studies conducted periodically by the Utility. As a result of the YUB Order 2005-12, effective January 1, 2005, the provision is not to exceed the cumulative value of the provision at December 31, 2004 of $5,757,000. YUB Order 2005-12 also directs the Utility to notify interveners and interested parties when the balance of the provision reaches $2,000,000.

Costs of dismantling capital assets, including site remediation, will be applied to this regulatory deferral account credit balance if they do not otherwise relate to an asset retirement provision. The period over which the provision will be reduced is dependent on the timing of future costs of demolishing, dismantling, tearing down, site restoration or otherwise disposing of the asset net of actual recoveries, and is therefore indeterminate. In the absence of rate regulation, IFRS would require these costs to be expensed or included in the gain or loss on disposal of the related property, plant and equipment, as applicable.

**(c) Regulatory account expenses**

Regulatory account expenses represent costs incurred related to regulatory account debit balances of $6,919,000 (2014 - $5,186,000) and regulatory account credit balances of $517,000 (2014 - $432,000). Total regulatory expenses were $7,436,000 (2014 - $5,618,000) and all these amounts were paid during the year.

**(d) Net movement in regulatory deferral account balances related to net income**

Net movement in regulatory deferral account balances related to net income is $(2,725,000) (2014 – $1,456,000) represents the adjustment to the net income for the year before net movement in regulatory deferral account balances for the effects of rate regulation in accordance with IFRS 14. The net movement figure of $(2,725,000) for 2015 is comprised of lower net income of $(1,686,000) and $(1,039,000) for both regulatory account debit balances and regulatory account credit balances for rate regulation compared to the amounts that would be recorded under IFRS. The net movement figure of $1,456,000 for 2014 is comprised of the higher net income of $2,741,000 for the regulatory debit balances which is partially offset by lower net income of $(1,285,000) for regulatory account credit balances.

**10. BANK INDEBTEDNESS**

The Utility has a $10 million unsecured line of credit that accrues interest on withdrawals at prime minus 0.75%. No commitment fees are payable on the unused portion of the line. At December 31, 2015, the outstanding balance under the line of credit was $125,000 (2014 - $1,416,019 and January 1, 2014 - $Nil).

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

### 11. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

| | December 31 2015 | December 31 2014 | January 1 2014 |
|---|---|---|---|
| Trade payables | $ 5,763 | $ 12,987 | $ 10,725 |
| Employee compensation | 885 | 1,087 | 358 |
| Due to related parties (Note 20) | 433 | 305 | 132 |
| Other | 229 | 538 | 1,088 |
| | $ 7,310 | $ 14,917 | $ 12,303 |

### 12. CONSTRUCTION FINANCING

| | December 31 2015 | December 31 2014 | January 1 2014 |
|---|---|---|---|
| Construction financing due December 31, 2016, bearing interest at 1.03% approved to a maximum of $25 million | $ 14,880 | $ 14,880 | $ 20,385 |
| Construction financing with an initial term ending September 30, 2015 bearing interest at 1.5% approved to a maximum of $21.2 million | - | 10,000 | - |
| Construction financing, due March 31, 2015, bearing interest at 1.5% approved to a maximum of $18 million | - | 18,000 | 12,000 |
| Construction financing, due December 31, 2016 bearing interest at 1.03% approved to a maximum of $8.4 million | 8,400 | - | - |
| | $ 23,280 | $ 42,880 | $ 32,385 |
| Less current portion | 23,280 | 42,880 | 20,385 |
| | $ - | $ - | $ 12,000 |

Construction financing balances are monies advanced from the Parent to assist in the development of the Utility's infrastructure and generally are repayable within one year. Interest is payable annually at December 31 and at the maturity date.

On January 23, 2015 the Utility received the remaining $11,200,000 proceeds as part of the $21,200,000 Construction Financing Agreement with YDC.

The Utility entered into an agreement with YDC, effective December 29, 2015, to convert $39,200,000 of the construction financing into a capital contribution - $18,265,000 contributions in aid of construction (Note 15), $4,135,000 funding for feasibility studies, $8,400,000 was converted to a short-term loan due December 31, 2016 and $8,400,000 was repaid.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

### 13. LONG-TERM DEBT

The Utility's long-term debt is summarized as follows:

| | December 31 2015 | December 31 2014 | January 1 2014 |
|---|---|---|---|
| **Yukon Development Corporation** | | | |
| $92,458,473 term note bearing interest at 2.40% repayable in annual installments of $3,683,800 principal, plus accrued interest with the balance of $77,726,473 due December 31, 2019 (i) | $ 88,775 | $ - | $ - |
| $81,890,873 term note bearing interest at 4.25% repayable in annual installments of $3,000,000 principal, plus accrued interest with the balance of $69,890,873 due December 31, 2015 (i) | - | 69,891 | 72,891 |
| $17,095,000 term note bearing interest at 3.69% repayable in annual installments of $683,800 principal, plus accrued interest, due December 31, 2036 (i) | - | 15,044 | 15,727 |
| $21,900,000 flexible term note bearing interest up to 5.46% repayable in annual installments of $336,923 principal, plus accrued interest with the balance of $8,423,078 due December 31, 2051 (ii) | 20,552 | 20,889 | 21,226 |
| $5,505,000 term note bearing interest at 2.40% interest only payable annually, due December 31, 2039 | 5,505 | 5,505 | - |
| $20,984,404 term note bearing interest at 2.21% repayable in annual installments of $839,376 principal, plus accrued interest with the balance due December 31, 2040 | 20,984 | - | - |
| Unsecured advance bearing interest at 3.97%, due one year after demand (i) | - | 2,053 | 2,053 |
| Unsecured advance bearing interest at 4.27%, due one year after demand (i) | - | 5,471 | 5,471 |
| **TD Bank** | | | |
| $12,400,000 term note bearing interest at 4.02% payable in monthly installments of $94,406 interest and principal, with the balance due September 30, 2016. The note is guaranteed by the Yukon Government. | 837 | 1,911 | 2,946 |
| The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptances amounts from a variable interest rate based on the Bankers' Acceptances rates to a fixed rate of 2.69% per annum. Payable in monthly installments of $50,407 interest and principal with the balance due on December 28, 2022 (iii) | 10,036 | 10,366 | 10,687 |
| **Carmacks Stewart First Nation Liability** | | | |
| Long-term liability payable to several First Nations related to the building of the Carmacks Stewart Transmission Line. These are non interest bearing, repayable in varying installments, due in 2028 | 251 | 281 | 311 |
| | 146,940 | 131,411 | 131,312 |
| Less current portion | 6,066 | 72,347 | 5,406 |
| | $ 140,874 | $ 59,064 | $ 125,906 |

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**13. LONG-TERM DEBT - continued**

**(i) Debt Refinancing**
The Utility entered into an agreement with YDC on January 1, 2015 (approved April 16, 2015) to renegotiate terms of all outstanding debt, excluding the $20,889,000 term note related to the Mayo Hydro Enhancement Project due December 31, 2051 and the $5,505,000 term note due December 31, 2039. The amount of the new restructuring is $92,458,473. The term of the new loan is until December 31, 2019 with interest payable at 2.40%. Interest on the loan is payable on the last business day of each month. The Utility will pay $3,683,000 against the outstanding principal annually on December 31 starting on December 31, 2015. The Utility will repay the outstanding principal balance in full by December 31, 2019, unless the parties negotiate alternative repayment.

**(ii) $21,900,000 Flexible Term Note**
The terms of the flexible term note provide for a maximum amount of interest payable within a calendar year, calculated based on the actual grid generation on the electrical grid system connected with the Mayo Hydro Enhancement Project. The amount of interest payable as a result of the interest rate exceeding the maximum interest payable will abate forever. The actual interest rate on this flexible note was 0.61% (2014 - negative 0.53% and January 1, 2014 - positive 0.60%)

**(iii) TD Bank Loan and Interest Rate Swap**
On December 28, 2012, the Utility entered into a loan and interest rate swap with TD Bank to arrange financing for the purpose of continuing to develop the electrical infrastructure in the Yukon. The interest rate swap matures December 28, 2022.

**Long-term debt repayment**
Scheduled repayments for all long-term debt are as follows:

| | |
|---|---|
| 2016 | $ 6,066 |
| 2017 | 5,245 |
| 2018 | 5,254 |
| 2019 | 79,283 |
| 2020 | 1,570 |
| Thereafter | 49,522 |
| | **$ 146,940** |

**Fair value**
The fair value of long-term debt at December 31, 2015 is $149 million (December 31, 2014 - $136 million, January 1, 2014 - $136 million). The fair value for all long-term debt including current portions was estimated using discounted cash flows based on an estimate of the Utility's current borrowing rate for similar borrowing arrangements.

## Yukon Energy Corporation

**Notes to Financial Statements**
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**December 31 2015**

### 14. POST-EMPLOYMENT BENEFITS

**Characteristics of benefit plans**
The Utility sponsors a defined benefit plan for employees joining the Utility before January 1, 2002 and a pension plan for a former executive. Benefits provided are calculated based on length of pensionable service, pensionable salary at retirement age and negotiated rates.

Employees joining the Utility after January 1, 2002 are not eligible to participate in the employee defined benefit plan. The Utility makes contributions to a Registered Retirement Savings Plan ("RRSP") on behalf of these employees and employees hired before January 1, 2002 who belonged to the employee defined benefit plan and elected to opt out of that plan. The RRSP is a defined contribution plan. The costs recognized for the period are equal to the Utility's contribution to the plan. During 2015, these were $446,000 (2014 - $378,000).

The employee plan is regulated by the Office of the Superintendent of Financial Institutions through the *Pension Benefits Standards Act and regulations*. This Act and accompanying regulations impose, among other things, minimum funding requirements.

These minimum funding requirements require the Utility make special payments as prescribed by the Office of the Superintendent of Financial Institutions to repay any unfunded liability or deficit that may exist. For the employee pension plan the Utility is required to pay $323,700 as a minimum annual payment in each of the next 12 years (2014 - $390,000 in each of the next 13 years, 2013 - $509,600 in each of the next 14 years).

A committee of the Utility's Board of Directors oversees these plans and is responsible for the investment policy with regard to the assets of these funds.

**Risks associated with defined benefit plans**
The pension plans expose the Utility to actuarial risk such as: investment risk, interest rate risk, longevity risk and salary risk.

Investment risk is the risk that the present value of the defined benefit plan liability is calculated using a discount rate determined by reference to high quality corporate bond yields; if the return on plan assets is below this rate, it will create a plan deficit. Currently the plan has a relatively balanced investment in equity securities, debt instruments and real estate.

Interest rate risk is the risk that bond interest will increase the plan liability; however, this will be partially offset by an increase in the return on the plan's debt investments.

Longevity risk is the risk that the present value of the defined benefit plan liability is calculated by reference to the best estimate of the mortality of plan participants both during and after their employment. An increase in the life expectancy of the plan participants will increase the plan's liability.

Salary risk is the risk that the present value of the defined benefit plan liability is calculated by reference to the future salaries of plan participants. As such, an increase in the salary of the plan participants will increase the plan's liability.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

### 14. POST-EMPLOYMENT BENEFITS - continued

**Net defined benefit liability**

| | December 31 2015 | December 31 2014 |
|---|---|---|
| **Present value of benefit obligations** | | |
| Balance, beginning of year | $ 20,690 | $ 17,953 |
| Employee Contributions | 89 | 100 |
| Current service cost | 544 | 561 |
| Interest cost | 847 | 861 |
| Benefits paid | (397) | (775) |
| Actuarial losses (gains) on experience | (657) | 1,990 |
| Actuarial losses (gains) on financial assumptions | (323) | - |
| Balance, end of year | $ 20,793 | $ 20,690 |
| **Fair value of plan assets** | | |
| Balance, beginning of year | 14,672 | 13,285 |
| Interest income on plan assets | 599 | 618 |
| Gain (losses) on plan assets | (468) | 479 |
| Employee contributions | 89 | 100 |
| Employer contributions | 905 | 1,040 |
| Benefits paid | (360) | (775) |
| Administrative costs | (80) | (75) |
| Balance, end of year | 15,357 | 14,672 |
| Net defined benefit liability | $ 5,436 | $ 6,018 |

The balance of the net defined benefit liability at January 1, 2014 is $4,668,000 which is the opening balance of the December 31, 2014 present value of benefit obligations ($17,953,000) net of the opening balance of the December 31, 2014 fair value of plan asset ($13,285,000).

**Components of benefit plan cost:**

| | December 31 2015 | December 31 2014 |
|---|---|---|
| Current Service cost | 544 | 561 |
| Interest cost | 847 | 861 |
| Interest income on plan asset | (599) | (641) |
| Administrative costs | 80 | 75 |
| Defined benefit expense in Statement of Operations | 872 | 856 |
| Defined contribution expense | 446 | 378 |
| Total benefit expense in Statement of Operations | $ 1,318 | $ 1,234 |

## Yukon Energy Corporation

**Notes to Financial Statements**
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**December 31 2015**

### 14. POST-EMPLOYMENT BENEFITS - continued

| | | |
|---|---|---|
| Actuarial (gains)/losses on obligation | (980) | 1,991 |
| Loss/(gains) on plan assets | 468 | (479) |
| Total re-measurements included in Other Comprehensive Income | (512) | 1,512 |
| Total benefit costs recognized in Statement of Operations and Other Comprehensive Income | 806 | 2,746 |

The fair value of the plan assets is based on market values as reported by the plans' custodians as at each applicable statement of financial position date. The distribution of assets by major asset class is as follows:

| | December 31, 2015 | December 31, 2014 | January 1, 2014 |
|---|---|---|---|
| Equities | 52.4% | 53.1% | 53.1% |
| Fixed income securities | 36.8% | 36.1% | 36.1% |
| Real estate | 10.8% | 10.8% | 10.8% |

**Significant assumptions:**

| | December 31 2015 | December 31 2014 | January 1 2014 |
|---|---|---|---|
| Discount rate - accrued benefit obligation | 4.10% | 4.00% | 4.75% |
| Assumed rate of salary escalation | 3.00% | 3.00% | 3.00% |
| Pension growth | 2.00% | 2.00% | 2.00% |

**Sensitivity analysis:**
The sensitivities of key assumptions used in measuring accrued benefit obligations at each statement of financial position date. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously. The sensitivity analysis has been determined based on reasonably possible changes of the respective assumptions occurring at the end of the reporting period. The mortality assumptions are based on the 2014 Canadian Pensioner Mortality Private Table projected with full generational mortality improvements using scale B.

Assumptions and sensitivity as at December 31, 2015

| Assumption | | +1% | -1% | +1% | -1% |
|---|---|---|---|---|---|
| Discount rate | 4.10% | -14.6% | 18.6% | $ (2,839) | $ 3,617 |
| Salary growth | 3.00% | 3.2% | -3.0% | 616 | (579) |
| Pension growth | 2.00% | 13.7% | -11.4% | 2,678 | (2,220) |
| Life expectancy (1 year movement) | | 2.3% | -2.3% | 446 | (450) |

Assumptions and sensitivity as at December 31, 2014

| Assumption | | +1% | -1% | +1% | -1% |
|---|---|---|---|---|---|
| Discount rate | 4.10% | -15.1% | 19.4% | $ (2,927) | $ 3,761 |
| Salary growth | 3.00% | 3.1% | -2.9% | 601 | (562) |
| Pension growth | 2.00% | 13.6% | -11.2% | 2,637 | (2,171) |
| Life expectancy (1 year movement) | | 2.3% | -2.3% | 446 | (446) |

## Yukon Energy Corporation

**Notes to Financial Statements**
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**December 31 2015**

**14. POST-EMPLOYMENT BENEFITS - continued**

Assumptions and sensitivity as at January 1, 2014

| Assumption | | +1% | -1% | +1% | -1% |
|---|---|---|---|---|---|
| Discount rate | 4.75% | -14.4% | 18.3% | $ (2,457) | $ 3,122 |
| Salary growth | 3.00% | 2.9% | -2.8% | 495 | (478) |
| Pension growth | 2.00% | 12.8% | -10.7% | 2,184 | (1,825) |
| Life expectancy (1 year movement) | | 2.1% | -2.1% | 358 | (358) |

The sensitivity analysis presented above may not be representative of the actual change in the defined benefit obligation as it is unlikely that the change in assumptions would occur in isolation of one another as some of the assumptions may be correlated.

Furthermore, in presenting the above sensitivity analysis, the present value of the defined benefit obligation has been calculated using the projected unit credit method at the end of the reporting period, which is the same that is applied in calculating the defined benefit obligation liability recognized in the statement of financial position.

The Utility pays the balance of the cost of the Plan over the employee contributions, as determined by the actuary. Members are required to contribute 3.5% of earnings up to the Year's Maximum Pensionable Earnings (YMPE) plus 5% of earnings above the YMPE. Permanent part-time members will have required contributions as above multiplied by their permanent part-time service ratio. Employees can make additional contributions to purchase ancillary benefits. Members choose the ancillary benefit on termination of service or on retirement.

The average duration of the benefit obligation is 16.6 years (2014 - 17.3 years, 2013 - 16.4 years).

The Utility expects to make payments of $871,000 to the defined benefit plans during the next financial year.

## Yukon Energy Corporation

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### 15. CONTRIBUTIONS IN AID OF CONSTRUCTION

| | Government of Canada | Parent since 1998 | Customer since 1998 | Yukon Government since 1998 | Pre-1998 contributions | Total |
|---|---|---|---|---|---|---|
| **Cost:** | | | | | | |
| At January 1, 2014 | 71,000 | 73,545 | 23,419 | 10,879 | 1,739 | 180,582 |
| Additions | - | - | 582 | - | - | 582 |
| At December 31, 2014 | 71,000 | 73,545 | 24,001 | 10,879 | 1,739 | 181,164 |
| Additions | - | 18,265 | 578 | 161 | - | 19,004 |
| At December 31, 2015 | 71,000 | 91,810 | 24,579 | 11,040 | 1,739 | 200,168 |
| **Accumulated amortization:** | | | | | | |
| At January 1, 2014 | 2,057 | 5,477 | 6,423 | 1,228 | 1,206 | 16,391 |
| Amortization | 991 | 1,217 | 1,165 | 197 | 43 | 3,613 |
| At December 31, 2014 | 3,048 | 6,694 | 7,588 | 1,425 | 1,249 | 20,004 |
| Amortization | 991 | 1,217 | 1,173 | 200 | 43 | 3,624 |
| At December 31, 2015 | 4,039 | 7,911 | 8,761 | 1,625 | 1,292 | 23,628 |
| **Net book value:** | | | | | | |
| At January 1, 2014 | 68,943 | 68,068 | 16,996 | 9,651 | 533 | 164,191 |
| At December 31, 2014 | 67,952 | 66,851 | 16,413 | 9,454 | 490 | 161,160 |
| At December 31, 2015 | 66,961 | 83,899 | 15,818 | 9,415 | 447 | 176,540 |

The sources of contributions received prior to 1998 were not recorded separately.

### 16. DECOMMISSIONING FUND

| | December 31 2015 | December 31 2014 |
|---|---|---|
| Opening balance | $ 2,586 | $ 2,553 |
| Interest | 26 | 33 |
| Closing balance | $ 2,612 | $ 2,586 |

## Yukon Energy Corporation

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**December 31 2015**

### 17. SALES OF POWER

| | 2015 | 2014 |
|---|---|---|
| Wholesale | $ 29,794 | $ 30,199 |
| Industrial | 4,230 | 4,095 |
| General service | 4,265 | 4,172 |
| Residential | 2,015 | 2,075 |
| Secondary sales | 544 | 410 |
| Sentinel and street lights | 100 | 102 |
| | **$ 40,948** | $ 41,053 |

### 18. OPERATIONS AND MAINTENANCE EXPENSES

| | 2015 | 2014 |
|---|---|---|
| Wages and benefits | $ 5,553 | $ 5,639 |
| Regulatory account expenses (Note 9 (c)) | 7,436 | 5,618 |
| Contractors | 1,826 | 1,551 |
| Materials and consumables | 1,143 | 1,409 |
| Travel | 341 | 458 |
| Rent | 234 | 238 |
| Fuel | 781 | 227 |
| Communication | 62 | 46 |
| | $ 17,376 | $ 15,186 |

### 19. ADMINISTRATION EXPENSES

| | 2015 | 2014 |
|---|---|---|
| Wages and benefits | $ 5,516 | $ 5,549 |
| External labour | 1,094 | 1,385 |
| Insurance and taxes | 1,593 | 1,348 |
| Materials, consumables and general | 849 | 955 |
| Licences and fees | 614 | 581 |
| Travel | 170 | 232 |
| Board fees | 55 | 123 |
| | $ 9,891 | $ 10,173 |

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

### 20. RELATED PARTY TRANSACTIONS

The Utility is related in terms of common ownership to all YG departments, agencies and Crown Corporations. Transactions are entered into in the normal course of operations with these entities. All sales transactions are recorded at the rates approved by the YUB.

Revenue from related parties is included in other revenue on the statement of operations and other comprehensive income. Interim Electrical Rebate program revenues are received from YDC in accordance with terms established by YG which established the program to protect certain ratepayers. These revenues are included in sales of power on the statement of operations and other comprehensive income.

The following table summarizes the Utility's related party transactions for the year:

| | 2015 | 2014 |
|---|---|---|
| **Revenue** | | |
| Sales of service to YDC | $ 14 | $ 65 |
| Program cost reimbursement from YG | 127 | 118 |
| Rate subsidy received from YDC | 274 | 269 |
| Funding from YDC | 6,135 | - |
| **Operating expenses** | | |
| Interest expense on borrowings from YDC | $ 2,964 | $ 4,166 |
| **Other receipts** | | |
| Construction financing from YDC | 11,200 | 16,000 |
| Long-term debt from YDC | 20,984 | - |
| **Other payments** | | |
| Repayment of principal on borrowings from YDC | $ 4,021 | $ 4,021 |
| Repayment of construction financing from YDC | 8,400 | - |

During January 2015 the Utility received an additional $11,200,000 of construction financing relating to a 2014 agreement (included in the above table).

The Utility entered into an agreement with YDC, effective December 29, 2015 to convert $39,200,000 (Note 12) of the construction financing into a capital contribution - $18,265,000 recorded as contributions in aid of construction (Note 15), $4,135,000 funding for feasibility studies which is recorded as funding from YDC (which is included in the above table), $8,400,000 was converted to a short-term loan due December 31, 2016 and $8,400,000 was repaid (included in the above table).

## Yukon Energy Corporation

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**December 31 2015**

**20. RELATED PARTY TRANSACTIONS - continued**

At the end of the year, the amounts receivable from and due to related entities are as follows:

| | December 31 2015 | December 31 2014 | January 1 2014 |
|---|---|---|---|
| YDC | | | |
| Accounts receivable | $ 27 | $ 158 | $ 146 |
| Accounts payable | 128 | - | 130 |
| Construction financing | 23,280 | 42,880 | 32,385 |
| Current portion of long-term debt | 4,860 | 70,911 | 4,021 |
| Long-term debt | 130,957 | 47,942 | 113,347 |
| YG | | | |
| Accounts receivable | $ 823 | $ 649 | $ 402 |
| Accounts payable | 301 | 305 | 2 |

These balances are non-interest bearing and payable on demand except for construction financing and long-term debt.

**Transactions with Key Management Personnel**
The Utility's key management personnel include members of the senior management team and the Board of Directors, a total of 18 individuals (2014 - 16 individuals). Key management personnel compensation is as follows:

| Year ended December 31 | 2015 | 2014 |
|---|---|---|
| Short-term employee benefits | 1,606 | $ 1,535 |
| Post-employment benefits | 55 | 42 |
| Retirement benefits | 18 | 32 |
| | 1,679 | $ 1,609 |

## Yukon Energy Corporation

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**December 31 2015**

### 21. COMMITMENTS

Aishihik water licence
The Yukon Water Board issued a water use licence in 2002, valid until December 31, 2019, for the Utility's Aishihik Lake facility. In addition to maintaining a minimum and maximum water level, this licence commits the Utility to meet a number of future requirements including annual fish monitoring programs.

Fish monitoring programs are also required under an authorization provided by the federal government Department of Fisheries and Oceans, which is valid until December 31, 2019. The costs of meeting these requirements are accounted for as water licence costs in the year they are paid.

**Contractual obligations**
The Utility has entered into contracts to purchase products or services for which the liability has not been incurred as at December 31, 2015 as the product or service had not been provided. The total commitments at year end are $5,712,000 (December 31, 2014 - $10,420,000, January 1, 2014 - $6,730,000).

### 22. CONTINGENCIES

**Aishihik Third Turbine Project**
This project was commissioned into service in December 2011. On March 2, 2012, the general contractor filed a claim with the Supreme Court of Yukon for $4,000,000 plus interest and costs alleging the Utility has not paid for work performed. The Utility has informed the contractor of claims for incomplete contract scope, uncorrected deficiencies and other claims. The outcome of the claim is not determinable at this time and no amount has been recognized in the financial statements.

**Asset Retirement Obligations**
The Utility has not recognized a provision for the closure and restoration obligations for certain generation, transmission and distribution assets which the Utility anticipates maintaining and operating these assets for an indefinite period, making the date of retirement of these assets indeterminate. These significant uncertainties around the timing of any potential future cash outflows are such that a reliable estimate of the liability is not possible at this time. A provision will be recognized when the timing of the retirement of these assets can be reasonably estimated.

### 23. PROVISION FOR ENVIRONMENTAL LIABILITIES

The Utility's activities are subject to various federal and territorial laws and regulations governing the protection of the environment or to minimize any adverse impact thereon. The Utility conducts its operations so as to protect public health and the environment and believes its operations are materially in compliance with all applicable laws and regulations.

The Utility has conducted environmental site assessments at all its diesel plant sites. At sites where environmental contamination was found and a legal obligation to remediate the site existed, the Utility has conducted a full remediation. As at December 31, 2015 no new provisions for environmental liabilities, for which a legal obligation exists to remediate, have been identified by the Utility. The Utility will continue to use its Environmental Management System to monitor and assess previous and potential existing environmental liabilities on an ongoing basis.

## Yukon Energy Corporation

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### 24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

At December 31, 2015, the Utility's financial instruments included cash, accounts receivable, bank indebtedness, accounts payable and accrued liabilities, construction financing, long-term debt and interest rate swaps. The fair value of cash, accounts receivable, bank indebtedness, accounts payable and accrued liabilities and construction financing approximate their carrying value due to the immediate or short-term maturity of these financial instruments.

The long-term debt is accounted for at amortized cost using the effective interest rate method. The fair value of the long-term debt is estimated by discounting the future cash flows using current rates for debt instruments subject to similar risks and maturities as disclosed in Note 13.

The Utility has access to a $10 million line of credit. The account accrues interest on withdrawals at prime rate minus 0.75% per annum.

Interest rate swaps are financial contracts that derive their value from changes in an underlying variable. The Utility's interest rate swaps are classified as held for trading and are recognized at their fair value on the date the contract has been entered into. Any subsequent unrealized and realized gains and losses are reported in net income during the period in which the fair value movement occurred. The fair value of the interest rate swaps is estimated using standard market valuation techniques and is provided to the Utility by the financial institution that is the counterparty to the transactions.

The Utility did not engage in any other hedging transactions.

**Interest rate risk**
Interest rate risk is the risk that future cash flows or fair value of a financial instrument will fluctuate due to changes in market interest rates. The Utility's future cash flows are not exposed to significant interest rate risk due to its long-term debt having fixed interest rates, with the exception of the Bankers' Acceptances from the TD Bank. The Bankers' Acceptances have had the variable rate converted to a fixed rate using an interest rate swap to eliminate the interest rate risk.

As at December 31, 2015, the Utility had an interest rate swap agreement in place with a notional principal amount of $10.0 million (December 31, 2014 - $10.4 million and January 1, 2014 - $10.7 million). The agreement effectively changes the Utility's interest rate exposure on this notional amount from a floating rate to a fixed rate of 2.69%.

The fair value of the interest rate swap agreement on December 31, 2015 was a liability of $553,000 (December 31, 2014 - liability of $213,000 and January 1, 2014 - asset of $430,000). The decrease in the fair value in 2015 of $340,000 (2014 – decrease of $644,000) is recorded on the statement of operations and comprehensive income as an unrealized gain/loss. A 100 basis point increase/decrease in the interest rate assumption would have resulted in an increase/decrease in the interest rate swap agreements fair value of $593,000 (December 31, 2014 - $665,000 and January 1, 2014 - $744,000).

**Credit risk**
Credit risk is the risk of failure of a debtor or counterparty to honour its contractual obligations resulting in financial loss to the Utility.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continued**

The following table illustrates the maximum credit exposure to the Utility if all counterparties defaulted:

| | December 31 2015 | December 31 2014 | January 1 2014 |
|---|---|---|---|
| Cash | $ 1,672 | $ 160 | $ 8,315 |
| Accounts receivable | 6,347 | 7,062 | 8,409 |
| | $ 8,019 | $ 7,222 | $ 16,724 |

Credit risk on cash is considered minimal as the Utility's cash deposits are held by a Canadian Schedule 1 Chartered bank.

Credit risk on accounts receivable is considered minimal as the Utility has experienced insignificant bad debt in prior years. In addition, its primary customer is a rate regulated utility that purchases power from the Utility for resale and as such these receivables are considered fully collectible. Included in the accounts receivable past due but not impaired at December 31, 2015 are $667,000 (December 31, 2014 - $514,000 and January 1, 2014 - $831,000) which are primarily due from related parties which management believes will be received in full.

**Liquidity risk**
Liquidity risk is the risk that the Utility will not be able to meet its financial obligations as they fall due. The Utility manages liquidity risk through regular monitoring of cash and currency requirements by preparing cash flow forecasts to identify financing requirements. The Utility's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Utility's reputation.

The Utility's largest current liability is current portion long-term debt which is predominantly due to the parent, and the Utility has successfully renegotiated this debt in prior years. In addition, rate regulation assists the Utility with liquidity management by providing consistent revenues and a consistent debt to equity ratio.

**Fair values**
The following table illustrates the fair value hierarchy of the Utility's financial instruments as at December 31, 2015:

| | Quoted prices in active markets (Level 1) | Other observable inputs (Level 2) | Unobservable inputs (Level 3) | Total |
|---|---|---|---|---|
| Derivative related liability | - | $553 | - | $553 |
| Long-term debt | | | $149,000 | $149,000 |

## Yukon Energy Corporation

**Notes to Financial Statements**
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**December 31 2015**

### 24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continued

The following table illustrates the fair value hierarchy of the Utility's financial instruments as at December 31, 2014:

| | Quoted prices in active markets (Level 1) | Other observable inputs (Level 2) | Unobservable inputs (Level 3) | Total |
|---|---|---|---|---|
| Derivative related liability | - | $213 | - | $213 |
| Long-term debt | - | - | $136,000 | $136,000 |

The following table illustrates the fair value hierarchy of the Utility's financial instruments as at January 1, 2014:

| | Quoted prices in active markets (Level 1) | Other observable inputs (Level 2) | Unobservable inputs (Level 3) | Total |
|---|---|---|---|---|
| Derivative related asset | | $430 | - | $430 |
| Long-term debt | | - | $136,000 | $136,000 |

### 25. CAPITAL MANAGEMENT

The Utility's capital is its shareholder's equity which is comprised of share capital, contributed surplus and retained earnings. The Utility manages its equity by managing revenues, expenses, assets and liabilities to ensure the Utility effectively achieves its objectives while remaining a going concern.

The Utility monitors its capital on the basis of the ratio of total debt to total capitalization. Debt is calculated as total borrowings, which is comprised of long-term debt, including the portion of long-term debt due within one year. Short term debt related to assets under construction at the balance sheet date is excluded from the calculation of total debt, as the assets are similarly excluded from the determination of rate base. In addition the provision for decommissioning of the Minto Mine spur line has been added (Note 16). Total capitalization is calculated as total debt plus total shareholder's equity as shown on the balance sheet. The Utility maintains a balance in retained earnings as an indicator of the Utility's equity position.

The Utility has a policy which defines its capital structure at a ratio of 60% debt and 40% equity. This policy has been reviewed and accepted by the YUB.

## Yukon Energy Corporation

**Notes to Financial Statements**
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**December 31 2015**

### 25. CAPITAL MANAGEMENT - continued

The table below summarizes the Utility's total debt to total capitalization position:

| | December 31 2015 | December 31 2014 | January 1 2014 |
|---|---|---|---|
| Long-term debt due within one year | $ 6,066 | $ 72,346 | $ 5,406 |
| Long-term debt | 140,874 | 59,065 | 125,906 |
| Total debt | 146,940 | 131,411 | 131,312 |
| Add provision for decommissioning of industrial customer spur line | 2,612 | 2,586 | 2,553 |
| Total debt to include in the calculation | $ 149,552 | $ 133,997 | $ 133,865 |
| Share capital | $ 39,000 | $ 39,000 | $ 39,000 |
| Contributed surplus | 14,600 | 14,600 | 14,600 |
| Retained earnings | 46,303 | 38,076 | 31,929 |
| Total shareholder's equity | 99,903 | 91,676 | 85,529 |
| Total capitalization | $ 249,455 | $ 225,673 | $ 219,394 |
| Total debt to total capitalization | 60 % | 59 % | 61 % |

There were no changes in the Utility's approach to capital management during the period.

### 26. EXPLANATION OF TRANSITION TO IFRS

As stated in Note 2(a), these are the Utility's first financial statements prepared in accordance with IFRS. The accounting policies set out in Note 3 comply with IFRS issued and effective as of December 31, 2015 (or not yet effective but available for early adoption, as in the case of IFRS 14) and have been applied in preparing the financial statements as at and for the year ended December 31, 2015, and December 31, 2014 and in preparing the opening IFRS statement of financial position as at January 1, 2014 (the Utility's date of transition).

IFRS 1 provides specific requirements for an entity's initial adoption of IFRS. In preparing its opening IFRS statement of financial position, the Utility has adjusted amounts reported previously in its financial statements prepared in accordance with previous GAAP. An explanation of how the transition from previous GAAP to IFRSs has affected the Utility's financial position, financial performance and cash flows is set out in the following tables and the notes that accompany the tables.

Pursuant to IFRS 1, the Utility has applied the following relevant mandatory exceptions to retrospective application of IFRS:

## Yukon Energy Corporation

**Notes to Financial Statements**
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**December 31 2015**

**26. EXPLANATION OF TRANSITION TO IFRS - continued**

Estimates

IFRS 1 provides that estimates made in accordance with IFRS at the date of transition shall be consistent with estimates made in accordance with previous GAAP (after adjustment to reflect differences in accounting policies), unless there is objective evidence those estimates were in error. There were no adjustments made to previous GAAP estimates.

In accordance with IFRS 1, the Utility has applied the following voluntary exemptions in the transition from previous GAAP to IFRS:

i) Deemed cost

IFRS 1 allows the Utility to use the previous GAAP carrying value of property, plant and equipment and intangible assets used, or previously used, in operations subject to rate regulation at the transition date as its new "deemed" cost for IFRS. The Utility has elected to apply this exemption to all rate regulated property, plant and equipment and intangible assets and none of these assets required an impairment provision at the transition date.

ii) Exemption for borrowing costs

IFRS 1 allows the Utility to apply the transitional provisions set out in IAS 23, *Borrowing Costs*. The Utility has elected to take the exemption to apply IAS 23 prospectively from the date of transition.

iii) Asset retirement obligations (ARO)

IFRS 1 allows the Utility to avoid retroactively applying the provisions of IAS 37, Provisions, *Contingent Liabilities and Contingent Assets* and IFRIC 1, *Changes in Existing Decommissioning, Restoration and Similar Liabilities*. The Utility has elected to determine the asset retirement obligation liability at the date of transition using current market-based discount rates, discounting the provision back to the date of the original obligation using historical risk-adjusted rates and depreciating the resulting present value from the date of the obligation to the transition date.

iv) Lease arrangements

IFRS 1 allows the Utility to elect to assess all arrangements for leases at the date of transition rather than the inception of the arrangements. The Utility has elected to apply this exemption.

v) Transfers of assets from customers

IFRS 1 allows the Utility to apply the transitional requirements of IFRIC 18, *Transfer of Assets from Customers*, prospectively to transfers from customers received on or after the date of transition. IFRIC 18 provides accounting and income recognition guidance for these transfers. The Utility has elected to apply this exemption.

Differences between the Utility's previous GAAP and its IFRS financial position as at January 1, 2014 and December 31, 2014, its financial performance for the year ended December 31, 2014, and its cash flows for the year ended December 31, 2014, are outlined in the following tables and explanatory notes:

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### 26. EXPLANATION OF TRANSITION TO IFRS - continued

**Reconciliation of the Statement of Financial Position as at January 1, 2014 (Transition Date)**

| | Notes | Previous GAAP | Effect of Transition to IFRS | IFRS |
|---|---|---|---|---|
| **Assets** | | | | |
| **Current** | | | | |
| Cash | | $ 8,315 | - | $ 8,315 |
| Accounts receivable | (b) | 8,415 | (6) | 8,409 |
| Inventories | | 3,222 | - | 3,222 |
| Derivative related asset | | 430 | - | 430 |
| Prepaid expenses | | 672 | - | 672 |
| | | **21,054** | (6) | **21,048** |
| **Non-current** | | | | |
| Deferred uninsured losses | (b) | 330 | (330) | - |
| Property, plant and equipment | (d, e) | 405,798 | (2,784) | 403,014 |
| Intangible assets | (d) | - | 7,683 | 7,683 |
| Deferred charges and intangible assets | (b, d) | 24,749 | (24,749) | - |
| **Total assets** | | **451,931** | (20,186) | **431,745** |
| Regulatory deferral account debit balances | (b, e) | - | 20,186 | 20,186 |
| **Total assets and regulatory deferral account debit balances** | | **$ 451,931** | - | **$ 451,931** |
| **Liabilities** | | | | |
| **Current** | | | | |
| Accounts payable and accrued liabilities | | $ 12,303 | - | $ 12,303 |
| Construction financing | | 20,385 | - | 20,385 |
| Current portion of long-term debt | | 5,406 | - | 5,406 |
| | | **38,094** | - | **38,094** |
| **Non-current** | | | | |
| Long-term construction financing | | 12,000 | - | 12,000 |
| Post-employment benefits | (a) | 1,160 | 3,508 | 4,668 |
| Contributions in aid of construction | (b) | 170,206 | (6,015) | 164,191 |
| Future removal and site restoration costs | (b) | 4,671 | (4,671) | - |
| Decommissioning fund | | 2,553 | - | 2,553 |
| Regulatory hearing reserve | (b) | 106 | (106) | - |
| Diesel contingency fund | (b) | 8,198 | (8,198) | - |
| Long-term debt | | 125,906 | - | 125,906 |
| **Total liabilities** | | **362,894** | (15,482) | **347,412** |
| **Equity** | | | | |
| Share capital | | 39,000 | - | 39,000 |
| Contributed surplus | | 14,600 | - | 14,600 |
| Retained earnings | (a) | 35,437 | (3,508) | 31,929 |
| **Total equity** | | **89,037** | (3,508) | **85,529** |
| **Total liabilities and equity** | | **451,931** | (18,990) | **432,941** |
| Regulatory deferral account credit balances | (b) | - | 18,990 | **18,990** |
| **Total liabilities, equity and regulatory deferral account credit balances** | | **$ 451,931** | - | **$ 451,931** |

## Yukon Energy Corporation

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**December 31 2015**

### 26. EXPLANATION OF TRANSITION TO IFRS - continued

**Reconciliation of the Statement of Financial Position as at December 31, 2014**

| | Notes | Previous GAAP | Effect of Transition to IFRS | IFRS |
|---|---|---|---|---|
| **Assets** | | | | |
| **Current** | | | | |
| Cash | | $ 160 | - | $ 160 |
| Accounts receivable | (b) | 7,081 | (19) | 7,062 |
| Inventories | | 3,065 | - | 3,065 |
| Prepaid expenses | | 719 | - | 719 |
| | | **11,025** | (19) | **11,006** |
| **Non-current** | | | | |
| Deferred uninsured losses | (b) | 300 | (300) | - |
| Property, plant and equipment | (d, e) | 434,435 | (3,149) | 431,286 |
| Intangible assets | (d) | - | 7,248 | 7,248 |
| Deferred charges and intangible assets | (b, d) | 26,707 | (26,707) | - |
| **Total assets** | | **472,467** | (22,927) | **449,540** |
| Regulatory deferral account debit balances | (b, e) | - | 22,927 | 22,927 |
| **Total assets and regulatory deferral account debit balances** | | **$ 472,467** | - | **$ 472,467** |
| **Liabilities** | | | | |
| **Current** | | | | |
| Bank indebtedness | | $ 1,331 | - | $ 1,331 |
| Accounts payable and accrued liabilities | (a) | 14,952 | (35) | 14,917 |
| Construction financing | | 42,880 | - | 42,880 |
| Derivative related liability | | 213 | - | 213 |
| Current portion of long-term debt | (f) | 5,456 | 66,891 | 72,347 |
| | | **64,832** | 66,856 | **131,688** |
| **Non-current** | | | | |
| Post-employment benefits | (a) | 950 | 5,068 | 6,018 |
| Contributions in aid of construction | (b) | 166,913 | (5,753) | 161,160 |
| Future removal and site restoration costs | (b) | 4,671 | (4,671) | - |
| Decommissioning fund | | 2,586 | - | 2,586 |
| Regulatory hearing reserve | (b) | 224 | (224) | - |
| Diesel contingency fund | (b) | 9,627 | (9,627) | - |
| Long-term debt | (f) | 125,955 | (66,891) | 59,064 |
| Total liabilities | | **375,758** | (15,242) | **360,516** |
| **Equity** | | | | |
| Share capital | | 39,000 | - | 39,000 |
| Contributed surplus | | 14,600 | - | 14,600 |
| Retained earnings | (a) | 43,109 | (5,033) | 38,076 |
| **Total equity** | | **96,709** | (5,033) | **91,676** |
| **Total liabilities and equity** | | **472,467** | (20,275) | **452,192** |
| Regulatory deferral account credit balances | (b) | - | 20,275 | 20,275 |
| **Total liabilities, equity and regulatory deferral account credit balances** | | **$ 472,467** | - | **$ 472,467** |

## Yukon Energy Corporation

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### 26. EXPLANATION OF TRANSITION TO IFRS - continued

**Reconciliation of Statement of Operations and Other Comprehensive Income for the year ended December 31, 2014**

| | Notes | Previous GAAP | Effect of Transition to IFRS | Effect of Reclass (Note g) | IFRS |
|---|---|---|---|---|---|
| **Revenue** | | | | | |
| Sales of power | (b) | $ 39,624 | 1,429 | - | $ 41,053 |
| Other | (b) | 340 | 132 | - | 472 |
| | | **39,964** | 1,561 | - | **41,525** |
| **Operating expenses** | | | | | |
| Operations and maintenance | (a,b,e) | 10,057 | 5,129 | - | 15,186 |
| Administration | | 10,173 | - | - | 10,173 |
| Amortization of property, plant and equipment | (b,c,d) | 6,473 | 2,120 | (8,593) | - |
| Amortization of deferred charges | (b,d) | 2,199 | (2,199) | - | - |
| Amortization of intangible assets | (d) | 568 | 410 | (978) | - |
| Amortization and depreciation | | - | - | 9,571 | 9,571 |
| | | **29,470** | 5,460 | - | **34,930** |
| **Income from operations** | | **10,494** | **(3,899)** | - | **6,595** |
| **Other income** | | | | | |
| Allowance for funds used during construction | | 1,188 | - | - | 1,188 |
| Amortization of contributions in aid of construction | (c) | 1,409 | 2,204 | - | 3,613 |
| Interest income | | 113 | - | - | 113 |
| | | **2,710** | 2,204 | - | **4,914** |
| **Other expenses** | | | | | |
| Interest on borrowings | | 4,662 | - | - | 4,662 |
| Unrealized loss (gain) on interest rate swap | | 644 | - | - | 644 |
| Provision for uninsured losses | (b) | 226 | (226) | - | - |
| | | **5,532** | (226) | - | **5,306** |
| **Net income for the year before net movement in regulatory deferral account balances** | | **$ 7,672** | (1,469) | - | **$ 6,203** |
| Net movement in regulatory deferral account balances (b, e) | | - | 1,456 | | 1,456 |
| **Net income for the year after net movements in regulatory deferral account balances** | | **7,672** | (13) | - | **7,659** |
| **Other comprehensive income** | | | | | |
| Remeasurement of defined benefit pension plans | (a) | - | (1,512) | - | (1,512) |
| **Total comprehensive income for the year** | | **$ 7,672** | $ (1,525) | - | **$ 6,147** |

## Yukon Energy Corporation

**Notes to Financial Statements**
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**December 31 2015**

### 26. EXPLANATION OF TRANSITION TO IFRS - continued

**Reconciliation of the Statement of Cash Flows for the year ended December 31, 2014**

| | Notes | Previous GAAP | Effect of Transition to IFRS | IFRS |
|---|---|---|---|---|
| **Operating activities** | | | | |
| Cash receipts from customers | (b) | $ 42,274 | 132 | $ 42,406 |
| Cash receipts from Contributions in aid of construction | (h) | - | 600 | 600 |
| Cash paid to employees and suppliers | (h) | (19,156) | 19,156 | - |
| Cash paid to suppliers | (h) | - | (12,150) | (12,150) |
| Cash paid to employees | (h) | - | (10,621) | (10,621) |
| Interest paid | | (4,663) | - | (4,663) |
| Interest received | | 113 | - | 113 |
| Cash provided by operating activities | | **18,568** | (2,883) | **15,685** |
| **Financing activities** | | | | |
| Receipt of construction financing | | 16,000 | - | 16,000 |
| Repayment of long-term debt | | (5,406) | - | (5,406) |
| Contributions in aid of construction | (b,h) | 732 | (732) | - |
| Cash provided by financing activities | | **11,326** | (732) | **10,594** |
| **Investing activities** | | | | |
| Additions to property, plant and equipment | (d) | (35,249) | 27 | (35,222) |
| Additions to deferred charges and intangible assets | (b,d) | (4,131) | 4,131 | - |
| Additions to intangible assets | (d) | - | (543) | (543) |
| Cash used in investing activities | | **(39,380)** | 3,615 | **(35,765)** |
| **Net decrease in cash** | | (9,486) | - | (9,486) |
| **Cash, beginning of year** | | 8,315 | - | 8,315 |
| **Cash, end of year** | | **$ (1,171)** | - | **$ (1,171)** |

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

### 26. EXPLANATION OF TRANSITION TO IFRS - continued

**Statement of Changes in Equity for the year ended December 31, 2014**
**Yukon Energy Corporation**

**Reconciliation of the Statement of Changes in Equity**
(in thousands of Canadian dollars)

| | Common Stock Number of shares | Share Capital | Contributed Surplus | Retained Earnings | Accumulated other Comprehensive Income | Total Equity |
|---|---|---|---|---|---|---|
| Previous GAAP at January 1, 2014 | 3,900 | 39,000 | 14,600 | 35,437 | | 89,037 |
| Effects of transition to IFRS (Note a) | | | | (3,508) | | (3,508) |
| IFRS at January 1, 2014 | 3,900 | $ 39,000 | $ 14,600 | $ 31,929 | $ - | $ 85,529 |
| Net income for the year after net movement in regulatory deferral account balances | - | - | - | 7,659 | - | 7,659 |
| Other comprehensive income | - | - | - | - | (1,512) | (1,512) |
| Transfer of remeasurement of defined benefit pension plans to retained earnings | - | - | - | (1,512) | 1,512 | - |
| **At December 31, 2014** | **3,900** | $ 39,000 | $ 14,600 | $ 38,076 | $ - | $ 91,676 |

**Notes to the Reconciliations**

The following material adjustments were made to previous GAAP balances to arrive at the IFRS financial statements:

**a) Post-employment benefits**

Under previous GAAP, subject to certain criteria, the Utility would defer and amortize unrealized actuarial gains and losses into wages and benefits expense using the corridor method. Under IFRS, unrealized actuarial gains and losses are recognized in other comprehensive income and the Utility has elected to immediately transfer these amounts to retained earnings within equity. As a result, post-employment benefits increased and retained earnings decreased by $5,020,000 at December 31, 2014 (January 1, 2014 - $3,435,000) and other comprehensive income decreased in fiscal 2014 by $1,512,000 for the unrealized actuarial losses. In addition, in fiscal 2014, operations and maintenance - wages and benefits expense increased $73,000 to derecognize the actuarial gains and losses recognized under the corridor method.

Under previous GAAP, the Utility recognized a transitional asset related to the initial adoption of the standard, which was being amortized over the average remaining service period of active employees. IFRS does not recognize these transitional assets. As a result, post-employment benefits increased and retained earnings decreased by $13,000 at December 31, 2014 (January 1, 2014 - $73,000) and operations and maintenance - wages and benefits expense decreased by $60,000 to derecognize the amortization of the transition asset recognized in fiscal 2014.

In addition, as at December 31, 2014, accounts payable and accrued liabilities decreased and post-employment benefits increased by $35,000.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**26. EXPLANATION OF TRANSITION TO IFRS - continued**

**b) Regulatory deferral accounts**

As discussed in Note 2(c), the Utility elected to adopt IFRS 14, *Regulatory Deferral Accounts* at the transition date. Under IFRS 14, regulatory deferral account balances are combined and separately presented from assets, liabilities, income and expenses. Specifically, all regulatory assets under previous GAAP are combined and reported as regulatory deferral account debit balances under IFRS and all regulatory liabilities under previous GAAP are combined and reported as regulatory deferral account credit balances under IFRS.

Under previous GAAP, cash/contributions received and cost incurred were netted against the regulatory deferral account. In addition, the amortization of the deferral accounts was presented as amortization of deferred charges. Under IFRS, the cash/contributions received are to be presented as revenue and the costs incurred are to be presented as expenses. Under IFRS, all changes in regulatory deferral account balances, including the amortization of deferred charges, is included in net movement in regulatory deferral account balances related to net income.

IFRS 14 impacted the following accounts:
Fuel price adjustment
As at December 31, 2014, accounts receivable decreased and regulatory deferral account debit balances increased by $19,000 (January 1, 2014 - $6,000) related to the fuel price adjustment. In addition, operations and maintenance - regulatory account expenses increased for costs incurred and net movement in regulatory deferral account balances related to net income increased by $13,000 for fiscal 2014.

Deferred uninsured losses
As at December 31, 2014, deferred uninsured losses decreased and regulatory deferral account debit balances increased by $300,000 (January 1, 2014 - $330,000). In addition, operations and maintenance - regulatory account expenses increased by $196,000 for costs incurred, the provision for uninsured losses decreased by $226,000 and net movement in regulatory deferral account balances related to net income decreased by $30,000 for fiscal 2014.

Deferred charges and intangible assets
As at December 31, 2014, deferred charges and intangible assets decreased and regulatory deferral account debit balances increased by $21,665,000 (January 1, 2014 - $19,591,000) related to feasibility studies, IFRS planning, regulatory costs, vegetation management and dam safety. In addition, other revenue increased by $132,000 for contributions received, operations and maintenance - regulatory account expenses increased by $4,293,000 for costs incurred, operations and maintenance - contractors expense decreased by $502,000 for regulatory provision, amortization of deferred charges decreased by $1,585,000 and net movement in regulatory deferral account balances related to net income increased by $2,074,000 for fiscal 2014. For the statement of cash flows for the year ended December 31, 2014, contributions in aid of construction decreased and cash receipts from customers increased by $132,000 for the amounts received during the year (Note 9). Also the additions to deferred charges and intangible assets decreased by $4,131,000 and cash paid for additions to intangible assets increased by $516,000 and the cash paid to suppliers increased by $3,615,000 (for the deferred charges).

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**26. EXPLANATION OF TRANSITION TO IFRS - continued**

**b) Regulatory deferral accounts - continued**

Contributions in aid of construction
As at December 31, 2014, contributions in aid of construction decreased and regulatory deferral account credit balances increased by $5,753,000 (January 1, 2014 - $6,015,000) related to the deferred insurance proceeds. In addition, amortization of property, plant and equipment and net movement in regulatory deferral account balances related to net income increased by $262,000 for fiscal 2014.

Future removal and site restoration costs
As at December 31, 2014, future removal and site restoration costs decreased and regulatory deferral account credit balances increased by $4,671,000 (January 1, 2014 - $4,671,000).

Regulatory hearing reserve
As at December 31, 2014, regulatory hearing reserve decreased and regulatory deferral account credit balances increased by $224,000 (January 1, 2014 - $106,000). In addition, operations and maintenance - regulatory account expenses increased by $432,000 for cost incurred, amortization of deferred charges decreased by $550,000, and net movement in regulatory deferral account balances related to net income decreased by $118,000 for fiscal 2014.

Diesel contingency fund
As at December 31, 2014, diesel contingency fund decreased and regulatory deferral account credit balances increased by $9,627,000 (January 1, 2014 - $8,198,000). In addition, sales of power increased and net movement in regulatory deferral account balances related to net income decreased by $1,429,000 related to cash received for fiscal 2014.

**c) Amortization of contributions in aid of construction**

Under previous GAAP, amortization of contributions from customers and the Government of Canada were netted on the statement of operations and other comprehensive income against amortization of property, plant and equipment. Under IFRS, amortization of contributions in aid of construction is to be presented as revenue and cannot be netted against amortization of property, plant and equipment. As a result, an adjustment has been made to increase revenues for amortization of contributions in aid of construction and increase the expense for amortization of property, plant and equipment by $2,204,000 for the year ended December 31, 2014.

**d) Intangible assets**

Under previous GAAP, certain mainframe and other software costs were included in property, plant and equipment. Under IFRS, software costs are included in intangible assets. As a result, at December 31, 2014, property, plant and equipment decreased and intangible assets increased by $2,206,000 (January 1, 2014 - $2,525,000). For the year ended December 31, 2014, the amortization of property, plant and equipment decreased and amortization of intangible assets increased by $346,000. For the statement of cash flows for the year ended December 31, 2014, cash paid for additions to property, plant and equipment decreased and the cash paid for additions to intangible assets increased by $27,000. There were no adjustments to the amortization periods.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**26. EXPLANATION OF TRANSITION TO IFRS - continued**

**d) Intangible assets - continued**

Under previous GAAP, deferred customer service costs and licencing costs were included in deferred charges and intangible assets. Under IFRS, the deferred customer service costs and licencing costs are presented only as intangible assets. As a result, at December 31, 2014, deferred charges and intangible assets decreased and intangible assets increased by $5,042,000 (January 1, 2014 - $5,158,000). For the year ended December 31, 2014, the amortization of deferred charges decreased and amortization of intangible assets increased by $64,000 related to the amortization of the deferred customer service costs. As noted in b) for the statement of cash flows for the year ended December 31, 2014 the cash paid for additions to intangible assets increased by $516,000. Total cash paid for additions to intangible assets is $543,000.

**e) Deferred overhauls**

Under previous GAAP, the Utility deferred all overhaul costs incurred after 2011 within construction work-in-progress as part of property, plant and equipment. As a result, AFUDC continued to be applied to these deferred overhauls and depreciation was not taken. Under IFRS, the deferred overhauls are to be included in property, plant and equipment and depreciated through net income when the overhaul is available for use. AFUDC would cease when the overhaul is substantially ready for its intended purpose. As a result, at December 31, 2014, regulatory deferral account debit balances increased and property, plant and equipment decreased by $943,000 (January 1, 2014 - $259,000). For the year ended December 31, 2014, operations and maintenance - regulatory account expenses and net movement in regulatory deferral account balances related to net income increased by $684,000 related to depreciation and AFUDC incurred during the year.

**f) Long-term debt**

Under previous GAAP, EIC 122 *Balance sheet classification of callable debt obligations and debt obligations expected to be refinanced* permitted the classification of long-term debt due within one year to be presented as non-current if, at the date of the financial statement preparation, a new financing agreement had been entered into. As a result, the Utility presented the refinanced long-term debt under previous GAAP as non-current. Under IFRS, an entity is permitted to present the long-term debt due within one year as non-current if, at the financial statement date, the entity had full discretion to renegotiate the debt. As the Utility did not have full discretion to refinance the long-term debt, the refinanced long-term debt cannot be recognized. As a result, the current portion of long-term debt increased and long-term debt decreased by $66,891,000 for the year ended December 31, 2014.

**g) Presentation of expenses**

IFRS states that expenses shall be classified on the statement of operations and other comprehensive income by either nature or function. Under previous GAAP, the Utility presented costs and expenses in a combination of both nature and function. The Utility has elected to present costs and expenses on the statement of operations and other comprehensive income by function and to disclose the expenses by nature in the notes to the financial statements.

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**26. EXPLANATION OF TRANSITION TO IFRS - continued**

The reconciliation of the operations and maintenance and administration notes from previous GAAP to IFRS is as follows:

**Operations and maintenance expenses**

| | Notes | Previous GAAP | Effect of Transition to IFRS | Effect of Reclass (Note g) | IFRS |
|---|---|---|---|---|---|
| Wages and benefits | (a) | $ 5,626 | 13 | $ - | $ 5,639 |
| Maintenance | | | | | |
| -lines and substations | | 1,345 | - | (1,345) | - |
| -hydro, diesel and wind | | 1,596 | - | (1,596) | - |
| -building and vehicles | | 1,102 | - | (1,102) | - |
| Fuel | | 227 | - | - | 227 |
| Water level measurement | | 161 | - | (161) | - |
| Regulatory account expense | (b,e) | - | 5,618 | - | 5,618 |
| Contractors | (b) | - | (502) | 2,053 | 1,551 |
| Materials and consumables | | - | - | 1,409 | 1,409 |
| Travel | | - | - | 458 | 458 |
| Rent | | - | - | 238 | 238 |
| Communication | | - | - | 46 | 46 |
| | | $ 10,057 | $ 5,129 | $ - | $ 15,186 |

**Administration expenses**

| | Previous GAAP | Effect of Reclass (Note g) | IFRS |
|---|---|---|---|
| Wages and benefits | $ 5,549 | $ - | $ 5,549 |
| Insurance and taxes | 1,348 | - | 1,348 |
| General office | 1,167 | (1,167) | - |
| Information systems | 736 | (736) | - |
| Environmental | 528 | (528) | - |
| Training, recruitment and development | 348 | (348) | - |
| Board of Directors | 255 | (255) | - |
| Regulatory loss | 120 | (120) | - |
| Material management and contracting | 62 | (62) | - |
| Intercompany services | 60 | (60) | - |
| External labour | - | 1,385 | 1,385 |
| Materials, consumables and general | - | 955 | 955 |
| Licences and fees | - | 581 | 581 |
| Travel | - | 232 | 232 |
| Board fees | - | 123 | 123 |
| | $ 10,173 | $ - | $ 10,173 |

## Yukon Energy Corporation

**Notes to Financial Statements**
(tabular amounts in thousands of Canadian dollars)

**December 31 2015**

**26. EXPLANATION OF TRANSITION TO IFRS - continued**

**h) Statement of Cash Flows**

Under previous GAAP, the cash paid to employees and suppliers are combined. Under IFRS, the cash paid to employees and suppliers are disclosed separately. As a result, the cash paid to employees and suppliers decreased by $19,156,000 cash paid to employees increased by $10,621,000 and cash paid to suppliers increased by $8,535,000 for the year ended December 31, 2014. As noted in b) for the statement of cash flows for the year ended December 31, 2014 the cash paid to suppliers increased by $3,615,000. Total cash paid to suppliers was $12,150,000.

Under previous GAAP, the cash contributions in aid of construction received during the year were presented as a financing activity. However, under IFRS, these contributions do not meet the definition of a financing activity and have been presented as an operating activity. As a result, contributions in aid of construction decreased and cash receipts from contributions in aid of construction increased by $600,000.

**YUKON ENERGY CORPORATION**
**UTILITY INCOME AND RATE OF RETURN**
**For The Year Ended December 31**
**($000s)**

| **Utility Revenue** | **2015** |
|---|---|
| Utility Electric Sales | 41,655 |
| Other Revenue | 200 |
| Total | 41,855 |
| **Utility Expense** | |
| Labour | 11,068 |
| Non-Labour | |
| Operations and Maintenance | 4,228 |
| Administration | 2,585 |
| Insurance | 1,030 |
| Donations | 86 |
| Fuel | 2,720 |
| Purchased Power | 36 |
| Total Operating and Maintenance Costs | 21,753 |
| Depreciation & Amortization | |
| Fixed Asset Depreciation | 9,792 |
| Amortization of Deferred Costs (incl. RFID) | 2,991 |
| Amortization of Contribution for Extensions | (3,624) |
| Amortization of Fire Insurance Gain | (262) |
| Other Taxes | 473 |
| Total Expenses | 31,123 |
| Less: Donations | 86 |
| Disallowed Depreciation | 4 |
| Total | 31,033 |
| **Utility (Regulatory) Income** | 10,822 |
| **Net Rate Base** | 239,462 |
| **Rate Of Return on Capital** | 4.52% |
| *Rate of Return on Equity* | 8.14% |
| *Cost of Debt* | 2.00% |

**YUKON ENERGY CORPORATION**
**COMPUTATION OF NET RATE BASE**
**For The Year Ended December 31**
**($000s)**

| | | 2015 |
|---|---|---|
| Property, Plant and Equipment | | 577,888 |
| Less: | Work in progress (includes deferred cost WIP) | 32,430 |
| | Accumulated Depreciation | 130,611 |
| | Reserve for Future Removal and Site Restoration | 4,367 |
| | Deferred Fire Gain | 5,490 |
| | Customer Contributions (excluding for WIP) | 175,935 |
| Subtotal | | 229,054 |
| Add: | Deferred Study, Relicencing & Regulatory Costs | 20,874 |
| | Accumulated Disallowed Depreciation | 102 |
| Less: | Disallowed Assets | 200 |
| | Reserve for Injuries and Damages | (267) |
| Net balance at year end | | 250,097 |
| Mid-year balance | | 233,205 |
| Add: | Allowance for Working Capital | 4,647 |
| | Mid-Year Rate Case Expense | 1,610 |
| Net Rate Base | | 239,462 |

**YUKON ENERGY CORPORATION**
**WORKING CAPITAL CALCULATION**
**For The Year Ended December 31**
**($000s)**

| Working Capital | 2015 |
|---|---|
| Operation and Maintenance | 19,779 |
| Add: Other Taxes | 473 |
| Less: Donations and Disallowed expenses | 86 |
| Allowable Operating Expense | 20,166 |
| Allowance: Operating Expense (27/365 * Allowable Operating Expense) | 1,492 |
| Three Year Average Inventory | 3,300 |
| GST Impact | (145) |
| Total Working Capital | 4,647 |

**YUKON ENERGY CORPORATION**
**RECONCILIATION OF UTILITY INCOME TO NET EARNINGS**
**For The Year Ended December 31**
**($000s)**

| | **2015** |
|---|---|
| Utility Income | 10,822 |
| Add Non Utility Income: | |
| Allowance for Funds Used During Construction | 714 |
| Other Income | - |
| Sub-Total | 11,536 |
| Less Non Utility Expenses: | |
| Long Term Interest | 3,322 |
| Other Interest | 337 |
| Capital Lease Interest | - |
| Donations | 86 |
| Disallowed Expenses | 71 |
| Disallowed Depreciation | 4 |
| Net Earnings | 7,716 |

**YUKON ENERGY CORPORATION**
**SUMMARY OF CAPITAL ASSETS**
**For The Year Ended December 31**
**($000s)**

| | 2015 |
|---|---|
| **Capital Assets** | |
| Land | 1,673 |
| Hydroelectric and Thermal Plants | 336,152 |
| Transmission | 180,671 |
| Distribution | 15,367 |
| Buildings, Office and General Equipment | 26,112 |
| Transportation | 4,561 |
| Construction Work-in-Progress | 13,352 |
| Cost | 577,888 |
| Less: Accumulated Depreciation | 130,611 |
| Net Book Value | 447,277 |
| Less: Net Contribution for Extensions | 175,935 |
| Net Capital Assets | 271,341 |

**YUKON ENERGY CORPORATION**
**COST OF CAPITAL CALCULATION**
**For The Year Ended December 31**
**(%)**

| 2015 | Capital Ratio | Cost | Return Component |
|---|---|---|---|
| Mid-year Long Term Debt | 59.0 | 2.00 | 1.181 |
| Mid-year Common Equity | 41.0 | 8.14 | 3.338 |
| | 100.0 | | 4.52 |

# YUKON ENERGY CORPORATION

## BOARD OF DIRECTORS AND OFFICERS

**(as at December 31, 2015)**

| DIRECTORS | |
|---|---|
| **GEORGINA LESLIE**<br>Whitehorse, YT | **ERIN STEHELIN**<br>Whitehorse, YT |
| **JOANNE FAIRLIE**<br>Whitehorse, YT | **SUSAN CRAIG**<br>Whitehorse, YT |
| **KELLS BOLAND, Chair**<br>Carcross, YT | **GLENN HART**<br>Marsh Lake, YT |
| **WENDY SHANKS**<br>Whitehorse, YT | **CAM MALLOCH**<br>Whitehorse, YT |
| **CLINT MCCUAIG**<br>Haines Junction, YT | **CURTIS SHAW**<br>Whitehorse, YT |
| **OFFICERS** | |
| **ANDREW HALL**<br>President and CEO | **ED MOLLARD**<br>Chief Financial Officer |
| **KELLY POLLARD**<br>Corporate Secretary | |

https://sp2010.yec.yk.ca/Departments/President/CorporateSecretary/YUB/AnnualFilings

# TAB 10
# ORDERS IN COUNCIL

# YUKON

# CANADA

ORDER-IN-COUNCIL 2014/ 23

PUBLIC UTILITIES ACT

Pursuant to subsection 17(1) of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows

1 The annexed *2014 Direction Amending the Rate Policy Directive (1995)* (O.I.C. 1995/090) is made.

Dated at Whitehorse, Yukon,
February 14 2014.

# YUKON

# CANADA

DÉCRET 2014/23

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

Conformément au paragraphe 17(1) de la *Loi sur les entreprises de service public*, le commissaire en conseil exécutif ordonne ce qui suit :

1 Est établie l'*Instruction de 2014 modifiant les Instructions sur la politique tarifaire (1995)* (*Décret 1995/090*) paraissant en annexe.

Fait à Whitehorse, au Yukon,
le 14 Février 2014.

Commissioner of Yukon/Commissaire du Yukon

R-PUA-IndRates-14-FIN

2014/23

PUBLIC UTILITIES ACT

2014 DIRECTION AMENDING THE RATE POLICY DIRECTIVE (1995)

1 This Direction amends the *Rate Policy Directive (1995)*.

2 In subsections 2.1(3) and 6(3), the expression "December 31, 2013" is replaced with the expression "December 31, 2018".

LOI SUR LES ENTREPRISES DE SERVICES PUBLICS

INSTRUCTION DE 2014 MODIFIANT LES INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

1 La présente instruction modifie les *Instructions sur la politique tarifaire (1995)*.

2 Aux paragraphes 2.1(3) et 6(3) l'expression « 31 décembre 2013 » est abrogée et remplacée par l'expression : « 31 décembre 2018 ».

| | |
|---|---|
| **YUKON** | **YUKON** |
| **CANADA** | **CANADA** |
| ORDER-IN-COUNCIL 2012/ 68 | DÉCRET 2012/ 68 |
| PUBLIC UTILITIES ACT | LOI SUR LES ENTREPRISES DE SERVICE PUBLIC |
| Pursuant to subsection 17(1) of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows | Conformément au paragraphe 17(1) de la *Loi sur les entreprises de service public*, le commissaire en conseil exécutif ordonne ce qui suit : |
| **1** The annexed *Direction Amending the Rate Policy Directive (1995)* (O.I.C. 1995/090) is made. | **1** Est établie l'*Instruction modifiant les Instructions sur la politique tarifaire (1995)* (*Décret 1995/090*), paraissant en annexe. |
| Dated at Whitehorse, Yukon, 26 April 2012. | Fait à Whitehorse, au Yukon, le 26 avril 2012. |

Commissioner of Yukon/Commissaire du Yukon

R-PUA-IndRates-12-FIN

2012/68

PUBLIC UTILITIES ACT

DIRECTION AMENDING THE RATE POLICY DIRECTIVE (1995)

1 This Direction amends the ***Rate Policy Directive (1995)***.

**2 Section 2.1 is replaced with the following**

"Retail and major industrial rate adjustments

2.1(1) The Board must ensure that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and, subject to subsection (2), to the class of major industrial customers.

(2) If the rates charged to retail customers for all or any part of 2012 are to be increased , then for that same period the greater of that increase and the percentage increase approved in Board Order 2011-14 is to apply to the class of major industrial customers.

(3) This section expires on December 31, 2013."

**3 Subsection 6(3) is replaced with the following**

"(3) Despite subsection (1), the Board must ensure that the rates charged to major industrial customers until December 31, 2013 conform to Rate Schedule 39, Industrial Primary, attached hereto as Schedule A, except that section 2.1 prevails over that Rate Schedule to the extent of any inconsistency."

LOI SUR LES ENTREPRISES DE SERVICES PUBLICS

INSTRUCTION MODIFIANT LES INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

1 La présente instruction modifie les ***Instructions sur la politique tarifaire (1995)***.

**2 L'article 2.1 est remplacé par ce qui suit :**

« Ajustements tarifaires pour les clients au détail et industriels majeurs

2.1(1) La Commission veille à ce que les ajustements tarifaires pour les clients au détail et industriels majeurs s'appliquent de façon uniforme en pourcentage à toutes les catégories de clients au détail et, sous réserve du paragraphe (2), à toutes les catégories de clients industriels majeurs.

(2) Lorsque les tarifs facturés aux clients au détail pour la totalité ou une partie de 2012 doivent faire l'objet d'une augmentation, ne s'applique à la catégorie de clients industriels majeurs pour cette même période, que le plus élevé entre cette augmentation et le pourcentage de l'augmentation, approuvés dans l'ordonnance de la Commission 2011-14.

(3) Le présent article vient à échéance le 31 décembre 2013. »

**3 Le paragraphe 6(3) est remplacé par ce qui suit :**

« (3) Malgré le paragraphe (1), la Commission veille à ce que les tarifs facturés aux clients industriels majeurs jusqu'au 31 décembre 2013 respectent l'annexe tarifaire n° 39, Clients industriels, paraissant à l'annexe A, sauf l'article 2.1 qui a préséance sur cette annexe tarifaire dans la mesure de leur incompatibilité. »

**YUKON**

**CANADA**

Whitehorse, Yukon

ORDER-IN-COUNCIL 2008/149

PUBLIC UTILITIES ACT

Pursuant to section 17 of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows

1 The annexed Directive to amend the *Rate Policy Directive (1995)* is hereby made.

Dated at Whitehorse, Yukon, this October 3 2008.

**YUKON**

**CANADA**

Whitehorse, Yukon

DÉCRET 2008/ 149

LOI SUR LES ENTREPRISES DE SERVICES PUBLICS

Le commissaire en conseil exécutif, conformément à l'article 17 de la *Loi sur les entreprises de service public*, décrète :

1 Sont établies *les Instructions modifiant les Instructions sur la politique tarifaire (1995)* paraissant en annexe.

Fait à Whitehorse, au Yukon, le 3 octobre 2008.

Administrator of Yukon/Administrateur du Yukon

Directive amending the Rate Policy Directive (1995).doc

PUBLIC UTILITIES ACT

DIRECTIVE TO AMEND THE RATE POLICY DIRECTIVE (1995)

1 This Directive amends the *Rate Policy Directive (1995)*.

2 The following section is added immediately after section 2 of the said Directive.

"**Retail rate adjustments**

**2.1**(1) The Board must ensure that rate adjustments for retail customers apply equally, when measured as percentages, to all classes of retail customers.

(2) This section expires on December 31, 2012."

LOI SUR LES ENTREPRISES DE SERVICES PUBLICS

INSTRUCTIONS MODIFIANT LES INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

1 Les présentes instructions modifient les *Instructions sur la politique tarifaire (1995)*.

2 L'article suivant est ajouté après l'article 2 des mêmes instructions.

« **Ajustements des tarifs de détail**

**2.1**(1) La Commission s'assure que les ajustements tarifaires pour les clients au détail s'appliquent uniformément en termes de pourcentage à toutes les catégories de clients au détail.

(2) Le présent article vient à échéance le 31 décembre 2012. »

**YUKON**

**CANADA**

Whitehorse, Yukon

ORDER-IN-COUNCIL 2007/94

PUBLIC UTILITIES ACT

Pursuant to section 17 of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows

**1** The annexed *Major Industrial Customer Rate Directive* is hereby made.

Dated at Whitehorse, Yukon,
this 04 June 2007.

**YUKON**

**CANADA**

Whitehorse, Yukon

DÉCRET 2007/94

LOI SUR LES ENTREPRISES DE SERVICES PUBLICS

Le commissaire en conseil exécutif, conformément à l'article 17 de la *Loi sur les entreprises de services publics*, décrète :

**1** Les *Instructions sur les clients industriels majeurs* paraissant en annexe sont établies

Fait à Whitehorse, au Yukon,
le 4 juin 2007.

Commissioner of Yukon/Commissaire du Yukon

OIC2007-94 Industrial primary rate directive .doc

2007/94

**PUBLIC UTILITIES ACT**

**MAJOR INDUSTRIAL CUSTOMER DIRECTIVE**

**1 This order amends the Rate Policy Directive (1995).**

**2 The following subsection is added immediately after subsection 6(2) of the said Directive.**

**“**(3) Despite subsection (1), the Board must ensure that the rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to Rate Schedule 39, Industrial Primary, attached hereto as Schedule A.**”**

**3 This Order expires on January 1, 2013.**

**LOI SUR LES ENTREPRISES DE SERVICES PUBLICS**

**RÈGLEMENT SUR LES INSTRUCTIONS SUR LES CLIENTS INDUSTRIELS MAJEURS**

**1 Le présent décret modifie les Instructions sur la politique tarifaire (1995).**

**2 L’article 6 est modifié par adjonction, après le paragraphe (2), de ce qui suit :**

**«** (3) Malgré le paragraphe (1), la Commission veille à ce que les tarifs facturés aux clients industriels majeurs du 1$^{er}$ janvier 2008 au 31 décembre 2012 respectent l’annexe tarifaire n$^{o}$ 39, Clients industriels, paraissant à l’annexe A. **»**

**3 Le présent décret expire le 1$^{er}$ janvier 2013.**

2007/94

SCHEDULE A

INDUSTRIAL PRIMARY

RATE SCHEDULE 39

**Available**

Throughout the service areas of Yukon Energy Corporation (**"YEC"**) and The Yukon Electrical Company Limited ("**YECL**") served by the Whitehorse-Aishihik-Faro and Mayo-Dawson systems.

**Applicable**

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

**Rate**

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

(a) Demand Charge of $15.00/kV.A of Billing Demand

(b) Energy Charge of 7.60¢/kW.h for all energy used.

(c) Fixed Charge

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

**Peak shaving credit**

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

**Minimum Monthly Bill**

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

**Peak Shaved Load**

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

**Billing Demand**

The Billing Demand shall be the greater of:

(a) the highest metered kV.A demand recorded in the current billing month; or

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

(c) the contract minimum demand.

**Winter Contract Load**

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

(a) the customer will thereby contract with YEC not to exceed the nominated Winter Contract Load whenever the temperature at Whitehorse is below -30 degrees Centigrade, based on YEC informing the customer by phone, fax or e-mail as to forecast and actual winter temperatures at Whitehorse as provided for in paragraph (b);

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

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

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

**Base Load Energy**

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

**Rate Modifications Applicable:**

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

***Electric Service Regulations*:**

The *Electric Service Regulations* approved by the Yukon Utilities Board form part of this rate schedule and apply to YEC and every customer supplied with electric service by YEC in the Yukon Territory. Copies of the *Electric Service Regulations* are available for inspection in the offices of YEC during normal working hours.

**Escalation of demand and energy charges**

Demand and Energy charges for the directed changes are to be escalated once each calendar year, starting January 1, 2010, based on the latest percentage increase in the 12 month implicit chain price index for gross domestic product at market prices for Canada as reported by Statistics Canada.

**Adjustment of fixed charge**

The Fixed Charge is to be adjusted to provide for fixed monthly charges as set out in any Power Purchase Agreement, or amendments thereto, between a Major Industrial Customer and either Yukon Energy Corporation or the Yukon Electrical Company Limited, as approved by the Board.

ANNEXE A

CLIENTS INDUSTRIELS

ANNEXE TARIFAIRE N$^{o}$ 39

**Offert**

Dans l'ensemble des régions desservies par la Société d'énergie du Yukon (« **SEY** ») et la Yukon Electrical Company Limited («**YECL** »), desservie par les systèmes de Whitehorse-Aishihik-Faro et Mayo-Dawson.

**Applicable**

À tous les clients industriels majeurs dont les activités sont la fabrication, le traitement ou l'exploitation d'une mine dont l'approvisionnement en électricité excède 1000 kW.

**Tarif**

Les tarifs facturés pour un mois de facturation sont la somme de ce qui suit :

a) une prime de puissance de 15.00 $/kVA de la demande facturée;

b) le coût de l'énergie établi à 7,60¢/kWh pour toute l'énergie consommée;

c) des frais fixes

Pour l'approvisionnement du site de la mine Minto, les frais fixes sont égaux aux paiements exigés en vertu de la convention d'achat intitulée *Power Purchase Agreement* (la « **PPA** »), avec ses modifications, datée du 14 mai 2007, conclue entre YEC et Minto Explorations Ltd. («**Minto** ») pour la contribution mensuelle des coûts d'investissement pour le branchement de l'approvisionnement de la mine.

**Crédit d'écrêtement de la demande de pointe**

Pour les clients dont la charge hivernale maximale est en règle, le crédit d'écrêtement de la demande de pointe de chaque mois de facturation représente 50 % de la prime de puissance multipliée par la charge réduite pour la demande de pointe.

**Facture mensuelle minimale**

La facture mensuelle minimale est égale au total de la prime de puissance et des frais fixes mensuels, desquels est soustrait tout crédit d'écrêtement de la demande de pointe.

**Charge réduite pour la demande de pointe**

La charge réduite pour la demande de pointe pour un mois de facturation, représente la différence entre la charge hivernale maximale et la demande facturée pour le mois.

**Demande facturée**

La demande facturée est le montant le plus élevé de :

a) la demande la plus élevée en kVA enregistrée au cours du mois de facturation courant;

b) la demande la plus élevée en kVA enregistrée au cours des 12 derniers mois, y compris le mois de facturation courant, mais à l'exclusion des mois d'avril à septembre;

(c) la demande minimale fixée par contrat.

**Charge hivernale maximale**

Un client peut, en donnant un préavis de six mois à la SEY, adopter une charge hivernale maximale qui représente au moins deux tiers de la demande maximale du client fixée par contrat, sous réserve des conditions suivantes :

a) le client s'engage envers la SEY à ne pas excéder la charge hivernale maximale adoptée lorsque la température à Whitehorse est inférieure à -30 degrés Celsius d'après les renseignements fournis au client par la SEY par téléphone, télécopieur ou courriel relativement aux prévisions météorologiques et la température hivernale véritable à Whitehorse, en conformité avec l'alinéa b);

b) YEC s'engage à informer le client au moins une heure à l'avance et au plus une journée à l'avance, si les prévisions météorologiques pour Whitehorse sont inférieures à -30 degrés Celcius. Dès lors et jusqu'à ce que la SEY l'avise du contraire, il incombe au client de veiller à ce que les kVA mesurés au compteur n'excèdent pas la charge hivernale au cours d'une heure pendant laquelle la température véritable à Whitehorse est inférieure à -30 degrés Celcius. La SEY informera immédiatement le client lorsque les prévisions météorologiques pour Whitehorse ne sont plus inférieures à -30 degrés Celcius pour les prochaines 24 heures;

c) le client consent à ce que le contrat relatif à la charge hivernale maximale demeure en vigueur jusqu'à ce qu'il soit annulé par le client avec un préavis écrit d'au mois 12 mois à la SEY;

d) si au cours de la période fixée par contrat pour la charge hivernale maximale, la demande en kVA mesurée au compteur du client excède la charge hivernale maximale, alors qu'un avis a été donné par la SEY en conformité avec l'alinéa b) et que la température à Whitehorse est inférieure à -30 degrés Celcius, le contrat relatif à la charge hivernale maximale est immédiatement résilié. Le client est dès lors tenu de rembourser immédiatement à la SEY tous les crédits d'écrêtement de la demande de pointe accordés au cours des 12 derniers mois de facturation, ainsi que qu'une pénalité pour le mois courant qui représente quatre fois la prime de puissance sur la demande du client en kVA mesurée au compteur qui excède la charge hivernale maximale. De plus, la SEY se réserve le droit, si cela est nécessaire pour satisfaire aux besoins du système lorsque la température à Whitehorse est inférieure à -30 degrés Celcius au cours du mois alors en cours et les 12 mois suivants, d'interrompre l'alimentation en électricité du client qui excède la charge hivernale maximale.

**Charge de base de l'énergie**

Un montant de charge de base de l'énergie par mois peut être fixé pour le client qui consomme 90 % de la consommation anticipée lorsque la SEY prévoit devoir faire appel à la production d'énergie au carburant diesel pour alimenter l'usage qui excède ce montant de charge de base de l'énergie. L'annexe tarifaire n$^{o}$ 39 est alors soumise à la Régie des entreprises de service public du Yukon pour être modifiée afin d'ajuster le tarif de l'énergie de façon à établir un tarif à deux paliers qui permet la même charge d'énergie pour la consommation d'énergie anticipée, avec un taux qui tient compte du coût additionnel pour la production d'énergie au carburant diesel applicable à toute l'énergie consommée en plus de la charge de base. Le tarif réduit nécessaire pour permettre la même charge d'énergie pour la consommation anticipée est applicable à l'énergie restante.

**Modifications des tarifs applicables :**

Pour la clause additionnelle relative au coût du carburant, consulter la clause additionnelle F. La clause additionnelle F s'applique exclusivement aux coûts de l'énergie, fixés à 0,0$ pour la prévision des prix de l'essence déposée le 20 novembre 2006.

***Electric Service Regulations* :**

Les *Electric Service Regulations*, approuvés par la Régie des entreprises de service public du Yukon font partie intégrante de la présente annexe relative aux tarifs et s'appliquent à la SEY et à tous les clients qui reçoivent des services d'approvisionnement en électricité de la SEY au Yukon. Il est possible de consulter les *Electric Service Regulations* aux bureaux de la SEY pendant les heures normales d'ouverture.

**Augmentation de la prime de puissance et du coût de l'énergie**

2007/94

La prime de puissance et le coût de l'énergie pour les modifications exigées font l'objet d'une augmentation par année civile à compter du 1er janvier 2010 et reposent sur la plus récente augmentation de l'indice de prix en chaîne pour les 12 mois inclusivement, pour le produit intérieur brut aux prix du marché pour le Canada, établi par Statistique Canada.

**Ajustement des frais fixes**

Les frais fixes sont ajustés pour tenir compte des coûts mensuels fixes établis dans toute convention d'achat d'énergie, ou dans les modifications à celle-ci, conclue entre un client industriel majeur d'une part et la SEY ou la YECL, d'autre part et qui a été approuvée par la Régie.

**O.I.C. 1995/090**
**PUBLIC UTILITIES ACT**

# PUBLIC UTILITIES ACT

Pursuant to sections 17 and 18 of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows:

**1.** Order-in-Council 1991/062 is hereby revoked.

**2.** The annexed Rate Policy Directive (1995) is hereby made.

Dated at Whitehorse, in the Yukon Territory, this 29th day of May, 1995.

_______________________________
Commissioner of the Yukon

**DÉCRET 1995/090**
**LOI SUR LES ENTREPRISES DE SERVICE PUBLIC**

# LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

Le Commissaire en conseil exécutif, conformément aux articles 17 et 18 de la *Loi sur les entreprises de service public*, décrète ce qui suit :

**1.** Le décret 1991/062 est, par les présentes, abrogé.

**2.** Les instructions sur la politique tarifaire (1995), paraissant en annexe, sont par les présentes adoptées.

Fait à Whitehorse, dans le territoire du Yukon, ce 29 mai 1995.

_______________________________
Commissaire du Yukon

## RATE POLICY DIRECTIVE (1995)

### Interpretation

**1.** In this Directive

"customer" refers to a purchaser of electricity; *«client»*

"government customer" means a retail customer

(a) who is a federal or territorial department or agency;

(b) a body, other than one carrying on a business with a view to making a profit, that derives all or substantially all of its funding from a body referred to in paragraph (a); *«client gouvernemental»*

"isolated industrial customer" means a customer engaged in manufacturing, processing, or mining and whose electrical service is not inter-connected with electrical service provided to any other customer; *«client industriel isolé»*

"major industrial customer" means a customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer; *«client industriel majeur»*

"province" has the same meaning as in the *Interpretation Act*; *«province»*

"retail customer" means a customer of Yukon Energy Corporation or of The Yukon Electrical Company Limited, other than a major industrial customer, an isolated industrial customer, or a wholesale customer; *«client au détail»*

"wholesale customer" means the Yukon Electrical Company Limited when it purchases electricity from Yukon Energy Corporation. *«client en gros»*

### Normal return on equity

**2.**(1) Subject to subsection (2), the Board must include in the rates of Yukon Energy Corporation and the Yukon Electrical Company Limited provision to recover a fair return on their equity used to finance their rate base.



## INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

### Définitions

**1.** Les définitions qui suivent s'appliquent aux présentes instructions :

«client» Acheteur d'électricité; *"client"*

«client au détail» Client de la Société d'énergie du Yukon ou de la Yukon Electrical Company Limited qui n'est ni un client industriel majeur, ni un client industriel isolé, ni un client en gros; *"retail Customer"*

«client en gros» La Yukon Electrical Company Limited lorsqu'elle achète de l'énergie de la Société d'énergie du Yukon; *"wholesale customer"*

«client gouvernemental» Client au détail qui est:

a) soit un organisme gouvernemental, un ministère fédéral ou territorial;

b) soit un organisme qui n'exploite aucune entreprise à des fins lucratives et dont le financement provient en totalité, ou pour l'essentiel, d'un organisme décrit à l'alinéa a); *"government customer"*

«client industriel isolé» Client qui se livre à une activité de fabrication, de traitement ou à l'exploitation d'une mine et dont l'approvisionnement en électricité est indépendant de celui de tout autre client; *"isolated industrial customer"*

«client industriel majeur» Client autre qu'un client industriel isolé qui se livre à une activité de fabrication, de traitement ou à l'exploitation d'une mine et dont la demande de pointe d'électricité dépasse 1 MW. *"major industrial customer"*

«province» S'entend d'une province au sens de la *Loi d'interprétation*. *"province"*

### Rendement normal sur la valeur nette

**2.**(1) Sous réserve du paragraphe 2, la Commission doit prévoir dans les tarifs de la Société d'énergie du Yukon et de la Yukon Electrical Company Limited les mesures pour réaliser un rendement équitable sur leur valeur nette utilisé pour financer leurs tarifs de base.

(2) The Board must include in the rates of the Yukon Energy Corporation provision to recover a fair return on the Corporation's equity, less one-half of one per cent (.5%).

(3) When finalizing the interim 1997 rates made by Board Order 1997-6, the Board may adjust the 1997 fair return provided on Yukon Energy Corporation's equity and on Yukon Electrical Company Limited's equity."

*(Section 2 replaced by O.I.C. 1998/32)*

## Normal principles to apply

**3.** Except to the extent otherwise stated by this Directive or the Act, the Board must review and approve rates in accordance with principles established in Canada for utilities, including those principles established by regulatory authorities of the Government of Canada or of a province regulating hydro and non-hydro electric utilities.

## Retail rates: non-government customers

**4.**(1) The Board must fix rates for retail customers, other than government customers, in accordance with the following rate policy for Yukon,

(a) the rates for non-government retail customers must be sufficient to recover costs that are not to be recovered from government customers or from major industrial customers;

(b) rates for each class of non-governmental retail customer must be the same throughout the Yukon without variation between Yukon Energy Corporation and The Yukon Electrical Company Limited customers;

(2) The Board must fix a runoff rate block for each non-government retail customer class applicable to all consumption by each customer of the class in excess of a specified consumption level per billing period, and such specified consumption level per customer is not to be less than 1,000 kWh for residential non-government retail customers and 2,000 kWh for general service non-government retail customers.

(3) The Board must fix runoff rates for each non-

(2) La Commission doit inclure dans les tarifs de la Société d'énergie du Yukon des mesures pour réaliser un rendement équitable sur la valeur nette de cette dernière, moins 5 dixièmes pour cent (,5 %).

(3) Lorsqu'elle met au point les tarifs intérimaires de 1997 établis par l'ordonnance 1997-6 de la Commission, cette dernière peut rajuster le rendement équitable de 1997 découlant de la valeur nette de la Société d'énergie du Yukon et de la Yukon Electrical Company Limited.

*(Article 2 remplacé par décret 1998/32)*

## Application des principes normaux

**3.** Sauf indication contraire dans les présentes instructions ou dans la Loi, la Commission examine et approuve les tarifs aux clients selon les principes établis au Canada pour des services publics, y compris les principes établis par les organismes régulateurs des gouvernements fédéral et provinciaux réglementant les entreprises de services publics, que ces derniers soient reliés à l'électricité ou pas.

## Tarifs au détail pour les clients non-gouvernementaux

**4.**(1) La Commission fixe les tarifs pour les clients au détail non-gouvernementaux selon la politique tarifaire suivante pour le Yukon :

a) les tarifs pour les clients non-gouvernementaux doivent suffire à générer les recettes nécessaires afin de recouvrer les coûts, lesquels ne doivent pas être récupérés des clients gouvernementaux ou des clients industriels majeurs;

b) les tarifs pour chaque catégorie de clients au détail non-gouvernementaux s'appliquent uniformément à la grandeur du Yukon et sans distinction entre la Société d'énergie du Yukon et la Yukon Electrical Company Limited.

(2) La Commission doit déterminer une série de primes de dépassement pour chaque catégorie visée de clients au détail non-gouvernementaux, lesquelles s'appliquent à la consommation de chaque client qui excède un niveau de consommation déterminée, au cours d'une période de facturation et un tel niveau de consommation déterminé par client ne peut s'appliquer qu'à la consommation atteignant 1 000 kWh ou plus pour la catégorie résidentielle de clients au détail non-gouvernementaux et de 2 000 kWh pour la catégorie de services généraux de clients au détail non-gouvernementaux.

(3) La Commission doit déterminer des primes de

government retail customer class on the basis of rate design principles to promote economy and efficiency, and separate runoff rates may be allowed in this regard for customers in different communities or rate zones, provided that such runoff rates for customers in each non-government retail customer class are fixed for each community or rate zone throughout Yukon in accordance with the same rate design principles.

dépassement pour chaque catégorie de clients au détail non-gouvernementaux sur la base de principes pour l'élaboration des taux afin de favoriser l'efficacité et l'économie et, dans cette optique, des primes de dépassement peuvent être permises à l'intention de clients demeurant dans différentes communautés ou dans des zones où les taux diffèrent, en autant que ces primes de dépassement dans chaque catégorie de clients au détail non-gouvernementaux soient les mêmes pour chaque communauté ou chaque zone tarifaire à travers le Yukon, conformément aux principes pour l'élaboration des tarifs.

### Retail rates: government customers

**5.**(1) The Board must fix rates for government customers in accordance with the following power rate policy for Yukon

(a) rates for government customers may be adjusted so as to simplify the rate structure and make the rates more consistent throughout Yukon;

(b) the rate for government customers in a community may not be lower than the rate for similar service to non-government retail customers in that community.

(2) Upon application of Yukon Energy Corporation, The Yukon Electrical Company Limited, or a customer, the Board must determine whether a customer is or is not a government customer.

### Tarifs au détail pour les clients gouvernementaux

**5.**(1) La Commission fixe les tarifs pour les clients gouvernementaux selon la politique tarifaire énergétique du Yukon qui suit :

a) les tarifs pour les clients gouvernementaux peuvent être ajustés aux fins de simplifier la structure tarifaire et d'uniformiser les tarifs à la grandeur du Yukon;

b) le tarif pour les clients gouvernementaux dans une agglomération ne peut être moindre que le tarif pour un service semblable pour les clients au détail non-gouvernementaux dans cette agglomération.

(2) À la demande de la Société d'énergie du Yukon ou de la Yukon Electrical Company Limited, ou d'un client, la Commission prend une décision sur le statut de client gouvernemental d'un client.

### Rates - major and isolated industrial customers

**6.**(1) The Board must ensure that the rates charged to major industrial power customers, whether pursuant to contracts or otherwise, are sufficient to recover the costs of service to that customer class; those costs must be determined by treating the whole Yukon as a single rate zone and the rates charged by both utilities must be the same.

(2) Rates of isolated industrial customers served by Yukon Energy Corporation or The Yukon Electrical Company Limited must conform with any contract between the customer and Yukon Energy Corporation or The Yukon Electrical Company Limited and the costs and revenues related to those contracts may not be considered by the Board when establishing rates for other customers.

### Tarifs pour les clients industriels majeurs et isolés

**6.**(1) La Commission doit s'assurer que les tarifs facturés aux clients industriels majeurs, en vertu d'un contrat ou autrement, suffisent à recouvrer les coûts du service pour cette catégorie de clients. Ces coûts sont déterminés en considérant tout le Yukon comme une zone tarifaire unique et les tarifs facturés par les deux services publics doivent être les mêmes.

(2) Les tarifs s'appliquant aux clients industriels et isolés desservis par la Société d'énergie du Yukon ou la Yukon Electrical Company Limited doivent être conformes à tout contrat entre le client et ces sociétés; les coûts et les revenus reliés à ces contrats ne peuvent être considérés par la Commission lorsqu'elle établit les tarifs pour d'autres clients.

### Wholesale rates

**7.** The Board must fix rates of Yukon Energy Corporation for the wholesale power customer in accordance with the following rate policy for Yukon:

(a) Yukon Energy Corporation shall sell electricity to The Yukon Electrical Company Limited at the same demand rate and the same energy rate throughout the Yukon and those rates must be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other customers;

(b) the wholesale rate to The Yukon Electrical Company Limited shall include appropriate provisions to ensure that Yukon Energy Corporation will recover its costs for retail and major industrial power service with adoption of the rates for retail power customers and major industrial power customers as specified herein.

### Fuel Price adjustment

**8.** The Board must permit Yukon Energy Corporation and The Yukon Electrical Company Limited to adjust their rates to retail customers, major industrial customers, and isolated industrial customers so as to reflect fluctuations in the prices for which the two utilities pay for diesel fuel, without the requirement for specific application to and approval of the Board.



### Tarifs de gros

**7.** La Commission doit déterminer les tarifs facturés par la Société d'énergie du Yukon au client en gros selon la politique tarifaire du Yukon qui suit :

a) la Société d'énergie du Yukon vend de l'électricité à la Yukon Electrical Company Limited au même tarif de demande et au même tarif d'énergie à la grandeur du Yukon et ces tarifs doivent suffire à la Société d'énergie du Yukon pour recouvrer les coûts qui ne sont pas recouverts de ses autres clients;

b) le tarif de gros facturé à la Yukon Electrical Company Limited comprend les mesures appropriées pour permettre à la Société d'énergie du Yukon de recouvrer ses coûts de service au détail et ses coûts de service aux clients industriels majeurs au moyen de tarifs qui s'appliquent à ces services en vertu des présentes.

### Ajustement du prix du combustible

**8.** La Commission permet à la Société d'énergie du Yukon et à la Yukon Electrical Company Limited d'ajuster les tarifs facturés aux clients au détail, aux clients industriels majeurs et aux clients industriels isolés de manière à refléter les fluctuations des prix payés pour le mazout par ces deux sociétés, sans avoir à faire une demande particulière à la Commission pour obtenir son autorisation.